Energy-Intensive Industrial Rates Workgroup Report

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Presented by

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Acknowledgement

Thanks are due to all the workgroup participants for the time and effort they have contributed to the workgroup process and report. Likewise, the staff at the Michigan Public Service Commission provided valuable expertise and support to the workgroup participants and chair. While the options and recommendations provided in this report are not those of the MPSC staff, they provided valuable technical information and assistance regarding the development of this report.

Executive Summary

As part of Governor Snyder's vision for a "No Regrets" energy future, the Governor's stated goal was to ensure energy-intensive industries can choose Michigan for job and investment decisions, to better compete. As a first step toward reaching this goal, a workgroup of various stakeholders was formed to solicit feedback and input on what steps might be taken toward this goal within the current legislative framework, which among other things, requires that electric rates conform to the cost of service for each class. The workgroup participants identified many potential changes that would achieve the goal while conforming to cost-causative principles. Though electric rates are currently cost based with regard to PA 286, refinements can be made to better reflect cost causation principles that the participants believe more appropriately reflects the lower cost of serving certain types of industrial customers, thereby make Michigan more attractive to energy-intensive industries through competitive electric rates.

In summary, the group discussed and agree that the following items should be considered when evaluating future cost causation principles:

- Utilize a 4CP 100% demand electricity production cost allocator to better reflect cost causation
- Consider aligning current electricity transmission cost allocators with how the utilities are billed for transmission cost, such as a 12CP 100% demand
- Distribution rates that are based on cost-of-service by voltage level
- Distribution rates that consist of only demand charges and customer charges with no energy charges
- Provide a tariff for time-based rates
- Explore energy cost allocation and collection that reflect seasonal cost variations
- Explore rate designs that appropriately compensate customers with loads that can be curtailed during peak periods
- Calculate load factors[1] as 12 month averages
- Recovery of surcharges allocated and collected in accordance with all of the cost of service principles outlined in the report should be explored

The participants agree that rates need to be designed to recognize high load factor customers' benefit to the system, and that coincident peak allocations, demand response programs, and distribution cost allocations should all be examined by the Commission and other affected parties, whether through a contested case or other Commission action.

The business participants further agree that market-based rates, separating transmission costs from the PSCR, capacity cost benchmarking, and individual coincident peak allocations should also be explored.

[1] The load factor for a customer, customer class, or system is the ratio of actual electric energy consumption during a given time period to the consumption that would have occurred had consumption been fully sustained at the peak (maximum) demand level during the same period of time.

The analysis and figures provided by the utilities herein are merely illustrative and have not been reviewed or confirmed by any other parties. However there is an expectation that the analysis and figures are indicative of the level of rate improvement that can be achieved.

Purpose

As part of Governor Rick Snyder's vision for a "No Regrets" energy future, this workgroup was initiated to get energy-intensive industrial customers' views on how one of the Governor's goals could be met, to "ensure energy-intensive industries can choose Michigan for job and investment decisions, to better compete." In order to help achieve the Governor's goal, the workgroup was formed to identify non-legislative options that can reduce electric rates for energy-intensive companies, while abiding by existing laws, including cost-of-service principles.

Regulatory cost-of-service principles dictate costs should follow causation; that is, when the actions of a customer impose a cost on the system, the costs should be, as well as can be managed, allocated to and collected from that customer. The current cost-of-service methodology utilized by Michigan's largest utilities was prescribed by 2008 PA 286, which specified electricity production and transmission costs be allocated on the basis of 50% demand, 25% on-peak energy usage, and 25% total energy usage. The same law, however, allowed for changes to this methodology in order to better reflect cost-causation principles, as long as such a change did not negatively impact primary customers. The production costs which are currently allocated using the prescribed methodology are far more demand-related, and should be re-allocated as such to follow the principles the law dictates. Similarly, rates should follow these same cost-causation principles; if a cost is associated with an action, the rate charged for the action should reflect its cost as allocated.

Many industrial customers use electricity differently from residential or commercial customers. Industrial customers tend to use electricity more consistently throughout the year, as well as throughout the day. Where the electricity usage of residential and commercial customers tends to be very sensitive to weather and time of day, the electricity usage of industrial customers is much less sensitive to these factors, instead depending more on shifts, processes, and shut downs. As a result, industrial customers tend to have better load factors, which impose fewer capacity costs on the system relative to energy costs. Facilities have to be built or maintained or capacity purchased to supply peak demand (regardless of the demand or energy at other times), and peak power tends to be the most expensive power. Thus, the bigger the peak, the greater short and long-term costs for all customers served by a utility. Failing to sufficiently account for cost-causative principles regarding this peak load in cost allocations and rate design can impose an inappropriate burden on customers with smoother loads, and also fails to incentivize the "load smoothing" that can reduce costs for all customers. Additionally, customers with loads that can be curtailed during peak periods (and thereby reduce total load to the system and reduce costs to all customers) need to be appropriately compensated in the rate design.

For energy-intensive industrial customers, electricity costs are a major expense that can dramatically affect decisions regarding where to locate and grow. With Michigan's talented workforce, improved tax climate, a resurgent economy and strong manufacturing sector, companies are again considering Michigan as an ideal location to locate or expand their facility. By making electricity prices more competitive for many industrial customers by appropriately reflecting cost causation in utility allocation and rate design, Michigan has a much improved chance to compete for these projects. This would lead to greater investment, employment, tax revenue for the state and local communities, and a higher utilization of Michigan's energy generation assets which ultimately helps provide lower electricity rates for all customers.

Process

The workgroup formed to address the Governor's mandate consisted of business decision makers representing two large utilities, a representative from the Michigan Electric & Gas Association (MEGA), a representative from the Michigan Electric Cooperative Association (MECA), and ten energy-intensive business customers from a broad range of industries and geographic locations, and staff members from the Michigan House, the Michigan Senate, the Michigan Public Service Commission (MPSC), and was chaired by Steve Bakkal of the Michigan Economic Development Corporation (MEDC).

On March 24, an informational meeting was held at the MPSC to announce the workgroup process and solicit businesses to serve on the workgroup. Utility and legislative representatives were selected by direct outreach. In addition, MPSC Staff were selected to act as technical advisors to the chair. Business customers were given the opportunity to nominate themselves or other businesses on the State of Michigan's energy web page from March 24 – 31, 2014. Business customer nominees were asked to submit a brief description of relevant experience and general knowledge of the regulatory process, topics, respective industry needs, and challenges. Preference was given to nominees who were recognized by multiple industry peers. The business members selected to participate in the workgroup were contacted directly by April 2, 2014. The selections were posted on the Michigan energy web page under the workgroup page. The Energy-Intensive Industrial Rates Workgroup was comprised of the following parties:

MEDC & MPSC
Steve Bakkal – MEDC
Dan Blair – MPSC
Steve McLean - MPSC

Utility Representatives
Don Stanczak – DTE Energy
Stephen Stubleski – CMS
Jim Ault - MEGA
Kim Molitor - MECA

Legislative Staff
Greg Moore
Dan Dundas

Business Customers
George Andraos - Ford Motor Company
Mike Binion - Gerdau Special Steel North America
Steve Brooks - Verso Paper Corp
Keith Tyson Kenebrew - Dow Chemical Company
Richard Nelson - Praxair, Inc.
Gerrit Reepmeyer - Severstal North America
Jennifer Steiner-Burner - Marathon Petroleum Company LP
David Stoner - United States Steel Corp
Daniel Voss - General Motors Company
Rod Williamson - Dow Corning Corporation

The workgroup met four times, bi-weekly on Mondays between April 7th and May 19th, 2014 at the Michigan Public Service Commission. After each meeting, the involved parties were asked to complete assignments for discussion in the following meeting. The workgroup developed, analyzed, and came to an agreement on several potential options, as well as areas for further review.

Discussion and Findings

During the workgroup's meetings, the participants discussed many ways to meet the Governor's goal, some of which were within the scope of the group, some without. Many areas of agreement were reached; some ideas had support from participants but no consensus, and others the group lacked sufficient time or information to decide.

Areas of Agreement

The participants agreed on several aspects of cost allocation and rate design that should be considered within current policy to better reflect cost-causative principles.

Cost allocation is the process by which it is decided which and/or what portion of a utility's costs various groups of similar customers (called rate classes) are responsible for. The process used by utilities and other participants in cases before the MPSC is referred to as a Cost of Service Study (COSS). Generally, there are four major rate classes, of which three are consistent across utilities. These are residential, commercial/secondary, and industrial/primary. The utilities' costs are also broken into three major categories (or functions); production, distribution, and transmission. Additionally, the production function has two major subcategories, generation plant investment and the demand-related portion of purchased power expense, and fuel and the energy-related portion of purchased power expense. In a utility general rate case, costs are first functionalized, or split into the categories listed above. These functionalized costs are then classified as customer-, energy-, or demand-related. Finally, these costs are allocated to the customer classes. The two major allocators discussed in this report are those relating to (1) production plant, non-fuel production operations and maintenance expenses, and demand-related purchased power expense, hereinafter referred to jointly as "production", and (2) transmission expense. Demand, for the purposes of these allocators, is identified as #CP, where CP stands for "coincident peak", or the highest load on the system as a whole, and the # represents the number of monthly coincident peaks averaged. For example, 4CP uses the four highest monthly coincident peaks averaged as the demand measure. For the two largest utilities in the state, demand is currently defined as 4CP for Consumers Energy's production and 12CP for DTE Electric's production and both companies' transmission, with all of these allocators utilizing the 50-25-25 method.

In Michigan, the peak demands occur during the four summer months, which require either using the highest coincident peak ("CP") monthly demand or the average of the four highest CP demands experienced during the year in order to be consistent with cost of service principals. Establishing rates on this basis will send price signals that it is more costly to consume electricity during peak periods than other periods. However, during non-peak periods, the non-summer months, it is appropriate to send a signal to maximize the use of the utility's transmission and generation assets.

The utilities modeled the monetary effect on the various classes of several COSS and rate design scenarios discussed by the participants designed to more appropriately reflect costs and their causation.

The COSS scenarios modeled were changing the production allocator to 4CP 75/25 (75% demand, 25% energy), 4CP 100 (100% demand), and changing the transmission allocator to 12CP 100. These scenarios were chosen because they allocate costs based on what actually causes utilities to incur the cost - demand. The potential effects of these changes are shown in the tables below.

Consumers Energy Company				
COSS Allocation Changes				
(thousands of dollars)				
Line	Description	Residential	Secondary	Primary
	Current Rates (U-17087)			
1	Prod 4CP50/25/25, Trans 12CP 50/25/25	$ 1,753,453	$ 974,566	$ 1,112,510
2	Prod 4CP75/25, Trans 12CP 50/25/25	1,769,384	980,419	1,092,954
3	% change from current	0.91%	0.60%	-1.76%
4	Revenue change from current	15,931	5,853	(19,556)
5	Prod 4CP100, Trans 12CP 50/25/25	1,794,150	977,727	1,072,174
6	% change from current	2.32%	0.32%	-3.63%
7	Revenue change from current	40,697	3,161	(40,336)
8	Prod 4CP50/25/25, Trans 12CP 100	1,764,421	973,496	1,102,792
9	% change from current	0.63%	-0.11%	-0.87%
10	Revenue change from current	10,968	(1,070)	(9,718)
11	Prod 4CP100, Trans 12CP 100	1,805,044	976,661	1,062,521
12	% change from current	2.94%	0.21%	-4.49%
13	Revenue change from current	51,591	2,095	(49,989)

DTE Electric Company				
COSS Allocation Changes				
(thousands of dollars)				
Line	Description	Residential	Secondary	Primary
	Current Rates (U-16472)			
1	Prod 12CP 50/25/25, Trans 12CP 50/25/25	$ 2,232,400	$ 1,099,900	$ 1,585,100
2	Prod 4CP 75/25, Trans 12 CP 50/25/25	2,276,700	1,108,400	1,537,200
3	% change from current	1.98%	0.77%	-3.02%
4	Revenue change from current	44,300	8,500	(47,900)
5	Prod 4CP 100, Trans 12 CP 50/25/25	2,292,500	1,115,100	1,516,000
6	% change from current	2.69%	1.38%	-4.36%
7	Revenue change from current	60,100	15,200	(69,100)
8	Prod 12CP 50/25/25, Trans 12 CP 100	2,242,700	1,101,800	1,573,200
9	% change from current	0.46%	0.17%	-0.75%
10	Revenue change from current	10,300	1,900	(11,900)
11	Prod 4CP 100, Trans 12CP 100	2,302,700	1,116,900	1,504,100
12	% change from current	3.15%	1.55%	-5.11%
13	Revenue change from current	70,300	17,000	(81,000)

Line 1 represents the costs allocated to each class as of each utilities' last rate case. Line 2 represents the costs that would have been allocated to each class in the last rate case if the production allocator had been 4CP 75/25, while lines 3 and 4 represent the corresponding percentage change and revenue change from the last rate case's allocations respectively. Line 5 represents the costs that would have been allocated to each class in the last rate case if the production allocator had been 4CP 100, while lines 6 and 7 represent the corresponding percentage change and revenue change from the last rate case's allocations respectively. Line 8 represents the costs that would have been allocated to each class in the last rate case if the transmission allocator had been 12CP 100, while lines 9 and 10 represent the corresponding percentage change and revenue change from the last rate case's allocations respectively. Line 11 represents the costs that would have been allocated to each class in the last rate case if the production allocator had been 4CP 100 and the transmission allocator had been 12CP 100. Lines 12 and 13 represent the corresponding percentage change and revenue change from the last rate case's allocations respectively. As an interpretive example, changing the DTE Electric production allocator from what was approved in the last case to 4CP 75/25 would have resulted in $47.9 million less in costs being allocated to the primary class, which is 3.02% percent lower.

Production Costs

Based on the COSS scenarios run by the utilities the participants agree the production cost allocator should be changed from a 4CP/12CP 50%/25%/25% production allocator to a uniform 4CP 100% demand production allocator. The 4CP allocator (which is based on a class' contribution to the utilities' highest four monthly coincident peaks) is the correct allocator to utilize for allocating fixed production costs.

The Michigan utilities have been and continue to be predominantly summer-peaking utilities. It is the summer demands which drive the need to build or purchase additional capacity.

A review of the utilities' historical monthly coincident peaks and forecasted monthly peaks clearly indicate the utilities are summer peaking utilities. Looking at the average of the four monthly peaks historically indicates, for the summer months, the highest average monthly peak is at least 85% of the highest peak demand experienced during a year.

If a utility must acquire additional capacity, this will result in higher rates to customers. Therefore, it is critical that proper price signals are sent to customers so they can respond to those signals by consuming less electricity during critical peak periods. Because the fixed capacity costs are driven by the summer peaks, it is appropriate to allocate these costs based on those same summer peaks.

Transmission Costs

The participants recommend the transmission allocator should be changed from a 12CP 50%/25%/25% to a 12CP 100% demand allocator. The MPSC does not regulate how transmission costs are allocated to DTE Electric and Consumers Energy. The Federal Energy Regulatory Commission ("FERC") establishes how the transmission costs are allocated to each of those utilities. A review of the transmission and Energy Information Administration expenses indicates over 90% of the transmission costs are allocated or assigned to DTE Electric and Consumers Energy based on 12CP demands. That is, those costs are incurred by each of those utilities based on demands, and not energy. Therefore, from a cost-causation standpoint, the participants agree that it's appropriate to allocate those costs to the various rate classes utilizing the same methodology as how the utilities are billed for these transmission cost (currently a 12CP 100% demand allocator). For clarification, in Michigan all utilities are billed for transmission costs under a FERC approved tariff rate. In the future if the FERC approved tariff is changed (for example such that utilities are billed for transmission cost on 4CP 100% demand), then the utilities should collect the transmission cost from customers utilizing this same methodology. If the costs are not allocated in this manner, rate classes will be providing a subsidy to other rate classes or will be subsidizing or receiving a subsidy. Specifically, if the allocator contains an energy component, then those customers with an above-average load factor will be subsidizing the other customers. This is not consistent with current Michigan law and with sound ratemaking principles.

Distribution Rates

The participants recommend that the distribution rates should be based on cost of service by voltage level. If the distribution rates are not based on voltage level, it is possible customers who are not utilizing a portion of the system would be paying rates in excess of what it costs to serve them. For example, if rates for customers taking service at transmission-level voltage are set above cost of service, a customer who takes service at the transmission voltage level would be providing a subsidy to customers who take service at subtransmission and/or primary voltage levels. That is, a transmission customer would be paying a cost for an investment it is not using and is not necessary to provide service. Conversely, if the transmission rates are too low, the subtransmission and/or distribution customers would be providing a subsidy to its transmission customers. In that instance, a transmission customer would not be paying its full cost of service and would not be receiving a proper price signal which could lead to over consumption. Rates should reflect cost-causation principles. That is, if you cause the cost, then you should be charged for that cost.

DTE Electric modeled the impact of moving to distribution rates by voltage level; Consumers Energy already allocates distribution costs by voltage level, though within the already existing COSS classes. The participants agree that voltage level is an appropriate way to split customers in groups causing like costs for distribution plant and expenses. For the purposes of this analysis, DTE Electric utilized the following classes: Residential-Secondary, Commercial-Secondary, Commercial/Industrial-Primary, Commercial/Industrial-Subtransmission, and Commercial/Industrial-Transmission. The monetary effects on the classes are shown below.

DTE Electric Company				
Voltage Level Cost of Service Impacts				
(Base Distribution Charges only)				
($ Millions)				
	Current Allocation U-16472	Voltage Level COSS	Change	Percent Change
Residential-Secondary	$922	$939	$17	1.8%
Commercial-Secondary	$309	$295	($14)	-4.5%
Commercial/Industrial-Primary	$101	$101	$0	0.0%
Commercial/Industrial-Substransmission	$9	$8	($1)	-11.1%
Commercial/Industrial-Transmission	$15	$14	($1)	-6.7%

As shown by the table, a voltage level-based COSS would have resulted in approximately $1 million less in costs being allocated to commercial or industrial customers taking service at transmission voltage, which would have been a reduction of 6.7%.

In addition to distribution rates by voltage level, the participants recommend primary distribution rates should consist only of demand charges. The National Association of Regulatory Utility Commissioners ("NARUC") published an Electric Utility Cost Allocation Manual ("Manual") in January 1992. This Manual is still relied upon in cases before the MPSC. This Manual addresses the classification and allocation of distribution costs. The cost recovery of distribution plant and the distribution expenses are only demand-related and customer-related. None of the distribution costs are classified by NARUC as energy-related. As a result, the manner in which those costs are allocated to the various rate classes should also be used to design the rates. That is, the distribution charges for the demand-related cost should all be recovered through a demand charge. To do otherwise would result in those customers with a higher load factor subsidizing customers with a lower load factor. It should be noted that generally the customer-related charges are recovered through a customer charge. In any event, recovery of distribution costs through energy charges is not consistent with sound ratemaking principles and does not reflect fundamental cost-causation principles.

Rate Design Factors (Load Factor, Average Demand and Load Factor Percentage)

The workgroup participants expressed a desire to use a consistent method of determining customer load factors when it is used for qualifying customers for participation under certain high load factor rates. The business participants agree that for purposes of designing retail rates the load factor should be based upon the average of the 12 coincident peak load factors established for each customer class. The average demand would be calculated by dividing the kilowatt hours used in a particular month by the number of hours in the month. The load factor percentage would be calculated by dividing the average demand by the peak demand for each month.

The utilities determine customer load factor by using the customer's 12 monthly average on-peak demands or the customer's annual maximum demand. The average on-peak demand or the maximum demand is then multiplied by total hours in the year to determine the total potential energy use by the customer. The customer's actual annual energy use is then divided by the total potential energy use to obtain a load factor percentage.

Cost studies conducted by the utilities confirm that higher load factor customers are less costly to serve on a per kWh unit. Rate designs can reflect the lower per unit cost of high load factor customers by establishing higher demand (capacity) charges relative to per kWh energy charges, thus lowering the per unit cost of electricity.

Time-of-Use Rates

The participants agree that time-of-use based rate design should be considered and offered where appropriate. Time-based rates reflect the fact that there are higher energy costs during the on-peak periods and lower costs during the off-peak periods. By having a time-based rate option, customers will be receiving proper price signals as to the energy cost that the utilities are incurring to serve the load. By receiving proper price signals, customers can take action to reduce load during the high cost periods and increase loads during the low cost periods.

Time-based rate design could also apply to the collection of demand-related fixed costs. Currently, the rates that are in effect for the major utilities contain an on-peak and off-peak time of day period. It is in the on-peak period that the maximum demand a customer imposes is used to develop the charges for the recovery of fixed production cost. Therefore a time-based rate design could have a higher on-peak and lower off-peak demand charge. This demand-based rate design option may exist regardless of whether there are time-of-use energy rates.

Similar to time of use based rates the participants recommend the allocation of energy costs, as well as their collection, could reflect the seasonal variations in such costs. Customers using relatively more energy during high cost times of the year under this type of rate design would pay proportionately more of the total energy costs.

Areas for Further Review

Certain of the ideas discussed by the workgroup, while within the scope of the workgroup, did not result in a consensus, whether due to lack of agreement among the participants or a lack of sufficient information.

Load Factor Rate Designs

High load factor customers benefit the system and are more efficient to serve than low load factor customers. The presence of high load factor customers in an electric utility system reduces the fixed cost responsibility of all customers. High load factor customers also more efficiently utilize production capacity by consuming more energy for each megawatt of peak demand than low load factor customers. As such, the costs to serve high load factor customers are less than the costs to serve low load factor customers. High load factor customer rates should reflect the costs to serve high load factor customers. Retaining and attracting high load factor customers through appropriate cost of service rates will result in lower rates for all customers.

In response to the participants' agreement that high load factor customers are a benefit to the system the utilities modeled several rate design scenarios to better recognize that benefit. However, there was no consensus agreement regarding the customer's qualifications for any such rate designs.

DTE modeled two rate design scenarios that also involved changes to the classes utilized in the COSS. One split high load factor customers into their own class and rate, rate DX, and the other combined all primary customers into one class, rate DN. DTE assumed rate DX would include customers with load of 2.5 MW or above, with 50% load factors or greater. The monetary effects on customers in DX and those remaining in the primary class, which includes the allocation changes to 4CP 100 for production and 12CP 100 for transmission, are shown below.

DTE Electric Company						
Rate Design Changes						
(thousands of dollars)						
Line	Description	Residential	Secondary	Total Primary	Rate D6/6.1/DN	Rate D7/DX
	Current Rates (U-16472)					
1	Prod 12CP50/25/25, Trans 12CP 50/25/25	$ 2,232,400	1,099,900	1,585,100	848,500	321,500
2	Average Rate	$ 0.1538	0.1219	0.0837	0.0850	0.0769
3	Average Rate by Load Factor	50% LF @ Trans. Voltage			0.0980	0.0940
4		70% LF @ Trans. Voltage			0.0850	0.0810
5		90% LF @ Trans. Voltage			0.0780	0.0750
6	Rate DX	$ 2,301,400	1,117,700	1,503,972	699,818	564,100
7	Average Rate	$ 0.1585	0.1240	0.0793	0.0848	0.0718
8	Average Rate change from current	$ 0.0048	0.0021	(0.0044)	(0.0002)	(0.0051)
9	% Average Rate change from current	3.09%	1.69%	-5.29%	-0.22%	-6.69%
10	Average Rate by Load Factor	50% LF @ Trans. Voltage			$ 0.0870	0.0830
11		70% LF @ Trans. Voltage			0.0740	0.0700
12		90% LF @ Trans. Voltage			0.0670	0.0640
13	Rate DN	$ 2,302,500	1,116,200	1,504,200	1,250,100	
14	Average Rate	$ 0.1586	0.1238	0.0793	0.0776	
15	Average Rate change from current	$ 0.0048	0.0019	(0.0044)	(0.0074)	
16	% Average Rate change from current	3.14%	1.57%	-5.27%	-8.70%	
17	Average Rate by Load Factor	50% LF @ Trans. Voltage			$ 0.0830	
18		70% LF @ Trans. Voltage			0.0720	
19		90% LF @ Trans. Voltage			0.0650	

Lines 1-5 represent the result of the most recent rate case, where line 1 is the amount allocated to each class or rate schedule listed, line 2 is the average rate for the entire class or rate, and lines 3-5 are the average rates by load factor. Lines 6-12 represent the effect of the creation of the DX rate, where line 6 is the amount allocated to each class or rate, line 7 is the average rate for the entire class or rate schedule, line 8 is the change in the average rate for each class from the last case, line 9 is the percentage change in the average rate for each class, and lines 10-12 are the average rates by load factor. Lines 13-19 represent the effect of the creation of the DN rate, where line 13 is the amount allocated to each class or rate, line 14 is the average rate for the entire class or rate schedule, line 15 is the change in the average rate for each class from the last case, line 16 is the percentage change in the average rate for each class, and lines 17-19 are the average rates by load factor.

Consumers Energy modeled several rate design scenarios. One, rate HLF, was very similar to the rate DX scenario run by DTE, but with a cutoff of 70% for load factor rather than 50%. Consumers Energy also ran a Wright rate design scenario, which has energy rates declining in tiers with more kWh used per kW; a power supply capacity rate design scenario, which has all demand-related power supply costs collected through demand charges; and a capacity rate design scenario, which has all demand-related costs for both power supply and distribution collected through demand charges. The monetary effects of these proposals are shown below.

CONSUMERS ENERGY COMPANY						CE RateComparisonSummary 04 30 14 with GPD diff			
ENERGY INTENSIVE INDUSTRIAL RATES WORK GROUP									
SUMMARY								4CP 100 Prod Alloc	
					4CP 50/25/25 Prod Alloc, 12CP 50/25/25 Trans Alloc			12CP 100 Trans Alloc	
					Alternative Rate Designs				
		Monthly	Annual			PS Capacity	Capacity	HLF Rate Design	
	LF	kW	kWh	Rate GPD	Wright	Rate Design	Rate Design	GPD	HLF
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Average Electric Rate (cents per kWh)									
Voltage Level 1									
High Load Factor (90%)	90%	1,000	7,884,000	7.08	6.41	6.40	6.28		6.48
Medium Load Factor (80%)	80%	1,000	7,008,000	7.27	6.73	6.75	6.64		6.73
Medium Load Factor (70%)	70%	1,000	6,132,000	7.52	7.15	7.19	7.11		7.06
Low Load Factor (60%)	60%	1,000	5,256,000	7.85	7.70	7.78	7.73	7.37	
Low Load Factor (50%)	50%	1,000	4,380,000	8.31	8.35	8.61	8.60	7.83	
Low Load Factor (40%)	40%	1,000	3,504,000	9.00	9.49	9.85	9.91	8.52	
Voltage Level 2									
High Load Factor (90%)	90%	1,000	7,884,000	7.87	7.11	7.35	7.18		7.18
Medium Load Factor (80%)	80%	1,000	7,008,000	8.08	7.43	7.74	7.62		7.46
Medium Load Factor (70%)	70%	1,000	6,132,000	8.36	7.85	8.24	8.19		7.82
Low Load Factor (60%)	60%	1,000	5,256,000	8.72	8.41	8.91	8.95	8.16	
Low Load Factor (50%)	50%	1,000	4,380,000	9.24	9.07	9.84	10.02	8.68	
Low Load Factor (40%)	40%	1,000	3,504,000	10.01	10.21	11.24	11.61	9.45	
Voltage Level 3									
High Load Factor (90%)	90%	1,000	7,884,000	8.77	7.87	8.01	7.66		8.52
Medium Load Factor (80%)	80%	1,000	7,008,000	9.01	8.19	8.50	8.21		8.82
Medium Load Factor (70%)	70%	1,000	6,132,000	9.32	8.59	9.13	8.91		9.22
Low Load Factor (60%)	60%	1,000	5,256,000	9.74	9.14	9.97	9.85	9.61	
Low Load Factor (50%)	50%	1,000	4,380,000	10.32	9.78	11.14	11.17	10.20	
Low Load Factor (40%)	40%	1,000	3,504,000	11.20	10.89	12.91	13.14	11.07	
Percent Change from Rate GPD									
Voltage Level 1									
High Load Factor (90%)					-9.5%	-9.6%	-11.3%		-8.5%
Medium Load Factor (80%)					-7.4%	-7.2%	-8.6%		-7.4%
Medium Load Factor (70%)					-4.9%	-4.4%	-5.4%		-6.1%
Low Load Factor (60%)					-1.9%	-0.8%	-1.5%	-6.1%	
Low Load Factor (50%)					0.6%	3.7%	3.6%	-5.8%	
Low Load Factor (40%)					5.4%	9.5%	10.1%	-5.3%	
Voltage Level 2									
High Load Factor (90%)					-9.7%	-6.6%	-8.8%		-8.7%
Medium Load Factor (80%)					-8.0%	-4.2%	-5.7%		-7.7%
Medium Load Factor (70%)					-6.1%	-1.4%	-2.0%		-6.5%
Low Load Factor (60%)					-3.6%	2.1%	2.6%	-6.4%	
Low Load Factor (50%)					-1.9%	6.5%	8.4%	-6.1%	
Low Load Factor (40%)					2.0%	12.3%	16.0%	-5.6%	
Voltage Level 3									
High Load Factor (90%)					-10.2%	-8.7%	-12.6%		-2.9%
Medium Load Factor (80%)					-9.1%	-5.7%	-8.9%		-2.1%
Medium Load Factor (70%)					-7.8%	-2.1%	-4.4%		-1.1%
Low Load Factor (60%)					-6.2%	2.3%	1.2%	-1.3%	
Low Load Factor (50%)					-5.3%	8.0%	8.2%	-1.2%	
Low Load Factor (40%)					-2.7%	15.3%	17.4%	-1.1%	

The table shows the effect of Consumers Energy's various proposals on a range of customer load factors across the three voltage levels available on rate GPD. The top section shows the average rate for each combination of load factor and voltage level on the current rate GPD, and under each of the alternative rate design scenarios. The bottom section shows the percentage change each alternative scenario represents from the current rate GPD for each combination of load factor and voltage level.

The industrial rate group participants did not reach a consensus on the rate design for higher versus lower load factor customers within the industrial class. All of the options put forward by the utility are viable, and recognize the benefit high load factor customers represent to the system, but the specifics of any given proposal will need to be vetted in the context of a contested case to ensure the adherence to cost-causative principles.

Cost Allocation

There were various discussions related to cost allocation apart from the Production and Transmission allocations discussed above. These vary from customer-specific cost allocations and market-based rates to simple changes in the way specific distributions costs are allocated in a cost-of-service study.

There was significant discussion amongst workgroup participants of individual CP related allocations. Various ideas were put forward on how this might be possible, including splitting those customers with a large enough demonstrated ability to respond to potential CPs by lowering their load that it might affect the utilities' CP, and thereby the allocation of related costs to the customer and the utility as a whole, into a separate class. The utilities stated an appropriately designed demand response program may have a similar effect, but some participants were interested in both ideas.

While there was not sufficient information to make a detailed recommendation, the participants agree a demand response rate or program appropriately based on costs avoided by the demand reduction supplied by a customer should be considered.

Some participants expressed interest in further examining the allocation of distribution costs. While distribution costs are demand related and could therefore be allocated on a demand basis, not all distribution costs are incurred by all classes of customers or by individual customers. Distribution rates should reflect only the costs of distribution facilities used to provide service. However, there was not enough time to properly examine these allocations. The participants agree these allocations should be further reviewed in the context of a contested case proceeding to ensure the allocations appropriately reflect cost-causation.

Other

There was discussion about market-based or –indexed rates. Many business participants want to see such an option, with appropriate rates. Utilities do not agree that market based rates conform to cost-causative principles in today's market environment where electric commodity rates are predicated upon generation marginal costs (LMPs), and ignores actual generation costs and capital investments.

The business participants also agree more action is likely necessary to change the current legislative framework to reach the Governor's stated goal to ensure energy-intensive industry choose Michigan for job and investment decisions, but agree that the areas of agreement are a good first step to achieve that goal.

Additional Recommendations

Certain ideas discussed during the course of the workgroup were outside the scope of the workgroup, but the participants agree they are important to consider for future action. The participants believe overall utility cost of service, including capacity costs, in Michigan are higher than those of competing jurisdictions, and thus affect Michigan's ability to have competitive energy rates. Action to control long-term costs so Michigan's energy rates can be competitive, thereby making the state more attractive to energy-intensive industries and the jobs and other benefits they provide, should be considered.

Conclusion

The recommendations and options provided by the workgroup participants are a first step towards the Governor's goal of making Michigan's industrial rates competitive for energy-intensive industries within the current legislative framework. In addition, by better reflecting the causation of costs in their allocation and collection, electric rates will send better price signals. This will result in more efficient use of the electric system, and potentially decrease costs for all customers in the future. The participants thank the Governor, the Legislature, and the Commission for this opportunity to have input for Michigan's energy future.