CHAPTER 1

Michigan Integrated Resource Plan Report

1. Executive Summary

The 21st Century Energy Plan (Plan) was created as a collaborative industry-wide process to assess the projected need for electrical generating capacity in Michigan over the near and long-term future and to provide recommendations on the state's electric energy policy. The CNF Update Workgroup was responsible for modeling the state's electric generation resource needs and scenario development. The Workgroup combined the demand forecast with the inventory of existing resources to determine the timing and characteristics of future capacity need. In addition, the Workgroup developed a set of scenarios likely to have a significant impact on the modeling results and provided an assessment of the scenarios. NewEnergy Associates was retained to perform the data development and modeling.

The purpose of NewEnergy Associates integrated resource plan (IRP) modeling 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 fit Michigan's needs from a reliability and economic perspective. This study was designed to be comprehensive, by evaluating a wide-ranging set of in-state resources and fully modeling economy energy markets within the eastern interconnection.

The IRP assessment exhibited a number of key resource planning results. Reliability analyses indicate that Michigan is in need of near-term capacity to meet planning reserve criteria. This need is demonstrated by the model's adoption of three combustion turbines, as soon as practical, in 2008. After the model added sufficient capacity for reliability, the model adopted baseload capacity for the state. The expansion plan selected energy producing baseload resources as soon as the construction schedule permits. Baseload coal units, when they became available in 2012, were the preferred resource. Throughout the remaining study horizon, coal continued to be the preferred resource for Michigan. The near-term need for immediate capacity to meet planning reserve criteria and the need for baseload energy was further underscored in a variety of sensitivities and scenarios. Emissions standards represent a major contingency that can be managed by use of energy efficiency and renewable energy options.

2. Introduction

2.1 Purpose of the Integrated Resource Plan

The purpose of this integrated resource IRP analysis modeling 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 fit Michigan's needs from a reliability and economic perspective. This study was designed to be comprehensive, by evaluating a wide-ranging set of in-state generation, energy efficiency, and transmission resources and fully modeling economy energy markets within the eastern interconnect.

2.2 Overview of Integrated Resource Plan Process

Step 1 – Review Planning Policies and Develop Key Assumptions

- Identify and review planning policies for the Plan, 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:
  - Load growth
  - Discount and inflation rates
  - Fuel prices
  - Emission allowance prices

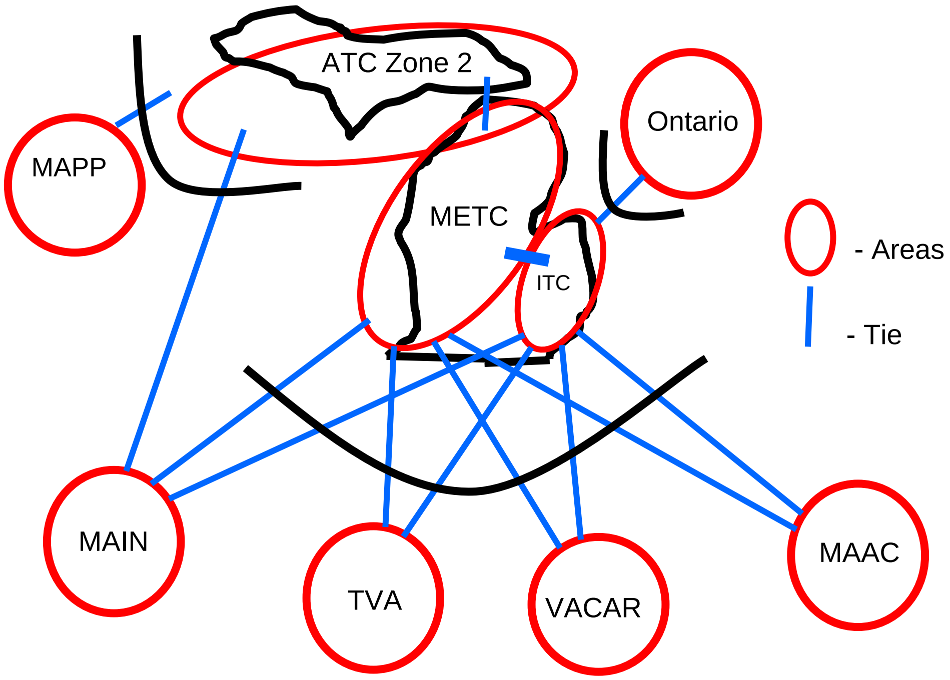
- Identify sources of uncertainty and define and develop future scenarios to capture the range of potential variations in such uncertainties.

The study was undertaken on a regional basis within Michigan. The 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, reliability and transmission modeling included ITC and METC collectively, referred to as the Michigan Electric Coordinated System (MECS).[1] Economy energy was sourced from five regions within the U.S. Because of Ontario's policy initiative to decommission all of its coal-based generation, Ontario was not considered as a source of economy energy. These regions are shown in Figure 1 on the following page.

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 in Figure 1 shows the key transmission constraints affecting the Michigan transmission system.

[1] Although ITC and METC have recently merged, the use of these three regions continues to reflect historic electric power transfer limits between the regions.

Figure 1: Michigan System Representation



Much of the data collected for the 2005 Capacity Needs Forum was determined to be current and appropriate to use for the Plan. This included the following types of existing and proposed resources:

- Supply-side resources
  - Existing generation units
  - Estimated retirements
  - Optional new supporting technologies

- Transmission interfaces
  - Existing capabilities
  - Optional enhancements

The data items compiled for each of the resource types include:

- Load representations
  - Forecast annual energy and peak demand growth
  - Consumption patterns: monthly peaks, energy, 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 operations and maintenance (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 fuel-related 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 and emissions rates

- Demand side resource representations
    - Annual energy savings
    - Utility administrative and program costs (fixed and/or per participant)
    - On-peak capacity savings

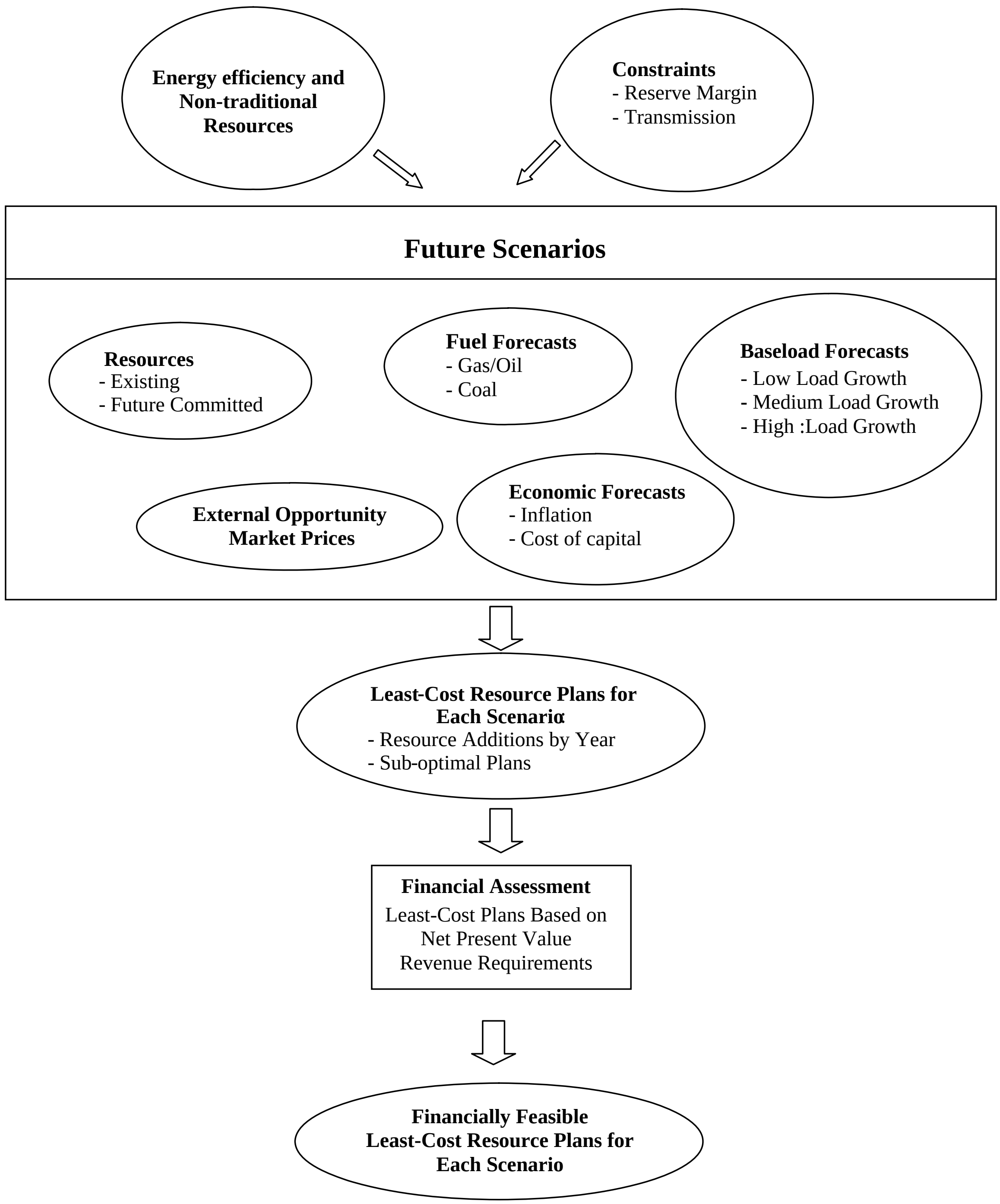
- Transmission interface representations
    - Bi-directional megawatt (MW) capabilities

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

- Performance measure(s), for example net present value (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
- Emissions constraints
- Sensitivity analysis criteria
- Emissions allowance prices

Step 2 – Optimize Michigan's Supply-Side Portfolio (Including new Demand Side Resources):

Figure 2: Optimization Process



Step 3 – Plan Integration:

- Screen all available future resource types on a full life-cycle, present value levelized, $/MWh bus-bar cost over a range of potential capacity factors.
- Eliminate from consideration, resources that are unable to compete economically over the study horizon.
- Schedule in all alternative generation (i.e., wind, landfill gas, anaerobic digestion, and combined heat and power) and demand side alternatives.
- Identify robust supply-side resources (resources selected under most scenarios).
- Identify resources which require near-term capital commitments.
- Achieve and maintain near-term reliability while attempting to meet a long-term 15 percent reserve margin.
- Identify key near-term resource contingencies for the optional plans, based upon quantifiable and subjective criteria:
  - Fuel diversification
  - Flexibility
  - Others

3. Planning Process

3.1 Planning Tools

The Integration Team relied on software developed by NewEnergy Associates, LLC (NewEnergy), to model electric generation resource needs. NewEnergy has developed several proprietary planning models to assist with electric capacity planning. These models are comprehensive, allowing comparisons of demand side measures along with Central Station and non-Central Station 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 allows planners 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 U.S. 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 provided in Section 7.

4. Modeling Requirements for Generation Resources

4.1. Existing System

4.1.1 Existing Central Station Generation Resources

All existing generation was reviewed in the CNF project by Consumers Energy, Detroit Edison, Wolverine Power Supply Cooperative, and Lansing Board of Water and Light (BWL). Plan participants agreed that the CNF data remained accurate and was appropriate for use in this modeling initiative. Existing resources consisted of natural gas combined cycle and combustion turbine units; hydroelectric run-of-river, storage, and pumped storage units; coal, natural gas, and oil steam turbines; and nuclear. The existing resources are listed in Section 6, and summarized in Figure 3 through Figure 6.

Figure 3: ITC Existing Capacity Mix

- ITC Area (see Table 20, p. 43)

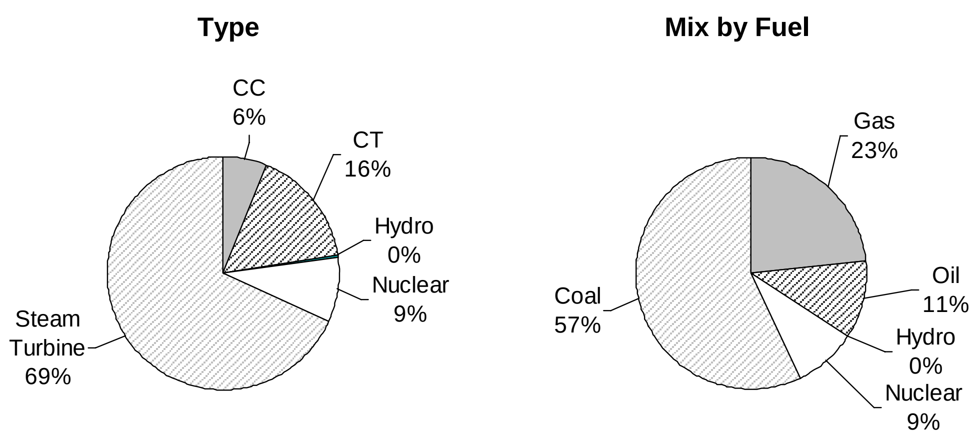


Figure 4: METC Existing Capacity Mix

- METC Area (see Table 21, p. 46)

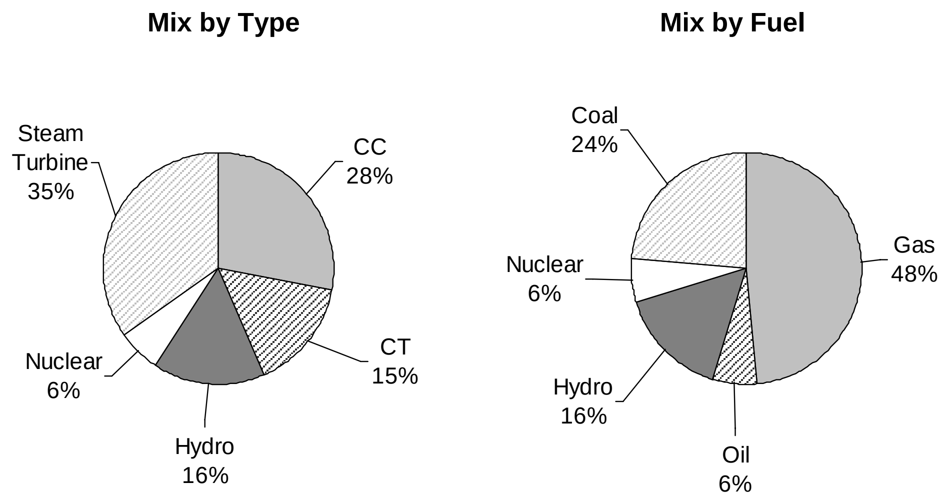


Figure 5: Wolverine Existing Capacity Mix

- Wolverine (see Table 22, p. 51)

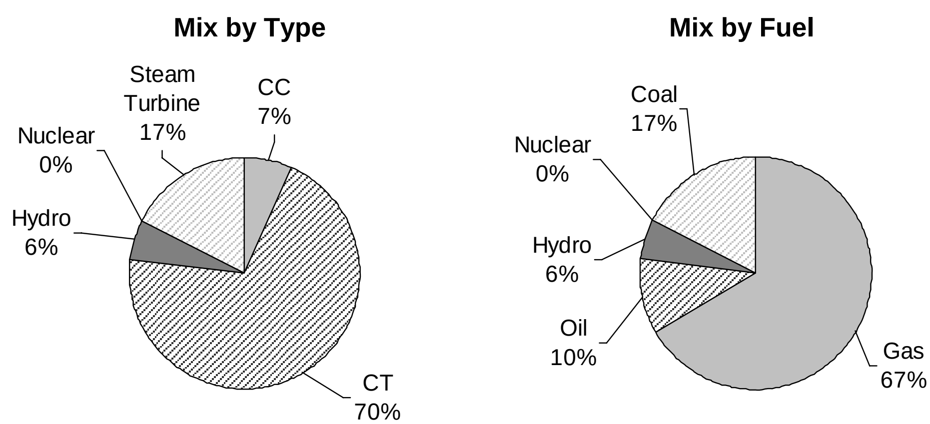
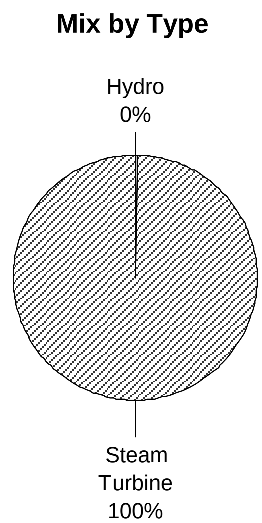
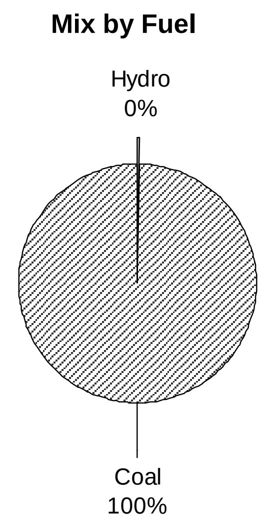


Figure 6: Lansing Board of Water & Light Existing Capacity Mix

- Lansing BWL (see Table 23, p.51)





4.1.2 Existing Non-Central Station Generation Resources

All non-Central Station generation was reviewed by Consumers, Detroit Edison, Wolverine, and the Lansing Board of Water and Light. Plan participants concluded that this data was accurate and reasonable for this modeling initiative. Non-Central Station resources consist of landfill gas, biomass, anaerobic digestion, other steam turbines, and wind. The existing resources are listed in Section 6, and summarized in Figure 7 and Figure 8.

Figure 7: ITC Non-Central Station Mix

- ITC Area (see Table 20, p. 43)

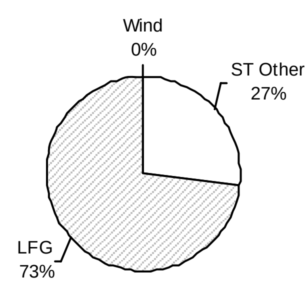
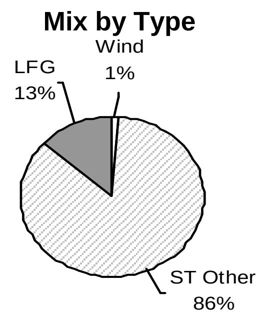


Figure 8: METC Non-Central Station Generation Mix

- METC Area (see Table 21, p. 46)



- Wolverine (see Table 22)
  - No Non-Central Station Generation
- Lansing BWL (see Table 23)
  - No Non-Central Station Generation

The CNF Update Workgroup provided the following assumptions for unit retirements.

- Coal units will retire after 65 years.
- Nuclear units will retire after 60 years.
- Combined cycle units will retire after 40 years.
- Combustion turbine units will retire after 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 detailed schedule of unit retirements is shown in Table 24 (p. 52). Table 1 summarizes the total capacity retirements each year, through the course of the study horizon.

Table 1: Aggregate Unit Retirements

Year	Modeled Capacity Retired (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

4.1.3 Existing Demand Side Resources

No existing demand side resources are assumed to be operational.

4.1.4 Existing Transmission Resources

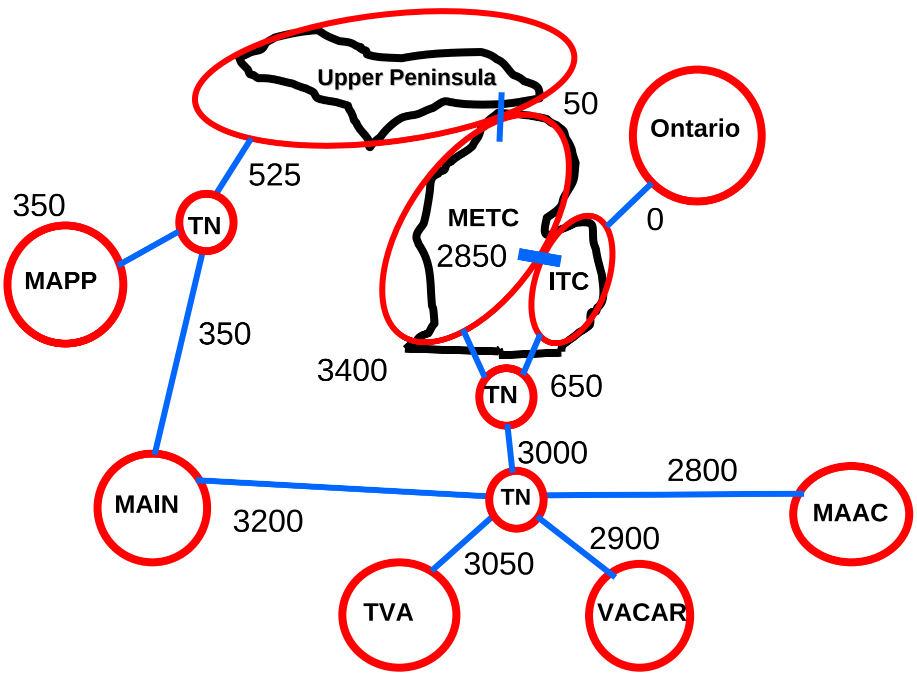
The Transmission and Distribution Workgroup from the 2005 Capacity Needs Forum was responsible for estimating the transmission import capability into Michigan. The Workgroup's specific responsibilities included:

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; and
3. reviewing issues that may have an impact on the state's ability to utilize or expand its transmission system.

The Figure 9 represents the results of the Transmission and Distribution Workgroup's estimation of import capability. These assumptions were augmented with import capabilities for the Upper

Peninsula, provided by ATC.[2] Interface capability between the Upper Peninsula and METC was assumed to be 50 MW, at the Straights of Mackinaw. Following the completion schedule planned for the Upper Peninsula northern umbrella project (NUP) transmission upgrades, ATC interface capability with external markets is expected to increase to 224 MW in 2005, 300 MW in 2006, 325 MW in 2008, and 525 MW in 2010.

Figure 9: Transmission Interface Capability in 2009 (in MW)



Interface	Capacity (MW)	ST[1] From	ST To
All to MECS	3000	TN[2] Hub	Michigan
Into METC	3400	TN Hub	METC
METC to ITC	2850	METC	ITC
Into ITC	650	TN Hub	ITC
Into Ontario	0	ITC	Ontario
Notes: [1] ST refers to Strategist. [2] TN refers to transfer node.			

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

4.2 Resource Options

4.2.1 Options Overview

The CNF Update Workgroup selected the base technologies for Central Station utility generation options. The generation options include:

- Pulverized coal (super-critical, sub-critical and ultra super-critical)
- Circulating fluidized-bed boilers (CFB)
- Nuclear
- Integrated gasification combined cycle (IGCC)
- Natural gas 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. While the Workgroup included ultra super-critical in its inventory of production technology options, this technology was not used in the modeling phase of this study. The generation options emissions assumptions are shown in Table 2.

4.2.2 Generation Options

The Table 3 summarizes the CNF Update Workgroup's estimate of costs for the generation options. All dollar figures are represented in 2006 real dollars.

Table 2: Generation Options Emissions Assumptions

Plant Type	SO_2 (lbs./MMBtu)	NOx (lbs./MMBtu)	Hg (lbs./MMBtu)	CO_2 (lbs./MMBtu)
Pulverized Coal Sub-Critical	0.05	0.08	1.22×10^{-6}	201
Pulverized Coal 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	0	0	0
Natural Gas Combined Cycle	.001	0.03	0	120
Natural Gas Combustion Turbines	.001	0.03	0	120
Note: MMBtu – million British Thermal Unit (BTU)				

The Workgroup 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 either eastern or PRB coal.

4.2.3 Other Assumptions

To more accurately represent the expected operating costs of natural gas combined cycle generation, $20.18/kW (2006$) was added to the plant's annual fixed O&M expenses, to represent the cost of reserving annual pipeline capacity. Pipeline capacity is needed to support the transmission of gas from Louisiana to Michigan. For natural gas combustion turbines, $5.12/kW (2006$) was added to the annual 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[3] was added to the commodity price for gas delivered under the reserved pipeline capacity.

All future generation options include a transmission interconnection cost based on 5 percent of the capital investment for a generic coal unit ($77.56/kW, 2006$).

4.2.4 Renewable Options

The CNF Update, Renewable Energy, and Alternative Energy Technologies Workgroups were responsible for compiling an inventory of existing renewable energy, distributed generators, combined heat and power (CHP), and other generation resources in Michigan. These groups were 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 Renewable Energy Workgroup provided estimates for the capacity potential for renewable resources, investment costs, operating costs, and operating characteristics. Renewable options considered for this study include: landfill gas, anaerobic digestion, cellulosic biomass, combined heat and power, and wind.

The Table 4 outlines the schedule of cumulative estimated available new nameplate capacity (MW) by renewable resource type used in the model.

[3] MMBtu – million British Thermal Units is a standard unit of measurement used to denote both the amount of heat energy in fuels and the ability of appliances and air conditioning systems to produce heating or cooling. A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit. Since BTUs are measurements of energy consumption, they can be converted directly to kilowatt-hours (kWh) (3,412 BTUs = 1 kWh).

Table 3: Generation Options Cost Table

Type	Capacity (MW)	Construction Cost ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Assumed First Year Available
Pulverized Coal Sub-critical	500	1,478	42.26	1.86	9,496	2012
Pulverized Coal Super-critical	500	1,551	44.91	1.75	8,861	2012
Pulverized Coal Ultra super-critical	500	1675	47.16	1.84	8000	2012
Fluidized Bed	300	1.628	46.11	4.37	9,996	2012
UP CFB	150	1.766	46.11	4.37	9,996	2012
IGCC	550	1,785	61.30	0.98	9,000	2012
IGCC-PRB	550	1,999	61.30	0.98	10,080	2012
Nuclear	1,000	2,352	70.04	0.55	10,400	2018
Natural Gas , CC	500	599	5.57	2.19	7,200	2009
Natural Gas , CT	160	425	2.19	3.83	10,450	2008

Table 4: Modeled Renewable Capacity (Cumulative New Generation in MW)

Year	Landfill Gas	Anaerobic Digestion	Cellulosic Biomass	Combined Heat & Power	Wind
2006	0	0	0	0	0
2007	24	4	0	36	10
2008	47	11	41	71	87
2009	71	18	81	107	88
2010	94	24	122	143	119
2011	118	30	162	178	154
2012	120	43	207	178	272
2013	123	53	251	178	360
2014	126	64	296	178	410
2015	128	73	340	178	465
2016	131	82	385	178	525
2017	134	83	392	178	535
2018	136	85	401	178	546
2019	139	87	410	178	559
2020	142	89	419	178	571
2021	145	91	428	178	583
2022	147	93	437	178	595
2023	150	95	446	178	609
2024	153	97	456	178	622
2025	155	99	465	178	634
Values shown are nameplate capacity.					

Table 5 outlines the capacity factor and cost assumptions for the renewable resources that were modeled.

Table 5: Capacity Factor and Cost Assumptions for Renewable Resources Modeled

	Capacity (%)	Cost (¢/kWh)
Landfill gas	90	7.4
Wind	28	7.4
CHP	90	7.9
Anaerobic digesters	80	8.2
Cellulosic biomass	80	6.9

All non-Central Station 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. As an alternative, for modeling in certain scenarios, the cost of renewable energy options was also included as a fixed-price, long-term contract with no escalation adjustments. Wind was assumed to have zero emissions. Cellulosic biomass was considered to be greenhouse gas neutral, and cogeneration, landfill gas, and anaerobic digestion emissions were assumed to result in zero net emissions.

4.2.5 Demand Side Options

The estimated potential impacts of energy efficiency programs were represented as a resource in the Energy Efficiency Scenarios. Table 6 represents the annual cumulative capacity and energy savings associated with the base energy efficiency program. These MW and gigawatt hour (GWh) savings include approximately 570 MW of new load management program impacts. In addition, a sensitivity on the energy efficiency was performed to represent more conservative estimates of achievable energy efficiency combined with higher program costs.

Table 6: Modeled Energy Efficiency Program Cost and Impacts

	Base Case Energy Efficiency			Reduced Penetration Energy Efficiency		
Year	Cost ($000')	Capacity[1] (MW)	Energy (GWh)	Cost ($000)	Capacity[1] (MW)	Energy (GWh)
2007	129,390	385	675	151,390	349	388
2008	130,247	513	1,334	152,247	442	760
2009	131,077	640	1,992	153,077	532	1,132
2010	131,880	764	2,651	153,880	620	1,504
2011	132,661	886	3,309	154,661	706	1,875
2012	197,022	1,069	4,349	217,222	814	2,498
2013	197,764	1,250	5,389	217,964	919	3,120
2014	198,489	1,429	6,429	218,689	1,023	3,742
2015	199,200	1,609	7,469	219,400	1,127	4,364
2016	199,897	1,787	8,509	220,097	1,229	4,987
2017	136,982	1,902	9,167	158,982	1,309	5,358
2018	137,656	2,016	9,825	159,656	1,387	5,729
2019	138,320	2,130	10,483	160,320	1,464	6,100
2020	138,975	2,243	11,141	160,975	1,541	6,471
2021	139,623	2,356	11,798	161,623	1,619	6,842
2022	140,263	2,468	12,456	162,263	1,695	7,213
2023	140,897	2,579	13,114	162,897	1,770	7,585
2024	141,525	2,690	13,772	163,525	1,844	7,956
2025	142,148	2,801	14,430	164,148	1,920	8,327

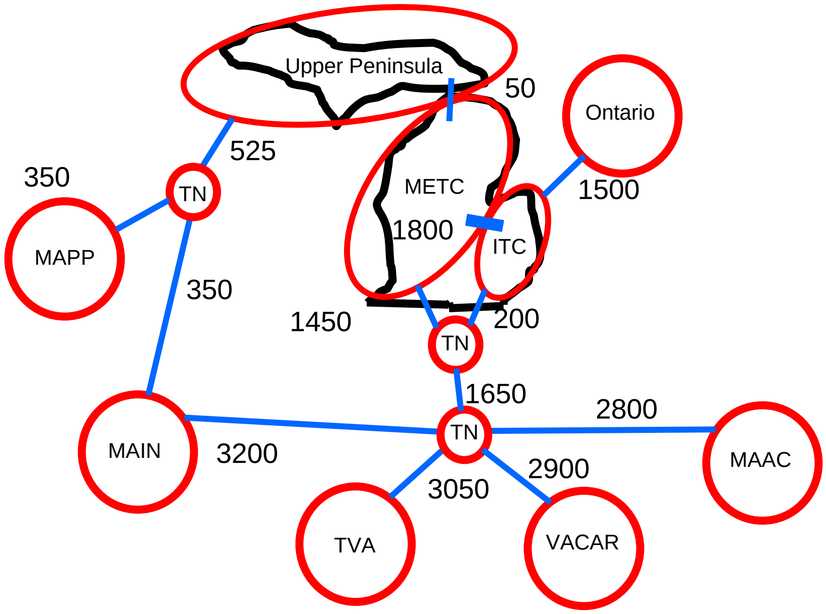
Note: [1] Includes 570 MW of new load management by 2015

4.2.6 Transmission Options

For the purpose of the Michigan IRP modeling, external capacity selling into or purchasing from the Michigan market was excluded. The external market was utilized to represent only non-firm economy energy interchanges.

Two transmission scenarios were modeled, one representing a Low Import case and the other an Expanded Transmission case. The Low Import case assumed 1,500 MW of sales utilizing Michigan transmission to transfer power from MISO to Ontario Hydro. Figure 10 represents transfer capabilities modeled for the Low Import case.

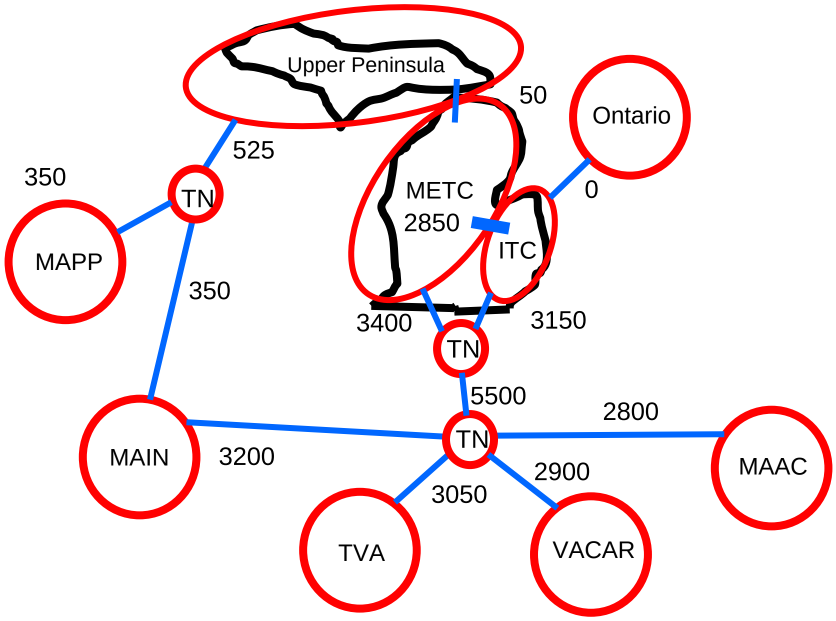
Figure 10: Low Estimate of Transmission Import Capabilities in 2009 (in MW)



Interface	Capacity (MW)	ST From	ST To
All to MECS	1650	TN Hub	Michigan
Into METC	1450	TN Hub	METC
METC to ITC	1800	METC	ITC
Into ITC	200	TN Hub	ITC
Into Ontario	1500	ITC	Ontario
Notes: TN refers to transfer node and ST refers to Strategist.			

The Expanded Transmission case assumed an additional 2,500 MW of transfer capability from the South into ITC with an option capital cost of \$800 million, of which \$640 million was assumed to be paid by Michigan. The remaining \$160 million was assumed to be paid by all transmission users in the rest of the MISO footprint. Figure 11 represents the impact of this 2,500 MW expansion transfer capability.

Figure 11: Expanded Estimate of Transmission Import Capability in 2009 (in MW)



Interface	Capacity (MW)	ST From	ST To
All to MECS	5500	TN Hub	Michigan
Into METC	3400	TN Hub	METC
METC to ITC	2850	METC	ITC
Into ITC	3150	TN Hub	ITC
Into Ontario	0	ITC	Ontario
Notes: TN refers to transfer node and ST refers to Strategist.			

The estimated 2009 transfer capabilities into Michigan's Lower Peninsula under the base, high import, and low import cases are shown in Table 7:

Table 7: Key Interface Capabilities

	Base Case (MW)	Expanded (MW)	Low Import (MW)
Into Michigan	3,000	5,500	1,650
Into METC	3,400	3,400	1,450
Into ITC	650	3,150	200
METC/ITC	2,850	2,850	1,800

4.3 Additional Assumptions

4.3.1 System Reserve Margin 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. 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.

For the Expanded Transmission sensitivity, the reserve margin requirement for the state was lowered to 12 percent. This reflects the reliability benefit that would be expected to result from the additional transfer capability into the state.

4.3.2 Demand Forecast

The CNF Update Workgroup was charged with preparing a base electric demand and energy forecast for the period running from 2006 to 2025 for use in modeling for the Plan. The projections rely primarily on forecast data provided by members of the Workgroup including: Consumers Energy, Detroit Edison, Wolverine Power Supply Cooperative, Michigan municipal utilities, We Energies, and Wisconsin Public Service. Due to the uncertainties in forecasting electric demand, forecast sensitivities were also developed by the Workgroup to represent low load growth and high load growth assumptions.

Michigan's total electricity needs from 2006 to 2025 are expected to grow from 112,183 to 143,094 GWh (27.6% cumulative, or about 1.3% per year). Over the same time period, peak demand is expected to grow from 23,756 to 29,856 MW (25.7% cumulative, or about 1.2% per year).

4.3.3 Fuel Forecast

Coal Price Forecast

Delivered coal forecasts were generated for 10 of the 13 EIA-defined coal demand regions (see Figure 12). These forecasts were sourced from four of the 14 EIA-defined coal supply regions shown in Figure 13.

Figure 12: Coal Demand Regions

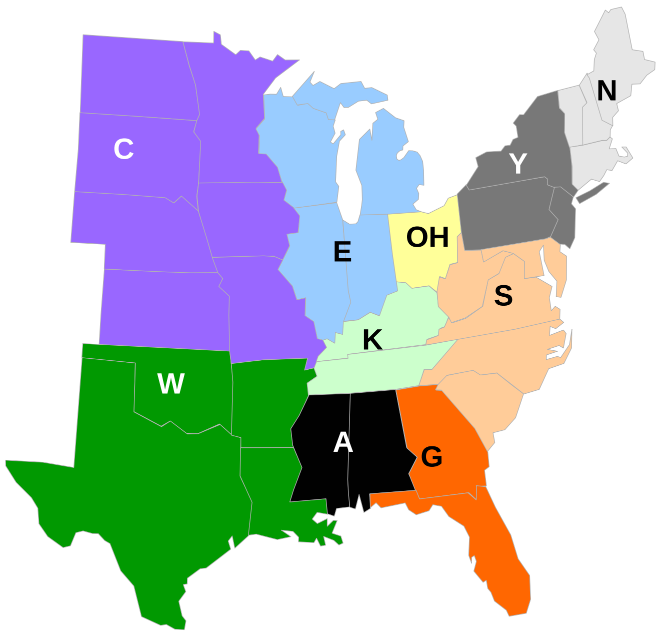
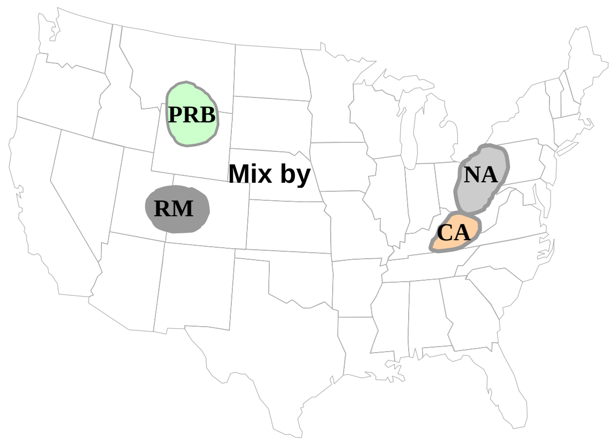


Figure 13: Coal Supply Regions



The average transportation cost between each supply and demand region was obtained from the EIA 2006 Annual Energy Outlook. Additionally, an annual transportation cost escalation rate of 2 percent was adopted, which is the rate from the EIA 2006 Annual Energy Outlook. Table 8 enumerates the transportation charges between each of the supply regions and the "EN" region, where Michigan is based.

Table 8: Estimated Coal Transportation Costs

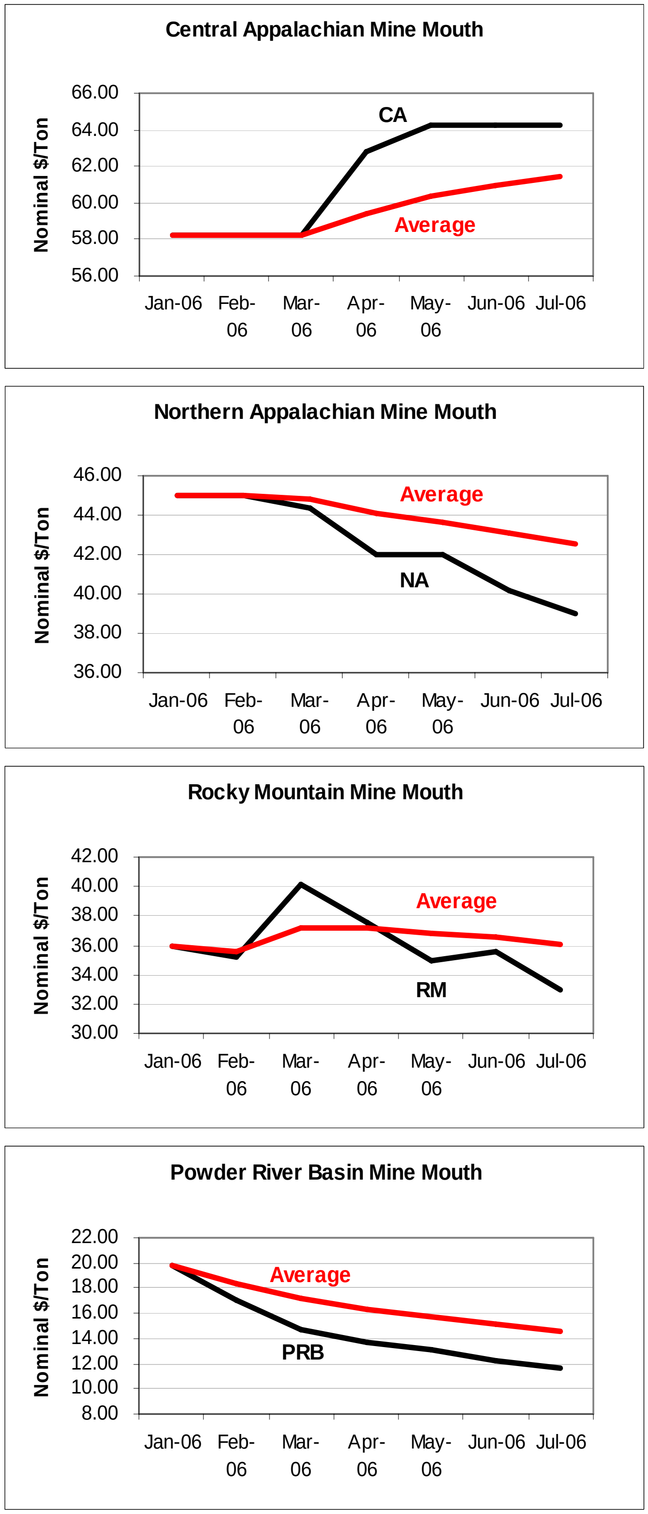
Demand Region[1]	Supply Region[2]	Average Transportation Cost (2006$)
EN	Powder River Basin	13.88
EN	Northern Appalachia	9.20
EN	Central Appalachia	10.75
EN	Rocky Mountain	21.99

[1] Michigan is located in the EN region.
[2] See Figure 13 for a map of the supply regions.

The starting free on board (FOB) mine price for coal was calculated for four supply regions within the United States: the Powder River Basin (PRB), Northern Appalachia, Central Appalachia, and Rocky Mountain. For each of the supply regions, the initial coal cost was calculated based on a seven month average of historical mine mouth prices (January to July, 2006); see Figure 14. This rate was then escalated each year, using the rates indicated in Table 9 (p. 30) to develop the forecast shown in Figure 15. The annual year-to-year percent change from the EIA 2006 Annual Energy Outlook mine mouth forecast for PRB, Rocky Mountain, Central Appalachia, and Northern Appalachia supply regions were utilized to preserve the base trends of the EIA forecast.

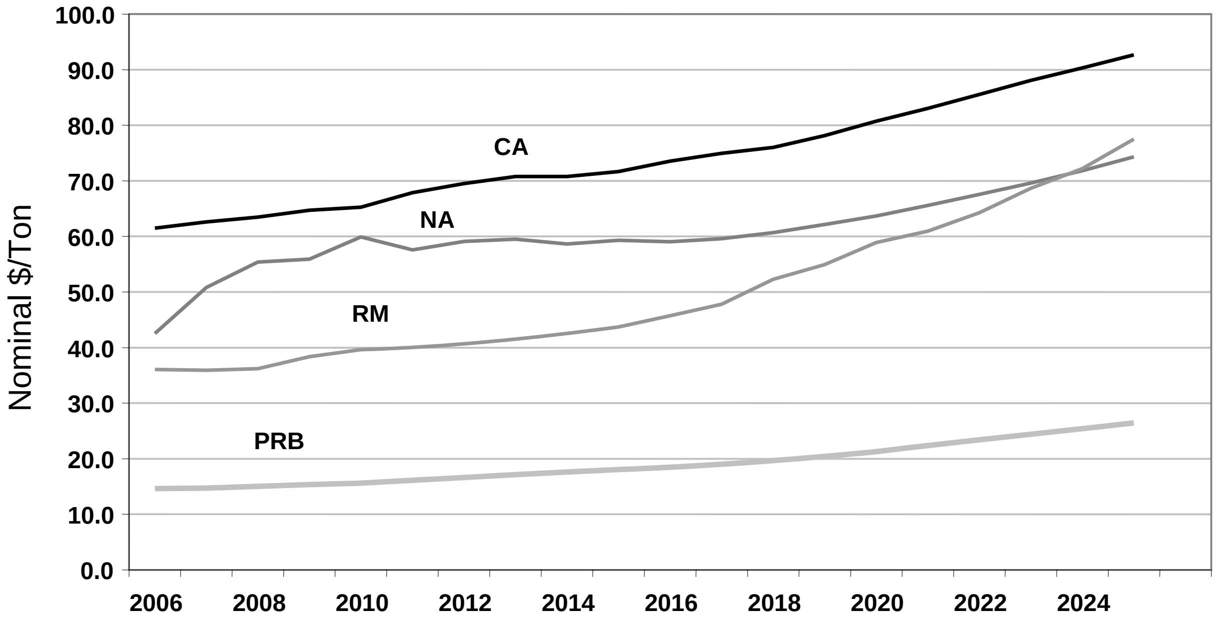
A blend of coal for each Michigan plant was developed from FERC Form 423 data and participant input. The final delivered price of coal was the sum of the mine mouth forecast (see Figure 15) and the average transportation charges, weighted to reflect the coal blend of coal used at each Michigan power plant.

Figure 14: Historical Mine Mouth Prices



Source: EIA Coal News and Markets – Average reflects a month running average.

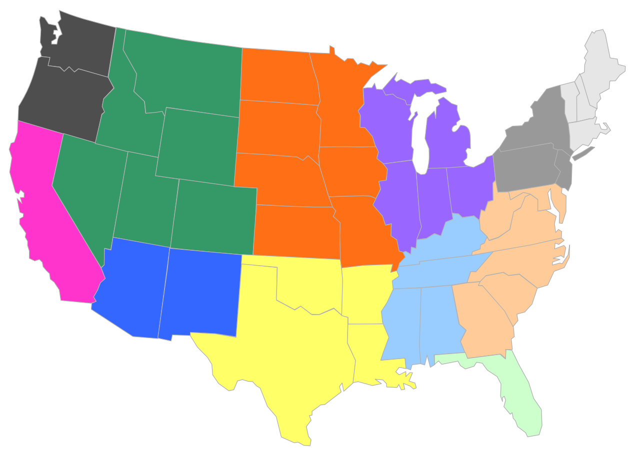
Figure 15: Mine Mouth Forecast



Natural Gas Price Forecast

The starting point for the Natural Gas Price Forecast was the Lower 48 Average Wellhead price forecast from the EIA 2006 Annual Energy Outlook. The process for forecasting natural gas prices concluded with a delivered price for 12 EIA-defined distribution regions, shown in the Figure 16.

Figure 16: EIA Natural Gas Distribution Regions



Source: EIA, 2006, Table 102: Lower 48 Natural Gas Production and Wellhead Prices by Supply Region.

The EIA Wellhead forecast was adjusted upward by 13.3 percent to account for the median historical difference between wellhead prices and Henry Hub Prices. This upward adjustment resulted from 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 percentage difference was used to scale the Wellhead price to Henry Hub, which is the same methodology employed by EIA.[4] The difference between the EIA delivered price forecast[5] and the Henry Hub forecast (see Figure 17) was used to create a matrix of basis points between Henry Hub and the various distribution regions depicted in Figure 16.

The year–to–year percent change from the wellhead price forecast from the EIA 2006 Annual Energy Outlook was used to preserve the base trends of the EIA forecast. The starting price for the forecast was the rolling one-month average of 18-month NYMEX futures strips (September 2006 through February 2008).

Figure 17: Henry Hub Natural Gas Price Forecast

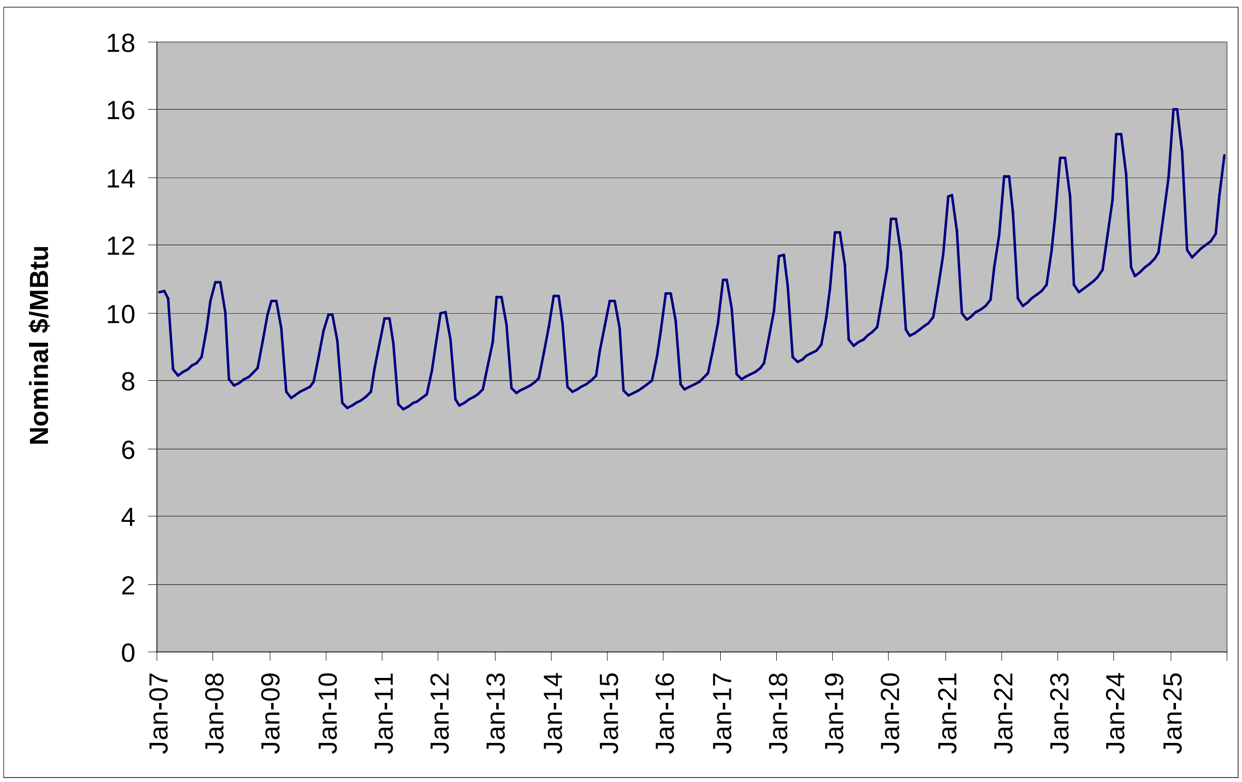


Figure note: Peaks reflect winter, and valleys reflect summer prices.

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

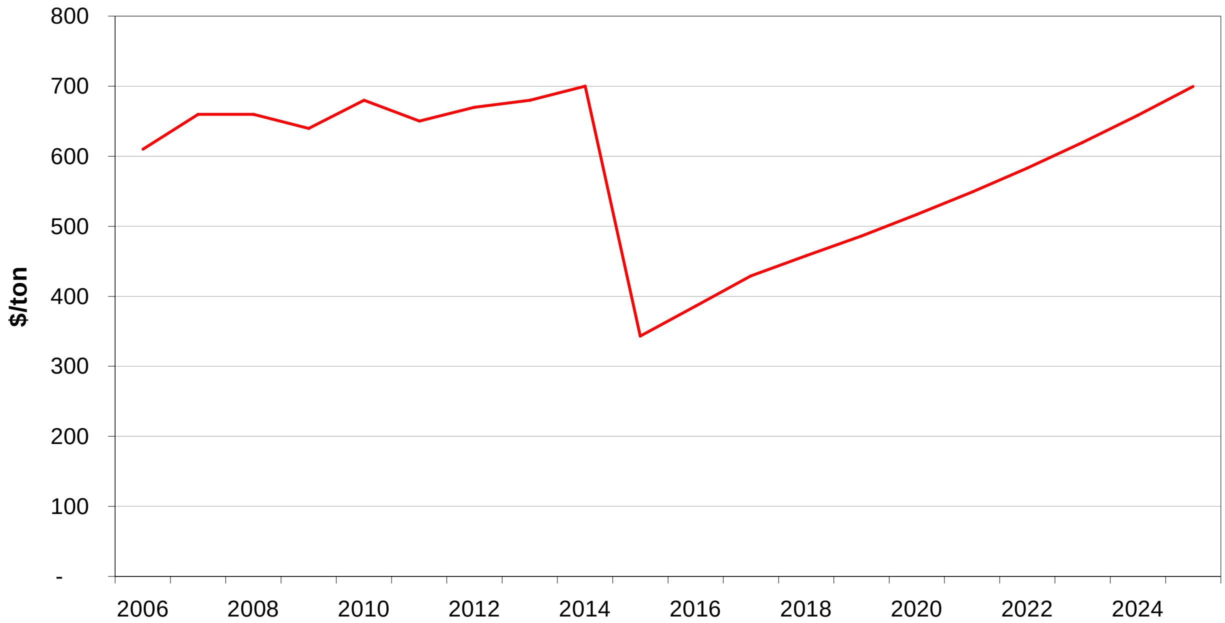
[5] 2006 EIA Annual Energy Outlook, Table 106: Natural Gas Delivered Prices by End-Use Sector and Census Division.

Emissions Price Forecast

The SO_2 price forecast shown in Figure 18, is based on Evomarkets' SO_2 allowance forwards, May 2006, and makes appropriate adjustments for Clean Air Interstate Transport Rule (CAIR)[6] provisions requiring a 2:1 retirement ratio of allowances in the years 2010-2014, and 2.86:1 retirement ratio of allowances in years 2015 and beyond.

The NOx price forecast, shown in Figure 19, takes into account CAIR provisions requiring both an annual and a seasonal NOx trading program beginning in 2009.[7]

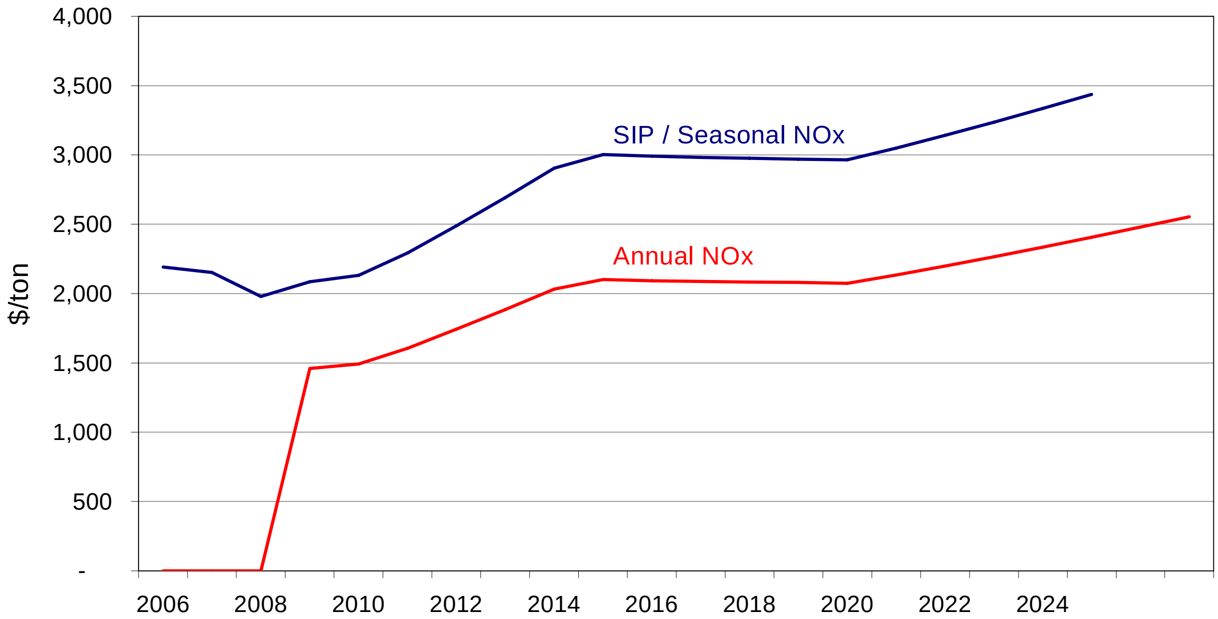
Figure 18: SO_2 Emission Price Forecast



[6] For more information on CAIR, see http://www.epa.gov/cair/.

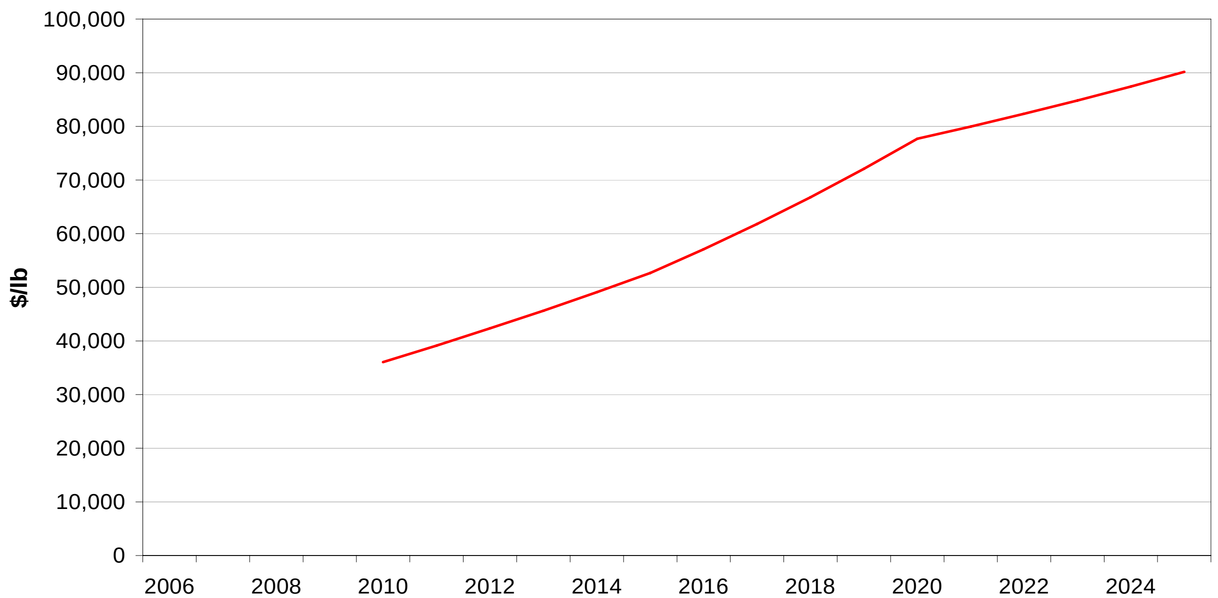
[7] The long-term NOx forecast is derived from the EPA projections (EPA-452/R-05-003, March 2005).

Figure 19: NO_X Emission Price Forecast



The mercury (Hg) forecast shown in Figure 20, 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 Rule (CAMR) initiative and was then escalated at the GDP deflator rate shown in Table 9 (p. 30).

Figure 20: Mercury Emission Price Forecast – 2010-2025

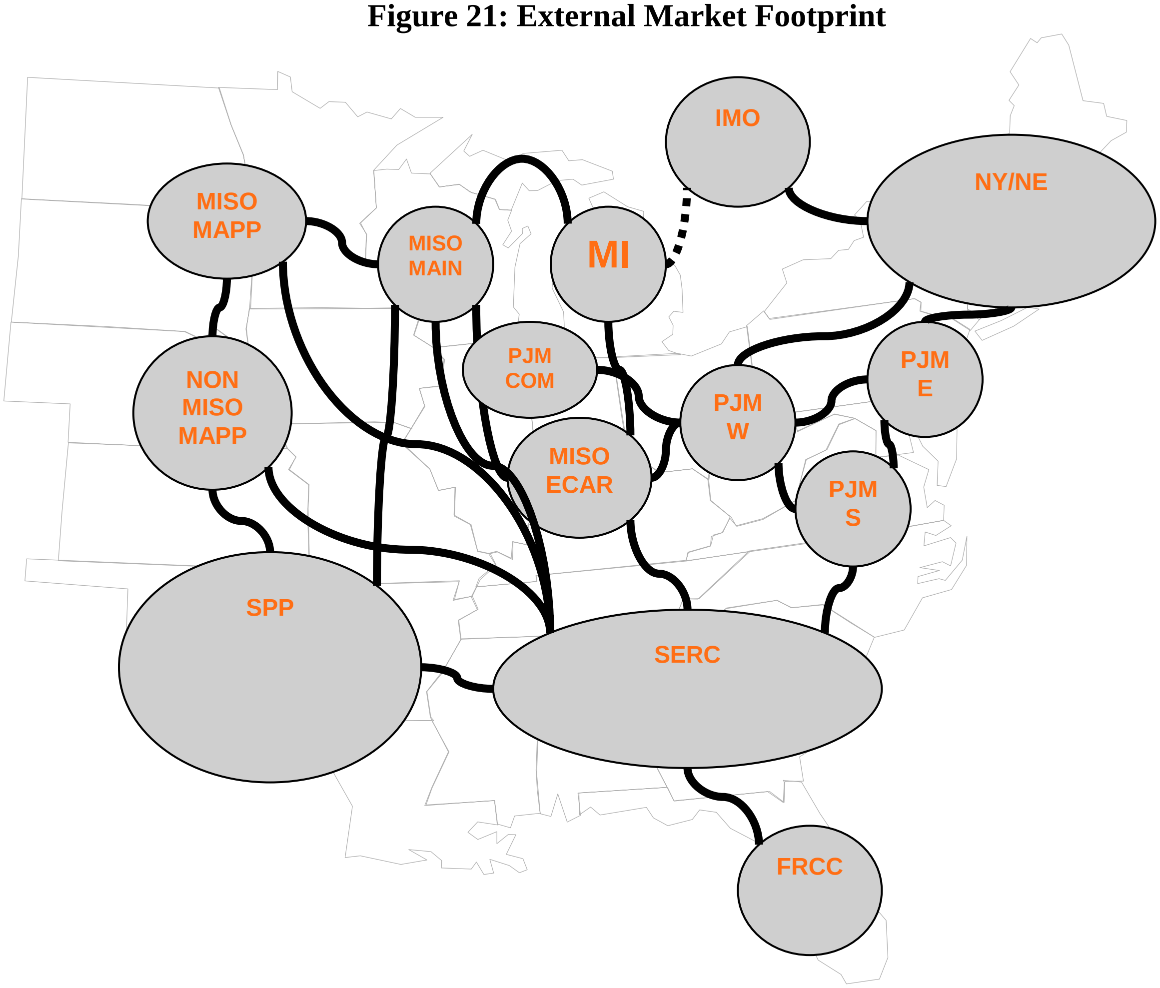


4.3.4 External Market Forecast

The external non-firm energy market forecast was developed using NewEnergy's MarketPower® system. MarketPower® is a regional capacity and energy market forecasting system and was used to produce the capacity and energy price forecasts. This software simulates regional power markets at a macro-economic level. MarketPower® performs the unit dispatch in the various regional markets 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, non-utility generator contract limits, and pumped storage). MarketPower® additionally assesses when and where new capacity would be added based on market drivers. In this model, existing generators can also be mothballed, restarted or converted to a different technology, depending on variations in market conditions. Separate prices can be produced for capacity and energy, or a single "all-in" commodity price can be produced.

The assumptions for the broader market were consistent with the assumptions made for the Michigan study. The Figure 21 represents the broader regional market:

Figure 21: External Market Footprint



Figures 22 and 23 present the external market price information. The spot-market on and off-peak values represent the energy price forecasts for external spot-markets that Michigan can purchase from or sell to, on a non-firm basis.

Figure 22: Michigan Lower Peninsula External Market Price Forecast

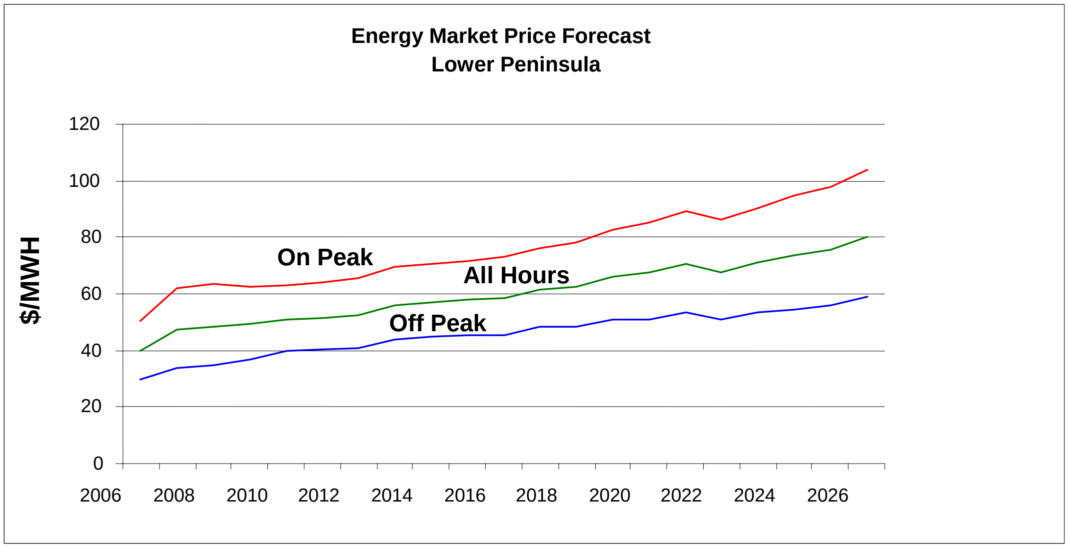
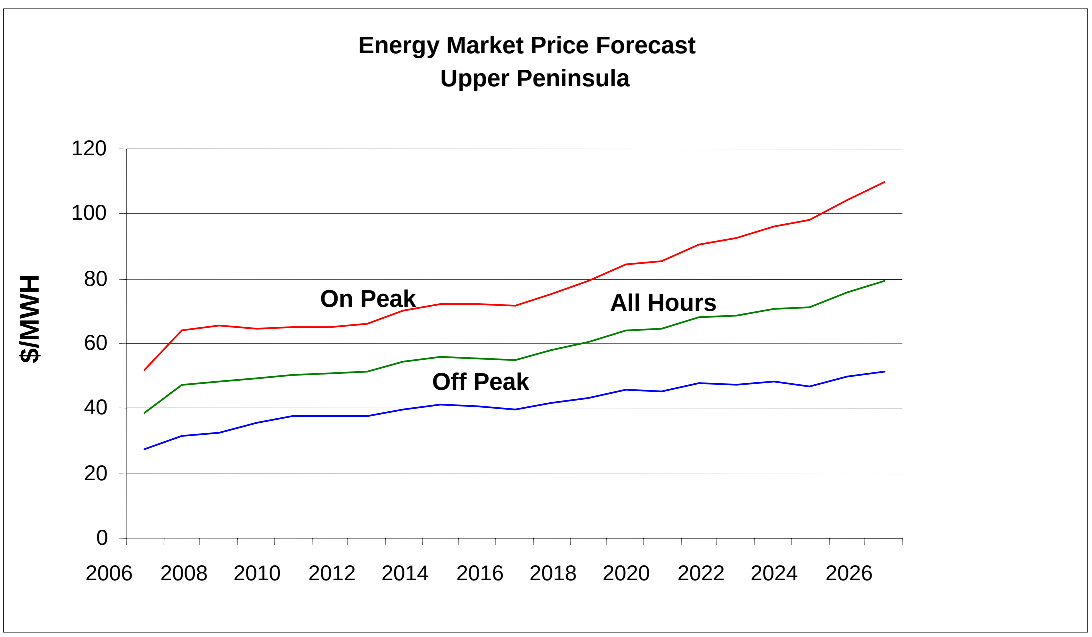


Figure 23: Michigan Upper Peninsula Market Price Forecast



4.3.5 Economic Forecast

The Table 9 presents the remaining economic assumptions from CNF Update Workgroup.

Table 9: Economic Assumptions

Factor			Escalation Rate	Notes, Data Sources
Construction Costs			2.47%	Construction and O&M costs are assumed to escalate at the same rate as gross domestic product.
Variable O&M			2.47%	
Fixed O&M			2.47%	
Gross Domestic Product			2.47%	Source: www.eia.doe.gov/oiaf.aeo/pdf/aeotab_19.pdf
Interest Paid on Debt			9.28%	Calculated to yield an after tax cost of capital of 8.04%
Fuel Types	Coal Supplies Regions	Powder River Basin	2.53%	Fuel escalation rates represent delivered costs.
		Northern Appalachia	2.81%	
		Central Appalachia	2.15%	
		Rocky Mountain	3.33%	
	Natural Gas		2.94%	
	Uranium		2.80%	

5. Resource Plans

5.1 Overview

The objective function for the Michigan resource plan optimization was to minimize the present value of utility incremental generating 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, phased in over the planning horizon. No additional generating units were allowed to be added once the minimum reserve requirement had been met for any given year. In addition, the modeling assumed that no more than one 500 MW baseload unit would be commissioned per area (that is, METC and ITC) per year.

Table 10 presents the projected future reserve margins if no additional resources were added to Michigan's resource portfolio.

Table 10: Reserve Margin Analysis

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Demand (MW)	22,302	22,598	22,885	23,066	23,334	23,612	23,925	24,198	24,487	24,778
Installed Capacity (MW)	26,017	26,017	26,017	26,017	26,017	26,017	26,017	25,897	25,897	25,601
Reserve Margin (%)	16.66	15.13	13.69	12.79	11.50	10.18	8.75	7.02	5.76	3.32
Capacity Shortage (MW)	–	–	300	509	817	1,137	1,496	1,930	2,263	2,893

The Tables 11 and 12 provide an overview of the modeling results for each of the scenarios and sensitivities considered in the Michigan IRP process.

Table 11: Summaries of Scenarios and Sensitivities (Present Value Revenue Requirements, Capacity Additions, and Ending Reserve Margins)

Scenario		10-Year PVRR ($ millions)	20-Year PVRR ($ millions)	10-Year Total Capacity Additions (MW)	20-Year Total Capacity Additions (MW)	10-Year Ending Reserve Margin (%)	20-Year Ending Reserve Margin (%)
Central Station		**$32,073.0**	**$56,716.9**	**3,440**	**11,260**	**15.26%**	**15.52%**
Sensitivity Analyses	High Load	$35,512.2	$64,116.8	6,740	15,040	15.26%	15.63%
	Low Load	$28,873.2	$49,811.6	660	7,640	17.28%	15.95%
	Reduced Import	$32,169.2	$57,004.8	3,440	11,220	15.26%	15.40%
	Expanded Transmission	$32,329.1	$57,085.5	2,660	10,300	12.53%	12.56%
Emissions		**$36,956.6**	**$70,752.2**	**3,440**	**10,760**	**15.26%**	**16.04%**
Sensitivity Analyses	High Load	$40,832.7	$79,492.7	6,760	14,240	15.33%	15.26%
	Low Load	$33,321.8	$62,254.7	320	7,480	15.96%	17.69%
	Renewable & Energy Efficiency	$36,098.0	$65,594.5	3,026	10,079	16.25%	16.89%
	EE Only	$36,189.0	$66,707.5	3,249	10,261	16.09%	16.53%
Renewable Energy		**$32,506.9**	**$57,496.7**	**3370**	**11,218**	**15.97%**	**16.28%**
Sensitivity Analyses	High Load	$35,929.4	$64,758.6	6,699	14,698	15.98%	15.48%
	Low Load	$29,436.3	$50,797,8	599	7,238	18.07%	15.55%
Energy Efficiency		**$31,510.1**	**$53,794.5**	**3,249**	**10,581**	**16.09%**	**15.73%**
Sensitivity Analyses	High Load	$34,918.3	$61,040.0	6,569	14,241	16.08%	15.45%
	Low Load	$28,638.7	$47,384.1	1,609	6,781	23.11%	15.53%
	Reduced Energy Efficiency Penetration	$32,208.7	$55,765.2	3,267	10,700	15.69%	15.36%
Energy Efficiency with Renewable Energy		**$31,998.1**	**$54,623.2**	**3,028**	**10,359**	**16.25%**	**15.95%**
Sensitivity Analyses	High Load	$35,354.4	$61,780.4	6,188	13,899	15.69%	15.28%
	Low Load	$29,246.5	$48,407.9	2,208	6,579	26.70%	15.86%
	Reduced Energy Efficiency Penetration	$32,692.1	$56,546.1	3,386	10,518	17.10%	15.70%
Combustion Turbine Only		**$32,126.9**	**$58,987.6**	**3,520**	**11,200**	**15.54%**	**15.34%**
Sensitivity Analyses	High Load	$35,630.2	$68,096.6	6,720	14,880	15.20%	15.18%
	Low Load	$28,856.0	$50,737.5	320	7,680	15.96%	16.09%

[1]Combined heat and power (CHP) resources were modeled along with renewable energy, in all renewable energy scenarios and sensitivities.

Table 12: Summaries of Scenarios and Sensitivities
(Modeled Capacity Added by Type of Resource, in Megawatts)

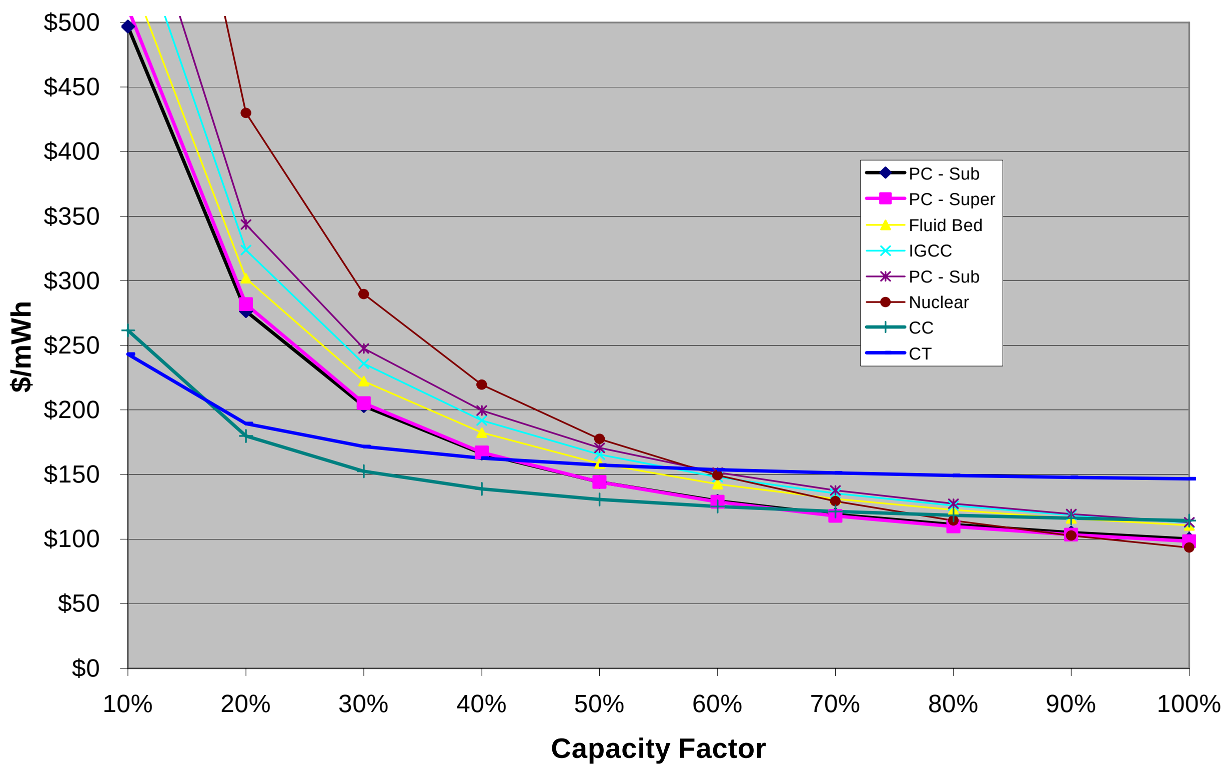
	Scenario	Combustion Turbine (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Nuclear (MW)	Renewable Capacity (MW)[1]	Energy Efficiency (MW)
Central Station		1,760	500	9,000	0	0	0
Sensitivity Analyses	High Load	3,040	2,000	10,000	0	0	0
	Low Load	640	500	6,500	0	0	0
	Reduced Import	2,720	1,000	7,500	0	0	0
	Expanded Transmission	800	1,000	8,500	0	0	0
Emissions		1,760	1,000	2,000	6,000	0	0
Sensitivity Analyses	High Load	2,240	2,000	4,000	6,000	0	0
	Low Load	480	0	1,000	6,000	0	0
	Renewable & Energy Efficiency	480	500	500	5,000	798[2]	2,801
	EE Only	960	0	1,500	5,000	0	2,801
Renewable Energy		1,920	500	8,000	0	798	0
Sensitivity Analyses	High Load	2,400	2,000	9,500	0	798	0
	Low Load	1,440	0	5,000	0	798	0
Energy Efficiency		1,280	0	6,500	0	0	2,801
Sensitivity Analyses	High Load	1,440	2,000	8,000	0	0	2,801
	Low Load	480	0	3,500	0	0	2,801
	Reduced Energy Efficiency Penetration	1,280	0	7,500	0	0	1,920
Energy Efficiency with Renewable Energy		1,760	0	5,000	0	798	2,801
Sensitivity Analyses	High Load	800	2,000	7,500	0	0	2,801
	Low Load	480	0	2,500	0	0	2,801
	Reduced Energy Efficiency Penetration	800	500	6,500	0	0	1,920
Combustion Turbine Only Case		11,200	0	0	0	0	0
Sensitivity Analyses	High Load	14,880	0	0	0	0	0
	Low Load	7,680	0	0	0	0	0

[1]Combined heat and power (CHP) resources were modeled along with renewable energy, in all renewable energy scenarios and sensitivities.
[2] Renewable Capacity represents on-peak capacity in 2025, using a capacity factor of 12.5% for wind and 100% for all other renewable resources modeled.

5.2 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, levelized present value cost, in $/kW-yr, for each resource alternative over a range of potential capacity factors. The calculations include overnight construction costs[8], fixed and variable operating costs including fuel costs, construction and operating cost escalations, allowance for funds used during construction (AFUDC), capital depreciation, property and income taxes, and insurance costs. The screening curve for the base case cost assumptions is depicted in Figure 24.

Figure 24: Base Case Technology Screening Curves



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.

[8] Overnight construction costs do not include financing costs.

On the basis of this screening curve, the following resources were screened out of the Central Station Base Case Scenario analyses:

- Fluidized Bed Coal
- IGCC
- IGCC – PRB Coal
- Nuclear

The remaining alternatives, combustion turbine, combined cycle, and pulverized super-critical coal, were included in the resource optimization. Note that the pulverized super-critical coal is nearly the same cost as sub-critical. Therefore, for the base case, the super-critical coal plant can be thought of as a placeholder for either type of coal baseload capacity. The results of the Central Station Base Case are summarized in Figure 25 and Figure 26.

Figure 25: Central Station Base Case Summary Results

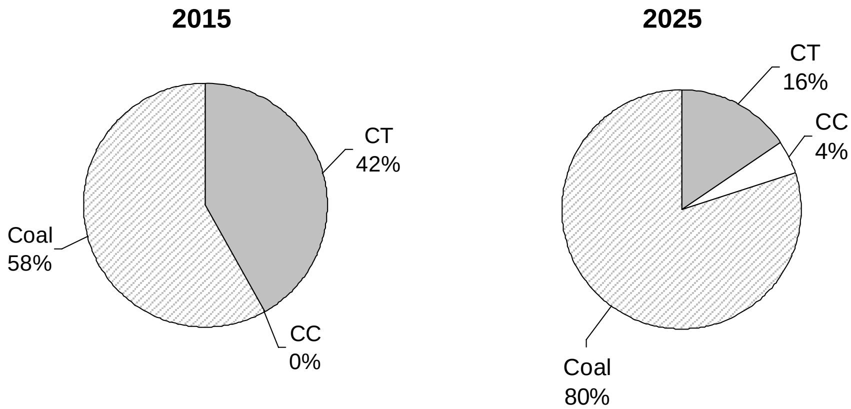
- 2006 to 2015
- Capacity Additions (in MW)
  - CT 1,440
  - CC
  - PC 2,000
  - Nuclear
  - Renewable
  - Conservation
- Total 3,440

- Demand Growth 1.17 %
- Reserve Margin 15.26 %
- Plan Costs
  - NPV Utility Cost $ 32,073.0 M
  - NPV Emissions $ 3,385.6 M
  - NPV CO2 $ 0.00 M

- 2006 to 2025
- Capacity Additions (in MW)
  - CT 1,760
  - CC 500
  - PC 9,000
  - Nuclear
  - Renewable
  - Conservation
- Total 11,260

- Demand Growth 1.21 %
- Reserve Margin 15.52 %
- Plan Costs
  - NPV Utility Cost $ 56,716.9 M
  - NPV Emissions $ 5,602.8 M
  - NPV CO2 $ 0.00 M

Figure 26: Central Station Base Case Expansion Plan Capacity Mix



The Base Central Station Expansion plan exhibited a number of key resource planning results. The State of Michigan is in need of approximately 300 MW of capacity by 2008 to meet planning reserve criteria. This is exhibited by the fact that the model shows three combustion turbines being added in 2008, or as soon as practical. After achieving the capacity necessary for reliability in the early years, the State of Michigan was in need of baseload energy. As soon as available, the Central Station expansion plan selected baseload energy resources. After 2012 when pulverized super-critical coal was available, it became the preferred resource. Throughout the remaining study horizon, coal was the preferred generating technology for the State of Michigan. Table 13 summarizes the expansion plan for the Central Station scenario.

5.3 Sensitivities Analysis

The following sensitivities were performed on the Base Case: High Load, Low Load, Expanded Transmission, and Low Imports. The High Load sensitivity represented a 1.61 percent annual average demand growth rate, whereas the Base Case demand growth rate was 1.21 percent. The Low Load sensitivity represented a 0.76 percent annual demand growth rate. The Expanded Transmission and Low Import sensitivities were defined in Section 4.2.6. The results of the Central Station sensitivities are contained in the expansion results file located on the Plan website.[9]

The need for near-term capacity for reliability, in the form of combustion turbines (CTs) in 2008, was common across all sensitivities except the Low Load sensitivity. Also, in the Energy Efficiency Scenarios, the number of CTs added from 2008 through 2012 is reduced from nine to three units. This is due to an additional 570 MW of load management in the energy efficiency program that displaces some of the CTs. CTs were added as soon as the modeled construction schedule could make them available. 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, super-critical coal (PC) units were the predominant choice for new generation. This modeling conclusion underscores the need for long-term baseload capacity in the State of Michigan.

[9] See http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/expansion_results.pdf.

Table 13: Central Station Base Case Expansion Plan (Units Added and Plant Types)

Total Units Added	Plant Type & Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2	CT-METC			1	1						
7	CT-ITC			2		2	2				
2	CT-ATC2							1			
0	CC-METC										
1	CC-ITC										
0	CC-ATC2										
6	COAL-METC										
12	COAL-ITC							1	1	1	1
0	COAL-ATC2										
0	CFB-ATC										

Plant Type & Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT-METC										
CT-ITC										1
CT-ATC2	1									
CC-METC										1
CC-ITC										
CC-ATC2										
COAL-METC	1	1		1		1	1	1		
COAL-ITC	1		1	1	1	1	1	1	1	
COAL-ATC2										
CFB-ATC										

Resource construction lead time proved to be a major driver of the near-term expansion plan choices. As soon as capacity becomes available, given the construction lead-times incorporated in the planning assumptions, the model adds CTs in order to serve the capacity reliability needs of the Michigan system. This can be seen in nearly every scenario and sensitivity, through the addition of CT capacity in the 2008 to 2011 timeframe. Coal units are added as soon as the modeled construction schedule assumes they can be completed. Pulverized coal super-critical units dominate the expansion plan from 2012 through the end of the study horizon.

The assumption regarding Low Imports did not make a substantial impact on the expansion plans in the near-term. Through 2015, the expansion plans across all scenarios assuming Low Imports were identical. This was due to the modeling assumption, as stated previously, that no external capacity is bought or sold in this sensitivity analysis.

The Expanded Transmission case adds, and incurs costs associated with, 2,500 MW of transmission upgrades. The added transmission capacity directly displaces only approximately 900 MW of new generation, however. This reduction in generation need is a result of reducing the reserve margin from 15 to 12 percent. In addition, the weighted cost of capital of the new transmission is 9.91 percent and recovered over a 40-year life, which is considerably higher than that of new generation, which is modeled on an 8.04 percent cost of capital. Given these assumptions, the Expanded Transmission case with the transmission upgrade costs more, on a present value basis, than the Central Station Base case.

5.4 Scenarios

5.4.1 Emissions Scenario

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

- A 15 percent increase to the mercury (Hg) emissions allowance prices to reflect an additional requirement to reduce Hg emissions to 85 percent of previous levels
- A nominal carbon tax on CO_2 emissions starting in 2010 at $10/ton and escalating to $30/ton in 2018

For the Emissions Scenario, resource options were evaluated on a levelized cost basis to screen out alternatives that would have limited economic viability. On the basis of this screening curve, as shown in Figure 27, fluidized-bed coal and IGCC technologies were not included in the analysis. The remaining alternatives: combustion turbine, combined cycle, pulverized sub-critical coal, and nuclear were included in the resource optimization.

Under the Emissions Scenario, the need for near-term capacity to meet reliability requirements 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 2018.

A major difference emerging from the Emissions Scenario was the added costs associated with emission allowances. Table 14 outlines the differences in the cost components.

The Emissions Scenario was further subjected to High Load, Low Load, Energy Efficiency, and Energy Efficiency with Renewable Energy sensitivities. The results of the Emissions Scenario sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

Figure 27: Emissions Scenario Screening Curve

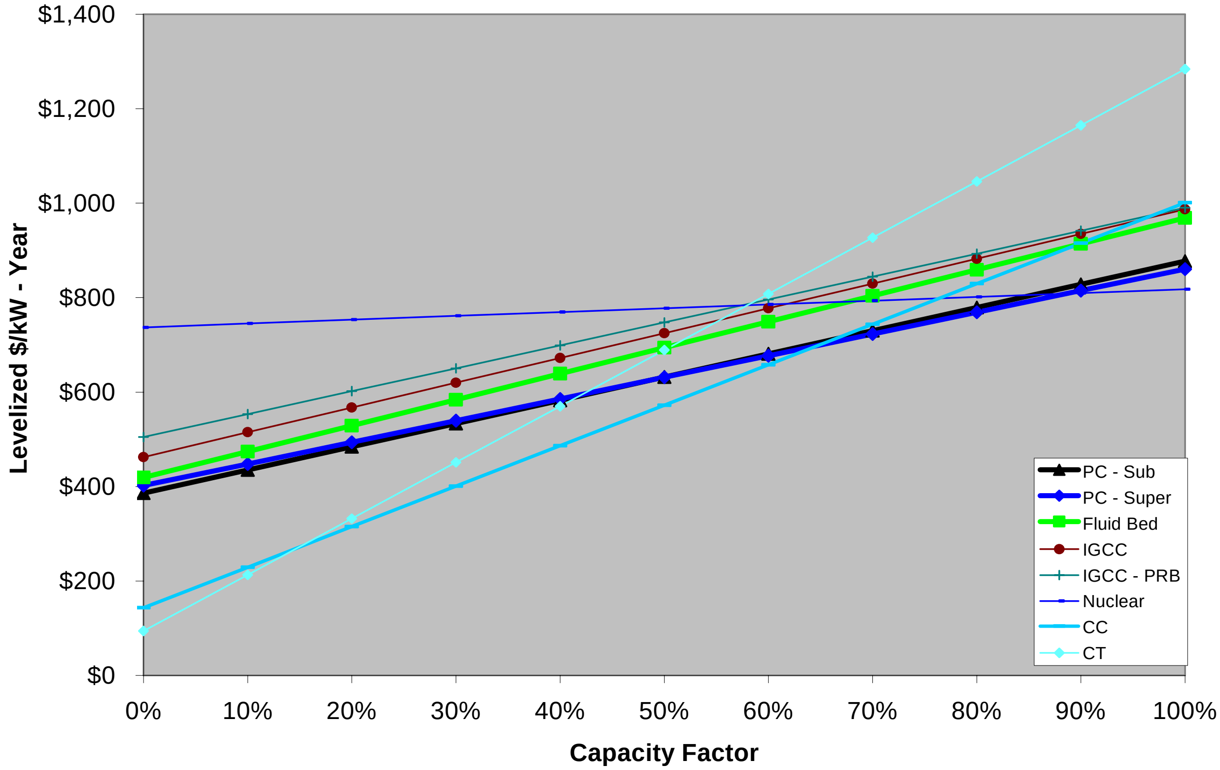


Table 14: Comparison of Cost Components in Emissions and Central Station Scenarios 2006-2025

1. Scenario	2. 20-Year PVRR ($ millions)	3. PV Total Emissions ($ millions)[1]	4. PV Total Carbon ($ millions)
Central Station	56,716.9	5,602.8	0
Emissions	70,752.2	18,991.7	13,358.9
[1]Includes cost of carbon emissions			

5.4.2 Energy Efficiency Scenario

The Energy Efficiency Scenario was focused on the effects of greater emphasis on energy efficiency investment and load management alternatives. The Energy Efficiency Scenario contained the following assumptions:

- Energy efficiency programs were scheduled in, and the program cost was incorporated into the present value cost calculation.
  - Approximately 570 MW of direct load control was included.
  - The Central Station generation options were then re-optimized, taking into account the energy efficiency options scheduled.

Table 15: Comparison of Energy Efficiency and Central Station Scenarios – 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	PVRR ($ millions)
Central Station	1,760	500	9,000	0	56,716.9
Energy Efficiency	1,280	0	6,500	2801	53,794.5

Under the Energy Efficiency Scenario, the need for new capacity in MECS was delayed until 2011, compared to 2008 in the Central Station (Base Case) Scenario. The longer term need for energy production still was met predominantly through the addition of coal resources.

The Energy Efficiency Scenario was further subjected to High Load, Low Load, and Low Energy Efficiency Penetration sensitivities. The results of the Energy Efficiency sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

5.4.3 Renewable Energy Scenario

The Renewable Energy Scenario incorporated targeted renewable alternatives, including wind, landfill gas, anaerobic digesters, and generation resources fueled by cellulosic biomass resources. Combined heat and power (CHP) resources, not necessarily fueled by renewable resources, were also included in this scenario. The Renewable Energy Scenario included the following assumptions:

- Landfill gas, anaerobic digestion, wind, cellulosic biomass, and CHP resources were scheduled in, according to an assumed portfolio standard for renewable resources and an assumed rate of growth for CHP.
- Wind energy was assumed to have a capacity value, on peak, of 12.5 percent of nameplate capacity.
- Central Station options remained the same but they were re-optimized after taking into account the schedule of renewable energy options.

Under the Renewable Energy Scenario, the need for immediate reliability capacity was still apparent. The longer term need for baseload energy production was met primarily through the addition of coal generating technology.

Table 16: Comparison of Renewable Energy and Central Station Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Integrated Gasification Combined Cycle (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Renewable Energy	1,920	500	8,000	0	798	57,496.7

The Renewable Energy Scenario was further analyzed under High Load and Low Load sensitivities. The results of the Renewable Energy Scenario sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

5.4.4 Energy Efficiency with Renewable Energy Scenario

The Energy Efficiency with Renewable Energy Scenario combined the scheduled resource additions shown in the Energy Efficiency and Renewable Energy Scenarios. The Energy Efficiency with Renewable Energy Scenario contained the following assumptions:

- Energy efficiency programs were scheduled in, and the program cost was incorporated into the present value cost calculation.
- Approximately 570 MW of direct load control was included.
- Landfill gas, anaerobic digestion, wind, cellulosic biomass, and CHP resources were scheduled in, according to an assumed portfolio standard for renewable resources and an assumed rate of growth for CHP.
- The Central Station options remained the same, but were re-optimized after taking into account the schedule of energy efficiency and renewable energy options.

The Energy Efficiency with Renewable Energy Scenario was further analyzed under High Load, Low Load, and Reduced Energy Efficiency Penetration sensitivities. The Reduced Penetration sensitivity reduced the amount of demand reduction associated with energy efficiency from 2,801 MW to 1,920 MW and increased the associated costs. The Reduced Energy Efficiency Penetration sensitivity closely approximates the estimates for energy efficiency program performance that were modeled in the 2005 Michigan Capacity Needs Forum. The results of the Energy Efficiency with Renewable Energy sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

Table 17: Comparison of Central Station and Energy Efficiency with Renewable Energy Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
EE with Renewable	1,760	0	5,000	2,801	798	54,623.2

[1] Included in modeling for the Renewable Energy Scenario was 178 MW of CHP capacity that is not necessarily assumed to be powered by renewable fuels.

5.5 Combustion Turbines Only Scenario

The final scenario modeled was that of an expansion plan limited to combustion turbines alone. In this CT Only Scenario, the super-critical coal and the combined cycle options were not considered as options available in this scenario.

Table 18: Comparison of Base Case and Combustion Turbines Only Scenarios 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Energy Efficiency (MW)	Renewable Resources and CHP (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Combustion Turbines Only	11,200	0	0	0	0	58,987.6

The CT Only Scenario was further analyzed under High Load and Low Load sensitivities. The results of the CT Only sensitivities are contained in the expansion results file located on the Plan website (see footnote 9).

The following tables examine all six scenarios under base case demand assumptions.

Table 19: Comparison of Scenarios Using Base Case Demand Assumptions 2006-2025

Scenario	Combustion Turbines (MW)	Combined Cycle (MW)	Pulverized Coal (MW)	Nuclear / IGCC (MW)	Renewable Resources and Energy Efficiency (MW)	20-Year PVRR ($ millions)
Central Station	1,760	500	9,000	0	0	56,716.9
Emissions	1,760	1,000	2,000	6,000	0	70,752.2
Energy Efficiency	1,280	0	6,500	0	2,801	53,794.5
Renewable	1,920	500	8,000	0	798	57,496.7
EE with Renewable	1,760	0	5,000	0	3,599	54,623.2
CT Only	11,200	0	0	0	0	58,987.6

6. Generation Capability Tables

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle (existing)	Dearborn Industrial Generation LLC:CC1	760.00
Combustion Turbine Gas	Ann Arbor GT:1	3.20
Combustion Turbine Gas	Belle River:GT1	75.00
Combustion Turbine Gas	Belle River:GT2	75.00
Combustion Turbine Gas	Belle River:GT3	75.00
Combustion Turbine Gas	Delray:11-1	63.00
Combustion Turbine Gas	Delray:12-1	64.00
Combustion Turbine Gas	DTE East China:GT10	76.00
Combustion Turbine Gas	DTE East China:GT7	76.00
Combustion Turbine Gas	DTE East China:GT8	76.00
Combustion Turbine Gas	DTE East China:GT9	76.00
Combustion Turbine Gas	Greenwood:GT1	75.00
Combustion Turbine Gas	Greenwood:GT2	75.00
Combustion Turbine Gas	Greenwood:GT3	75.00
Combustion Turbine Gas	Hancock (DETED):1	11.00
Combustion Turbine Gas	Hancock (DETED):2	18.00
Combustion Turbine Gas	Hancock (DETED):3	17.00
Combustion Turbine Gas	Hancock (DETED):4	17.00
Combustion Turbine Gas	Hancock (DETED):5	38.00
Combustion Turbine Gas	Hancock (DETED):6	40.00

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Gas	Hutzel Hospital:GTGS2	1.60
Combustion Turbine Gas	Main Street (SEAW):GTGS6	6.13
Combustion Turbine Gas	MPPA : Belle River	234.00
Combustion Turbine Gas	Northeast (DETED):1	14.75
Combustion Turbine Gas	Northeast (DETED):2	14.75
Combustion Turbine Gas	Northeast (DETED):3	14.75
Combustion Turbine Gas	Northeast (DETED):4	14.75
Combustion Turbine Gas	Pine Street (SEAW):GTGS4	5.00
Combustion Turbine Gas	Sumpter Township:GT1	72.25
Combustion Turbine Gas	Sumpter Township:GT2	72.25
Combustion Turbine Gas	Sumpter Township:GT3	72.25
Combustion Turbine Gas	Sumpter Township:GT4	72.25
Combustion Turbine Gas	Ubly:GTGS2	4.04
Combustion Turbine Gas	Wayne County Airport:GTGS3	17.10
Combustion Turbine Oil	Belle River:GTOL5	13.75
Combustion Turbine Oil	Caro:GTOL6	8.55
Combustion Turbine Oil	Colfax (DETED):GTOL5	13.75
Combustion Turbine Oil	Conners Creek:GTOL2	5.50
Combustion Turbine Oil	Croswell Plant:3	1.21
Combustion Turbine Oil	Croswell Plant:GTGS4	4.02
Combustion Turbine Oil	Dayton (DETED):GTOL5	10.00
Combustion Turbine Oil	Fermi:GTOL4	51.00
Combustion Turbine Oil	Harbor Beach:GTOL2	4.00
Combustion Turbine Oil	Michigan Automotive Research:1-8	0.00
Combustion Turbine Oil	Mistersky:GT1	30.00
Combustion Turbine Oil	Monroe (DETED):GTOL5	13.75
Combustion Turbine Oil	Northeast (DETED):5	17.00
Combustion Turbine Oil	Northeast (DETED):6	19.50
Combustion Turbine Oil	Northeast (DETED):7	19.50
Combustion Turbine Oil	Oliver:GTOL5	13.75
Combustion Turbine Oil	Pine Street (SEAW):GTOL2	2.28
Combustion Turbine Oil	Placid 12:GTOL5	13.75
Combustion Turbine Oil	Putnam (DETED):GTOL5	13.75
Combustion Turbine Oil	River Rouge:GTOL4	11.00
Combustion Turbine Oil	Slocum:GTOL5	13.75

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Oil	St. Clair:11	19.00
Combustion Turbine Oil	St. Clair:GTOL2	5.50
Combustion Turbine Oil	Superior:GTOL4	52.00
Combustion Turbine Oil	Ubly:GTOL5	4.51
Combustion Turbine Oil	Wilmont:GTOL5	13.75
Hydro Run-of-River	DETED Small Hydros:HYOP2	1.40
Hydro Run-of-River	Ford Lake:HYOP1	0.85
Hydro Run-of-River	French Landing Dam:HYOP1	1.80
Interruptible Load	DETED Interruptible:1	0.00
Landfill Gas	Ann Arbor Generating Station:1	1.60
Landfill Gas	Arbor Hills Generating Facility: CC	17.40
Landfill Gas	Carleton Farms Generating Project:1	6.40
Landfill Gas	EQ - Waste Energy Services Inc: GTGS4	1.40
Landfill Gas	Lyon Generating Facility:GTGS7	4.50
Landfill Gas	Pine Tree Acres:GTGS5	4.00
Landfill Gas	Riverview Energy Systems:GTGS2	6.60
Landfill Gas	Sumpter Energy Assoc.: GTGS10	12.00
Nuclear (existing)	Fermi:2	1111.00
Steam Turbine Coal	Belle River:ST1	509.00
Steam Turbine Coal	Belle River:ST2	517.00
Steam Turbine Coal	Harbor Beach:1	103.00
Steam Turbine Coal	Monroe (DETED):1	770.00
Steam Turbine Coal	Monroe (DETED):2	785.00
Steam Turbine Coal	Monroe (DETED):3	785.00
Steam Turbine Coal	Monroe (DETED):4	775.00
Steam Turbine Coal	NAO GM Pontiac Power Plant:1	28.94
Steam Turbine Coal	River Rouge:2	238.00
Steam Turbine Coal	River Rouge:3	272.00
Steam Turbine Coal	St. Clair:1	153.00
Steam Turbine Coal	St. Clair:2	162.00
Steam Turbine Coal	St. Clair:3	171.00
Steam Turbine Coal	St. Clair:4	158.00
Steam Turbine Coal	St. Clair 6	321.00
Steam Turbine Coal	St. Clair 7	450.00
Steam Turbine Coal	Trenton Channel:7	0.00
Steam Turbine Coal	Trenton Channel:8	210.00

Table 20: ITC Region, Detroit Edison Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Steam Turbine Coal	Trenton Channel:9	520.00
Steam Turbine Coal	Wyandotte (WYAN):7	30.00
Steam Turbine Coal	Wyandotte (WYAN):8	22.00
Steam Turbine Gas	Conners Creek:15	0.00
Steam Turbine Gas	Conners Creek:16	215.00
Steam Turbine Gas	River Rouge:1	234.00
Steam Turbine Gas	Wyandotte (WYAN):5	20.00
Steam Turbine Oil	Greater Detroit Resource Recovery: GEN1	30.75
Steam Turbine Oil	Greenwood:1	785.00
Steam Turbine Oil	Mistersky:5	34.29
Steam Turbine Oil	Mistersky:6	38.96
Steam Turbine Oil	Mistersky:7	46.75
Steam Turbine Other	Refuse 2:1	20.00

Table 21: METC Region, Consumers Energy Company Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Combined Cycle (existing)	Ada Cogeneration Limited Partn:CC	29.40
Combined Cycle (existing)	Covert:CC3	384.00
Combined Cycle (existing)	Covert:CC4	384.00
Combined Cycle (existing)	Covert:CC5	384.00
Combined Cycle (existing)	Covert:CCGS3	48.00
Combined Cycle (existing)	Jackson:CCA	280.00
Combined Cycle (existing)	Jackson:CCB	280.00
Combined Cycle (existing)	Michigan Power L.P.:CC	123.00
Combined Cycle (existing)	Midland Cogeneration Venture (MCV):CC	1240.00
Combined Cycle (existing)	Zeeland (MIR):CC1	532.00
Combustion Turbine Gas	491 E. 48th Street:7	37.60
Combustion Turbine Gas	491 E. 48th Street:8	37.60
Combustion Turbine Gas	491 E. 48th Street:9	83.50
Combustion Turbine Gas	B.E. Morrow GTGS2	34.00
Combustion Turbine Gas	Clinton (CLIN):6	2.00
Combustion Turbine Gas	Coldwater:GTGS2	8.50
Combustion Turbine Gas	Diesel Plant (GHLP):GTGS3	11.90
Combustion Turbine Gas	Diesel Plant – STURGI:6	6.00
Combustion Turbine Gas	Gaylord:GTGS5	85.00

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Gas	Grand Rapids East:1	0.00
Combustion Turbine Gas	Hart:GTGS4	4.82
Combustion Turbine Gas	Hillsdale:GTGS4	17.70
Combustion Turbine Gas	Kalamazoo River Generating Station:GT	68.00
Combustion Turbine Gas	Livingston Generating Station:1	42.90
Combustion Turbine Gas	Livingston Generating Station:2	42.43
Combustion Turbine Gas	Livingston Generating Station:3	42.43
Combustion Turbine Gas	Livingston Generating Station:4	42.43
Combustion Turbine Gas	Renaissance Power Project:GT1	171.00
Combustion Turbine Gas	Renaissance Power Project:GT2	171.00
Combustion Turbine Gas	Renaissance Power Project:GT3	171.00
Combustion Turbine Gas	Renaissance Power Project:GT4	171.00
Combustion Turbine Gas	Straits:1	21.00
Combustion Turbine Gas	Thetford:1	37.00
Combustion Turbine Gas	Thetford:2	37.00
Combustion Turbine Gas	Thetford:3	37.00
Combustion Turbine Gas	Thetford:4	37.00
Combustion Turbine Gas	Thetford:GTGS5	86.00
Combustion Turbine Gas	Weadock:A	17.00
Combustion Turbine Gas	Zeeland (MIR):GT1	149.00
Combustion Turbine Gas	Zeeland (MIR):GT2	149.00
Combustion Turbine Gas	Zeeland (ZBPW):GTGS7	24.00
Combustion Turbine Oil	Alma Modular:GTOL7	0.00
Combustion Turbine Oil	APG Four Mile Substation (PPA):GTOL1	18.25
Combustion Turbine Oil	APG Long Lake Road (PPA):GTOL1	9.00
Combustion Turbine Oil	APG Michigan Limestone (PPA):GTOL1	18.25
Combustion Turbine Oil	APG Rockport (PPA):GTOL1	9.13
Combustion Turbine Oil	Campbell (CEC):A	17.00
Combustion Turbine Oil	Chelsea Modular:GTOL3	0.00
Combustion Turbine Oil	Clinton (CLIN):GTOL5	2.20
Combustion Turbine Oil	Coldwater Modular:GTOL10	0.00
Combustion Turbine Oil	Coldwater:GTOL2	3.50
Combustion Turbine Oil	Diesel Plant (GHLP):5	3.00
Combustion Turbine Oil	Diesel Plant (GHLP):7	5.10
Combustion Turbine Oil	Diesel Plant - STURGI:GTOL4	2.80

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Combustion Turbine Oil	Frank Jenkins:5	1.70
Combustion Turbine Oil	Frank Jenkins:GTOL2	0.38
Combustion Turbine Oil	Henry Station:GTOL2	15.40
Combustion Turbine Oil	Hillsdale:2	1.90
Combustion Turbine Oil	Marshall (MCWEW):GTGS5	10.70
Combustion Turbine Oil	Saginaw Station:GTOL2	12.60
Combustion Turbine Oil	Sixth Street Mi:1	22.00
Combustion Turbine Oil	St. Louis (STLO):GTGS2	2.50
Combustion Turbine Oil	St. Louis (STLO):GTOL2	1.70
Combustion Turbine Oil	Whiting (CEC):A	17.00
Combustion Turbine Oil	Zilwaukee:1-12	0.00
Combustion Turbine Oil	Zilwaukee:13-33	0.00
Hydro Run-of-River	Ada Dam:HYOP1	1.40
Hydro Run-of-River	Alcona:HYOP2	8.00
Hydro Run-of-River	Allegan Dam:HYOP3	2.50
Hydro Run-of-River	Beaverton (PPA):HYOP1	0.50
Hydro Run-of-River	Black River (PPA):HYOP1	0.84
Hydro Run-of-River	C.W. Tippy:HYOP3	21.00
Hydro Run-of-River	Cascade Dam:HYOP1	1.40
Hydro Run-of-River	CEC Small Hydros:HYOP20	0.00
Hydro Run-of-River	Cheboygan:HYOP1	0.00
Hydro Run-of-River	Commonwealth (Hubbardston PPA):HYOP1	0.22
Hydro Run-of-River	Commonwealth (Irving PPA):HYOP1	0.24
Hydro Run-of-River	Commonwealth (LaBarge PPA):HYOP1	0.70
Hydro Run-of-River	Commonwealth (Middleville PPA):HYOP1	0.20
Hydro Run-of-River	Cooke:HYOP1	1.50
Hydro Run-of-River	Cooke:HYOP2	3.00
Hydro Run-of-River	Cooke:HYOP3	3.00
Hydro Run-of-River	Croton:HYOP4	8.40
Hydro Run-of-River	Edenville:HYOP2	11.00
Hydro Run-of-River	Five Channels:HYOP1	3.20
Hydro Run-of-River	Five Channels:HYOP2	3.20
Hydro Run-of-River	Foote:HYOP1	3.30

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Hydro Run-of-River	Foote:HYOP2	3.30
Hydro Run-of-River	Foote:HYOP3	3.30
Hydro Run-of-River	Four Mile Dam:HYOP3	1.80
Hydro Run-of-River	Grenfell Hydro (PPA):HYOP1	0.30
Hydro Run-of-River	Hodenpyl:HYOP1	9.20
Hydro Run-of-River	Hodenpyl:HYOP2	9.20
Hydro Run-of-River	Hydro Plant - STURGI:HYOP4	1.50
Hydro Run-of-River	Loud:HYOP1	2.20
Hydro Run-of-River	Loud:HYOP2	2.20
Hydro Run-of-River	Michiana Hydro (PPA):HYOP1	0.08
Hydro Run-of-River	Mio:HYOP1	2.20
Hydro Run-of-River	Mio:HYOP2	2.20
Hydro Run-of-River	Ninth Street Dam:HYOP3	1.20
Hydro Run-of-River	Norway Point Hydropower Project: HYOP2	4.00
Hydro Run-of-River	Rogers:HYOP1	1.50
Hydro Run-of-River	Rogers:HYOP2	1.50
Hydro Run-of-River	Rogers:HYOP3	1.50
Hydro Run-of-River	Rogers:HYOP4	1.50
Hydro Run-of-River	Sanford:HYOP3	0.00
Hydro Run-of-River	Secord:HYOP1	0.00
Hydro Run-of-River	Smallwood:HYOP1	0.00
Hydro Run-of-River	Webber:HYOP1	2.30
Hydro Run-of-River	Webber:HYOP2	1.00
Hydro Run-of-River	Whites Bridge Hydro (PPA): HYOP1	0.82
Hydro Storage	Hardy:HYOP1	10.80
Hydro Storage	Hardy:HYOP2	10.80
Hydro Storage	Hardy:HYOP3	10.80
Interruptible Load	CEC Interruptible:1	0.00
Landfill Gas	Adrian Energy Assoc. LLC: GTGS3	2.50
Landfill Gas	Brent Run Generating Station: GTGS2	1.60
Landfill Gas	C & C Generating Facility:GTGS3	2.75
Landfill Gas	Grand Blanc Generating Station: GTGS3	3.81
Landfill Gas	Granger Electric Generating Station I: GTGS4	3.04
Landfill Gas	Granger Electric Generating Station II: GTGS5	3.79
Landfill Gas	Ottawa Generating Station: GTGS6	4.57
Landfill Gas	Peoples Generating Station: 1	3.06
Landfill Gas	Seymour Road Generating Station: GTGS2	0.75

Table 21: METC Region, Consumers Energy Company Existing Generation Resources (Continued)		
Generator Type	**Generator Name**	**Annual Maximum Capacity (MW)**
Landfill Gas	Venice Resources Gas Recovery: GTGS2	1.50
Nuclear (existing)	Palisades (CEC):1	803.00
Pumped Storage Hydro	Ludington:PSOP6	1871.70
Steam Turbine Coal	Campbell (CEC):1	260.00
Steam Turbine Coal	Campbell (CEC):2	360.00
Steam Turbine Coal	Campbell (CEC):3	820.00
Steam Turbine Coal	Cobb:4	160.00
Steam Turbine Coal	Cobb:5	160.00
Steam Turbine Coal	Endicott:1	55.00
Steam Turbine Coal	James De Young:3	10.50
Steam Turbine Coal	James De Young:4	20.50
Steam Turbine Coal	James De Young:5	27.00
Steam Turbine Coal	Karn:1	255.00
Steam Turbine Coal	Karn:2	260.00
Steam Turbine Coal	S. D. Warren Co. #1 Muskegon: GEN5	0.00
Steam Turbine Coal	S. D. Warren Co. #1 Muskegon: STCL2	0.00
Steam Turbine Coal	TES Filer City Station:1	60.00
Steam Turbine Coal	Weadock:7	155.00
Steam Turbine Coal	Weadock:8	155.00
Steam Turbine Coal	Whiting (CEC):1	102.00
Steam Turbine Coal	Whiting (CEC):2	102.00
Steam Turbine Coal	Whiting (CEC):3	124.00
Steam Turbine Gas	Cobb:1	68.00
Steam Turbine Gas	Cobb:2	61.00
Steam Turbine Gas	Cobb:3	52.00
Steam Turbine Gas	Karn:4	638.00
Steam Turbine Oil	Karn:3	638.00
Steam Turbine Oil	Recycled Board Division: STOH2	0.00
Steam Turbine Other	Cadillac Renewable Energy: 1	34.00
Steam Turbine Other	Genesee Power Station: 1	35.00
Steam Turbine Other	Grayling Generating Station: 1	36.17
Steam Turbine Other	Hillman:1	16.00
Steam Turbine Other	Jackson County Resource Recovery: 1	0.00
Steam Turbine Other	Kent County Waste-to-Energy Facility: ST2	15.68
Steam Turbine Other	Lincoln Power Station: 1	18.00
Steam Turbine Other	McBain Power Station: 1	18.00
Wind	Mackinaw City: WIOP5	1.80

Table 22: Wolverine Power Supply Cooperative Existing Generation Resources

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

Table 23: Lansing Board of Water & Light Existing Generation Resources

Generator Type	Generator Name	Annual Maximum Capacity (MW)
Hydro Run-of-River	LBWL Small Hydros:HYOP2	1.06
Hydro Run-of-River	Moores Park:HYOP2	1.00
Interruptible Load	LBWL Interruptible:1	12.00
Steam Turbine Coal	Eckert:1	45.63
Steam Turbine Coal	Eckert:2	46.62
Steam Turbine Coal	Eckert:3	50.79
Steam Turbine Coal	Eckert:4	78.23
Steam Turbine Coal	Eckert:5	79.35
Steam Turbine Coal	Eckert:6	77.33
Steam Turbine Coal	Erickson:1	158.53

Table 24: Modeled Unit Retirements Schedule

Plant Name	Unit #	Owner	Retire Year	Capacity MW
COBB	1	Consumers Energy	2013	68
COBB	2	Consumers Energy	2013	61
COBB	3	Consumers Energy	2015	52
MSTERSKY	5	City of Detroit	2015	39
TRNTNCHN	8	Detroit Edison	2015	210
JMSDYUNG	3	Holland DPW	2016	11
CNNRSCRK	16	Detroit Edison	2016	215
WHTNGCEC	1	Consumers Energy	2017	102
WHTNGCEC	2	Consumers Energy	2017	102
WHTNGCEC	3	Consumers Energy	2018	124
STCLAIR	1	Detroit Edison	2018	153
STCLAIR	2	Detroit Edison	2018	162
ECKERT	1	Lansing BWL	2019	46
STCLAIR	3	Detroit Edison	2019	171
STCLAIR	4	Detroit Edison	2019	158
WEADOCK	7	Consumers Energy	2020	155
PRSQISLE[1]	1	Upper Peninsula Power	2020	25
COBB	4	Consumers Energy	2021	160
RVRROUGE	1	Detroit Edison	2021	242
COBB	5	Consumers Energy	2022	160
WEADOCK	8	Consumers Energy	2022	155
RVRROUGE	2	Detroit Edison	2022	247
WYNDTTWY	5	Wyandotte	2022	22
ECKERT	2	Lansing BWL	2023	47
MSTERSKY	6	Cit of Detroit	2023	47
RVRROUGE	3	Detroit Edison	2023	280
ESCANABA	2	Escanaba Municipal	2023	26
KARN	1	Consumers Energy	2024	255
KARN	2	Consumers Energy	2024	260

[1] Presque Isle units 1 and 2 were retired on January 1, 2007

7. Review of Modeling Software

7.1 Overview

Strategist, a computer software system developed by NewEnergy 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 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 are 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 and comprehensive *pro forma* financial results. The system includes full input summaries and detailed diagnostics.

7.2 Supply Side Representation

The Generation and Fuel 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:

- Probabilistic production costing techniques to simulate the effects of forced outages.
- Most module calculations performed seasonally, where seasons are defined in both number of seasons and by number of days per season.
- Sales, purchases, and hydro generation accounted for on a seasonal basis.
- Hour-by-hour transaction schedule defined or simply specified as occurring during peak load hours, low load hours, or randomly.
- Thermal generating units represented by capacity segments.[10]
- Dispatch of thermal units and economy energy performed on a seasonal or annual basis.
- Pumped hydro projects and direct load control programs economically dispatched on a seasonal basis, based on marginal cost.
- Units dispatched to conform to upper and lower limitations on fuel usage.
- Unit dispatch performed on an “as burned” or replacement cost of fuel basis.
- Unit, company and system emissions calculated based on actual runtimes and fuel usage. Emissions allowances 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 calculated for emissions, emergency energy, and direct load control.
- Multi-company dispatch provided, with interchange accounting for holding companies or power pool simulation.
- Numerous diagnostic reports provided, 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:

[10] 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.

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 (DLC) 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, to achieve the greatest possible savings and avoid setting a new peak. 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 the maximum number and duration 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 electricity industry structures, such as a generation company (Genco) and distribution company (Disco) model 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 both market value and 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 by up to seven incremental 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 by either derating the unit's capacity or adjusting 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 impacts 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 (known as loss of load hours, or LOLH);
- expected emergency energy; and
- reserve margin.

Alternatively, reliability measures can be held constant, so that equivalent capacity benefits for demand side management (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 the pollution control devices associated with each generating unit are input. The individual unit results are then aggregated into company and system emissions rates and totals. Emissions cost, whether represented in the form of allowance purchase price, emissions tax, or emissions externalities, is a result calculated from the thermal dispatch. Separate inputs allow any of these types of emissions costs to be included in a unit's dispatch price, if desired.

7.3 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 natural 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 hourly load shapes. Customer groups for which load shapes are not available are processed differently from those with load 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.

7.4 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 constrained 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 transmission 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 NEI module reflects the market clearing price of the system. Therefore, if there are no losses, no connection charges, and no transmission interconnection 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.

7.5 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 DSM or marketing programs.

The module allows modeling of emissions-related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers or 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 the 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) tests. 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 users to specify demand side or marketing programs on an hourly 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 using a separate GAF production cost model 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 capital expenditure recovery 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 structured in a similar manner to Strategist GAF data.
- Provides quick turn-around time by eliminating options that are not feasible and eliminating unnecessary detail.
- 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 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.
- 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.
- 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.
- Provides users one of five objective functions in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost, minimization of total resource costs, or maximization of total unit profitability.
- Evaluates financial performance of any expansion plan optimized by one of the five objective functions. 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.

- 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 (e.g. 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 limits can also be specified to reduce the alternatives considered.
- Optimization can 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.
- Models the addition of alternatives which are owned by a company other than the company (or pool) which is being optimized when using multi-company logic.
- 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.
- Explains in detail, using numerous diagnostics how PROVIEW reaches its optimal plan decision.

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 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 and LFA Modules' 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 the model can assume 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 cost 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 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 both the optimal plan and each sub-optimal plan.

6. All plans are saved in the database. The optimal plan is set up in the LFA and GAF for subsequent analysis and reporting.

CHAPTER 2

Capacity Need Forum Update Workgroup Resource Assessment

1. Introduction

The CNF Update Workgroup was charged with reviewing and providing updates to five principal data and analysis sections of the Capacity Need Forum (CNF) study from 2005. First, it reviewed and updated information on central station generation options. This task included confirming the inventory of generating plants currently operational in Michigan and reviewing investment and operating costs, performance, and emissions profiles of central station generation technologies, and assessing planning reserve requirements. It also included a review of siting issues, especially matters related to air permit requirements.

Second, the Workgroup was charged with reviewing the transmission analysis performed for the CNF, confirming the simultaneous, on-peak transmission capability, and determining the amount of capability available for reliability support for the Lower Peninsula. It was also tasked with assessing the follow-on Michigan Exploratory study.

Third, the Workgroup was also responsible for electric reliability assessments for regions within Michigan.

Fourth, the Workgroup provided an updated twenty-year electric sales and peak demand forecast for Michigan. As in the CNF, the long-term forecast was provided for each of the three geographical regions within Michigan.

Fifth, the Workgroup managed the expansion modeling, provided fuel and emission cost forecasts, and developed model scenarios and sensitivities. A description of the modeling efforts are presented in Chapter 1.

The Workgroup followed the same process used in the Capacity Needs Forum and relied on data, analysis, and narrative from that effort where appropriate.

2. Resource Assessment: Central Station Generation Options

2.1 Current Inventory

The state's inventory of generating options has not changed since the CNF report was issued in January 2006. In 2004, Michigan relied on coal and nuclear fueled baseload generation units for about 83 percent of its annual electricity production, natural gas for about 13 percent of its annual production, and from hydro and other sources, for about 4 percent of its generation.

Table 1 summarizes the currently operational generating units in Michigan. It excludes American Electric Power's (AEP) Cook nuclear units in Southwestern Lower Michigan, which collectively represent approximately 2,000 megawatts (MW) of generating capacity. The Cook