Hunterston Consulting LLC

Where Things Stand on Standby Rates (August 2019)

By Jamie Scripps, Hunterston Consulting LLC

Jamie Scripps is a principal with Hunterston Consulting LLC, where she offers advanced energy policy expertise to clients across the Midwest. Jamie's standby rate research has been featured in a number of proceedings throughout the country, and she is a recognized expert on policies related to cogeneration. In 2016, Jamie was featured as a Midwest Energy News "40 under 40" awardee. Prior to founding Hunterston Consulting LLC, Jamie was a partner with 5 Lakes Energy LLC.

Acknowledgments

Thank you to the Great Plains Institute, whose industrial energy efficiency program has supported technical and policy work on improving standby rates across the Midwest since 2015. Thank you also to the Midwest Cogeneration Association and the Alliance for Industrial Efficiency for their collaboration and insights in putting together the "apples to apples" standby rate comparison and advocating for emerging best practices in standby rate design.

Introduction

There has recently been a fair amount of public utility commission activity around standby rates and their impact on the deployment of distributed energy resources, such as combined heat and power (CHP). From 2014 to 2019, interest in CHP has increased across a number of states. Many Midwestern states have among the highest technical potential for CHP in the country, and interest has been particularly high in those states. This has led to a range of opportunities for stakeholders to examine utility standby tariffs. Throughout these discussions, there has been keen interest in evaluating how best to revise utility tariffs in order to achieve fair and just standby rates going forward.

When a customer installs a CHP system, the issue of standby or backup service from the electric utility arises. When the customer's CHP system needs to be shut down for maintenance, or on the rare occasion[1] when the CHP system encounters a problem and turns off unexpectedly, how will the customer meet its energy needs? Typically, this issue is resolved with an agreement by the electric utility to provide standby (backup) service to the customer.

The amount of money customers are charged to both reserve and use electric utility standby service has long been a factor in the return on investment for CHP installations. The higher and more

[1] CHP systems are historically quite reliable, with average forced outage rates on the order of less than 5%. *See* Energy and Environmental Analysis, Inc., Final Report: Distributed Generation Operational Reliability and Availability Database (January 2004), prepared for Oakridge National Laboratory, available at https://www.energy.gov/sites/prod/files/2013/11/f4/dg_operational_final_report.pdf.

confusing these standby charges are, the greater the risk that a utility's approach to providing standby service will pose a barrier to the construction of an otherwise economical CHP system. As the CHP Roadmap for Michigan report found, "[R]egulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. … . Standby rates, or charges a utility customer pays for the utility to provide backup service in case of a scheduled or unscheduled CHP system outage, can be so high as to completely undermine the economic viability of a proposed CHP system."[2]

As the popularity of customer-sited distributed generation like CHP has grown across the country, there has been renewed interest in examining the impact of standby charges on the deployment of CHP. More and more, potential CHP customers and utility regulators are asking: What are fair and just standby rates? How can existing utility standby tariffs be improved?

Early State Activities

While recent opportunities to examine standby rates and other potential barriers to CHP emerged at the end of 2014, various states' interest in standby rates for combined heat and power (CHP) can be traced back to the passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA), which was passed with the intention of promoting energy conservation and greater use of domestic energy resources, including CHP. Following the passage of PURPA, the creation of early net metering programs in the 1980's and the deregulation trend throughout the 1990's and early 2000's further encouraged competition and self-generation, highlighting the need for fair electricity rates for self-generators.[3] In the 2000's, Oregon and Hawaii took the lead in examining potential regulatory barriers to distributed generation, laying a foundation for when Minnesota initiated its standby rate review in 2014.

Oregon

In 2002, the Oregon PUC established an objective to "identify and remove regulatory barriers to the development of distributed generation."[4] Overcoming regulatory barriers to distributed generation, including onerous standby tariffs, was seen as a means of encouraging "utilities and customers to meet energy needs at the lowest possible cost and risk."[5] Oregon PUC staff examined regulatory barriers and

---

[2] CHP Roadmap for Michigan, prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the U.S. Department of Energy (February 2018), p. 12, *available at* https://www.michigan.gov/documents/energy/CHP_Roadmap_for_Michigan_Full_Report_final_628532_7.pdf.

[3] "PURPA encourages cogeneration and renewable energy technologies by requiring utilities to interconnect with cogenerators and renewable energy facilities and to purchase power generated by them. When designing rules to implement PURP A and FERC regulations, some states decided to take the intent of PURP A one step further by including net metering as an option for smaller generators." National Renewable Energy Laboratory (NREL), "Current Experience with Net Metering Programs," (1998), p. 2, *available at* https://www.nrel.gov/docs/legosti/old/24527.pdf.

[4] Oregon Public Utility Commission, Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations, Prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), p.1.

[5] Ibid.

developed recommendations for overcoming them. In its report to the PUC, staff stated that standby tariffs should "be based on the actual costs of providing backup generation and grid capacity for distributed generators during their occasional outages, spread across the year and following random patterns."[6] Overall, staff emphasized the need for "standby tariffs that properly reflect the costs and benefits of serving customers with distributed generation."[7]

Hawaii

In 2006, Hawaii PUC Decision and Order No. 22248 affirmed that "standby and backup charges should be cost-based."[8] The Hawaii PUC required each utility to establish standby rates based on "unbundled costs associated with providing each service."[9] The Hawaii PUC again took up the issue of standby rates in 2008 when it issued an order making standby rates "optional for 10 years for CHP-using consumers taking service from the state's investor-owned utilities."[10] Customers opting out of standby rates were to be charged according to the applicable full requirements tariff. In the years following this order, fluctuations in standby rates on the part of Hawaii utilities were seen as a serious potential barrier to the deployment of CHP. In a 2008 report, the Pacific Region Combined Heat and Power Application Center stated: "The greatest immediate threat to the CHP market in Hawaii is the large increase in standby charges for CHP projects that are being proposed by the major island utilities. If these charges are implemented, CHP economics will be dramatically affected and may no longer be attractive except possibly in the very best settings."[11]

Minnesota

In the Midwest, efforts to re-examine standby rates began in Minnesota, with a stakeholder process convened by the Minnesota Department of Commerce in 2014 to address the issue. A statutory change in 2013[12] prompted Minnesota utilities to update their standby service tariffs. At first, the Minnesota PUC directed stakeholders to confer with the Minnesota Department of Commerce to further develop the issue, which led to stakeholder discussions in 2014 and eventually to the state's regulated utilities being required to file revised standby tariffs with the Minnesota PUC in Docket 15-115. With guidance from the Energy Resources Center at the University of Illinois at Chicago, the

---

[6] Oregon Public Utility Commission, Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations, Prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), p. 2.
[7] Ibid.
[8] Pacific Region CHP Application Center, 2008 Combined Heat and Power Baseline Assessment and Action Plan for the Hawaii Market, p. 10, *available at* https://www.energy.gov/sites/prod/files/2013/11/f4/chp_hawaii_2008.pdf.
[9] Ibid.
[10] ACEE State and Local Policy Database: Standby Rates, Hawaii, *available at* https://database.aceee.org/state/standby-rates.
[11] Pacific Region CHP Application Center, p. ix.
[12] *See* Minn. Stat. § 216B.164.

standby tariffs were evaluated in part based on "transparency, flexibility and promotion of efficient consumption."[13]

Comments were filed by a number of interested stakeholders, including the Midwest Cogeneration Association, a leading advocate on this issue through its Midwest Standby Rates Initiative. On October 3, 2017 and April 5, 2018, the Minnesota PUC approved revised standby tariffs that reflect the initial results from this process. Utilities, regulators and stakeholders alike recognized that the process had led to notable improvements over the original standby rate submissions.

Comparing "Apples-to-Apples"

Stakeholder engagement and feedback was crucial to the success of the Minnesota process. The Energy Resources Center, Midwest Cogeneration Association (with support from GPI) and Fresh Energy evaluated the different utility standby tariff proposals, offering insights as to how each proposal might impact the future of CHP in Minnesota. It was during this evaluation of utility proposals that the 5 Lakes Energy "apples-to-apples" methodology was born.

In order to provide a side-by-side comparison of the effects of each utility's standby tariff on the monthly bills of customers with CHP systems, 5 Lakes Energy conducted an analysis in which it compared estimated standby bills for a hypothetical customer experiencing a range of CHP system outages. The "apples-to-apples" standby rate comparison was important for highlighting the wide variation of standby charges experienced by customers on a monthly basis, depending on the location of a CHP system in a particular state and electric utility territory. The "apples-to-apples" comparison also demonstrated key rate design features, including, for example, whether a particular utility's standby rate design differentiated between scheduled and unscheduled CHP system outages, and whether demand charges were pro-rated based on on-peak consumption.

The sample customer used in the analysis exhibited the following characteristics:

- 2,000 kW in standby load for CHP system
- 3,000 kW in supplemental load
- service taken at the primary distribution level

In order to evaluate the rate design features of a utility's approach, depending on variations in customer behavior, the "apples-to-apples" standby rate analysis examined published tariffs to compare estimated bills for the following CHP system outage scenarios:

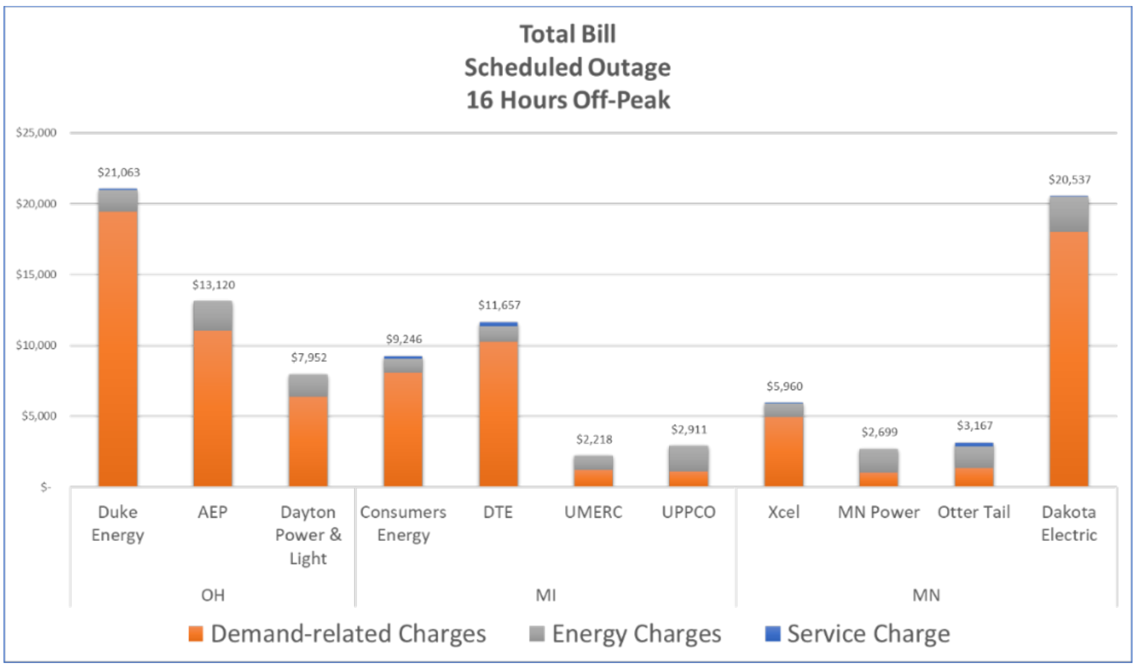
- a "no outage" month
- a scheduled 16-hour outage occurring during off-peak times
- a scheduled 16-hour outage occurring during on-peak times
- a scheduled 8-hour on-peak/8-hour off-peak outage

[13] Energy Resources Center, Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota, prepared for the Minnesota Department of Commerce Division of Energy Resources, April 2014, p. 10, *available at* http://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf.

- a scheduled 32-hour outage occurring during on-peak times
- an unscheduled 8-hour on-peak/8-hour off-peak outage

Figure 1 illustrates the "apples-to-apples" estimated monthly standby bills for a customer experiencing a 16-hour off-peak CHP system outage. Ideally, a customer would experience lower standby charges during an off-peak outage. The figure below illustrates both the wide variation in monthly standby charges and the heavy reliance by most utilities on demand charges in standby rate design.

Figure 1. "Apples-to-Apples" Monthly Standby Bill for 16-hour Off-Peak CHP System Outage



Across the Midwest (and extending into the Mid-Atlantic), the "apples-to-apples" standby rate analysis has been used in workshops and proceedings in Indiana, Illinois, Michigan, Minnesota, Ohio, and Pennsylvania. The "apples-to-apples" standby rate analysis debuted in comments by Fresh Energy and Midwest Cogeneration Association in Minnesota PUC Docket. No. E-999/CI-15-115 and was presented at a Minnesota Department of Commerce stakeholder workshop in December 2016. Table 1 below illustrates the variation among Minnesota utilities' monthly standby charges, as well as highlighting rate design sensitivities based on customer behavior (e.g., scheduled vs. unscheduled outages and on-peak standby consumption).

Table 1- Minnesota: Total Monthly Estimated Bills by CHP System Outage Scenario

	No Outage	Scheduled – 16 hr Outage (off-peak)	Scheduled – 16 hr Outage (on-peak)	Scheduled – 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hours (on-peak)	Unscheduled (8 hrs on-peak, 8 hrs on-peak)
Minnesota Power	$1,007	$2,699	$2,699	$2,699	$4,391	$20,180
Xcel Energy	$4,966	$5,935	$5,935	$5,935	$7,958	$6,135
Otter Tail Power	$1,632	$3,167	$4,113	$3,640	$6,594	$4,408
Dakota Electric	$6,594	$20,127	$20,127	$20,127	$22,561	$20,127

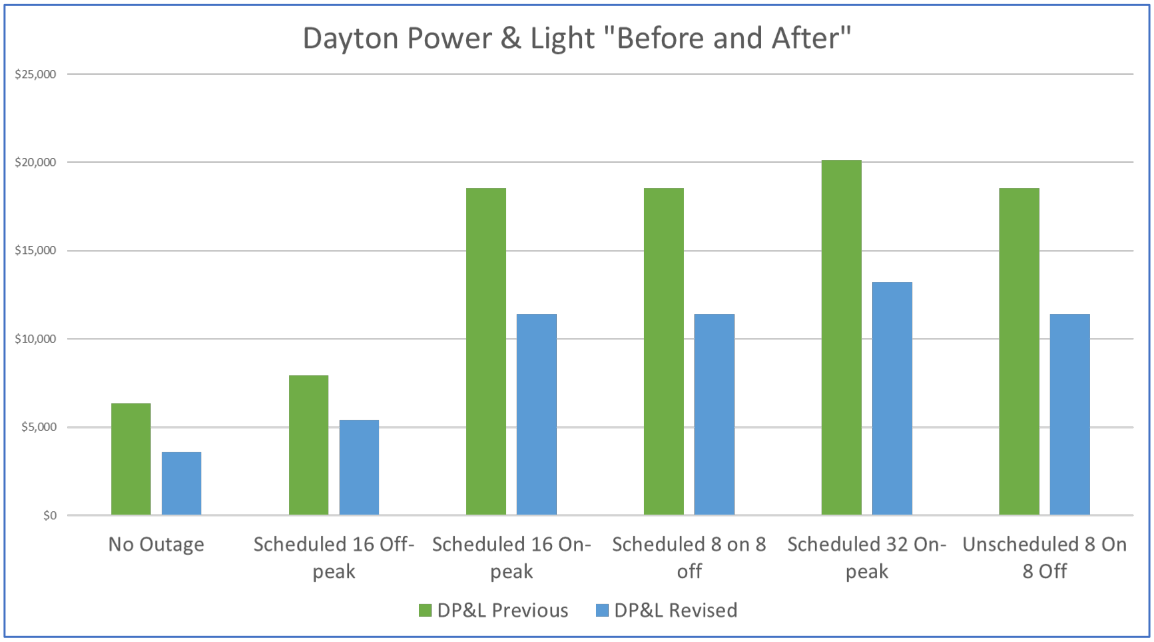
A Michigan-focused "apples-to-apples" standby rate analysis was referenced by Midwest Cogeneration Association in comments to the Michigan Public Service Commission Staff Standby Rate Working Group in 2016 and 2017. Adapted "apples-to-apples" analyses were included in testimony submitted in the 2017 and 2018 Consumers Energy and DTE general rate cases. Table 2 below illustrates the variation among Michigan utilities' monthly standby charges, as well as highlighting rate design sensitivities based on customer behavior (e.g., scheduled vs. unscheduled outages and on-peak standby consumption).

Table 2- Michigan: Total Monthly Estimated Bills by CHP System Outage Scenario

	No Outage	Scheduled – 16 hr Outage (off-peak)	Scheduled – 16 hr Outage (on-peak)	Scheduled – 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hours (on-peak)	Unscheduled (8 hrs on-peak, 8 hrs on-peak)
Consumers Energy	$8,300	$9,246	$11,645	$11,191	$14,833	$11,191
DTE Energy	$10,535	$11,657	$18,653	$13,405	$30,272	$17,545
Upper Michigan Energy Resources	$0	$2218	$3098	$2658	$6196	$30,536
Upper Peninsula Power Company	$0	$2911	$3883	$3397	$7766	$31,631

In Ohio, Dayton Power & Light has been collaborating with the Ohio Environmental Council and the Ohio Manufacturers' Association to develop a revised standby tariff (per a consent agreement approved by the PUC of Ohio). 5 Lakes Energy, through support from GPI, provided ongoing technical support to this collaborative discussion, including a focus on estimated monthly charges in the "apples-to-apples" comparison. In 2018, Dayton Power & Light removed generation demand charge from its standard service offer for generation service. This change is illustrated in Figure 2 below. While there is still more work to be done, this change significantly reduced monthly charges for standby service.

Figure 2. "Apples-to-Apples" Monthly Standby Bill for Dayton Power & Light – Before (Including Generation Demand Charges) and After (Excluding Generation Demand Charges)



The PUCO also featured a panel on standby rate design during Phase 3 of its "PowerForward" Initiative in March 2018, in which an Ohio-focused "apples-to-apples" standby rate analysis was presented. On August 29, 2018, the PUCO released its final PowerForward report that found, in part, that a "smart technology," such as CHP, cannot "reach their full potential without the appropriate regulatory framework."[14] Table 3 below illustrates the variation among Ohio utilities' monthly standby charges, as well as highlighting rate design sensitivities based on customer behavior (e.g., scheduled vs. unscheduled outages and on-peak standby consumption.)

[14] PowerForward, A Roadmap to Ohio's Electricity Future, the Public Utilities Commission of Ohio, dated August 29, 2018, p. 10, *available at* https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/powerforward-a-roadmap-to-ohios-electricity-future/.

Table 3 - Ohio: Total Monthly Estimated Bills by CHP System Outage Scenario

	No Outage	Scheduled – 16 hr Outage (off-peak)	Scheduled – 16 hr Outage (on-peak)	Scheduled – 8 hrs on-peak, 8 hrs off-peak	Scheduled 32 hours (on-peak)	Unscheduled (8 hrs on-peak, 8 hrs on-peak)
Duke Energy	$19,531	$21,063	$21,063	$21,063	$22,661	$22,011
American Electric Power	$0	$13,120	$22,360	$22,360	$24,436	$22,360
Dayton Power & Light	$6,357	$7,952	$18,547	$18,547	$20,143	$18,547

An Indiana-focused "apples-to-apples" standby rate comparison was submitted as part of comments pursuant to the Indiana Utility Regulatory Commission's Backup, Maintenance, and Supplemental Power Rate Review. Indiana Code 8-1-2.4-4(h), effective July 1, 2017, required the commission to: review the backup, maintenance, and supplemental power rates; identify the extent to which the rates are cost based, nondiscriminatory, and do not result in the subsidization of costs within or among customer classes; and report the Commission's findings to the Interim Study Committee on Energy, Utilities, and Telecommunications before November 1, 2018. Importantly, the IURC was interested in exploring the full value of CHP to the grid, stating: "…[W]e appreciate that a well-placed cogeneration facility with well-timed maintenance outages can enhance value to both the providing customer-generator and the utility system customers as a whole, and direct IPL to explore with existing and potential industrial customer-generators how to capture such value."[15]

Stakeholders who participated in NextGrid: the Illinois Utility of the Future Study examined standby rates as part of Working Group 7 (Ratemaking), in part by referencing the results of an Illinois-focused "apples-to-apples" standby rate analysis. The working group's final report was issued on October 8, 2018 and states: "The rates charged for these [standby] services can affect the economics of a DER [distributed energy resources] project. One outcome of appropriate standby rates is that they do not discourage economical combined heat and power (CHP) while avoiding a subsidy from full-requirements customers: Less-than-full cost recovery by the utility shifts costs to other customers; more-than-full cost recovery results in excessive payment by DER customers making DER less economically attractive. In sum, a good standby rate would result in no subsidy, be fair to DER customers and full-requirements utility customers, and not discourage good DER projects or encourage bad DER projects."[16]

The "apples-to-apples" standby rate comparison was used in standby rate discussions in Pennsylvania as well. In April 2018, the Pennsylvania Public Utility Commission (PA PUC) adopted a policy statement aimed at helping to "advance the development of combined heat and power (CHP) technology." The PA PUC formally recognized the benefits of CHP and encouraged utilities to support the development of CHP by evaluating and implementing new strategies and programs and requires

[15] Indiana Utility Regulatory Commission, Cause No. 44576 (March 16, 2016), p. 77

[16] NextGrid Illinois, Working Group 7: Ratemaking Report, October 8, 2018, *available at* https://nextgrid.illinois.gov/workinggroup7/final_report.pdf.

biennial reporting to inform the commission and stakeholders and help frame future policy discussions. In connection with the PA PUC's CHP policy statement, the PA PUC's Bureau of Technical Utility Services initiated a CHP Working Group to "engage with stakeholders and encourage the deployment of, and reduce barriers to, CHP initiatives in the Commonwealth."[17] In conjunction with the Mid-Atlantic CHP Technical Assistance Partnership, 5 Lakes Energy expanded on the "apples-to-apples" methodology to develop an avoided electricity rate analysis comparing standby rates of Pennsylvania utilities, which was presented at the July 16, 2018 meeting of the CHP Working Group. The "apples-to-apples" standby rate comparison was also featured in the Duquesne Light Company 2018 distribution rate case, as discussed below.

Where are the positive outcomes?

Reservation Fees

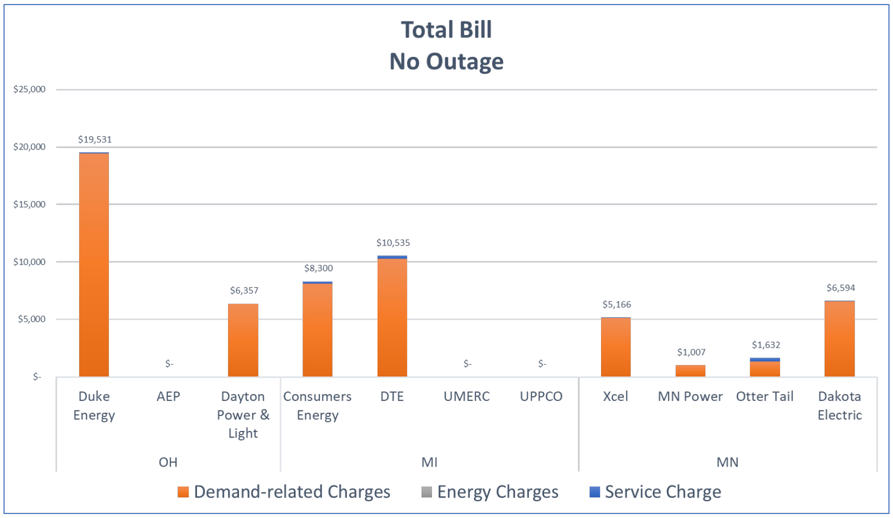
As a result of the standby rate analysis and interventions by supporters of CHP, one of the positive outcomes came on the issue of reservation fees in the 2017 DTE general rate case in Michigan. Many utilities charge standby customers a fixed per kW fee each month in order to reserve standby service. While not always labeled as such, demand charges calculated based on contract capacity and imposed on a customer during a "no outage" month can be categorized as a kind of reservation fee.

The reservation fee is usually the primary driver of customer costs incurred during a "no outage" month and are therefore the main component of the "no outage" charges experienced by a customer using CHP. Additional charges can include an administrative charge or service fee. Sometimes, depending on a utility's standby rate structure, if an outage occurs and demand charges are assessed, the reservation fee is waived if the demand charges exceed the reservation fee amount.

As a best practice, a CHP system's forced outage rate (FOR) should be used in the calculation of a customer's reservation fee. According to the Energy Resources Center, "The Forced Outage Rate should be used in the calculation of a customer's reservation charge. The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further links the use of standby to the price paid to reserve such service creating a strong price signal for customers to run most efficiently."[18] This practice creates an incentive for standby customers to limit their use of unscheduled standby (backup) service and strengthens the link between use of standby service to the price paid by customers to reserve such service, creating a strong price signal for customers to run more efficiently overall. Figure 3 below illustrates the variation among utility standby charges for months in which a customer's CHP system works perfectly and no standby service is actually consumed.

[17] Pennsylvania Public Utilities Commission, Combined Heat and Power (Cogeneration), *available at* http://www.puc.state.pa.us/utility_industry/natural_gas/chp_cogeneration.aspx.
[18] Energy Resources Center, p. 11.

Figure 3. "Apples-to-Apples" Standby Bill for No Outage Month



In its order in Case No. U-18255, dated April 18, 2018, the Michigan Public Service Commission stated: "The Commission finds that it is reasonable to approve an R3 standby tariff that sets a monthly power supply reservation charge based on the forced outage rates of the best performing generators."[19] This concept was re-affirmed in the Commission's recent Order in Case No. U-20162, which states: "The Commission agrees that the company's proposal fails to recognize that the generation reservation fee is not related to actual use of R3 standby service but rather reflects a minimum required contribution toward fixed power supply costs."[20]

By focusing on the probability of a forced outage, the risk to a utility of having to serve a standby customer unexpectedly can be expressed through the reservation fee that a standby customer pays to the utility in months when the CHP system does not experience a forced outage. In a month in which a customer makes use of standby service during an outage, the other rate design features of a standby tariff, such as on-peak daily backup demand charges, can kick in to collect cost-based revenues from customers with a standby requirement higher than their availability might otherwise suggest. When scheduled maintenance outages are taken into account, it is not surprising that owners of CHP systems with very low FORs might have regular standby service needs to accommodate proactive maintenance. Standby tariffs can make use of a variety of mechanisms to charge customers for actual use of standby service during an outage, but the generation reservation fee should be geared toward the likelihood of unexpected use, which is captured by a CHP system's FOR.

[19] Michigan Public Service Commission, Order, U-18255, April 18, 2018, p. 77.
[20] Michigan Public Service Commission, Order, U-20162, May 2, 2018, p. 152.

Generation/Power Supply Demand Charges

As described above, Dayton Power & Light eliminated altogether the generation/power supply demand charges in its standard service offer for standby generation service. This was an important change for standby customers, significantly reducing monthly charges for standby service.

While generation/power supply demand charges have not been eliminated in Michigan, the MPSC has provided direction that these charges should be fairly pro-rated to reflect standby service customers' partial and infrequent use of generation resources. In its order in Case No. U-18255, dated April 18, 2018, the Commission stated "that it is reasonable to approve an R3 standby tariff that sets … an on-peak daily power supply demand charge based on a proration of the full service D11 monthly power supply demand charge, and a maintenance on-peak demand charge of 50% of the on-peak daily power supply demand charge."[21] This recommendation represents an improvement over the previous design because it explicitly reflects a proration (set at 1/10) of the full service rate – and was recently re-affirmed in the Order in Case No. U-20162: "The Commission agrees with the Staff, MEIBC/IEI [Michigan Energy Innovation Business Council/Institute for Energy Innovation], ABATE [Association of Businesses Advocating Tariff Equity] and the ALJ [administrative law judge] and finds that the current method for allocating power supply capacity costs to R3 customers should be retained."[22]

Fair pro-ration of demand charges begins with fair cost allocation in the utility's cost of service study; this issue came to the fore in the most recent DTE rate case, U-20162, in which the administrative law judge and commission both affirmed that both full service D11 power supply capacity costs and partial requirements R3 power supply capacity costs should be allocated with reference to 4CP, which is calculated based upon customer demand coinciding with the system peak demands during the summer months. This method of power supply capacity cost allocation aligns with cost causation principles for standby service customers because it reflects customers' actual contribution to system peaks, which drive company investments in common, shared facilities. Standby customers do not hit the 4CP system peaks very often, which makes sense in light of the overall reliability of CHP systems.

Distribution Charges

In April 2018, the Pennsylvania Public Utility Commission ("PA PUC") adopted a policy statement aimed at helping to "advance the development of combined heat and power (CHP) technology." The PA PUC formally recognized the benefits of CHP and encouraged utilities to support the development of CHP by evaluating and implementing new strategies and programs, and now requires biennial reporting to inform the commission and stakeholders and help frame future policy discussions. It is against this backdrop that in May 2018, Duquesne Light Company proposed to more than triple its distribution charge rate (from $2.50 per kW to $8.00 per kW) for standby customers in its 2018 distribution rate case, Docket No. R-2018-3000124. A settlement was reached on every issue in the case except for Rider 16, the company's standby service rider, and a week-long evidentiary hearing on Rider 16 was held in August 2018. The "apples-to-apples" analysis was presented in evidence at the hearing. At the

---

[21] Michigan Public Service Commission, Order, U-18255, April 18, 2018, p. 77.
[22] Michigan Public Service Commission, Order, U-20162, May 2, 2018, p. 150.

conclusion of the hearing, Duquesne Light Company withdrew its request to increase its Rider 16 distribution charge rate, agreeing instead to return to a pro-rated distribution charge rate. In its final order, the PA PUC agreed that it is reasonable and just to pro-rate distribution charges for standby customers. "We also conclude that the $2.50 Rider No. 16 rate is reasonable because it is voluntary, and the customers can achieve savings through Rider No. 16 because it is less than the applicable full requirements rate."[23]

Transparency

One of the most tangible, positive outcomes for CHP standby service over the past few years has centered around the transparency and accessibility of standby tariffs. This is particularly important because an indecipherable standby tariff can pose significant a barrier to the deployment of otherwise cost-effective CHP.

In Minnesota, as of October 2017, the Public Utilities Commission requires Minnesota Power, Xcel Energy and Dakota Electric to follow the model provided by Otter Tail Power of offering customers a concise two-page "explainer" document to accompany the published standby tariff.[24] Similarly, in Michigan, the MPSC Staff Standby Rate Working Group Supplemental Report, issued in June 2017, recommended: "To assist with standby service tariff transparency, a clear and concise description of the tariff structure and each term used should be included with the tariff."[25] In testimony across a number of proceedings, we have noted that American Electric Power Ohio and Dayton Power & Light both offer online bill calculators.[26] These are transparency practices that could relatively easily be replicated by other utilities across the Midwest.

Discussions related to the "apples-to-apples" standby rate comparison has initiated an important conversation around the transparency and accessibility of standby tariffs. As grid modernization efforts progress and the role of the customer continues to evolve, open and meaningful communication between utilities and their customers will become increasingly important. Transparency and accessibility of tariffs, particularly those relevant to customer-sited generation, will be crucial to this effort.

Going forward, the "apples-to-apples" analytical tool will continue to be valuable as a means of evaluating the transparency, clarity and straightforwardness of a utility's published standby tariff. The process of developing an "apples-to-apples" standby rate analysis shines a spotlight on each utility's standby tariff and provides a real-world view of a utility's level of openness and cooperation in working with a stakeholder in verifying the correct interpretation.

---

[23] Pennsylvania Public Utility Commission, Order, R-2018-3000124, December 20, 2018, p. 62.
[24] Minnesota Public Utilities Commission, Docket No. CI-15-115, Order, October 3, 2017.
[25] MPSC Staff Standby Rate Working Group Supplemental Report (June 2017), p.23, *available at* https://www.michigan.gov/documents/mpsc/SRWG_Supplemental_2017_Report_576352_7.pdf.
[26] See AEP Ohio on-line bill calculator, *available at* https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx; *see also* Dayton Power & Light on-line bill calculator, *available at* https://www.dpandl.com/customer-service/account-center/understand-your-bill/commercial-bill-calculator-guides/.

What's next for standby rates?

As a result of the above-described efforts, there have already been several positive steps taken by regulators and utilities to improve upon standby rates across the Midwest:

- DTE Rate Case, U-18255 (Michigan): Order directing that standby service reservation fee be based on forced outage rate of best-performing generators.
- DTE Rate Case U-18255 (Michigan): Order directing that standby customers' on-peak daily demand charge rate be set at 1/10th of the full requirements demand charge rate.
- DTE Rate Case U-20162 (Michigan): Order re-affirming reservation fee and demand charge directives from U-18255.
- Duquesne Light Company R-2018-3000124 (Pennsylvania): Order affirming pro-rated distribution charges for standby customers.
- Consumers Energy Case U-20134 (Michigan): Settlement agreement in which utility will provide a study analyzing the distribution system costs associated with serving standby service customers.
- Dayton Power & Light (Ohio): Utility eliminated its generation demand charge, significantly reducing monthly standby charges.
- Improved transparency in Michigan and Minnesota.
- Standby rates addressed in grid modernization proceedings in Ohio and Illinois.
- Standby Rates resolution adopted by the National Association of Regulatory Utility Commissioners (NARUC) on February 13, 2019.[27]

Despite this recent progress, challenges remain, and standby rates will continue to be a hot topic for regulators and utilities. In 2019, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution:

- Supporting "further exploration" of issues related to standby rates;
- Reaffirming that rates should be "simple, transparent, and consistent;" and
- Encouraging commissioners to ensure standby rates acknowledge that CHP and WHP [waste heat to power] can reduce demand and costs and improve system reliability and resiliency.[28]

With NARUC again highlighting the importance of reasonable standby rates, there is an opportunity to take next steps, as described below, for additional progress.

[27] *See* Alliance for Industrial Efficiency, NARUC Acts to Reduce Barriers to Clean Combined Heat and Power and Waste Heat to Power, February 13, 2019, *available at* https://alliance4industrialefficiency.org/naruc-acts-to-reduce-barriers-to-clean-combined-heat-and-power-and-waste-heat-to-power/.

[28] *See* Alliance for Industrial Efficiency, NARUC Acts to Reduce Barriers to Clean Combined Heat and Power and Waste Heat to Power, February 13, 2019, *available at* https://alliance4industrialefficiency.org/naruc-acts-to-reduce-barriers-to-clean-combined-heat-and-power-and-waste-heat-to-power/.

Cost-of-Service Analysis and Intervention

Beyond continuing outreach and education around the rate design insights contained in the "apples-to-apples" comparison, there will be a need for detailed cost-of-service analysis and associated intervention in contested proceedings, particularly with regard to distribution system costs. In a recent settlement agreement in Michigan (Case No. U-20134), Consumers Energy agreed "to provide a study analyzing the cost to serve standby service customers, and will provide its distribution cost allocation study to interested parties."[29] More detailed data from the utilities regarding the distribution costs attributable to the provision of standby service will be helpful as stakeholders work toward fair apportionment of distribution system costs for these customers.

Integrated Resource Planning

As states encourage utilities to engage in robust long-term energy planning, the many benefits of CHP should be considered. This will require expert input to accurately and thoroughly reflect the potential contribution of CHP in integrated resource planning (IRP) modeling. In Michigan, consideration of CHP in integrated resource planning is required by Public Act PA 341 of 2016, which sets criteria to be considered in a utility IRP filing with the Michigan Public Service Commission. Specifically, a utility IRP must include the projected energy and capacity purchased or produced by the utility from a cogeneration resource (MCL 460.6t(5)(g)).

In February 2018, the Michigan Energy Office (MEO) released its "CHP Roadmap for Michigan" report, in which it applied cutting-edge integrated resource modeling tools to determine least-cost deployment of CHP resources. The model used–the State Tool for Electricity Emissions Reduction (STEER)–calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors. As part of its CHP Roadmap project, the MEO funded 5 Lakes Energy to perform upgrades to the STEER Model in order to thoroughly represent the potential contribution of CHP in Michigan utilities' IRP. "STEER was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. In our primary application of STEER, we considered the net value of CHP to the economy by considering the cost of installing and operating various CHP systems, the value of the heat produced by CHP measured as the cost of supplying heat in the least-cost way other than CHP, and the value of electricity produced by the CHP system measured as the marginal cost of producing electricity absent the CHP system."[30]

The CHP Roadmap for Michigan project also found that IRP modeling can reflect the impact of standby rates on the deployment of otherwise least-cost CHP. "Because we determined that standby rates are one of the principal barriers to CHP adoption and may be amenable to policy adjustments, we

---

[29] Michigan Public Service Commission, Order, U-20134, January 1, 2019, p. 4.

[30] CHP Roadmap for Michigan, prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the U.S. Department of Energy (February 2018), p. 48, *available at* https://www.michigan.gov/documents/energy/CHP_Roadmap_for_Michigan_Full_Report_final_628532_7.pdf.

also used STEER to evaluate the effect of standby rates on the economic potential for CHP in Michigan… Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more."[31] These STEER Model results further underscore the importance of the "apples-to-apples" analytical work and efforts to improve standby rates.

<u>Codifying Standby Rate Best Practices</u>

The most pressing and broadly applicable next step in standby rates work centers on testing among stakeholders and standardizing emerging best practices in standby rate design. As described above, there has been meaningful progress on standby rates since 2015, including a range of positive regulatory outcomes focused on reducing this potential barrier to the deployment of CHP. However, despite this recent progress, challenges remain. Without a standardized approach to standby rates rooted in accepted best practices in rate design, customers will continue to face tariffs that are difficult to navigate. In fact, standby rates are sometimes so complicated that utilities and regulators find them confusing, as well. A standardized approach will therefore benefit customers, utilities and regulators alike.

Best practices in standby rates are beginning to emerge based on the work done to date, but additional work is needed to further define and standardize these practices, including the need to test these emerging recommended practices with interested stakeholders such as regulators, potential CHP users, developers, technical experts, and utilities. So far, emerging best practices for standby rate design include the following:[32]

- <u>Rates should be transparent, fair, and aligned with the cost of service.</u> One of the most significant barriers to CHP implementation is overly-complicated tariffs. The language of a utility's standby tariff should be clear enough so that a potential CHP user can understand and estimate their future bills. In addition, fair standby rates should not assume that backup or maintenance power will be needed during peak hours as this is already seldom the case, and thoughtful standby rate design can further reduce this risk by incenting proactive, scheduled maintenance and efficient operation of CHP systems.
- <u>Rates should incent efficient operation and maintenance of CHP systems.</u> In most cases, costs imposed on the utility can be almost entirely avoided by incenting CHP system outages to take place with advance notice to the utility (i.e., scheduled maintenance), and during off-peak hours. Modern CHP systems are very reliable, as reflected by their very low forced outage rates (under 5 percent), making it unlikely that CHP systems will require backup power during peak hours, let alone simultaneously throughout the utility's service area. Utilities should reward CHP customers for the efficient operation and maintenance of on-site generation which provides benefits to the grid as a whole.

---

[31] Ibid. p. 48-49.

[32] Great Plains Institute, "Improving Standby Rate Design Would Help Industries Increase Efficiency, Reduce Emissions, and Save Money," (March 2018), *available at* https://www.betterenergy.org/blog/standby-rates-barriers-combined-heat-and-power/.

- Reservation fees should be small (or non-existent) and should take into account a CHP system's reliability. Some utilities charge standby customers a fixed per kilowatt (kW) fee each month in order to reserve standby service. The reservation fee is usually the primary driver of customer costs incurred during a "no outage" month. If a utility deems it necessary to charge a reservation fee, it should be relatively small and calculated based on the reliability of the system. Taking reliability into account (by reference to the CHP system's forced outage rate) incents proactive maintenance and investment in the latest, most reliable technology.
- Rates should not include demand ratchets. Many utilities employ "demand ratchets" in their standby tariffs. A demand ratchet fixes a customer's minimum billing demand (expressed in kW of standby capacity used) based on the customer's maximum demand during a month, and applies that fixed amount of demand on the customer's subsequent monthly bills (often over a 12-month period). A utility may justify the use of a demand ratchet under the theory that it helps to reduce the risk on the utility when a customer can potentially experience large swings in demand during the year. A high demand ratchet can be fixed in place for up to a year or more, even if the customer only experiences a CHP outage for a very short period of time. According to emerging best practices, standby rates should not include ratcheted demand charges, especially over periods extending longer than one month. In general, a CHP system's forced outage in one month is not a reliable predictor for forced outages in subsequent months. Instead, utilities should consider an hourly or daily "as-used" demand charge to recover any costs associated with providing standby service during a CHP system outage.

Overall, standby rates should attempt to align customer rates with the actual costs imposed on the utility's system and should provide appropriate incentives for proactive maintenance and efficient operation of the CHP system.[1] Building upon the strong work and initial successes of the past four years, now is the time to test these emerging best practices among stakeholders, revising and expanding upon recommended practices based on real-world CHP applications. Through such a process, we can offer a more transparent, standardized approach to utilities and regulators seeking to reduce and eliminate barriers to customer-sited generation.

Conclusion

As interest in and deployment of distributed generation, such as CHP systems, continues to rise, utilities and regulators have an opportunity to take a renewed look at approaches to charging customers for standby service. The 2019 NARUC resolution supporting "further exploration" of issues related to standby rates further highlights standby rates as a continuing hot topic across the country. When utilities engage in a thoughtful examination of their standby rate designs, as has been demonstrated across the Midwest, it is a win-win situation, allowing the numerous benefits of CHP to accrue to customers, utilities and the grid as a whole.