



WISCONSIN LEGISLATIVE COUNCIL
INFORMATION MEMORANDUM

**Customer-Owned Electric Generation: Opportunities for
Customers, Challenges for Utilities**

For more than a century, electric companies have been regulated as monopoly providers of a necessary public good. Under the long-standing “regulatory compact,” these companies act as monopolies under state and federal regulations that guarantee that the public receives reliable and adequate service at fair prices and that the companies recover the cost of providing the service and earn a fair return on their capital investments.

Technological advances in the generation, storage, and use of electricity are changing the relationship between electric utilities and their customers. These developments present substantial challenges to the utilities and the traditional regulatory paradigm, as customers are becoming, to varying degrees, producers, as well as users of electricity. In some cases, customers are leaving their utilities entirely. While this phenomenon is in its infancy, utility and consumer advocates alike see the potential for wide-spread customer-owned electric generation in the near future.

Policy makers are just beginning to grapple with the potential consequences of expanding customer-owned generation and to develop policy responses. Utilities are responding with new approaches to rates for electric service while advocates of energy conservation and renewable energy resources are responding with their own rate proposals and other policy options.

INTRODUCTION

Since the energy crisis of the 1970s and before, there has been an interest in alternative methods of generating electricity, including technologies for generating electricity at the point of use. The earliest end-user sited energy systems were the mills that converted water and wind power directly to work. These were followed by manufacturing facilities run on hydroelectric power and, later, by gas-fired turbines that co-generated electricity and steam for industrial applications.

Residential scale energy generation has been slower to develop. For a long time, it was limited largely to solar thermal applications for water and space heating. However, the installed cost of photovoltaic (PV) systems¹ has fallen steadily and substantially over the past 15 or more years, making PV increasingly cost-effective. The installed cost for systems smaller than 10 kW was

¹ Systems that convert sunlight directly to electricity.

approximately \$12/watt in 1998 and had fallen to about \$4.70/watt by 2013. The installed cost of larger systems is even less: in 2013, it was about \$4.30/watt for 10 to 100 kW systems and about \$3.70/watt for systems larger than 100 kW.² Indications are that this trend is continuing.

At the same time, advances are occurring in battery technology, driven in part by the development of batteries for electric vehicles. One innovation is the integration of an electric car into a home electrical system, charging the car's battery with PV panels during the day and drawing power from it at night (when the car is not in use). The advances in battery technology are expected to continue, as well.³

These developments offer residential electric customers opportunities not previously affordable. In some parts of the country, customers who are attracted by the "green" attributes of solar energy but have been dissuaded from installing PV systems because of the cost are now finding that the systems pay for themselves in a reasonable period of time. A report by the Rocky Mountain Institute and others (the RMI report),⁴ examines the cost of PV systems combined with storage batteries in comparison to the cost of electricity purchased from the incumbent electric utility. It concludes that "solar-plus-battery grid parity is already here or imminent for certain customers in certain geographies, such as Hawaii. Grid parity will also arrive within the next 30 years (and in many cases much sooner) for a much wider set of customers in all but regions with the cheapest retail electricity prices."

A report prepared for the Edison Electric Institute (the EEI report)⁵ identifies expansion of customer-owned generation as one among a number of what it terms "disruptive challenges" to the electric utility industry. Other challenges the report identifies are increasing interest in energy conservation (demand-side management, or DSM), government programs incentivizing selected technologies, slow economic growth, declining natural gas prices, and increasing electricity prices. The report states that these trends challenge the financial health of the electric utility industry: "Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality."

The EEI report expresses concern about what the RMI report terms "grid defection," the choice of individual utility customers to supply their own electricity and to sever both their physical connection to the electric grid and their business connection to the incumbent electric utility. The loss of these customers represents a loss of market share and of revenues. What is more, utilities recover the cost of major investments, such as base-load generating plants and high-voltage transmission lines, over terms of 20 to 30 years. If significant numbers of customers end

² Galen Barbose, et al., 2014, *Tracking the Sun VII, An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013*. Lawrence Berkeley National Laboratory.

³ At least one other technology is being pursued with similar results. So-called micro combined heat and power (CHP) systems use fuel cells, natural gas, or other fuels to generate electricity, capturing the waste heat for water and space heating. As with PV, if not more so, this technology is scalable to residential, commercial and industrial applications. See, for example, Brooks et al., 2013, *Business Case for a Micro-Combined Heat and Power Fuel-Cell System in Commercial Applications*, Pacific Northwest National Laboratory, U.S. Department of Energy.

⁴ Peter Bronski, et al., 2014, *The Economics of Grid Defection; When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Service*, Rocky Mountain Institute, et al.

⁵ Peter Kind, Energy Infrastructure Advocates, 2013, *Disruptive Challenges; Financial Implications and Strategic Responses to a Changing Retail Electric Business*, Edison Electric Institute.

their relationship with a utility, those customers are no longer contributing to this cost recovery. The EEI report expresses concern about the potential of this trend to increase the cost of credit for future utility investments and even to result in “utility stranded cost exposure” – the inability to recover past investments. The RMI report concurs, asserting that the loss of revenue that customer-owned generation could bring to electric utilities could render the traditional rate-based utility cost recovery mechanism obsolete, strand utilities’ capital investments, and undermine their traditional business models.

While much of the EEI report focusses on the effect of these trends on the utilities, it also highlights the effect on energy users who do not take advantage of the new opportunities of customer-owned generation. It makes two points, in particular. First, to the extent that electric rates and government programs subsidize the implementation of customer-owned generation, it is largely the non-self-generating customers who provide the subsidy. Second, as self-generating customers leave the grid entirely, fewer utility customers are left as a rate-base from which a utility can recover past and future investments in infrastructure.

Around the time the EEI report was released, the New York Public Service Commission was commencing a regulatory review titled, *Reforming the Energy Vision (REV)*.⁶ The study started from the premise that the electric industry is in the process of “momentous change” that presents opportunities and the need for regulatory change to realize those opportunities. In its order to staff, the commission identified two key questions:

- What should be the role of the distribution utilities in enabling system-wide efficiency and market-based deployment of distributed energy resources and load management?
- What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives?

In its draft State Energy Plan, the commission staff called on the commission to:

- Enable and facilitate new energy business models for utilities, energy service companies, and customers to be compensated for activities that contribute to grid efficiency.
- Maximize the cost effective utilization of all customer-sited resources that can reduce the need for new infrastructure through expanded DSM, energy efficiency, clean distributed generation, and storage.

In other words, this report calls for regulatory actions that would encourage and even compensate utilities and other entities that engage in distributed generation. In its February 26, 2015, “Order Adopting Regulatory Policy Framework and Implementation Plan” (the REV order),⁷ the commission states that REV “... aims to reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets. Distributed energy resources ... will be integrated into the planning and operation of electric distribution systems ...”.

⁶ *Reforming the Energy Vision (REV)*, New York Public Service Commission, Case 14-M-0101. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument>.

⁷ <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d>.

TRADITIONAL RATES AND RATE-MAKING

The following description of electric utility rates and rate-making is provided as background for later discussion of rate-based responses to the growing trend of customer-owned generation.

RATE-MAKING PRINCIPLES

There are many principles that regulators apply in rate-making, some based in state or federal law and others in historical practice. The federal Public Utilities Regulatory Policies Act of 1978⁸ requires state regulators to consider certain rate-making standards (essentially, rate designs) to be applied to achieve three purposes:

- Promoting end-use energy conservation.
- Ensuring efficient operation of public utilities.
- Ensuring equitable rates.

Other purposes, or principles, are often applied in rate-making, as well, such as ensuring that affordable service is available to all members of society and encouraging economic development by keeping utility costs low for customers. Individual commissions and commissioners give differing weight to these principles. Even where a principle is statutory, there is discretion in how individual commissioners interpret and apply it.

RATE-MAKING PROCESS

Developing electric utility rates typically consists of the following five general steps: ⁹

- *Determining the utility's revenue requirement.* The revenue requirement is the total amount of revenue that the utility needs in order to cover its operating costs and provide its investors with a PSC-approved rate of return on its capital assets.
- *Functionalizing operating costs* by attributing them to the utility's major functions of production, distribution, customer service and facilities, and administration.
- *Classifying operational costs* based on whether the costs are customer-based (necessary to serve an individual customer regardless of the customer's energy consumption), variable (dependent on the amount of energy the utility must supply), or fixed (constant regardless of the number of customers or the amount of energy supplied in the short run).
- *Allocating costs among customer classes* by determining whether the costs are necessary to serve residential, commercial, or industrial customers.
- *Designing specific rates* based on the foregoing steps and consistent with the rate-making principles described earlier.

⁸ 16 U.S.C. s. 2601, et seq.

⁹ Jonathan Lesser and Leonardo Giacchino, 2013, *Fundamentals of Energy Regulation*, 2d Edition, 176.

With each of these steps in this process, there are multiple approaches that can be taken and greatly varying results that can be produced.

The formal rate-making process begins with the submission of a proposed new tariff to the Public Service Commission (PSC) for approval. The proposal is analyzed by PSC staff and by interveners; staff develop alternatives for consideration by the PSC, while interveners develop alternatives based on their particular perspectives, which they advocate to the PSC. PSC staff summarizes the options presented by the applicant, interveners, and staff in a decision matrix, upon which the PSC makes its decisions regarding the rates it will approve.

RATES AND RATE DESIGN

Elements of Rates

There are myriad rate designs, an overview of which is beyond the scope of this Information Memorandum. However, certain elements and designs are briefly described here as background for the following discussion. Rates generally consist of the following kinds of charges:

- *Fixed charge.* This is a fixed dollar amount charged equally each billing cycle (usually a month) to each customer in a customer class.
- *Variable charge.* This is a charge that is based on the amount of energy used by a customer in a billing cycle. For electric service, this charge is billed in dollars per kilowatt-hour (kWh) of electricity used.
- *Demand charge.* This is a charge that reflects a customer's contribution to the need for (the customer's demand for) electric generation, transmission, and distribution facilities. A customer's demand is measured as the maximum amount of electricity the customer uses in a time period established in the utility's tariff (typically 15 or 60 minutes). The utility determines in which time period (in which 15 or 60 minute interval) the customer uses the most electricity; the demand charge is a dollar amount (specified in the tariff) multiplied by the amount of electricity the customer used in that interval of the customer's peak demand. There are two kinds of demand charges:
 - A *coincident demand charge* is based on a customer's peak demand when the system as a whole is at peak demand. This charge reflects the demand the customer places on the system as a whole, from generation of electricity to its transmission and delivery to the customer. When the system is already at its peak, what increment of capacity is needed to meet this customer's demand?
 - A *noncoincident demand charge* is based on a customer's peak demand at any time. If a customer's overall peak demand occurs when the system is at peak demand, that customer's coincident and noncoincident demand are the same. If a customer's peak demand occurs when there is spare system capacity, the noncoincident demand charge largely reflects the cost of the final delivery of electricity to the customer.

The *stand-by charge* is a special charge sometimes used by a utility to recover the cost of providing access (connection) to the utility grid for a customer who generally does not use utility service but who needs the security of having the service available, or a customer who does not need the service at a particular point in time but anticipates needing the service in the future.

Rate Designs

These charges may be combined in various ways. A rate may include multiple fixed charges, identifying the fixed costs the charges are designed to recover, or these may be combined in a single charge. The same is true of variable charges. A demand charge may substitute for a fixed charge or be in addition to it. Most rate structures include one or more variable charges in combination with one or more fixed or demand charges.

Rates have policy implications and often are designed explicitly for policy purposes.¹⁰ Rates with relatively high variable charges provide greater incentives for energy conservation than do rates with lower variable charges. Time-of-use and seasonal rates, which have higher variable charges at the time of day or during the season of a utility's peak demand, encourage customers to shift their energy use to lower demand periods; this not only saves the customer money, but makes more efficient use of the utility's facilities and reduces its need to build additional facilities. Other examples could be given.

Demand charges are a common element of rates for industrial and large commercial customers. Not only do these customers place large demands on the utility system, their demands vary greatly between customers. The demand charge is a tool to recover system costs from these large energy users in proportion to the costs they impose on the system. Demand charges generally have not been included in residential rates because, given the relatively little variation in demand within this class of customers, these costs can be recovered equitably in a fixed charge.¹¹

CUSTOMER-OWNED GENERATION

Elements of Rates

Electric generation equipment that a utility customer installs on his or her premises is variously called customer-owned, end user-sited, distributed, and parallel generation.¹² PURPA requires utilities to purchase electricity generated by what it terms qualifying facilities at a price equal to the utility's avoided cost. A "qualifying facility" is a facility with an electric generating capacity less than 80 megawatts that uses an energy source other than a fossil fuel or that cogenerates electricity and heat (usually as steam). The "avoided cost" is the cost the utility would have incurred to generate the electricity, had it not bought it from the qualifying facility. Most customer-owned generation is subject to this requirement of PURPA.

Parallel generation tariffs generally address matters such as the following:

- *Net metering.* This is the practice of crediting a customer for electricity put back into the utility's system, up to the amount of the customer's actual use, at the same price the utility charges the customer for electricity. It is an important factor in making the customer's generation system cost-effective.

¹⁰ The rate-making principles specified in PURPA are an explicit example.

¹¹ *Understanding Electric Demand*, ElectricGrid, undated, https://www.nationalgridus.com/niagaramohawk/non_html/eff_elec-demand.pdf.

¹² The abbreviation DG is often used to denote distributed generation, and utility tariffs applicable to customers with on-site generation are often identified as parallel generation tariffs.

- *Netting period.* This is the time period over which generation and purchases by a self-generator are netted. It is significant because electricity generated by the customer that off-sets electricity bought by the customer is credited at the retail price, whereas electricity the customer generates in excess of the customer's usage is sold to the utility at the utility's lower avoided cost. If a utility requires a customer to net electricity bought from and sold to the utility on a daily basis, the customer sees little benefit; on a cloudy day, the customer's PV system may provide little of the electricity the customer uses that day and off-set none of the electricity used that night. Netting over a month averages out sunny and cloudy days, giving the customer greater benefit. Netting on an annual basis provides even greater benefit to the customer, averaging seasonal variations in electricity generation and use.
- *Buy-back rate.* The price the utility pays a customer for electricity the customer generates in excess of what the customer uses is the buy-back rate. A higher buy-back rate, such as the utility's retail price for electricity, is more advantageous to the customer than a lower price, such as the utility's wholesale price.
- *Stand-by charges.* Some utilities impose additional, fixed charges on customers who install generating equipment on their premises. They are sometimes referred to as system or demand charges.
- *Interconnection requirements.* Utilities impose various requirements on customers who connect their own generation equipment to the utility's system. These requirements are necessary to ensure that the customer's equipment does not adversely affect the utility's system or create dangerous conditions for utility personnel when conducting maintenance on the system.

Third-Party Ownership

Many, perhaps most, individual utility customers, in whatever customer class, lack the technical expertise and, perhaps, the capital to install, operate and maintain an on-premises energy system. A class of companies, termed energy service companies (ESCOs), using various business models, will provide these services.¹³ Under some models, the ESCO operates equipment owned by its client; in other models, the ESCO owns equipment located on the client's property and sells the power to the client. These latter models are referred to as third-party ownership.

In Wisconsin, as in other states with fully-regulated electric utilities, the legality of the third-party ownership model depends on whether the third-party owner is a public utility. If it is a public utility, it must obtain a certificate of authority from the PSC, specifying a unique territory that it will serve, and it must provide its service to the public under PSC regulation. The Wisconsin Statutes define "public utility," in pertinent part, as a person "that may own, operate, manage or control ... all or any part of a plant or equipment, within the state, for the production, transmission, delivery or furnishing of heat, light, water or power either directly or indirectly to or for the public." [s. 196.01 (5) (intro.), Stats.] The Wisconsin Supreme Court has interpreted this definition on the basis of what constitutes the provision of service "to or for the public." In *Cawker v. Meyer* [147 Wis. 320, 324-25 (1911)], the court said that the "furnishing of power,

¹³ Milwaukee-based Johnson Controls is an example of an ESCO.

light, and heat to a few neighbors was incidental” and did not make a building owner who generated power for use in his building a public utility. The court went on to say: “Should plaintiffs, however, enlarge their field of service, it is by no means certain that they would remain exempt from the operation of the law.”

The PSC has not articulated a clear rule on when a third-party owner becomes a public utility but has applied the concepts articulated in *Cawker v. Meyer* on a case-by-case basis. There are circumstances where third-party ownership of electric generation equipment and sale of electricity to the occupant of the property is permissible. However, it appears clear that a person who offers that business model to any person requesting the service is offering utility service to the public and so will be considered a public utility. Since the state is entirely assigned into exclusive territories of electric utilities, current law does not allow such a public utility to be created.¹⁴

COST-EFFECTIVENESS AND “GRID DEFECTION”

In deciding whether to install electric generation equipment, a person will consider not just the up-front cost, but the time it takes for monthly cost savings from the system to equal the cost of the system, referred to as the payback period.^{15 16} The payback period, in months, is simply the total system cost divided by the monthly savings. The monthly savings is more complicated to determine but, in the simplest scenario, is the reduced energy purchased from the utility multiplied by the variable charge in the utility’s rates.

Two rate elements can increase the length of the payback period for a customer-sited generation facility:

- *Variable charge.* The smaller the variable charge, the longer it takes for cost savings resulting from energy savings to equal the system cost.
- *Stand-by charge.* If customers who install their own generation equipment are subject to a stand-by charge, which does not apply to other customers, only that portion of the monthly savings resulting from the generation equipment that exceed this charge contributes to recovering the cost of that equipment.

The RMI report states that “grid parity” exists in some localities and for some customers. This means that, for these customers, the cost of installing a complete, stand-alone electric system, consisting of generation equipment (such as PV), a storage system, and back-up generation, is no greater than the cost of receiving service from the incumbent electric utility. These are the customers for whom “grid defection” is a possibility without consideration of payback periods.

For a customer not at grid parity, the utility’s rate structure can have a significant impact on the decision to install generation equipment. A small variable charge (and the relatively high fixed charges that would accompany it) and a stand-by charge, together or separately, could have two,

¹⁴ February 28, 2012, letter from Robert Norcross, Administrator, Division of Energy and Gas, Public Service Commission, to Representative Gary Tauchen.

¹⁵ More sophisticated analyses will evaluate an investment on other bases, such as the net present value of the money to be invested.

¹⁶ Some customers will consider benefits other than monetary benefits in this analysis, including the value to the person of reduced reliance on carbon-based fuels or of greater energy reliability or independence.

very different effects on the customer's decision. They could result in an unacceptably long payback period for the customer, discouraging the customer from installing the equipment. Alternatively, if the fixed charge or stand-by charge, or both, are set too high, they could result in conditions in which it becomes cost-effective for the customer to install a stand-alone energy system and defect from the grid.

TRENDS IN ELECTRIC UTILITY RATES

Early electric utility rates used fixed charges largely to recover customer-related costs, recovering shared system costs through variable charges. By the middle decades of the 20th Century, electric utilities had largely adopted a declining block rate structure. These rates charged an initial fixed charge and declining per-kWh rates for increasing electricity usage (i.e., the first X kWh a customer used was billed at one rate, the next X kWh at a lower rate, etc.). Fixed system costs were recovered from the fixed charge and the first blocks of the variable charge. The balance of the variable charges, especially the later blocks, largely recovered fuel costs.

The energy crisis of the 1970s, among other factors, brought an awareness that the declining block rate structure encouraged energy use, as each unit of energy used cost less than the previous unit. The enactment of PURPA and its mandate that state commissions design rates to conserve energy led to revised rate designs, particularly with regard to residential customers. The declining blocks were eliminated, and variable charges became uniform (with the exception of time-of-use and seasonal rates). System costs were recovered in part through the fixed charge, and in part through the variable charge.

The EEI report advocates further revision of rate structures “to mitigate (or eliminate) cross subsidies and provide proper customer price signals.” It recommends three immediate actions:

- Establish monthly customer service charges to recover all fixed costs and “eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources.”
- Develop parallel generation tariffs that reflect the cost of providing self-generators off-peak service, back-up interruptible service, and the opportunity to sell excess generation to the utility.
- Revise net metering policies, to treat all sales from self-generators to utilities as wholesale transactions.

Longer-term actions recommended by the EEI report include various mechanisms to counter lost revenues due to energy conservation and self-generation and, in particular, ensuring revenue streams to cover the imbedded cost of capital investments.

Of the three immediate actions recommended by the EEI, the first two have been proposed in Wisconsin and the second of them has been implemented in at least one case.

MADISON GAS & ELECTRIC CO. RESIDENTIAL RATES

In 2014, Madison Gas & Electric Co. (MG&E) proposed a series of residential rates that had a goal of instituting a demand charge over a period of several years. In 2015 to 2017, MG&E proposed to shift all fixed and customer-related costs from the variable charge to a series of transitional charges and ultimately, in 2018 or later, to a demand charge. MG&E made clear in

its filing with the PSC that it was not at that time requesting approval of the 2017 rates included in the proposal or of the institution of a demand charge in its residential rates, explaining that it included them in the filing to indicate to the PSC what it was considering for future rate filings.

MG&E’s proposal generated opposition from ratepayers and from advocates of energy conservation and renewable energy. In response, MG&E dropped its proposals relating to 2016 and 2017 and the proposed transition to a demand charge, and agreed to a more modest revision of rates for 2015, which the PSC approved in December 2014. In addition, MG&E stated its intention to engage in a public dialogue with stakeholders regarding the form its future rates should take.

The table below presents a summary of the fixed and variable charges in MG&E’s 2014 and 2015 residential rates, as well as its 2016 and 2017 proposals. Keep in mind that the 2017 rates were not actually proposed by MG&E, but included in the filing for illustrative purposes, and that both the 2016 and 2017 rates were removed from the rates that the PSC ultimately approved. The new rates, effective in 2015, include a substantial increase in the fixed charge, but a relatively small reduction in the variable charge, compared to the 2014 rates. This table, though, includes the 2017 proposal as a representation of MG&E’s estimate of a rate structure that would use variable charges to recover only the cost of fuel and power purchase agreements and allocate all other costs to a demand charge or other form of fixed charge. Thus, it represents the best available estimate of what rates designed with that objective would look like.¹⁷

Summary of MG&E’s Residential (RG-1) Rates

	2014 (Actual)	2015 (Actual)	2016 (Withdrawn)	2017 (Withdrawn)
Fixed Charges	\$10.44/month	\$19.00/month	\$48.65/month	\$68.37/month
Variable Charges (annual weighted average) ¹⁸	\$0.14402/kWh	\$0.13382/kWh	\$0.07413/kWh	\$0.03059/kWh

WISCONSIN ELECTRIC POWER COMPANY PARALLEL GENERATION TARIFFS

The Wisconsin Electric Power Company (WEPCO) also proposed new rates in 2014, which were approved for 2015. The new WEPCO rates include a complex set of rules that apply to customers who install generating facilities on their premises. The result of these rules is that, by 2016, in

¹⁷ The proposed 2017 fixed charge was comprised of four separate charges: a customer charge (22% of the total); a grid connection service charge (10%); a transition energy charge (46%); and a transition distribution charge, (22%). Note that, while the MG&E filing describes the transition energy and distribution charges as coincident and noncoincident demand charges, respectively, they are based on class average demand, and so function as fixed charges.

¹⁸ MG&E’s rates include a summer rate applicable for four months of the year and the winter rates applicable for the other eight months.

general, two sets of rules will apply to customer-sited renewable energy generation in the WEPCO service territory.

Owners of systems with the capacity to generate up to 20 kW that were subscribed under the appropriate tariff by October 7, 2014, will be under a net metering system. That is to say, they will receive a credit for any energy they put into the utility system, up to the amount of energy they use from the system, at the retail price of electricity, \$0.1299/kWh. Furthermore, they are paid for any additional electricity they put into the system at the same price. These customers must pay an additional charge of \$1.79/month for the second meter required to measure reverse energy flow.¹⁹

Most other owners of such customer-sited generation will receive the same credit for electricity they put into the utility system up to the amount of energy they use, but the utility will pay \$0.04245/kWh, an approximation of the wholesale price of electricity, for any additional electricity the customer sells to the utility. Further, in addition to the \$1.79/month meter charge, these customers must pay a fee based on the size of their energy system. For energy systems the utility deems to be intermittent (including solar and wind energy systems), the fee is \$3.794/month/kW of generation capacity; for other energy systems, the fee is \$8.602/month/kW of generating capacity.²⁰

DISCUSSION

The EEI report and the REV order provide contrasting views of the regulatory path to take in the coming decades. The EEI report describes recent advances in PV and other distributed generation technologies and customer behavioral changes that reduce load as a “threat to the centralized utility service model,” that is, the model of a centralized utility generating or procuring electricity for sale to all users of electricity in its exclusive service territory. The policy recommendations of the report focus on maintaining this model. The REV order pursues the opposite objective, to encourage distributed generation, fully engaging utility and non-utility generators. This section identifies some of the policy options available to state regulators and legislatures.

RATE REGULATION

Within the traditional paradigm of rate regulation, there are many ways to design rates. As was described earlier, the EEI report calls for using fixed charges to recover all fixed costs, so as to “eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources.” This is the basis of the trend in residential rates toward larger fixed charges (or demand charges) and smaller variable charges.

Criticism of this approach comes in two forms. First, as has been noted above, reducing variable charges increases the payback period on investments in energy conservation and renewable

¹⁹ This grandfathered group is under what is sometimes termed a “legacy” tariff, which applies to customers in a particular circumstance prior to a change in policy. In this case, customers who invested in generation facilities counting on the net metering and retail-level buyback rates to make the systems cost-effective are not disadvantaged by the rule changes in the new tariffs.

²⁰ This fee applies to customers who generate electricity for their own use but who do not sell any power to the utility, as well as to customers who sell power to the utility.

energy systems and can discourage such investments.²¹ Stand-by charges applied to self-generators are criticized on the same basis.²² The short payback periods under historic rates, however, are precisely the subsidies that the EEI report seeks to eliminate; those are the subsidies paid by other rate payers who do not invest in energy conservation and renewable energy.

Second, other critics note that, while addressing some inequities in rates, such a design creates other inequities. For example, it is asserted that a high fixed charge inequitably burdens low use and low-income customers.²³

The application of a demand charge in residential rates is also criticized on two bases.²⁴ First, depending on how it is implemented, a demand charge can be an imprecise measure of a customer's demand. If measured on an annual basis, for example, the 15 minute or 60 minute interval, or whatever interval is used, with the highest energy use in an entire year is used as a measure of a customer's demand for that year. If the measurement is made monthly, there is less opportunity for a single outlying event of high energy use to skew the demand charge applied to the customer; if it is measured daily, it becomes a still more precise measurement, although possible more burdensome from an administrative perspective. The other criticism is that a demand charge is not easily understood to customers, and so does not send clear market signals. In both bases, the demand charge is compared to time-of-use rates, which are seen as both more closely tied to actual usage and more easily understood and responded to by customers.

REVENUE REGULATION, OR “DECOUPLING”

Under traditional rate regulation, utilities' revenues are tied to sales. As a result, anything that reduces sales – reduced energy use due to economic conditions or energy conservation efforts, reduced energy sales due to customer-owned generation, etc. – also reduces revenues. This provides utilities a disincentive to support energy conservation or customer-owned generation. Revenue regulation refers to a regulatory strategy that breaks the tie between, or decouples, sales and revenues. It is frequently referred to as “decoupling.”

Under rate regulation, a utility's rates are set at a level anticipated to generate the calculated revenue requirement of the utility. Actual revenues vary, depending on many factors. Under revenue regulation, rather than letting revenues vary while holding rates steady, rates are adjusted as needed to ensure that the utility earns its calculated revenue requirement. The aim of this approach is to make utilities “indifferent” to changes in sales volume.²⁵

²¹ See, e.g., *Direct Testimony of Michael J. Vickerman on Behalf of RENEW Wisconsin and the Environmental Law and Policy Center*, 2014, in PSC Docket 3270-UR-120, *Application of Madison Gas and Electric for Authority to Change Electric and Natural Gas Rates*.

²² See, e.g., *Combined Heat and Power: A Resource Guide for State Energy Officials*, National Association of State Energy Officials, 2013.

²³ See, e.g., *Initial Brief of the Citizens Utility Board*, 2014, in PSC Docket No. 6690-UR-123, *Application of Wisconsin Public Service Corporation for Authority to Change Electric and Natural Gas Rates*.

²⁴ Richard Sedano, Principal and U.S. Programs Director, Regulatory Assistance Project, personal communication.

²⁵ Richard Sedano, Regulatory Assistance Project, 2015, *The Basics of Decoupling, A Superior Solution to the Throughput Incentive*, presentation to the National Conference of State Legislatures. http://www.ncsl.org/Portals/1/Documents/energy/RAP_Sedano_Slides.pdf.

DISTRIBUTE GENERATION AND DECENTRALIZED UTILITIES

The EEI report describes recent advances in PV and other distributed generation technologies and customer behavioral changes that reduce load as a “threat to the centralized utility service model,” that is, the model of a centralized utility generating or procuring electricity for sale to all users of electricity in its exclusive service territory. Its recommendations are explicitly designed to preserve that model and protect the ability of utilities to repay past investments and raise capital for future investments in the infrastructure of that model.

As noted earlier, the REV order takes the opposite approach, seeking to maximize the deployment of diverse, distributed generation resources by utility and non-utility entities. It and other sources cite advantages of distributed generation that include greater system security, reduced demand for large, central generating stations, and shorter transmission distances.²⁶

The RMI report expresses the view that “[t]he United States’ electric grid is in the midst of transformation, but that shift need not be an either/or between central and distributed generation. Both forms of generation, connected by an evolving grid, have a role to play.”

Two policy paths could be followed to allow decentralization to occur. One is to allow market competition in delivery of electric service through distributed facilities. This could be accomplished through the exclusion of third-party owners of distributed resources from the definition of “public utility.” Alternatively, third-party owners could be regulated as competitive electric utilities, acting within the service territories of incumbent utilities, in much the way that competitive local exchange carriers brought competition into telecommunications. This approach would require legislation to establish the regulations that will apply to this new category of public utilities.

In addition, or as an alternative to this path, electric utilities themselves could be encouraged to make greater use of distributed generation technologies. The EEI report lists, as one of the longer-term actions electric utilities need to take, the identification of new business models and services that can be provided by utilities to customers in order to recover lost margin while providing a valuable customer service. It makes the analogy to the telecommunications companies who were successful following deregulation of that industry. One such business opportunity might be to offer decentralized utility service to individual customers.

The REV order goes further. It proposes the concept of a distributed system platform (DSP), which would be responsible for integrated system planning, grid operation, and market operations. The DSP provider would be a regulated utility, so that system planning and grid operation would remain in a single entity.

RECOVERY OF CAPITAL INVESTMENTS

The availability of grid independence does not make the grid obsolete. Those who do not choose to become self-generators will still need the grid. Plus, even if an individual’s home is off the grid, that individual still relies on the grid to supply power to all the other buildings he or she uses for work, entertainment, shopping, etc. Consequently, the grid must be maintained, and future investments in the grid will be needed. Also, under the regulatory compact, the investors

²⁶ See, e.g., Jefferson Tester, et. al. , 2005, *Sustainable Energy: Choosing Among Options*, p.679, MIT Press.

who paid for the grid, and who pay for its maintenance, must be repaid their investment, with the reasonably anticipated earnings.

To avoid the problem of stranded investments in utility infrastructure, the EEI report suggests that each self-generator and each customer who terminate service be assessed a fee that represents the portion of the utility's investments that become stranded as a result of the customer's actions. For the customer who remains connected to the grid, this would be, essentially, a stand-by fee. It could be designed to reflect the cost to the utility of providing that grid connection and the benefit to the customer of the ability to both buy electricity from the utility and to sell electricity to the utility. It could also reflect the value to the utility of the customer's generation assets.

The EEI report also suggests the concept of "customer aid in advance of construction ... to mitigate future stranded cost risk." The report does not offer a specific mechanism for how this front-loading of the cost of construction would be accomplished.

CONCLUSION

Technological developments, coupled with economic conditions, are introducing the likelihood of significant change in the electric industry. In particular, the cost of PV and other technologies has fallen to levels that make it possible for end users of electricity, including residential customers, to generate some or all of their own electricity. In some cases, conditions are developing that would allow a customer to become entirely independent of the local electric utility. While not necessarily exhaustive, two reports illustrate the range of possible responses to these developments: the EEI report argues for, and offers policy options to protect the status quo of centralized utility service; the REV order lays out a framework for incorporating decentralized elements, under the control of utility and non-utility players, into the utility structure to the greatest extent possible. The path Wisconsin follows could reflect elements of both.

This memorandum is not a policy statement of the Joint Legislative Council or its staff.

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