GPI/5 Lakes "Apples-to-Apples" Standby Rate Comparison: Ohio Report

Contents

Introduction

Standby rates are a type of electric tariff imposed on customers with on-site distributed generation such as combined heat and power (CHP) systems. The rates are intended to help the utility recover costs related to reserving such service and providing backup electricity during scheduled and unscheduled outages of the customer's CHP system.

Poorly designed standby rates can be a barrier to the development of otherwise economically viable CHP projects. When 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." When this happens, it represents a significant missed opportunity for the state. CHP offers many important benefits, such as increased reliability and efficiency. While two-thirds of the fuel used to generate electricity in the U.S. is wasted by venting or dissipating unused thermal energy, CHP systems generate both heat and electricity from a single fuel source, and can operate at efficiency levels as high as 80%, creating energy savings and reducing emissions.[1]

In order to demonstrate the wide variation among standby rates within and across state boundaries, and to highlight areas for improvement in standby rate design, the Great Plains Institute ("GPI") and 5 Lakes Energy LLC ("5 Lakes") have performed an "apples-to-apples" scenario-based analysis of standby tariffs in Minnesota, Michigan, Pennsylvania, and Ohio.[2] While a number of valuable standby rate analyses have been completed in the past[3] the GPI/5 Lakes "apples-to-apples" analysis is unique in that it compares monthly bills across a variety of outage scenarios, demonstrating the impact of widely varying standby tariffs on current and potential CHP customers.

Methodology

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

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[1] See U.S. EPA Combined Heat and Power (CHP) Partnership, CHP Benefits, https://www.epa.gov/chp/chp-benefits

[2] The "apples to apples" analyses of standby rates of utilities in Minnesota, Michigan and Pennsylvania have all been verified by utility representatives.

[3] *See* the University of Illinois at Chicago's Energy Resources Center "Avoided Rate" analysis in Minnesota (2014), available at http://mn.gov/commerce-stat/pdfs/card-report-anal-standby-rates-net-metering.pdf and the Ohio Manufacturers' Association analysis (2013) comparing capacity costs incurred by utilities in providing standby service versus capacity charges imposed on standby customers, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A13A30B61816B45344.

in which it compared estimated standby bills for a hypothetical customer experiencing a range of CHP system outages.[4] The sample customer[5] used in the analysis exhibits 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.

5 Lakes Energy has also included discussion of standby costs for a sample customer with 2,000 kW in total load who takes no supplemental service beyond the 2,000 kW in standby service used to back up the customer's CHP system (see Standby vs. Supplemental Service discussion, beginning on page 12). While not originally part of the "apples to apples" methodology, this addition proved important to discussing significant features of Ohio utilities' standby rates.

For each type of customer, the "apples to apples" standby rate analysis examined published tariffs to compare estimated 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 8-hour on-peak/8-hour off-peak outage;
- a scheduled 32-hour outage occurring during on-peak times; and
- an unscheduled 8-hour on-peak/8-hour off-peak outage.

"Apples-to-Apples" Results: Ohio

The GPI/5 Lakes "apples-to-apples" analysis for Ohio looks at the following utilities: Duke Energy, AEP, and Dayton Power & Light.[6] The process of calculating estimated standby bills is particularly complex in Ohio, due to the practice of separating out charges into dozens of individual riders. Requiring customers to locate these riders and calculate kW-based and/or

[4] GPI/5 Lakes reached out to each Ohio utility in an attempt to verify that it correctly interpreted the published tariffs and riders. AEP Ohio was extremely helpful, providing clarifications to our initial analysis. Dayton Power & Light provided general guidance as to how to approach their rate structure. Duke Energy declined to talk to us until such time that "the Commission wishes to hold a more global forum with all interested parties."
[5] Sample customer characteristics were adapted from Minnesota Power's billing simulations provided in Minnesota PUC Docket No. E-999/CI-15-115, and adapted for a General Service customer served at the Primary Distribution level.
[6] GPI/5 Lakes had also originally intended to include FirstEnergy in this analysis. However, representatives from the utility requested that we hold off on performing an analysis of FirstEnergy's current tariff, stating: "Please be advised that our partial service tariffs are under revision pursuant to the PUCO Order dated 3/31/16 in Case No. 14-1297-EL-SSO. The Companies will file amended partial service tariffs that minimize risks to other non-shopping customers and reflect the fact that the Companies no longer own generation and source generation for their non-shopping customers via a competitive bid process."

kWh-based charges in reference to each is an example of a barrier to CHP deployment that could be solved by streamlining and simplifying the structure of these utility standby rates.

Overall, Ohio standby rates are high compared to utilities in other states. For example, the average total bill for a Scheduled 16-hour off-peak outage is $10,354 across all utilities in the analysis, and $14,045 for the Ohio utilities in the analysis. The disparity is even more dramatic when you look at the average total bill for a Scheduled 16-hour on-peak outage, which is $13,144 across all utilities in the analysis, and $20,656 for the Ohio utilities in the analysis.

For the Ohio utilities, these high total charges are driven by high demand charges, which are calculated based on contract capacity and subject to little to no pro-ration based on partial use by standby customers. For Duke Energy, this applies even to the "no outage" scenario.

For AEP, there are no charges at all for the "no outage" scenario when the customer takes 3,000 kW in supplemental service. However, if a customer takes no supplemental service, the total charges for the "no outage" scenario jump to $11,698.13. Across the Ohio utilities included in this analysis, a customer's level of supplemental service has a material impact on standby charges. This topic will be discussed in more detail later on in this report (see Standby vs. Supplemental Service discussion, beginning on page 12). Overall, separating supplemental service from standby service for purposes of calculating standby charges is another example of way in which the Ohio utilities should improve their standby rates to remove a barrier to CHP deployment.

Finally, it is notable that the Ohio utilities included in this analysis do not differentiate significantly between scheduled and unscheduled outages, which raises the question whether customers who pre-schedule maintenance outages are subsidizing customers who experience unscheduled outages under this rate design. Scheduled and unscheduled outages should be treated differently in standby rates to promote efficient use and proactive maintenance of the CHP system.

The tables below highlight total estimated standby bills by outage scenario:

Table 1: Ohio – Total Estimated Bills by 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
AEP	$0	$13,120	$22,360	$22,360	$24,436	$22,360
DP&L	$6,357	$7,952	$18,547	$18,547	$20,143	$18,547

Table 2: Minnesota – Total Estimated Bills by 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)
Minn 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

Table 3: Michigan – Total Estimated Bills by 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	$8,300	$9,246	$11,645	$11,191	$14,833	$11,191
DTE	$10,535	$11,657	$18,653	$13,405	$30,272	$17,545
UMERC	$0	$2218	$3098	$2658	$6196	$30,536
UPPCO	$0	$2911	$3883	$3397	$7766	$31,631

Table 4: Pennsylvania – Total Estimated Bills by 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)
PECO Energy	$11,519	$12,379	$12,609	$12,494	$13,699	$12,494
PPL Electric	$5264	$6111	$6396	$6254	$7530	$6254

Comparison of Charges

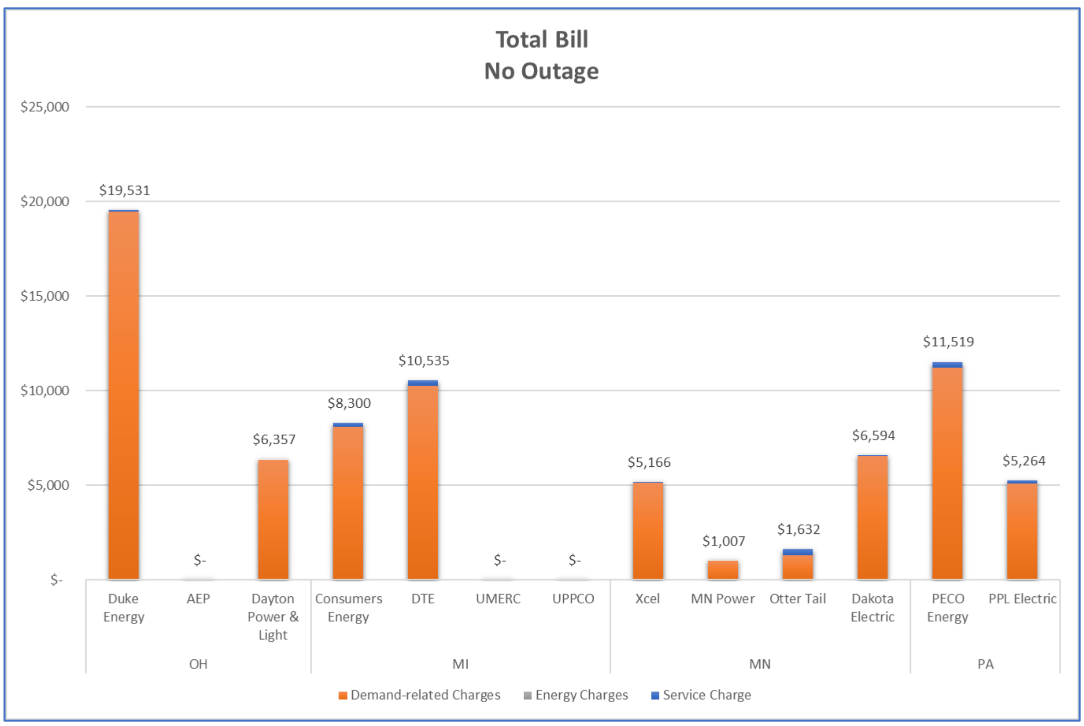
In addition to demonstrating discrepancies among total estimated standby bills, the GPI/5 Lakes "apples-to-apples" analysis illustrates variations that emerge with regard to individual charges that comprise the total standby bill for a customer. These charges often include a reservation fee, demand charges, and energy charges.

Reservation Fee

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 in the apples-to-apples analysis. 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.

Figure 1: Total Monthly Bill, No Outage Scenario



As a best practice, a CHP system's forced outage rate (FOR) should be used in the calculation of a customer's reservation fee. This practice creates an incentive for standby customers to limit their use of unscheduled standby service (*i.e.*, fewer unscheduled outages lead to a better FOR) 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.

None of the Ohio utilities in our analysis incorporates a CHP system's forced outage rate in calculating the reservation fee. With the exception of AEP, which imposes no standby reservation fee when a customer contracts for sufficient supplemental service, the other Ohio utilities' reservation fees are relatively high compared to the other utilities in the analysis, with Duke's being the highest.

To illustrate, the average reservation fee is $6674 across all utilities in the analysis; Duke's reservation fee is $19,456 per month. Notably, Minnesota Power is an example of a utility that relies on the FOR in calculating its reservation fee; its Reservation Fee is only $1007 per month.

Table 5: Comparison of Reservation Fees

Duke Energy	**Ohio**	**$19,456**
AEP	**Ohio**	**$0**
DP&L	**Ohio**	**$6357**
Minnesota Power	Minnesota	$1007
Xcel Energy	Minnesota	$4940
Otter Tail Power	Minnesota	$428
Dakota Electric	Minnesota	$6560
Consumers Energy	Michigan	$8100
DTE Energy	Michigan	$10,260
UMERC	Michigan	$0
UPPCO	Michigan	$0
PECO Energy	Pennsylvania	$11,208
PPL Electric	Pennsylvania	$5094

Demand Charges

Demand charges are capacity 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, in order 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 without advanced notice.

As discussed above, the Ohio utilities in this analysis fail to meaningfully differentiate between scheduled and unscheduled outages with regard to the level of demand charges imposed. Revising the tariffs to provide more meaningful incentives with regard to scheduling maintenance outages would bring these tariffs closer in line with recognized best practices.

Figure 2: Total Monthly Bill, Scheduled Outage 16-Hours Off-Peak

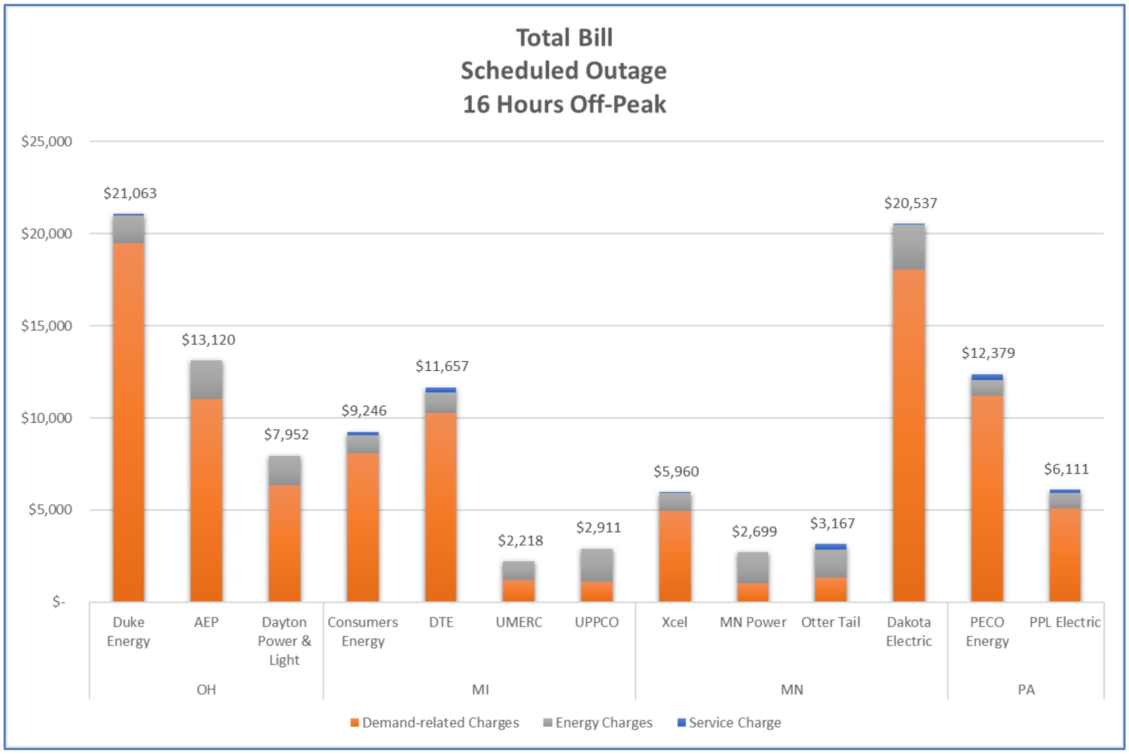


Figure 3: Total Monthly Bill, Scheduled Outage 16-Hours On-Peak

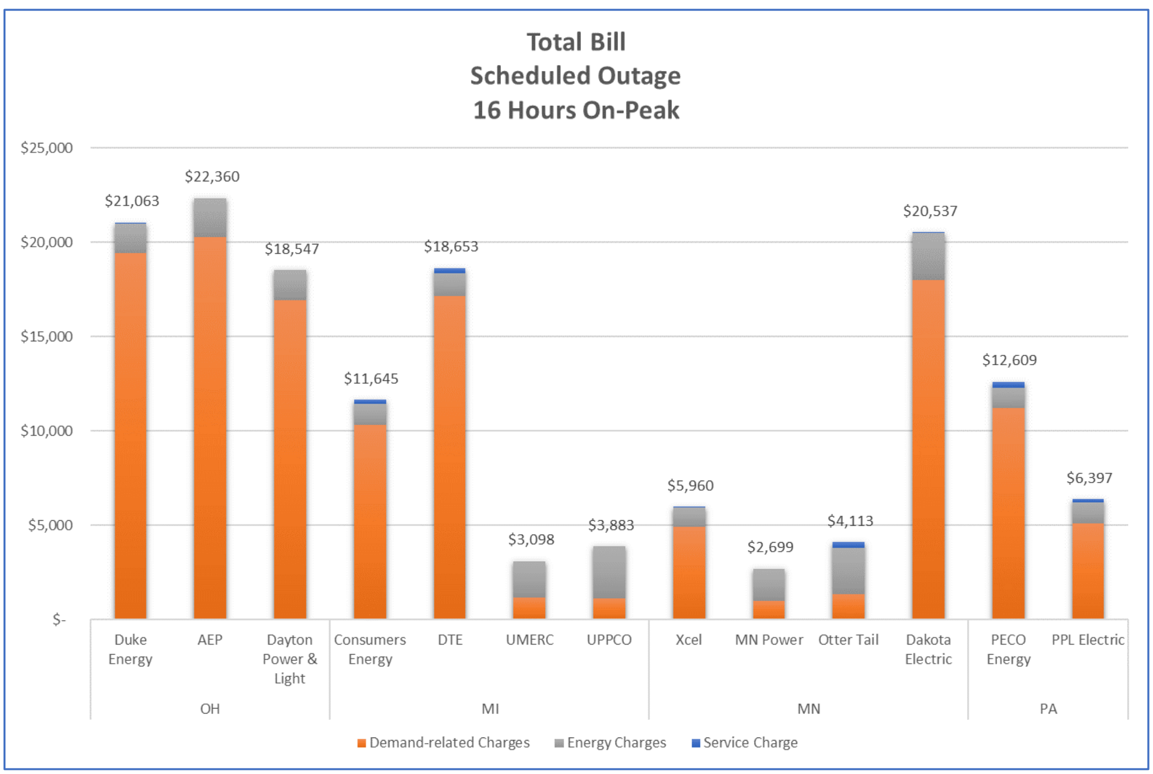


Table 6: Ohio - Demand Charges

	Duke	AEP	DP&L
Scheduled 16 hrs off-peak	$19,456	$11,045	$6357
Scheduled 16 hrs on-peak	$19,456	$20,285	$16,951
Unscheduled 8 on 8 off	$19,456	$20,285	$16,951

Table 7: Minnesota - Demand Charges

	Xcel	Minn Power	Otter Tail Power	Dakota Electric
Scheduled 16 hrs off-peak	$0	$0	$0	$18,020
Scheduled 16 hrs on-peak	$0	$0	$0	$18,020
Unscheduled 8 on 8 off	$0	$21,180	$816	$18,020

Table 8: Michigan - Demand Charges

	Consumers	DTE	UMERC	UPPCO
Scheduled 16 hrs off-peak	$0	$0	$1182	$1106
Scheduled 16 hrs on-peak	$2,232	$10,400	$1182	$1106
Unscheduled 8 on 8 off	$1,116	$9,340	$29,060	$29,340

Table 9: Pennsylvania – Demand Charges

	PECO Energy	PPL Electric
Scheduled 16 hrs off-peak	$11,208	$5094
Scheduled 16 hrs on-peak	$11,208	$5094
Unscheduled 8 on 8 off	$11,208	$5094

Energy charges

Energy charges reflect consumption of electricity and are assessed per kWh used during an outage. Because energy charges are assessed on an “as-used” basis, they are automatically pro-rated to reflect standby customers’ partial use of the system. In our analysis, charges for energy were roughly comparable across the board.

Table 10: Ohio – Energy Charges

	Duke	AEP	DP&L
No outage	$0	$0	$0
Scheduled 16 hrs off-peak	$1532	$2076	$1596
Scheduled 16 hrs on-peak	$1532	$2076	$1596
Scheduled 8 on 8 off	$1532	$2076	$1596
Scheduled 32 hrs	$3129	$4151	$3191
Unscheduled 8 on 8 off	$2480	$2076	$1596

Table 11: Minnesota – Energy Charges

	Xcel	Minn Power	Otter Tail Power	Dakota Electric
No outage	$0	$0	$0	$0
Scheduled 16 hrs off-peak	$995	$1,692	$1,534	$2,483
Scheduled 16 hrs on-peak	$995	$1,692	$2,481	$2,483
Scheduled 8 on 8 off	$995	$1,692	$2,008	$2,483
Scheduled 32 hrs	$1,989	$3,384	$4,961	$4,966
Unscheduled 8 on 8 off	$995	hourly incremental energy costs	$1,959	$2,483

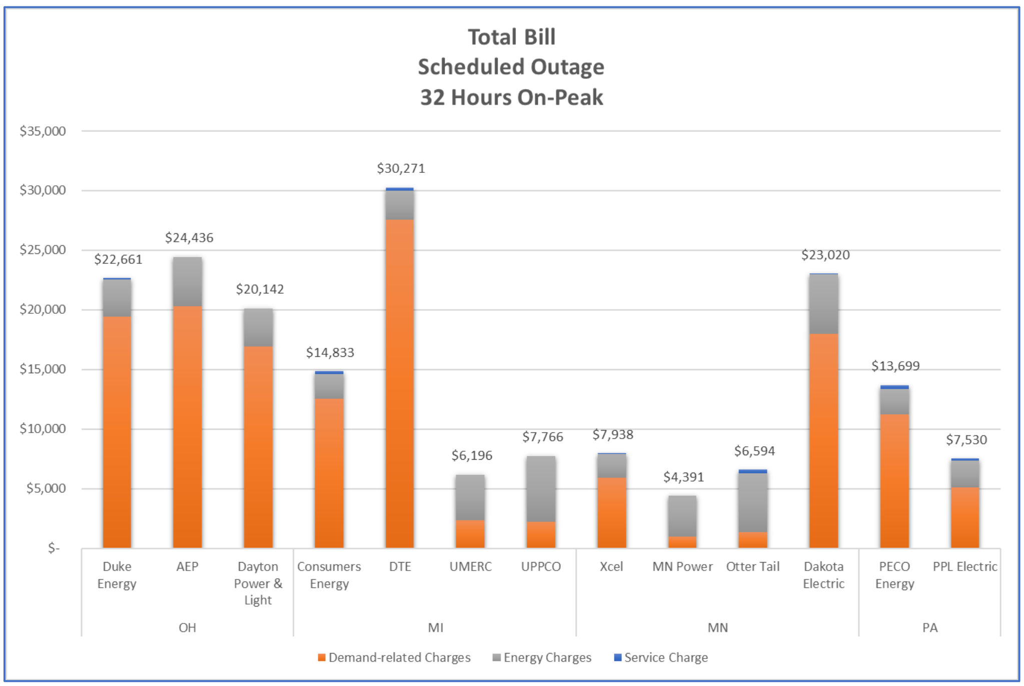
Table 12: Michigan – Energy Charges

	Consumers	DTE	UMERC	UPPCO
No outage	$0	$0	$0	$0
Scheduled 16 hrs off-peak	$946	$1,122	$1036	$1805
Scheduled 16 hrs on-peak	$1,113	$1,218	$1916	$2777
Scheduled 8 on 8 off	$1,775	$1,170	$1476	$2291
Scheduled 32 hrs on-peak	$2,070	$2,436	$3832	$5554
Unscheduled 8 on 8 off	$1,775	$1,170	$1476	$2291

Table 13: Pennsylvania – Energy Charges

	PECO Energy	PPL Electric
No outage	$0	$0
Scheduled 16 hrs off-peak	$860	$847
Scheduled 16 hrs on-peak	$1090	$1133
Scheduled 8 on 8 off	$975	$990
Scheduled 32 hrs on-peak	$2180	$2266
Unscheduled 8 on 8 off	$975	$990

Figure 4: Total Monthly Bill, Scheduled Outage 32-Hours On-Peak



Transparency

The process of conducting the GPI/5 Lakes "apples-to-apples" analysis highlighted a need for increased clarity and transparency in the presentation of standby tariffs to customers contemplating the installation of a CHP system. Standby rates are complicated, and it is difficult for a customer to interpret the published tariffs in order to estimate the potential standby costs involved. Historically, the discussion of standby rates has been utility-centric, the only concern being whether the utility is recovering its costs from standby customers. While this is an important consideration, the perspective of the customer as s/he attempts 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.

The themes of transparency and clarity may represent the least controversial means of improving standby rates in the near term. With regard to Duke Energy, AEP and DP&L, the interpretation and application of the published tariffs to potential CHP projects is complicated by the sheer volume of riders that must be tallied to arrive at an estimated monthly standby bill. 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. Examples of 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.

Along these lines, AEP helpfully provides bill calculation spreadsheets on its website: https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx. This is a best practice that should be emulated by the other Ohio utilities.

Standby vs. Supplemental Service

As mentioned previously, the Ohio utilities' approach to standby rates features an important interrelationship between levels of standby and supplemental service. If a customer's CHP system is not sized to cover the customer's entire load, the additional power needed by a customer on a regular basis is not considered to be standby power but is instead referred to as supplemental power. For example, if a customer requires 5 MW of total load and has a 2 MW CHP system, the customer would need to contract for 2 MW of standby service (to back up the CHP system) and 3 MW of supplemental service to meet their total power requirements.

Supplemental service from the utility provides regular, 24/7 power -- and supplemental rates reflect the standard rates paid by full service customers. In contrast, standby rates should be pro-rated to reflect the marginal cost to the utility of serving customers with occasional backup and maintenance needs.

Standby and Supplemental Charges

Most of the time, if a customer contracts for both standby and supplemental service to meet their total power needs, the customer's charges for standby service and supplemental service are calculated independently from one another.

In general, whether or not a customer contracts for supplemental service in addition to standby service should not affect their standby charges, as the level of supplemental service needed is not related to the marginal cost to the utility of providing occasional backup or maintenance service. However, based on our research, we have identified three notable exceptions to this rule: two are positive and reflect recommended practices, and the third is potentially problematic and a feature of the Ohio utilities' approach to calculating standby charges.

The first exception to the independent calculation of standby and supplemental charges might occur in relation to small fixed customer charges, which are designed to recoup administrative costs. Often, if a standby customer also signs up for supplemental service, the customer charge is not duplicated – which makes sense based on cost justification principles. Standby customers should only pay for the marginal costs associated with providing them with standby service, and any additional administrative burden is likely very small and already covered by the fee charged on the supplemental side of a customer bill.

The second exception to the independent calculation of standby and supplemental charges might occur if a customer is able to shed load during a CHP system outage in order to mitigate standby charges. Allowing the customer the flexibility to make internal adjustments to avoid imposing costs on the utility offers benefits for the customer, the utility and the grid as a whole, and was recently cited as a recommendation by the Michigan Public Service Commission staff in its report from a 2016-17 Standby Rate Working Group: "For customers taking both supplemental and standby service, the standby service tariff should be structured to allow the standby capacity and delivery demand charges to be structured to recognize the demand interactions between supplemental and standby service (net load)."[7] Under this approach, a customer's standby demand would be calculated as the difference between the customer's total load and their standard supplemental load. If the customer were able to shed enough load during a CHP system outage, he or she could avoid the bulk of standby charges normally associated with such an outage.

[7] Michigan Public Service Commission Staff Report from the Standby Rate Working Group, p. 23, available at http://www.michigan.gov/documents/mpsc/SRWG_Supplemental_2017_Report_576352_7.pdf

Buy Supplemental, Get Standby Free

The third exception to the independent calculation of standby and supplemental charges occurs when the utility structures its standby rate to incorporate a minimum billing demand that effectively gives the customer credit for its supplemental service contract on its standby bill. For example, an AEP Ohio[8] customer with a 2 MW CHP system and 3 MW of supplemental load incurs no standby charges in a "no outage" month because the customer's level of supplemental load dominates the minimum standby threshold of roughly 60% of the customer's total load of 5 MW.

This can seem like a great deal, and indeed such a structure has some advantages over a fixed reservation fee charged in "no outage" months, as it is sometimes difficult to justify standby reservation fees from a marginal cost standpoint, unless the reservation fee takes into account the forced outage rates of CHP systems (usually around 5%).

However, by providing an incentive to retain a certain level of supplemental service in relation to a customer's level of standby service, the rate structure could be seen as discriminatory against customers with distributed generation, which would arguably violate the Public Utility Regulatory Policies Act (PURPA): "Rates for sales … shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[9]

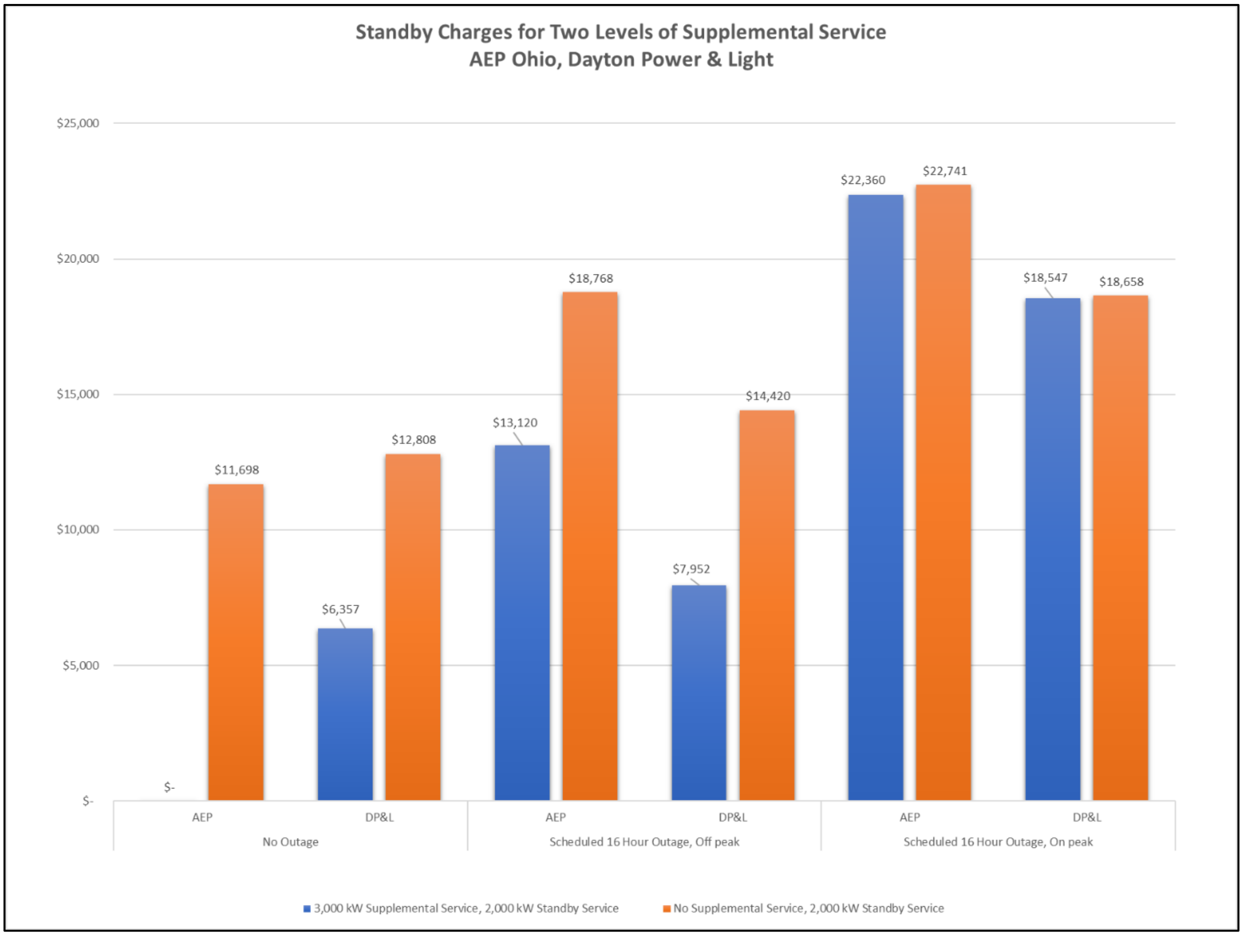
The impact of this interaction between the level of supplemental service and standby charges becomes more clear when you imagine the same scenario as above, but without supplemental service. In that case, a customer with the same size CHP system – 2 MW – incurs $11,698.13 in standby charges for a "no outage" month. The best case scenario for this customer is an annual bill of $140,377.56 attributable to their CHP system over the course of the year (assuming no outages).

The graph below illustrates a comparison of monthly standby charges for a customer with and without supplemental service, through a sampling of CHP outage scenarios. The greatest difference is evident in the "no outage" and "off-peak" scenarios.

[8] AEP Ohio (Ohio Power Company Rate Zone).

[9] 18 C.F.R. 292.305(a)(1)(ii)

Figure 5: Standby Charges for Two Levels of Supplemental Service



CHP System Sizing

The above-described relationship between supplemental and standby service in the calculation of a customer's standby charges creates an economic incentive for a customer to size their CHP system at less than half of their total load. This incentive may contradict the technical or reliability needs of a customer. The U.S. EPA recommends that CHP systems "are sized to meet the base thermal requirements of the facility so that 100% of the system's thermal output can be used on site. This approach to CHP system design is the most fuel efficient, most environmentally beneficial, and usually provides the best return on investment."[10] Notably, the CHP system sizing incentive embedded in this standby structure may even conflict with sizing recommendations embedded in CHP incentive programs, discussed below.

[10]U.S. EPA Combined Heat & Power Technical Assistance Partnership, Level 1 Feasibility Study, July 2015, p. 2, *available at* https://www.epa.gov/sites/production/files/2015-07/documents/combined_heat_and_power_chp_level_1_feasibility_analysis_industrial_facility.pdf

CHP Incentive Programs

Standby rates should be set according to cost of service and best practices, and should not take into account any other policies that may promote CHP in the state. That said, for the purposes of the wider discussion of the policy context for CHP in Ohio, we recognize that both AEP and DP&L offer incentive programs for the installation of CHP projects. These incentive programs are structured as rebates and are not directly linked to standby rates. The discussion that follows is an attempt to acknowledge the impact of the CHP incentive programs from the customer perspective, and also to highlight the need to also take a thoughtful look at standby rate design if a utility and/or regulators are serious about removing barriers to CHP deployment. While DP&L's program is aimed at smaller projects, AEP's program allows for eligibility of larger systems and can therefore be modeled against the hypothetical "apples to apples" customer discussed above. We have included below an analysis of how AEP's CHP Incentive Program would play out in relation to its standby rates.

AEP's Combined Heat and Power and Waste Energy Recovery Program (CHP/WER) "supports the installation of high efficiency, sustainable and cost effective projects in AEP Ohio's service territory as allowed by SB 315."[11] CHP projects are eligible for the incentive if they meet minimum efficiency requirements of 60% overall efficiency and 20% useful thermal energy. CHP incentive payments are based on production of kWh recovered by the project, and incentive rates for projects approved in 2017 are $0.035 per kWh recovered for systems > 1000 kW. There is a yearly cap of $500,000. [12]

In a "no outage" month, the 2,000 kW system from the "apples to apples" analysis would generate 1,440,000 kWh of electricity. Multiplied by the incentive of $0.035 per kWh, this yields a rebate of $50,400 per month. However, given the annual cap of $500,000, the maximum monthly rebate would be $41,666.67. (This is true for all listed outage scenarios, as well.)

The table below highlights the impact of standby rates on the net benefit to the customer of the CHP incentive program:

Table 14: AEP CHP Incentive with Standby Charges

	CHP Incentive Rebate	Standby Charges	Net Incentive
No outage	$41,667	$0	$41,667
Scheduled 16 hrs off-peak	$41,667	$13,120	$28,547
Scheduled 16 hrs on-peak	$41,667	$22,360	$19,307

[11] https://www.aepohio.com/save/business/programs/CombinedHeatandPower.aspx
[12] Ibid.

Scheduled 8 on 8 off	$41,667	$22,360	$19,307
Scheduled 32 hrs on-peak	$41,667	$24,436	$17,231
Unscheduled 8 on 8 off	$41,667	$22,360	$19,307

These numbers demonstrate the importance of understanding the full context of barriers and incentives facing customers interested in deploying CHP. As designed, the standby rates erode the benefit of the incentive program. While it is encouraging to see utilities putting into place programs to incent the installation of CHP, any serious effort to promote CHP must be done in the context of a fair, cost-based approach to standby rate design.

Issues and Recommendations

Duke Energy

Duke Energy imposes very high total costs on standby customers. High demand charges drive these totals; they are calculated based on contract capacity, and are not pro-rated based on the duration of an outage. This failure to pro-rate demand charges sets up standby customers, who are partial users of the system, to significantly overpay based on their actual cost of service. For Duke, these high demand charges act as a Reservation Fee during the "no outage" scenario.

Duke does not differentiate significantly between scheduled and unscheduled outages. While there is a slight difference in cost between scheduled and unscheduled outages, the difference is not a meaningful one in relation to overall charges, and raises the question whether customers who pre-schedule maintenance outages are actually subsidizing customers who experience unscheduled outages under this rate design. As discussed above, scheduled and unscheduled outages should be treated differently in standby rates to promote efficient use and proactive maintenance of the CHP system.

AEP

For AEP, the interrelationship between supplemental service and standby service, for the purposes of calculating standby charges, is a significant issue (see Standby vs. Supplemental Service discussed above at page 12). Here, the absence of charges during the "no outage" scenario is in line with best practices recognizing that standby customers do not contribute significantly to utility costs during "no outage" months.

For the scheduled outage scenarios, AEP's demand charges are high in comparison to most of the other utilities in the analysis. For example, the average demand charges during a Scheduled 16-hour outage during off-peak times is $8720 across all utilities in the analysis; AEP's demand charges are $11,045 for this scenario. The disparity is even more dramatic when you look at the average demand charges for a Scheduled 16-hour on-peak outage, which are $11,353 across all utilities in the analysis, and $20,285 for AEP.

While its demand charges are higher than average, and should be explored to ensure that standby customers are not paying more than their cost of service, the fact that AEP meaningfully differentiates between on-peak and off-peak charges is in line with best practices recognizing higher utility costs during on-peak times. This structure also provides a helpful incentive for the customer to plan maintenance outages during off-peak periods.

Dayton Power & Light

DP&L does not offer a separate standby tariff or rider. Instead, the utility applies the supplemental service tariff to the entire month of service, whether or not an outage takes place, and with no pro-ration for standby use in case of an outage.

For the "no outage" and off-peak outage scenarios, the company's 75% demand ratchet is applied to the customer's total demand of supplemental plus standby load, in this case 5,000 kW. (The demand ratchet kicks in whenever there is a scheduled or unscheduled outage and persists for 12 months; here it is reasonable to assume that there has been an outage within the past year.) When the ratchet is applied, demand is calculated as 3750 kW. When the customer's supplemental load of 3000 kW is taken away, that leaves 750 kW of demand attributable to standby service.

For the on-peak outage scenarios, the customer's demand matches its total on-peak demand of 5,000 kW, of which 2,000 kW is attributable to standby service.

For the off-peak outage scenario, DP&L's demand charges are slightly lower than average compared to most of the other utilities in the analysis. For example, the average demand charges during a Scheduled 16-hour outage during off-peak times is $8720 across all utilities in the analysis; DP&L's demand charges are $6357 for this scenario.

DP&L's demand charges are relatively higher for the on-peak outage scenarios. For example, the average demand charges for a Scheduled 16-hour on-peak outage are $11,353 across all utilities in the analysis, and $16,951 for DP&L. As with AEP, the fact that DP&L meaningfully differentiates between on-peak and off-peak charges is in line with best practices recognizing higher utility costs during on-peak times, and provides a helpful incentive for the customer to plan maintenance outages during off-peak periods.

Finally, similarly to Duke Energy, there is no differentiation between scheduled and unscheduled outages. As discussed previously, scheduled and unscheduled outages should be treated differently in standby rates to promote efficient use and proactive maintenance of the CHP system.

Conclusion

In light of the GPI/5 Lakes “apples-to-apples” comparison both within Ohio and across other Midwestern states, there are key areas of potential improvement in standby rates among Duke Energy, AEP, and DP&L. In addition to improved clarity and transparency for current and potential customers, both reservation fees and demand charges are clear areas for further discussion, especially in light of utility efforts to promote CHP deployment through their incentive programs. The interrelationship between standby and supplemental service when calculating standby charges also deserves reflection, as it may pose a barrier to some CHP applications, or have unintended consequences as to proper system sizing.

Overall, when utilities engage in thoughtful discussion around standby rate design, it can be a win-win for utilities, customers, regulators and other stakeholders. Experience has shown that reference to the GPI/5 Lakes “apples-to-apples” comparison can be useful in stimulating such discussion. Through interaction grounded in the application of published tariffs from the customer’s perspective, standby tariffs can be made clearer and more transparent, helping regulators and customers alike. When wide variation and unexplained differences are examined closely, there is potential for significant improvement in standby rates, and as a result, meaningful progress in removing this barrier to CHP deployment.

Glossary

- **Backup power:** Energy supplied during an unscheduled outage of the customer's on-site generation.
- **Demand ratchet:** A mechanism by which rates are billed based on either the peak demand by a customer in the current month, or some percentage of the peak demand for that customer during previous months.
- **Energy charges:** Charges assessed per kWh reflecting actual energy consumption.
- **Forced outage:** An unscheduled/unplanned outage.
- **Forced Outage Rate (FOR):** The probability of failure of a generator, usually measured as a ratio of failure hours to total service hours.
- **Maintenance power:** Electricity supplied during scheduled outages of the customer's on-site generation.
- **Off-peak:** Off-peak refers to lower electricity prices during specific times, generally when homes and businesses use less electricity. Off-peak times vary depending on location and meter type, but typically are at night or on weekends.
- **On-peak:** On-peak refers to higher electricity prices during specific times, generally when homes and businesses use more electricity.
- **Reservation fee:** Per kW fee paid monthly by standby customers in order to reserve standby service.
- **Scheduled outage:** A scheduled time period where a CHP system is taken out of operation for maintenance. Advanced notice is usually required.
- **Shed load:** If a CHP system undergoes scheduled or unscheduled maintenance, the customer can decrease their overall energy use (i.e., shed load) to decrease the need to use electricity from the grid. For example, a customer could turn off a system with high electricity needs or shut down part of their facility.
- **Supplemental service:** Energy purchased by a standby rate customer in addition to the energy that is generated on-site.
- **Unscheduled outage:** A period of time during which a CHP system is taken out of operation for maintenance without advance notice to the utility. Also known as a forced outage.