

Comments of Fitch Ratings in Michigan Public Service Commission Investigation into Future Capacity Requirements April 22, 2005 (REVISED)

Introduction

My name is Ellen Lapson and I am a Managing Director in the Global Power Group of Fitch Ratings. I am joined today by my colleague Jonathan Cho, a Director in the Global Power Group, co-author of the comments I will deliver on behalf of Fitch. Our professional credentials appear as an appendix to our printed remarks.

Thank you for the invitation to address this Capacity Needs proceeding regarding the important topic of future electricity resource adequacy for the State of Michigan.

Fitch Ratings is one of the three largest credit rating agencies in the U.S. financial market with more than 50 offices in 34 countries. In the U.S. utilities, power and gas sector, Fitch rates the bonds and debt obligations of approximately 350 companies and over 100 municipal utilities. Among the companies whose securities Fitch rates are a number that already participate in the Michigan electricity sector, a few represented today in this hearing room. Examples of companies in the sector with Fitch credit ratings are DTE Energy, CMS Energy, American Electric Power, Dynegy, Kinder Morgan, Mirant, Constellation Energy, First Energy, Midwest Independent System Operator, and American Transmission Company, and active developers such as AES Corporation and Calpine. As a credit rating agency that rates the debt of companies in all parts of the energy and power sector, including utilities, generation companies, retail and wholesale energy marketers, and industrial consumers of power, Fitch has no preference for any type of company or participant within the electricity market. Nor do we have any vested interest in any particular electricity market structure.

Jonathan and I have come at Fitch's expense to provide our independent view on what effect credit considerations will have on future investments in generation assets in Michigan. The questions we have been asked to address are:

- Who are the likely candidates to invest in new power generation assets if additional capacity is needed?
- Would those entities be able to finance the construction of new investments in capacity?
- How would such investments affect the credit condition of companies that invest in new electric capacity?

The questions will be considered within the context of Michigan's current market structure.

Overview of Current Michigan Market Structure

Michigan has a “hybrid” market structure. The utilities in the state still own generation assets that are included in regulated rate base. Power generation has been subject to various rate caps which have expired or are expiring. However, retail customers have the right to choose their suppliers.

This hybrid market structure is unusual in the U.S. In most other U.S. jurisdictions, utilities are either fully regulated and integrated, or the generation and energy component of service has been fully deregulated, and most or all of the prior generation assets of the utility have been sold to third parties or transferred to a non-utility corporate affiliate. The utility then becomes responsible for distributing electricity to customers. In many states that took the divestiture route, utilities continue to purchase power on behalf of those utility distribution customers who have not chosen to buy energy from a competitive direct access energy provider (so called “provider of last resort” service or “default” service).

In Michigan, utility generation assets are still integrated, but utilities are subject to the risk of losing customer loads to alternate suppliers. This hybrid market structure complicates the issue of generation planning.

One other background consideration about the Michigan electricity market is that industrial consumption is relatively high in the state, and there is a fairly high concentration of industrial and large commercial demand relating to autos and related industries. In total, industrial and commercial customers in Michigan account for around 65% of total electric demand. While there is some diversity within those categories, if U.S. manufacturing becomes less competitive in world markets, the volume of industrial and large commercial power demand in Michigan could decline in the future.

Finally, Michigan is currently transmission constrained. Should the transmission transfer capability with adjoining regions improve in the future, Michigan may see a flow of electricity into or out of the state. The recently launched MISO energy market will provide generators with price transparency. Fitch did not consider the potential for new transmission construction and its implications for the market since major new transmission construction is difficult to predict and subject to numerous obstacles.

Candidates to Build New Generation

Let’s assume that there is a need for additional generation capacity in the future. Who could make such investments? There are several types of candidates to consider:

- A Michigan utility;
- An independent power developer;
- A large, well capitalized generation company, possibly an affiliate of a utility

We briefly considered private equity investment companies as candidates, since companies of this type have recently acquired merchant generating capacity. Such acquisitions have typically been assets sold by distressed owners at substantial discounts from the actual construction costs. Fitch does not believe that private equity investors are likely candidates to fund construction of new generation facilities and to withstand the added time prior to operation and completion risk of new facilities. Consequently, we excluded private equity funds from consideration as a type of candidate.

Let's take these one at a time.

Utility - In states where generation is still part of integrated monopoly service, new capacity additions can be financed by the utility, after receiving a certificate of need and convenience from the state regulatory commission. Even in such cases, Fitch has become more concerned about such investments than in the past, and now seeks a greater degree of assurance in advance regarding the commission's public position as to the prudence of the investment and the mechanism for timely recovery of investment in utility tariffs. With that in place, most utilities are capable of attracting financing for such an investment.

However, under the current hybrid market structure in the state, Michigan electric utilities face a risk of declining bundled retail load, exacerbated by a distortion in the current tariff structure which encourages commercial load to switch suppliers. Fitch would consider that any additional investment in new generation by the utilities under the current market structure as adding more risk to the utilities' credit profile. Investing in generation would potentially open the utility to additional stranded costs, whether associated with the old power assets or the new assets. While in theory as load migrated away from the utilities, the utilities can seek a rate increase, the rate increase itself may propel additional customer migration which, in turn, will necessitate additional rate increases. In addition, if further customer loss resulted in excess capacity, the utility could mitigate its loss by selling surplus power into the wholesale market, possibly at a loss. Reliance on such sales would increase the volatility of the utility's revenues and weaken that utility's credit profile.

As we will see, for the same reasons as explained above, the Michigan utilities are unlikely to enter into a multi-year long-term contract (power purchase agreement or "PPA") to buy power from another provider.

Independent Power Developer - The classic model for independent power developers to build power plants was to rely on the strength of a PPA with a credit-worthy off-taker (usually a utility). Take-or-pay power contracts or firm capacity payments under the PPAs would allow the developer to raise debt financing for the project, either using single asset project financing or under a portfolio financing approach. The average corporate credit rating for companies of this type is in the range of 'B' to high 'BB', that is, non-investment grade. In general, power developers of this type have lower credit ratings than those of the power purchasers, and can raise capital on more favorable terms if they can take advantage of the credit enhancement that comes from contractual cash flows from credit-worthy counterparties.

However, in the current hybrid market structure, given the uncertainty as to the utility's bundled load, a utility is unlikely to enter into any long term PPAs (beyond a few years in duration.) The utility could be left with too much power capacity, considering the sum of the power commitments to purchase under long-term contracts plus its owned resources, relative to diminished customer load.

Thus, the developer might face the need to justify an investment based on at most a few years of contracted revenues, with revenues over the remaining economic life of the resource dependent on future spot market or forward market prices. We would classify this as a “merchant” power project. A merchant investment would present a number of challenges for an independent developer. It would be difficult to raise debt financing for such a project, or if added to a portfolio of projects, it would reduce the credit quality of the portfolio. If it could be financed, the funding costs would be high, raising the hurdle of the level of predicted income needed to cover fixed costs. In Fitch’s opinion, such developers would not be likely to invest in generation resources with high capital component and long construction times, such as conventional coal-fired base load generation, and investment in more innovative technologies is even more remote, absent significant subsidies. Reserve margins in the region would have to be very low to maximize the likelihood of the plant in question operating and producing enough cash flow to recover its fixed costs. Such low reserve margins would expose electricity customers in Michigan to greater price volatility and greater risk of service interruptions in the intermediate term.

Wholesale Generator - Another possible builder of new capacity in Michigan is a large and credit-worthy wholesale generation company, for example, the non-utility generation company affiliated with a utility holding company group. There are companies in that category with sufficiently strong capital resources and cash flow from their current business that could support a merchant investment, perhaps in the environment of one-to three-year contracts awarded by auction. Companies of this type would theoretically have a better capability to invest in types of resources with a longer construction, including solid-fuel plants.

Within Fitch’s power group, opinions are mixed as to whether such credit-worthy generation companies are likely to make a merchant investment of this type. Under the current Michigan market structure and in the current capital market environment, the management of a company that announces a commitment to build new merchant generation could well face adverse investor reactions, both from the equity and debt investors. It is possible that the credit rating of such a company would be reduced as a result of the combination of construction/completion risk, external funding requirements, negative cash flow prior to operation, and the uncertainty of future operating earnings from the new assets. On the other hand, I believe it is possible that a company of this type could make a limited number of such investments within the context of a larger portfolio. The management’s decision would in that case be based upon its assessment of future market demand and the position that the new resource would have in the merit dispatch order relative to other installed capacity in the region. If a very large and profitable company limits the number and amount of investment in such speculative projects to a fraction of their portfolio of operating projects, the resulting dilution of the credit fundamentals would perhaps not be too severe.

Should an investor of this type choose to make a limited amount of investments of this type, it may choose to invest in another jurisdiction where the economics look more attractive. There is no obligation to build a merchant plant in Michigan. In other words, this does not provide a

high degree of assurance to public policy officials in Michigan that investors of this type will choose to anticipate and fulfill the resource adequacy needs of the state.

Implications of Current Market Structure

Should non-regulated generators be willing to add generation capacity in Michigan on a merchant basis, without the benefit of a long-term PPA, it is Fitch's view they are only likely to do so when reserve margins in the state become very low. Since merchant plants need to be dispatched in order to generate revenues, developers of such plants will try to maximize the likelihood of dispatch. Low reserve margins would increase the likelihood of dispatch while at the same time ensuring higher prevailing spot market prices as less efficient units are dispatched to meet the load. However, low reserve margins would expose customers in the state to higher and more volatile electricity prices and potential power outages.

Even where reserve margins are low, economic and financial market realities may make developers of merchant plants reluctant to build generation. Given the lack of a PPA, such plants are exposed to being displaced on the dispatch stack, for example, due to rising fuel costs. In addition, the large percentage of industrial load in Michigan and concentration of that load in the automotive and related sector results in sensitivity of load to the prevailing economic conditions and the fate of a single industry.

Lessons from Other Jurisdictions

A number of deregulated states including Maryland, Massachusetts and Connecticut have adopted what has come to be called a "New Jersey-style" auction for procurement of power. In these states, the incumbent utilities either sold their generation assets to a third party or transferred the generation to a non-regulated affiliate. The utilities continue to provide transmission and distribution services to ultimate consumers. They also procure power for customers who elect to receive bundled service.

To serve such bundled load, a competitive auction is held periodically wherein generators/marketers bid to supply a portion of the energy. The supply agreements typically run for one to three years, consistent with the ability of suppliers to predict and hedge their forward energy and fuel needs. In such arrangements, the utility pays suppliers only for energy, not for capacity. The cost of such supply is passed through by the utilities to the retail customers while suppliers undertake both volumetric risk and fixed price risk.

The one to three year term of such supply agreements is, in Fitch's, view too short to provide a foundation on which to build new generation. Moreover, given the timing of such auctions, there is not sufficient time between the awarding of the supply agreement and construction of a new plant. In order to bid on such auctions, a generator would have to have generation already in place or contract for supply from existing resources.

It is too early to prove or disprove whether such auctions will support construction of new generation. To determine who is currently building new capacity and where, Fitch conducted a review of all of the new additions to capacity that is purported to be completed in the next four years. We found that the vast majority of such projects are being built by municipalities, cooperatives, other quasi-

governmental agencies (such as the TVA) and by integrated utilities in states that have not restructured the electricity market. Most of the remaining projects are legacies from the generation boom period. That is, the owner made the investment decision several years ago in a different capital market environment and perhaps delayed completion due to weak market conditions. To date, there have been no new generation additions begun in states with restructured power markets and New Jersey-style auctions (with the exception of the repowering of a couple of older power plants in New Jersey.) The low proportion of new capacity under construction in restructured states could be because the restructured states attracted more new construction during the boom, and now have more surplus capacity. However, in a recent filing with the FERC, ISO-NE acknowledged the failure of deregulated energy markets to promote new generation additions:

Results of the wholesale market operations to date show that the price signals from the energy markets alone are not sufficient to support new entry and may not even support continued operation of existing units needed to reliably meet system or local load requirements.¹

One noteworthy new construction project in a deregulated state is the SCS Astoria plant located in New York City. SCS Astoria is a 500 MW combined-cycle gas plant. The project has a 10 year PPA with Consolidated Edison Company of NY (Con Ed) with a fixed capacity payment. This PPA allowed the project to raise project finance debt for approximately 65% of the project costs. Con Ed entered into the PPA for three key reasons. First, Con Ed had sold the vast majority of its generation assets and it has a substantial “short” position of approximately 50% of its current non-switched customer demand. Thus, Con Ed can sustain a loss of 50% of its current load before it runs a significant risk that it will be “long” power. Second, Con Ed used a contract solicitation process which the New York Public Service Commission (NYPSC) ratified as a prudent process to procure capacity. Finally, the NYPSC stated in an order that while it could not bind future commissions regarding the recovery of the contract payments, under the current market conditions it would be imprudent if Con Ed did not enter into the Astoria contract. By way of contrast, the utilities in Michigan own generation and have pre-existing contractual purchases that account for the majority of their energy needs. As such, they face a greater risk of being long capacity if their current customers switch to other providers or if total market demand declines in Michigan.

Locational Installed Capacity

To address the difficulties in encouraging generation additions in a deregulated market, some regions in the country including ISO-NE and PJM are moving towards introducing Location Installed Capacity (LICAP) payments. LICAP is a capacity payment which is designed to promote generation additions in regions where generation is needed. The payment would vary over time depending on a number of factors including the reserve margins in the region.

However, it is not clear that LICAP will accomplish the stated goal. Because LICAP payments are variable, it would be difficult to rely upon such payments to support debt necessary for new plant construction. In addition, LICAP payments are unlikely to encourage owners of existing plants in the region to build additional generation as this would reduce LICAP payments for their existing plants. Even ISO-NE, in its filing with FERC regarding LICAP, stated:

The Locational ICAP Proposal submitted by [ISO-NE] is not intended to be the final word on resource adequacy in New England. As described [elsewhere in the filing], the ISO has initiated a process for bringing together market participants and state regulators to continue the development of a broadly supported and stable resource adequacy mechanism for New England...²

In Fitch's view, LICAP by itself is unlikely to be sufficient to stimulate generation additions.

Possible Alternatives

There are three possible scenarios that Fitch has considered if public policy makers in Michigan determine it is in the state's interest to foster generation additions in Michigan in addition to a fourth alternative, the status quo.

Alternative 1: Hybrid market structure with a carve-out

As discussed earlier, under the current hybrid market structure, there is significant uncertainty as to a utility's ultimate load. As such, utilities are reluctant to make investments in new generation for fear that they would not be able to earn a reasonable return of their investment. Similarly, the uncertainty in total load makes it difficult for utilities to enter into long term PPAs. Assuming the current hybrid market was maintained, the difficulties presented by the market structure can be addressed by creating a "carve out" for new generation.

Under this scenario, required new generation additions could be carved out from the current electricity regime. The owners of such generation are assured of recovering their investment through a dedicated, non-bypassable charge levied on all electricity customers. The generation in question can be built by a utility and the utility receives a dedicated revenue stream associated with that generation. Alternatively, the generation can be built by a non-regulated developer and the utility enters into a long-term PPA with that developer. The PPA payments are then recovered by the utility through a non-bypassable charge. Another possibility would be that a government entity rather than the utility is the counter-party to such a PPA as was the case with the California Department of Water Resources. Under the carve-out scenario, the parties involved are flexible. The key point is that there is a dedicated stream of revenues which provides assurance of investment returns for the new capacity which the current hybrid market structure does not provide.

It should be noted that the carve-out generation charge must be non-bypassable. This would permit the maintenance of a reasonable reserve margin by socializing the cost of that reserve margin. Customers who purchase their electricity from sources other than the utilities may argue that it would be inequitable for them to be required to pay the capacity payments under such a PPA as they would not be purchasing any power from this new generation. However, by definition, the reserve margin is surplus generating capacity. As such, no one receives power from the reserve margin generation. To levy the charge only on the utilities' customers would create a class of free-riders (those who procure their power other than from the utilities) and would promote migration of load away from the utilities with the attendant consequences.

In Fitch's view, creating a special carve-out to fund new construction while preserving the current hybrid market structure would not be a desirable solution. Uncertainty about the future market structure would continue to undermine the credit quality of investor-owned electric utilities in Michigan, and there would be an eventual need to reform the structure to remove the risk to the utilities' solvency.

Alternative 2: Reregulate

A second alternative would be to re-regulate generation in Michigan. A variant on this theme would be to return residential and small commercial consumers to the regulated, integrated utility model while allowing industrial and larger commercial customers direct access to the wholesale market.

Under such a plan, Michigan utilities would be required to sell to a third-party or transfer to a non-regulated affiliate a portion of their generation assets. The utilities would retain sufficient generation to serve their residential and small commercial customers. If it is the MPSC's desire to have a competitive wholesale market, the amount of rate-based generating capacity retained by the utility could be sized to leave a "short" position in generation (e.g., the utility might retain generation to supply only 70% of expected residential and small commercial load). The utility would then enter into solicitations for forward contracts to cover the projected "short position" including some longer term contractual tranches that could only be met by commitments of new-build capacity

Re-regulation would eliminate the problem of load migration and provide the utility with greater certainty with respect to total load. At the same time, it would provide assurance that investments made by utilities in generation would be recovered through rates. Moreover, should the utilities choose not to build additional generation, they could enter into long term PPAs with greater confidence in the ability to recover prudently incurred power supply costs through the regulatory process.

Numerous aspects of such a reregulation scenario require further decisions and planning. For example, the sale or transfer of a portion of the utilities current generation assets may result in stranded costs which would need to be recovered. In addition, disputes may arise as to which assets are to be divested, the more marketable coal-fired assets (which would reduce the likelihood of stranded costs but would result in higher rates for bundled customers) or the less efficient gas and oil plants (which increases the likelihood of stranded costs but would lower rates for bundled customers).

Alternative 3: Full deregulation

The third possibility would be to fully deregulate the generation sector in Michigan and cause the utilities to divest all or most of their existing generation assets either to third parties or to affiliates. (If there would be any additional stranded cost at the investor-owned utilities as a result of such divestiture, a plan for compensation would be a prerequisite.) As discussed earlier in the context of Con Ed and the SCS Astoria PPA, if the utilities own little or no generation, they may then enter into long-term PPAs for a portion of their load without only modest risk that they will be excessively "long" power. By engaging in a PSC-approved contract solicitation process and limiting participation to new plants, these long-term PPAs can serve to stimulate generation additions in Michigan.



Alternative 4: Status quo

The final alternative is to do nothing. As capacity margins are reduced as older plants are retired and load in the state grows, eventually market prices may be sufficiently high that someone might be willing and able to build generation in the state. However, this would expose rate payers to rising and more volatile power prices as reserve margins decline as well as to higher risk of supply disruption. In addition, state policy makers would have no control over the type of generation added. For example, volatile power prices may encourage developers to add peaking capacity rather than base load generation or gas-fired resources in preference to coal-fired resources. Finally, there can be no assurance that generation would be added in Michigan as opposed to another state. Should another state have lower reserve margins or more consistent and predictable growth in demand, developers may choose to add generation in that other state rather than Michigan.

That concludes our prepared comments.

Thank you for the opportunity to provide Fitch's views to the Michigan Public Service Commission investigation into future capacity requirements.

Appendix:

Professional Qualifications of Ellen Lapson:

Ellen Lapson is a Managing Director in Fitch Ratings' U.S. Global Power Group. She leads the development of rating criteria and sector outlook for the group, and also chairs or participates in rating committees for U.S. and international electric and gas utilities, energy marketers, project finance transactions, and structured finance based on utility tariffs or contracts. In addition, Ellen is a member of Fitch's Corporate Finance Credit Policy Board, the body that approves Fitch's rating criteria for corporate ratings worldwide.

Prior to joining Fitch in 1994, Ellen was an officer of Chemical Securities Inc. and Chemical Bank, specializing in banking and corporate finance transactions for the electric, gas and telecommunications industries. Ellen began her career as an equity analyst at Argus Research Corp., where she covered securities of companies in the electric, gas, and telephone industries.

Ellen is a chartered financial analyst (CFA) and a member of the Wall Street Utility Group, the Fixed Income Analysts' Society and the Advisory Council to the Electric Power Research Institute. She earned an MBA in accounting from New York University. Her articles on energy market risk and counterparty credit risk in the energy sector have been published in books and professional journals.

Professional Qualifications of Jonathan Cho

Jonathan Cho is a director in Fitch Ratings' global power group. Jonathan's responsibilities include analysis and ratings of investor-owned utilities and nonregulated generators. Previously, Jonathan was a member of the U.S. utilities research team at Dominion Bond Rating Service. Prior to joining DBRS, Jonathan was a vice president in the Global Energy and Power investment banking group of Credit Suisse First Boston and Donaldson Lufkin & Jenrette. Jonathan began his career with the Canadian law firm of Holden Day Wilson.

Jonathan earned an LL.B. from Osgoode Hall Law School and an MBA from Cornell University.

¹ Compliance Filing of ISO New England Inc., Devon Power LLC, et. al., Docket No. ER03-563, p.4.

² Compliance Filing of ISO New England Inc., Devon Power LLC, et. al., Docket No. ER03-563, p.6.