



Jennifer M. Granholm
GOVERNOR

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

J. Peter Lark
CHAIRMAN

Laura Chappelle
COMMISSIONER

Monica Martinez
COMMISSIONER

August 29, 2005

During Steering Committee meetings and the July Capacity Need Forum meeting, I asked participants to identify and provide comments on the Commission's resource addition policy. The question that I posed was "if additional generating based resources are needed, would the Commission's current policy be sufficient to assure construction of needed generation". My second question was if current policies are insufficient, what changes should be made to assure that needed generation is constructed. Some participants indicated that they thought the Commission's policies were adequate and should not change, and other participants identified policies that they thought needed changing. A considerable gulf exists among participants regarding the effectiveness of the Commission's existing policies. Attached are the written comments submitted by CNF participants regarding these two questions.

George Stojic

TABLE OF CONTENTS

Energy Options & Solutions	page 3
Customer Choice Coalition	page 10
American Council for an Energy Efficient Economy	page 13
Consumers Energy Company	page 34
Detroit Edison Company.....	page 36
Energy Michigan	page 40
Indiana Michigan Power Company	page 47



August 1, 2005

George Stojic
Patricia Poli
Engineering & Quality Division
Michigan Public Service Commission
6545 Mercantile Way, Suite 7
Lansing, MI 48911

SUBJECT: Capacity Needs Forum Comments

This letter is in response to your request or comments on the various issues raised to date in association with the Capacity Needs Forum. As a member of the Forum, I appreciate the Commission Staff's efforts to work through the very complex issues associated with defining Michigan's future electric power needs and the attempt to develop potential solutions to any short falls in resources to meet Michigan's electric supply requirements. There has been an obvious effort to listen to all parties in the process and to incorporate the data into a broad assessment of options. The issues I am raising in this document are related to concerns that I feel have not been adequately addressed. The opinions being presented here are associated with my experience in the industry and the focus on developing fair/equitable solutions for all parties, including, customers, utilities, independent power suppliers, the energy marketing community, renewable energy developers, etc.

I am a firm believer that there is no silver bullet to resolve the combined problem of meeting increased energy consumption caused by economic growth and the impact on the environment. Certain options such as cogeneration, demand side management and improved energy efficiency can reduce the rate of growth in energy consumption, but will not eliminate it. To eliminate

increased energy consumption we would need to stop economic growth as a whole and that is not a viable option. Thus the solution must come from a matrix of available options, with a near term focus on renewable resources.

RENEWABLE RESOURCES

Michigan is way behind its neighbor states in moving forward on renewables. Renewable energy resources are important options that need to be moved to the front of the list of solutions because it is time to implement these options. I am convinced that those states that are early adopters of these technologies will be the long term winners. From a state perspective, all fossil fuels used in electric production are imported into the state, resulting in an economic transfer of wealth to other states. The economic impact analysis and use of criteria for keeping rates as low as possible does not incorporate the transfer of wealth issue. In addition, the economic models due not include the economic impact on farmers or other potential energy supply sources. For example, a dairy farmer installing a manure digester system will solve an environmental problem, develop a source of revenue (compost) and provide new generation capacity. Only the additional generation capacity is included in the economic model used in the Capacity Needs Forum. Somehow the analysis of power supply options needs to include economic impacts of wealth transfer to other states, environmental impact of coal use and health impacts. The quantification of these issues is difficult, but there have been several studies attempting to define these costs that can be included in this study.

CONSERVATION & DEMAND SIDE MANAGEMENT

All of us went through the attempt to develop programs in the 1980's to provide incentives to influence the conservation of energy. Some of these programs worked and many did not. In many instances it was difficult to track the results of the incentives and the administrative costs resulted in a very high cost per kWh saved. Recent efforts by private and non-profit groups have shown there are economic ways for conservation programs to work. Industry still has significant opportunity to reduce energy consumption and to put in place workable demand side management options. The problem is that most companies have very high return on investment requirements which cannot be met by many conservation measures. As a result capital investment is moved to other projects which provide a better return on investment. We need to find a viable method of funding conservation projects for business that do not cause economic harm to those businesses.

COGENERATION/COMBINED HEAT AND POWER

Past utility practices have made the installation of cogeneration/combined heat & power systems uneconomical or has discouraged potential users. In the 1980's, utilities spent considerable effort to develop programs that encouraged companies with existing cogeneration systems, to eliminate those systems. These same programs also discouraged the installation of new cogeneration systems. The current tariff structure for electricity continues to incorporate the disincentives for the development of cogeneration/CHP. As with conservation measures, companies will not make the investment in cogeneration systems without paybacks in the range of 2-3 years. The reduction of electric costs under existing tariff structures should not be the only incentive the business owner has to install these systems. If we truly need to develop new

capacity supply options, then the cost of these options need to be incorporated into an incentive package to encourage cogeneration/CHP.

CAPACITY NEEDS & COMPETITIVE BIDDING

There has been significant discussion regarding the financing of future capacity needs. The need for future capacity is dependent upon many factors, including the success of conservation/DSM, state economic growth, wholesale power markets, Retail Open Access market penetration, impact of MISO, to name a few. Many of these issues were well framed in Mr. Stojic's July 18th presentation. Utilities are seeking pre-approval, funding as spending occurs and a guarantee of the ability to recovery any costs associated with addition of new capacity, regardless of source. It is important to understand that utility earnings growth is largely driven by return on capital investment. If new capacity is provided by any entity other then the utility, all costs associated with that capacity is treated as pass through costs in which the utility only acts an agent for the collection and dispersal of funds. Thus, the utility has an incentive to be the owner of any new capacity.

I think it is time we consider changing that equation so that the utility is indifferent to the source of capacity and has an opportunity to achieve some form of earnings on purchased capacity. The market conditions have changed since many of the laws and policies governing utility operations were put into effect. Electric generation is no longer a monopoly service provided only by utilities. Wholesale markets are now used on a daily basis by many entities for the purchase and sale of power on both short and long term basis. The Commission should consider a pricing mechanism in which the utility has the opportunity to be rewarded for smart purchasing of power and penalized for bad power purchase decisions. This is currently done in many other commodity markets and similar structures could be applied here.

The key to a fair market will be ensuring there is sufficient capacity of all parties supplying electricity to Michigan consumers. This capacity can be best obtained through a competitive bid process in which all entities and resources are considered. While at Nordic Energy, I participated in several capacity bid solicitations in several states. The Prairie Island Contingency Request for Proposal, under the guidelines of the Minnesota Public Utility Commission (MPUC), provided the fairest opportunity for all parties to participate. This RFP included allowances for the incumbent utility, Excel Energy, as well as REA's, to participate in the bid. The process was initiated with submittal of the RFP to the MPUC for comments. Once the final bid process was established, all parties were given six months to complete their bids. The incumbent utility was required to submit its bid one day prior to the due date of all other bids. The bids were evaluated by an independent third party. The results were then submitted by the incumbent utility for approval to the MPUC.

This process was fair and equitable, but still needs a few adjustments. The timing was such that bidders needed to be in the interconnection queue prior to the solicitation process. In the current transmission environment with MISO oversight, transmission studies can take well over a year and cost several hundreds of thousands of dollars. Utilities have a decided advantage with their knowledge of the transmission grid and their systems. In addition, the cost for these studies by the utilities is usually recovered in its rates whereas other entities need to pay these costs out of their own pockets. Although the independent ownership of Michigan's transmission grid reduces the utility advantage in transmission issues it is still a key advantage. To help alleviate these issues, the following items need to be included in any RFP for new capacity:

1. The due date for the bids must be at least 18 months after issuance of the RFP.
2. All participating bidders need access to all load flow studies and any other transmission studies performed for purposes of identifying potential points of interconnection.

3. Any transmission studies performed for purposes of interconnection need to be paid from a fund setup by the MPSC and collected from all rate payers. To avoid abuse by potential bidders, each bidder should be restricted to only request two such studies. Study requests must be submitted with 90 days of notice of intent to bid.
4. Utilities must identify all studies performed within the last five years for purposes of interconnection with the transmission grid or distribution grid.
5. The criteria for evaluation of the bids must be spelled out in the bid and the economic evaluation models are to be provided to all bidders.
6. The bids should be evaluated by third party under the auspices of the MPSC.

One other concept should be considered in this process in regard to bids by utilities. Since generation is a competitive product, utilities should be required to be treated in the same fashion as any other party. I suggest that if the utility is the successful bidder, their winning project should be set up as an independent entity with a purchase power contract identical to that of any other third party or wholesale supplier. This would ensure that the utility's cost recovery would be locked in at the time of bid, the MPSC would not have to revisit the issue of cost recovery, cost overruns, future plant improvement costs or changes in fuel costs. The utility would be subjected to the same risks and rewards as any other non-utility bidder.

Under these conditions, cost recovery and approval should be guaranteed by the MPSC. In addition, combining this with adjustments in the ROA program would provide an equitable mix for all customers.

CONCLUSION

In conclusion, my recommendations are summarized as follows:

1. Do not establish the recommended course of action in this report, but focus on outlining various scenarios and the resulting solutions to those scenarios. The focus of the final report should be on the policy and or legislative changes needed to allow the potential solutions to be successful.
2. Move conservation, cogeneration, and renewables to the top of the list of solutions. These should be the first choices and we need to change the policies and incentives to make these items successful. In the long term these will prove to be the most beneficial to the state of Michigan. In addition, these options should not wait until capacity is needed before being implemented. The time is now for these resources to be tapped.
3. Any new capacity additions need to be competitively bid with all parties participating.

I want to thank you for the opportunity to provide these comments. I hope they are helpful and useful in this process. If you would like to discuss these comments further, feel free to contact me at any time at 734-417-8106.

Respectfully,

Richard Polich
Energy Options & Solutions

AARP/Alticor/Association of Businesses Advocating Tariff Equity/Associated Petroleum Industries-Michigan/A Dealers of Michigan LLC/Central Michigan University/Dow Corning/Energy Michigan/Metropolitan Hospital/Michigan Association of Broadcasters Service Corp./Michigan Association of Convenience Stores/Michigan Association of Intermediate School Administrators/Michigan Association of Non-Public Schools/Michigan Association of School Administrators/Michigan Association of School Boards/Michigan Grocers Association/Michigan Interfaith Power & Light/Michigan Petroleum Association/Michigan Press Association/Michigan Restaurant Association/Michigan Retailers Association/Michigan School Business Officials/Michigan School Energy Cooperative/Michigan Tooling Association/Middle Cities Education Association/National Federation of Independent Business/Service Station Dealers Association of Michigan/ Small Business Association of Michigan/Spartan Stores/and many more



To: George Stojic

From: Barry Cargill, on behalf of the Customer Choice Coalition

Re: Comments on the Capacity Needs Forum issues

Date: Aug. 1, 2005

The Customer Choice Coalition, the voice of customers large and small in the discussion of Michigan's energy policies, continues to believe that Michigan will be best served by moving as quickly as possible toward a competitive market in electricity.

It is important to recognize that a major reason why our state today faces the highest electricity costs in the Midwest is due to the massive cost overruns and delays that characterized the last two major generation development projects by our primary electric providers. Our state today continues to pay for the management mistakes that plagued the development and construction of the Fermi II nuclear plant and the Midland Nuclear Plant, now the Midland Cogeneration Venture, which has been all but mothballed at the request of Consumers Energy.

Our current electricity policies, which require those electric users who leave our two major electric providers to subsidize their inefficiencies, hinder development of a competitive electric market.

Moreover, both Edison and Consumers have currently petitioned the Commission to adopt new Regulatory Adjustment Charges (RACs) that would essentially recover lost generation revenue from Electric Choice customers in an amount equal to the retail rate minus a cost of service. The magnitude of these charges, together with the existing securitization and other "stranded cost" charges would end Electric Choice service throughout this State because the charges end any possible benefits under current market conditions.

The end of Electric Choice would have highly undesirable consequences for all customers on the Detroit Edison and Consumers Energy systems.

First, the approximately 2500 MW of Electric Choice service currently in operation has in effect reduced utility demand by a corresponding amount plus reserve margin. If Electric Choice is priced out of existence, load equaling 2500 MW of demand plus the

need for 12-15% reserve margins will migrate back to utility service thus increasing utility requirement for new generation capacity. If these new generation units are more expensive than current units in the rate base (very likely to be the fact) this migration will significantly increase electric rates above levels that would have been the case if the smaller amount of capacity additions indicated by the initial CNF reports is added by regulated utilities.

This is just a way of suggesting that not all knowledge about the development of new electric capacity in Michigan resides in the offices of Detroit Edison or Consumers Energy. The Customer Choice Coalition hopes that the interests and views of customers, other potential electric providers and organizations such as the Midwest Independent System Operators will be given at least as much consideration as those of our traditional utilities.

We offer these views:

- 1. Michigan should consider transmission expansion before generation construction.** Our state's current economic flux suggests that electric use growth projections may be unreliable. To give policymakers an appropriate vision of the future needs of the state, additional time may be necessary. Moving now to expand transmission can give the state the time it needs to properly assess the future electric needs of a state that is less reliant on manufacturing.
- 2. The state should not rule out support for new generation outside of Michigan that can be transmitted into the state.** For a variety of reasons, including location of key coal facilities, air pollution requirements, taxes and others, a facility located outside of Michigan could provide high quality, reliable power to our state at a lower price than a facility built inside the state.
- 3. The Midwest Independent System Operator should be intimately involved in any decisions to upgrade transmission or develop major new generation capacity.** Federal law tasks MISO to determine the generating needs of the region in conjunction with available and potential upgrades of the transmission system. If additional power generation is required the MISO is tasked to make that decision and assure that the needed plants are built in the most desirable locations. If Michigan chooses to ignore less expensive alternatives both for generation and transmission, the consequences could be extremely damaging. If, for instance, large scale mine mouth coal plants are built in southern Illinois, Indiana and Ohio, those plants will likely have the lowest cost of production and will be run virtually flat out under MISO's dispatch orders. If a Michigan power plant is not priced competitively, MISO will not dispatch that plant on a base load basis until all other less expensive plants are used.

The consequence is that if a new Michigan generating plant is not needed or is not economically competitive, it will not be run as much and a large amount of cost will be unrecovered and obviously passed through to Michigan customers thereby

making our power even more expensive. The stakes are huge when the magnitude of the investment (\$1.5 billion to \$2 billion) is considered. How can we be a part of an expensive MISO process and then ignore and effectively frustrate the chief goal of that process, which is to ensure regional economic dispatch of power plants to increase reliability and reduce costs?

- 4. Pre-approval is not consistent with development of an energy market.** If Michigan is committed to using competition to drive down the high price of electricity in our state, it would seem that giving one or two companies pre-approval and a guaranteed profit for development of a plant would seem short sighted.
- 5. Revenue certainty is not consistent with development of an energy market.** Actually, we should call this “profit certainty,” based on the results of recent years. A plant that is needed, built efficiently and operated effectively will not need a guarantee of profit. Indeed, such a guarantee is a way to ensure that plants are not built or operated efficiently. And a guarantee of revenue, assuming some of it will come from customers who do not use electricity from the new facility, will kill competition.

Current securitization programs approved for Consumers Energy and Detroit Edison have added 5-10% to the cost of competitive power and are effectively eliminating competition in a high cost market.

Either Choice customers should not be required to participate in funding or funding guarantees for new generation plants or all customers who pay non-bypassable charges should be allowed to bring a corresponding entitlement to the output of the generating plant with them to any supplier: utility or AES. If a large new base load unit is needed, there should be full offset to existing securitization charges and elimination of any stranded cost charges or other utility generation charges to AES customers on the grounds that such facilities are no longer stranded.

- 6. Bidding may be a useful tool.** If the commission determines that it will provide up-front approvals and profit guarantees to those who develop new generation, there is no reason to limit the pool of potential developers to our existing utilities. We should encourage many companies to consider developing a plant in Michigan, bidding to provide the lowest cost of construction and operation.

We appreciate the opportunity to offer these thoughts as you move through the difficult job of developing a public policy that will ensure electric reliability at a reasonable cost. It is vital that we keep both ends of that policy in mind, particularly in the competitive world in which Michigan operates today. We simply cannot afford the practices of the past, which have led us to the high-priced power of today.

COMMENTS TO THE MICHIGAN CAPACITY NEEDS FORUM

By

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

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

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

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

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

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

In contrast, it appears that the current debate in this forum regarding capacity needs in Michigan is almost entirely dominated by discussion of additional generation (e.g., there was only a brief mention by Staff of energy efficiency under “Other Issues” in the July 18th public meeting; and

the MISO representative didn't mention energy efficiency at all - - other than admitting, in response to a question, that MISO was not really considering any role in fostering energy efficiency). If only supply side generation options are considered in Michigan, our electric system will be more costly, less reliable, and more polluting than it will be if demand side resources such as energy efficiency programs are fully included.

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

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

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

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

and has requested comment.

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

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

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

As for the second additional question, there are a number of regulatory mechanism and strategies that other states employ to help bring about utility sector energy efficiency programs, including providing convenient and reliable cost-recovery mechanisms; offering financial incentives for good utility performance in delivering savings (Michigan successfully employed that in the early

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

1990's); implementing regulatory adjustments to “de-couple” utility profits from their sales volume; and providing various other regulatory and public relations items important to utilities.

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

Conclusion

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

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

² Michigan imports 100% of the coal; 100% of the uranium; 96% of the petroleum products; and nearly three-fourths of the natural gas we use.

³ Michigan's cost for imported energy fuels is now estimated to be approximately \$18 billion per year.

ATTACHMENT A

Table 3: Energy Efficiency Program Spending and Savings¹

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

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

Table 5: Energy Efficiency Program Cost-Effectiveness

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

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

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

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

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

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

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

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

ATTACHMENT B

[Please insert report entitled *Funding and Savings for Energy Efficiency Programs for Program Years 2000 Through 2004*, which I am sending over as a pdf file.]

FUNDING AND SAVINGS FOR ENERGY EFFICIENCY PROGRAMS FOR PROGRAM YEARS 2000 THROUGH 2004

Cynthia Rogers
Mike Messenger
Sylvia Bender

*Energy Efficiency, Demand Analysis and
Renewable Energy Division
California Energy Commission*

In support of the
2005 Integrated Energy Policy Report

STAFF PAPER

DISCLAIMER

This document was prepared by the staff of the California Energy Commission for public review and consideration. The conclusions and recommendations are based on information reviewed by staff and represent staff's best professional judgment, but do not necessarily represent the views of the Energy Commission. The Energy Commission has not approved or disapproved this report, nor has the Commission assessed the accuracy or adequacy of the report's information.

FUNDING AND SAVINGS FOR ENERGY EFFICIENCY PROGRAMS FOR PROGRAM YEARS 2000 THROUGH 2004

This paper is a brief summary of the energy efficiency programs administered by the major investor-owned utilities (IOUs) in California: Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) over the last five years. The purpose of this paper is to highlight recent trends regarding energy efficiency funding, savings, and cost-effectiveness of these programs.

The data used in this paper was compiled from the annual reports on energy efficiency filed by each IOU with the California Public Utilities Commission (CPUC). This paper tracks energy efficiency efforts for the program years 2000 through 2004. All dollar amounts are reported in nominal dollars.

Annual Spending for Energy Efficiency Programs

Figure 1
Annual Spending for Energy Efficiency Programs
(\$1.4 billion was spent for PY 2000-2004 with an average of \$286 million per year)

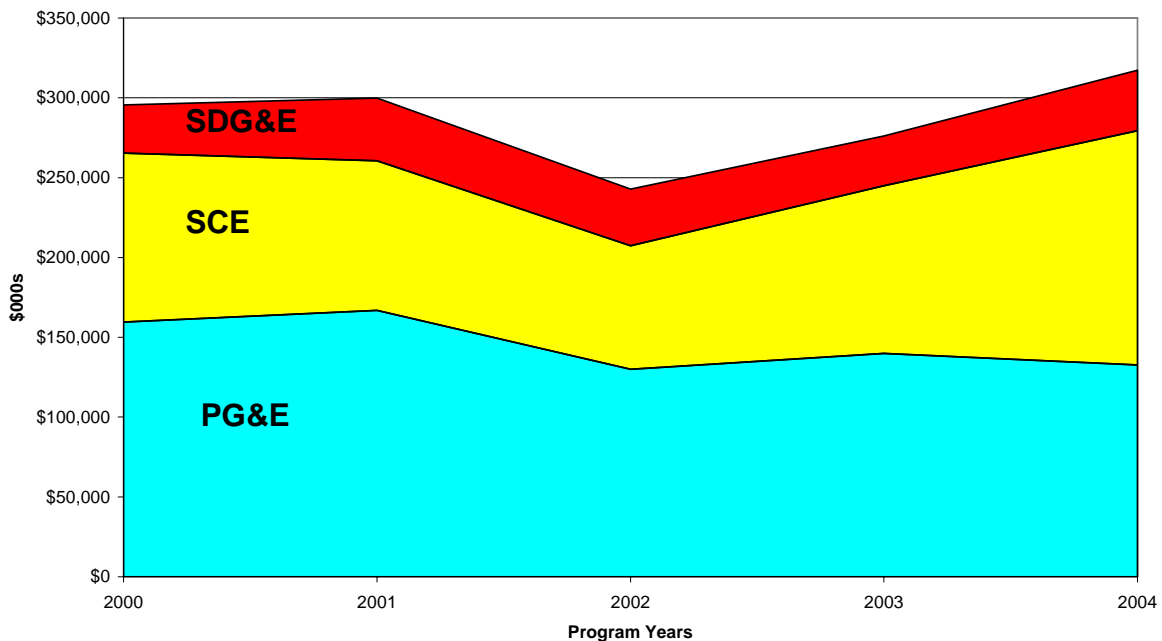


Figure 1 - Collectively, the three IOUs expended \$1.4 billion on energy efficiency programs for the program years 2000 through 2004. For the years 2000 and 2001, the three IOUs expended close to \$300 million each year. In 2002, the spending fell to \$243 million. Spending increased in 2003 to \$276 million and increased again in 2004 to a high of \$317 million.

Annual Spending by Sector

Figure 2
Cumulative Spending by Sector for PG&E, SCE and SDG&E for Program Years 2000-2004
(\$1.4 billion was spent for PY 2000-2004 with an average of \$286 million per year)

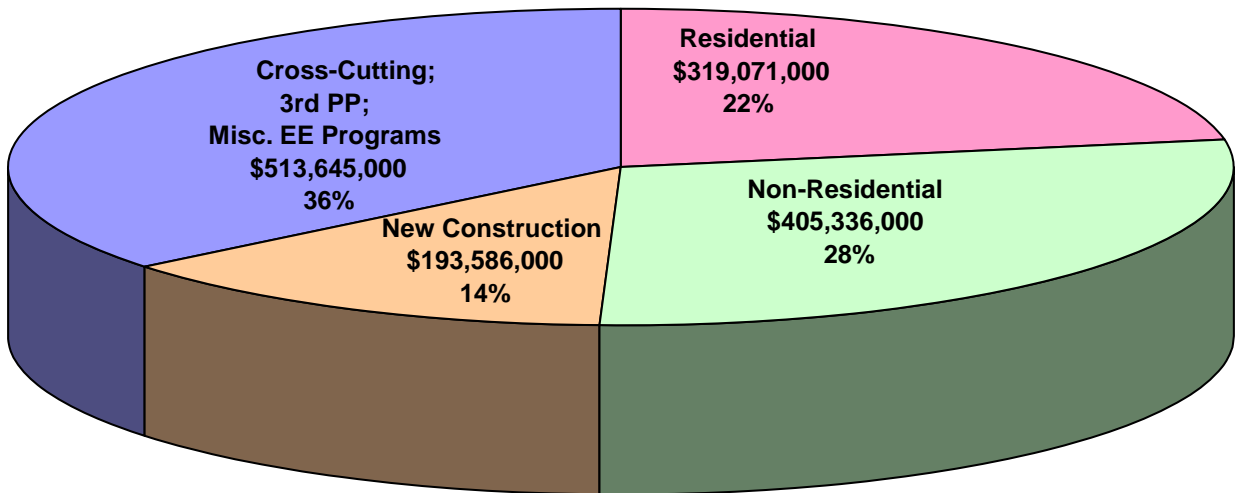


Figure 2 – Of the \$1.4 billion that the three IOUs expended on energy efficiency programs for the program years 2000 through 2004, 14 percent was spent on new construction programs; 22 percent was spent on residential programs; 28 percent was spent on non-residential programs; and 36 percent was spent on cross-cutting, third party programs, and miscellaneous energy efficiency programs.

The term cross-cutting is used for energy efficiency programs that involve any or all of the following: multiple customer types (residential and/or non-residential), and/or multiple building types (retrofit, remodeling, and/or new construction). All of these programs are designed to support and drive energy efficiency and energy savings. Some examples of cross-cutting programs include information and education, marketing and outreach, codes and standards advocacy, and emerging technology.

Figure 3
Spending by Sector for PG&E, SCE and SDG&E for Program Years 2000-2004
 (\$1.4 billion was spent for PY 2000-2004 with an average of \$286 million per year)

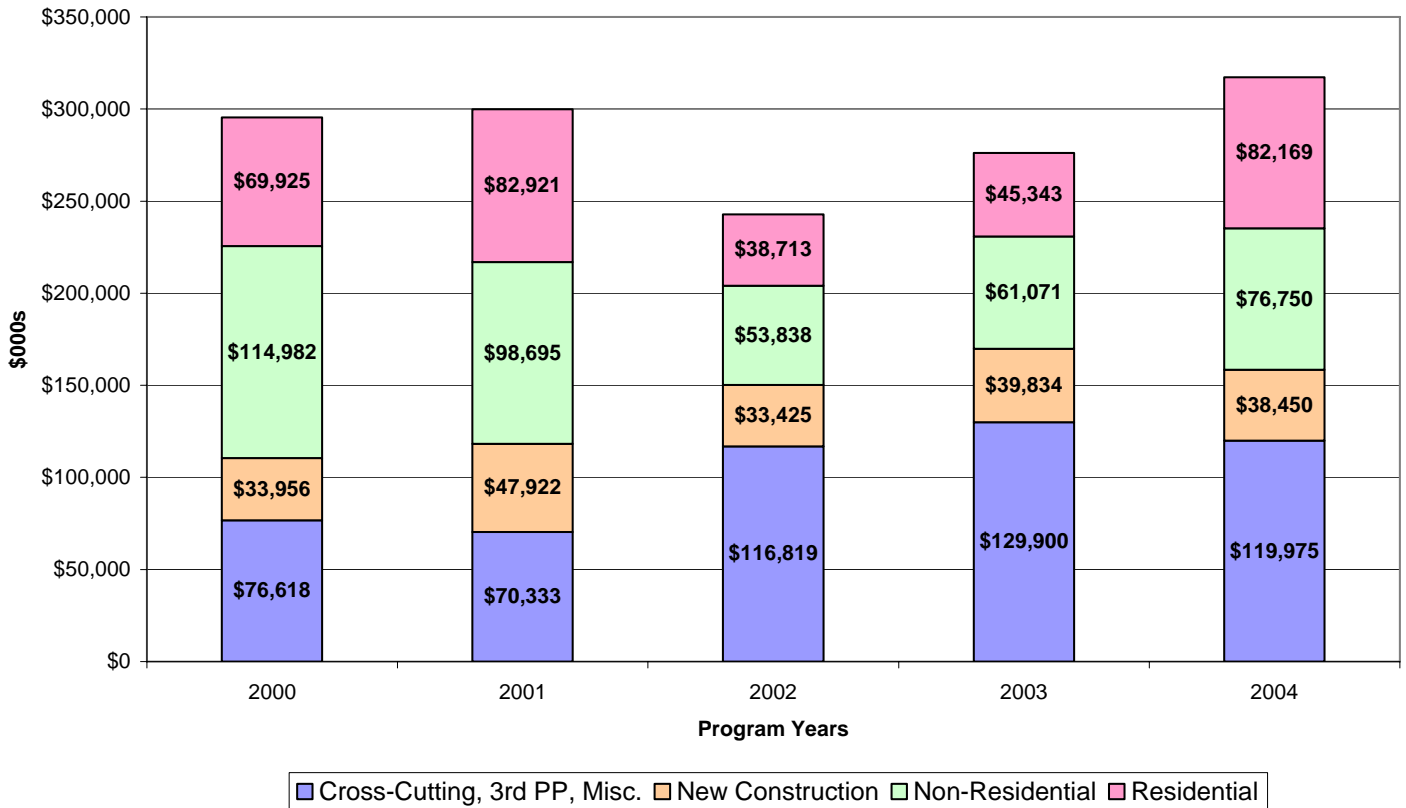


Figure 3 – This graph shows the breakdown by year of the spending for the three different customer sectors and a combination category. This combination category includes cross-cutting utility programs that have multiple customer sectors as well as programs that are administered by third parties. For years 2000 through 2004, these third-party programs accounted for nearly \$50 million dollars of the combination category budget.

Except for years 2000 and 2001, the spending has been highest in the combination category. Spending on non-residential programs energy efficiency programs was highest in 2000 and 2001, and the second highest amount of money for years 2002 and 2003. The non-residential energy efficiency programs include both industrial and commercial customers. Spending for residential programs has been the most volatile; spending in this sector has ranged from \$38.7 million in 2002 to nearly \$83 million in 2003. For all five years, new construction programs have spent the least amount of money.

Spending by Individual Utility

Figure 4
Annual Spending for Energy Efficiency Programs by PG&E, SCE and SDG&E for PY 2000-2004
 (\$1.4 billion was spent for PY 2000-2004 with an average of \$286 million per year)

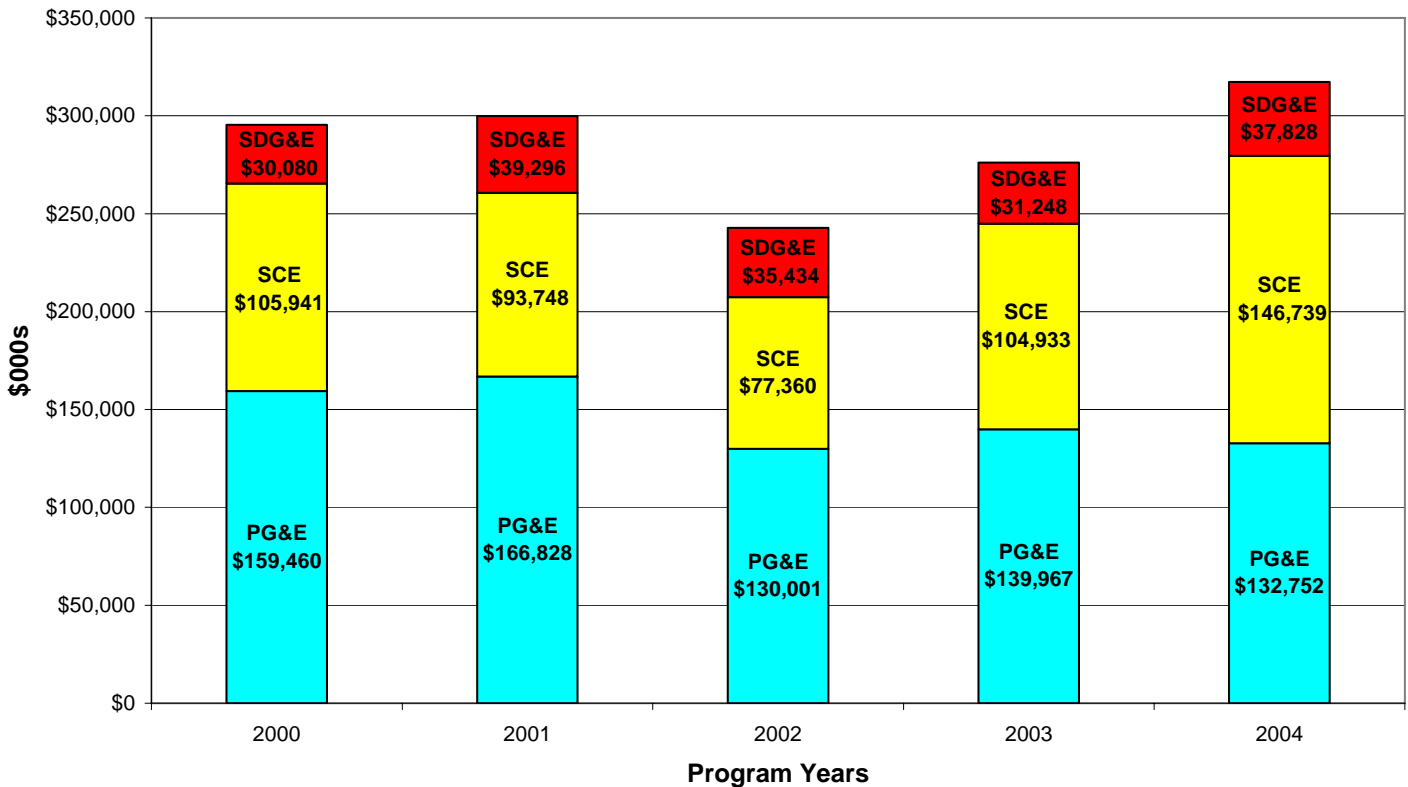


Figure 4 – This graph shows what each IUO spent on energy efficiency programs for each program year. Spending from PG&E was the highest of all the utilities for all years except 2004. In 2000, PG&E spent 88 percent of its energy efficiency budget. In the year 2001, PG&E’s actual spending exceeded its budget for energy efficiency programs. In 2002, 2003 and 2004, PG&E spent 91 percent, 92 percent, and 90 percent respectively of its budget for energy efficiency programs. In the years 2000 and 2004, SCE spent 99 percent and 98 percent respectively of its energy efficiency budget. For the years 2001 and 2003, SCE spent 93 percent and 87 percent respectively of its budgeted funds. For program year 2002, SCE only spent 64 percent of its budget on energy efficiency programs. SDG&E spent less than 77 percent of its budgeted funds on energy efficiency programs for program years 2000, 2002, and 2004. In 2001 and 2003, SDG&E spent 90 percent and over 100 percent respectively of its budgeted funds.

First Year Savings in Gigawatt Hours

Figure 5
First Year Savings (GWh/yr) by Utility Energy Efficiency Programs

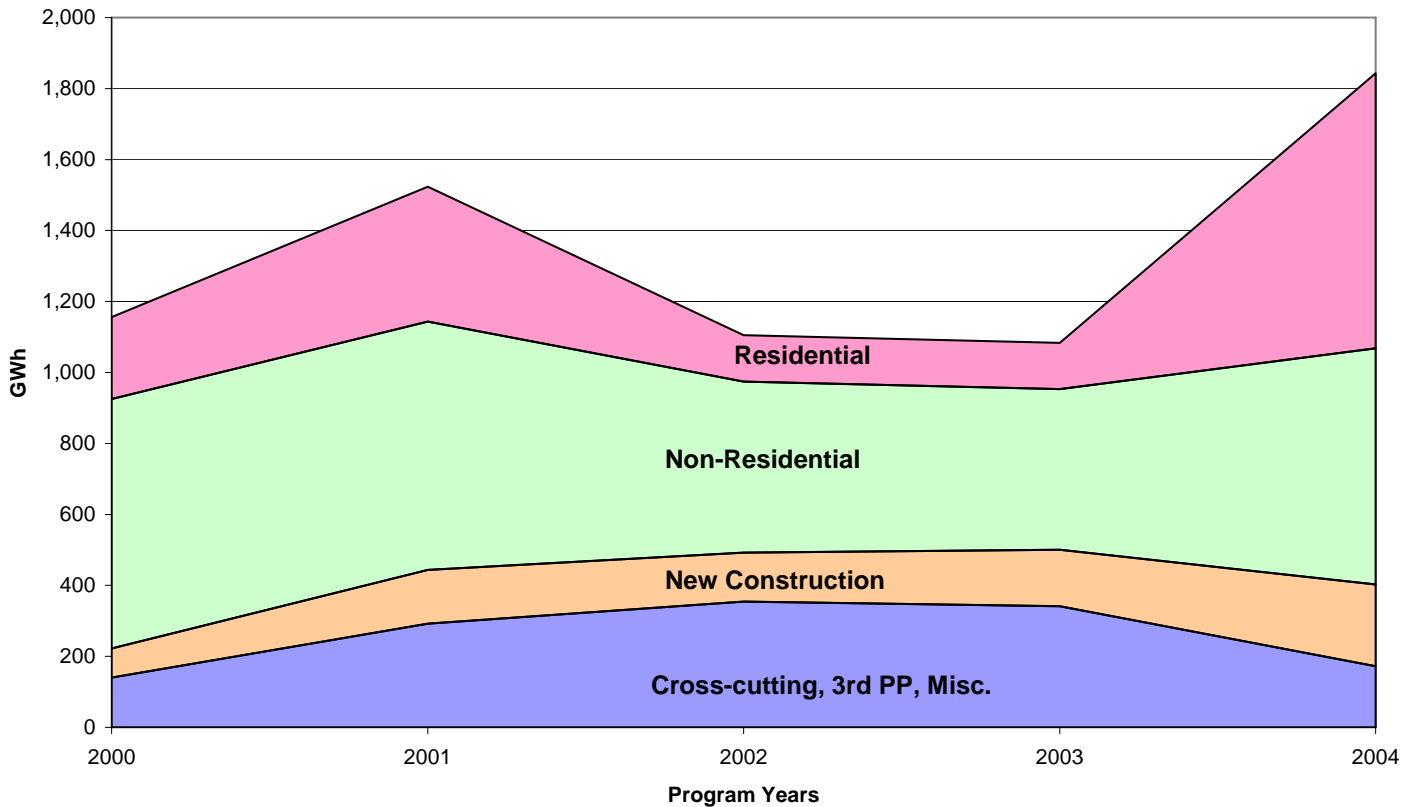


Figure 5 – This graph shows the first year savings in Gigawatt hours from the previously identified sectors. The year 2004 had the greatest first year savings with 1,843 Gigawatt hours saved. Program Year 2003 had the least first year savings with only 1,084 Gigawatt hours saved. For all program years except for the year 2004, non-residential energy efficiency programs had the greatest first year savings in Gigawatt hours. The year 2004 had the greatest first year savings in the residential energy efficiency programs. It appears that this major upswing in savings was caused by a significant increase in lighting savings from the residential sector that has yet to be verified.

First Year Peak Savings in Megawatts

Figure 6
First Year Peak Savings of Utility Energy Efficiency Programs

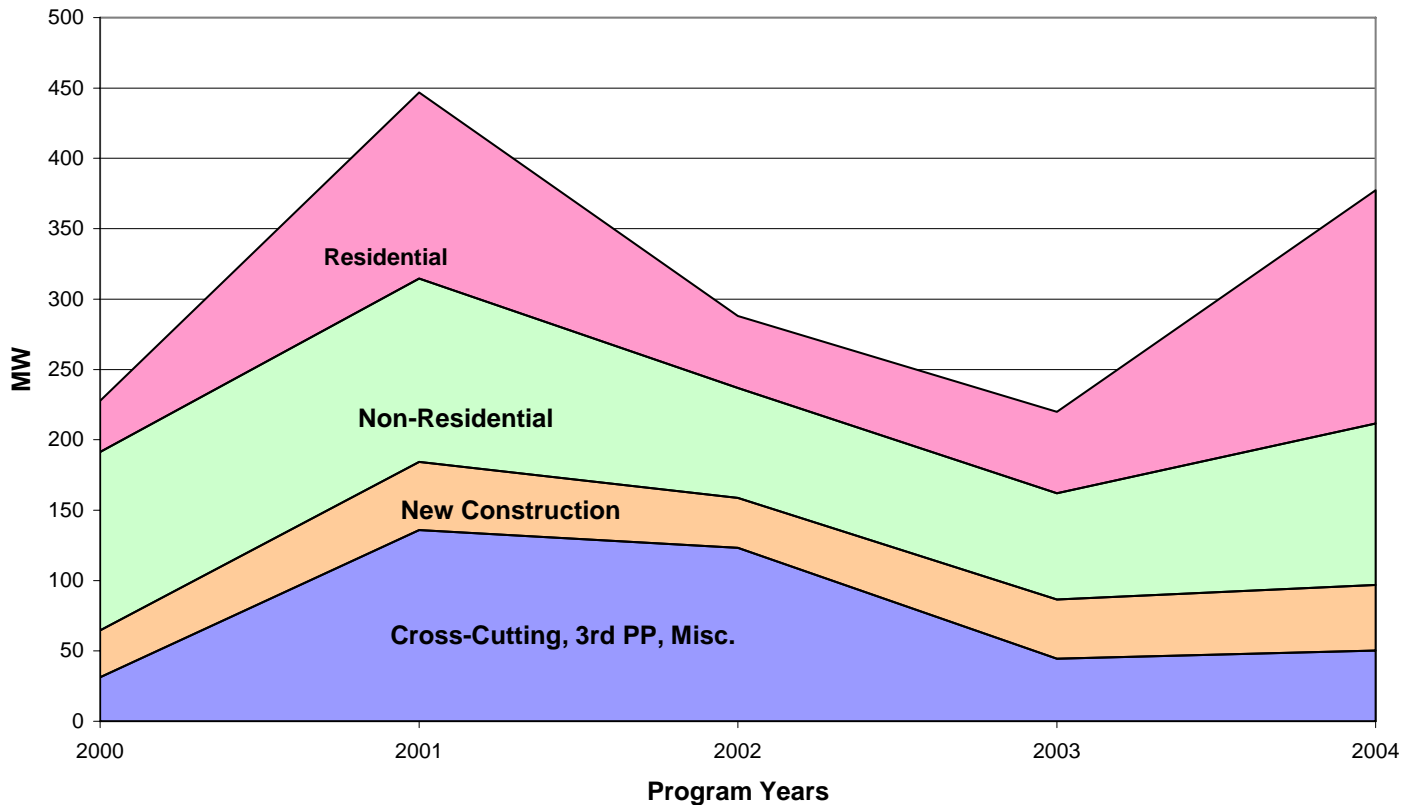


Figure 6 – Shows the first year peak savings in megawatts. The year 2001 had the greatest first year peak savings with 447 megawatts saved. The year 2004 was close behind in savings with 377 megawatts saved. For program years 2000 and 2003, non-residential programs had the greatest first year peak savings. The cross-cutting and third party programs had the greatest megawatts savings for years 2001 and 2002. The year 2004 had the greatest first year peak savings in the residential energy efficiency programs with 166 megawatts saved.

Cost Effectiveness

Figure 7
Summary of Cost Effectiveness by Sector for PG&E, SCE and SDG&E
for Program Years 2000-2004

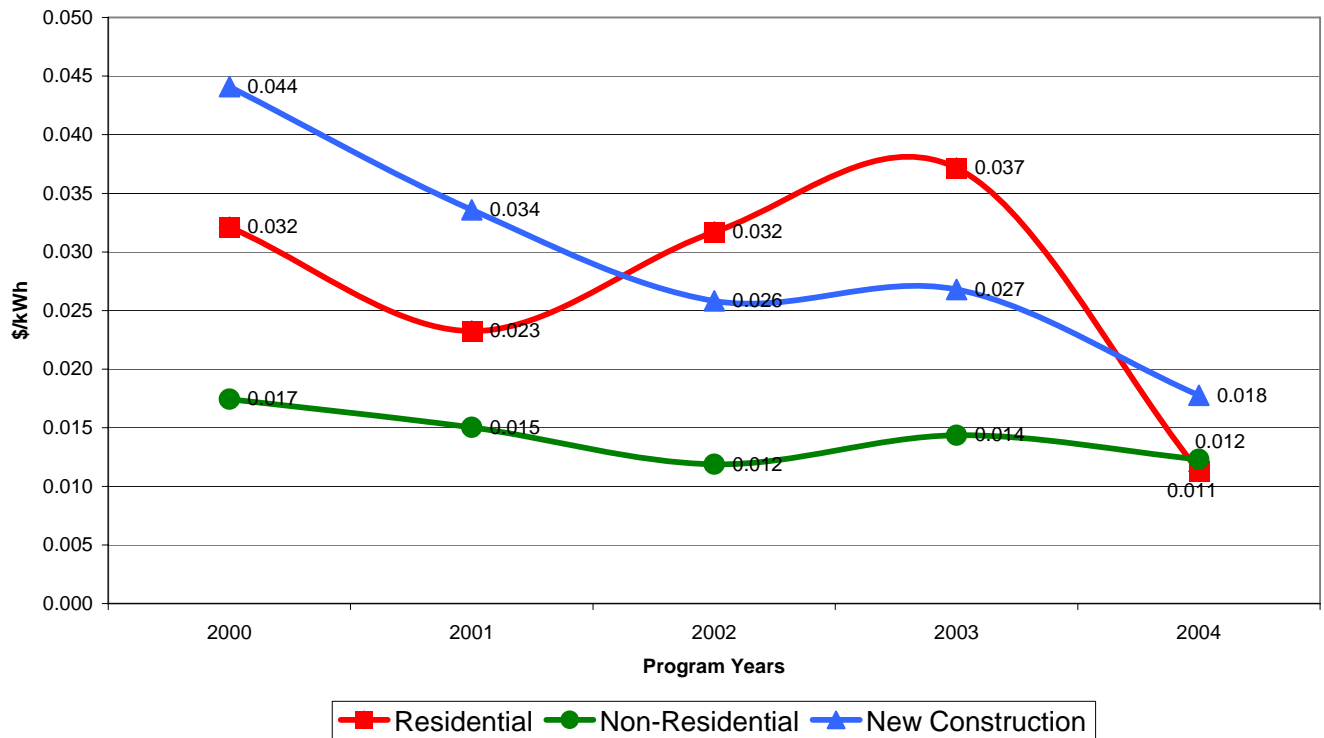


Figure 7 – This graph shows a summary of the reported program cost effectiveness by sector for the aggregated IOUs for program years 2000 through 2004. We used levelized costs (in \$/kWh) as the indicator of cost effectiveness, but information on benefit cost ratios is also available. We chose this method because research has shown that policy makers have an easier time comparing levelized costs for demand versus supply sources than comparing benefit cost ratios which are often not provided for supply options.

Over the past five years, program effectiveness has increased in all the sectors. For the year 2004, all sectors were at a levelized cost of a little over 1.1 cents per kWh. New construction had the greatest decrease in levelized cost over the five years. In 2000, the new construction energy efficiency programs were at a levelized cost of 4.4 cents per kWh. By the year 2004, the costs for these programs were now at 1.8 cents per kWh. The non-residential programs were the most stable for the 2000 through 2004 varying only slightly from a high of 1.7 cents per kWh in 2000 to 1.2 cents per kWh in 2004. The residential energy efficiency programs had the most variance of all three sectors. The year 2003 had a high of 3.7 cents per kWh and then dropped to the lowest point in the five years to 1.1 cents per kWh in 2004.

These calculations assume an average useful measure life of 12 years and a real discount rate of 4 percent per year. These savings calculations count only utility program costs and incentives and do not include the incremental costs of the measures. Adding these costs would increase the estimates of levelized costs here from 30 to 80 percent, depending on the fraction of the measure cost covered by utility incentives.

To calculate the levelized cost of conserved energy, we used the following formulas:

$$\text{Levelized Cost of Conserved Energy} = \frac{\text{Program Costs} \times \text{CRF}}{\text{First year kWh saved}}$$

$$\text{Capital Recovery Factor (CRF)} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

i = real discount rate

n = useful life period

These calculations assume an average useful measure life of 12 years and a real discount rate of 4 percent per year.

Figure 8
Comparison of EE Program Costs to Supply Generation Costs

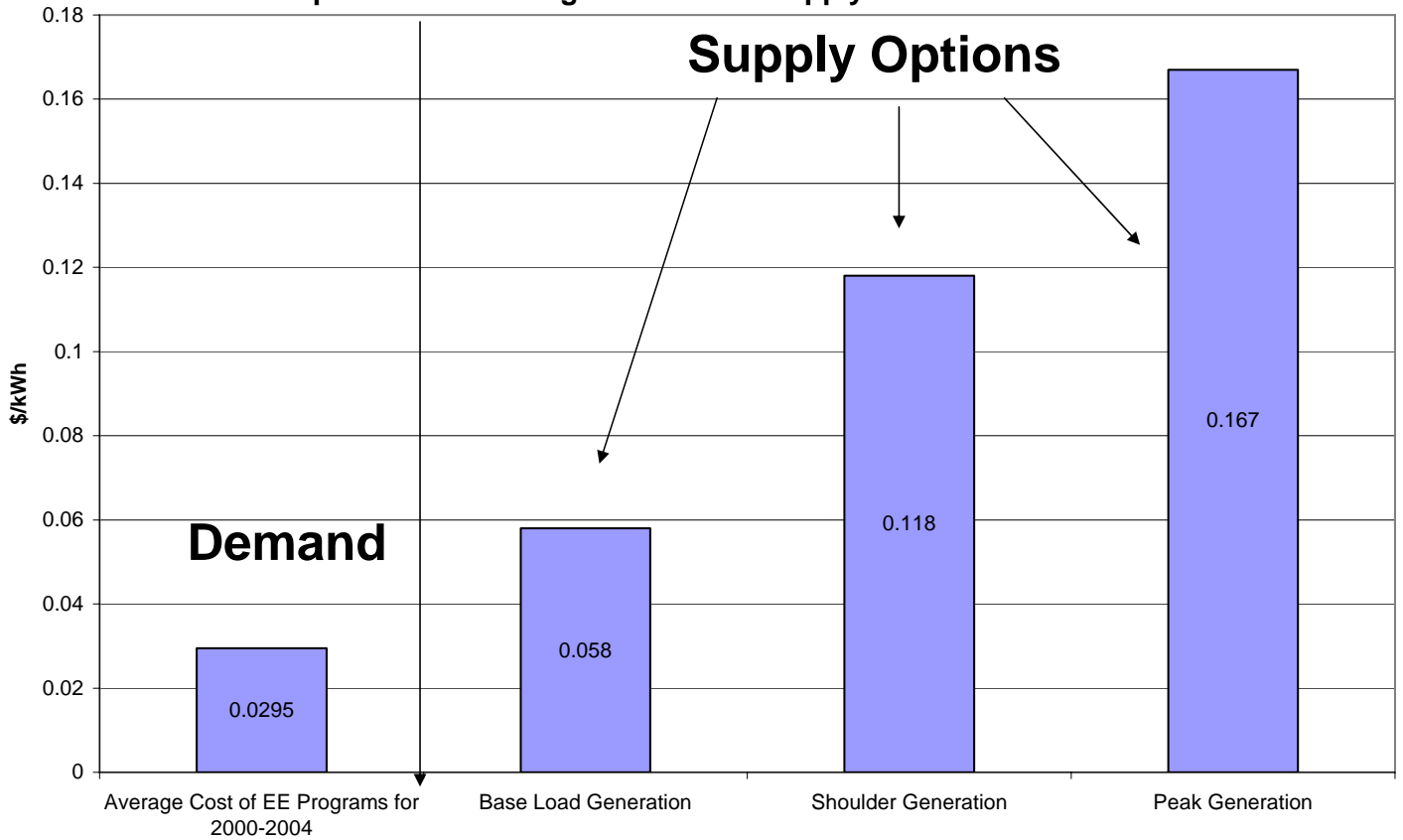


Figure 8 – This graph compares the levelized costs of the of the energy efficiency programs averaged for program years 2000 through 2004 to the costs of providing energy generation for specific load blocks. The average cost of the energy efficiency programs for program years 2000 through 2004 was 2.9 cents per kWh. As noted in the 2003 electricity goals report (*Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission, October 27, 2003), the levelized cost for electricity generation during the Base Load was estimated at 5.8 cents per kWh, nearly double the cost of the averaged levelized cost for the energy efficiency programs. The levelized cost for electricity generation provided during the Shoulder time period is 11.8 cents per kWh, four times the cost of the averaged levelized cost for the energy efficiency programs. Finally, the levelized cost for the electricity generation for Peak time period is 16.7 cents per kWh, five and half times the cost of the averaged levelized cost for the energy efficiency programs for years 2000 through 2004. This graph shows that the average levelized costs for demand are still much less than the levelized costs for supply generation alternatives.

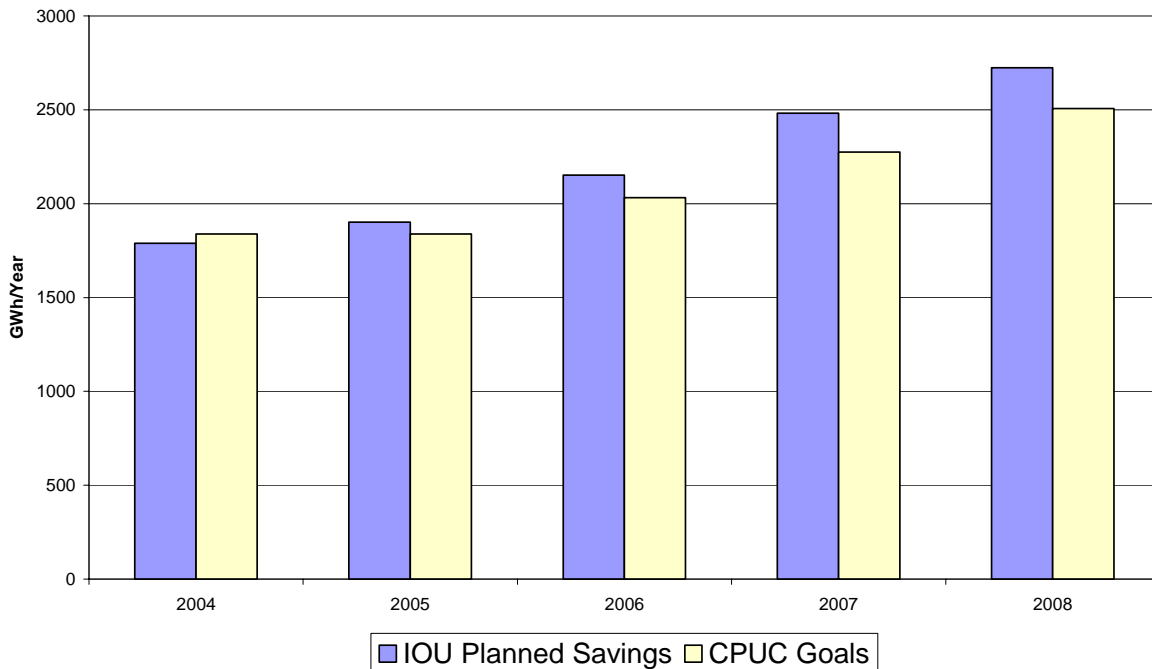
We use the following time periods to define base load, shoulder time period, and peak time period:

- Shoulder time period includes weekdays from 8 a.m. to 1 or 2 p.m. and from 7 p.m. to 9 p.m.
- Peak time period is between 12 p.m. and 7 p.m. on weekdays between the months of May and October.
- Base load is essentially all other time periods.

2006 through 2008 IOU Energy Efficiency Program Portfolios

California's investor-owned utilities submitted their portfolio plans to the CPUC on June 1, 2005. Initial assessments by the utilities' Peer Review Groups and the CPUC's consultants conclude that the total program portfolio "has a good chance" of meeting the near term goals for energy savings, peak demand reduction, and therm savings. Figure 9 shows the comparison of projected savings with goals for the IOUs. The 2004 through 2013 goals should achieve 90 percent of the remaining cost-effective potential that is reachable through aggressive program activity.

Figure 9
IOU Projected Savings Compared to Goals 2004-2008



Through procurement proceedings, ratepayer funds are once again available to fund energy efficiency beyond levels in the PGC. The IOUs have proposed large increases over their 2004-2005 budgets as a result. Table 1 shows the preliminary spending proposals and the relative sizes of the annual increases.

Although energy savings declined significantly following the 2000-2001 crisis, the trend today points toward significant increases in both spending and savings, consistent with the policies adopted in the *Energy Action Plan*.

**Table 1
Funding for 2006-2008 Programs (\$000)**

	2006	% Diff from Previous Year	2007	% Diff from Previous Year	2008	% Diff from Previous Year
PG&E	\$240,000	83%	\$281,000	17%	\$345,000	23%
SCE	\$243,000	43%	\$243,000	0%	\$243,000	0%
SDG&E	\$81,000	107%	\$91,000	12%	\$106,000	16%
SCG	\$48,000	47%	\$61,000	27%	\$73,000	20%

The likelihood of meeting the longer-term goals, however, is less certain. Achieving the future goals will require a commitment to innovative programs, including new technologies and program strategies, continuous improvement in program designs, and investments in program approaches expected to yield significant savings in the outer years. Uncertainties that could affect the achievement of these goals include the following:

- The amount of future cost-effective potential could increase or decrease, depending on cost-effectiveness, standards, equipment saturation, and emerging technologies.
- Values for evaluation parameters (net-to-gross ratio, unit energy savings, etc.) may be revised.
- Ramping up funding to these levels may be difficult. Coupling large funding increases with unproven program ideas carries greater risk for successful program delivery.
- Emphasis on current year savings, as required by the new counting rules, could dampen interest in longer-term investments, such as new construction and standard performance contracting.
- Achieving the long-range goals will depend on the ability of the utilities to expand their reach to customers and increase both the level of

savings per customer and the probability that customers will sustain these savings and continue to make efficient decisions.

Summary

This paper describes the latest trends in funding and savings for energy efficiency programs over the last five years. We believe this information provides the necessary background for discussion on how to improve energy efficiency portfolios in the future and the likelihood that future program efforts will meet the Commission's energy and peak goals.

Total expenditures for the different energy efficiency programs ranged from a low of \$243 million in 2002 to a high of \$317 million in 2004. This is still less than the high water mark for efficiency programs of roughly \$400 million in 1994. The total amount spent during these five years, 2000 through 2004, was \$1.4 billion. The majority of the money spent was on cross-cutting and third party programs. The non-residential sector, which includes industrial and commercial customers, spent the second highest amount of money. New construction received the least amount of the funding for energy efficiency programs.

Average energy and peak savings from programs have been steadily increasing over the five year period, even after the significant drop in savings experienced between 2001 and 2004. The levelized costs for the energy efficiency programs in all sectors reached a low of a little over 1.1 cents per kWh in 2004 and when compared to the supply generation costs, the energy efficiency programs proved to be very cost effective.

The investor-owned utilities are likely to achieve the goals over the near-term 2004 through 2008 period. This likelihood is less certain looking out to 2013, unless significant changes occur in program investments and approaches.

Links

California Energy Commission Homepage - <http://www.energy.ca.gov/>

California Energy Demand 2006-2016 Staff Energy Demand Forecast - <http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SD.PDF>

California Public Utilities Commission - <http://www.cpuc.ca.gov/static/index.htm>

Pacific Gas & Electric 2004 Annual Earnings Assessment Proceeding - https://www.pge.com/regulation/AnnEarnAssessProc2005/Testimony/PGE/2005-01-Fwd/AnnEarnAssessProc2005_Test_PGE_20050502-03-Vol-III.pdf

Southern California Edison 2000-2004 Energy Efficiency Annual Reports - http://www.sce.com/AboutSCE/Regulatory/eefilings/Annual_Reports/

San Diego Gas & Electric 2004 Energy Efficiency Programs Annual Summary and Technical Appendix - http://www.sdge.com/regulatory/docs/eep_sdge.pdf

Consumers Energy Comments for Consideration of Capacity Need Forum

Subject: Current MPSC Resource Addition Policy

August 1, 2005

Recently, the MPSC staff requested that participants in the ongoing Capacity Need Forum submit recommendations related to the current resource addition policy.

Consumers Energy offers comments on the following:

1. **Pre-approval:**

The policy of deferring consideration of cost recovery issues until the plant enters commercial operation (used and useful model) provides a barrier to the development of new generation by not maintaining significant financial assurance and increasing long-term business risk. The MPSC should administratively establish an efficient up-front approval and certification process that would grant pre-approval for projects before construction commences.

2. **Competitive Bid Process:**

The existing competitive bid process applicable to certain Michigan utilities promotes considerable uncertainty with the construction decision process. The MPSC could rescind the current order for competitive bidding of new generating additions to eliminate this uncertainty.

3. **Revenue Certainty:**

The existence of possible load loss creates uncertainty of a customer base and makes financing a new generation facility extremely difficult, if not impossible. Due to the complexity of this policy issue, we are unable to make a specific recommendation at this time but encourage the MPSC to investigate all options.

4. **Financial Considerations:**

The inability to recover construction costs in rates during construction creates significant cash flow requirements pending project completion, and increases financing costs and increases investment uncertainty. The MPSC should modify existing ratemaking treatment to ensure construction work in progress (CWIP) costs are recoverable on a cash basis without the Allowance for Funds Used During Construction (AFUDC) offset. These costs would be recovered on a regular basis throughout the construction cycle.

In summary, Consumers Energy supports the MPSC's investigation into identifying ways to meet Michigan's future electric capacity needs. We look forward to continued participation in this important process and will offer further comments as needed.

**Comments of The Detroit Edison Company
Current MPSC Resource Addition Policy
Capacity Needs Forum
August 1, 2005**

A reliable electricity system is critical to the economic development and well being of Michigan and its citizens. Underlying a reliable electricity system is a robust transmission and distribution infrastructure with sufficient generating facilities to meet consumer demand for both today and into the future. However, many factors make the construction of new generating facilities financially risky today. These factors include the overall volatility in fuel and power prices, the long lead times in building base load generation, the impact of transmission additions and out-of-state generating facilities on the price of electricity, increases in capital costs due to current environmental compliance rules and regulations, and the lack of clarity surrounding future federal and state environmental rules and regulations for NO_x, SO₂, Hg and CO₂, and the substantially higher costs of new generating facilities when compared to existing facilities.

It is also important to note that credit rating agencies have become highly sensitive to even modest changes in the health of energy companies. Since 2001, credit rating agencies have downgraded many major companies in the power industry. As stated in the Fitch report that was presented to the Capacity Needs Forum on April 22, 2005:

Even in such cases [where generation is still part of integrated monopoly service] Fitch has become more concerned about such investments [new capacity additions] 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.

Given this apprehension on the part of the credit rating agencies to support new capacity additions absent changes in current policy, utilities are likely to choose only safe investments, forgoing riskier investments that could potentially lead to a downgrade. Rather than adopt a long-term perspective where generating assets with high capital requirements and low fuel costs are considered to meet future needs, Michigan's electric utilities are forced to adopt a myopic perspective where generating assets with low capital requirements and high fuel costs are considered. This dilemma results in higher and less stable prices for Michigan's electricity consumers.

In an attempt to address some of the risks noted above, many states (e.g., Iowa, Wisconsin, and Missouri) have developed new rules and regulations to aid in the construction of new base load generating facilities. Iowa and Wisconsin have recently approved legislation providing for its regulatory agencies to implement a pre-approval process for new generating facilities while Missouri has pre-approved a new coal facility and additional environmental control technologies on existing generating facilities via a collaborative settlement process.

In addition, Michigan's hybrid regulatory structure complicates the capacity addition process. The introduction of customer choice has fragmented responsibility for generation supply between incumbent electric utilities and alternative electricity suppliers. Michigan's electric utilities no longer have sole responsibility for electric supply in their service territory. Without a certain and defined base of customers and the associated revenue certainty, both Michigan's electric utilities and independent power suppliers face substantial financial risk associated with the construction of new generating facilities. In short, Michigan's current hybrid regulatory structure does not facilitate the construction of new generating capacity to meet future needs due to the high degree of financial risk created by an uncertain future customer base and an unsustainable regulatory environment.

While the energy needs of Michigan's consumers are currently being supplied through a combination of in-state generation and transmission infrastructure that relies on sufficient generating capacity beyond our borders, any surpluses are temporary and will disappear over time. Michigan and its energy consumers

cannot wait until capacity shortages are imminent for the state to incentivize or mandate additional generating facilities that will take a minimum of several years to develop, construct, and place into operation.

With that as background, The Detroit Edison Company responds to each of the issues raised by participants of the Steering Committee in the Michigan Public Service Commission's Capacity Need Forum.

Pre-Approval of Need, Plant Type, and Cost

The Company supports a Commission pre-approval process for the construction of new generating facilities. A pre-approval process would reduce the financial and regulatory risks associated with an after-the-fact review process with respect to capacity needs, fuel source and type of plant, construction cost estimates, and investment type (generation or transmission). As noted previously, numerous issues have arisen over the past several years that have increased the financial risk of constructing new generating facilities. Without some form of pre-approval from the Commission, incumbent electric utilities are likely to forgo the financial risk of constructing new generating facilities.

Revenue Certainty

Under Public Act 141, customers are allowed to choose alternative suppliers for their electricity needs. Public Act 141 did not restructure or deregulate Michigan's incumbent electric utilities. It did however, alter the customers' obligation to purchase electricity from the incumbent electric utility thereby breaking the obligation to serve compact that had existed for over 100 years. As a result, customers are free to choose the regulated rate of the incumbent utility or the market price offered by an alternative supplier. As market prices decrease, customers will naturally migrate to alternative suppliers leaving the remaining customers of the regulated utility with the costs previously borne by the departing customers.

In a traditional market model, a company would respond to a reduction in customers and associated load by shutting down or selling the formerly utilized assets. Unfortunately, under Michigan's hybrid regulatory structure with a continuing obligation to serve all customers, an electric utility cannot reduce costs by shutting down or selling assets. As market prices increase, customers will naturally migrate back to the protection of the utility's regulated rates. Therefore, the assets must remain to serve Electric Choice customers in the event they choose to return to the electric utility's regulated rates. As a result, the incumbent electric utility is confronted with an ever-changing base of customers and associated revenue stream.

As stated in the Fitch report, "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."

Additionally, as new base load generating facilities are added in Michigan, the locational marginal price of energy at the Michigan Hub will likely decrease. This decrease in market price coupled with higher regulated rates due to the impact of new capacity additions to the traditional utility rate base will increase the disparity between the cost-based, regulated rates of the incumbent electric utility and the market price of energy. As this disparity increases, more customers will likely migrate to Electric Choice, thereby increasing the likelihood of additional stranded costs.

If new generating facilities are to be constructed in Michigan, the Commission must enact policies which provide the necessary revenue certainty in light of the hybrid regulatory structure that currently exists in Michigan.

Recovery of Financing Costs During Construction (CWIP)

The Commission policy should allow Construction Work in Progress (CWIP) without the Allowance for Funds Used During Construction (AFUDC) offset as the new base load plant is being constructed. This would reduce the financial uncertainty and overall financing costs of the facility while supplementing cash flow during the construction period. Placing these CWIP rate adjustments into effect throughout the construction cycle has the added benefit of phasing-in the rate impact on customers.

Competitive Bidding

The Commission should require an incumbent, regulated electric utility building new generation to competitively bid the engineering, procurement, and construction of any new generating facility.

If the Commission were to adopt a competitive capacity solicitation process, then it must be recognized that Michigan's incumbent electric utilities and IPPs are regulated by different entities. A capacity solicitation process entails the procurement of wholesale power for resale. As a result, a competitive capacity solicitation process may create state-federal regulatory policy conflicts.

Also in a competitive capacity solicitation process, IPPs would likely seek a long-term Purchase Power Agreement (PPA) with the incumbent utility. Rating agencies currently recognize PPAs as off-balance sheet debt and impute it into the capital structure. Additional equity capital would be required to maintain the same pre-PPA debt to equity ratio and credit rating. The incumbent utility must be able to earn a return on the additional equity capital required to maintain a balanced capital structure and which would also provide a financial incentive to contract rather than build.

Investment in Existing Generation

The Fitch report highlights the risk to utilities in making additional investments in existing generation assets:

Investing in generation would potentially open the utility to additional stranded costs, whether associated with the old power assets or the new assets. (emphasis added)

As long as the current hybrid regulatory structure remains in Michigan, investments in base load generation, whether new or existing, are at risk. As previously mentioned, as new base-load capacity is added in Michigan, the market price for energy will likely decline. This decline in price will only serve to lower the value of existing generation and increase the prospect of additional stranded cost.

Adopting new regulatory policies to provide revenue certainty to facilitate new generation investment creates substantial economic and financial risk distinctions between new and existing generation with existing generation clearly at risk. Such a policy distinction will likely lead to unintended consequences whereby low cost capacity expansions on existing generating units are forgone for investment in new generating facilities that may be of lower financial risk due to inconsistent regulatory treatment.

It should be noted that for all their shortcomings, RTO- managed capacity markets have not distinguished between new and existing generation when applying capacity charges. The reason is that all capacity is required to provide system reliability. If new generation that provides only a small portion of the total supply reliability is deemed to be a public good, then the same must certainly be true for existing generation.

Michigan electric utilities have and will be required to make massive investments in environmental retrofits at existing coal-fired generating plants. It is not good public policy to treat large generation investments in Michigan differently for regulatory cost recovery purposes simply because one occurs in a new plant and another in an existing plant to preserve its operation. Without preserving existing capacity, Michigan will require much greater investments in new capacity.

Energy Efficiency

Energy efficiencies should be part of the overall strategy in addressing future generation needs within the state. Any programs adopted must be cost competitive with supply options.

Market Power

Public Act 141 addresses utility market power issues. Specifically, Section 10f states:

If, after subtracting the average demand for each retail customer under contract that exceeds 15% of the utility's retail load in the relevant market, an electric utility has commercial control over more than 30% of the generating capacity available to serve a relevant market, the utility shall do one or more of the following with respect to any generation in excess of that required to serve its firm retail sales load, including a reasonable reserve margin: (a) Divest a portion of its generating capacity, (b) Sell generating capacity under a contract with a non-retail purchaser for a term of at least 5 years, (c) Transfer generating capacity to an independent brokering trustee for a term of at least 5 years in blocks of at least 500 megawatts, 24 hours per day.

It is important to recognize that the market power calculation and mitigation measures appear to conflict with the addition of new generating capacity in Michigan's hybrid regulatory structure. For instance, a situation may arise whereby a utility adds new generating capacity (or contracts to purchase power) to serve its customers' needs and subsequently, as customers migrate to alternative electricity suppliers, the utility would fail the market power calculation thereby requiring the utility to mitigate its market power through one of the means stated above.

Legislation

The foregoing regulatory policy changes would likely enable Michigan's incumbent, regulated electric utilities to construct new generation capacity to provide the long-term, least-cost generation supply for customers. However, these policy changes must be codified to insure the unequivocal legal authority to implement such policies. In addition, a future Commission cannot be bound by a decision of the current Commission without modification to existing statutes. Given the tremendous investment required in new and existing generation infrastructure in Michigan, and the long-term financial assurances required by the capital markets, legislation is necessary to ensure that future Commissions could not alter the policies of the current Commission after the investments are made by the electric utilities.



201 N. WASHINGTON SQUARE • SUITE 810
LANSING, MICHIGAN 48933

TELEPHONE 517 / 482-6237 • FAX 517 / 482-6937 • WWW.VARNUMLAW.COM

ERIC J. SCHNEIDEWIND

E-MAIL ejschneidewind@varnumlaw.com

TO: George Stojic

FROM: Eric J. Schneidewind

RE: Energy Michigan Comments on July 18, 2005 List of Capacity Need Forum Issues

DATE: August 1, 2005

Thank you for the opportunity to comment on the issues presented to the Capacity Need Forum steering committee on July 18, 2005. Following are the comments of Energy Michigan.

I. Introduction: The MPSC Staff List of Issues Ignores Competition As A Solution to Future Capacity Requirements

It is the position of Energy Michigan that any new power plant should be competitively bid for construction. Performance standards for long term operations should be designed into the bid contract. As this Commission questions how to best secure the next round of generation resources, the overriding guiding principle should be to ensure the least cost, most efficient, and most reliable resource is sought. The only way to reasonably ensure consumers are getting reliable, efficient and lowest cost power supply service is through a fair, transparent and reliable competitive solicitation.

Several options are available to the Commission to meet this objective of procuring the most efficient, reliable and least costly addition of generation supply to meet future demand of the public utilities:

- Power Purchase Agreements (PPAs) with longer-term commitments of up to 15 – 20 years.

August 1, 2005

Page 2

- Full-Requirement Service Agreements (FRSAs) where the utilities in Michigan can contract for energy, capacity and ancillary services to meet all of a utility's supply requirements above that which can be served by the capacity of the utility owned generation.
- Slice-of-system power purchases on a short- and longer-term basis where the utilities essentially auction portions of the load where competitive power suppliers compete to serve that demand at wholesale.
- Spot market purchases from the MISO energy markets.
- Utility self-build after a competitive assessment or RFP process in which an apples-to-apples comparison of risks / benefits and overall costs of the RFP proposals.

Regardless of the procurement option or combination of options pursued, regulatory uncertainty is detrimental for the MI consumer as it not only raises overall energy costs but also jeopardizes reliability.

Risk mitigation is greater under a competitive solution than under a utility-build only resource procurement model. Under a competitive solution, consumers and the public utility are insulated from a variety of risks including:

- Customer migration or load volatility (contracts for a load-following product are very commonplace in organized markets such as MISO);
- Volatility of fuel price changes;
- Construction and plant operating risks;
- Performance requirements including reliability standards;
- Flexible contracting;
- Environmental compliance; and

August 1, 2005

Page 3

- Protection of the utility's cost of capital.

These mitigated risks can result in lower overall rates for consumers for generation service and frees up the utility to invest its capital for other much-needed infrastructure investments such as transmission and distribution.

The Commission should review existing policy regarding competitive solutions such as longer-term PPAs and ensure that existing policy permits timely and certain recovery and/ or look at ways to compensate the utility for PPA financial risk through a cost-of-capital review. At the end of the day however, all generation capacity in the state should be fully exhausted and provided a level playing field so that Michigan consumers get the best deal.

II. Comment on Preapproval Concept

Preapproval should not be a code word for limiting generation construction opportunities to regulated utilities. Regulatory approvals for power plant cost recovery should be given only after there is a fair bid process that allows all interested parties to bid for the right to construct the required capacity. All generation, including any proposed rate-based self-build option by the utilities, should be subject to a market test in which multiple generators and suppliers can participate in to ensure that Michigan utility customers are getting the lowest cost, most efficient and reliable supply option. Such a bid process should include enforceable performance standards and proper risk allocation to make sure that costs are limited to the maximum extent possible. If the end result of the bid process is a guaranteed power sale contract with a utility or group of utilities, private capital can finance the required facilities without new legislation.

III. Revenue Certainty

It appears that revenue certainty is really a proposal for securitization type financing applicable to all the utility retail and Electric Choice customers. Evidently, Choice customers would be required to pay for a generation facility regardless of the fact that they derive no benefits as is currently the case with the securitized Fermi and Palisades plants.

August 1, 2005

Page 4

Energy Michigan opposes this concept. "Revenue Certainty" together with a preapproval process limited to a single utility build-own-operate option precludes the benefits of the market process such as competitive pricing, ability to obtain performance standards and transfer of the risks of development, permitting and operation cost overruns to developers instead of customers. Revenue Certainty under utility build-own-operate approach is nothing more than a new energy tax to fund otherwise uncompetitive generation plants.

Current securitization programs approved for Consumers Energy and Detroit Edison have added 5-10% to the cost of competitive power and are effectively eliminating competition in a high cost market.

Energy Michigan's preferred position is that the Commission should pursue a competitive solution to acquire new generation resources for utility load service obligations and the cost of procurement should be born by those customers taking the generation supply service from the utility. Sufficient retail rate design mechanisms have been established to protect both consumers and the utility from taking undue risk or subsidizing customer migration risk. Consumers who return to utility service must pay market-based pricing for a period before returning to utility tariff rates for a minimum stay period, which protects the utility from financial harm.

However, if funding guarantees are used, all customers who pay the non-bypassable charges should be allowed to bring a corresponding entitlement to the output of the generating plant with them to any supplier: utility or AES. Further, if a large new base load unit is needed and absolutely must be securitized, there should be full offsets to existing securitization charges and elimination of any stranded cost charges or other utility generation charges to AES customers on the grounds that such existing generating facilities cannot be stranded if new capacity is needed.

IV. Recovery of Financing During Construction

This concept appears to eliminate all utility responsibility for performance and cost risk. Moreover, it represents an unfair customer subsidy to the utility that not only penalizes customers but also is not available to competitors. Construction delays or increased financing costs become the risk of the customer rather than the risks of the utility. All incentives to

August 1, 2005

Page 5

eliminate or reduced those risks disappear or are greatly reduced. The current system of financing places those risks upon the utility and allows the utility to recover reasonable but not unlimited expenses plus profit.

In the era of MISO Day 2 markets, the risks of a poorly performing or overly expensive generating plant are magnified. If a generating plant has an uncompetitive cost structure due to price or reliability factors, it may become one of the least desirable units in order of dispatch. Such an outcome will result in reduction of income to cover operating or capital costs and these unrecovered costs will be transferred to captive ratepayers. Mechanisms that allow a utility to completely or largely avoid these risks virtually guarantee a transfer of such risks to captive customers: a very undesirable outcome.

V. Competition Is Being Harmed By Unpredictable Utility Charges

Since the passage of PA 141 Michigan's two largest electric utilities: Consumers Energy and Detroit Edison have proposed and obtained Commission approval to implement the following generation costs chargeable to Electric Choice customers who use no utility generation:

1. Securitization bond and tax charges.
2. Nuclear decommissioning costs.
3. Stranded cost charges.

The total cost of these charges currently ranges from about 5-10% of Choice power supply costs on the Consumers and Edison systems.

Both Edison and Consumers have currently petitioned the Commission to adopt new Regulatory Adjustment Charges (RACs) which would essentially recover lost generation revenue from Electric Choice customers in an amount equal to the retail rate minus a cost of service. The magnitude of these charges, together with the existing three charges numerated above would end Electric Choice service throughout this State because the charges are unaffordable under current market conditions.

August 1, 2005

Page 6

The end of Electric Choice will have several immediate and highly undesirable consequences for all customers on the Detroit Edison and Consumers Energy systems.

First, the approximately 2500 MW of Electric Choice service currently in operation has in effect reduced utility demand by a corresponding amount plus reserve margin.¹ If Electric Choice is priced out of existence, load equaling 2500 MW of demand plus the need for 12-15% reserve margins will migrate back to utility service thus increasing utility requirement for new generation capacity. If these new generation units are more expensive than current units in the rate base (very likely to be the fact) this migration will significantly increase electric rates above levels that would have been the case if the smaller amount of capacity additions indicated by the initial CNF reports is added by regulated utilities. The result will be a rate increase for all customers. This fact is confirmed by data from the recent Detroit Edison Case U-13808 in which even Edison witnesses testified that load reduction caused by Choice migration had allowed Edison to avoid approximately .3 ¢/kWh (about 4-5%) of power supply expenses.

Second, the substantial amount and unpredictability of proposed utility generation charges applicable to Choice has created substantial market uncertainty. Under these circumstances, potential Electric Choice suppliers, whether contracting for long term generation capacity or evaluating construction of generation capacity, are unable to predict the magnitude of demand due to the regulatory and economic uncertainty created by Michigan's electric utilities proposals for new stranded cost or lost revenue recovery and MPSC adoption of some of those proposals. Electric utilities have complained of load uncertainties created by competition as an impediment to their financing requirements. Consider the fact that these utilities are themselves creating an uncertainty which, from the perspective of a Choice supplier, could result in a loss of 100% of load within the year or so that the proposed RACs will be considered and acted upon by the Commission.

¹ See Detroit Edison and Consumers Energy filings in Case U-14414 dated 3/31/05.

August 1, 2005

Page 7

However, a significantly greater level of unpredictability is created by new proposed utility charges to Choice customers and uncertainty regarding the fate of those proposals at the Michigan Public Service Commission. Recent utility proposals for RAC charges and support of those proposals by MPSC Staff have cast doubt upon the long term prospects for Choice service in Michigan. The consequences of this doubt will be the loss of funding for new capacity to serve competitive markets as well as unpredictable migration of large Choice load back to the utility systems.

VI. Conclusion.

Virtually all of the alternatives presented by Capacity Need Forum Staff represent a substantial reduction or elimination of competitive forces in the financing and construction of needed generating capacity. Customers will suffer if competition is excluded from this process. In the new world of MISO Day 2 markets, inefficient, unreliable or overpriced generating capacity will face reduced markets. Inevitably, the loss of markets for such capacity will result in increased costs to captive customers. Competitive forces have been successful in increasing performance, reducing cost and enhancing reliability. Any policy which discards these desirable outcomes inevitably will raise the cost of energy in Michigan at a time when the State can ill afford increased costs in any sector.

**Indiana Michigan Power Company
Informal Comments in the Capacity Need Forum**

(1) Preapproval of used and useful status of new plant, along with investment cost.

I&M supports the use of regulatory proceedings to review new generating plants proposed to be built by utilities. The proceeding would provide the Commission with an opportunity to evaluate the need for the capacity, the projected costs of the proposed addition, and the alternatives to construction, including market options, alternate plant types, renewable options, and transmission options. If the Commission approved the construction, timely recovery of the construction costs, including any costs reasonably incurred beyond those projected, through a rate adjustment mechanism would be the appropriate means of mitigating the significant risks of constructing baseload generation. A good example of the process is found in the Indiana certificate of need law, IC 8-1-8.5.

(2) Revenue certainty.

The Fitch report accurately describes the general risks and associated costs of investing in new generation. The structure of Michigan's electric industry creates additional risks of building to serve customer load growth without knowing if that load will be the utility's responsibility once the plant is complete. Taken together, it is little wonder that investors are unwilling to invest billions of dollars unless the risks are somehow mitigated. Upfront review and approval of the project and a commitment to allow timely cost recovery provides more certainty and thus makes it more likely that the investment will be made. The greater certainty of cost recovery would significantly improve credit ratings, and thus reducing borrowing costs, which accrues to the benefit of customers.

(3) Level playing field between IPP's and incumbent utilities.

IPPs and utilities are not similarly situated in terms of the risks they face or the obligations they bear. Treating them exactly the same for the purpose of building new generation is not required so long as neither receives an undue preference when the Commission considers the various alternatives. IPPs should not be mandated to go through the pre approval process even if jurisdiction to do so could be found. While IPPs will assume the risk of investing without having a regulated customer base paying regulated prices, they also have the opportunity to earn larger economic rewards in the unregulated market.

Utilities in Michigan still have an obligation to serve even though the former paradigm of an exclusive customer base has disappeared. Utilities also face an implicit limit on the regulated return they can earn no matter how superior their operations might be. In exchange, they should be allowed to achieve certainty in recovery of costs reviewed and approved by regulators.

(4) Competitive bid process.

I&M uses competitive bidding when warranted by the circumstances to obtain the fuel supply and purchase power resources required to serve our customers. Competitive bidding is utilized for other acquisitions as required by the Company's internal control policies and procedures. However, it is not apparent that competitive bidding for all aspects of the construction of new generation, which may involve multiple procurement and construction contracts, will produce better results than present practices. All impacts and implications of adopting competitive bidding rules would need to be explored to avoid creating a system that unintentionally creates inefficiencies and causes higher costs in the long run. Last, it would

be inappropriate to require competitive bidding for the actual operation of new or existing generation because plant operations are the responsibility of the utility's management.

(5) Capital investment in existing generation should be included in policy change.

While generation-related capital investment does not generally warrant Commission review, new capital investment in existing generation could be considered as part of the review process when evaluating whether to build new generation to meet load growth. The purpose of the review would be to evaluate the available alternatives, as opposed to some kind of hindsight review of sunk costs already invested in existing generation.

(6) Compensation for capital costs.

The reasonable return on and timely return of investment (through depreciation rates and the inclusion of construction work in progress (CWIP) in rate base) is an essential element in investor confidence, credit risk, capital cost, and ultimately the build decision. Allowing the use of CWIP assures investors that they will receive timely recovery of the costs of new generation and, if properly accounted for, would reduce the rates paid by customers over time compared to the current policy.

(7) Efficiencies (energy) should be valued and included in the Commission's decision making process.

The Commission when evaluating the need for the project and the means to meet that need should consider all supply and demand side resource options. If the benefits of energy efficiencies and conservation measures are proven to exceed total program costs without an inflationary impact on customer rates, they should be considered along with supply side alternatives.