ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

ABATES Reply Comments to Readying Michigan to Make Good Energy Decisions: Additional Areas Draft Report of October 1, 2013

Electric Reliability

The Draft Report missed a significant part of the reliability issue from industrial customers viewpoint. Namely, the Draft Report misses the issue of power quality. Industrial customers regularly report voltage sags, momentary outages, and other power quality issues which in the era of computer controlled equipment and production facilities causes very serious problems. The Draft Report has only one sentence related to power quality where the report states: "The MPSC also initiates investigations related to electric distribution reliability such as the 'Report on the Status of Power Quality in Michigan, September 1, 2009.'" That report was not initiated by the Commission, but rather was required by Section 10p(8) of Act 286 as a result of industrial customers expressing concerns to the legislature about the power quality disturbances that were not being addressed. That report did nothing to solve the problems. Any evaluation of reliability which only measures "minutes of outages" completely misses the power quality problems of the 21st century. There needs to be a systematic data recording system to identify and create a database of power quality issues, collaboration between the Commission, utilities, and industrial customers, and a serious effort to address these problems, especially before state officials begin touting Michigan as somehow having some superior electric reliability to other states.

Rates and Utility Regulation

Much of the Draft Report section on rates and utility regulation is spent reciting the utilities explanations of why their rates are so un-competitively high. For example, they contend that, for the period of 2000 to 2008 while Michigan had full customer choice, that the only reason that Michigan rates compared more favorably to the national average was because of high natural gas prices, strongly implying that it had nothing to do with the existence of a competitive marketplace and that market pressures worked to keep their costs and their rates down.

The Draft Report also cites the utilities claims that the majority of deregulated states where customer choice exists do not have lower rates. However the report does not adequately address the real issue. There are states that have serious regulation with low rates and there are states that have competitive markets with lower rates. Unfortunately, Michigan has neither. Michigan's regulatory scheme was substantially undermined by provisions of Act 286 which allow self-implemented rates, encouraged projected costs as the basis for rate increase rather than actual cost, and made other provisions which accelerated rate increases. This was done at the same time that customer choice was eliminated but for 10% of utility load. Unquestionably, there are some states that have deregulated poorly and produced higher rates than should be the case. Correspondingly there are some states which regulate poorly and produce higher rates. However the fact is since the passage of Act 286 regulation in Michigan has produced such un-competitively high rates, it is little wonder that more than 11,000 customers are in the queue seeking to access the competitive market and obviously believing that they could do better themselves than what regulation has produced in Michigan.

The Report also spends time reciting the utilities arguments that although Michigan residential customers rates are high, their bills are actually lower than the national average because Michigan residential customers use less per customer. This is hardly surprising. Instead, it is the classic economic phenomenon known as price elasticity—when prices go up, consumption goes down. It is little wonder customers use less than the average when their rates are so much higher than the average.

The Draft Report also has a section entitled "Rate Structures for Large Volume Users" . The Draft Report notes that the utilities argue "they should have the discretionary ability to offer economic development rates, appropriately designed, with MPSC oversight." The Draft Report also goes on to mention that the MPSC approved "dozens of special contracts during the 1990's." However, the Draft Report misses the most fundamental difference between the special contracts that had gone on historically for nearly 100 years, as well as during the 90's, and the perversion of "special contracts" which began to occur in the 2000's when the MPSC began to charge the so called "lost revenues" of the utility to all of the other customers. Historically rates were to be non-discriminatory for like customers. The only exception was a "special contract" which under the law could only be given in certain circumstances and according to specific legal standards developed over many decades. The very first standard was that the "special contract" could not harm the other customers. By departing from this long standing historical requirement and allowing utilities to charge so called "lost revenues" to their other customers, particularly in a state with un-competitively high rates to begin with, the MPSC has created a vicious cycle aggravating the un-competitive rate problem. When economic development rates are used to attract or maintain load in a way that benefits all of the customers, and the utility over the long term since it has been able to acquire or maintain that load, everybody wins. However, when any economic development benefits granted are simply charged to all of the other utility customers, no one wins except the utility which <u>temporarily</u> increases its revenues. Ultimately, that economic development rate customer will be unhappy when that economic development rate cannot be sustained. Other utility rate payers are unhappy because they have been charged for that additional cost. Even the utility loses if it cannot maintain that load under regular normal rates. In short, the payment of "lost revenues" to the utility for any discounts it provides is a disastrous policy which has contributed to Michigan's un-competitively high rate problem.

The Draft Report also spends much time discussing the utilities concerns about "regulatory lag". Although many regulators have historically viewed "regulatory lag' an important element in the regulatory process to create incentives for economic efficiency, the Draft Report treats it as a universally bad thing. However, the bottom line is that the national average for rate cases is 9 months and the Michigan average is 9.2 months. The Draft Report notes that Act 286 encourages the use of projected test periods or future test periods as a way to deal with regulatory lag. However Act 286 also allowed self-implementation of utility rates, required rate orders within 12 months, and several other provisions, any one of which was more than sufficient to eliminate regulatory lag. Consequently in Michigan it is easy for utilities to get rate increases out ahead of incurred costs and again leads to some of the un-competitively high rate problem. The use of projected or future test periods is a particular challenging situation for state utility commissions. That has been the subject of considerable research by the National Regulatory Research Institute (NRRI) and particularly by principal researcher Ken Costello in his documents entitled " Future Test Years: Challenges Posed for State Utility Commissions", issued in July of 2013. This document notes the many challenges presented by using future test periods for commissions and discusses numerous safeguards that need to be implemented in order to use future test periods properly and to protect customers. Although since the enactment of Act 286, the MPSC frequently uses projected test periods, it utilizes virtually none of the necessary safeguards that the NRRI paper indicates are needed in order to use future test periods properly and to protect rate payers.

Next, the Draft Report discusses the self-implementation of rates. The Draft Report then unfortunately lumps together Michigan's version of " self-implemented rates", where there is no oversight, no MPSC finding, no MPSC order, and a rate increase automatically implemented by the utility itself, with the generic category of "interim rates" which the Draft Report misleadingly states that "the majority of states (45) allow for some form of interim or self-implementation of rates." Michigan would have been part of that 45 states before Act 286 made such radical changes, since Michigan by law allowed "partial and immediate" rate increases for utilities when meeting certain standards. "Interim rates" like in other states and Michigan's "self-implemented rates" are dramatically different. "Interim" rates in other states typically require some finding of need by the commission and the issuances of an order based upon evidence. That is drastically different than the self-implementation under Act 286 which allows the utility to implement a rate increase without any finding of need by the commission.

In short, it is little wonder that Michigan has un-competitively high rates given all of the utility preferences built into Michigan's current regulatory regime. ABATE has attached to these comments the Electricity Reform Recommendations that it proposed to solve Michigan's un-competitive rate problem.

Also attached are three charts showing Michigan's un-competitively high electric rates for residential, commercial, and industrial customers compared to utilities in surrounding states.

ABATE

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

Michigan Electricity Reform Recommendations

A Blueprint for reaching competitive rates and creating jobs in Michigan

October 2013

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

Alcoa Inc.
Cargill
Chrysler Group LLC
Delphi Corporation
Dow Chemical Company
Dow Corning Corporation
Eaton Corporation
Edward C. Levy Company
Enbridge Energy Limited Partnership
Ford Motor Company
Gerdau MacSteel – Monroe and Jackson
J. Rettenmaier USA LP
General Motors Company
Marathon Petroleum Corporation
Martin Marietta Magnesia Specialties
Metal Technologies, Inc.
MPI Research
Praxair, Inc.
United States Gypsum
Severstal Dearborn, LLC

Chairperson –
Rod Williamson
Dow Corning Corporation

Robert A. W. Strong and Roderick S. Coy,
Legal Counsel
Clark Hill PLC
151 S. Old Woodward Ave., Suite 200
Birmingham, MI 48009-6179
(248) 988-5861; Fax (248) 642-2174
rstrong@clarkhill.com; rcoy@clarkhil.com

Dear State Official:

Michigan is on the brink of making important energy policy decisions that will have ramifications for many years to come. We must get it right this time. The Association of Businesses Advocating Tariff Equity has spent many months examining why Michigan's utility rates are uncompetitively high and what could be done to improve the situation. This report summarizes several recommendations that we believe are necessary to put Michigan on the right path for a prosperous future.

Sincerely,

Rod Williamson

Rod Williamson

Chairperson

ABATE

Michigan needs competitive price electricity to retain jobs, create jobs and re-build our economy. Manufacturing is the building block of the economy. Unfortunately Michigan's electricity rates are the highest in the Midwest and well above the national average where manufactures compete. The increase in Michigan's electricity rates since the 2008 legislation is alarming and out of step with the states that compete for manufacturing. Michigan must do a better job at competing. In order to achieve competitive electricity pricing, Michigan needs:

- "Effective" regulatory oversight which "emulates market competition" to ensure prudent business decisions and drive continuous improvement in efficiency, productivity and cost control measures, and
- Market competition (i.e. Electric Choice) where utilities must compete for our business.

1. <u>Electricity Choice</u>

In 2000, the Michigan legislature enacted the Customer Choice and Electric Reliability Act of 2000. The new law opened up the electrical energy market to competition and provided the opportunity for customers to shop for the lowest cost electrical energy from alternative electric suppliers. "From 2000 to 2004, industrial and commercial electric rates fell by approximately 3 percent and 4 percent respectively in Michigan, while rising by about 13 percent and 10 percent nationwide. The state's average rates for all customers moved below the national average. Just as telling, Michigan's electricity prices, which are typically higher than those of Illinois, Indiana, Ohio and Wisconsin, fell enough to diminish the gap and make the state more competitive with its neighbors."[1] In return for opening up the market to competition, Michigan's major utilities received recovery of approximately $160 million in "net stranded costs" and (under PA 142 of 2000) were allowed to securitize $2.2 billion in assets funded by 15 year bonds paid for by monthly charges on all Michigan rate payers which continue until 2015. From 2004 to 2007 these subsidies to the incumbent utilities undercut the price advantage of their competitors. During this time natural gas prices also began to rise and Michigan's electricity prices started rising once again. However, even though the customers choosing an alternative electric supplier declined during this time, Michigan's rates remained below the national average.
In 2008, the legislature made significant changes to Michigan's energy law with the enactment of PA 295 of 2008 and PA 286 of 2008. PA 286 imposed a 10% cap on participation in Michigan's "electric choice" program established under PA 141 of 2000. Conceptually, there is no reason to need a cap whatsoever. The utilities have been granted the right to full recovery of their "stranded" investments and should be required to compete against other non-utility generators to ensure that generation continues to be cost-efficient. The utilities will continue to provide and profit from their transmission and distribution business (as well as all of the generation business that they win through competition). Additionally, the cap on electricity choice prevents economic development in Michigan by out-of-state energy companies. When customer choice was active under PA 142 of 2000, out-of-state energy companies invested millions of dollars in Michigan and built more than 4,000 MW of new generating capacity in the state. With a cap on electricity choice we have sent a message to these companies not to invest in Michigan.

Opening the electric choice market also buttresses the pillars to a successful energy policy that Governor Snyder has laid out in his energy message - reliability, affordable price, protect the environment and overall adaptability.
Reliability: In a competitive / retail choice market nothing changes regarding the delivery of the electricity. Reliability is maintained by the utilities and transmission companies. For generation, each load serving entity must either own or have under contract enough generation to serve customers and

[1] "Proposals to Further Regulate Michigan's Electricity Market: An Assessment", Diane S. Katz and Theodore Bolema, Ph.D, May 16, 2008

have a reserve. In a competitive market, generation will get built to meet the demand. For instance from 2000-2008 when we had full retail customer choice over 4,000 MW of new generation was built by independent developers in Michigan.

Affordable Price: Retail choice allows more suppliers of energy to compete for customers. Competition between suppliers helps reduce prices offered by suppliers. Competition on the energy supply also forces the utilities to control the cost of their energy supply which helps even those customers who do not choose another supplier.

Protect the environment: The competitive market will drive the development of technology to meet environmental requirements at the lowest cost to consumers! Under the regulated model, the utilities decide what type of generation they want to build.

Adaptability: The competitive market is much quicker to adjust to changing market conditions. Recently when electricity demand dropped in Michigan due to the recession and new environmental regulations were being put in place impacting coal fired generation, a competitive supplier responded and canceled plans to build a coal fired generation facility in Michigan. This change did not cost customers anything! Under the monopoly model it took the utility two years to decide to cancel their plans to build a coal fired generation facility and customers had to pay over $14M to the utility to cover engineering and planning cost.

- ✓ Amend PA286 to eliminate the 10% cap on participation in Michigan's electric choice program.

2. <u>Securitization of Pollution Control Facilities</u>

New EPA rules, such as the Cross-State Air Pollution Rule, EGU MACT (MAT), Section 316b regulations, and coal combustion by-products or residue rules, require electric utilities to invest billions of dollars in water and pollution control facilities or shut down coal-fired generating plants. Securitization is the process by which a utility, following the issuance of a financing order by the PSC, replaces relatively high-cost debt and equity with lower-cost debt in the form of securitization bonds. If water and pollution control facilities were financed by securitization bonds instead of traditional financing, then the savings to customers receiving generation supply services from the utility are enormous. These environmental control facilities are generation related expenditures not distribution. These savings will benefit the full service customers of the utility (i.e. customers who purchase generation from the utilities). Those customers on Retail Choice who purchase their generation from another supplier will already be paying their supplier for the cost of environmental compliance associated with the generation being used to supply them. For Detroit Edison, the equity savings are the pre-tax return of 9.76% less the yield on AAA corporate bonds of 2.2%, for a net savings of 7.56%. The debt savings are Detroit Edison's borrowing cost of 5.53% less the AAA corporate bond yield of 2.2%, for a net savings of 3.3%. The net savings of financing water and pollution control facilities with securitization bonds in the amount of $1 billion, where the proceeds are used to retire equal amounts of debt and equity, are $903 million. The reduced financing costs will minimize the rate increases associated with the installation of this mandated environmental control equipment. Securitization is a financing tool that the utilities have used before. Consumers and Detroit Edison, in 2000 and 2001, under PA 142 of 2000, issued more than $2 billion in securitization bonds in order to fund a 5% residential rate reduction and pay off certain stranded costs. Recently Consumers Energy Company, in case U-17473, is seeking authority to securitize $454 million related to demolition of some power plants that cannot meet MATS and other environmental regulations and impose a "Coal plant securitization charge". Consumers Energy makes the point that securitization will save customers money, "the proposed securitization of $425.8 million provides a net present value benefit of approximately $133.5 million".

"Securitization provides a mechanism for recovering the Company's prudently incurred costs at a lower cost to Consumers Energy's customers than would occur through conventional financing methods" (CE Witness D. Kehoe, p5)

- ✓ Legislation be enacted requiring that Michigan electric utilities utilize securitization bonds to finance all new pollution control equipment required by any rule or regulation adopted by the federal environmental protection agency or the Michigan Department of Environmental Quality.

3. <u>Elimination of Self-implementation of Rate Increases and the use of Projected Cost</u>

Prior to the enactment of PA 286 of 2008, the major utilities filed general rate cases every few years and modest rate increases were approved by the MPSC every couple of years. Since the enactment of the "file and use" provisions, both major utilities have filed general rate cases every 12-14 months and sought interim rate increases 6 months after the date of each filing. The file and use mechanism has clearly resulted in more frequent rates increases and higher costs for ratepayers. The utilities argued that the rate case process was taking too long with no certainty of when a case would be decided. However another change from PA 286 is that the MPSC must make a final ruling in a rate case within 12 months of the utility filing the rate case. This change alone provides timing certainty and there is no need for utilities to self-implement rates which have had no effective regulatory review. The use of a projected test year has also resulted in higher rates. Rates are now being set on projections of utility cost and these projections have been high. There is also no recourse once the utilities rates have been set based on projected cost and actual cost are lower. This has only resulted in the utilities over-earning and customers paying higher rates than needed to recover the utilities actual cost. With the ability of utilities to file a rate case every 12 months (which they are), there is no need to use projected cost. Rates should be set based on the utilities actual cost over the prior 12 months. These costs are easier to verify and result in more accurate rates for all customers. Self-implemented rates and utilizing projected cost have resulted in a process where Michigan rate payers are consistently over-paying for utility service.

- ✓ Amend PA286 to eliminate the utilities ability to self-implement rate increases
- ✓ Amend PA286 to require the use of actual cost from a prior 12 month test period and only make adjustments for known and measurable changes.

4. <u>Establish True Cost of Service Electricity Rates</u>

PA 286 required that electricity rates be based on cost-of-service with the subsidies being paid by one class of customers to another class of customers (rate skewing) be eliminated over a 5 year period. However the Commission has failed to address the rate skewing caused by certain cost allocation methods and believes that a certain amount of cost shifting from residential to manufacturing customers is appropriate.

- ✓ Amend PA286 to require Michigan electric utilities to allocate production costs on a 4CP, 100% demand basis, allocate electrical transmission costs on a 12 CP, 100% demand basis, and eliminate all surcharges and trackers that are charged on a kWh basis and skew rates.

5. Supply Planning and Competitive Bid Process for New Electricity Supply

Methods of electric resource planning with in Michigan have been focused on individual regulated utility franchise territories demand forecast and supply-side projects only (i.e., construction of generation, transmission, and distribution facilities). Even the assessment of supply-side options has been limited to a few major technologies, and cost-benefit analysis of the alternatives was rudimentary. Independent power producers, exempt wholesale generators within the NERC region are not considered. This top-down approach only allows for other key stakeholders and public consultation as a last step, if at all, when plans are virtually complete. Michigan needs a competitive bid supply planning process that makes planning more open to relevant governmental agencies, consumer groups, and others, thus considering the needs and ideas of all parties with a stake in the future of the electric system. For instance, as part of the supply planning process transmission and distribution systems should be reviewed to determine if upgrades to these systems would allow any existing underutilized generation to serve the needs in other areas of the state. If it is determined that new generation capacity is required, this competitive bid supply planning process must not favor or give advantage to native utility companies. Non-utility companies should not be limited to construction only or partial ownership. A large portion of cost savings can come from the efficient operation and maintenance of the generation plant. Additionally, the cost per kW of capacity, the cost per kWh of generation output and the cost of transmission interconnection should be calculated for each generation option along with a weighing of reliability and operational considerations (run-time availability / capacity factor, useful asset life, fuel diversity, etc.). This supply planning process should also require utilities to include a review of utilizing combined heat and power (CHP) which would be installed at or near customer facilities generating electric power and utilizing thermal energy for various combinations of industrial process, space and water heating and cooling. CHP is generally twice as efficient as conventional generation facilities and is made possible at its basic level because of an industrial or commercial business' need for the non-electrical thermal energy output. This represents one significant way by which the state could assist their large customers with managing energy costs.

- ✓ Legislation be enacted requiring that Michigan electric utilities utilize a competitive bid supply planning process which is open to all relevant stakeholders to procure electricity to meet anticipated future demand

6. Establish a Reasonable Transfer Price for Renewable Energy Cost

Act 295 established a renewable portfolio standard which required utilities to serve 10% of their sales with renewable energy as of 2015. Act 295 established two sources of funding for payments made to renewable energy developers. A portion of the money was to come from the surcharges established on a per-meter basis, and the market or "transfer" price was to be included in the Power Supply Cost Recovery (PSCR) expense. The Legislature also sought to cap the RPS expense over a 20 year period and to provide "off ramps" if the expense exceeded certain limits. To the extent that more of the cost is included in the transfer price, then the caps and the off ramps can be evaded. The MPSC developed estimates of the transfer price back in 2008 which are now equal to approximately 75% of the price being paid to renewable energy developers. This is far above the utilities' current avoided cost or the market rate contrary to the Legislative intent. This has resulted in the majority of the renewable generation cost being hidden in the PSCR expense.

- ✓ Public Service Commission establish a transfer price with reference to the locational marginal price in the wholesale market instead of basing it upon a gas-fired combined cycle plant

7. Energy Optimization

Under PA 295, a utility that meets or exceeds the statutory energy optimization goals receives a financial incentive (see excerpt from PA 295 below).
"Sec. 75. An energy optimization plan of a provider whose rates are regulated by the commission may authorize a commensurate financial incentive for the provider for exceeding the energy optimization performance standard. Payment of any financial incentive authorized in the EO plan is subject to the approval of the commission. The total amount of a financial incentive shall not exceed the lesser of the following amounts:
(a) 25% of the net cost reductions experienced by the provider's customers as a result of implementation of the energy optimization plan.
(b) 15% percent of the provider's actual energy efficiency program expenditures for the year"

The total electric & natural gas energy optimization financial incentive bonuses received under PA 295 of 2008 For DTE/MichCon and Consumers Energy for program years 2009-2012 is $42,000,000.

Manufacturers already pay large EO charges. Industrial customers should not have to pay again for utility bonuses. The financial reward should be to the customer who achieved the energy cost savings, not the utility that collected their money and made them apply to get it back for use in their own energy efficiency projects.

A more fundamental issue is that these energy efficiency programs are an inherent conflict with a utilities business goal of selling more energy. The utilities should not be the entity that administers any energy optimization / energy efficiency program. A separate state-wide organization should administer the energy optimization program and be paid a set administrative fee. This organization would then develop a budget and provide EO rate charge recommendations to the MPSC. This structure would not require any expensive incentives.

Lastly, large industrial customers are required to pay volumetric natural gas energy optimization surcharges under PA 195 with no ability to seek an exemption. The electricity energy optimization surcharges are a per-meter charge and industrial customers can seek an opt-out of the charges by establishing a "self-directed" energy optimization program. However the opt-out process is cumbersome and establishes a risk of penalties. Manufacturing customers are both sophisticated and highly motivated to reduce energy consumption and costs and their mandatory participation in these energy optimization programs is unnecessary and burdensome. The program has value for small commercial or residential customers who can benefit from the expertise and rebates provided by the program.

- ✓ Amend PA295 to eliminate the EO financial incentive bonus program
- ✓ Amend PA295 to require a separate state wide independent organization to administer the energy optimization program
- ✓ Amend PA295 to allow an easy, straight-forward opt-out of the energy efficiency programs for industrial / manufacturing customers

8. Revenue Decoupling

Advocates of utility "revenue decoupling" believe it will remove economic incentives that work against energy efficiency. The rate design for regulated utilities rewards utilities for selling more energy, while energy efficiency projects result in decreased energy sales. "Revenue decoupling" breaks – or decouples – the link between the amount of energy sold and the revenue realized by utilities, thereby supposedly removing the economic incentives against energy efficiency. However as noted above:
a) The utilities should not be the administrator of energy efficiency programs, and
b) The new utility rate case timing process established in PA 286 already allows for a timely cost recovery and a timely earnings opportunity for utilities. Thus utilities are able to make adjustments for any lost sales/revenue from energy efficiency efforts as part of their overall utility rate case review.
Therefore there is no need for separate decoupling mechanisms.

- ✓ Amend PA295 to eliminate the use of all revenue decoupling mechanisms

9. Generation Efficiency

"Today most coal fired generation facilities converts fossil fuel into electricity at 33% efficiency, throwing away two-thirds of every unit of fuel we burn in cooling towers and smoke stacks. That's the same conversion efficiency we had last year. That's the same efficiency we had in 1980. In fact, you have to go all the way back to 1957 to find a year when the electric sector wasted more energy than it does today.
It's not stagnant because we've hit any fundamental limit. Indeed, studies by the US Department of Energy and Environmental Protection Agency have identified a whopping 200,000 MW of potential (that's 20% of the peak power demand of the US) for proven technologies that either recover waste energy from industrials and/or cogenerate heat and electricity from a single fuel source." [2]
One of the key issues holding back increased generation efficiency is our regulated utility model. Our electric regulatory model pays utilities a return on their capital investment, but compels them to pass along all operating costs to consumers at zero mark-up. This creates a great incentive to build capital-intensive new generation. It isolates electric utilities from the economic principles that drive "normal" businesses, wherein capital and operating cost reductions are a route to greater profits.
Our ability to avoid building costly new generation is not just demand side energy conservation and energy efficiency. It is more importantly tied to improving the efficiency of our existing generation fleet.

- ✓ Improve generation efficiency by establishing (i) a formal evaluation of Michigan's generation fleet operational efficiency and (ii) a regulatory model that requires utilities to improve the operational efficiency (increase generation plant heat rates, increase on-line time, reduce system loses and station loads, improve turn down capability, etc.)

10. Audit of Utility Cost

The monopoly position enjoyed by the utility companies in Michigan and throughout the nation gives them an extraordinary degree of power, both economic and political. Their corporate policies not only control the basic resources of industry and commerce and the livability of our homes and communities, but also determine the shape – and cost – of our future. And the primary institutional check on these policies is the Michigan Public Service Commission, a statutorily-created body established by the

[2] "Power Plant Efficiency Hasn't Improved Since 1957", Sarah Lozanova, June 26, 2008

legislature to oversee and regulate in the public interest the operations of Michigan's utility industry. The United States Supreme Court has made it clear that in establishing a fair rate of return, the Commission must consider how efficiently and economically utilities are managed:

"The return should be reasonable sufficient to assure confidence in the financial soundness of the utility, and should be adequate, **under efficient and economical management**, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield Water Works and Improvement Co v Public Service Commission, 262 US 679, 67 L Ed, 1176 (Emphasis Added).

- ✓ Legislation be enacted requiring the public service commission to conduct a continuing management efficiency review and to periodically make a determination of whether a utility's operations are being conducted in a prudent and efficient manner, and whether its expenses have been reasonably and prudently incurred. The commission should not assume a utility's failure to earn the authorized rate of return results from inadequate rate increases without being completely satisfied, after a specific investigation, that the utility is operating at an efficient and economical level.

- ✓ Legislation be enacted granting the commission an absolute right of discovery to insure that they will be able to secure the required information and data to determine whether the utility is operating under economical and efficient management.

- ✓ Legislation be enacted requiring that the commission make public its findings with respect to the management efficiency review of a utility's operations and the prudence of its expenses in rate proceedings before the commission.

- ✓ Legislation be enacted requiring the commission to include in the rates paid by ratepayers only the costs associated with any utility decision or conduct, or any utility expenses, which are both reasonably and prudently incurred and result in investment that is used and useful in providing retail utility service.

Funding for a management efficiency review:
(A) New Funding.
The funding for a Utility Management Efficiency Audit could first be included in a budget request made by the Administration in the budget for the MPSC. It would not necessarily be a specific line item, but would logically be included in with other costs of regulating the utilities. Then the budgets go through the appropriation process of the Legislature. Once the Legislature has approved a budget for the MPSC for its regulatory activities, then the state Department in which the MPSC is located (currently LARA) assess that amount against the regulated utilities in proportion to the amount of their intrastate revenues. See Act 299 of 1972, MCL 460.111 et seq. The new state budget begins October 1 of each year.

OR,

(B) Existing Funds.
The funding could come from the MPSC's existing budget for regulation which has already been appropriated by the Legislature and already assessed against the utilities pursuant to MCL 460.111 et seq. Obviously the MPSC would have to find the funds within its existing budget amounts under this alternative.

2012 - 2013 Residential Electric Rates for Investor Owned Utilities 1,000 kWh Consumption

Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	Madison Gas & Electric Company	WI	15.24
2	Southern Indiana Gas & Electric Company	IN	15.17
3	**DTE Electric Company**	**MI**	**15.07**
4	We Energies (formerly Wisconsin Electric)	WI	14.20
5	Dayton Power & Light Company	OH	13.41
6	AEP (Columbus Southern Power Rate Area)	OH	13.27
7	Northern Indiana Public Service Company	IN	12.92
8	**Consumers Energy**	**MI**	**12.79**
9	Interstate Power & Light	IA	12.79
10	Wisconsin Public Service Corporation	WI	12.63
11	AEP (Ohio Power Rate Area)	OH	12.40
12	WP&L	WI	12.09
13	Northern States Power Company (WI)	WI	11.99
14	Northern States Power Company (MN)	MN	11.98
15	Ohio Edison Company	OH	11.93
16	Commonwealth Edison Company	IL	11.81
17	Cleveland Electric Illuminating Company	OH	11.67
18	Toledo Edison Company	OH	11.63
19	Empire District Electric Company	MO	11.34
20	Kansas City Power & Light - MPS (formerly Aquila)	MO	11.30
21	Kansas City Power & Light - L&P (formerly Aquila)	MO	11.24
22	Duke Energy Ohio	OH	11.19
23	Duke Energy Indiana	IN	10.99
24	Ameren Illinois Rate Zone III (formerly IP)	IL	10.18
25	Kansas City Power & Light Company	MO	10.13
26	AEP (Indiana Michigan Power combined MI rate areas)	MI	10.02
27	Minnesota Power Company	MN	9.77
28	Indianapolis Power & Light Company	IN	9.70
29	Louisville Gas & Electric Company	KY	9.27
30	AmerenUE	MO	9.26
31	Ameren Illinois Zone II (formerly CILCO)	IL	9.23
32	Ameren Illinois Rate Zone I (formerly CIPS)	IL	9.13
33	MidAmerican Energy	IA	9.02
34	Duke Energy Kentucky	KY	8.98
35	AEP (Kentucky Power Rate Area)	KY	8.93
36	Kentucky Utilities Company	KY	8.69
37	AEP (Indiana Michigan Power)	IN	8.60

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.

2012 - 2013 Commercial Electric Rates for Investor Owned Utilities 500 kW Demand and 150,000 kWh Consumption

Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	AEP (Columbus Southern Power Rate Area)	OH	12.02
2	Madison Gas & Electric Company	WI	11.67
3	We Energies (formerly Wisconsin Electric)	WI	11.58
4	**DTE Electric Company**	**MI**	**11.57**
5	AEP (Ohio Power Rate Area)	OH	11.14
6	Northern Indiana Public Service Company	IN	10.98
7	Dayton Power & Light Company	OH	10.86
8	**Consumers Energy**	**MI**	**10.12**
9	Northwestern Wisconsin Electric Company	WI	9.92
10	Duke Energy Ohio	OH	9.71
11	Northern States Power Company (MN)	MN	9.63
12	AEP (Indiana Michigan Power combined MI rate areas)	MI	9.49
13	Northern States Power Company (WI)	WI	9.45
14	Interstate Power & Light	IA	9.36
15	WP&L	WI	9.30
16	Duke Energy Kentucky	KY	9.22
17	Louisville Gas & Electric Company	KY	9.18
18	Empire District Electric Company	MO	9.18
19	Ameren Illinois Rate Zone III (formerly IP)	IL	9.14
20	Southern Indiana Gas & Electric Company	IN	8.93
21	Duke Energy Indiana	IN	8.81
22	Kansas City Power & Light - L&P (formerly Aquila)	MO	8.80
23	Ameren Illinois Zone II (formerly CILCO)	IL	8.76
24	Indianapolis Power & Light Company	IN	8.75
25	AEP (Kentucky Power Rate Area)	KY	8.73
26	Wisconsin Public Service Corporation	WI	8.71
27	Ameren Illinois Rate Zone I (formerly CIPS)	IL	8.57
28	Kansas City Power & Light Company	MO	8.38
29	Ohio Edison Company	OH	8.28
30	Cleveland Electric Illuminating Company	OH	8.28
31	Minnesota Power Company	MN	8.16
32	AEP (Indiana Michigan Power)	IN	8.02
33	Toledo Edison Company	OH	7.89
34	Kansas City Power & Light - MPS (formerly Aquila)	MO	7.69
35	Kentucky Utilities Company	KY	7.48
36	AmerenUE	MO	7.30
37	MidAmerican Energy	IA	5.97

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.

2012 - 2013 Industrial Electric Rates for Investor Owned Utilities 50,000 kW Demand and 25,000,000 kWh Consumption

Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Wisconsin

Line	Utility	State	¢/kWh*
1	Madison Gas & Electric Company	WI	9.10
2	We Energies (formerly Wisconsin Electric)	WI	8.67
3	**DTE Electric Company**	**MI**	**8.25**
4	Northern States Power Company (MN)	MN	7.68
5	Southern Indiana Gas & Electric Company	IN	7.61
6	Dayton Power & Light Company	OH	7.49
7	**Consumers Energy**	**MI**	**7.40**
8	Empire District Electric Company	MO	7.10
9	AEP (Indiana Michigan Power combined MI rate areas)	MI	7.04
10	Duke Energy Indiana	IN	6.98
11	Northern States Power Company (WI)	WI	6.90
12	Indianapolis Power & Light Company	IN	6.83
13	Kansas City Power & Light - L&P (formerly Aquila)	MO	6.72
14	WP&L	WI	6.68
15	Wisconsin Public Service Corporation	WI	6.63
16	AEP (Ohio Power Rate Area)	OH	6.53
17	Minnesota Power Company	MN	6.53
18	Ohio Edison Company	OH	6.49
19	Northern Indiana Public Service Company	IN	6.49
20	Cleveland Electric Illuminating Company	OH	6.45
21	Duke Energy Kentucky	KY	6.40
22	Toledo Edison Company	OH	6.26
23	Duke Energy Ohio	OH	6.23
24	AEP (Columbus Southern Power Rate Area)	OH	6.00
25	Kansas City Power & Light - MPS (formerly Aquila)	MO	5.94
26	Louisville Gas & Electric Company	KY	5.94
27	Kansas City Power & Light Company	MO	5.61
28	Interstate Power & Light	IA	5.61
29	AEP (Indiana Michigan Power)	IN	5.49
30	AmerenUE	MO	5.40
31	Kentucky Utilities Company	KY	5.25
32	AEP (Kentucky Power Rate Area)	KY	4.83
33	MidAmerican Energy	IA	4.44

* Weighting = Four (4) 2012 Summer Months and Eight (8) 2013 Winter Months
Illinois utilities with open access are excluded.

Source: Edison Electric Institute Typical Bills and Average Rates Reports.