Best Practices for Standby Rates for Combined Heat and Power

MARCH 2021

Prepared by Jamie Scripps, Hunterston Consulting,
for the Great Plains Institute

GREAT PLAINS INSTITUTE

ABOUT THE AUTHOR

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, Jamie was a partner with 5 Lakes Energy LLC.

ABOUT THE GREAT PLAINS INSTITUTE

A nonpartisan, nonprofit organization, the Great Plains Institute is transforming the energy system to benefit the economy and environment. Working across the US, we combine a unique consensus-building approach, expert knowledge, research and analysis, and local action to find and implement lasting solutions. Our work strengthens communities and provides greater economic opportunity through creation of higher paying jobs, expansion of the nation's industrial base, and greater domestic energy independence while eliminating carbon emissions. Learn more at www.betterenergy.org.

ACKNOWLEDGEMENTS

We are grateful for the support of the Energy Foundation, which supported this research and to the Joyce Foundation, which supported the work that led to this research. We are grateful for the thoughtful contributions of Carl Linvill of the Regulatory Assistance Project in advising on the starting point for this research, and for his review of the final product. We are also grateful for prior collaborators in the Great Plains Institute's combined heat and power work, including the CHP Alliance, the Energy Resources Center at the University of Illinois at Chicago, and the Midwest Cogeneration Association.

TABLE OF CONTENTS

TERMINOLOGY

AS-USED: reflecting the actual quantity used.

BACKUP DEMAND CHARGE: a demand charge assessed during a period when a customer is using standby service due to an unplanned outage of a combined heat and power system.

BACKUP POWER: electric capacity and energy supplied by an electric utility during an unscheduled outage of the customer's on-site generation.

DEMAND CHARGES: a per kW charge representing the amount of energy consumed at a single point in time, usually reflecting the customer's highest peak demand in a given month or 12-month period.

DEMAND RATCHETS: reference to a customer's highest monthly demand experienced during the preceding period (usually 12 months) in the calculation of demand charges, as opposed to referencing the customer's actual as-used demand during a given month.

ENERGY COMPONENT: energy is the product of power supplied (demand) multiplied by the length of time it is used, usually measured in kilowatt-hours (kWh). The energy component of rates is based on actual consumption by the customer.

FORCED OUTAGE RATE ("FOR"): the probability of failure of a generator, usually measured as a ratio of failure hours to total service hours.

LOCATIONAL MARGINAL PRICING ("LMP"): the cost to buy and sell power at different locations within wholesale electricity markets.

MAINTENANCE DEMAND CHARGE: a demand charge assessed during periods when a customer is using standby service due to planned repairs to a combined heat and power system.

MAINTENANCE SERVICE: standby service used during planned repairs to a combined heat and power system.

PRORATED: assessed proportionally, according to a standby service customer's actual consumption in a given month.

TIME OF USE: the timing of a customer's consumption, usually in relation to a utility's peak periods.

EXECUTIVE SUMMARY

Combined heat and power (CHP) systems generate electricity and harness the thermal energy from power generation for heating and cooling applications (typically burning natural gas[1] for electricity and capturing the exhaust for steam heat).[2] Combining these two processes means that some CHP systems can achieve thermal efficiencies of 60-80 percent—up to twice the efficiency of traditional power generation.[3] CHP is increasingly recognized as an efficient and resilient resource that can act as a bridge towards a future with zero carbon emissions.[4] As interest in CHP grows, and states explore ways to remove barriers or encourage its deployment, there is a recognition that any serious effort to promote CHP must be done in the context of a fair, cost-based approach to standby rate design. When standby rates are too high, inflexible, unpredictable, or simply too difficult for customers to navigate, these extra costs imposed on a customer mean that the economics of a CHP system will fail to provide the needed return on investment, and a potential project will not pencil out.

Standby rates are charged to customers with on-site distributed generation (i.e., generation sited close to its end-use) such as CHP systems. The rates are intended to help the utility recover costs related to reserving and providing backup electricity during scheduled and unscheduled outages of the customer's CHP system. Standby rates can be prorated to reflect partial and/or infrequent use by these customers. Customers relying on distributed energy such as CHP systems pay standby charges to a utility even when their systems work perfectly and do not need standby power. Depending on the size of a customer's CHP system, standby charges can run in the thousands (or tens of thousands) of dollars per month, which can significantly impact the economic viability of distributed energy options for industrial facilities.

Building on previous research and its strong history of supporting CHP policy work in the Midwest, the Great Plains Institute (GPI) recognized that while best practices in standby rates had begun to emerge, work was needed to further define and test these emerging recommended practices with interested stakeholders such as regulators, potential CHP users, developers, technical experts, and utilities.[5]

In June 2020, GPI launched a survey requesting feedback on best practices in standby rates for CHP. There were 34 total survey responses: 2 respondents were affiliated with an electric utility and 0 were affiliated with

1 This can include renewable natural gas. *See* Lynn A. Kirshbaum, "CHP and Renewable Fuels: A Cost-Effective Option for Long-Term Emissions Reductions," CHP Alliance, September 1, 2020, https://chpalliance.org/chp-and-renewable-fuels-a-cost-effective-option-for-long-term-emissions-reductions.

2 *See* Anna Dirkswager and Jamie Scripps, "What is Combined Heat and Power?," Great Plains Institute, March 13, 2018, https://www.betterenergy.org/blog/standby-rates-barriers-combined-heat-and-power.

3 *See* Dirkswager and Scripps, 2018.

4 See David Jones, Deborah Harris, and Bill Prindle, "As the Grid Gets Greener, Combined Heat and Power Still Has a Role to Play," ICF, 2019, https://www.icf.com/insights/energy/chp-role-in-decarbonization.

5 Regulators are also on the record on the issue of standby rates for CHP in states like Indiana, Michigan, Minnesota, Oregon, and Pennsylvania. *See, for example,* Indiana Utility Regulatory Commission, Cause No. 44576 (March 16, 2016), 77; Michigan Public Service Commission, Order, U-18255 (April 18, 2018), 77; Minnesota Public Utilities Commission, Docket No. CI-15-115, Order (October 3, 2017); Oregon Public Utility Commission, *Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations,* prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), 1; and Pennsylvania Public Utility Commission, Order, R-2018-3000124 (December 20, 2018), 62.

a gas utility; 4 were affiliated with a governmental entity (including regulators from Michigan and Ohio); 3 were categorized as providers of technical assistance; 1 was a consultant for a utility; 3 were consultants for advocates; 3 were consultants for other; 7 were manufacturers; 1 was an advocate; 8 were developers; 1 was an equipment supplier; and 1 was an original equipment manufacturer. In addition to the survey responses received, 20 individuals participated in direct interviews.

In both the survey results and interviews, there was overwhelming support for transparency and simplicity in standby rates. Ninety-one percent of survey respondents agreed that it should be considered a best practice for standby rates to be reasonably simple and transparent such that customers and third-parties can make informed decisions based on reading the published tariff, along with any accompanying educational materials.

There was also support for reference to a CHP system's forced outage rate in the calculation of a customer's monthly reservation fee. For example, Minnesota Power references a system's forced outage rate in calculating the customer's monthly "standby reservation fee."[6] Seventy percent of survey respondents agreed that it should be considered a best practice in standby rates to take into account both the utility's cost and the forced outage rate of customers' generators on the utility's system. This approach aligns with previous research on standby rates best practices published by the Regulatory Assistance Project, which states: "Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system."[7]

In both the survey results and interviews, there was strong support for reflecting time of use in the energy component of standby rates. Ninety-two percent of survey respondents agreed that it should be considered a best practice for the energy component of standby rates to reflect time of use, for example by reference to locational marginal price. Incorporating time of use through a reference to locational marginal price in calculating the energy component of a customer's standby charges aligns with an increasing focus on time-variant rates in rate design for all types of distributed generation, including CHP. The Energy Resources Center recommends the use of time-variant rates for the energy component of standby rates to "send clear price signals as to the cost for the utility to generate needed energy."[8]

Demand charges are capacity-related charges incurred when standby service is used during a scheduled or unscheduled outage. Sixty-two percent of survey respondents agreed that it should be considered a best practice in standby rates to use prorated, daily (or hourly) as-used demand charges for backup power. This aligns with previous research by Regulatory Assistance Project, which states: "Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability."

6 Minnesota Power, Rider for Standby Service, https://www.mnpower.com/Content/Documents/CustomerService/mp-ratebook.pdf#page=132.

7 Brubaker & Associates, Inc., and Regulatory Assistance Project, *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States*, prepared for Oak Ridge National Laboratory (February 2014), 5-6, https://info.ornl.gov/sites/publications/Files/Pub47558.pdf.

8 Energy Resources Center for the Minnesota Department of Commerce, *Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota* (2014), 11, https://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf.

For example, DTE Energy prorates its demand charges by the day, and only applies demand charges for outages taking place during on-peak hours.[9]

To keep a CHP system running efficiently, and to prevent unnecessary forced outages, scheduled maintenance outages are necessary at various times throughout the year. Seventy-seven percent of survey respondents agreed that it should be considered a best practice in standby rates for maintenance demand charge rates to be discounted relative to backup demand charge rates to recognize the scheduling of maintenance service during periods when the utility generation requirements are low. This aligns with previous research by Regulatory Assistance Project, which states: "Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low."[10]

A demand ratchet in standby rates is a mechanism by which a customer's rates are billed based on some percentage of the customer's peak demand during previous months—commonly the previous 11 months. Because it looks to a customer's highest peak over a timeframe in the past, a demand ratchet may reduce the incentive for a standby service customer to make efficient use of the grid in the present month. Seventy-five percent of survey respondents **disagreed** that it should be considered a best practice in standby rates for a utility to recover fixed costs using demand ratchets. Several interviewees expressed doubts as to the fairness of demand ratchets, citing a strong preference for as-used demand charges.

Lastly, the jury is still out on the use of coincident peak in calculating demand charges in standby rates. While a facility's coincident peak can be an indication of a customer's contribution to grid stress and related costs and can also be an incentive for a customer to avoid adding demand to the system during high-stress times, only 35 percent of survey respondents agreed that it should be considered a best practice in standby rates for demand charges to be assessed based on a facility's coincident peak. Forty-five percent of survey respondents disagreed with the use of coincident peak, and 23 percent of respondents stated that they needed more information. Based on this research, GPI recommends that utilities, regulators, and stakeholders look to the following as best practices in standby rates for CHP:

- Standby rates should be reasonably simple and transparent.
- Standby rates should take into account the forced outage rate of customers' generators.
- Time of use should be reflected in the energy component of standby rates.
- Maintenance demand charge rates should be discounted relative to backup demand charge rates.
- Demand charges for backup power should be prorated based on actual use.
- Demand ratchets in standby rates should be avoided where possible.

Utilities, regulators, and stakeholders may wish to investigate further the assessment of demand charges based on a facility's coincident peak.

9 DTE Energy, Rider 3, https://www.newlook.dteenergy.com/wps/wcm/connect/4c8d3126-f3f4-40ff-b436-b35f38f934c2/StandardContractRiderNo3.pdf?MOD=AJPERES.

10 Brubaker & Associates, Inc., and Regulatory Assistance Project (February 2014), 5-6.

Beyond these proposed best practices in standby rates for CHP, those interested in embracing the benefits of CHP as a resilient, low-carbon resource should also investigate: (1) distribution system cost allocation and rate design for CHP systems; (2) possibly exempting small CHP systems from standby charges; (3) updates to interconnection standards; and (4) the availability of CHP operational data to improve rate design in the future.

BACKGROUND

Standby rates are charged to customers with on-site distributed generation (i.e., generation sited close to its end-use) such as CHP systems. The rates are intended to help the utility recover costs related to reserving and providing backup electricity during scheduled and unscheduled outages of the customer's CHP system. Standby rates can be prorated to reflect partial and/or infrequent use by these customers.
In general, utilities' standby rates distinguish between two types of power:

- Maintenance power: Energy used during planned repairs to a CHP system. All CHP systems require infrequent but periodic maintenance. If a customer cannot fully cease business operations during this time, they will likely need to be connected to the utility for the purchase of maintenance power.
- Backup power: Backup power is energy supplied during unanticipated (or forced) outages of CHP systems. Modern CHP systems have very low forced outage rates (under 5 percent), making it unlikely that CHP systems will require backup power during peak hours.[11]

If a CHP system only covers a portion of the site's energy needs, the customer typically also contracts for supplemental power service, usually under a separate full requirements tariff. An agreement for supplemental service is not prorated, as the assumption is that the utility will provide 24/7 service.

WHY DO STANDBY RATES MATTER?

Customers relying on distributed energy (e.g., CHP, solar, etc.) pay standby charges to a utility even when their systems work perfectly and don't need standby power. There can be costs to a utility to provide power "on call" in the event of unplanned outages, and industrial customers expect to pay a fair rate for their energy needs. But standby rates can be poorly designed, or sometimes seem to intentionally discourage the use of CHP.

Depending on the size of a customer's CHP system, standby charges can run in the thousands (or tens of thousands) of dollars per month, which can significantly impact the economic viability of distributed energy options for industrial facilities.

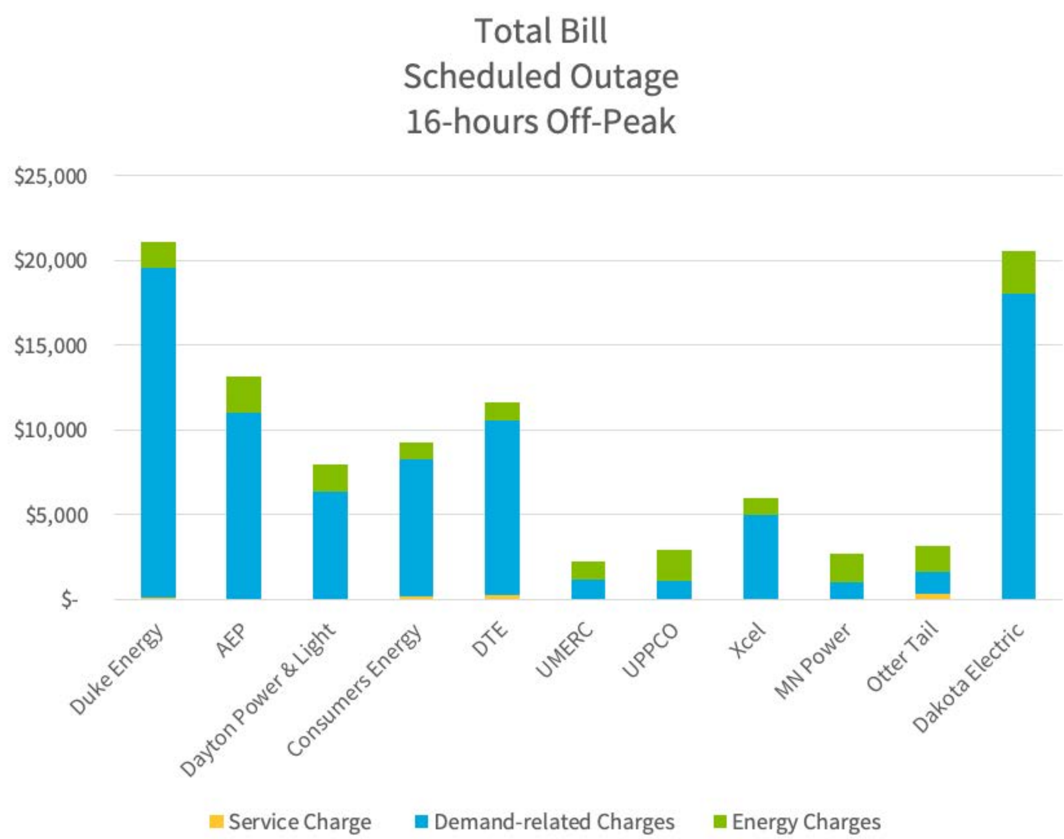
Additionally, because standby charges can vary significantly from utility to utility and across state lines, this variation can pose economic development challenges for states hoping to attract new companies that may be interested in pursuing CHP or other distributed generation to increase efficiency, reduce emissions, and save money.

GPI'S HISTORY OF CHP POLICY WORK

The Great Plains Institute (GPI) has a strong history of supporting CHP policy work in the Midwest.
Over the past five years, GPI has been actively engaged in standby rates work, initially supporting the

11 *See* Energy and Environmental Analysis, Inc., *Final Report: Distributed Generation Operational Reliability and Availability Database* (January 2004), prepared for Oakridge National Laboratory, https://www.energy.gov/sites/prod/files/2013/11/f4/dg_operational_final_report.pdf.

Figure 1. Monthly standby charges for CHP system experiencing a 16-hour scheduled off-peak outage



Source: 5 Lakes Energy, Apples-to-Apples: *Comparing Customer Standby Charges for Improved Rate Design* (2018).

development of the "apples-to-apples" standby rate analytical tool to inform stakeholder comments in the Minnesota standby rates proceeding in 2015.[12] The "apples-to-apples" tool compared monthly standby charges for a sample customer exhibiting the following characteristics:

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

For each sample customer, the apples-to-apples tool compared monthly standby bills for the following 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 32-hour outage occurring during on-peak times
- an unscheduled 8-hour on-peak/8-hour off-peak outage

12 *See* Minnesota Public Utilities Commission, Docket No. CI-15-115.

By using the apples-to-apples comparison tool, GPI has been active in supporting technical assistance in standby rate discussions across a number of states, including Michigan, Ohio, Indiana, and Illinois.[13]

GPI's standby rates best practices work[14] builds upon previous efforts related to standby rates and CHP, including:

- Hunterston Consulting (2019), *Where Things Stand on Standby Rates,* http://hunterstonconsulting.com.
- Exergy Partners and Entropy Research (2018), *Standby/Capacity Reservation Charge Best Practices and Review,* prepared for Pennsylvania PUC CHP Working Group, http://www.puc.state.pa.us/Electric/pdf/CHPWG/Standby_Cap_Res_Best_Practices_Review-071618.pdf.
- United States Environmental Protection Agency (EPA) CHP Partnership (2018), CHP Utility Rates, "Role of Standby Rates Webinar," https://www.epa.gov/chp/chp-utility-rates-role-standby-rates-webinar-may-31-2018RAP.
- Midwest Cogeneration Association (2016), "Model Conceptual Tariff Template" (attached as appendix A).
- Regulatory Assistance Project (2014), *Standby Rates for Combined Heat and Power Systems*, http://www.raponline.org/wp-content/uploads/2014/02/rap-standbyratesforchpsystems-2014-feb-18-updated.pdf.
- Energy Resources Center for the Minnesota Department of Commerce (2014), *Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota*, https://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf.
- US EPA (2009), *Standby Rates for Customer-Sited Resources*, https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf.

13 *See* 5 Lakes Energy, "Apples-to-Apples: Comparing Customer Standby Charges for Improved Rate Design" (2018), https://5lakesenergy.com/a2a_whitepaper/.

14 Anna Dirkswager and Jamie Scripps, *Improving Standby Rate Design Would Help Industries Increase Efficiency, Reduce Emissions, and Save Money*, Great Plains Institute, March 13, 2018, https://www.betterenergy.org/blog/standby-rates-barriers-combined-heat-and-power/.

STUDY: BEST PRACTICES FOR STANDBY RATES FOR CHP

In 2019, GPI recognized that while best practices in standby rates had begun to emerge, additional work was needed to further define and standardize these practices. Specifically, there was a need to test these emerging recommended practices with interested stakeholders such as regulators, potential CHP users, developers, technical experts, and utilities.[15] Early in 2020, GPI contracted with Jamie Scripps of Hunterston Consulting to conduct a survey and interviews to evaluate emerging best practices in standby rates for CHP. The following sections summarize the results and recommendations from the survey and subsequent interviews.

The starting point for GPI's study regarding best practices in standby rates for CHP was an initial list of emerging best practices, developed in collaboration with the Regulatory Assistance Project:[16]

- **Rates should be as simple and transparent as possible.** 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.
- **Rates should not assume usage during peak times.** Standby rates should not assume that backup or maintenance power will be needed during peak hours as this is seldom the case.[17]
    - o Thoughtful standby rate design can further reduce this risk[18] by incenting:
        - · proactive, scheduled maintenance; and
        - · efficient operation of CHP systems (during off-peak times).
- **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 can be the primary driver of customer costs incurred during a "no outage" month. Any reservation fee should be calculated based on the reliability of the system, which 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).

15 Regulators are also on the record on the issue of standby rates for CHP in states like Indiana, Michigan, Minnesota, Oregon, and Pennsylvania. See, for example, Indiana Utility Regulatory Commission, Cause No. 44576 (March 16, 2016), 77; Michigan Public Service Commission, Order, U-18255 (April 18, 2018), 77; Minnesota Public Utilities Commission, Docket No. CI-15-115, Order (October 3, 2017); Oregon Public Utility Commission, *Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations,* prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), 1; and Pennsylvania Public Utility Commission, Order, R-2018-3000124 (December 20, 2018,) 62.

16 Special thanks to Carl Linvill of the Regulatory Assistance Project for his thoughtful input.

17 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. *See* Energy and Environmental Analysis, Inc., *Final Report: Distributed Generation Operational Reliability and Availability Database* (January 2004), prepared for Oakridge National Laboratory, https://www.energy.gov/sites/prod/files/2013/11/f4/dg_operational_final_report.pdf.

18 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.

- 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.

In June 2020, GPI launched a survey requesting feedback on best practices in standby rates for CHP. The purpose of the survey was to begin the process of critically examining emerging best practices with interested stakeholders such as regulators, potential CHP users, developers, technical experts, and utilities. On June 29, 2020, GPI hosted a webinar to introduce and officially launch the survey.[19] Subsequent to the webinar, the survey was advertised widely within CHP networks, including through the CHP Alliance, the EPA CHP Partnership, the Midwest Cogeneration Association, and the Michigan Energy Innovation Business Council. Additionally, a GPI blog post introducing the survey was published on July 1, 2020.[20]

SURVEY RESPONDENTS

There were 34 total survey responses: 2 respondents were affiliated with an electric utility and zero were affiliated with a gas utility; 4 were affiliated with a governmental entity (including regulators from Michigan and Ohio); 3 were categorized as providers of technical assistance; 1 was a consultant for a utility; 3 were consultants for advocates; 3 were consultants for other; 7 were manufacturers; 1 was an advocate; 8 were developers; 1 was an equipment supplier; and 1 was an original equipment manufacturer.

INTERVIEWS

In addition to the survey responses received, 20 individuals participated in direct interviews. Of these interviewees, 2 were advocates; 2 were consultants for advocates; 1 was a consultant for other; 1 was a developer; 1 was affiliated with an electric utility; 1 was affiliated with a gas utility; 9 were affiliated with government (including regulators from Michigan and Ohio); 2 were affiliated with manufacturers; and 1 was affiliated with a technical assistance provider. Excerpts from some of the interviews are included in the section on interview and survey results.

PRESENTATIONS

On June 29, 2020, GPI hosted a webinar to introduce and officially launch the survey.[21] With over 35 participants, the webinar audience included a diverse range of perspectives, including CHP developers, utilities, technical consultants, and regulatory staff. In addition, on September 14, 2020, Jamie Scripps hosted a breakout session at the 2020 CHP Alliance Summit, in which she presented an overview of GPI's survey regarding best practices in standby rates for CHP, including results to date. [22]

19 Recording of Great Plains Institute webinar available at https://youtu.be/LCdk6AYGcdE.

20 Jamie Scripps, "GPI Launches Survey on Standby Rates Best Practices for Combined Heat and Power," Great Plains Institute, July 1, 2020, https://www.betterenergy.org/blog/gpi-launches-survey-on-standby-rates-best-practices-for-combined-heat-and-power/.

21 Recording of GPI webinar available at https://youtu.be/LCdk6AYGcdE.

22 See 2020 CHP Alliance Summit Agenda, https://web.cvent.com/event/3eef7932-ed4a-4896-8c72-28e2535d1284/websitePage:645d57e4-75eb-4769-b2c0-f201a0bfc6ce.

SURVEY AND INTERVIEW RESULTS

Question #1

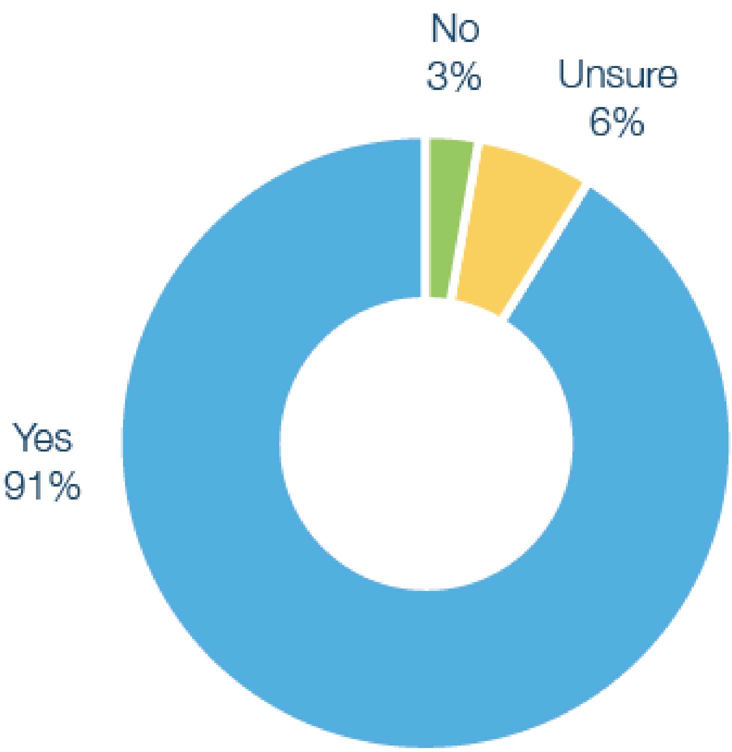
Please identify your relevant affiliation.

As stated above, there were 34 total survey responses: 2 respondents were affiliated with an electric utility and 0 were affiliated with a gas utility; 4 were affiliated with a governmental entity; 3 were categorized as providers of technical assistance; 1 was a consultant for a utility; 3 were consultants for advocates; 3 were consultants for other; 7 were manufacturers; 1 was an advocate; 8 were developers; 1 was an equipment supplier; and 1 was an original equipment manufacturer.

Question #2

Should it be considered a "best practice" for standby rates to be reasonably simple and transparent such that customers and third-parties can make informed decisions based on reading the published tariff (and any accompanying educational materials)?

Figure 2. Responses to question #2 of GPI survey re: best practices for standby rates for CHP



"A limited amount of complexity is feasible, so we should use complexity where it does the most good."

-STEVE HUSO, XCEL ENERGY MINNESOTA

GPI's previous research on standby rates highlighted a need for increased clarity and transparency in the presentation of standby tariffs to customers contemplating the installation of a CHP system.[23] Standby rates are complicated, and it can be difficult for a customer to interpret the published tariffs to estimate the potential standby costs involved. Historically, the discussion of standby rates has been utility-centric, the only concern

23 Jamie Scripps and Lola Schoenrich, "Q&A: Update on Where Things Stand on Standby Rates for Combined Heat and Power", Great Plains Institute, August 8, 2019, https://www.betterenergy.org/blog/where-things-stand-standby-rates-chp/.

being whether the utility was recovering its costs from standby customers. While this remains an important consideration, the perspective of the customer as they attempt to navigate a labyrinth of complicated standby charges is also a vital concern, to regulators and to a range of stakeholders, including those involved in a state's economic development efforts. In an age of increasing deployment of distributed generation resources, such as CHP, this emphasis on the needs and experience of the customer will only continue to grow.

While it may not always be possible to alter the structure and presentation of official tariffs, it is feasible for a utility to provide supplemental educational materials to current and potential customers to assist in navigating the published tariffs. Such materials might include a sample standby customer bill with an explanation of how charges are applied, and/or a fact sheet consolidating relevant information from various riders all in one place for easier access by customers. American Electric Power (AEP) Ohio, for example, provides bill calculation spreadsheets on its website.[24]

In both the survey results and interviews, there was overwhelming support for transparency and simplicity in standby rates. Ninety-one percent of survey respondents agreed that it should be considered a best practice for standby rates to be reasonably simple and transparent such that customers and third-parties can make informed decisions based on reading the published tariff, along with any accompanying educational materials.

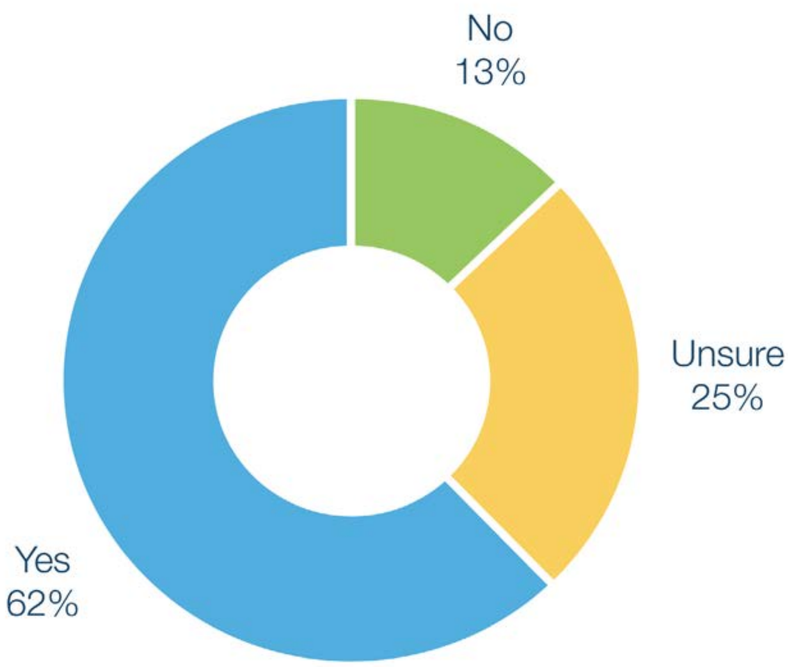
While they agreed with the principles of transparency and simplicity, some interviewees cautioned that standby rates must be sufficiently nuanced to reflect partial use of the grid. As a result, the goals of fairness and simplicity in standby rates might exist in tension with one another. In striking the appropriate balance, utilities and regulators should be aware of the benefits and challenges presented by the incremental detail added to standby rates. As Steve Huso of Xcel Energy Minnesota stated, "A limited amount of complexity is feasible, so we should use complexity where it does the most good."

24 "AEP Ohio Electric Rates," AEP Ohio website, https://www.aepohio.com/company/about/rates/.

Question #3

Should it be considered a "best practice" in standby rates to take into account both the utility's cost and the forced outage rate of customers' generators on the utility's system?

Figure 3. Responses to question #3 of GPI survey re: best practices for standby rates for CHP



"Standby rates shouldn't assume the worst case scenario. Forced outage rates are a good way to address this."

-KEVIN O'CONNELL, MICHIGAN CAT

When a CHP system's forced outage rate (FOR) is used in the calculation of a customer's reservation fee, an incentive is created for the customer to limit their use of unscheduled standby service due to the fact that fewer unscheduled outages lead to a better FOR, creating a strong price signal for the customer to run more efficiently. According to the Energy Resources Center, "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."[25] From a utility perspective, the FOR can be an indication of the likelihood of a future forced outage. Referencing the FOR in standby rates is one way to incorporate the risk of an unscheduled outage into the cost of standby service.

In practice, a CHP system's FOR might be factored into the calculation of a customer's monthly reservation fee. For example, Minnesota Power references a system's FOR in calculating the customer's monthly "standby reservation fee":

> The Customer shall pay a Standby Reservation Fee equal to the rate specified below times the contracted Reserved Standby Service and multiplied by the Generator Outage Rate as stated in the Customer's

25 Energy Resources Center for the Minnesota Department of Commerce, *Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota* (2014), 11, https://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf.

> Standby Service Agreement.[26]

This approach aligns with previous research on standby rates best practices published by the Regulatory Assistance Project, which states: "Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system."[27]

A majority of respondents and interviewees supported the use of FOR data in calculating a customer's standby charges. Seventy percent of survey respondents agreed that it should be considered a best practice in standby rates to take into account both the utility's cost and the FOR of customers' generators on the utility's system.

Some interviewees noted that reference to a CHP system's actual performance may be preferable to reliance on a class average FOR from a fairness and accuracy standpoint. While actual performance data may not be available during a CHP system's first year on a standby tariff, a utility will likely have sufficient FOR data in subsequent years such that reference to a CHP system's actual performance will become feasible after year one. For example, Minnesota Power strikes this balance by distinguishing between a CHP system's first year and subsequent years in its definition of "generator outage rate." For the first year, Minnesota Power's "Rider for Standby Service" states:

> For the first twelve (12) months the Customer takes service under this Rider, such rate shall be the Equivalent demand Forced Outage Rate (EFORd) class average published on the Midcontinent Independent System Operator (MISO) website most similar to the Customer's generation. The EFORd measures the probability that a generating unit will not be available. [28]

For subsequent years, Minnesota Power's "Rider for Standby Service" states:

> For subsequent 12-month periods, the Generator Outage Rate will be calculated based on generator availability for the Customer's generating facilities within the previous 12-month period. The Generator Outage Rate for the Customer's generating facilities shall be calculated as the number of hours the generator was not available in the prior 12-month period excluding Scheduled Outages divided by the *number of hours in a year.*[29]

26 Minnesota Power, *Rider for Standby Service* https://www.mnpower.com/Content/Documents/CustomerService/mp-ratebook.pdf#page=132.

27 Brubaker & Associates, Inc., and Regulatory Assistance Project (February 2014), 5-6.

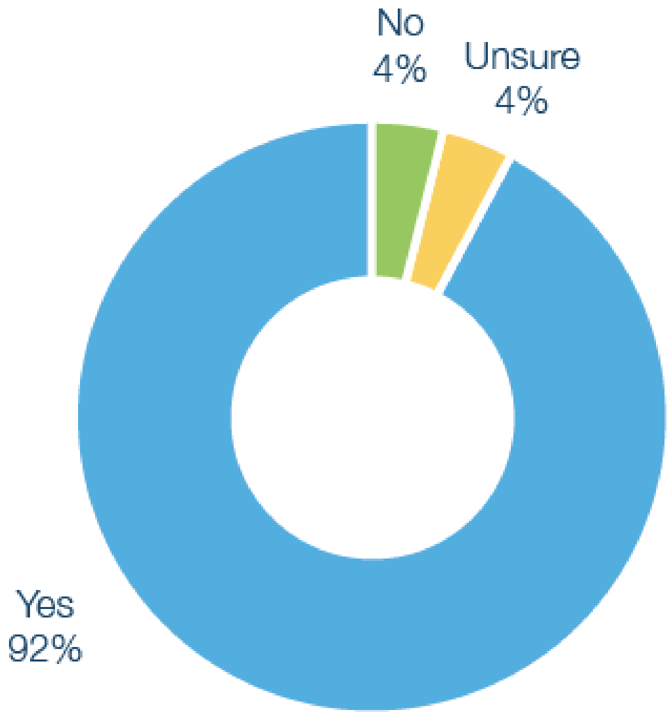
28 Minnesota Power, *Rider for Standby Service*.

29 Minnesota Power, *Rider for Standby Service*.

Question #4

Should it be considered a "best practice" for the energy component of standby rates to reflect time of use, for example by reference to locational marginal pricing ("LMP")?

Figure 4. Responses to question #4 of GPI survey re: best practices for standby rates for CHP



Incorporating time of use through a reference to LMP in calculating the energy component of a customer' standby charges aligns with an increasing focus on time-variant rates in rate design for all types of distributed generation, including CHP. According to the National Association of Regulatory Utility Commissioners (NARUC)), "Time-variant rates (TVRs) are designed to recognize differences in a utility's cost of service and marginal costs at different times (e.g., hour, day, or season)."[30]

The Energy Resources Center recommends the use of TVRs for the energy component of standby rates in order to "send clear price signals as to the cost for the utility to generate needed energy."[31]

Real-time pricing, such as referencing LMP for the energy component of standby rates, is an example of a time-variant rate: "Under a real-time pricing (RTP) plan, the customer is charged for generation at the price set by the wholesale market (for deregulated utilities or vertically integrated utilities participating in an organized wholesale market) or at the short-run marginal generation costs (for vertically integrated utilities not participating in an organized wholesale market) by the hour."[32]

30 National Association of Regulatory Utility Commissioners (NARUC), *NARUC Manual on Distributed Energy Resources Rate Design and Compensation* (2016), 26, https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

31 Energy Resources Center for the Minnesota Department of Commerce (2014), 11.

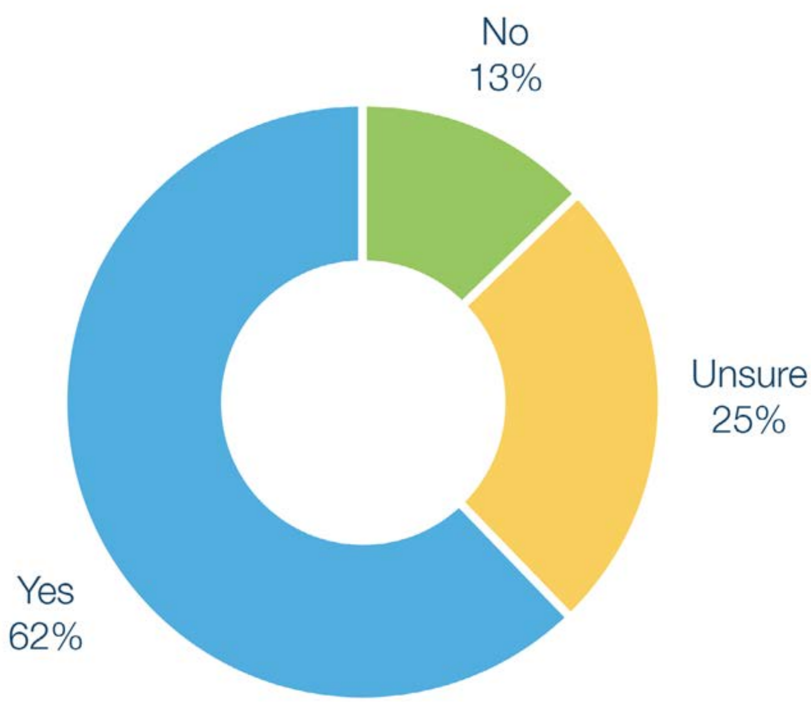
32 National Association of Regulatory Utility Commissioners (2016), 28.

In both the survey results and interviews, there was strong support for reflecting time of use in the energy component of standby rates. Ninety-two percent of survey respondents agreed that it should be considered a best practice for the energy component of standby rates to reflect time of use, for example by reference to LMP. While generally supportive of reflecting time of use, many interviewees noted that the energy component is the least problematic aspect of standby rates, as it is calculated on a per kWh basis and thus inherently linked to a standby customer's partial use of the grid. Some interviewees noted that a fixed energy price, versus reference to LMP, would provide more long-term certainty for CHP system owners and energy managers.

Question #5

Should it be considered a "best practice" in standby rates to use prorated, daily (or hourly) as-used demand charges for backup power?

Figure 5. Responses to question #5 of GPI survey re: best ractices for standby rates for CHP



Demand charges are capacity-related charges incurred when standby service is used during a scheduled or unscheduled outage. For some utilities, demand charges are waived if the reservation fee is higher than demand charges incurred (to avoid duplicating capacity charges). Demand charges are often higher during peak times, or for unscheduled outages, to provide an incentive for scheduling maintenance during off-peak times, and to ensure that a utility recovers the additional costs associated with providing standby service without advanced notice. In its 2014 research on standby rates best practices, RAP stated: "Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability."

Utilities may wish to further limit the application of as-used demand charges to outages that take place during on-peak times. According to the Energy Resources Center, "The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage distributed generation customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages."[33]

A majority of respondents and interviewees supported the use of prorated, as-used demand charges. Specifically, 62 percent of survey respondents agreed that it should be considered a best practice in standby rates to use prorated, daily (or hourly) as-used demand charges for backup power.

Demand charges can be prorated at the daily or hourly level. For example, DTE Energy prorates its demand charges by the day, and only applies demand charges for outages taking place during on-peak hours:

> A daily on-peak standby demand charge based on the determination of standby power coincident with the daily highest 30-minute integrated reading during on-peak hours of the demand meters which measure the total load served by the Company.[34]

By contrast, Xcel Energy prorates at the hourly level with its "peak period standby energy usage" surcharge:

> Peak period standby energy usage is the amount of Standby Energy Usage occurring during the peak period that does not occur during a qualifying scheduled maintenance period or is associated with Non-Firm service. Peak period standby energy usage is subject to the Peak Period Standby Energy Surcharge.[35]

Question #6

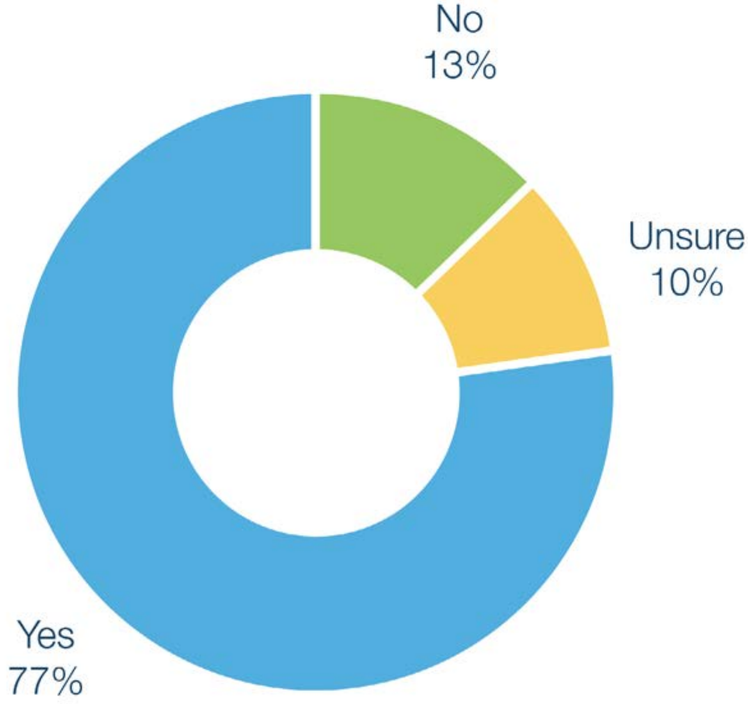
Should it be considered a "best practice" in standby rates for maintenance demand charge rates to be discounted relative to backup demand charge rates to recognize the scheduling of maintenance service during periods when the utility generation requirements are low?

33 Energy Resources Center for the Minnesota Department of Commerce (2014), 11.

34 DTE Energy, *Rider 3*, https://www.newlook.dteenergy.com/wps/wcm/connect/4c8d3126-f3f4-40ff-b436-b35f38f934c2/StandardContractRiderNo3.pdf?MOD=AJPERES.

35 Xcel Energy, *Standby Service Rider*, https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf.

Figure 6. Responses to question #6 of GPI survey re: best practices for standby rates for CHP



"Maintenance service is usually scheduled far in advance, and can take place during non-peak periods and seasons, so it creates few additional capacity costs for the utility."

-GRAEME MILLER, ENERGY RESOURCES CENTER

To keep a CHP system running efficiently, and to prevent unnecessary forced outages, scheduled maintenance outages are necessary at various times throughout the year. These scheduled CHP system outages typically are planned and communicated ahead of time in ways that minimize costs to the utility. As a result, scheduled outages have little downside, and create the additional benefit of reducing more costly unscheduled outages, which helps to achieve optimum use. For these reasons, scheduled maintenance outages should be encouraged by a utility through communication with the customer and through intentional standby rate design. One way to do this is to build in reduced demand charge rates for scheduled maintenance outages.

This recommended best practice aligns with previous research and regulatory recommendations. In its 2014 research, the Regulatory Assistance Project stated: "Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low."[36]

Additionally, in their 2017 Standby Rate Working Group Supplemental Report, Michigan Public Service Commission staff recommended: "Standby service tariffs should include a reasonable capacity price differential to encourage scheduled maintenance, which in turn may reduce unscheduled outages."[37]

A strong majority of respondents and interviewees supported the use of discounted maintenance demand charges. Specifically, 77 percent of survey respondents agreed that it should be considered a best practice in standby rates for maintenance demand charge rates to be discounted relative to backup demand charge rates to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.

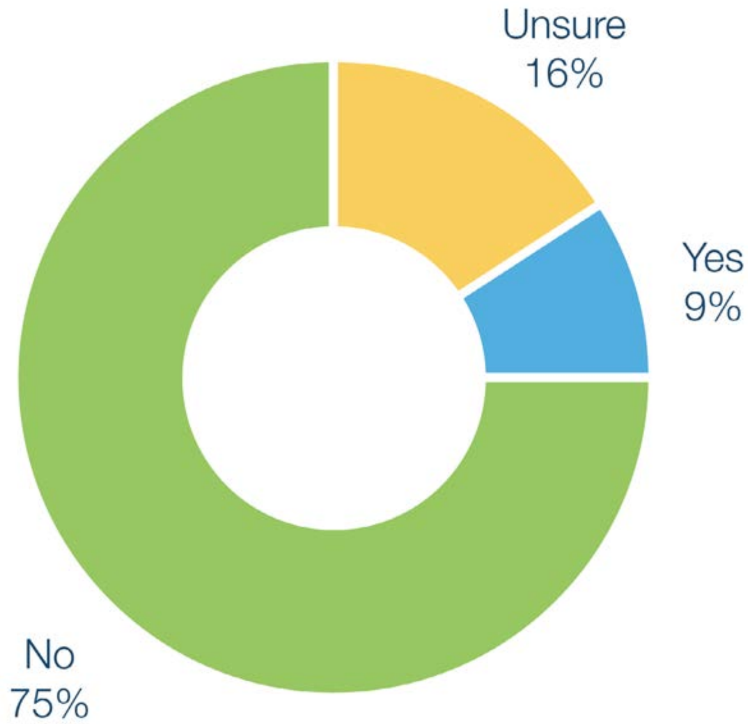
36 Brubaker & Associates, Inc., and Regulatory Assistance Project (February 2014), 5-6.

37 Michigan Public Service Commission Staff, *Standby Rate Working Group Supplemental Report* (June 2017), 23, http://www.michigan.gov/documents/mpsc/SRWG_Supplemental_2017_Report_576352_7.pdf.

Question #7

Should it be considered a "best practice" in standby rates for a utility to recover fixed costs through the use of demand ratchets?

Figure 7. Responses to question #7 of GPI Survey re: best practices for standby rates for CHP



A demand ratchet in standby rates is a mechanism by which a customer's rates are billed based on some percentage of the customer's peak demand during previous months—commonly the previous 11 months. Sometimes the demand ratchet captures 100 percent of the customer's previous peak demand. More often, the demand ratchet references a portion (e.g., 60-75 percent) of the customer's peak demand over the previous timeframe. Because it looks to a customer's highest peak over a timeframe in the past, a demand ratchet may reduce the incentive for a standby service customer to make efficient use of the grid in the present month. According to research by the Rocky Mountain Institute (RMI), "A Ratchet Mechanism can help stabilize utility revenue by locking in a floor at a certain level for the customer's demand bill, but the mechanism may remove customers' incentive to reduce peak load, depending on how the ratchet is designed."[38]

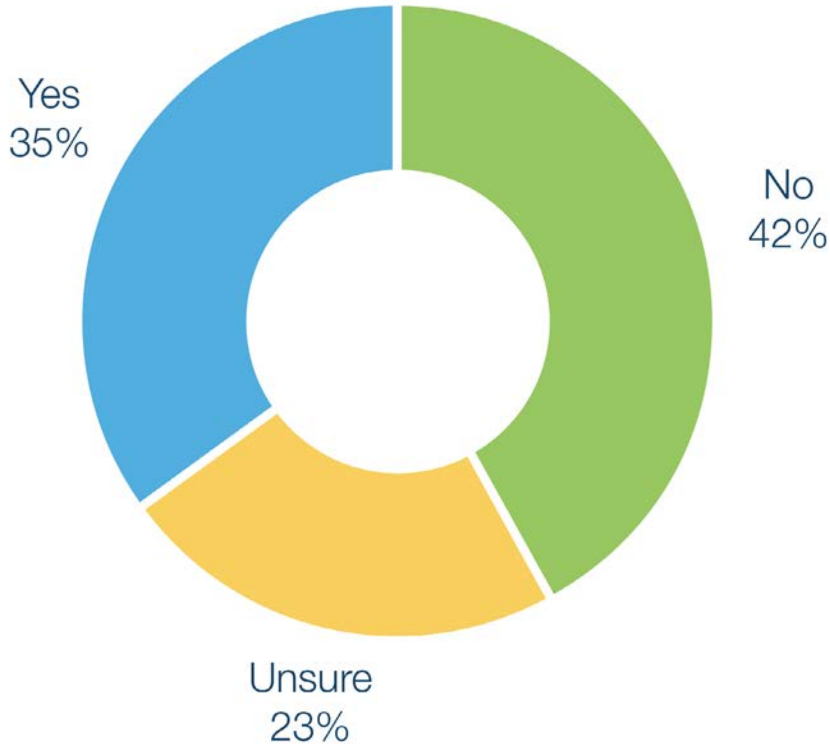
Most survey respondents and interviewees opposed the use of demand ratchets in standby rates. Specifically, 75 percent of survey respondents disagreed that it should be considered a best practice in standby rates for a utility to recover fixed costs through the use of demand ratchets. A number of interviewees expressed doubts as to the fairness of demand ratchets, citing a strong preference for as-used demand charges as an indication that a particular standby rate design reflects the true cost of service.

38 Rocky Mountain Institute, *A Review of Alternative Rate Designs* (2017), 7, https://rmi.org/wp-content/uploads/2017/04/A-Review-of-Alternative-Rate-Designs-2016.pdf.

Question #8

Should it be considered a best practice in standby rates for demand charges to be assessed based on a facility's coincident peak?

Figure 8. Responses to Question #8 of GPI Survey re: Best Practices for Standby Rates for CHP



A facility's coincident peak can be an indication of a customer's contribution to grid stress and related costs; it can also be an incentive for a customer to avoid adding demand to the system during high-stress times. According to RMI, "Peak Coincidence can provide a more-targeted price signal, where charges coincident with system peak may help customers understand when to reduce their demand."[39] Reference to peak coincidence is typically seen where generation, distribution, and transmission costs have been unbundled in rates, and transmission charges are assessed in alignment with a regional transmission organization's transmission tariff. For example, PECO's "Transmission Service Charges" are allocated "to each rate class based upon the coincident peak used by PJM to establish the network service obligation."[40]

The jury is still out on the use of coincident peak in calculating demand charges in standby rates. Only 35 percent of survey respondents agreed that it should be considered a best practice in standby rates for demand charges to be assessed based on a facility's coincident peak. Forty-five percent of survey respondents disagreed with the use of coincident peak, and 23 percent of respondents stated that they needed more information.

39 Rocky Mountain Institute (2017), 7.
40 PECO Energy Company, *Electric Service Tariff*, https://www.peco.com/SiteCollectionDocuments/elec_tariff_eff_June_1_2016.pdf.

OTHER THEMES FROM INTERVIEWS

CHP as a Low-Carbon Resource

Multiple interviewees noted that, as the power system transitions from a focus on centralized generation to more distributed, low-carbon resources, there is an opportunity for CHP to provide valuable contributions to this future energy mix. CHP works well in conjunction with other clean energy resources, such as solar and wind, which can be integrated with CHP to create hybrid low-carbon systems.[41] As utilities and regulators examine potential improvements to standby rates, there may be strong policy motivation to ensure that standby rates do not pose an undue barrier to the deployment of CHP as a low-carbon, resilient energy resource.

Exempting Small CHP Systems

Some interviewees noted that standby rates can be particularly onerous for small CHP systems, and expressed a view that small CHP systems should be exempt from standby charges. According to the National Renewable Energy Laboratory (NREL), "Customers with demand metering and a contract demand less than 50 kW, as well as all non-demand metered customers, can be exempt from standby tariffs in New York."[42] For example, Consolidated Edison Company of New York (Con Edison) provides the following section titled "Customers Exempt from Standby Service Rates" in its schedule for electric service:

> Customers with a Contract Demand of less than 50 kW with on-site generating equipment having a total nameplate rating greater than 15 percent of the maximum potential demand served from all sources, provided, however, that a Customer not described in subparagraph (a) may elect to be billed under Standby Service rates in its application for Standby Service.[43]

Under the Con Edison model, customers with small CHP systems who are on a demand rate may choose to be billed under the utility's standby rates; otherwise, they are exempt from standby charges.[44]

Distribution System Cost Allocation and Rate Design

Interviewees expressed a range of opinions on the topic of distribution system cost allocation and rate design for CHP. Some expressed reluctance regarding proration of distribution costs, stating that the distribution grid must "stand ready" to serve standby customers at all times.

41 *See* Mary Kate McGowan, American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), *A Strategy to Create a Lower Carbon Future: Integrating CHP Systems, Renewable Energy to Increase Resilience* (2019), https://www.ashrae.org/technical-resources/ashrae-journal/featured-articles/a-strategy-to-create-a-lower-carbon-future-integrating-chp-systems-renewable-energy-to-increase-resilience.

42 National Renewable Energy Laboratory (NREL), *Rate Structures for Customers With Onsite Generation: Practice and Innovation* (2005), 36-37, https://www.nrel.gov/docs/fy06osti/39142.pdf.

43 Con Edison, *Schedule for Electric Service*, 175, https://www.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf#page=156.

44 *See* Con Edison, *Schedule for Electric Service*, 175.

Other interviewees viewed the distribution grid as a shared resource, the costs for which should be apportioned according to standby customers' actual use of the resource.[45]

The concept of prorating distribution charges for standby service customers was highlighted in a distribution rate case proceeding in Pennsylvania. There, in her recommended decision dated October 18, 2018, Administrative Law Judge Katrina Dunderdale agreed with intervenors that it was unreasonable to allocate distribution charges to standby service customers without taking into account those customers' partial and infrequent use of system resources. The recommended decision in that proceeding stated: "Duquesne Light is unreasonable to insist that it must calculate its rate for this class based on an assumption that it will provide service constantly during the entire time period."[46] Though the Pennsylvania Public Utility Commission declined to adopt all of the administrative law judge's recommendations, the result of the case was for the electric utility's distribution charge rate to remain at $2.50 per kW for standby customers, rather than increase to $8.00 per kW as was originally proposed by Duquesne Light. Overall, CHP systems' high availability, low forced outage rates and load diversity, all played a role in the discussion of how standby customers should be charged for their use of the distribution grid.[47]

"Improving the interconnection process will be a big help for businesses that are trying to meet sustainability goals and others who want to install CHP systems or other on-site advanced energy systems to improve reliability and decrease costs."

-DR. LAURA SHERMAN,
MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

While the proration of distribution charges for standby service customers is not a universally accepted practice, increases in distribution spending by utilities in the future may create elevated tension between utility and customer interests in standby rate design, and may warrant a fresh look at how standby customers are charged for their partial and infrequent use of the distribution system. Utilities and regulators interested in exploring this topic in more detail may benefit from conducting a distribution-level cost of service study specific to standby customers. The concept of a distribution-level cost of service study was highlighted in a recent Michigan rate case, in which Consumers Energy agreed in a settlement to "provide a study analyzing the cost to serve standby service customers" and to "provide its distribution cost allocation study to interested parties."[48]

45 In January 2020, Regulatory Assistance Project published a helpful cost allocation guide for the modern grid, including extensive discussion of distribution cost allocation. *See* Jim Lazar, Paul Chernick, William Marcus, *Electric Cost Allocation for a New Era: A Manual*, ed. Mark LeBel (Montpelier, VT: Regulatory Assistance Project, January 2020), 142, https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/.

46 Administrative Law Judge Katrina Dunderdale, Recommended decision in R-2018-3000124, 174.

47 *See* Pennsylvania Public Utility Commission, Order, R-2018-3000124, December 20, 2018, 44-67.

48 Michigan Public Service Commission, Case No. U-20134, Order Approving Settlement Agreement (January 9, 2019), 4.

Interconnection

Standardized interconnection rules are helpful in promoting safe and reliable parallel operation of distributed generation facilities. Interviewees remarked that the easier it is for system owners to navigate interconnection rules and procedures, the easier it will be to realize the benefits of distributed generation such as CHP. Utilities and regulators looking to standardize and streamline the interconnection process may wish to pursue an update to statewide interconnection procedures. For example, Minnesota was among the first to implement new interconnection standards that comport with IEEE 1547-2018,[49] and the Minnesota Public Service Commission (MN PUC) recently updated the state's interconnection procedures in Docket EEE/CI-16-521[50] with the goals of:

- Establishing a practical, efficient interconnection process that is easily understandable for everyone involved;
- Maintaining a safe and reliable electric system at fair and reasonable rates;
- Giving maximum possible encouragement of distributed energy resources consistent with protection of the ratepayers and the public;
- Being consistent statewide and incorporate newly revised national standards;
- Being technology neutral and non-discriminatory.

Adopted in August 2018,[51] the Minnesota Distributed Energy Resources Interconnection Process[52] applies to distributed energy resources, including CHP, no larger than 10 MW, and includes a fast-track process, a supplemental review, a streamlined interconnection process for projects less than 20 kW, the addition of energy storage as an eligible project, a pre-application report, and requirements for utilities to publish a public interconnection queue every year. Detailed technical requirements were updated as of July 1, 2020, via the Minnesota Technical Interconnection and Interoperability Requirement.[53]

Importance of CHP Data

Interviewees emphasized the importance of access to real-world CHP data, which can help utilities, regulators, and other stakeholders better understand how CHP systems perform, which can enable improvements to rate design. With actual performance data, the benefits and risks of CHP operation can be analyzed and integrated into how customer standby charges are calculated, increasing the fairness and accuracy of cost-based rates.

For example, performance data for all New York State Energy Research and Development Authority (NYSERDA)-incentivized distributed energy resource (DER) projects are publicly available, including "real-world data from over 1,200 live DER projects in New York State in one of two ways, by viewing a map of DERs across New York or

49 IEEE Standards Association, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, https://standards.ieee.org/standard/1547-2018.html.

50 Minnesota Public Utilities Commission, *State of Minnesota Distributed Energy Resources Interconnection Process v. 2.3 (MN DIP)*, approved by Minnesota Public Service Commission in Docket No. E999/CI-16-521 (Order dated April 19, 2019), https://mn.gov/puc/assets/MN%20DIP_tcm14-431769.pdf.

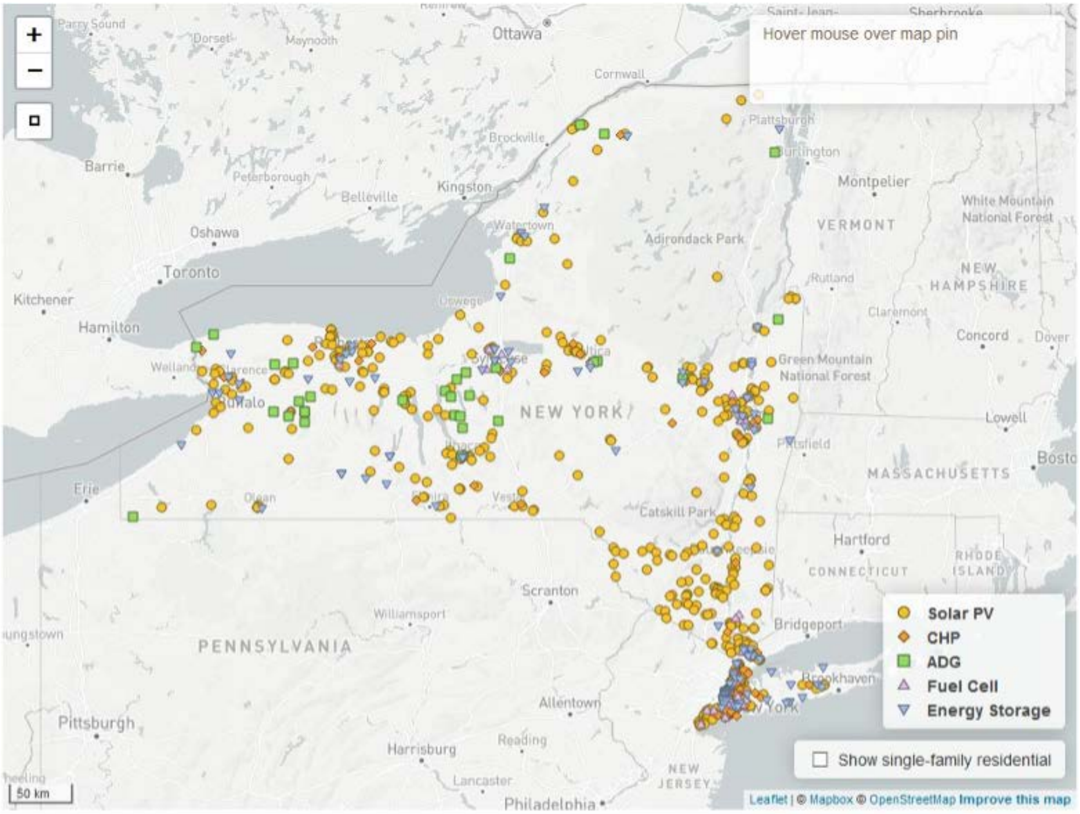
51 On August 13, 2018, the MN PUC issued its Order Establishing Updated Interconnection Process and Standard Interconnection Agreement in Docket No. E-999/CI-16-521.

52 Minnesota Public Utilities Commission, *State of Minnesota Distributed Energy Resources Interconnection Process v. 2.3 (MN DIP)*, approved by Minnesota Public Service Commission in Docket No. E999/CI-16-521 (Order dated April 19, 2019).

53 State of Minnesota, Minnesota Technical Interconnection and Interoperability Requirement, as approved by the Minnesota Public Utilities Commission (Order dated January 22, 2020), https://mn.gov/puc/assets/TIIR%20w%20CORRECTED%20Interim%20Implementation%20Guidance_tcm14-431321.pdf.

by searching for projects through criteria you select."[54] The NYSERDA DER dataset includes performance data for over 200 completed and operational CHP projects that were funded under now-closed NYSERDA incentive programs.[55]

Figure 9. Map of New York state distributed energy resource facilities



Source: "Map of New York State Distributed Energy Resources Facilities," NYSERDA, accessed March 10, 2021, https://der.nyserda.ny.gov/map/.

Beyond improvements to traditional standby rate design components, and through increased access to real-world CHP operational data, there may be ways in the future to quantify the resilience benefits of CHP and reflect those benefits in rate credits, or other compensation from the utility, in cases such as when a CHP unit can provide power or ancillary services as a least cost solution to local congestion or reliability challenges, or where a CHP facility with the ability to island might provide a location of resilience in the community.

54 "Distributed Energy Resources Performance Data," New York State Energy Research and Development Authority website, https://der.nyserda.ny.gov/data/performance/.

55 *See* "Distributed Energy Resources Performance Data," New York State Energy Research and Development Authority website, https://der.nyserda.ny.gov/data/performance/.

RECOMMENDATIONS

When GPI initiated this study on best practices for standby rates for CHP, it recognized that work was needed to further define and standardize these practices. There was also a need to test emerging recommended practices with interested stakeholders such as regulators, potential CHP users, developers, technical experts, and utilities. Based on a diverse range of stakeholder input, including survey responses and direct interviews collected from June through September 2020, GPI recommends that utilities, regulators, and stakeholders look to the following as best practices in standby rates for CHP:

- Standby rates should be reasonably simple and transparent.
- Standby rates should take into account the forced outage rate of customers' generators.
- Time of use should be reflected in the energy component of standby rates.
- Maintenance demand charge rates should be discounted relative to backup demand charge rates.
- Demand charges for backup power should be prorated based on actual use.
- Demand ratchets in standby rates should be avoided where possible.

In addition, while GPI is not recommending it as an accepted best practice at this time, utilities, regulators, and stakeholders may wish to investigate further the assessment of demand charges based on a facility's coincident peak.

Beyond these proposed best practices in standby rates for CHP, those interested in embracing the benefits of CHP as a resilient, low-carbon resource should also investigate: (1) distribution system cost allocation and rate design for CHP systems; (2) possibly exempting small CHP systems from standby charges; (3) updates to interconnection standards; and (4) the availability of CHP operational data to improve rate design in the future.

APPENDIX A:

CONCEPTUAL MODEL TARIFF TEMPLATE

SOURCE: REPUBLISHED WITH PERMISSION FROM THE MIDWEST COGENERATION ASSOCIATION (2016).

Midwest Cogeneration Association
Conceptual Model Standby Rate Tariff

Monthly Customer Charge	Zero, assuming this is already included in the customer's supplemental power tariff (Based on administrative costs) **AND** Charge or Credit to reflect greater or lesser administrative costs associated with partial-use customer.
Monthly Reservation Fee	Zero (instead recover in demand charge) **OR** Fixed fee to recover utility's embedded costs for generation capacity (or capacity market purchases) and transmission based on FOR of best performing CHP systems
On-Peak Daily, Daily or Hourly Demand Charge	**SCHEDULED** Zero **OR** Low variable demand charge proportionate to hours of planned usage reflecting utility's lower costs due to planning at times that impose zero or low cost to utility. **AND** Reduced (or zero) variable demand charge for off-peak usage to reflect utility's lower costs during off-peak hours. **UNSCHEDULED** If no Reservation Fee, variable demand charge designed to recover proportion of utility's embedded costs for generation capacity (or capacity market purchases) and transmission based on CHP partial-use customer's hours of unscheduled use. **OR** If a fixed Reservation Fee is also charged, variable demand charge designed to recover utility's embedded costs for generation capacity (or capacity market purchases) and transmission based on CHP partial-use customer's proportionate use above FOR assumed in Reservation Fee **AND** Reduced (or zero) variable demand charge for off-peak usage to reflect utility's lower costs during off-peak hours.
Energy Charge	If no Reservation Fee and Demand Charge, recover proportion of utility's embedded costs for generation capacity (or capacity market purchases) and transmission in energy charges based on CHP partial-use customer's hours of use. Pricing should reflect utility's lower costs for scheduled usage and off-peak usage. **OR** If embedded generation capacity (or capacity market purchases) and transmission are recovered in Reservation Fee and/or Demand Charge, energy pricing should reflect utility' s average fuel and purchased energy costs (or utility's spot energy market purchases in the case of capacity market purchases). **AND** Pricing should reflect peak and off-peak energy prices or real-time energy prices.

Conceptual model tariff template notes::

1. On-Peak Daily, Daily and Hourly demand billing units should be calculated as the customer's demand in excess of its supplemental service demand billing units. For example, assume a customer has a 50 MW generator and 50 MW of supplemental demand. If the customer in a given hour has a 25 MW generation derate, but its supplemental demand is simultaneously down by 25 MW such that the customer's net demand is still below 50 MW, the standby demand for that customer for that hour should be zero.

2. Delivery (i.e., distribution) service charges for standby service should generally be the same for standby service as they are for supplemental service (including any credits for a customer ownership of their own substation). However, where there are distribution networks whose costs are driven by the peak demand on that network rather than the non-coincident peak demand of individual customers, consideration should be given to the expected contribution of the standby service to the peak demand placed on that distribution network.