Standby/Capacity Reservation Charge Best Practices and Review:

Prepared for Pennsylvania Public Utility Commission
CHP Working Group

July 16, 2018 Revised

By:

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Acknowledgments

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- Joseph M. Sherrick Supervisor Technical Utility Services, Policy & Planning, Pennsylvania Public Utility Commission
- Dr. James Freihaut, Director of DOE's Mid-Atlantic CHP Technology Assistance Partnership
- Jamie Scripps, Principal, 5 Lakes Energy LLC – for initial data collection and analysis

We also acknowledge the rate review guidance provided by PECO, PPL and Duquesne Light.

Background

On April 5, 2018 the Pennsylvania Public Utility Commission issued its Final Policy Statement on Combined Heat and Power. The opening of the statement reads:

> *In light of the potential benefits to the public of Combined Heat and Power (CHP), the Commission is interested in considering ways to advance the development of CHP in Pennsylvania. The Commission recognizes that CHP is an efficient means of generating electric power and thermal energy from a single fuel source, providing cost effective energy services to commercial businesses like hotels, universities and hospitals. CHP systems capture the waste heat energy that is typically lost through power generation, using it to provide heating and cooling for manufacturing and business. In addition to improving manufacturing competitiveness and reducing greenhouse gas emissions, CHP benefits businesses by reducing energy costs and enhancing reliability for the user.*
>
> *The Commission observes that there are several areas where electric and natural gas distribution companies (EDCs and NGDCs) may be able to implement policies and practices that reduce barriers to such development. With this Order, the Commission establishes a biennial reporting requirement for EDCs and NGDCs regarding their efforts to eliminate obstacles to the development of CHP in the Commonwealth.*

Purpose of this Analysis

Standby tariffs and rates can affect the economic feasibility of CHP projects. Customers who receive all of their electricity from the utility are known as "full requirements" customers. Their electricity is provided under rates that are primarily some mix of fixed customer charges - a recurring charge (monthly or daily) intended to cover the constant costs of metering, billing, and service drop facilities; energy charges - the charges for consumption of the electricity commodity applied on a per-kWh basis; and demand charges – charges based on the peak electricity demand (kW) during a given period and used to recover the capital costs of the capacity necessary to meet the customer's peak loads. Customers with onsite generation typically require a different set of services, which includes continuing electricity service for the portion of usage that is not provided by the onsite generator, as well as service for periods of scheduled or unscheduled outages. "Partial requirements" is the more precise name for *standby* or *backup* service: the set of retail electric products that customers with onsite, non-emergency generation typically need. This service could be provided under a tariff that replaces the standard full requirements tariff, or an additional tariff that applies on top of the standard tariff for certain special types of services. Common components of service for partial requirements customers can include:

(1) *Supplemental Service*. Supplemental service for customers whose on-site generation does not meet all of the customer's needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
(2) *Back-up Service*. Back-up, or stand-by, serves a customer's load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
(3) *Scheduled Maintenance Service*. Scheduled maintenance service is taken when the customer's generator is due to be out of service for routine maintenance and repairs.
(4) *A capacity reservation charge* to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customers own generation unit.

This analysis was undertaken to support the PA PUC's CHP working group to better understand the nature of standby, reservation charge and supplemental charges in Pennsylvania and the impact of these charges on CHP project economics. 5-Lakes Energy was initially engaged to gather the relevant rate data from three EDCs - PECO, PPL and Duquesne - and develop a model to assess the annual electricity costs for three CHP use cases detailed later in this report. 5-Lakes later became involved in an ongoing EDC rate case and did not participate in subsequent direct EDC contact or further analysis based on feedback from the EDCs. Exergy Partners Corp. and Entropy Research LLC worked with PECO, PPL and Duquesne to improve the accuracy of the modeling within current time constraints to be sure the relative comparisons are as accurate as possible.   It should be noted that the three EDCs were cooperative in preparing this report to aid in discussion during the PA PUC CHP Working Group. Also note that it is conceivable that not all applicable rate tariffs have been demonstrated in the use cases as the structures are generally complex.

Standby/Reservation Charges

To better understand the nature and structure of Electric Distribution Companies (EDCs) standby, Penn State University contracted with 5-Lakes Energy to initially examine standby charges impacting three typical CHP systems types and applications[1]:

1. 8 MW combustion turbine CHP system used in a high load factor production facility - 24/7 operation

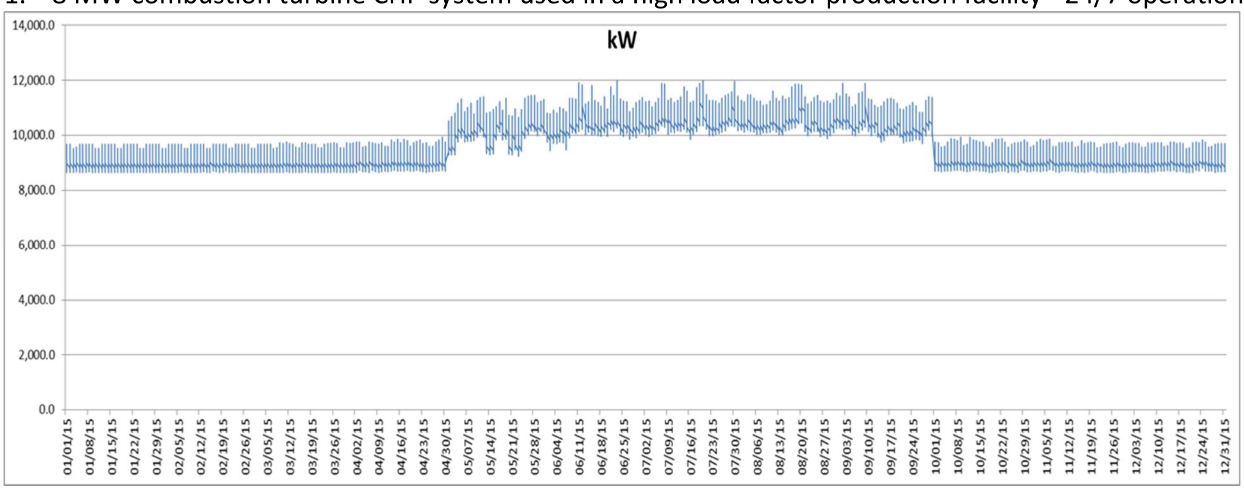

*Figure 1: **High Load Factor Production Load Profile***

Application: High Load Factor Production - 24/7 Oper							Base Voltage: 13,200						
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8760
Maximum Demand, kW	9,685	9,691	9,754	9,939	11,454	12,000	11,992	11,874	11,898	9,939	9,872	9,845	12,000
Average Demand, kW	8,988	8,978	8,976	9,017	10,173	10,363	10,556	10,512	10,411	9,034	9,015	9,011	9,590
Minimum Demand, kW	8,659	8,659	8,659	8,659	9,238	9,454	9,851	9,889	9,712	8,659	8,659	8,659	8,659
Consumption, kWh	6,687,328	6,033,316	6,678,317	6,492,359	7,568,346	7,461,397	7,853,748	7,821,226	7,496,206	6,721,619	6,490,696	6,704,248	84,008,805
CHP Generation, kWh	4,040,000	5,376,000	5,952,000	5,760,000	5,952,000	5,760,000	5,760,000	5,952,000	5,760,000	5,952,000	5,760,000	5,952,000	67,976,000
Standby Generation kWh	1,912,000	0	0	0	0	0	192,000	0	0	0	0	0	2,104,000
Supplemental Generation kWh	735,328	657,316	726,317	732,359	1,616,346	1,701,397	1,901,748	1,869,226	1,736,206	769,619	730,696	752,248	13,928,805
Max Supplemental Demand kW	1,685	1,691	1,754	1,939	3,454	4,000	3,992	3,874	3,898	1,939	1,872	1,845	4,000
Average Supplemental Demand kW	988	978	976	1017	2173	2363	2556	2512	2411	1034	1015	1011	1586
Load Factor													0.799

*Table 1: **High Load Factor Production CHP Dataset Example***

CHP system assumptions:
CHP Capacity: 8 MW
CHP Electrical Efficiency: 29.2%
Useful Thermal: 4,848 Btu/kWh

[1] For comparison purposes a natural gas price of $5 / MMBtu was used in all cases for CHP prime mover fuel and displaced boiler fuel costs

CHP O&M cost: 0.012 $/kWh
Fuel Price, $/MMBtu: $5.00
Scheduled Maintenance Outage: One 10-day outage in January
Unscheduled Forced Outage: One 24-hour outage in July

2. 1 MW reciprocating engine CHP system in an average load factor production facility - 2 shifts/5 days per week operation

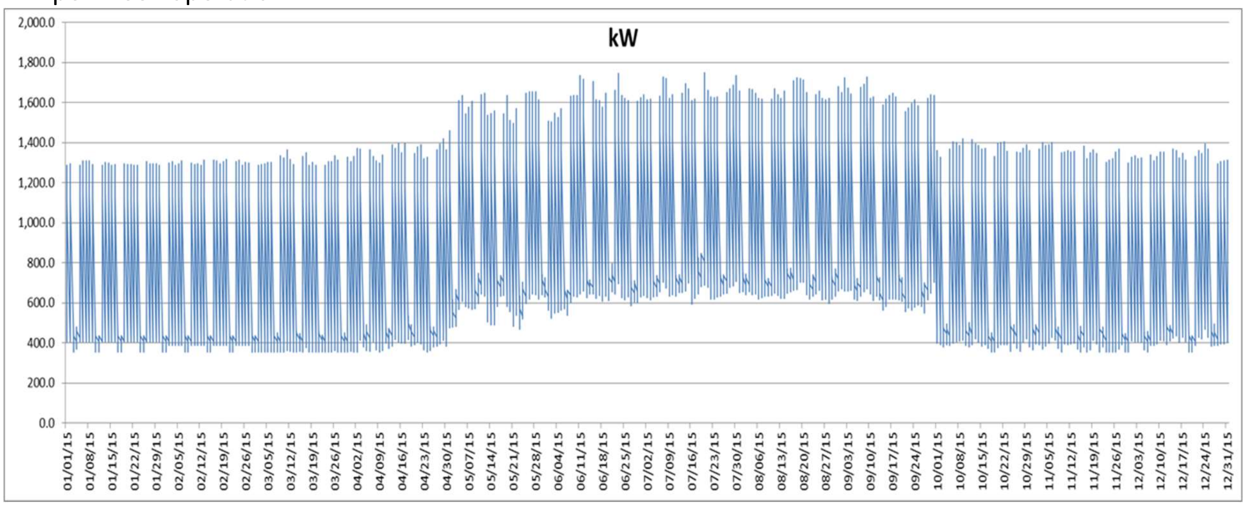

Figure 2: ***Average Load Factor Production Load Profile***

Application: Average Load Factor Production - 2 Shifts/5 Days per Week Oper								Base Voltage: 13,200/4,160					
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Maximum Demand, kW	1,311	1,318	1,363	1,418	1,656	1,747	1,750	1,723	1,726	1,418	1,401	1,394	1,750
Average Demand Op Hours, kW	1,079	1,080	1,075	1,162	1,384	1,450	1,474	1,399	1,456	1,160	1,126	1,152	1,250
Average Demand, kW	760	761	758	804	976	1,036	1,081	1,044	1,052	803	785	799	889
Minimum Demand, kW	357	357	357	357	471	524	593	598	551	357	357	357	357
Consumption, kWh	565,565	511,189	564,035	579,036	726,320	746,125	804,061	776,422	757,465	597,739	565,336	594,669	7,787,962
CHP Generation, kWh	361,479	341,014	397,479	384,658	397,479	384,658	379,479	397,479	384,658	397,479	384,658	397,479	4,608,000
Standby Generation kWh	36,000	18,000	0	0	0	0	18,000	0	0	0	0	0	72,000
Supplemental Generation kWh	168,085	152,175	166,556	194,378	328,840	361,467	406,582	378,943	372,808	200,260	180,678	197,190	3,107,962
Max Supplemental Demand kW	432	432	432	432	656	747	750	723	726	432	432	432	750
Average Supplemental Demand kW	226	226	224	270	442	502	546	509	518	269	251	265	354
Load Factor													0.508

Table 2: ***Average Load Factor Production CHP Dataset Example***

CHP system assumptions:
CHP Capacity: 1 MW
CHP Electrical Efficiency: 37.6%
Useful Thermal: 3,909 Btu/kWh
CHP O&M cost: 0.011 $/kWh
Fuel Price, $/MMBtu: $5.00
Scheduled Maintenance Outage: One 36-hour outage in January (five additional 36-hour outages during the year on weekends)
Unscheduled Forced Outage: Two 36-hour outages in February and July

3. 200 kW microturbine CHP system in an office building with normal business hour operation

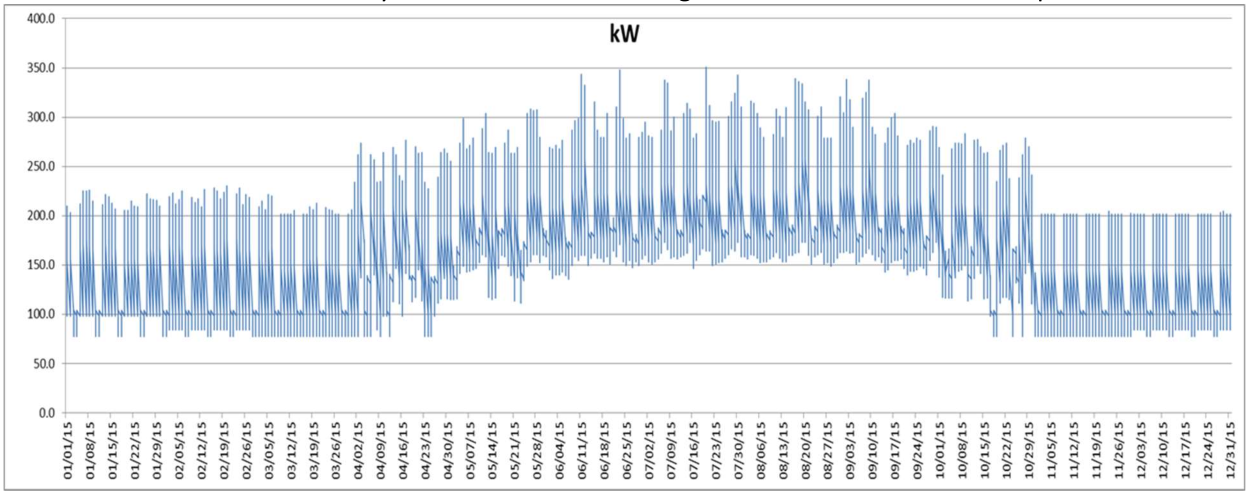

*Figure 3: **Office Building with Normal Business Hour Operation Load Profile***

Application: Office Building - Normal Business Hrs Oper									Base Voltage: 480				
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Billing days per month	31	28	31	30	31	30	31	31	30	31	30	31	365
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
Maximum Demand, kW	226	231	221	276	308	348	350	339	338	283	204	204	350
Average Demand Op Hours, kW	216	219	198	256	287	301	308	290	305	244	190	198	251
Average Demand, kW	135	136	129	164	191	202	212	207	207	175	126	129	168
Minimum Demand, kW	78	78	78	100	125	136	146	149	140	125	78	78	78
Consumption, kWh	100,422	91,442	95,734	117,795	141,884	145,750	157,623	154,011	149,040	130,396	90,602	95,754	1,470,454
CHP Generation, kWh	40,997	47,868	52,997	51,288	52,997	51,288	50,597	52,997	51,288	52,997	51,288	52,997	609,600
Standby Generation kWh	12,000	0	0	0	0	0	0	2,400	0	0	0	0	14,400
Supplemental Generation kWh	47,424	43,574	42,736	66,508	88,887	94,463	107,026	98,614	97,753	77,398	39,314	42,757	846,454
Max Supplemental Demand kW	103	103	103	125	150	161	171	174	165	150	103	103	174
Average Supplemental Demand kW	64	65	57	92	119	131	144	133	136	104	55	57	96
Load Factor													0.479

*Table 3: **Office Building with Normal Business Hour Operation CHP Dataset Example***

CHP system assumptions:

CHP Capacity: 200 kW

CHP Electrical Efficiency: 28.4%

Useful Thermal: 4,578 Btu/kWh

CHP O&M cost: 0.02 $/kWh

Fuel Price, $/MMBtu: $5.00

Scheduled Maintenance Outage: One 7-day outage in January

Unscheduled Forced Outage: One 12-hour outage in July

Results

Figures 4 to 9 show the calculated electric utility bill charges for the three Pennsylvania EDCs (PECO, PPL and Duquesne[2]) for the three CHP applications. The figures include calculated annual charges for each facility under the applicable full load requirements tariffs (no CHP or Grid Only case) and supplemental/standby tariffs (CHP Plant). Figures 4, 6 and 8 show the total electric grid cost to the site with and without the respective CHP systems delineated above. Figures 5, 7 and 9 show the detailed electric charges by rate tariff and identifiable component (transmission, outage energy, outage demand, reservation, distribution demand and energy).

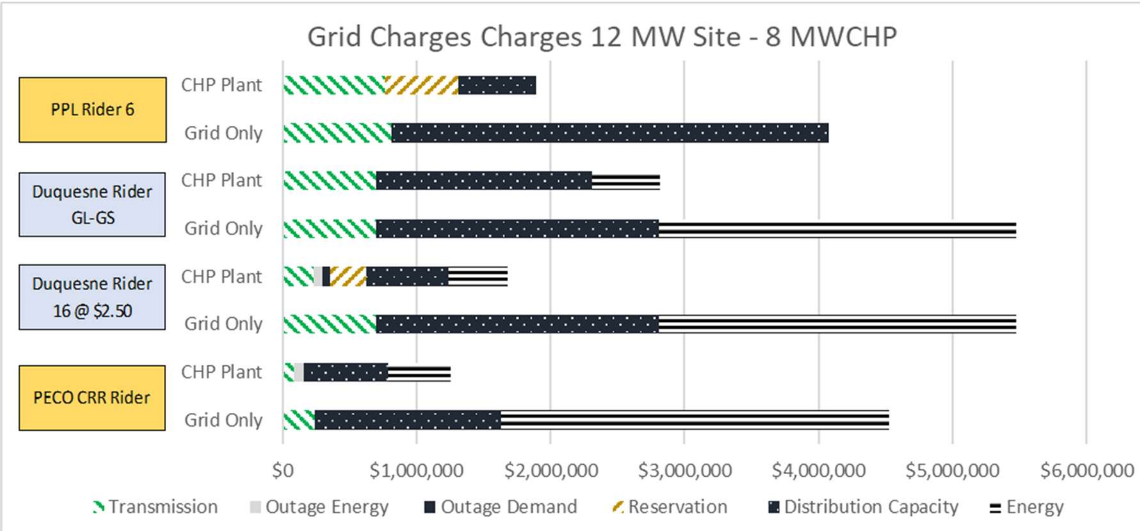

Figure 4: Annual Grid Cost for a 12 MW High Load Factor Production Site with and without an 8 MW CHP System

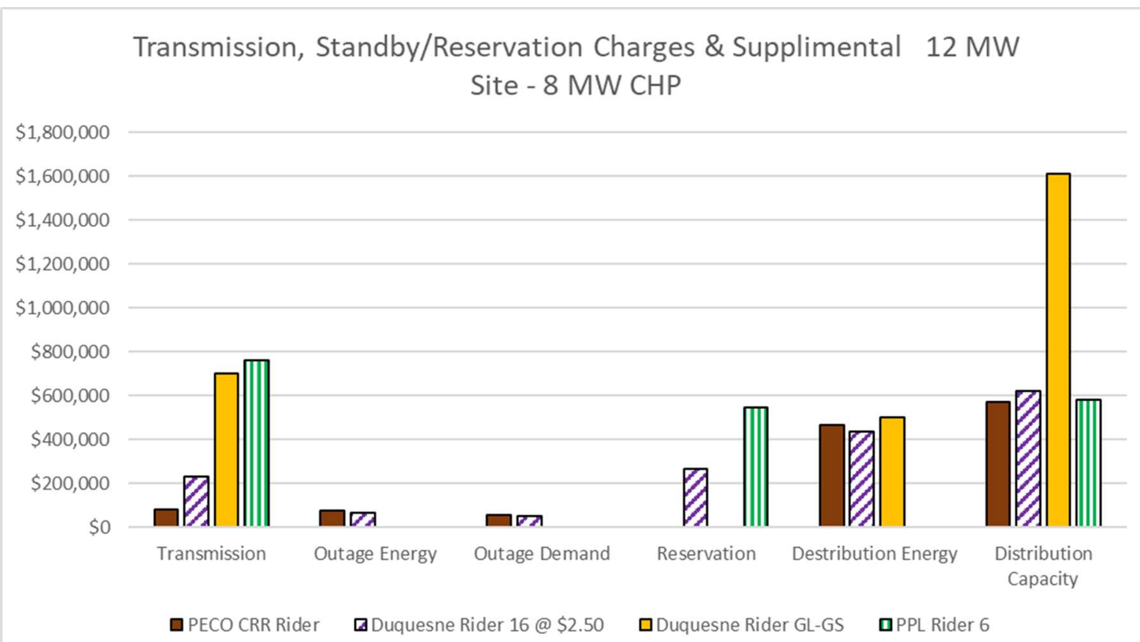

Figure 5: Annual Grid Cost for a 12 MW Peak Demand High Load Factor Production Site with an 8 MW CHP System

[2] Duquesne rates were tabulated based on their standby tariff in effect prior to March of 2018 as well as their new tariff effective after March 2018

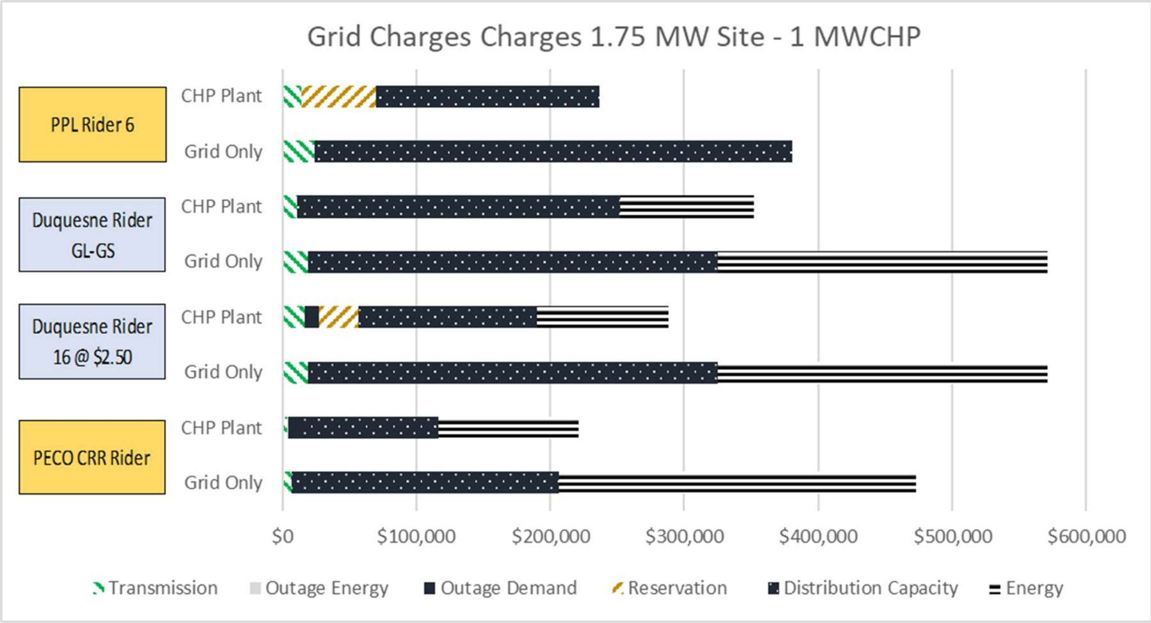

Figure 6: Annual Grid Cost for a 1.75 MW Peak Demand Average Load Factor Production Site with and without a 1 MW CHP System

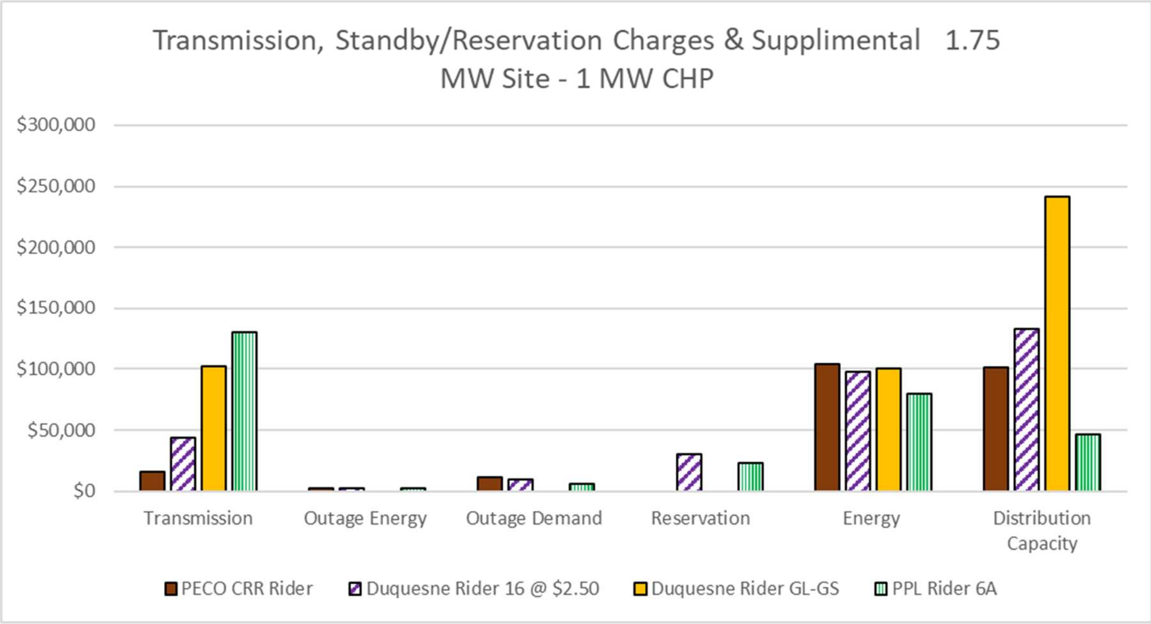

Figure 7: Annual Grid Cost for a 1.75 MW Peak Demand High Load Factor Production Site with a 1 MW CHP System

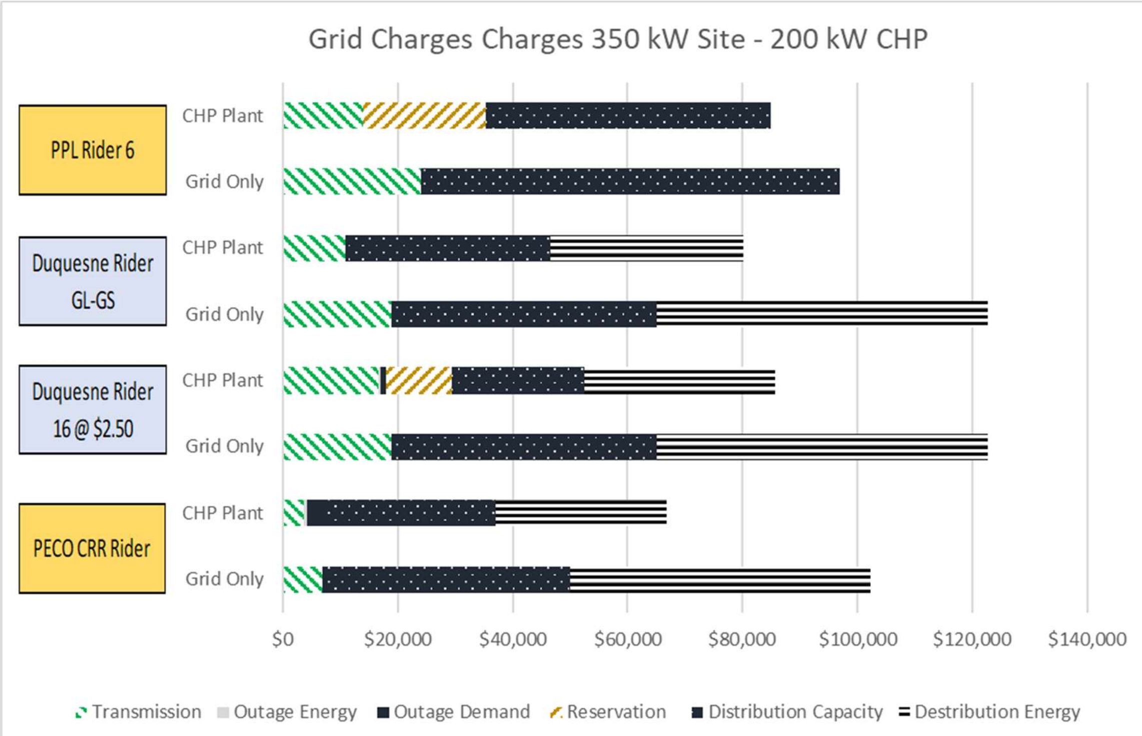

Figure 8: Annual Grid Cost for a 350 kW Peak Demand Office Building with Normal Business Hour Operation with and without a 200 kW CHP System

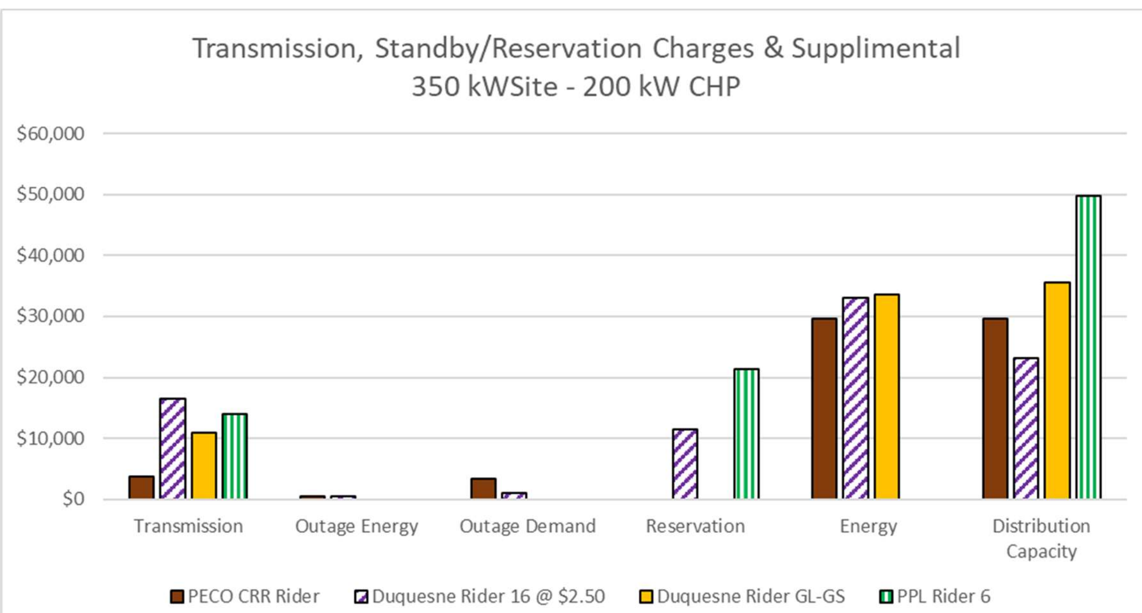

Figure 9: Annual Grid Cost for a 350 kW Peak Demand Office Building with Normal Business Hour Operation with a 200 kW CHP System

Findings

The analysis raises a series of question regarding standby rate complexity, transparency and equity:

1. There appears to be little consistency between the EDCs with respect to the structure of standby charges.
2. Standby / Reservations charges and structure vary considerable between the three EDCs
3. Descriptors vary widely for services, which fosters confusion
4. Standby tariff structures can be complex and difficult to properly apply without utility input
5. Tariffs descriptions were sometimes not clear – providing example calculations would help (one EDC had an example calculation)
6. There was no distinction between maintenance backup power (which can often be scheduled off-peak) demand and unscheduled downtime
7. Some of the reservation charges appear to assume that all forced outages of on-site generators on the system occur simultaneously, or at the time of the utility system peak (no recognition of the diversity of multiple on-site generators).

Electricity Offset Cost

Electricity Offset Cost is a method used by the DOE CHP Technology Assistance Partnerships in conducting economic screening of CHP projects. Electricity Offset Cost is the measure of the cost savings realized from the displacement of purchased electricity from the grid by installing the CHP system. Ideally, from the CHP project development perspective, the reduction in electricity costs from the grid due to installing CHP should be commensurate with the reduction in purchased electricity from the grid. However, this is rarely the case as certain fixed costs for electric service cannot be avoided and there are additional costs legitimately required for compensating the servicing utility for the capability of providing standby service. However, the economics of CHP can be significantly impacted if partial requirements rates are structured so that only a small portion of the electricity price can be avoided.

Electricity Offset Cost is a unit-less number calculated by dividing the electricity cost savings of the CHP system in terms of $/kWh generated by the all-in average electricity price in terms of $/kWh before installation of the CHP system:

Electricity Offset Cost =

$$\frac{(\text{Purchased Grid Costs}_{\text{no CHP}} - \text{Purchased Grid Costs}_{\text{with CHP}}) / \text{kWh}_{\text{CHP generation}}}{(\text{Purchased Grid Costs}_{\text{no CHP}} / \text{kWh}_{\text{no CHP}})}$$

Electricity Offset Cost is a direct measure of the impact of standby/reservation charges on the energy savings of any onsite distributed energy resource.

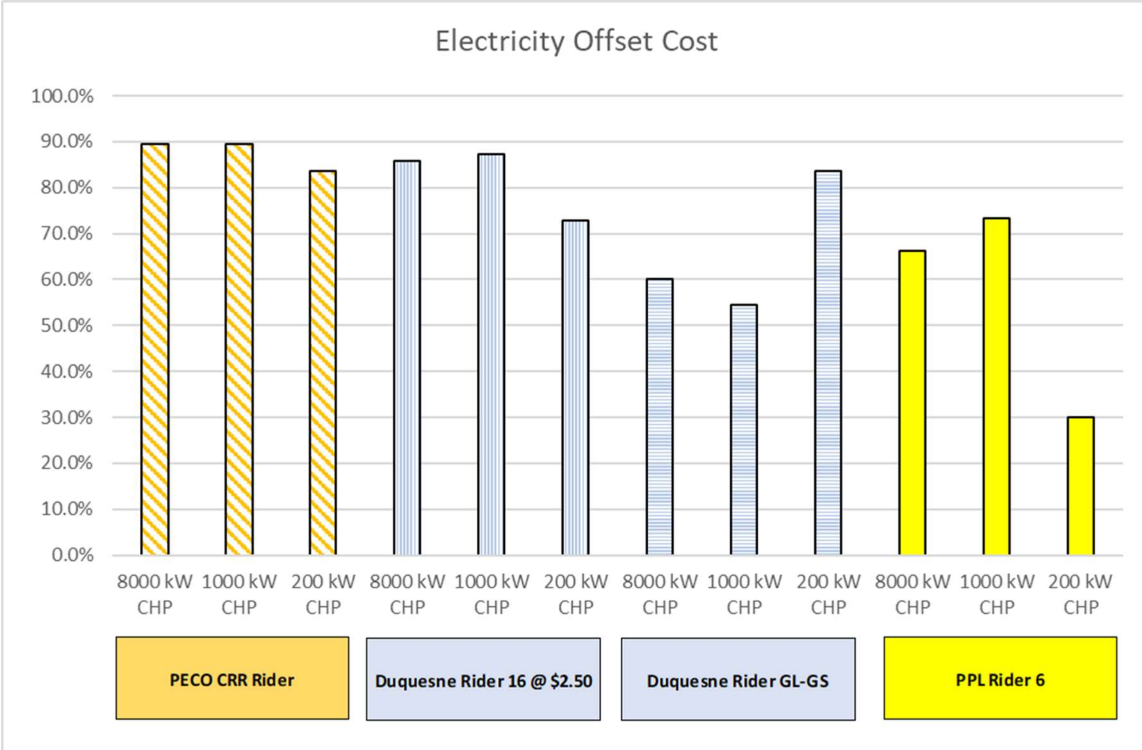

Figure 10 Electricity Offset Cost for the Tariffs Examined

Utility Rate Tariff	CHP Syatem	Grid Cost no CHP	Grid Cost with CHP	Grid Cost Difference	Site with no CHP kWh	CHP Generatated kWh	Average Grid Price $/kWh	Displaced Grid Electricity $/kWh	Avoided Electricity Cost
PECO CRR Rider	8000 kW CHP	$4,528,162	$1,253,006	$3,275,156	84,008,805	67,976,000	$0.0539	$0.0482	89.4%
	1000 kW CHP	$499,635	$235,444	$264,191	7,787,962	4,608,000	$0.0642	$0.0573	89.4%
	200 kW CHP	$102,207	$66,746	$35,461	1,470,454	609,600	$0.0695	$0.0582	83.7%
Duquesne Rider 16 @ $2.50	8000 kW CHP	$5,476,993	$1,679,120	$3,797,873	84,008,805	67,976,000	$0.0652	$0.0559	85.7%
	1000 kW CHP	$654,586	$316,891	$337,695	7,787,962	4,608,000	$0.0841	$0.0733	87.2%
	200 kW CHP	$122,655	$85,585	$37,070	1,470,454	609,600	$0.0834	$0.0608	72.9%
Duquesne Rider GL-GS	8000 kW CHP	$5,476,993	$2,812,510	$2,664,483	84,008,805	67,976,000	$0.0652	$0.0392	60.1%
	1000 kW CHP	$654,586	$443,276	$211,310	7,787,962	4,608,000	$0.0841	$0.0459	54.6%
	200 kW CHP	$122,655	$80,093	$42,562	1,470,454	609,600	$0.0834	$0.0698	83.7%
PPL Rider 6	8000 kW CHP	$4,072,187	$1,891,769	$2,180,418	84,008,805	67,976,000	$0.0485	$0.0321	66.2%
	1000 kW CHP	$654,586	$370,875	$283,711	7,787,962	4,608,000	$0.0841	$0.0616	73.3%
	200 kW CHP	$97,005	$84,915	$12,090	1,470,454	609,600	$0.0660	$0.0198	30.1%

Table 4: Electricity Offset Cost Details for the Tariffs Examined

General Recommendation for Standby and Reservation Charges

Summary of Best Practices in Standby

Rate Design

Based on the experience of the Regulatory Assistance Project (RAP) and Brubaker & Associates, Inc. (BAI) in evaluating standby rate design on the CHP project economics[3], the following are best practices for consideration in the development of standby rates:

Allocation of Utility Costs

- Generation, transmission, and distribution charges should be unbundled in order to provide transparency to customers and enable appropriate and cost-based standby rate design.
- Supplemental power charges should be based on charges in the applicable full requirements tariff.
- 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.

Judgments Based on Statistical Method

- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak.
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity.
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low.

Value of Customer Choice and Incentives

- 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.
- Customers should have the option to purchase all or some portion of their standby service on an interruptible basis and thereby avoid generation reservation demand charges.
- 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.

[3] Standby Rates for Combined Heat and Power Systems Economic Analysis and Recommendations for Five States, James Selecky, Kathryn Iverson, and Ali Al-Jabir, Regulatory Assistance Project, February 2014

Analysis Assumptions and Background

There remain questions regarding rate design. Time did not permit developing datasets for Duquesne's large capacity L rate, or PECO's general tariff rate which appears to lower the cost of service somewhat for all use cases which raises the question of the purpose for Rider CRR, but this issue requires more clarification. Duquesne's Rider 16 changes, filed in its March 28, 2018 rate case, remain under review and therefore are not presented in this report.

Undoubtedly, the use case data can be improved, however, this material has already yielded some important areas for useful discussion.

PJM Energy Supply Calculations

In general terms, PJM pricing is very volatile. For the purpose or this evaluation, certain assumptions and averages were taken into account for this analysis:

- We calculated the 2017 monthly average PJM LMP based on day-ahead PJM LMP data for each utility's Residual Aggregate Node. The monthly average was then applied to the customer's kWh usage in each month.
- Energy capacity charges are based on the PJM Reliability Pricing Model ("RPM") final zonal capacity prices for 2017-2018.

	PECO	PPL	Duquesne
January	30.20649	30.61089	30.0076
February	39.59797	39.3292	33.153
March	30.56154656	31.60815262	31.43346834
April	28.58596	28.70995	29.0747
May	28.36229126	27.73956067	29.91115258
June	23.99012409	24.80413879	26.93483563
July	28.13849565	27.38558508	29.68729356
August	24.30736	23.87917	27.6499
September	22.81338146	25.4501381	30.38491258
October	23.89861838	23.5205417	29.69778168
November	26.10073849	25.33266873	29.65648
December	39.59797276	39.32921505	33.15304021
Based on Day Ahead Hourly LMP data in PJM from 2017 residual metered load aggregate			

Table 5: Day Ahead Hourly LMP data in PJM from 2017 residual metered load aggregate in $/MW-hour

Capacity Peak Load Contribution (PLC)

Capacity Peak Load Contributions or "PLCs" reflect a customer's average demand during each of the five days coincident with the highest PJM system peak hours, as determined by PJM. Unlike Network Service Peak Load (NSPL) calculations, PLCs include an add-back of energy curtailed due to load management activities. There are various zonal scaling factors applied to PLCs. For the purposes of this analysis, PLCs are scaled at 107% and used in calculating energy capacity charges and energy efficiency charges.
For hourly usage, the 5 CPs are determined by interval demand coinciding with PJM's five seasonal peaks over the summer months, June through September (the customer's max demand may or may not coincide during the five peaks). These five peaks are then used by the utility to determine the customer's Peak Load Contribution (PLC). The average of the five peaks and a combination of zonal and

system-specific scaling factors makes up the customer's PLC. For non-hourly usage, the utilities determine the customer's PLC based on rate class and profile.

2017/2018 Final Zonal Scaling Factors, UCAP Obligations, Zonal Capacity Prices, & Zonal CTR Credit Rates:

2017/2018 Final Zonal Scaling Factors, UCAP Obligations, Zonal Capacity Prices, & Zonal CTR Credit Rates					
Final Forecast Pool Requirement =		1.0967			
Final DR Factor =		0.947			
Zone	**Final Zonal RPM Scaling Factor**	**Final Zonal UCAP Obligation, MW**	**Final Zonal Capacity Price with CP Transition IA Cost Component ($/MW-day)**	**Final Zonal CTR Credit Rate ($/MW-UCAP Obligation-day)**	**Final Zonal Net Load Price ($/MW-day)**
DLCO	1.03575	3,123.8	$153.61	$0.00	$153.61
PECO	1.04639	9,318.4	$153.74	$0.00	$153.74
PL	1.05325	7,935.5	$151.86	$0.00	$151.86

Table 6: 2017/2018 Final Zonal Scaling Factors, UCAP Obligations, Zonal Capacity Prices, & Zonal CTR Credit Rates $/MW-day

The above numbers vary widely and can ultimately impact results. The model used 2017/2018:

Duquesne: 0.15361 $/kW-day
PECO: 0.15374 $/kW-day
PPL: 0.15186 $/kW-day

Note that 2018/2019 PJM data shows:
Duquesne: 0.16470 $/kW-day
PECO: 0.21898 $/kW-day
PPL: 0.15511 $/kW-day

PLC calculations are a direct input to NSPL calculations and are roughly equal to the initial NSPLs.

The PJM capacity obligation tag used to determine the ISO capacity charge for an entity connected to the grid is based on the average peak load recorded at the facility meter(s) during the five systems 'call' days. The actual average facility kW demand recorded on these call days is adjusted using 'Loss Expansion' and 'Capacity Scale' factors to determine the facility 'Capacity Obligation' which is the kW rating used to determine the capacity obligation charge assessed to the facility. Based on an assessment of various regions within PJM, it has been determined that using a factor of 107% is a reasonable adjustment factor to convert actual recorded facility kW demand to the ISO Capacity Obligation for that facility.

Because we are assuming no CHP outages on the 5 CPs, the standby-specific PLC and NSPL values are set to zero for the analysis.

Network Transmission Service Peak Load Contribution
Each local distribution company within PJM has a network transmission service peak load contribution requirement. To allocate fairly the EDC's daily requirement to electricity suppliers, network transmission service peak load contributions (transmission PLCs) are determined. In accordance with the Open Access

Transmission Tariff (OATT) and PJM rules and procedures, each EDC will calculate a transmission PLC "ticket" for each electric account on an annual basis. For a given year, an account's daily network transmission service PLC requirement is based on its load at the time of the actual unrestricted peak hours that occurred during the twelve months ending October 31 of the prior calendar year. Network Service Peak Loads or "NSPLs" are similar to PLCs, but they exclude energy curtailed due to load management activities. There are various zonal scaling factors applied to NSPLs. For the purposes of this analysis, NSPLs are scaled at 100% and are used in calculating non-bypassable transmission charges. Per instructions, NSPL is assumed to be max demand for full requirements/supplemental analyses, scaled to 100%.