Gas-Fired Generation in Michigan: Assessment of Gas Infrastructure and Generation Costs

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Michigan Public Service Commission
Gas Division
Electric Division
Executive Secretary Division
Licensing and Enforcement Division

PREFACE

Low fuel costs and low emissions have made natural gas the preferred fuel for new electricity generation. Expanded use of gas raises questions regarding its impact on Michigan's natural gas markets, including the future supply and price of gas, the ability of the gas pipeline system to deliver gas to gas-fired generators, the impact of gas-fired generation on Michigan's gas distribution and storage infrastructure, and the expected cost of electricity from gas generators. This report presents an initial assessment on these questions and the general viability of using natural gas to generate electricity in Michigan.

This report was prepared by the Gas, Electric, Executive Secretary, and Licensing and Enforcement Divisions of the Michigan Public Service Commission, Michigan Department of Consumer and Industry Services.

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Executive Summary

The Michigan Public Service Commission Staff provides an initial assessment on the viability of using natural gas to generate electricity in Michigan in "Gas-Fired Generation in Michigan: Assessment of Gas Infrastructure and Generation Costs" (March 1999). Low fuel costs and low emissions have made natural gas the preferred fuel for new electricity generation. In the latest Annual Energy Outlook, the U.S. Department of Energy projects that gas will fuel 88 percent of all new generation plants in the U.S. in the 1999-2020 period.

Expanded use of gas raises questions regarding its impact on Michigan's natural gas markets. Key items addressed in this report are the future supply and prices of gas, the ability of the gas pipeline system to deliver gas to gas-fired generators, the impact of gas-fired generation on Michigan's distribution and storage infrastructure, and the expected cost of electricity from gas generators. In this initial assessment, the Commission Staff finds:

- ♦ Michigan's gas pipeline capacity is currently inadequate for serving significant gas-fired generation in Michigan, but currently proposed projects will provide the necessary pipeline capacity.
- ♦ Gas supplies will be sufficient to provide fuel for gas-fired generation and to serve traditional natural gas markets for the foreseeable future, at reasonable prices.
- ♦ Michigan's abundant natural gas storage should provide fuel price benefits for gas-fired generators similar to the price benefits already received by Michigan's gas space heating customers.
- ♦ Michigan's gas storage combined with its current winter peaking season for gas use suggest that Michigan is a good location for gas-fired electricity generation, given summer peaking electricity demand.
- ♦ Natural gas prices should remain favorable for the foreseeable future. However, Commission Staff believes the likelihood of higher than expected prices is greater than for lower prices.
- ♦ Under the U.S. Department of Energy's reference wellhead natural gas prices, busbar baseload generation using natural gas is approximately 3.4-3.5 cents per kilowatt-hour in 1999, and will increase to about 4.1-4.2 cents by 2005.

The assessment period is through 2010. To assess the potential impact of gas-fired generation, 100% of the growth in electric demand was assumed to be met using gas-fired generation.

The added gas-fired generation would translate to additional capacity requirements for the intra- and interstate gas transmission pipelines:

Michigan Gas Requirements For Gas-Fired Generation	***2005***	***2010***
Average MMcf/day	327	544
Summer Peak Day MMcf/day	522	890
Winter Peak Day MMcf/day	374	645
Annual Supply - Bcf	119	198

The 119 Bcf annual requirement in 2005 is about 13 percent of Michigan's current annual natural gas consumption. To meet the electric generation needs, existing pipelines will need to be used more efficiently, and new pipeline facilities will need to be built.

Two current proposals would provide the necessary peak and annual capacity. The proposed Vector pipeline is a 1.01 Bcf per day, $419 million pipeline that would transport gas from Joliet, Illinois to Canada near St. Clair, Michigan starting in October, 2000. Second is the proposed TriState pipeline, a 0.65 Bcf per day, $361 million pipeline that would transport gas from Joliet, Illinois to Canada near Marine City, Michigan starting in November, 2000.

Either of these two proposed pipelines[1], when combined with unused transportation capacity on existing pipelines, will provide sufficient capacity to meet annual, summer peak and winter peak generation requirements in 2005, and all but 47 MMcf/d of summer peak generation in 2010.

The assessment assumes that reliable gas supply will be available at the Chicago Hub. Currently there are several proposed new pipelines that would transport additional gas supplies to Chicago. One such pipeline, Alliance Pipeline, has been approved by the FERC.[2]

Under the assumption that 100% of the electricity demand growth is met with gas, electric

[1] The Federal Energy Regulatory Commission (FERC) approved Vector on 10/19/98. "Preliminary Determination on Non-Environmental Issues" 19 October 1998, Docket number CP98-131-000. 85 FERC ¶61,083 <http://cips.ferc.fed.us/cips/>

[2] The FERC approved Alliance Pipeline on 9/17/98. "Order Issuing Certificates, Granting NGA Section 3 Authorization, and Granting and Denying Rehearing" 17 September 1998. Docket number CP97-168-000. 84 FERC ¶61,239 <http://cips.ferc.fed.us/cips/>

generation capacity requirements, gas requirements, and the kwh cost of gas-fired generation would be:

Summary of Michigan Gas-Fired Generation

	2005	**2010**
Gas Fired MW needed	3,400	5,723
Natural gas Bcf needed	119	198
Delivered natural gas $1998/Mcf	$2.85-3.02	3.05-3.51
Busbar comb-cycle, cents/kwh - $1998	3.4-3.5	3.5-3.8
Busbar comb-cycle, cents/kwh - $actual	4.1-4.2	4.8-5.2
Busbar peakers, cents/kwh - $1998	9.0-9.2	9.2-9.7
Busbar peakers, cents/kwh - $actual	10.8-11.0	12.8-13.5

Busbar is price at the point of generation, and does not include line losses and other costs of delivering electricity to meet a specific load profile. $1998 are inflation adjusted to 1998 dollars. $actual are the nominal prices in the given year.

Most of the pipeline infrastructure and Michigan's abundant storage fields (Michigan's storage capacity equals over 60% percent of its annual natural gas requirements) is used for injecting gas into storage in the summer, for use in the winter. The gas storage resources will allow load shifting to serve significant gas-fired generation for summer peaking purposes without restricting service to traditional gas customers. With relatively inexpensive improvements to Michigan's storage, gas can be delivered to meet Michigan's peak electric needs, and still allow adequate gas to be injected into storage for the coming heating season. During periods of peak summer electric demands, gas utilities can cycle between the demand for injections into gas storage and the demand for gas for electric generation. Conversely, during periods of peak winter gas loads, gas-fired generation might be interrupted and replaced with other electric generation. This will enable the natural gas delivery and storage operations to operate more efficiently, although this will require additional coordination by the gas and electric utilities.

The major gas cost factor is the wellhead price. In its review, Commission Staff concluded that the EIA wellhead price projection reflects a reasoned outlook and captures the range of other independent price projections. Delivery costs to Michigan include transportation to the Chicago Hub, and then to Michigan.

Staff concludes that there is currently and will be adequate competition to keep the delivered price to the Chicago Hub low, given the ever increasing competition by the gas pipeline companies. Transportation costs from Chicago are expected to remain at today's levels, with the higher costs of new pipelines being offset with increased operational efficiencies in both the pipeline and storage operations.

Gas-fired Generation in Michigan:
Assessment of Gas Infrastructure and Generation Costs

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Chapter 1. Introduction

The current low natural gas prices and adequate gas supplies have made natural gas the fuel of choice for new electrical generation in the U.S. and elsewhere. Therefore, the MPSC Chief Administrative Officer asked Staff to report on key issues related to the use of gas to meeting Michigan's electricity needs. First is the question of whether Michigan's natural gas transmission and supply network is adequate for expanded use of gas to generate electricity.

Second, although current gas prices are low and supplies abundant, what does the future hold with respect to the availability and price of natural gas? And third, what is the approximate cost of producing electricity using natural gas-fired generation?

This report is a summary of the key findings pertaining to the future use of natural gas for electricity generation in Michigan. The future world and U.S. supply and U.S. prices of natural gas are covered in Chapter 2, and this material is based almost completely on the U.S. Department of Energy's long-term outlook by DOE's Energy Information Administration (EIA).

The demand for natural gas in Michigan is addressed in Chapter 3. Included is a scenario of future Michigan natural gas demand which was developed by the Statistical Analysis Section, Executive Secretary Division. The chapter concludes with a discussion on the expected world and U.S. natural gas demand which is based on EIA information. This provides the larger geographic context, which is necessary given the fact that the gas market relevant for Michigan goes far beyond Michigan's borders.

Chapter 4 summarizes the findings regarding Michigan's gas transportation and distribution infrastructure. The findings reflect the Gas Division's assessment of whether the proposed projects added to the current system will provide sufficient capacity to meet gas demand requirements for electricity generation. To complete this chapter, Staff discussed the current and proposed infrastructure with Michigan's gas transportation companies.

Estimates of the busbar kilowatt-hour price of electricity using gas-fired generation in Michigan are presented in Chapter 5. The chapter addresses the major price components in turn and focuses on two generic generating units, a combined-cycle gas configuration assumed for baseload generation and a gas combustion turbine assumed for peaking generation. The price estimates are busbar, which means that system line losses are not included. System losses might add about ten percent to these costs. Also, busbar estimates reflect the cost for delivering electricity to the electricity grid, and do not reflect the costs of delivering electricity to a customer or group of customers. To deliver to a group of customers, a generator has to match the load profile of the customers. The busbar cost for a combined-cycle baseload plant (plus line losses) is therefore lower than any generator can produce for a customer or a group of customers.

Finally, chapter 6 is a brief discussion of the key reliability issues affecting the use of gas for electricity generation. This discussion is applicable to Michigan and other geographic areas.

Chapter 2. Future Availability and Prices of Natural Gas

Three factors combine to paint Michigan's prospects for the use of natural gas: available supply, price, and deliverability. The deliverability of gas is dependent on the pipeline infrastructure in and to Michigan. Deliverability is the topic of Chapter 4. This chapter discusses the expected supply availability and prices of natural gas.

It is noteworthy that this chapter does not address the production of natural gas in Michigan. The future of Michigan production was not addressed for this report because it is not seen as a major factor influencing the broad supply and demand picture for Michigan. However, Michigan production is significant in volume terms. Michigan's production generally provides about one fourth of Michigan's consumption, and was 277 billion cubic feet (Bcf) in 1997. Production in Michigan has grown in recent years and is not expected to increase further, but rather is expected to slowly decline in the 1999-2010 period.

World and U. S. Natural Gas Reserves

The size of natural gas markets generally falls between the petroleum market, where there is a single world market, and the coal markets, which are more regionalized in part because of the high cost of coal transportation. Gas is relatively easy to transport in pipelines. Delivered gas prices in the U.S. vary due to differences in gas contracts and differences in the pipeline transportation costs to specific regions, and also to the local availability of natural gas storage capability.

A single international market for natural gas has not emerged due to the limitations of the pipeline infrastructure and the relatively high cost of liquefying and moving gas on tanker ships. However, market developments have more closely unified natural gas markets around the world and in North America. New pipelines in North America, in Europe, and in Asia will continue to expand the size of and increase competition in regional natural gas markets. Also, liquified natural gas (LNG) technology is expanding, mostly in the Middle East and Asia, and this can expand the reach of gas supplies to the entire world.

The North America natural gas supplies and prices will continue to determine the availability and prices of energy in Michigan. Michigan's gas supply is part of a market including the United States and Canada. Although Mexico has significant reserves of gas, natural gas supplies are not well developed in Mexico and there is no significant integration of the U.S. and Mexican supply pipeline networks.

The significant Michigan-specific factor which affects local gas supply and prices is the abundant gas storage capacity in Michigan, as discussed in Chapter 4. Michigan's gas usage is highly seasonal, and the storage capability allows gas purchases to be made throughout the year. This lowers prices for consumers, since gas can be purchased in summer months when prices are lower, then put in underground storage and used in winter months.

The short-term supply of natural gas in local markets is constrained by the current wellhead production and gas pipeline distribution system capacity limits. However, in the longer-term, pipeline capacity can be increased. The wellhead supply of natural gas is dependent on the amount which is potentially recoverable from deposits around the world. The amount of gas which is economically recoverable is not unlimited, but according to EIA will be sufficient to meet the growing World and U.S. demand.

The convention of breaking the recoverable supply into components lends to the ability to characterize the supply as a looming shortage or as ample. Proven reserves is the amount of gas expected to be recovered from existing fields and is the portion of future supply which has the highest degree of reliability or certainty. Since proven reserves represent only a small portion of total reserves, the use of proven reserves alone gives a much less optimistic appraisal of the future availability of natural gas. The other categories of natural gas reserves are no less certain to be available than proven reserves, but estimates of the volumes for these categories have a much lower degree of reliability.[1]

The basic components of the in-ground supply of gas are:

- **Proven Reserves.** This is the amount of gas which geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known conventional gas reservoirs in existing fields under current economic and operating conditions.

- **Reserve Growth.** Reserve growth consists of the additions to proven reserves which are likely to occur due to additional reservoirs found in existing fields, or to the use of improved recovery techniques in existing fields.

- **Undiscovered Conventional Reserves.** These are estimates of the amount of gas which is technically recoverable from undiscovered fields, based on geological information and assuming the use of existing technology but without regard to the economic cost. This excludes gas included in the proven reserves and reserve additions categories.

- **Undiscovered Unconventional Reserves.** These are estimates of gas from sources other than gas reservoirs, based on geological information, which are technically recoverable, using existing technology but without regard to the economic cost. This includes gas which

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[1] Although statistical measures are not applied to the reliability of the reserve estimates, the concept of a statistical confidence interval does illustrate the differences in reliability of the gas reserve estimates. For the estimate for proven reserves, it might be said that future actual production might have an judgmental 90% probability of falling within 20 percent of the estimate. For other reserve categories, a judgmental 90% probability might be future actual production within 100 or even 200 percent of the estimate.

is recoverable from sandstone, shale, and coal.[2]

Proven reserves can be viewed intuitively as the estimate of the supply of gas which can be made available without additional exploration activity. The EIA publishes annually its world and U.S. estimates of the amount of proven natural gas reserves.[3] Figure 1 shows the current EIA proven reserves estimates for the top 10 countries, including the United States. For the U.S., the table also shows the number of years the reserves that proven reserves would last at the 1995 consumption levels. The World total years supply is 29.6 years at current consumption levels, and for the U.S. is just 6.9 years.

Natural Gas Reserves as of January 1998

Country	Reserves (TCF)	Percent of Total	1996 Withdrawals	Year's Supply
World	5,086	100.00%		
Top 5 Countries				
Russian Federation	1,700	33.43%		
Iran	810	15.93%		
Qatar	300	5.90%		
United Arab Emirates	205	4.03%		
Saudi Arabia	190	3.74%		
North America				
U.S. (rank 6th)	166	3.26%	24.1	6.9
Canada (rank 15th)	65	1.28%		
Mexico (rank 17th)	64	1.26%		

Figure 1

Prepared by: Statistical Analysis Section, MPSC, July 1998.
Source: Reserves are in EIA International Energy Outlook, 1998, which cites original source as "Worldwide Look at Reserves and Production," Oil&Gas Journal, Vol. 95, No. 52, December 29, 1997, pp. 38-39.

However, much of the future supply of natural gas will come from the reserve growth and undiscovered categories. Including other reserve categories along with proven reserves adds

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2 One example is potential future gas production from hydrates under the ocean. The potential U.S. reserves are enormous, 112,765 to 676,110 trillion cubic feet (Tcf), but are not currently economic. Collett, Timothy. Kuuskra, Vello. “Hydrates contain vast store of world gas resources” *Oil and Gas Journal.* 11 May, 1998, pages 90-95.

3 “U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996 Annual Report” by the Energy Information Administration, is the latest available and the 20th annual in this series. The Energy Information Administration (EIA), U.S. Department of Energy, is an excellent source of all types of energy related information, including historic data, market summaries, and projections. EIA’s Web site is http://www.eia.doe.gov For this report, see ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/historical/1996/pdf/021696.pdf

greatly to the supply. Figure 2 summarizes the current EIA estimates of U.S. natural gas reserves by reserve category. The U.S. reserve estimates total to about 60 years of gas supply at current U.S. consumption.

U.S. Natural Gas Reserves 1996

Reserve Category	Bcf Reserves	Years Supply
Discovered		
Proved (EIA 1996)	175,147	7.3
Reserve Growth (USGS, 1991)	360,900	15.0
Undiscovered		
Conventional, onshore (USGS, 1994)	258,690	10.8
Conventional, offshore (MMS, 1994)	268,000	11.1
Continuous-type	357,990	14.9
Subtotal		
Total, 1996	1,420,727	59.1

Figure 2

Prepared by: Statistical Analysis Section, MPSC, July 1998.
Source: Reserve data is from "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996 Annual Report," Energy Information Administration, November, 1997. The year's supply is based on 1996 U.S. wet gas withdrawals of 24,052 billion cubic feet (Natural Gas Annual 1996, EIA, Table 1)

The petroleum and natural gas supply industries add to proven reserves by exploring and drilling. Proven reserves are continuously being withdrawn from, and they are added to by successful exploration and drilling activity. Drilling activity is very cyclical, higher when gas prices are high or expected to be high and lower when prices are low.[4]

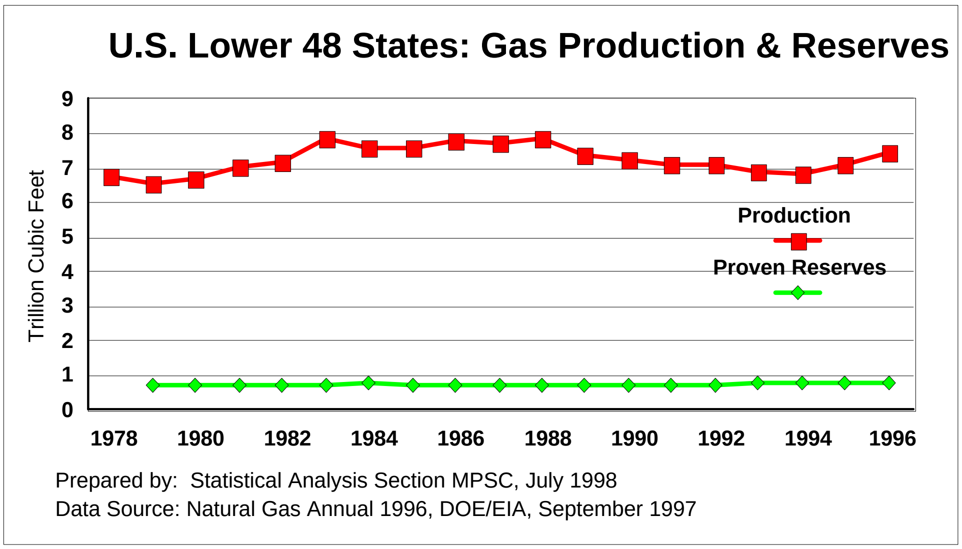

Figure 3 - Comparison of Proven Reserves to Production

4 Drilling activity this year has hit record lows. The Associated Press reported that drilling activity for combined gas and oil was at a record low of 531 on 2/19/99. This is due to very low oil and natural gas prices. "Rig Count." *Associated Press*. 19 February 1999

Figure 3 shows the aggregate effect of the gas industry exploration operations on the annual additions and withdrawals from proven reserves for the Lower 48 States for the years 1978 through 1996. Withdrawals from the ground in each year have been approximately ten percent of the proven reserves. However, as the graph shows, estimated proven reserves have remained relatively steady through the period. This is the result of exploration and drilling, which has generally added to proven reserves an amount of gas sufficient to offset the annual withdrawals from the reserves.

While the current data on gas reserves and the historic additions to proven reserves show that the industry has continued to provide adequate supply to meet demand, it also true that the ultimate supply which appears to be economically recoverable is limited. The EIA projects that reserves will increase to 189.5 Tcf in 2013, with reserves replacement exceeding production in each year through 2013,[5] then decline after 2013. Whether the industry can produce from the undiscovered conventional reserves and the unconventional reserves while maintaining low gas prices remains uncertain and a point of debate in the industry.

Future supplies of gas which will contribute most to future supply available to the U.S. and Michigan will be from new finds and expanded production in Canada and in the Gulf of Mexico. The EIA report on "Deliverability of Interstate Pipelines" discusses the importance of Canadian supply.[6] The report estimates Canadian reserves at 570 Tcf[7] and that half of Canadian production is exported to the U.S. The report projects 7.8% increase in production from 50.1 Bcf/d in 1996 to 54.0 Bcf/d in 2000.

Even though offshore projects in the Gulf are expensive (over $1 billion each for ultra deep projects being constructed in the Gulf of Mexico beyond the outer continental shelf), the large size of each find (up to 500 million Barrels of Oil Equivalent BOE each) make them economical at today's prices. Technology gains continue to impact the viability of exploring further into the Gulf. EIA's report on Deliverability on the Interstate Natural Gas System found prices necessary to make offshore production profitable declined from $2.50/Mcf (current dollars) in 1992-2 to only $1.75/Mcf in 1995-6. Data from Offshore Data Services reported last summer showed that there is a shortage of deep-water drilling rigs[8] and that drilling will not peak until around 2013-2015. Therefore, additional capacity from the Gulf will depend on how fast new supply can be drilled and brought to market. In the meantime, new supplies from Canada will fill in.

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[5] "Natural Gas Monthly" *EIA.* December 1997.

[6] Dated May 8, 1998. Page 22. This report is available at EIA's web site <ftp://ftp.eia.doe.gov/pub/ oil_gas/ natural_gas/analysis_publications/deliverability/pdf/deliver.pdf >.

[7] *Canadian Gas Potential Committee* as cited in report, page 22.

[8] As reported in the *Biloxi-Gulfport Sun Herald* 14 June 1998. <http://www.sunherald.com/>

Natural Gas Prices

The benefits of electric industry restructuring depend in part on the marginal cost of generation. Since gas is the current low cost option, gas-fired generation costs may be vital to the benefits of a competitive retail direct access market in Michigan.[9] This section discusses gas prices in general, while gas prices assumed for natural gas-fired generation costs are developed in Chapter 5. While gas prices are not expected to fall in the future as they have in the past 20 years, price changes are expected to be slight. The key factor driving future prices is the expected increase in technology used to find and develop natural gas reserves.

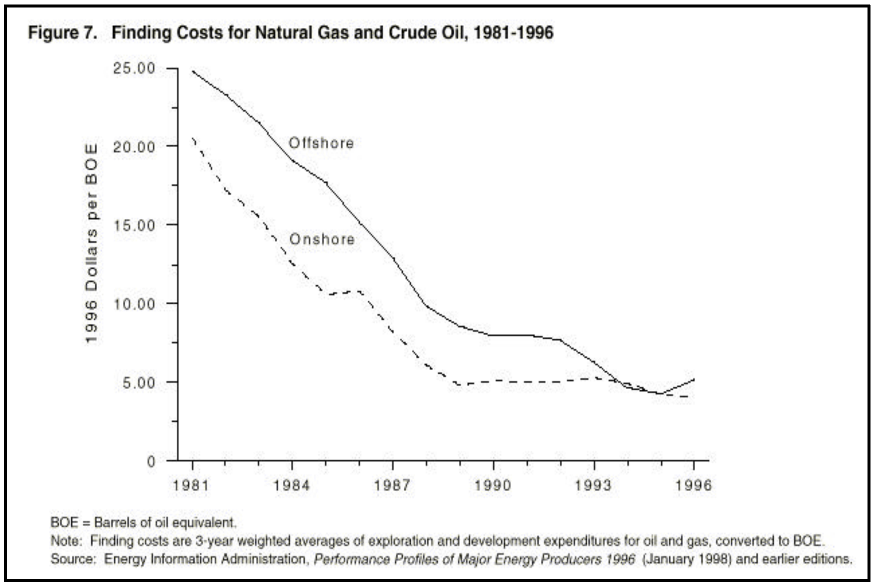

Figure 4- Historic Finding Costs Source: EIA Deliverability of the Interstate Natural Gas Pipeline System, May, 1998, page 27

In the 1980's and 1990's, significant gains in technology have impacted the industry's ability to increase reserves while holding down gas costs. Figure 4 shows the effect that technology has had on finding costs for gas, and is from EIA's report on gas deliverability. Finding costs have decreased significantly, falling at a rapid rate in the early 1980's. Not shown on the graph are finding costs for the year 1997, but initial evidence suggests 1997 costs were higher than in 1996. Paine Webber's study[10] that found a 37% increase in 1997 finding costs for independent producers, which would be represented on the graph as an upward trend from $4.24/BOE[11] in 1996 to $5.77/BOE in 1997.

Technology gains are expected to continue, however, and to contribute to keeping gas costs low. ICF Kaiser's recent study found that "Aggressive implementation of exploration and production

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[9] The "Issues in Focus" section, pages 21-22 in EIA's "Annual Energy Outlook 1998" has a good discussion on this.

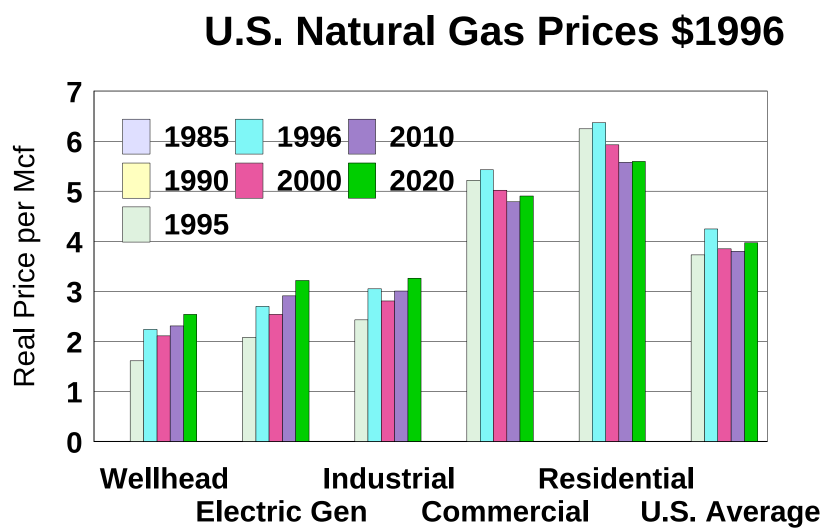
[10] "Finding, Development Costs Rise 36% For Independents, Less For Majors." *Inside FERC Gas Market Report*. 29 May 1998. Page 15.

[11] Barrels of Oil Equivalent, which is calculated by converting the energy content of natural gas and oil products into barrels of oil, using the average energy value of oil.

(E&P) technology advances would result in future savings of 15 to 60 cents/Mcf at the wellhead and could spur over 21 Tcf of new reserve additions in North America." [12]

The EIA, in its Annual Energy Outlook for 1998 (AEO98), presents high and low price scenarios for natural gas. According to EIA, future natural gas prices are more uncertain, and the price range is wider, than for any other major fuel.

Wellhead natural gas prices are projected to rise 0.5 percent faster than inflation from 1996 to 2020. The slight increase in wellhead prices is driven by the EIA assessment that technology gains have slowed and will continue to slow, combined with the need to add to production from the more difficult and expensive reserve formations.



Prepared by: Statistical Analysis Section, MPSC, July 1998
Data: Annual Energy Outlook 1998, DOE/EIA, December 1997

Figure 5

Although the projected wellhead gas prices will rise, the price path for the various major end users will vary significantly, according to EIA. The average delivered real prices of natural gas to end users are expected to fall slightly during the 1996-2020 projection period, according to EIA. Figure 5 shows the AEO98 reference case price projection. The prices shown on the figure are inflation adjusted[13] to 1996 dollars. As the chart shows, the real price is expected to decline for the residential and commercial sectors. For these sectors, the real price of natural gas is projected to decline about one-half of one percent per year. This decline is attributed to reduced margins in the distribution component of the gas price, which is expected to more than offset the projected increases in wellhead prices.

The electric generation sector already has relatively low transportation/distribution charges, and so the projected rise in wellhead natural gas prices directly translates to higher prices for the delivered price of natural gas to the electric generation sector. As Figure 5 shows, a similar trend is shown for the industrial sector which also has relatively low delivery charges. Note too that the electric generation and industrial sector natural gas prices converge slightly in the

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[12] Potential North America Gas Supply" *ICF Kaiser Consulting Group.* January, 1997. Summarized on Internet <http://www.icfkaiser.com/kaiserweb/Press97/Jan_1997.htm#1/2/97>

[13] Inflation as measured by the Gross Domestic Product (GDP) all index deflator rises at an average annual rate of 3.1% from 1996 to 2020 in the EIA projection.

projection period. EIA expects the historic and current differences in prices to these customers, an artifact of a more regulated gas pricing environment, to be greatly reduced as natural gas pricing becomes more market driven.[14]

[14] EIA's price projections are based on demand forecasts that assume normal weather. Variations in demand will cause actual prices to be higher or lower than the forecast for brief periods. For example, the mild weather this past winter will result in lower actual prices during 1999.

Chapter 3. Natural Gas Demand Outlook

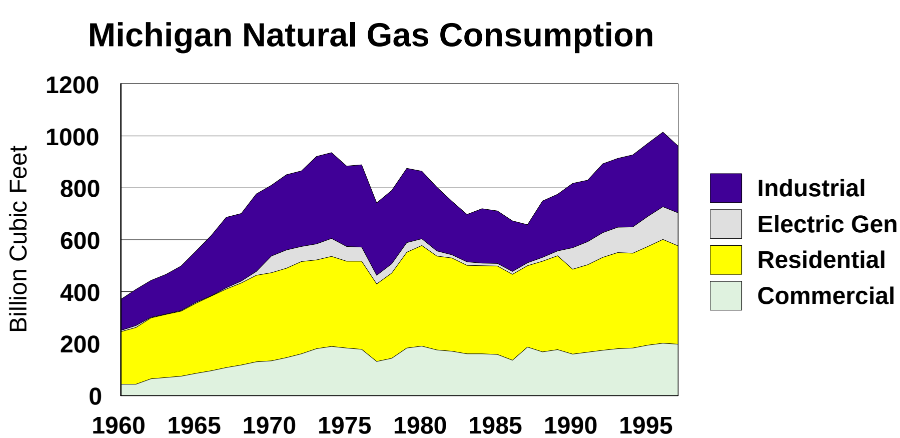
Introduction

The Michigan natural gas demand analysis below was prepared by the Statistical Analysis Section of the Michigan Public Service Commission. The Michigan demand section provides an overview of the recent historic and possible future path of Michigan natural gas consumption.

The world and U.S. assessments for natural gas demand which follow the Michigan analysis provide a broader perspective of current and future natural gas demand. The information is largely excerpted from U.S. Department of Energy's publications, and unless otherwise noted the Department of Energy is the source of the U.S. overview.[15]

Michigan Natural Gas Demand: History

Michigan consumption of natural gas by sector for 1960-1996 is shown on Figure 6. Major factors affecting consumption in this period include:



Prepared by: Statistical Analysis Section, MPSC, July 1998
Data: State Energy Data System (SEDS), DOE/EIA

Figure 6

1. Steady growth 1960-1974. During this time, the natural gas distribution system in Michigan was expanding, leading to a rapid increase in the use of gas.

2. Post-Embargo 1974-1977. Natural gas shortages were seen in interstate markets as early as 1972, leading to price increases.[16] By 1974, the prices increases were significant enough to offset demand growth in the industrial sector. Industrial and electric utility use of gas declined as prices rose. To alleviate shortages, the Federal Power Commission in 1976 issued Opinion No. 770, which set ceiling prices almost twice the previous rates for interstate gas, further reducing demand. Gas shortages

[15] Information is generally from Energy Information Administration reports, available on the Internet <http://www.eia.doe.gov/>

[16] "The Current State of the Natural Gas Market" DOE/EIA-0313, December 1991. Page 11.

continued, and shortage-induced curtailments (failure to deliver contracted quantities) were highest in 1977.

3. 1978-1984. Two national laws were passed in 1978 to alleviate the gas supply problem. The Fuel Use Act of 1978 restricted the use of gas for industrial applications and for electrical generation. The Natural Gas Policy Act established new price ceilings for wellhead prices of certain types natural gas and, more importantly, provided for the gradual deregulation of wellhead gas prices. These Acts initially reduced consumption directly, and indirectly through the price ceilings. As Figure 10 shows, industrial use continued to decline, and residential and commercial demand was reduced significantly by conservation measures of homeowners and businesses.[17]

4. 1984-1998. FERC initiated open access transportation in Orders 436 and 500 in 1984. This lead to lower natural gas prices to end-uses and, combined with the phased-in deregulation of wellhead prices in the Natural Gas Policy Act, contributed to renewed growth in gas consumption, especially in the industrial sector. In 1992, FERC in Order 636 set new requirements for interstate pipeline companies to expand competition and provide equal access in gas transportation.

The consumption trend represented in Figure 6 indirectly shows a key point with respect to capacity on the gas transportation and distribution system. Transportation and distribution capacity growth in the 1960's was sufficient to meet annual consumption in 1974. Gas consumption dropped thereafter, and through the 1970's, 1980's, and into the early 1990's there was little concern about the capacity of Michigan’s natural gas delivery system. However, the recent increases in gas consumption have pushed Michigan gas use above the peak in 1974. Recent consumption levels have renewed the need to identify potential limitations or bottlenecks to Michigan’s natural gas delivery system. This interest is highlighted because relatively low natural gas prices have made gas the preferred fuel for new electric generation facilities, which is expected to lead to additional growth in gas demand.

Michigan’s recent increase in natural gas used for electric generation shown on the Figure is almost entirely due to the Midland Cogeneration Venture[18]. In 1997, the MCV plant consumed 95 Bcf of gas, which is almost 10 percent of Michigan’s total consumption of 961 Bcf. Without the MCV, Michigan consumption in 1996 would have totaled 866 Bcf -- below the 936 Bcf consumed in the year 1974.

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[17] For instance, the average residential customer of Consumers Energy, consumed 178 thousand cubic feet (Mcf) of gas annually in 1972. By 1982, this had dropped to 148 Mcf, and to 132 Mcf in 1992. “Gas Forecast, Consumers Power Company 1992-1996." August 1991.

[18] The compiled data by the EIA includes the category “Electric Utility” which does not include non-electric utility use of gas for electric generation. Non-utility gas used for generation is included in the EIA “industrial” category. For Figure 6, the level of annual gas consumption estimates for the Midland Cogeneration Venture were removed from the EIA industrial total and added to the EIA electric utility total.

Future Michigan Natural Gas Demand

To analyze the potential impact of increasing use of natural gas on Michigan's gas transportation and distribution system, natural gas demand is projected by two major categories. The first category is natural gas consumption for uses other than electricity generation. The second category is the potential gas demand for electricity generation. The projection for this second category, gas used for electricity generation, is the focus of concern in this report and is used as the basis for additional gas demand requirements discussed in Chapter 4.

For purposes of looking at long-term impacts, annual projections are not necessary. Focus years or 2000, 2005, and 2010 were developed. Linear interpolation may be used for interim years. The projection results are shown in Figure 7. The residential, commercial, and industrial gas consumption increases from 855 Bcf in the year 1995 to 1,003 Bcf in the year 2010. Total gas used for electric generation grows from 116 Bcf to 314 Bcf, an increase of 171 percent.

Michigan Natural Gas Consumption
Scenario for Potential Use (Bcf)

								Compound Annual Growth Rates		
Use	1990	1995	1996	1997	2000	2005	2010	1997-2000	1997-2005	1997-2010
Non-Electric	734	855	889	833	929	958	1,003	3.7%	1.8%	1.4%
Elect. Gen	83	116	126	128	158	232	314	7.3%	7.7%	7.1%
Total Michigan	817	971	1,015	961	1,087	1,190	1,317	4.2%	2.7%	2.5%

Figure 7 - Prepared by: Statistical Analysis Section, MPSC, July 1998.

As discussed in the previous section, the non-electric generation use of natural gas represents the majority of Michigan's current consumption. In the year 1997, the non-electric generation consumption of gas in Michigan was 833 Bcf, 86.7 percent of Michigan's total consumption. This category, consisting of the Residential, Commercial, and Industrial sector total, is projected by trending the Annual Energy Outlook 1998 Reference case scenario for the U.S.[19] The approach is simple and easy to implement, and assumes Michigan's future natural gas consumption will follow the national trend. The results are best characterized as a scenario, and not a projection.[20] For natural gas used for electricity generation, a projection of Michigan's total electricity demand, sales, and net generation was compiled. Projected electricity demand and generation inputs are based on a trend projection for the Lower and Upper Peninsulas. Detroit Edison and Consumers Energy Company projections are used, and the Edison and Consumers

[19] The EIA projects national annual load growth for 1995 - 2020 of 1.6%, consisting of 0.7% non-electric generating and 5.1% electric generating. "Annual Energy Outlook, 1998" Table A2 <ftp://ftp.eia.doe.gov/pub/forecasting/aeo98/reports/0383(98).pdf>

[20] Labeling a forecast or scenario is not a science. In this case, the lack of analysis of Michigan-specific trends in natural gas consumption suggested the label "scenario" best describes the future year consumption figures.

projections are used to determine growth rates for the remainder of the state.[21]

The scenario for additional gas use assumes that 100 percent of the incremental electricity generation from 1998 to 2010 is gas-fired.[22] This sets a reasonable upper bound for scenario purposes, to address potential capacity or supply constraints on the gas supply and transportation system.

World Natural Gas Demand Projection

Natural gas is expected to be the fastest-growing primary energy source in the world over the next 25 years, according to EIA in its 1998 "International Energy Outlook." As shown in Figure 8, world natural gas consumption growth averages 3.3 percent annually to the year 2020 in the EIA reference case, compared to 2.2 percent for coal. By 2020, gas consumption will be 172 trillion cubic feet (Tcf) per year, more than double the 1995 consumption of 78.3 Tcf. Primary determinants of growth of world gas consumption are resource availability, cost, and environmental considerations, all of which contribute to favoring gas over other major fuel sources.

Much of the world growth in natural gas consumption will be for electrical generation. World use of natural gas for electrical generation was 22.2 Tcf in 1995, and this is expected to increase to 59.5 Tcf by 2020.

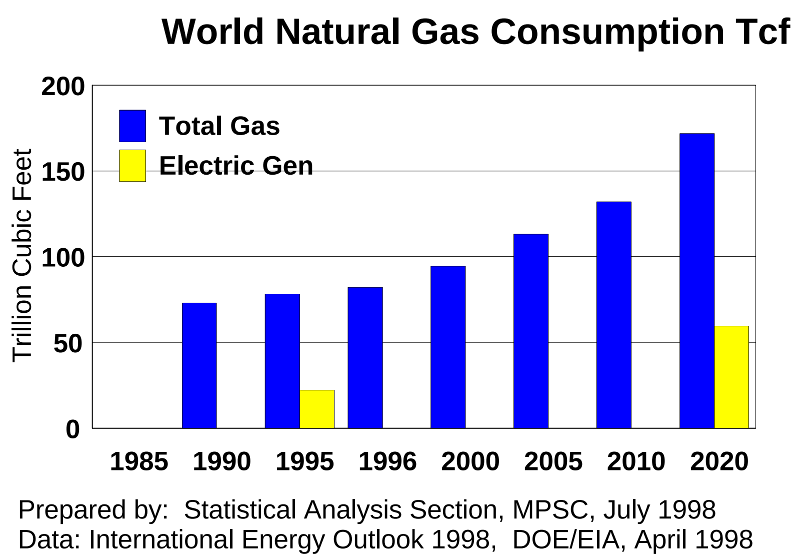

Figure 8

U. S. Natural Gas Demand Projection

Growth in natural gas consumption in the United States will be slower than world growth, but never-the-less will be very significant. EIA projects in its Annual Energy Outlook 98 that U.S.

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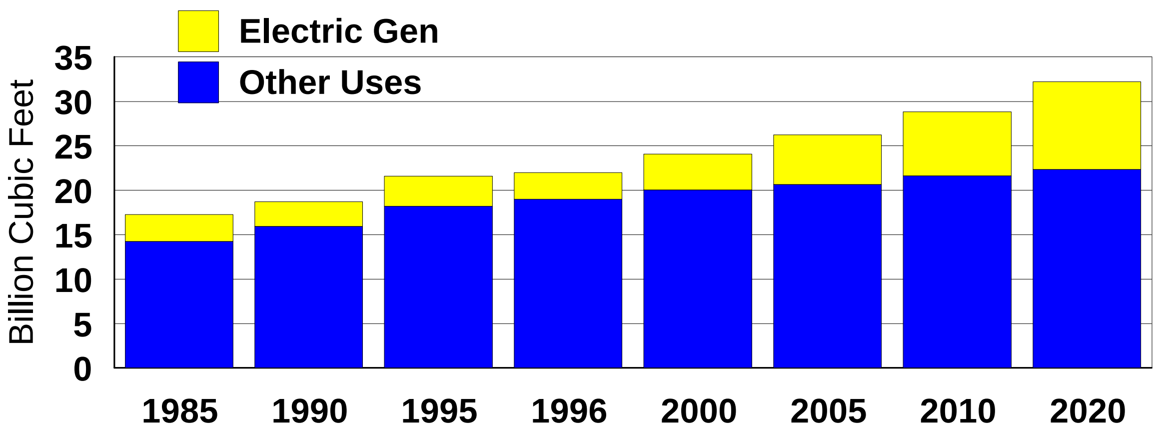
[21] See Appendix A for details of the projection method and data.

[22] For simplicity, an average heat rate of 7,000 btu per kwh (kilowatt-hour) is assumed for the projection in Figure 7 and Appendix A. This represents an average of 6,500 btu per kilowatt-hour combined-cycle baseload plant and 10,000 btu per kilowatt-hour peaking plant.

consumption will grow from 21.6 Tcf in 1995 to 33.7 Tcf in 2020, an increase of 12.1 Tcf or 49 percent.

Natural gas used for generating electricity is projected to triple from 1995 to 2020, from 3.4 to 9.9 Tcf. This 6.5 Tcf increase in the use of natural gas for electrical generation represents 53 percent of the projected 12.1 Tcf total increase in gas consumption shown on Figure 9.

U.S. Natural Gas Consumption Bcf



Prepared by: Statistical Analysis Section, MPSC, July 1998
Data: Annual Energy Outlook1998, DOE/EIA, December 1997

Figure 9

Chapter 4. Natural Gas Infrastructure needed to Serve Michigan's Electric Needs

To study the impact that new gas-fired generation could have on Michigan, and the ability to bring more gas to Michigan, several possibilities were considered. The analysis used for both pricing scenarios in Chapter 5 assumes that additional gas supplies will be available at or near Chicago[23], and that supply sellers will find a way to bring that gas to Chicago at a competitive price.

Using projected electric growth (see Appendix A) and assumptions for heat rates (see Chapter 5), the additional gas needed to supply 100% of the additional generation requirements are:

Requirement	2005	2010
Average Capacity - Mcf/day	327	544
Summer Peak Day Capacity - Mcf/day	522	890
Winter Peak Day Capacity - Mcf/day	374	645
Annual Supply - Bcf/year	119	198

While there is currently not sufficient pipeline capacity into Michigan to accomplish this, several new pipelines have been proposed. The analysis in this report assumes that one or more of these pipelines will be built. This chapter looks first at currently available pipeline capacity to Michigan.

Current Pipeline and Storage field Infrastructure

Michigan is uniquely situated, with its extensive natural gas storage, production, and with supply basins located both to the north (in western Canada) and to the south. While Michigan-produced gas meets about 25% of Michigan's needs, Michigan must import the remaining gas supply. Because of its extensive storage, pipeline transportation into Michigan is generally more constrained in summer than it is in winter. Some of the pipelines actually change flow direction so that gas physically flows out of Michigan in the winter, from Michigan storage, to help meet the demand in nearby states.

Michigan has 609 Bcf of cyclable storage capacity, more than any other state.[24] During the

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[23] References to Chicago in this analysis refer to various points of sale in the northern Illinois area near Chicago, Illinois. One such point, for example, is the Joliet Hub, near Joliet, Illinois.

[24] Based on working gas. Michigan's total storage is over 1 Tcf when non-cycling base gas is included. "Michigan Natural Gas Storage Field Summary" *MPSC.* 4 March 1999. <http://cis.state.mi.us/mpsc/gas/storage.htm>

coldest winter day, about 4.7 Bcf of the total 12 Bcf per day of deliverable storage goes to Michigan utility sales, while the remainder serves Michigan utility transportation customers and other states. Although data is not available to calculate the how much storage serves transportation end-users in Michigan, it is safe to assume that at least 5 Bcf , or 40%, of storage deliverability leaves Michigan on a winter design day.[25] In addition to gas from Michigan storage, Michigan imports approximately 2.3 Bcf on a winter design day to meet Michigan demand. Therefore, during brief periods of winter when the weather is coldest, Michigan is a net exporter of about 3 to 5 Bcf of gas per day.

The amount of winter transportation capacity available into Michigan is proportional to how cold it is in the Midwest. When the weather is colder, more gas is withdrawn from Michigan storage and is transported out of Michigan, causing more capacity to be available into Michigan. This is expected to continue in the future. The amount of capacity available in winter will likely increase if Vector[26] or TriState[27] or some other pipeline from Chicago through Michigan is built because their additional supply will likely be tied to additional Michigan storage.[28]

In the summer, the major source of capacity into Michigan is during periods between storage injections. The current and expected storage injection cycle does not require use of pipeline capacity into Michigan every summer day. As discussed later in this chapter, over 50 Bcf of summer capacity is and will be available into Michigan. Additional summer capacity is and will be available in proportion to how warm the past winter was. After a warm winter, remaining storage balances are higher, and require less supply imports during the following summer to refill storage. This occasionally leaves additional pipeline capacity that can be released and used for electric generation. The analysis in this report, as shown in Figure 11, relies solely on summer capacity that is assured - the minimum capacity expected following a colder-then normal winter where storage is completely emptied.

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[25] The design day is the coldest day that could be expected under gas utility purchase plans, which is used to estimate the maximum gas load that must be contracted for under Michigan gas utilities' purchase plans.

[26] Vector Pipeline Company is a proposed interstate pipeline that would be built from Joliet, Illinois through Indiana and Michigan to Canada near St. Clair, Michigan. Vector's expected capacity is 1.01 Bcf/d. See FERC docket no CP98-131-000. Vector's proposal was approved by FERC order dated 10/19/98. "Preliminary Determination on Non-Environmental Issues" 19 October 1998. 85 FERC ¶61,083 <http://cips.ferc.fed.us/Q/CIPS/GAS/CP/CP98-131.00P.TXT>

[27] TriState Pipeline is a proposed interstate pipeline that would be built from Joliet, Illinois through Indiana and Michigan to Canada near Marine City, Michigan. TriState filed before the FERC November 9, 1998 in FERC Docket Number CP99-61-000. TriState's expected capacity is 650 MMcf/d additional capacity to Michigan. "Notice of Applications For Certificates And For A Presidential Permit And Section 3 Authorization." 24 November 1998. <http://cips.ferc.fed.us/Q/CIPS/GAS/CP/CP99-61.000.TXT>

[28] Potential additional storage includes Washington 10 (with 42 Bcf of working gas), and Leonard (with 4 to 7 Bcf of working gas), which are currently being built.

The minimum available, however, will not be enough to meet all of Michigan's incremental electric needs. The remaining needed capacity is expected to be provided by new pipelines that go through Michigan.

Future Pipeline and Storage field Infrastructure Improvements

With several new pipeline projects being proposed to bring more gas to Chicago,[29] new gas load in Michigan will likely be served via firm transportation of gas purchased at the Chicago hub. The supplies will likely come from Canada and the Gulf. Figure 10 shows the annual flow of gas to the Midwest. The amount of gas transported is proportional to the width of the lines. The arrows show the path that expected additional supplies will take to get to Michigan, showing flows from both the west and south to Michigan and eastern states.

To rely on additional gas supplies from Chicago, new pipelines and/or significant pipeline expansion to Chicago will be needed. Also, the ability to deliver adequate gas supplies in Michigan significantly depends on at least one of the new pipelines proposed to transport gas from Chicago through Michigan, particularly for the eastern half of Michigan. Alternative pipeline proposals that transport gas from Chicago east through states outside of Michigan will provide significantly less benefits to the growth of gas-fired generation in Michigan. Scenarios in this study did not consider gas transported through Indiana and Ohio because additional expansion to Michigan from Ohio, or backhauls[30] from Ontario, Canada would probably be more costly than pipelines directly through Michigan.

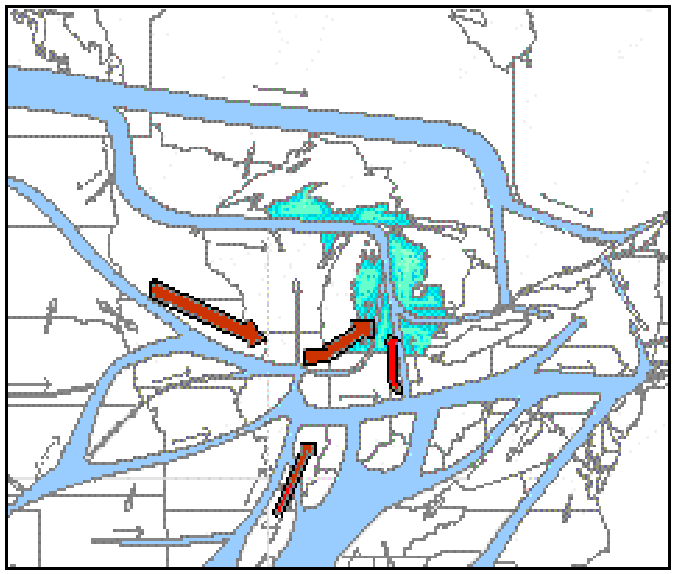

Figure 10 - Weighted Current and Future Midwest Gas Flows.
Source: EIA Deliverability on the Interstate Natural Gas Pipeline System, May, 1998, Figure 12, page 36.

Figure 11 shows that, with either of the proposed Vector or TriState pipelines, there will be

[29] Alliance Pipeline (1.3 Bcf/day), Northern Border (0.5 Bcf/day), and also potential Transcanada/Great Lakes expansion to the Midwest (0.3 Bcf/day). Total new certificated, pending, and anticipated pipeline capacity represents a 30% increase in U.S. pipeline capacity. Wright, Jeff. FERC Office of Pipeline Regulation. Presentation to NARUC Annual Regulatory Studies Program. 11 August 1998.

[30] A backhaul is transportation in a direction opposite to that of flowing gas in the pipeline. It is actually an exchange, but is often referred to as backhaul because it is still considered transportation for a fee by the transporting pipeline.

sufficient transportation capacity available into Michigan for annual and winter generation needs through 2010. To the extent that gas supplies are available for purchase at or near Chicago, there will be adequate capacity for winter supplies necessary to serve electric needs without jeopardizing service to existing gas customers. During the summer, however, there will not be enough capacity to serve all of the electric needs during peak periods. By 2010, constraints during these peak periods will require expanding pipeline capacity into Michigan by 47 MMcf/day.[31]

Interstate Pipeline Capacity Required

Chicago to Michigan - MMcf/day

	ANRPCo	TIGCo	Proposed Vector/ Tristate	Total
2005				
Average Day	138	47	142	327
Capacity Available	138	47	142	327
Additional Capacity Needed	0	0	0	0
2010				
Average Day	280	47	216	544
Capacity Available	233	47	216	496
Additional Capacity Needed				
Summer	47	0	0	47
Winter	0	0	0	0

Figure 11 - Transportation Capacity required on existing and proposed pipelines
Source: Gas Division, MPSC

The pipelines listed in Figure 11 are those most likely to provide transportation to various points in Michigan where they intersect with major electric transmission lines. Each of these are discussed later in the chapter.

To most efficiently use all available gas transportation capacity into Michigan to meet additional electric generation needs, both of the gas price scenarios assume that:

- The FERC will further change the design of pipeline rates to be more milage sensitive or change the method that capacity is released to further increase competition and efficiency. Currently, pipeline rates include an access charge, a fixed rate component designed to make it more economical to use one pipeline for long hauls instead of multiple pipelines. To the extent that it becomes easier to chain together transportation paths, transportation will see efficiency gains, and therefore lower costs.

- Adequate storage will be made available to meet the additional demand. There are many gas fields in Michigan that would make good storage fields.[32] Existing storage can be

[31] The analysis places the required additional summer peak capacity on ANR due to the random locations chosen for required generation facilities. The required additional capacity could be on any pipeline, including Vector or TriState.

[32] The best storage fields are former gas producing Silurian-Niagaran reefs that are located in the northern and southern portions of Michigan's lower peninsula.

expanded with relatively inexpensive improvements.[33] Also, there are several places in the lower half of Michigan's lower peninsula that salt cavern storage can be built. While more expensive to develop than converting gas producing fields, salt cavern storage can be cycled as often as the surface facilities will allow, reducing the per unit cost to be competitive with other storage. Either way, new and existing storage will have to be able to be cycled more often that is currently the case.[34]

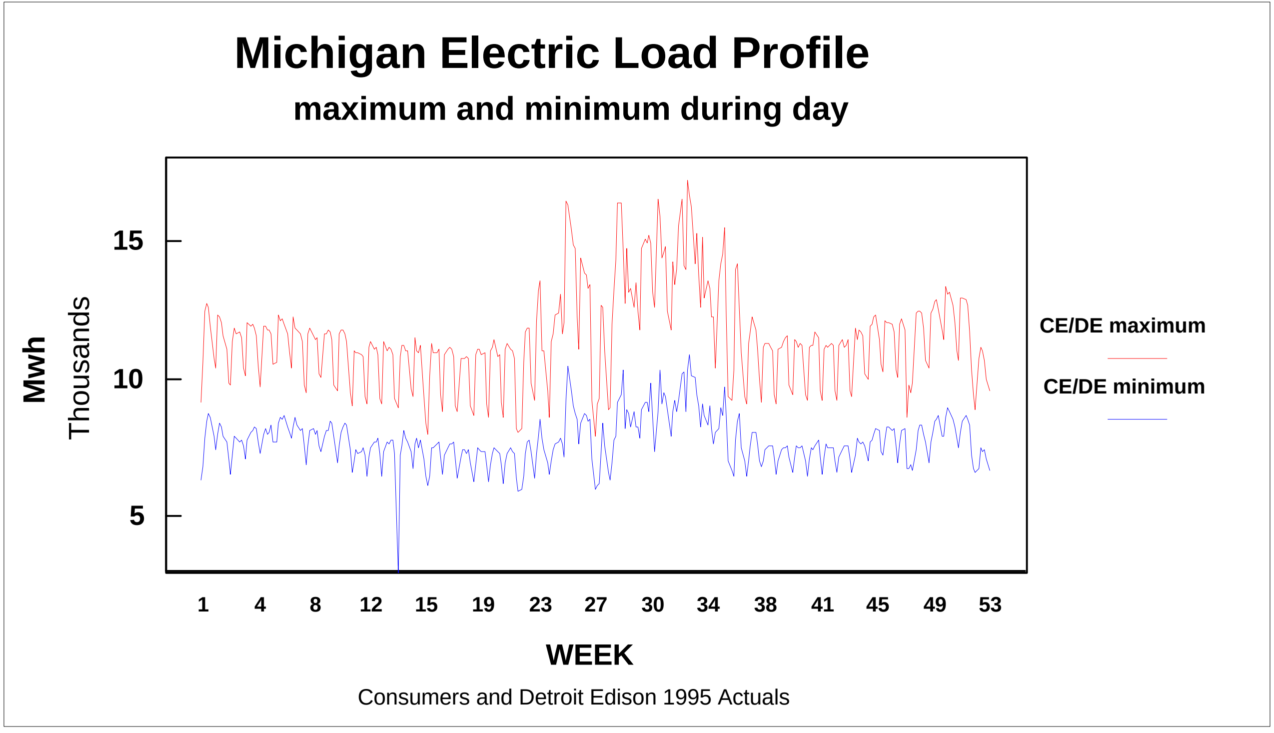

Figure 12 - Seasonal load profile for electricity needs based on actual 1995 Consumers Energy and Detroit Edison load profiles.
Source: Statistical Analysis Section, MPSC

The chart in Figure 12 shows the seasonality of the electric load that additional gas supply would need to meet. Each dip on the chart is due to reduced electric demand on weekends and holidays. Much of this load will have to be handled by storage that can inject gas on weekends and

[33] Improvements to wells and field piping can improve deliverability to storage, shortening the injection time needed to only 3-4 months of 7-month injection season. While this leaves more flexibility for serving electric generation during the summer, it does not create any additional summer pipeline capacity into Michigan.

[34] An example of how existing storage can be improved is to drill a well horizontally into the gas bearing zone of the storage field, significantly increasing withdrawal and injection capability. Consumers Energy drilled two such wells in its Overisel and Salem gas storage fields this past summer. "Horizontal gas storage wells drilled successfully." *Michigan Oil & Gas News* Vol 104, No. 30. 24 July 1998. Page 1. "Consumers Energy plans Salina horizontal wells in Allegan Co. gas storage fields." Vol 104, No. 20 15 May 1998. Page 1. Also, new Washington 10 Storage Corporation drilling include 14 horizontal drain holes that started in September, 1998. "Washington 10 drilling program kicked off." *Michigan Oil & Gas News.* Vol 104, No. 38. 18 September 1998. Page 1.

withdraw it during the week. The average gas load required generally has both a summer and winter peak. The amount of gas required to serve this load profile in the highest winter month (in 2005 and 2010) averages 96% of the high summer month load. Therefore the total monthly gas requirements are relatively equal throughout the year.

The daily swings in load, however, are greatest in the summer months June though August, where the daily peaks are highest, and the load can change by a factor of 2 by the next day or two. In addition, the summer peaks are likely to be met using peakers with higher heat rates (10,000 Btu's/kwh) than combined cycle (6,500 Btu's/kwh), which further increases peaking gas requirements. Thus, the gas required in 2005 and 2010 to serve this load profile on the highest winter day is only 69-72% of the highest summer day.

Currently, there is pipeline capacity available into Michigan at a discount. Much of the pipeline transportation to Michigan is discounted below maximum FERC-allowed rates. Trunkline Gas Company, which is currently fully subscribed, says that recent experience reveals that over 90% of its capacity is discounted, two thirds at discounts exceeding 33% of maximum rate.[35] The recently reported basis from Henry Hub to Chicago is only a fraction of maximum rates (see Figure 18, Chapter 5).[36] On a short-term basis, then, it is a buyers market for off-peak transportation. These market prices do not, however, reflect expected future demand growth. While there will likely continue to be off-peak discounts available for transportation into Michigan, the scenarios assume that, when averaged on an annual basis, there will be no or insignificant discounting in 2005 and 2010.

Michigan production is not included as a potential source of additional supply for meeting additional electric generation needs. This is because current projections for Michigan production show that future Michigan production will be "a long steady decline." [37]

Finally, it is important to note here that the FERC no longer relies on proven long term reserves to approve new pipelines. Since interstate pipelines are now transporters instead of sellers, adequate long-term transportation contracts to fill the pipeline are all that is necessary. [38] The supply to fill those contracts is assumed to be provided by the market. This highlights one

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[35] In its application, Trunkline says that it operates close to capacity only by discounting, and projects that it will have excess capacity in the future. "Notice of Application." FERC. Docket number CP98-645-000. 3 August 1998 <http://cips.ferc.fed.us/Q/CIPS/GAS/CP/CP98-645.00A.TXT>.

[36] See also Gas Daily table of average weekly index prices for Henry Hub, Chicago City Gates, and Southern Michigan Consumer Energy, and MichCon.

[37] See for example "Antrim Production Set to Decline, Ending Nine Years of Growth." *Inside Ferc Gas Market Report.* 27 November 1998. Page 1.

[38] The FERC can approve a new pipeline without it being fully contracted by putting the recovery of the pipeline's cost at risk (see §157, 18 CFR of FERC regulations). FERC's preliminary approval of Vector Pipeline, for example, used a at risk condition because Vector was only partially contracted.

important difference between the gas and electric industry - that the gas industry has always relied on contracts for supply from unregulated producer-sellers.[39] Pipeline transportation contracts often have term lengths that exceed those of the supply that fill them. The industry has and will continue to rely on the market to cause more gas to be found and produced to meet the remaining contract terms.

Details of Current and Future Capacity to Michigan by Pipeline

To determine the capacity requirements on each pipeline, a 500 Mw "average" generation plant was developed whose requirements represent the average summer peak day, winter peak day, and annual requirement for both 2005 and 2010. Figure 13 shows the transportation capacity requirements for such a plant. The averages were calculated using the average of combined cycle and peaker capacity factors and heat rates detailed in Chapter 5. These requirements were then applied to each of the interstate pipelines that serve Michigan according to likely geographical locations as well as available capacity.

Interstate Pipeline Capacity Required - Chicago to Michigan MMcf/day

	2005	2010
Average 500 Mw generation		
Annual Average	47	47
Winter Peak	54	56
Summer Peak	75	78

Figure 13 - Gas requirements for average generating plant
Source: Gas Division, MPSC

ANR Pipeline Company

ANR Pipeline Company (ANR) is the major interstate natural gas pipeline serving Michigan. ANR's pipelines enter Southwest Michigan in Berrien and Cass Counties, Southeast Michigan in Lenawee County, and extend throughout the southern half of the Lower Peninsula. ANR connects with Great Lakes Gas Transmission in the Lower Peninsula and the western Upper Peninsula.

ANR is fully subscribed in winter, which means that ANR does not have any available forward long-haul winter capacity.[40] Due to Michigan's extensive storage, however, ANR's transportation in Michigan actually reverses, flowing out of Michigan during cold periods. This leaves significant capacity into Michigan available during the winter. Because significant storage gas does and will continue to leave Michigan towards Chicago and Ontario during the winter, backhaul capacity sufficient to meet electric generation needs will be available from Chicago to Michigan via ANR.

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[39] From 1954 until 1985, the wellhead price of gas was regulated, but the producers never were regulated. Their decision to find and develop gas reserves have always been based on market perception.

[40] ANR Pipeline Company reports its unsubscribed transportation capacity on its web site <http://www.anrpl.com/GISB/>

During the summer, ANR operates its total system at an average that is only 66% of capacity.[41] However, its transportation into Michigan is much closer to capacity due to summer storage injections. ANR's summer transportation to Michigan will therefore come from the construction of new incremental capacity or contracted but unused summer capacity.

ANR has significant storage in Michigan. ANR reports that its annual storage capacity is fully subscribed.[42] ANR's storage, like other Michigan storage, is primarily used to store gas injected during 7 summer months for withdrawal during 5 winter months. The design of the injection and withdrawal cycle, however, does not require all of the transportation capacity every day.

Interstate Pipeline Capacity Required - Chicago to Michigan MMcf/day		
Pipeline	2005	2010
ANR Pipeline Company		
Annual Average	138	280
Winter Peak	162	331
Summer Peak	226	460
Great Lakes Gas Transmission Co		
Annual Average	0	0
Northern Natural Gas Company		
Annual Average	0	0
Panhandle Eastern Pipe Line Co		
Annual Average	0	0
Trunkine Gas Company		
Annual Average	47	47
Winter Peak	54	56
Summer Peak	75	78
Vector/TriState Pipeline Companies		
Annual Average	142	216
Winter Peak	158	257
Summer Peak	220	352

Figure 14 - Capacity Required By Pipeline
Source: Gas Div, MPSC

ANR's customers contract for transportation capacity for storage injection for the full 214-day summer injection period. According to ANR, their storage service requires injections on only 175 of 214 summer days.[43] This leaves 39 days where ANR's storage-related transportation capacity into Michigan is not being used. At an injection rate of about 1.3 Bcf/d, this leaves a minimum of 51 Bcf of available summer transportation capacity on ANR. This is contracted-for transportation that cannot be used to fill storage. Following warm winters, which leaves gas storage balances at high levels, the available summer transportation capacity into Michigan is even greater. If, for example, 20% of storage balances were left from the previous winter, then injections would require only 140 days to fill storage, leaving 74 days, or 92 Bcf of storage-related summer transportation capacity available on ANR. This unused capacity into Michigan

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[41] See Figure 15.

[42] ANR has 133 Bcf of underground storage in Michigan. "Michigan Natural Gas Storage Field Summary" *MPSC.* 4 March 1999. <http://cis.state.mi.us/mpsc/gas/storage.htm>. ANR reports its unsubscribed storage capacity on its web site <http://www.anrpl.com/GISB/>

[43] The gas industry in Michigan considers summer the 7-month period April through October, or 214 days. Winter is the remaining 5 months. Gas is traditionally injected into Michigan storage during the 7 summer months, and withdrawn during the 5 winter months.

will continue to be available, even after other load growth.[44] In addition, gas loads are less on summer weekends. ANR's customer shippers in the Midwest send more gas into Michigan on weekends for storage injection than they do during the week. This increases the likelihood that the unused storage-related transportation capacity into Michigan will be available during the week, when it would likely be required for electric generation.

The analysis locates three 500 Mw average plants near ANR in 2005, and 3 more by 2010. The requirements are shown in Figure 14.

Great Lakes Gas Transmission, LP

Great Lakes Gas Transmission, Limited Partnership's (Great Lakes) pipelines enter into Michigan in Gogebic County. Great Lakes is essentially the southern arm of TransCanada Pipelines Ltd, bringing Canadian gas into Michigan's western Upper Peninsula, then back into Canada north of Detroit near St. Clair, Michigan. According to Great Lakes Gas, it does not have any available forward haul capacity for any time of the year. This means that additional transports will require pipeline additions, and associated compression facilities. According to Great Lakes, rates for such expansion would be well above current maximum rates.[45]

As Great Lakes transports gas through Michigan, significant amounts of gas are injected into and withdrawn from storage fields in northern Lower Michigan. During winter storage withdrawal periods, Great Lakes' transportation is at capacity downstream of the storage fields, but there is and will be some winter transportation capacity on Great Lakes in the Upper Peninsula. This would not provide any needed summer transportation into Michigan. Therefore, the analysis assumes that gas for additional electric generation will not be transported into Michigan via Great Lakes.

Great Lakes's facilities in Michigan will be useful, however, for backhaul capacity to various parts of northern Michigan for gas that is has been transported into southern Michigan via other pipelines. The analysis concludes that Great Lakes will only be used for backhaul or relatively short forward haul of gas that has already been delivered into Michigan from ANR Pipeline and the proposed Vector or TriState pipelines. Since Great Lakes has connections with ANR at Farwell, Michigan and at the Capac and Muttonville storage fields, capacity on Great Lakes is

[44] See Chapter 5. This load growth will require pipeline capacity additions for winter peak periods, and additional storage, but will likely also create additional unused capacity in similar proportion during periods in the summer when storage is not being refilled.

[45] Great Lakes projects a rate of about $0.80/Mcf (including scenario projected price of compressor fuel used along the way) from Emerson, Manitoba, its source. Great Lakes' current maximum rates, including projected fuel price, would be about $0.55/Mcf by comparison.

instead assumed to be used to backhaul gas north to Gaylord in northern Michigan.[46] Also, Great Lakes has a connection with MichCon at St. Clair, so Great Lakes could be used to backhaul gas back into lower Michigan from either Vector or TriState via MichCon at St. Clair.

Northern Natural Gas Company

Northern Natural Gas Company's (Northern) pipelines enter into Michigan in Gogebic County, traveling east to Marquette and north to the Keweenaw Peninsula. According to Northern, significant capacity additions would be necessary to deliver additional volumes in Michigan's upper peninsula at a sufficiently high pressure to serve electric generation. Northern projects that it would have to add approximately $80 million of pipeline and compression facilities from Minnesota into Michigan to be able to supply a 500 Mw combined cycle plant in Marquette, Michigan. The high cost of expansion would make the delivered gas cost prohibitively expensive when compared to other possible ways to get gas to Michigan's Upper Peninsula. For example, Great Lakes Gas Transmission can backhaul gas to anywhere along its pipeline across the southern part of the U.P. for less that what Northern would have to charge with expansion. Therefore, it is not economical to transport gas into Michigan via Northern's pipeline, from Minnesota to Marquette, for use in electric generation.

The analysis therefore assumes no gas via Northern.

Panhandle Eastern Pipe Line Company

Panhandle Eastern Pipe Line Company's (Panhandle) pipelines enter into Michigan in Lenawee County, extending to Wayne and Kalamazoo Counties. While Panhandle is a relatively minor supplier to Michigan, it has connections with several other pipelines in the Midwest.[47] Although Panhandle is fully subscribed,[48] it occasionally has unused capacity that would be useful for transporting to other pipelines. Panhandle would also be useful for partial backhauls, such as for gas transported from storage fields in Ontario, Canada to areas south of Detroit, Michigan. Backhauling from Canada during cold periods would make more capacity on other pipelines in Michigan available for electric generation.

The analysis does not assume any gas via Panhandle.

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[46] Gas can also be transported to Gaylord via exchange, using Michigan production or storage that is delivered near Gaylord.

[47] Panhandle intersects with Trunkline in Tuscola, Illinois, and ANR in Defiance, Ohio.

[48] Panhandle reports its unsubscribed capacity on its web site <http://msrpost.messenger.cmsenergy.com/scripts/ndisapi.dll/pe/Home_Frame_PE>

Trunkline Gas Company

Trunkline Gas Company's (Trunkline) pipelines terminate at the Michigan border, serving facilities of Consumers Energy Company (Consumers) and Michigan Gas Utilities Company in St. Joseph County. Trunkline has capacity available both summer and winter. Trunkline's primary Michigan customer, Consumers, has released 485 MMcf/d of capacity back to Trunkline over the past decade.

Although Trunkline reports that it is fully subscribed[49], the analysis concludes that Trunkline currently has up to 350 MMcf/day available from Tuscola, Illinois to Michigan. This pipeline was originally built to provide 700 MMcf/day to Consumers, but is used today to meet Consumers design day of only 336 MMcf/day.

Capacity will not likely be available on Trunkline, however, if TriState Pipeline is built. The proposed TriState Pipeline will use all available capacity on Consumers pipeline system from the Michigan border[50], so any available long-line Trunkline capacity will be better used to transport gas to Chicago, or to markets served from Chicago.[51]

In the event that TriState is not built, up to 350 MMcf/d of gas could be transported to Michigan on Trunkline using supply from Chicago or elsewhere delivered to Trunkline from various pipelines that intersect Trunkline (such as Panhandle, which could deliver gas to Trunkline at Tuscola, Illinois).

In addition, Trunkline has filed with the FERC to convert one of its pipelines to transport liquids, removing 250 MMcf/d of long-line capacity from Louisiana.[52] While this capacity may eventually be needed for additional gas load in Michigan, Trunkline's interest is to find a more immediate use of the pipeline.

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[49] Trunkline reports its unsubscribed capacity on its web site <http://msrpost.messenger.cmsenergy.com/scripts/ndisapi.dll/tg/Home_Frame_TG>

[50] As proposed, TriState would transport up to 450 MMcf/d through Consumers, and up to an additional 200 MMcf/d to Consumers near its White Pigeon connection with Trunkline. The later could be delivered to Consumers from TriState or Trunkline, but not both at the same time.

[51] Trunkline could also be used to transport gas to its Tuscola interconnect with Panhandle Eastern Pipe Line Company near Tuscola, Illinois. See Panhandle discussion.

[52] "Notice of Application." *FERC* Docket no CP98-645-000. 3 August 1998. <http://cips.ferc.fed.us/Q/CIPS/GAS/CP/CP98-645.00A.TXT>. The pipeline is one of Trunkline's three mainline parallel pipelines, and will be used to transport hydrocarbon vapors from Chicago to Louisiana, and is related to the Alliance Pipeline project. "Notice of Availability of Final Environmental Impact Statement." 24 August 1998. Docket no CP97-168. <http://cips.ferc.fed.us/Q/CIPS/GAS/CP/CP97-168.0AJ.TXT>. Since Alliance is expected to result in excess capacity into Chicago for the first few years, Trunkline's excess capacity will get worse before it will get better.

The analysis assumes that one 500 Mw average plant will be located near Trunkline in 2005. The requirements are shown in Figure 14.

Vector/TriState Proposed Pipelines

Assuming that either Vector Pipeline or TriState Pipeline is built from Chicago through Michigan to Ontario, capacity will be available at market prices for transportation from Chicago to Michigan. Even if most or all of the initial capacity is contracted for deliveries east of Michigan, either pipeline can be expanded at nominal costs.[53]

The analysis assumes that a significant portion of gas, 142 to 352 MMcf/d, will be delivered by one or both of these pipelines from Chicago to Michigan.[54] If neither pipeline is built, then other additional capacity will be required from Chicago to Michigan. The requirements are shown in Figure 14.

Transportation To Chicago

According to a recent EIA report Deliverability on the Interstate Natural Gas Pipeline System (May 1998)[55], there is currently long-line capacity to the Midwest to meet new gas demand, but it is only available off peak.

The timing of the available capacity is important. Although the EIA report shows that nationwide only 80 Tbtu/d, or 63%, out of 127 Tbtu/d was used on an annual average,[56] figures for Michigan show less capacity. The summary of the Midwest report section says that, "when deliveries to other interconnecting interstate pipelines are included, the peak-day total is equivalent to 99 percent of available transportation capacity."[57]

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[53] Available transportation capacity will consist of capacity not already under contract as well as unused capacity under contract. Both pipelines have entered into precedent agreements with various customers to demonstrate market need to the FERC. Often, with new pipelines, the entire capacity is not contracted for. Also, gas marketing companies, which are not limited to specific service areas, can and do contract for a large portion of the new pipeline's capacity. On TriState, for example, 26% of its 450 MMcf/d long haul (Joliet to Dawn) capacity is not contracted for. Marketers CMS Marketing and Westcoast Energy have contracted for 180 MMcf/d, or 40% of TriState's long haul capacity. Therefore, two thirds of TriState's long-haul capacity is either available, or held by marketing companies that will use it where their future business is. At least some of this capacity will therefore be available to Michigan.

[54] As proposed, either have adequate capacity. Vector proposes 1.1 Bcf/d of capacity, and TriState proposes 0.65 Bcf/d. Vector has been approved by FERC order.

[55] "EIA report Deliverability on the Interstate Natural Gas Pipeline System." *EIA*. May, 1998. Page 103.

[56] EIA report. Figure 32. Page 94.

[57] EIA report. Page 60.

Broken down by supply area, the report details 10 major national supply corridors. Deliveries to the Midwest are via 3 of the corridors - Southwest, Southeast, and Canada, and also indirectly from Western. These corridors provide the deliveries to Michigan shown in Figure 15. The Southwest corridor consists of pipelines from Kansas, Oklahoma, and Texas. The Southeast corridor consists of pipelines from Louisiana. The Canadian corridor consists of pipelines from Alberta, Canada. The Western corridor consists of pipelines from Wyoming and Colorado that connect to the Southwest corridor. From the Southwest, transportation capacity serving the Midwest off peak is only 50% of utilized, so no additional capacity is needed.[58] New supply, however, will require additional capacity from the Southeast and Canada. From Canada major transportation capacity expansions are projected to the Midwest. As more Canadian gas goes to Chicago, expansions will be needed to bring gas to Michigan. The transportation capacity expansions to bring more Canadian gas into the US are closely tied to proposed pipelines that would transport more gas through or near Michigan towards the Northeast.

Existing Interstate Pipeline Capacity To Michigan

	Net Capacity[59] MMcf/d Table A2	Ave Usage Table A2	Ave Use Figure 15	Peak Use Figure 15	Off Peak Use Figure 15
ANR Pipeline	1,470 SW	42%[60]	70%	100%	66%
	932 SE	48%			
Great Lakes	120	91%	94%	132%	59%
NNGCo	125	66%	92%	107%	80%
PEPLco	760	59%	78%	98%	58%
Trunkline	739	78%	74%	90%	66%

Figure 15 Capacity to Michigan from Supply Areas
Source: EIA Report on Deliverability On the Interstate Natural Gas System, May, 1998, Table A2, page 103, and Figure 15, page 61.

The EIA report notes that gas from Western supply uses most of existing transportation capacity, and projects capacity expansions will bring more gas to the Midwest. From the Southeast, new supply being developed in the Gulf of Mexico will be filling existing capacity from that area, so the report concludes that new pipelines will not be needed until deep-water development in the Gulf increases production over the next decade. New production will then replace the rapid decline in production brought on by low prices (and low drilling) in the late 1980's.

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[58] EIA report. Page 42.

[59] Total capacity into Michigan per Table A2 is 6,476 MMcf/d, and total capacity out is 3,747, for a net capacity to Michigan of 2,729 MMcf/d. Amounts shown on this table are net amounts to Michigan except for ANR. ANR SW capacity is total to Michigan, and is not reduced for up to 1,417 MMcf/d of export capacity, which varies depending on how storage services for other states are used.

[60] Low usage reflects full capacity being available for transports both into and out of Michigan, as pipeline flow changes direction in winter due to use of storage.

There are several proposed new pipelines that would bring gas to Chicago.[61] One of them , Alliance Pipeline, is a 1.3 Bcf/day pipeline that would bring gas from western Canada to Chicago starting in the fall of 2000. Alliance Pipeline was approved by the FERC on 9/17/98. See FERC docket number CP97-168-000. Also, Northern Border Pipeline Company recently put its new 0.7 Bcf/day expansion capacity into service.[62]

[61] See footnote 29.

[62] Gas Daily reported that Northern Border's expansion went into service on 12/22/98. "Northern Border opens expansion for deliveries." *Gas Daily*. 22 December 1998. Page 1.

Chapter 5. Cost of Gas-Fired Electricity Generation

The busbar cost of electricity from gas-fired generation is driven by two major cost components, capital costs and fuel costs. In the judgement of Commission Staff, capital costs represent much less uncertainty than fuel costs, and so variations from the results shown on Figure 16 will be driven primarily by differences in the delivered cost of natural gas.

Gas supply costs are market driven, and therefore uncertain in the future. Actions taken by the MPSC will not have direct effects on the price of gas supply into Michigan, although approvals for local pipelines and storage facilities may have an indirect effect.

Figure 16 summarizes the projected busbar costs for both Combined Cycle and Turbine Peaker in $ per Mwh.[63] Figure 17 shows the same gas supply projected costs in $ per Mcf.[64] These prices are in 1998 dollars, and would need to be adjusted upward if converted to nominal costs.[65] For instance, the year 2005 real dollar price of $34.32 shown on the Figure converted to nominal dollars is $41.12.

Bus Bar Cost of Gas-Fired Generation - $/Mwh

	2005		2010	
Cost Item	Ref	HiGrowth	Ref	HiGrowth
Combined Cycle				
Gas transportation	3.04	3.09	3.11	3.24
Gas storage	0.51	0.51	0.64	0.64
Gas w ellhead	14.68	15.71	15.78	18.58
Capital Costs	12.09	12.09	11.17	11.17
O&M	4.00	4.00	4.00	4.00
Total (1998$)	**34.32**	**35.39**	**34.69**	**37.62**
Total Nominal	**41.12**	**42.40**	**48.22**	**52.30**
Peaker				
Gas transportation	4.68	4.75	4.78	4.98
Gas storage	0.79	0.79	0.98	0.98
Gas w ellhead	22.59	24.16	24.27	28.58
Capital Costs	58.24	58.24	58.24	58.24
O&M	4.00	4.00	4.00	4.00
Total (1998$)	**90.29**	**91.94**	**92.26**	**96.77**
Total Nominal	**108.18**	**110.15**	**128.25**	**134.52**

Figure 16 - Estimated Bus Bar costs for two gas supply scenarios (1998 dollars)
Source: Gas Div, MPSC

[63] In the electric industry, prices and costs are stated either in $/Mwh (dollars per megawatt-hour) or ¢/kwh (cents per kilowatt-hour). For comparison, a cost of 34.32 $/kwh is equal to 3.432 ¢/kwh.

[64] The Gas industry uses $ per dekatherm ($/Dth or $/MMBTU) for pricing gas to reflect its energy level in BTU's (British Thermal Units). Natural gas that is delivered to Michigan has an energy value of 1,016 BTU's per cubic foot per EIA's "Natural Gas Annual 1997" *EIA*. <ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/nga97.pdf>. All gas units in this report are stated in Mcf using the equation 1 Mcf (thousand cubic feet) = 1.016 Dth.

[65] To convert these to nominal dollars, multiply the year 2005 figures by 1.198 and the year 2010 figures by 1.390. These adjustments are calculated from the GDP all index deflator in EIA's Annual Energy Outlook 1998. This for instance, gives a year 2005 actual price for the combined cycle of $41.12, compared to the real (inflation adjusted) price of $34.32 shown on figure 16.

Two wellhead gas price scenarios were developed. The first price scenario uses the EIA reference wellhead price projection from its Annual Energy Outlook 1998. The high price scenario uses the EIA high growth wellhead price projection from the same report. Each scenario uses the same projected transportation and storage costs, developed by Commission Staff. However, gas is used for transportation and storage costs and so the higher wellhead prices in the high price scenario also yields higher transportation and storage costs .[66]

The cost components for gas-fired electricity generation are presented in the following sections. Discussions of the components for gas costs are first, and the chapter concludes with the components affecting the capital costs for two representative gas-fired generation facilities. Not quantified for this report but discussed briefly is the impact of the utilization of the generating units. The more the plant is used, the more Mwh the capital costs are spread, and the lower the final Mwh cost.

Cost of Gas Supply - $/Mcf

	2005		2010	
Cost Item	Ref	HiGrowth	Ref	HiGrowth
Gas transportation	0.48	0.48	0.49	0.51
Gas storage	0.08	0.08	0.10	0.10
Gas wellhead	2.29	2.46	2.47	2.90
Total (1998$)	**2.85**	**3.02**	**3.05**	**3.51**

Figure 17- Estimated Gas Supply costs for supply scenarios in figure above (1998 dollars)
Source: Gas Div, MPSC

Assumed Characteristics of Gas-Fired Generation

Geographic location

The most economical, and therefore logical, locations for new gas-fired generation in Michigan are where existing high-pressure gas transmission pipelines intersect high-voltage electric transmission lines. A review of possible plant locations shows that a significant number of locations in Michigan might be available to reduce the capital construction costs of a generating plant, and the summary capital costs in this report assume optimum plant locations. The cost of lateral pipelines from high-pressure interstate pipelines to the point of use at the generation plant is therefore an insignificant portion of total costs.[67]

Michigan's natural gas transmission pipeline maps and Michigan's electric transmission line maps were compared to judge likely locations for 500 Mw plants. Major gas transmission pipelines cross electric transmission lines at these locations:

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[66] The scenarios assume that 4.3% of gas transported and 1.1% of gas injected and withdrawn from storage will be used for fuel to drive compressors that move the gas.

[67] No attempt is made to determine the need for an Act 69 (PA 1929) review to determine the need for a certificate of convenience and necessity. To the extent that new gas-fired generation is located in the service territory of a gas utility, such a review may be necessary.

Gas Pipeline(s)	Location	Scenario Use	Mw
ANR Pipeline	Sparta Twp, Kent County	2005	500
	Jamestown Twp, Ottawa County	2005,2010	1,000
	Covert Twp, Van Buren County	2010	500
	York Twp, Washtenaw County	2010	500
	Baroda Twp, Berrien County	-	
Consumers Energy	Alamo Twp, Kalamazoo County	2005	500
Great Lakes	Thetford Twp, Genessee County	2005	500
	Hayes Twp, Otsego County	2005	500
Great Lakes/MichCon	China Twp, St. Clair County	2005	500
MichCon	South Lyon Twp, Oakland County	2005	500
	Independence Twp, Oakland County	2010	500
Mich Gas Storage/MichCon	North Star Twp, Gratiot County/ Newmark Twp, Gratiot County	2010	500

Each of these are logical locations for 500 Mw generation plants, either combined cycle or peaker. The locations on Consumers Energy and MichCon require that gas supply be transported to their facilities in Michigan via either an existing interstate pipeline (such as ANR Pipeline or Trunkline) or a new pipeline (such as Vector or TriState). Capacity on an existing pipeline of Consumers and MichCon may be a limiting factor unless the gas is delivered to a point that is opposite to the seasonal flow through that pipeline in amounts that do not exceed design limits. Deliveries to Consumers near Kalamazoo can be made via ANR Pipeline from the north, Trunkline from the south, or via interconnection with a new pipeline from Chicago.

Deliveries on Great Lakes can be made by backhauls from St Clair, Michigan using supply from Vector or TriState, or from Farwell from ANR Pipeline.

For the purpose of examining the cost of delivered supply, it is assumed that 7 of these locations are selected to meet projected additional electric requirements for 2005, and another 5 are selected to meet projected additional electric requirements for 2010. Since projected demand was not divided regionally, no attempt was made to precisely match location with projected electric demand for that area. Instead, locations were chosen with priority given to existing population centers and location of existing generation. Berrien County could have just as well be used, for example, as Gratiot County or other counties not included in the listing above. Local siting issues and economics may result in many other possible locations where non-major electric and gas transmission facilities cross.

The availability of these locations for generation suggests that the average length of laterals from existing gas transmission pipelines to the plant will be less than 1 mile.[68] When averaged with other costs, the cost effect of these required laterals will be insignificant. Due to cost and environmental considerations, no electric transmission lines were assumed to be constructed. Instead, the scenarios place new generation near existing electric transmission. To the extent future locations require electric transmission lines to be constructed, significant additional costs

[68] If the location in Gratiot County is connected to both Michigan Gas Storage and MichCon, about 3 miles of pipeline would have to be built to each existing gas transmission line. When averaged in with the other locations, the total is still less than one mile.

could be added.[69]

Capital costs

Capital costs are in a range of $450.00 to $600.00 per kw (1997 $s) for combined cycle and $250.00 to $350.00 per kw for gas peakers. These numbers are very sensitive to site costs such as distance to gas and electric transmission lines. Also there are economies of scale when additional capacity is installed at one site. For this study, $500 per kw was used for combined cycle, and $300 was used for peakers.[70] Both are assumed as 1998 dollars.

Heat rates

Heat rates are expected at 6,300 to 6,700 British Thermal units (BTU) per kwh for combined-cycle units and about 10,000 BTUs per kwh for gas turbine peakers. Plant use and dispatch can have an impact on overall heat rates. For this study, 6,500 BTU was used for combined cycle, and 10,000 BTU was used for peakers. Steam and heat balances have to be optimized to reach these optimal heat rates.

The starting point for the combined cycle heat rate analysis is the Detroit Edison's 1994 Integrated Resource Plan filed in August 1994.[71] The new combined - cycle unit (non - phased) had a heat rate of 6,949 BTU /kwh at 241 Mw maximum. The new combustion turbine had a heat rate of 10,545 BTU /kwh at 159 Mw maximum. This 1994 study is now a bit dated. Indeed, improvements in heat rates could be significant in the 1998-2010 time frame, but for this analysis future improvements based on technology not yet operationally proven were not considered.[72]

Capacity factor

The capacity factor for gas combined-cycle units could vary from 40% to 80% or even higher depending on dispatch, contracts, etc. The Mwh availability is assumed to be about 90%. This factor could have the single biggest impact on unit cost. Because the Midwest is predominately coal generation and pooling dispatch is based on marginal cost (fuel plus incremental operating

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[69] Estimated cost for electric transmission line is as much as $1 million per mile, and is very site specific.

[70] These capital costs assume larger installations. Smaller sizes may result in higher per unit costs.

[71] Appendix C, "Integrated Resource Plan 1994-2008" The Detroit Edison Company, August, 1994

[72] For an example of this improvement, an article in Power Generation Technology International states that increases in gas turbine exhaust temperatures over the last decade have significantly improved combined cycle performance to 59% gross thermal efficiency (5,785 BTU/kwh). "Next Generation In Combined Cycle For A Deregulated Market." *Power Generation Technology International.*

and maintenance cost), any gas plant must overcome the disadvantage of a relatively high variable cost and hence a lower dispatch priority if it is part of a power pool.[73] By contrast, the MCV plant in Midland had a very high utilization rate of 91.3 % in 1997 because of a specific contract clause which based payments on total delivered electricity, and so the MCV plant was not dispatched on an "economic basis." Thus, actual capacity factors will depend on whether the additional generation capacity is a dispatched merchant plant or a contracted plant. In 1998, for example, the MCV plant was dispatched on a more economic basis, and had a utilitzation rate of 79.5%. For this study 80% was used for 2005, and 87% was used for 2010 for combined cycle, and 10% was used for both 2005 and 2010 for peakers.

Combined Cycle Plant Annual Fixed Costs

The capital costs calculated in Figure 16 started with a projected cost of $500 /kw, then applied an annual fixed cost factor for merchant plants of 16.83%[74] and the capacity factors stated above. For the purposes of calculating fixed costs, the plants were assumed to be dispatched merchant plants.

Peaking Plant Annual Fixed Costs

The capital costs calculated in Figure 16 started with a projected cost of $300 /kw, then applied an annual fixed cost factor of 16.83%, and a capacity factor of 10% for both 2005 and 2010.

Natural Gas Fuel Costs

To estimate costs of transporting gas from the wellhead to each generating plant in Michigan, the scenarios use current pipeline rates as a proxy for future costs. This assumes that cost reductions due to competition and increases in efficiency are offset by the increased cost of expansions. However, for major pipeline expansions, costs are not likely be rolled directly into (and therefore increase) current rates. For major expansions, the incremental expansion transportation cost is calculated on a stand-alone basis.

The costs assume gas is delivered to the Chicago Hub, and then adds the cost of transporting that gas to Michigan. Further, the scenarios rely on available supply from Chicago throughout the year. Because Chicago is expected to be a competitive market[75] the total delivered price to

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[73] Of course, a generating plant may be built for the purpose of selling to a specific retail open access market, rather than into a wholesale power pool. The future structure of the electric generation market is not clear at this time.

[74] Per a June 4, 1998 analysis by Financial Analysis and Accounting Section, 16.83% is for combined cycle merchant plant. The cost factor for a utility-owned base load plant is 13.66%.

[75] ICF Kaiser Consulting Group studied the effects of proposed new pipelines to the Midwest on gas supply prices in the years 2000-2001. The study projects a $0.20-0.30/Mcf price decrease in Chicago if Alliance

Michigan is likely to be less under this approach.

If gas is not purchased at Chicago, but purchased from the various supply basins then transported to Michigan, the result could be based on all of the same assumptions and costs except for transportation, which would be slightly higher. Therefore, if Chicago is not used as a market center, the only change to the scenarios would be slightly higher busbar electricity costs.

The scenarios do not attempt to predict the extent that prices for existing transportation capacity may or may not be discounted in the future. Capacity will likely be discounted during periods of reduced demand, just as it will likely be priced above projected prices during high demand.[76] The scenarios assume that, on the average, no discounting will occur for incremental gas transportation capacity into Michigan.

The scenarios assume that, due to competition, the delivered cost of gas to Michigan will be current maximum pipeline rates plus fuel at the projected wellhead price. This is not meant to be a precise estimate of transportation costs, but a compromise between the upward pressure on future rates that the additional costs of required new pipeline facilities will cause and the downward pressure on rates caused by competition and efficiency gains in pipeline operations. The downward pressure will tend to be greater in the near term when new pipelines to Chicago are not yet at full capacity.[77] The projected rates also reflect an annual average, and do not reflect likely day-to-day market fluctuations.

Transportation to Michigan

Based on current plans for new pipelines to transport gas supplies east from Chicago, there will be plenty of new capacity available from Chicago at market prices.[78]

Assuming that the Vector Pipeline, TriState Pipeline, or both pipelines are built from Chicago through Michigan to Canada (near Port Huron), capacity will be available at a market price representing the Chicago to Detroit basis.[79] According to ANR, incremental transportation from

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Pipeline is built. If Vector Pipeline is also built, the price decrease would instead be about $0.15/Mcf. Potential new Gulf Coast supply could bump this decrease up to $0.30/Mcf. Under the scenarios in this report, extra supply and capacity is assumed to be absorbed by market growth by 2005. “Study: New Supply to Deflate Prices in Midwest, Northeast But Not West.” *Inside FERC Gas Market Report.* 15 May 1998. Page 7.

[76] Where the transportation rate cannot be increased due to FERC regulation, the rate for the supply can be increased to compensate.

[77] Under the scenarios in this report, extra supply and capacity is assumed to be absorbed by market growth by 2005. Transportation to Chicago is therefore assumed to be only slightly less in 2005 than 2010.

[78] Based on FERC filings of Vector, TriState, and Independence.

[79] The Chicago to Detroit basis is the Detroit market price minus the Chicago market price.

Chicago will cost $0.10-0.15/MMBtu. Vector and TriState estimate $0.18/MMBtu. Recent historical Chicago to Detroit basis is not indicative.[80]

The scenarios assume that a significant portion of gas will be delivered by one of these pipelines from Chicago. If neither pipeline is built, then 142 MMcf/day of additional annual capacity will be required in 2005, and 216 MMcf/day of annual capacity will be required in 2010 from Chicago to Michigan on other pipelines. Figure 14 in Chapter 4 details these requirements.

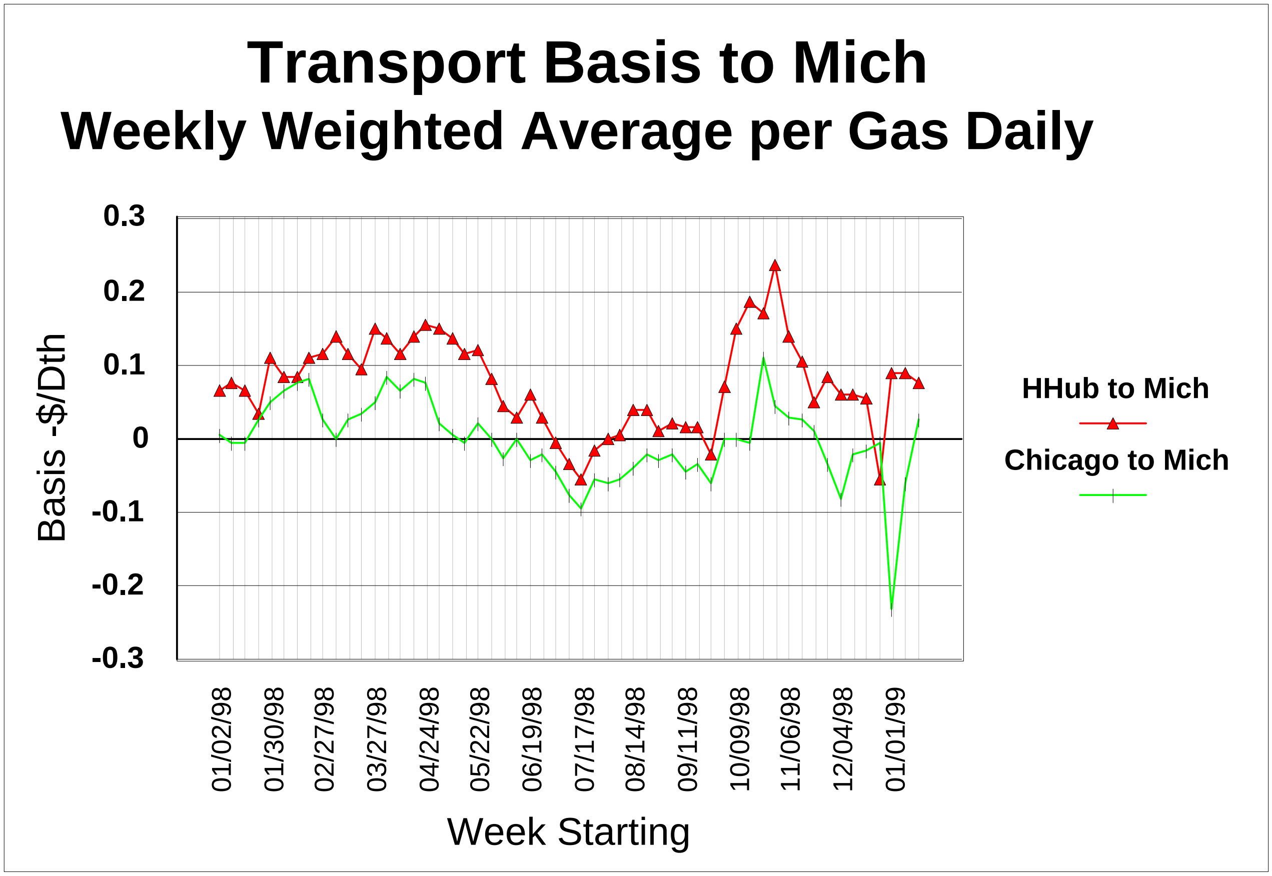

Figure 18 - **Transportation basis to Michigan from Gas Daily average weekly index prices.**

Current price differences average far below maximum FERC-approved pipeline rates. As shown in Figure 18, the current Henry Hub (Louisiana) to Midwest averages less than $0.15/MMBtu, while current maximum pipeline rates, including fuel at projected gas costs, average $0.45 to $0.50/MMBtu.[81] This suggests that current pipeline transportation maximum rates are too high.

[80] See Figure 18. Actual Chicago to Michigan basis for 1998 averaged $0.23/Dth based on weekly prices reported in Gas Daily, with a weekly high of $0.11/Dth, and a weekly low of -0.23/Dth. "Weekly Average Prices." *Gas Daily*. Every Monday. Page 3.

[81] The prices in Figure 18 are reported in $ per million BTU's. To convert to $ per Mcf, multiply by 0.9843.

This basis, or the difference between the price of gas delivered in Louisiana and that delivered in the Midwest, is a proxy for current short-term transportation. The transportation needed for gas-fired generation, however, is long-term. The current basis is sufficiently below pipeline rates that major pipeline expansion will be discouraged until this basis converges with pipeline rates.[82]

The FERC recently proposed new rules that would change the way capacity is released by interstate pipelines.[83] One result may be that storage would compete with pipeline capacity that is allowed to rise to a market price during high winter demand periods. This may result in increased demand and higher prices for Michigan storage. While this could result in slightly higher storage costs for gas used for electric generation, it could also reduce peak-period transportation costs and increase supply reliability by freeing up transportation capacity when it is needed most.[84]

Transportation to Chicago

Because the delivered cost of gas to Michigan is projected to average slightly less when purchased from Chicago, the projected transportation cost to Chicago is estimated by subtracting projected transportation cost from Chicago to Michigan from total transportation costs. The projected cost to Chicago is $0.20/MMBtu in 2005, and $0.25/MMBtu in 2010, which, when added to projected transportation from Chicago to Michigan is delivered to Michigan at a total delivered price about $0.05 cheaper than projected transportation direct to Michigan in 2005, and about the same in 2010.[85]

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[82] See for example, FERC Notice of Proposed Rulemaking (NOPR) in docket number RM98-10-000 which addresses currently price disparity between short and long term transportation markets. The NOPR also addresses peak pricing, which will have an effect on storage prices. "Regulation of Short-Term Natural Gas Transportation Services." *FERC.* 29 July 1998. <http://cips.ferc.fed.us/Q/CIPS/RULES/RM/RM98-10.000.TXT>.

[83] See FERC NOPR in FERC docket number RM98-10-000. In this proposed rule, FERC would remove the maximum rate cap for short term transportation. See also FERC Notice of Inquiry in FERC docket number RM98-12-000,. In this Inquiry, FERC expects to examine its pricing policies for transportation. Both will likely affect the pricing of capacity segments from Chicago to Michigan. "Regulation of Interstate Natural Gas Transportation Services." *FERC.* 29 July 1998. <http://cips.ferc.fed.us/Q/CIPS/RULES/RM/RM98-12.000.TXT>

[84] As proposed in RM98-10-000, FERC would allow a utility to release capacity on a short-term basis at any price. By using more storage during peak periods, the utility can then release unneeded transportation at higher rates than currently allowed. The could cause Michigan utilities to use more gas from their own storage during limited times where transportation is worth enough to make it sufficiently economical to risk the need to purchase replacement gas before the winter is over.

[85] Vector Pipeline projected that by 2000, there will be 5.9 Bcf/d more pipeline capacity to Chicago than the Midwest needs. "Vector Sees Excess Capacity; Suppliers Step Up Pace." *Natural Gas Intelligence*. 27 July 1998. Page 8.

Storage Costs

Although storage is not a significant component of the delivered cost of gas supply, it does have significant impact on pipeline capacity needed during peak periods, and therefore is included so as not to understate delivery costs. Storage costs were projected using current storage rates for ANR firm storage service. Minor amounts of summer interruptible storage were projected at a discounted rate of one half the ANR firm rates (without fuel). Withdrawals from storage in the summer are mostly backhauls. As with pipeline transportation, the increased costs of new storage are projected to be offset by competitive pressures as well as improvements to storage wells that increase deliverability and allow storage to be cycled many times within a season.

To be competitive with conventional storage, salt cavern storage will have to be cycled sufficiently to bring its unit cost down to that of existing storage. For salt cavern storage, sufficient cycles (10-12) are assumed over a year, so that unit cost of storage roughly equals ANR's firm storage rate. The amount of storage service that is provided by salt cavern storage will therefore not impact total costs.[86]

Wellhead Gas Costs

For projecting the wellhead cost of gas, the EIA's Annual Energy Outlook for 1998 (AEO98)[87] is seen by Staff as the best reference projection because this source is viewed as impartial, the analysis considers both demand and technology impacts, and the EIA scenarios capture the range of most other independent sources. Chapter 2 herein discussed the EIA reference case gas price projection trends for the major sectors. Wellhead prices for the two scenarios considered by Staff to be most likely come from two EIA scenarios.

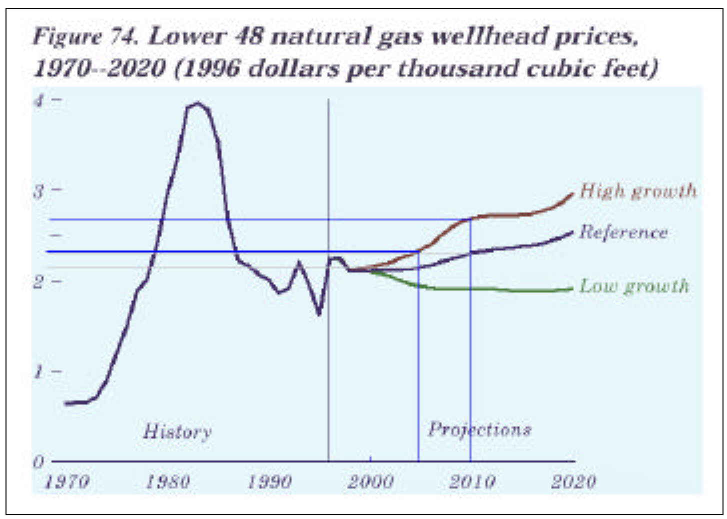

Figure 19 - Wellhead prices from EIA AEO 1998

[86] The amount of available salt cavern storage was not estimated. Salt Cavern storage is generally superior to conventional storage in its ability to provide short-term injection/withdrawal cycling that is required for gas-fired generation. However, constructing them requires the proper disposal of large amounts of brine that result from creating the caverns, and construction of surface facilities that have a large transportation capacity.

[87] "Annual Energy Outlook 1998" *EIA*. <http://www.eia.doe.gov/oiaf/aeo98/homepage.html>. Also, Chapter 2 discussed key factors which will drive gas prices and the EIA's projection of U.S. retail gas prices by sector.

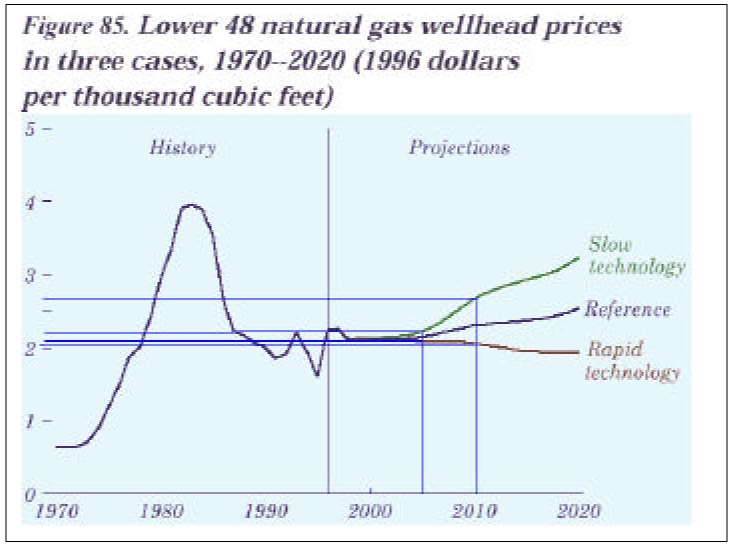

Figure 20 - Wellhead prices from EIA AEO 1998

The first scenario is the EIA's reference case for wellhead prices in 2005 and 2010. Figure 19 shows Figure 74 from EIA's AEO98 with 2005 and 2010 highlighted. The second scenario is the EIA's high growth projection for 2005 and 2010. The prices were converted to 1998 dollars. The high growth case makes sense if the same assumptions used for load growth in the analysis are also applied to other states. The gas required for all incremental generation is therefore closer to the high growth projection than the reference case.

Effect of Technology on Gas Supply - $/Mcf

	2005		2010	
	Slow	Fast	Slow	Fast
Change (1998$)	0.07	-0.06	0.37	-0.26

Figure 21 - Effect of slow, fast technology on gas price projections
Source: Gas Div, MPSC

The EIA projections for high/low technology were also studied, and did not require separate scenarios because their effect was only significant in 2010. Figure 20 shows the effect using Figure 85 from EIA's AEO98 with 2005 and 2010 highlighted. Figure 21 shows the effect of high/low technology on the cost of gas supply. The effect of slow technology increases the total gas suppy costs in 2010 by $0.37/Mcf.

Chapter 6. Reliability Issues

In the past year, reliability of service of electricity has moved to the top tier of issues related to restructuring the electricity industry. Insuring adequate generating capacity and efficient mechanisms to allocate generation and transmissions at times of peak electricity demand is being addressed by the Federal Energy Regulatory Commission and the National Electric Reliability Council. States addressing restructuring have these concerns along with maintaining reliable distribution utilities and reliable service for customers in any deregulated environment.

Greatly expanded use of gas for generating electricity also has reliability risks. These are price risk and deliverability risk. Each of these depend greatly on how the market for gas-based electricity generation converges with the market for natural gas space heating in Michigan. As explained below, the partial non-coincidence of electric load verses gas, along with adequate gas storage, help to mitigate this risk.

Price Risks

Under a system where gas availability will be determined by market conditions, price risks will be a major factor of reliable gas supply. Price risks are judged by Commission Staff to not significantly affect the economics of gas-fired generation through the 1999-2010 study period.

One price risk is that significant increases in market demand will drive the market price for gas higher, especially during periods of high gas demand. In the past, peak period demand was only during the winter heating season. With the addition of gas-fired generation, peak demand for gas will also occur during summer electric peaks as well as during peak periods of storage injections, since the need for gas for electric generation concentrates seasonal storage injections into a shorter period in the spring and fall. This will very likely create several additional periods of high demand for gas, which may create brief periods of higher demand-induced prices.

The risk of future technology improvements in gas exploration and production adds to price risk. In this report, this is reflected in the use of EIA's reference (reference price) and slow technology (high price) scenarios. Staff believes the risk of higher prices than the EIA reference price scenario is much more likely than the risk of lower prices, leading to the omission of the EIA low price scenario for the summary results in this report.

The amount of gas storage and the ability to cycle storage reduces the price risk. Michigan's abundant gas storage, particularly that which can be cycled several times within a season, allows purchases to be reduced when prices are high. This should serve to reduce prices for electric generation in Michigan by moving the price risk for a portion of the gas supply to other time periods.

Gas supply and transportation contacts whose terms and pricing provisions mirror electric sales contracts tend to mitigate price risk. There are also various financial instruments available to hedge prices, allowing prices to be fixed in advance, or indexed to other things such as electricity prices. Relying on financial instruments to reduce price risk generally adds to the cost of gas supply, and introduces the risk of failure of the financial instrument.[88]

Deliverability Risks

To ensure reliability, new storage services will have to be and are projected to be available that can inject and withdraw the same week. This will allow gas to be imported to Michigan on weekends and off peak to meet peak generation demands during 16-hour weekday periods. This report assumes that sufficient storage will be available to facilitate deliveries, at reasonable prices.

Faster cycling of gas storage for electric generation has both costs and benefits. It ties up storage capacity. This will give gas utilities less ability to purchase additional amounts of gas in the lowest priced months in the summer to inject it into storage. However, increased cycling of storage can make the transportation system to Michigan more efficient and therefore lower cost. Depending on the timing and magnitude of gas supply price variations, it is possible that efficiency induced cost reductions will offset the loss of flexibility.

It is possible that existing gas customers will be better off even with this loss of flexibility from gas-fired electric generation. The efficiency of additional cycling allows the transportation and storage systems to be relatively smaller to meet varying gas demand. This combined with the fact that peak use of gas for space heating is in the winter and peak use of gas for electric generation will likely be in the summer means the gas system will operate closer to its design limits during additional peak periods. This benefit of this increased efficiency, which lowers delivery costs, may also increase the risk that deliveries cannot be made since the system will operate closer to capacity in more hours in the year.[89]

There is also the risk of pipeline breaks, which is minimized where interconnections are at multi-pipeline locations, such as where interstate pipelines have multiple lines. Only one of the 11 locations used in the scenarios has a single pipeline connection.

Finally, Michigan appears to be well-suited as a location for gas-fired electric generation given the assumed additional transportation pipelines. The high gas peaks of the natural gas space heating market along with Michigan's abundant storage give Michigan a location advantage over many other states. Electricity demand is summer peaking, and so the electric supply industry may be more tolerant of price and deliverability risk during peak winter demands. To the extent

[88] Gas futures contracts at the New York Mercantile Exchange are guaranteed, for example, so if delivery fails the exchange partners will cover costs.

[89] Such synergies will likely require electric and gas utilities to more closely coordinate their emergency procedures and service priorities.

that there is coal, nuclear, or other non-gas generation capacity available during periods of peak winter gas loads, gas-fired generation might find winter interruptions of gas supply acceptable and even desirable given an appropriate price break, thereby increasing the reliability of gas service to other Michigan customers. During periods of peak summer electric demands, the opposite might occur, with gas utilities occasionally interrupting their injections into storage to meet gas-fired generation requirements during Michigan's summer electricity peaks.

Appendix A Scenario for Needs in Michigan Through 2010

Projected Electric Needs in Michigan in 2005, 2010

The scenarios for Michigan's future natural gas consumption for electric generation use is based on projected Michigan electric demand and generation. For non-electric generation use of gas, the Michigan projection is based on projected growth in U.S. natural gas consumption. Tables A-1 through A-5 document this projection. Key assumptions are:

- Non-electric-generation use of gas will grow at the rate projected for the U.S. by the Energy Information Administration in the "Annual Energy Outlook 1998."

- All of the increased electrical generation needs in Michigan are met with natural gas-fired generation.[90] This assumption, however, does not include any current electric generation plants which will be retired, including the Palisades nuclear plant in 2007. To the extent that current Nuclear plants are retired and replaced with gas-fired generation, an additional 140 to 160 Bcf per year of gas will be needed.

These scenarios provide the basis for electric generation growth used in the this report. However, the gas use figures on A-4 and A-5 are based on slightly different assumptions than were used for the final analysis. On A-5 for instance, the gas use is based on an initial simplifying assumption of baseload capacity using a heat rate of 7,000 Btu/kwh.

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[90] This report analyzes only large-scale, central station gas-fired generation. Emerging technologies for small-scale gas-fired generators may also make an impact on Michigan gas markets during the time frame of this analysis (by 2010) but were not evaluated for this report. Such technologies, including fuel cells and micro-turbines, may come in sizes all the way down to a few kilowatts, suitable for residential use. They may also be used in the automotive industry. These applications could replace existing gas space and water heating appliances with cogeneration systems that also produce electricity. The resulting synergy may result in less of a required increase in natural gas supply than stand-alone, large, central station units.

Table A1

Michigan Annual Electricity Sales
Composite Forecast

	Annual Sales (GWh)				
Year	Consumers Energy	Detroit Edison	Balance of Lower Penninsula	Upper Penninsula	State-wide Total Sales
1990	28,668	39,674	9,145	4,183	81,670
1991	29,593	40,135	9,258	4,838	83,825
1992	29,428	39,377	9,983	5,052	83,840
1993	30,729	41,716	10,263	4,880	87,589
1994	31,932	43,211	10,735	5,281	91,160
1995	33,266	44,926	11,119	5,390	94,701
1996	34,015	45,328	11,383	5,514	96,240
1997	34,247	45,582	11,773	5,752	97,354
	Forecast				
1998	35,453	46,850	12,033	5,874	100,210
1999	36,270	47,698	12,285	5,996	102,249
2000	37,111	48,491	12,546	6,124	104,272
2001	37,983	49,143	12,782	6,239	106,147
2002	38,819	49,929	13,020	6,355	108,123
2003	39,673	50,728	13,262	6,474	110,137
2004	40,545	51,540	13,510	6,594	112,189
2005	**41,437**	**52,364**	**13,761**	**6,717**	**114,280**
2006	42,349	53,202	14,018	6,842	116,412
2007	43,281	54,054	14,280	6,970	118,584
2008	44,233	54,918	14,546	7,100	120,798
2009	45,206	55,797	14,818	7,233	123,054
2010	**46,201**	**56,690**	**15,095**	**7,368**	**125,353**
Staff 2006	40,727				
Staff 2007		54,094			
Compound Annual Growth Rate:					
1991 - 1996	2.8%	2.5%	4.2%	2.6%	2.8%
1996 - 2001	2.2%	1.6%	2.3%	2.5%	2.0%
1996 - 2010	2.2%	1.6%	2.0%	2.1%	1.9%

Prepared by: Statistical Analysis Section, Executive Secretary Division, Michigan Public Service Commission
Source: 1990-2001 is from "Michigan State-Wide Electric Sales Forecast," Technical Services Division, MPSC, April 20, 1998. 2002-2010 applies 1996-2001 growth rates for Edison and Consumers. For other areas, the year 2001 ratio (area/(CE+DE)) is fixed through the 2002-2010 period. Staff 2006 and Staff 2007 are from unpublished Staff projections for CE (3/97) and DE (12/97).

Table A2

Michigan Annual Electricity Generation and Peak Demands Composite Forecast

	CE	DE	Balance of LPenn	Total Lower Penninsula		Upper Penninsula		State Total	
Year	Generation	Generation	Generation	Generation	Peak Demand	Generation	Peak Demand	Generation	Peak Demand
1990	30,893	42,251	9,940	83,084	15,807	4,547	865	87,630	16,672
1991	31,890	42,742	10,063	84,695	16,114	5,259	1,001	89,954	17,114
1992	31,711	41,935	10,851	84,497	16,076	5,491	1,045	89,988	17,121
1993	33,113	44,426	11,155	88,695	16,875	5,305	1,009	94,000	17,884
1994	34,410	46,019	11,669	92,097	17,522	5,740	1,092	97,837	18,614
1995	35,847	47,845	12,086	95,778	18,223	5,858	1,115	101,636	19,337
1996	36,654	48,272	12,373	97,300	18,512	5,993	1,140	103,293	19,652
1997	36,904	48,543	12,797	98,244	18,692	6,252	1,190	104,496	19,881
			----------------------	Forecast	----------------------				
1998	38,204	49,894	13,079	101,177	19,250	6,385	1,215	107,561	20,464
1999	39,084	50,797	13,353	103,234	19,641	6,517	1,240	109,751	20,881
2000	39,990	51,641	13,637	105,268	20,028	6,657	1,266	111,925	21,295
2001	40,930	52,335	13,893	107,159	20,388	6,782	1,290	113,940	21,678
2002	41,830	53,173	14,152	109,155	20,768	6,908	1,314	116,063	22,082
2003	42,751	54,024	14,416	111,190	21,155	7,036	1,339	118,226	22,494
2004	43,691	54,888	14,684	113,263	21,549	7,168	1,364	120,431	22,913
2005	**44,652**	**55,766**	**14,958**	**115,377**	**21,951**	**7,301**	**1,389**	**122,678**	**23,341**
2006	45,635	56,658	15,237	117,530	22,361	7,437	1,415	124,968	23,776
2007	46,639	57,565	15,521	119,725	22,779	7,576	1,441	127,301	24,220
2008	47,665	58,486	15,811	121,962	23,204	7,718	1,468	129,679	24,673
2009	48,713	59,422	16,106	124,242	23,638	7,862	1,496	132,103	25,134
2010	**49,785**	**60,373**	**16,407**	**126,565**	**24,080**	**8,009**	**1,524**	**134,574**	**25,604**
Loss Factor	7.2%	6.1%	8.0%			8.0%			
Load Factor					60.0		60.0		60.0
Compound Annual Growth Rate:									
1991 - 1996	2.8%	2.5%	4.2%			2.6%	2.6%	2.6%	
1996 - 2001	2.2%	1.6%	2.3%			2.5%	2.5%	2.5%	
1996 - 2010	2.2%	1.6%	2.0%			2.1%	2.1%	1.9%	

Prepared by: Statistical Analysis Section, Executive Secretary Division, Michigan Public Service Commission

Source: Generation is derived from Sales on Table A1, using the shown loss factors. Peak demands are derived from sales using the shown annual load factor of 60 percent. Loss factors for CE and DE are fixed at the reported annual losses from the CE and DE 1997 FERC Form 1 Reports. Losses for other areas simply assume 8 percent (higher than CE). The assumed 60 percent annual load factor is based on the average of CE and DE annual load factors.

Table A3
Michigan Annual Electricity Generation
Composite Forecast

	Total Lower Penninsula					Upper Penninsula				
Year	Generation	Comm. Chg.	Peak Demand	Comm. Chg.	add 15% RM	Generation	Comm. Chg.	Peak Demand	Comm. Chg.	add 15% RM
1990	83,084		15,807			4,547		865		
1991	84,695		16,114			5,259		1,001		
1992	84,497		16,076			5,491		1,045		
1993	88,695		16,875			5,305		1,009		
1994	92,097		17,522			5,740		1,092		
1995	95,778		18,223			5,858		1,115		
1996	97,300		18,512			5,993		1,140		
1997	98,244		18,692			6,252		1,190		
					Forecast					
1998	101,177	2,933	19,250	558	642	6,385	133	1,215	25	29
1999	103,234	4,990	19,641	949	1,092	6,517	265	1,240	50	58
2000	105,268	7,024	20,028	1,336	1,537	6,657	404	1,266	77	88
2001	107,159	8,915	20,388	1,696	1,951	6,782	529	1,290	101	116
2002	109,155	10,911	20,768	2,076	2,387	6,908	656	1,314	125	143
2003	111,190	12,946	21,155	2,463	2,833	7,036	784	1,339	149	172
2004	113,263	15,020	21,549	2,858	3,286	7,168	915	1,364	174	200
2005	**115,377**	**17,133**	**21,951**	**3,260**	**3,749**	**7,301**	**1,049**	**1,389**	**200**	**230**
2006	117,530	19,286	22,361	3,669	4,220	7,437	1,185	1,415	225	259
2007	119,725	21,481	22,779	4,087	4,700	7,576	1,324	1,441	252	290
2008	121,962	23,718	23,204	4,513	5,189	7,718	1,465	1,468	279	321
2009	124,242	25,998	23,638	4,946	5,688	7,862	1,609	1,496	306	352
2010	**126,565**	**28,321**	**24,080**	**5,388**	**6,197**	**8,009**	**1,756**	**1,524**	**334**	**384**
Load Factor			60.0					60.0		
			21,942							
Compound Annual Growth Rate:										
1991 - 1996	2.8%		2.8%			2.6%		2.6%		
1996 - 2001	1.9%		1.9%			2.5%		2.5%		
1996 - 2010	1.9%		1.9%			2.1%		2.1%		

Prepared by: Statistical Analysis Section, Executive Secretary Division, Michigan Public Service Commission

Source: Table A2 provides the Generation and Peak Demand data. Comm. Chg. is cummulative change; add 15% RM simply adds a 15 percent Reserve Margin to the peak demands.

Table A4

Michigan Natural Gas Use for Electric Generation
Scenario for Potential Use (Bcf)

Year	Michigan Total Generation	Annual Change	Cummulative change	Potential added Natural Gas Use	Current Use (1997 Year)	Total Use
1990	87,630					
1991	89,954	2,323				
1992	89,988	35				
1993	94,000	4,011				
1994	97,837	3,838				
1995	101,636	3,799				
1996	103,293	1,657				
1997	104,496	1,203			128.0	128.0
		---------------------- Forecast ----------------------				
1998	107,561	3,065			assume 128	
1999	109,751	2,190	2,190	15.1	128.0	143.1
2000	111,925	2,174	4,364	30.0	128.0	158.0
2001	113,940	2,016	6,379	43.9	128.0	171.9
2002	116,063	2,123	8,502	58.5	128.0	186.5
2003	118,226	2,163	10,665	73.3	128.0	201.3
2004	120,431	2,205	12,870	88.5	128.0	216.5
2005	**122,678**	**2,247**	**15,116**	**103.9**	**128.0**	**231.9**
2006	124,968	2,290	17,406	119.7	128.0	247.7
2007	127,301	2,334	19,740	135.7	128.0	263.7
2008	129,679	2,378	22,118	152.1	128.0	280.1
2009	132,103	2,424	24,542	168.8	128.0	296.8
2010	**134,574**	**2,470**	**27,012**	**185.7**	**128.0**	**313.7**

Note: The Midland Cogeneration Venture consumed 95 Bcf in 1997, and generated Gwh of electricity.

Compound Annual Growth Rate:		
1997 - 2000	2.3%	7.3%
1997 - 2005	2.0%	7.7%
1997 - 2010	2.0%	7.1%

Prepared by: Statistical Analysis Section, Executive Secretary Division, Michigan Public Service Commission, July, 1998

Source: The assumed conversion rate for natural gas to electricity is 7000 Btu per kilowatt hour. One kilowatthour has 3412 Btu. Therefore, the assumed conversion efficiency is 48.7 percent. The assumed BTu per thousand cubic feet of natural gas is 1.018 million, from State Energy Data Report1995, page 485.

Table A5
Michigan Natural Gas Use for Other Scenario for Potential Use (Bcf)

Year	U.S. total Natural Gas	Michigan total Natural Gas	Rato MI/US
1990	15,929	734	4.61%
1991	16,246	740	4.55%
1992	16,778	797	4.75%
1993	17,597	815	4.63%
1994	17,721	826	4.66%
1995	18,384	855	4.65%
1996	19,235	889	4.62%
1997	18,934	833	4.40%
----------------------	Forecast	----------------------	
1998			4.61%
1999			4.61%
2000	20030	923	4.61%
2001			4.61%
2002			4.61%
2003			4.61%
2004			4.61%
2005	**20650**	**952**	**4.61%**
2006			4.61%
2007			4.61%
2008			4.61%
2009			4.61%
2010	**21620**	**997**	**4.61%**

Compound Annual Growth Rate:		
1997 - 2000	1.9%	3.5%
1997 - 2005	1.1%	1.7%
1997 - 2010	1.0%	1.4%

Prepared by: Statistical Analysis Section, Executive Secretary Division, Michigan Public Service Commission, July, 1998
Source: The U.S. and Michigan history through 1995 is from the State Energy Data system; For 1996 is from Natural Gas Annual (DOE/EIA); For 1997 is Natural Gas Monthly (DOE/EIA). Michigan history is adjusted by reallocating Midland Cogen Venture consumption to Electric Generation. U.S. projection is Annual Energy Outlook 1998, Reference Case (DOE/EIA).