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September 14, 2018

VIA eFILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v. Duquesne Light Company
Docket Nos. R-2018-3000124 and C-2018-3001152

Dear Secretary Chiavetta:

Enclosed for filing is the **Reply Brief of Duquesne Light Company ("Reply Brief")** in the above-referenced matter.

As evidenced by the attached Certificate of Service, a copy of the Reply Brief has been served upon Administrative Law Judge Katrina L. Dunderdale, Judge Dunderdale's Technical Assistants, and all parties of record.

Should you have any questions, please contact me directly at 215.963.5034. Thank you.

Very truly yours,

Anthony C. DeCusatis

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ACD/ap
Enclosures

c: Per Certificate of Service (w/encls.)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket Nos. R-2018-3000124**
v.	:	**C-2018-3001152**
	:	
DUQUESNE LIGHT COMPANY	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing **Reply Brief on behalf of Duquesne Light Company** have been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant):

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Dated: September 14, 2018

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket Nos. R-2018-3000124**
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	:	
DUQUESNE LIGHT COMPANY	:	

REPLY BRIEF OF DUQUESNE LIGHT COMPANY

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I. INTRODUCTION

Duquesne Light Company ("Duquesne Light," "DLC" or the "Company") files this Reply Brief in response to the Initial Brief filed on behalf of members of the Duquesne Industrial Intervenors ("DII")[1] excluding Duquesne University,[2] regarding the single issue that was reserved for decision in the Joint Petition for Approval of Settlement Stipulation ("Joint Petition") filed contemporaneously with this Reply Brief. As explained in the Company's Initial Brief, a settlement has been achieved on all issues in this case except those pertaining to Rider No. 16 to the Company's tariff.[3]

Rider No. 16 makes available an optional rate for "back-up" service that can be elected by eligible customers that meet a portion of their load with their own generating facilities.[4] Although the Company initially proposed an increase in the Rider No. 16 rate, the Company withdrew its requested increase and, therefore, proposes to keep in place the existing rate of $2.50 per kW applied to the back-up contract demand of a customer with on-site generation that

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[1] DII is an *ad hoc* group of five large-use customers of Duquesne Light consisting of the Allegheny County Airport Authority, Duquesne University, Linde Energy Services Corporation, United States Steel Corporation, and the University of Pittsburgh (Complaint of DII, Appendix A (Revised)).

[2] Duquesne University entered into a Memorandum of Understanding (MOU) with Duquesne Light that is consistent with Duquesne Light's position (which has been accepted, or is not opposed, by all parties except the remaining members of DII), that the Company's Rider No. 16 rate should not be changed in this case. *See* DLC Initial Brief, pp. 8-9, 11 and 12. As part of the MOU, Duquesne Light has committed to work with the Company to obtain Commission approval of the MOU. DLC Exhibit No. CJD-1-R, p. 3, Paragraph 8; *see* DLC Initial Brief, p. 11 n.49.

[3] DLC Initial Brief, pp. 9-12.

[4] DLC Initial Brief, p. 1 and n.3. Unlike the "back-up" rates of other major electric distribution companies in Pennsylvania, Rider No. 16 is *not* mandatory. Customer-generators in Duquesne Light's service area retain the valuable option to remain on their general service rate schedules without electing Rider No. 16. DLC Statement No. 16-R, pp. 7-10, 19-22; DLC Statement No. 16-RJ, pp. 10-14. *See* DLC Initial Brief, p. 1 n.3.

elects to be served on Rider No. 16.[5] All parties except certain members of DII support, or do not oppose, the Company's proposal to leave the existing Rider No. 16 rate in place.[6]

Certain members of DII rejected the consensus achieved among all other parties to this case and have elected to continue to advocate the position advanced by their witness, James L. Crist. Mr. Crist contends that the Rider No. 16 rate should be reduced from its current level of $2.50 per kW as applied to an electing customer's back-up contract demand to approximately 36 cents per kW, to be applied only on an "as used" basis.[7] For so-called "maintenance" outages, the rate proposed by Mr. Crist would be even lower.

II. SUMMARY AND OVERVIEW

To a substantial extent, the arguments advanced in DII's Initial Brief in support of the steeply discounted rates proposed by Mr. Crist have been addressed and refuted in the Companies' Initial Brief filed on September 6, 2018. In short, DII proposes that customers with on-site generation receive a discount of more than 95% even through DII witness Crist conceded that the Company must keep distribution system capacity available 24-7-365 to furnish back-up service sufficient to meet those customers' peak loads at any time – including on-peak periods: "There will always be an outage. I don't know when the unpredicted outages are, that's why they're unpredicted."[8] DII's proposal is contrary to sound, well-accepted cost-of-service

[5] These are the same fundamental terms and conditions embodied in the Company's MOU with Duquesne University.

[6] Peoples Natural Gas Company, LLC ("Peoples") had opposed the Company's proposed increase to Rider No. 16 and had indicated that, unless the issues it raised with Rider No. 16 were resolved to its satisfaction, it would oppose the entire settlement. The Company's withdrawal of its proposed increase in Rider No. 16 resolved Peoples' issues pertaining to Rider No. 16 to its satisfaction, and Peoples now does not oppose any aspect of the proposed settlement nor does it oppose the Company's proposal to retain the existing Rider No. 16 rate. *See* DLC Initial Brief, pp. 10-13.

[7] Under the "as used" application advocated by Mr. Crist, a customer-generator would pay even Mr. Crist's steeply (95%) discounted rate only for the demand registered during a month when that customer used back-up distribution service because of the outage of its own generator. *See* DLC Initial Brief, p. 8.

[8] Tr. at 612, lines 20-22.

principles. As Office of Small Business Advocate ("OSBA") witness Brian Kalcic affirmed, the "partial requirements" approach advocated by Mr. Crist does not capture all of the fixed costs of distribution capacity that Duquesne Light must keep available on its system to furnish back-up service.[9] Therefore, as Mr. Kalcic also explained, Mr. Crist's partial-requirements back-up rate would[10] "result in subsidized back-up service."

Duquesne Light's Initial Brief demonstrates the lack of merit in all of the principal arguments advanced by DII. DII's Initial Brief, however, contains numerous additional errors of fact and law that must now be addressed, including, among others, the following:

Significant Misstatements Of What The Record Evidence Shows. To cite one notable – and highly relevant – example, DII contends that the Company "did not examine the historic usage patterns of the Rider No. 16 customer" it currently serves and suggests there is no evidence in the record of that customer's "usage patterns" to show that the current rate of $2.50 per kW is not excessive.[11] However, DII knew – or clearly should have known – that Company witness Gorman presented for the record extensive, actual operating data for the customer that is currently receiving service on Rider No. 16.[12] Significantly, those actual operating data show that the Company must stand ready to meet a customer's maximum need for back-up service at the time of *both* the applicable customer-class peak and the Company's system peak. In other words, the current back-up customer has imposed peak demands that are coincident with both the peak demand of its customer class and the peak demand of the Company's entire distribution

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[9] OSBA Statement No. 1-R, p. 6.

[10] *Id*.

[11] DII Initial Brief, p. 42 and n.144.

[12] DLC Statement No. 14-R, pp. 28-31.

system.[13] As a consequence, that customer has imposed demands that are no different from those imposed by full-requirements distribution customers. DII's contentions to the contrary are, therefore, contradicted by the record evidence and are demonstrably incorrect.

Fundamentally Erroneous Interpretations Of The Findings And Recommendations Of A Study Of Standby Rates That DII Relied Upon Extensively As Alleged Support For Its Position. DII relies upon findings and recommendations of a study prepared by Brubaker & Associates, Inc. and the Regulatory Assistance Project for the Oak Ridge National Laboratory[14] to try to support its position that the fully-allocated costs of furnishing distribution service should be multiplied by a "forced outage rate" (which DII erroneous equates with a "load factor"[15]) to determine an appropriate back-up distribution rate. [16] However, the Brubaker/RAP Study explicitly provides that applying a "forced outage rate" to the cost of full requirements service is proper *only* to develop a "generation reservation charge": "Specifically, the standby *generation reservation charge* would be calculated as the product of the FOR [forced outage rate] and the demand-related *generation* costs underlying the applicable full-requirements electricity rate."[17] Moreover, the Brubaker/RAP Study also recognizes that in states (like Pennsylvania) where generation has been "unbundled," customer-generators' ability to purchase "back-up power at prevailing market prices" is a complete substitute for any form of generation reservation

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[13] DLC Statement No. 14-R, p. 30.

[14] James Selecky, Iverson K., Al-Jabir A., *Standby Rates for Combined Heat and Power Systems – Economic Analysis and Recommendations for Five States* (Feb. 20-14) ("Brubaker/RAP Study"). The Brubaker/RAP Study was submitted by Peoples' witness Jamie W. Scripps as Peoples Exhibit No. JWS-6.

[15] *See* Section III.C., *infra*.

[16] DII Initial Brief, pp. 36-38.

[17] Brubaker/RAP Study, p. 13 (emphasis added).

charge.[18] Contrary to DII's erroneous contention,[19] the Brubaker/RAP Study clearly does *not* endorse (or even suggest) using a "force outage rate" (or "load factor") to discount the fully-allocated costs of distribution service to determine a cost-based back-up distribution service rate.

Inaccurate Representations Of The Holdings Of Utility Regulatory Commissions In Other States.[20] The portions of the Michigan Public Service Commission ("Michigan PSC") and Minnesota Public Utility Commission ("Minnesota PUC") decisions cited by DII pertain to *generation* reservation charges and not charges for back-up *distribution* service. As explained hereafter, throughout its Initial Brief, DII consistently confuses rate design principles that are proper only for back-up *generation* service with the principles that should govern the design of back-up charges for *distribution* service. Significantly, the Michigan PSC's decision for Consumers Energy Company discussed by DII[21] actually affirmed a methodology for calculating back-up distribution charges that is entirely consistent with Mr. Gorman's recommendations in this case.[22] In fact, the Michigan PSC approved a "delivery standby charge" for Consumer Energy of $4.21 per kW of back-up demand[23] – something DII does not mention in its Initial Brief.

[18] *Id*. at 5, 6 and 11. In fact, the Brubaker/RAP Study prefers and strongly recommends that those states that have not yet "unbundled" generation should do so at least for the purpose of allowing "standby" customers to purchase market-priced generation service as a substitute for a "generation reservation" charge of any kind. *Id*. As noted above, this is already the case in Pennsylvania. *See also* DLC Initial Brief, p. 32 n.125.

[19] *See* DII Initial Brief, p. 37.

[20] DII Initial Brief, pp. 37-38.

[21] DII Initial Brief, p. 38.

[22] *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief,* Case No. U-18322, 2018 Mich. PSC LEXIS 70, *175 (Mar. 29, 2018) ("*Application of Consumers Energy Company*"). The decision explains that Consumers Energy measures its customers' use of the distribution system by their "non-coincident peak demand" and the "class demand was used to allocate costs to each class." The Michigan PSC accepted its Staff's recommendation that the "distribution charges for GSG-2 [the standby rate for a customer with on-site generation] continue to be charged in the manner that they historically have been."

[23] *Id*. at *340.

Selectively Referencing Broad General Statements In The Commission's Policy Statements While Failing To Address – Or Even Mention – Specific Commission Findings In Those Documents That Refute The Fundamental Premise Underlying DII's Position.

DII references, and purports to rely upon, the Commission's Policy Statements on combined heat and power ("CHP")[24] and alternative ratemaking methodologies.[25] In so doing, however, DII simply repeats broad, general statements from those Policy Statements, such as observations about potential efficiency gains that CHP may provide,[26] the Commission's intent to "promote the development of CHP" and "reduce barriers to [CHP] deployment,"[27] and the Commission's acknowledgement that "some commenters encouraged the Commission to work with utilities" to adopt "fair, transparent standby tariffs."[28] At the same time, DII chose not to address – or even acknowledge – *specific* findings and statements by the Commission in those same documents that contradict the fundamental premise underlying DII's proposed back-up rates.

DII and its witness, Mr. Crist, have built their entire case on the premise that back-up distribution rates should reflect how *frequently* a back-up customer may impose its peak demand on a distribution system.[29] The reasons why that premise is wrong are set forth in the Company's Initial Brief.[30] In addition, in the same Policy Statements cited by DII, the

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[24] *Final Policy Statement on Combined Heat and Power*, Docket No. M-2016-2530484 (Apr. 5, 2018) ("CHP Policy Statement").

[25] *Fixed Utility Distribution Rates Policy Statement*, Docket No. M-2015-2518883 (May 23, 2018) ("Alternative Ratemaking Policy Statement").

[26] DII Initial Brief, pp. 11-12.

[27] *Id*. at 11.

[28] *Id.* at 17 n.45.

[29] *See, e.g.*, DII Initial Brief, p. 32 (Asserting that the percentage of time that a customer uses the distribution system should determine distribution rates, not the peak load that the customer imposes and for which capacity must be available whenever that peak occurs.)

[30] DLC Initial Brief, pp. 19-25.

Commission itself has expressly found that the premise underlying DII's position is erroneous. Of particular significance, the Commission has determined that the costs of furnishing distribution service do *not* vary with customers' energy usage or the frequency or timing of their usage. Thus, in discussing the concept of "straight fixed/variable pricing," the Commission concluded that it is not appropriate to treat fixed costs as if they were "variable" (i.e., a function of usage) because doing so not only contravenes the principle of cost-causality, it sends entirely the wrong "price signals." [31] The Commission determined that it is particularly important to adhere to this principle when pricing distribution service "because the costs of the distribution system, in the short run, are fixed and do not vary by day or by month."[32] The Commission further found:

> More significantly, while the supply costs of energy . . . vary as their consumption varies, distribution service costs do not vary, in the short run between rate cases, in proportion to a consumer's daily or monthly levels of consumption.[33]

Similarly, the CHP Policy Statement does not support – indeed, refutes – DII's attempt to justify its steeply discounted back-up service rate based on claims that the proliferation of CHP will "reduce" the "peak loads" of electric distribution companies and, therefore, "reduce the need for additional investment" in transmission and distribution ("T&D") facilities.[34] The Commission determined that DII's contentions are unfounded and acknowledged that such "savings/avoided costs" may or may not exist and could "take years to realize:"[35]

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[31] Alternative Ratemaking Policy Statement, p. 16.

[32] *Id*.

[33] *Id*.

[34] DII Initial Brief, p. 13 n.33 and accompanying text.

[35] CHP Policy Statement, p. 18.

> We acknowledge PECO's assertions that transmission & distribution savings/avoided costs may or may not exist because of CHP installation. We note that avoided costs may be difficult to quantify, that we currently lack information to confirm the impact of CHP on the electric system, and that it may take years to realize the benefits of any future avoided costs.[36]

Claiming That The Commission Expects Back-Up Rate Design Issues To Be Definitively Resolved In This Case, When The CHP Policy Statement Suggests Otherwise. DII also asserts that issues relating to the design of back-up distribution rates should be resolved in this case[37] despite the fact that the CHP Policy Statement was issued to gather additional information about CHP deployment and to initiate a collaborative fact-gathering working group that, among other things, is analyzing various approaches to back-up distribution rate design. In fact, DII acknowledges that the Commission's Bureau of Technical Utility Services "is planning to develop a list of suggested best practices regarding the design and implementation of standby rates."[38] DII does not explain – nor could it – why back-up rate design issues should be definitively resolved in this case when the Commission clearly expressed its intention to gather additional information in order to assist electric distribution companies and other stakeholders analyze those issues as part of an on-going collaborative process.[39]

This Reply Brief addresses the errors, misstatements and erroneous depictions of the record evidence in DII's Initial Brief, which were summarized above, while also identifying for

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[36] *Id.*

[37] DII Initial Brief, p. 5.

[38] DII Initial Brief, p. 26 and n.85.

[39] Additionally, as explained in DLC's Initial Brief (pp. 12-13), the two customers that either have elected Rider No. 16 or may elect Rider No. 16 for a CHP project that is under construction either support (Duquesne University) or do not oppose (Peoples) leaving the existing Rider No. 16 in place. Moreover, as also explained in DLC's Initial Brief, leaving the existing Rider No. 16 rate unchanged would not impact DII's members still litigating this issue because they have not expressed a firm expectation (let alone any definitive plan) to install CHP during the period rates established in this case can reasonably be expected to remain in effect.

the convenience of the Administrative Law Judge ("ALJ") the important evidence that DII did not discuss in its Initial Brief.

III. ARGUMENT

A. DII's Initial Brief Does Not Engage – Or Even Acknowledge – The Significant Record Evidence That Supports Approval Of The Company's Current Rider No. 16 Rate

The extensive evidentiary record is this case fully supports leaving the current Rider No. 16 rate in place, as the Company has proposed and as all parties other than certain members of DII either support or do not oppose. The record evidence shows that the current Rider No. 16, together with the valuable option Duquesne Light provides for customer-generators to remain on their general service rate schedule without electing Rider No. 16, provides significant savings to customers with on-site generation.[40]

DII's Initial Brief, while offering only conclusory statements that the Company "provided no evidentiary support for the existing $2.50 per kW rate,"[41] does not discuss – or even acknowledge – the extensive evidence the Company submitted. Indeed, DII's Initial Brief would lead one to believe that Duquesne Light did not present Rebuttal or Rejoinder Testimony. Even worse, DII's Initial Brief includes statements that are exactly the opposite of what the record evidence shows. This is exemplified by DII's contentions that Commission intervention is needed to address "high Back-up rates in DLC's territory" and that the Company's rates for back-up service are not "consistent with best practices recognized in Pennsylvania."[42] DII does not even mention unrebutted evidence that the Company's rates for back-up service allow customer-generators to avoid far more distribution charges than the back-up rates of electric

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[40] DLC Initial Brief, pp. 14-15.

[41] DII Initial Brief, p. 9. *See also* pp. 31-33.

[42] DII Initial Brief, pp. 26-27.

distribution companies to which it has been compared, and its back-up rates (Rider No. 16 and the option to stay on general service rates without electing Rider No. 16) meet even the very high standard for "best practices" that CHP advocates themselves have offered in this case.[43] Consequently, it is important to summarize the most significant record evidence supporting approval of the existing Rider No. 16 rate in this case:

Rider No. 16 Is Not Mandatory. Unlike the back-up rates of other electric distribution companies, notably PECO Energy Company's Capacity Reservation Rider ("CRR") and PPL Electric Utilities Corporation's Rule 6, Duquesne Light allows customers the flexibility to choose whether to elect Rider No. 16 or to remain on general service rates without Rider No. 16.[44]

The Flexibility To *Not* Elect Rider No. 16 Is Very Valuable. Customers that have a relatively flat load profile or have a generator that will frequently not be operating during or near the hours the customer experiences its peak load will benefit from being on Rider No. 16.[45] Alternatively, customers with CHP that operates as a baseload unit and has few outages or outages predominantly during off-peak hours would achieve a greater benefit from remaining on their general service rate schedule and not electing Rider No. 16.[46] Duquesne Light witness Fisher analyzed customer savings under both options for a CHP customer of the size, and with the operating characteristics, that Peoples' witness Scripps determined is a good representation for comparing back-up rates across multiple companies.[47]

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[43] *See* DLC Initial Brief, pp. 14-17, which summarized the unrebutted rebuttal and rejoinder testimony of DLC witness Fisher on these points.

[44] DLC Statement No. 16-R, pp. 7-10, 19-22.

[45] DLC Statement No. 16-RJ, pp. 11-12.

[46] *Id.*

[47] DLC Statement No. 16-R, p. 20, n.17 (approximately 5.0 MW or connected load and a 2.0 MW CHP facility).

Mr. Fisher's Analysis Shows That Very Substantial Savings Can Be Achieved Under The Company's Back-Up Rates. Mr. Fisher's analysis, which was not rebutted by any party in this case, shows that:

(1) A representative customer-generator on Rider No. 16 at the current $2.50 per kW rate that experienced a 32-hour outage *every* month would save at least $258,000 per year in T&D charges as compared to a customer without CHP.[48] That level of savings represents 37% of the customer's total T&D charges.[49] Additionally, under the rates agreed to as part of the settlement in this case, the customer savings would be even higher.[50]

(2) A representative customer-generator with a CHP facility reliable enough to avoid generator outages that would cause the customer to register on-peak demand above its Supplementary demand would realize even more significant savings by choosing the option to remain on general service rates without Rider No. 16. In that case, the customer would have annual savings of $318,000 to $356,000 per year or 45% of its T&D charges.[51]

Duquesne Light Allows Customer-Generators To Avoid A Much Higher Portion Of Their T&D Charges Than Electric Distribution Companies To Which It Was Compared. As previously explained, a representative CHP customer in Duquesne Light's service territory can avoid between 37% and 45% of its T&D charges as compared to a customer without CHP. The same customer-generator on PECO Energy's CRR, however, could avoid at most 12% of its T&D charges, while that customer-generator would not avoid any T&D charges on PPL

[48] *Id*. at 22.

[49] *Id*.

[50] *Id*.

[51] *Id*. at 21.

Utilities' Rule 6.[52] And, because the CRR and Rule 6 are mandatory for customers with on-site generation, those customers do not have the option to remain on PECO Energy's or PPL Utilities' general service rates without the CRR or Rule 6, respectively.

The Company's Back-Up Service Rates (Rider No. 16 And The Option To Not Elect Rider No. 16) Meet Or Exceed The Benchmark For "Best Practices" That Even CHP Advocates Have Proposed. A customer with a reasonably reliable on-site generator can avoid between $64 and $67 per MWH (between 90% and 94%) of the total-bill charges (generation plus T&D) of $71 per MWH that a similar full-requirements customer of Duquesne Light would incur.[53] Peoples witness Scripps presented evidence that a back-up rate allowing a customer with on-site generation to avoid at least 90% of the customer's otherwise applicable charges for full-requirements service conforms to what CHP advocates themselves consider "best practices" for back-up rate design.[54] The same evidence conclusively demonstrates the error in DII witness Crist's contention that Rider No. 16 would force a customer to pay the same level of T&D charges as a "full-requirements" customer without on-site generation.[55]

A Representative CHP Customer With A Reliable Generator Can Avoid Paying Distribution Charges To The Company That Exceed The Costs The Company Can Avoid By That Customer Self-Generating A Portion Of Its Electric Load. Company witness Fisher analyzed and quantified the level of costs that Duquesne Light can avoid when a representative CHP customer generates its own electricity, and he compared those costs to the distribution

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[52] DLC Statement No. 16-R, p. 43, line 11 through p. 44, line 6.

[53] DLC Statement No. 16-R, p. 30, Figure 4 (revised Aug. 17, 2018).

[54] Peoples Exhibit No. JWS-9 (U.S. EPA, *Standby Rates for Customer-Sited Resources: Issues, Considerations and the Elements of Model Tariffs* (2009), p. 9 ("EPA Standby Rates Study"); Peoples Statement No. 3, p. 24, lines 15-17 and n.20.

[55] *See, e.g.*, DII Statement No. 1-S, p. 15, lines 3-15.

charges that such a customer can avoid paying to Duquesne Light. That analysis was not rebutted by any witness in this case. Mr. Fisher's analysis shows that, under Duquesne Light's existing rates (including the current Rider No. 16), the distribution charges that a representative CHP customer with a reliable generator could avoid paying to Duquesne Light would exceed by between $15 and $18 per MWH the costs that the Company could avoid by that customer self-generating a portion of its electric load equal to its generator's capacity.[56] Specifically, the Company's avoided costs are $49 per MWH, while the representative CHP customer would avoid paying total charges of between $64 and $67 per MWH under current rates. The difference between the charges a customer avoids and the costs Duquesne Light can avoid are shifted to, and must be paid by, other customers. A further reduction in the charges paid by a representative CHP customer (as Mr. Crist proposes) would shift even more costs to non-generating customers.

Actual Operating Data For The Company's Existing Rider No. 16 Customer Demonstrate That Back-Up Service Customers Experience Generator Outages During Customer-Class And System Peak Periods And Impose Total Peak Demands On The Distribution System That Are Not Materially Different From Those Of Customers Without On-Site Generation. As recently as June 2016, the peak demand of the customer currently on Rider No. 16 was coincident with the peak demand of its class (Rate GL),[57] when the customer registered its monthly peak because its generator was not operating.[58] Additionally, in two other months (May and September), the customer's demand was at least 90% of its monthly peak at

[56] DLC Statement No. 16-R, p. 30, revised Figure 4. Avoided costs would exceed avoided charges by an even larger margin if the settlement rates are approved and the current Rider No. 16 rate remains unchanged. See DLC Initial Brief, p. 24 n.94

[57] DLC Statement No. 14-R, p. 30, lines 2-6.

[58] *Id*.

the time the Rate GL class peak occurred, which shows that outages of the customer's generator were material contributors to the class monthly peaks.[59] Similarly, when the customer achieved its annual peak demand for 2016 (at 2:15 PM on August 10), the Rate GL class demand was at 98% of its annual peak and the entire distribution system was at 97% of its total annual peak demand.[60] Thus, actual operating data confirm that the unavailability of a customer's generator can be a major contributor to both *class* and *total system* peak demands.[61] If a customer-generator is receiving distribution service that is equivalent to the service furnished to customers without on-site generation – and the operating data for the existing Rider No. 16 customer show that to be the case – there is no valid cost-of-service basis to grant customer-generators a steep (over 95%) discount from the fully-allocated cost of service, as DII and Mr. Crist propose.[62]

B. The Methodology Employed By DII Witness Crist And Advocated In DII's Initial Brief Is Fundamentally Flawed Because It Treats The Costs Of Furnishing Distribution Service, Which Do Not Vary With A Customer's Energy Usage, The Same As The Costs Of Furnishing Generation Service, Which Do Vary With Energy Usage

The issue presented in this case involves distribution capacity *not* generating capacity. As explained hereafter, DII and its witness consistently, repeatedly and improperly try to apply criteria that are appropriate only for designing standby generation rates to design rates for back-up distribution service. As a consequence, DII has misrepresented the findings and conclusions of the Brubaker/RAP Study and seriously misstated the holdings of regulatory commission decisions it relies upon.[63]

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[59] *Id*. at lines 7-8.

[60] *Id*. at lines 10-14.

[61] DLC Statement No. 14-R, p. 30, lines 16-20.

[62] *See* DLC Initial Brief, pp. 28-30.

[63] *See* Section II, *supra* and Sections II.D. and II.E., *infra*.

Rider No. 16 (like the Company's general service distribution rates) does not govern the provision of energy and generating capacity that would be used to meet a customer-generator's load when its generator is not operating. In an "unbundled" state like Pennsylvania, energy and capacity are obtained at market-based prices either from electric generation suppliers (for shopping customers) or from market-priced, competitively-procured default service made available by the default service provider.[64] Rates for energy and capacity are, therefore, not at issue in this case.[65]

Rider No. 16 pertains to the provision of distribution service only. Consequently, the service provided to customers that elect Rider No. 16 ensures that capacity is available on the *distribution* system for a contracted level of kW demand. If a customer-generator expects the Company to provide back-up distribution service whenever its generator is not operating (and it is clear DII's members have this expectation[66]), then the reserved capacity must be available 24 hours per day, 365 days per year, because, as DII witness Crist acknowledged and as operating data for the existing Rider No. 16 customer confirm, outages of customers' generators occur at any time, including during class and system peak periods.

The distribution capacity reserved for back-up service cannot be used for any purpose other than remaining available for use by a customer-generator who contracts for that capacity under Rider No. 16.[67] And, because the Company is always holding that distribution capacity available, whether or not the customer is having generation delivered to it from an external source, there are no "avoided cost" benefits to the distribution system from a customer installing

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[64] *See* DLC Statement No. 16-R, pp. 12-13; DLC Statement No. 16-RJ, p. 9.

[65] *See* DLC Initial Brief, p. 32 n.125.

[66] Tr. at 573, lines 9-14.

[67] DLC Statement No. 16-R, p. 18, lines 17-21.

on-site generation.[68] As previously explained these bedrock principles have been recognized and affirmed by the Commission, which found that, unlike "the supply costs of energy . . . [that] vary as their consumption varies," "distribution service costs do not vary, in the short run . . . in proportion to a customer's daily or monthly levels of consumption."[69] For that reason, the Commission has also acknowledged that there is no basis to conclude that an electric distribution company will actually see any T&D "savings/avoided costs" and, even if it did, they would "take years to realize."[70]

The Commission's findings also reflect broadly-accepted cost-of-service principles that, in turn, are grounded on the actual design criteria for distribution systems. Thus, the National Association of Regulatory Commissioners' *Electric Utility Cost Allocation Manual*[71] – a widely-recognized, authoritative source for the utility industry – provides that distribution system facilities must be sized to meet customers' load (i.e., demand): "[W]hen designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels."[72] For that reason, non-coincident peak demand (not an energy or usage-based factor) is used to allocate costs: "Local area loads are the major contributors in sizing distribution equipment. Consequently, customer-class non-coincident peak demands (NCPs) and individual customer maximum demands are the load characteristics that are normally

[68] In contrast, generation from external sources that is used to meet a customer's load when the customer's generator is not operating can be sold to other customers (or into real-time generation market) whenever the customer-generator is not calling upon those external sources as a substitute for its on-site generator.

[69] Alternative Ratemaking Policy Statement, p. 16.

[70] CHP Policy Statement, p. 18.

[71] National Association of Regulatory Commissioners, *Electric Utility Cost Allocation Manual* (Jan. 1992)

[72] *Id.* at 97.

used to allocate the demand component of distribution facilities."[73] Indeed, neither Mr. Crist nor any other witness has disputed the use of non-coincident peak demand as the proper determinant for allocating the demand-related fixed costs of the distribution system.[74]

DII contends that the fully-allocated cost of providing distribution service should be discounted by multiplying that cost by 5% (i.e., a 95% discount) to reflect how often DII believes a back-up customer may use the distribution system. DII's approach is a significant, and erroneous, departure from the Commission's findings and the established cost-of-service principles discussed above. The costs to furnish distribution service, whether to a full-requirements customer or a "back-up" service customer, is a function of the customer's peak demand, not the frequency of the customer's use. In fact, DII's frequency-of-use approach is not different from an energy-based allocation of costs and, as such, improperly assumes that the costs of providing distribution service vary with energy usage (consumption).[75] As such, DII's proposal in this case is fundamentally defective, contrary to prior Commission findings, and totally inconsistent with both distribution system design criteria and well-established cost-of-service principles.

C. DII's Attempt To Manipulate The Facts And The Decision In The Company's Last Case To Advance Its Contention That The Current Rider No. 16 Rate Is Not Supported By Substantial Evidence Should Be Rejected

Mr. Crist could not decide what his proposed 5% multiplier is, or what he would like to call it.[76] At various places in his written testimony, DII witness Crist referred to his proposed

[73] *Id*.

[74] *See* Tr. 588, lines 5-7 and DLC Initial Brief, p. 25.

[75] See DLC Initial Brief, p. 21, which provides example showing quantitatively that DII witness Crist's proposed methodology mirrors a consumption (energy) based allocation of distribution capacity costs.

[76] *See* DLC Initial Brief, pp. 7-8 (documenting the variety of different terms and concepts Mr. Crist attached to his proposed 5% multiplier).

5% multiplier as a "load factor."[77] At other points in his testimony, his description of the 5% multiplier indicates he actually intends it to be a forced outage rate.[78] In its Initial Brief, DII continues the confusion by consistently trying to equate "load factor" and "forced outage rate."[79] "Load factor" and "forced outage rate" are two significantly different concepts that measure two significantly different things.

The U.S. Energy Information Administration ("EIA") defines load factor as: "The ratio of the average load to peak load during a specified time interval."[80] A load factor measures how efficiently a customer uses a facility, such as an electric utility's distribution system.[81] A high load factor means the customer's peak demand is close to its average demand (it uses the facility on a relatively steady basis over the time interval of the measurement). Therefore, the higher the load factor, the better (i.e., the more efficiently the customer uses the facility).[82] A forced outage rate, however, is something completely different.

A forced outage rate measures the reliability of a generator. The Brubaker/RAP Study provides this generally-accepted definition:

> The Forced Outage Rate (FOR) of a generating unit for a given time interval is defined as the number of hours that the unit is forced out of service for emergency reasons, divided by the total number of hours that the generating unit is available for service

[77] *See, e.g.*, DII Statement No. 1-S, p. 12, lines 13-15 ("I will continue to explain that my method of applying a load factor of 5% to the Company's ACOSS for Rider No. 16 is the appropriate method . . ."); DII Statement No. 1-S, p. 11, lines 10-12 (referring to his multiplier as "a load factor to determine an appropriate back-up amount").

[78] *See, e.g.*, DII Statement No. 1, p. 25, lines 18-20 (describing his proposed multiplier in terms of "unplanned outage hours"); DII Statement No. 1-S, p. 11, lines 16-18 (describing his 5% multiplier as the "small percentage of the annual hours" that back-up customers would allegedly "need back-up service").

[79] *See, e.g.*, DII Initial Brief, p. 32

[80] https://www.eia.gov/tools/glossary/. *See also* Peoples Exhibit JWS-9, p. B-5, defining load factor as "the ratio of average electric load to peak load."

[81] Tr. at 261, lines 23-25.

[82] Tr. at 261, line 23, through 262, line 4.

> during that interval plus the number of hours that the generating unit experiences a forced outage. The FOR of a generating unit measures the probability that the unit will not be available for service when required . . . . The FOR is a measure of a generating unit's availability.[83]

Because a forced outage rate measures the percentage of time a generating unit is forced out of service for emergency reasons, a *lower* percentage is *better* than a higher percentage. This is the exact opposite of the directions of good and bad for a load factor – where *higher* is *better*. Consequently, it is inexplicable that Mr. Crist (or DII, in its Initial Brief) would even try to use the terms "load factor" and "forced outage rate" interchangeably. Mr. Crist's attempt to equate these two dramatically different concepts is rooted in the ambivalence he and DII have regarding the Company's last (2013) base rate case.

In its 2013 case, the Company proposed, and the Commission approved, reducing the Rider No. 16 rate from above $6.00 per kW to the current $2.50 per kW.[84] The final approved rate reflected the fully-allocated cost of distribution service multiplied by 30%, which was deemed to provide an appropriate reduction from the fully-allocated cost based upon an estimate of the "load factor" for customers served or seeking service on Rider No. 16.[85] Both Mr. Crist and Peoples' witness, James W. Daniel, contended that the Company (and the Commission)

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[83] Brubaker/RAP Study, p. 10.

[84] As explained in the Company's Initial Brief (p. 26 n.101), since its last case, the Company has carefully reviewed the cost-of-service basis for its current back-up rate and concluded that a different and more analytically rigorous approach should be considered so that back-up service will be properly priced and increased penetration of distributed generation in the future will not lead to inappropriate subsidization of on-site generation. The Company initially proposed to increase the Rider No. 16 rate to reflect that approach, but subsequently withdrew its proposed increase because it determined that this case would not be an appropriate venue for comprehensively reexamining Rider No. 16.

[85] *See* Peoples Statement No. 2, p. 9, quoting Duquesne Light's testimony on this issue from its 2013 base rate case.

should not depart from the approach used in the Company's last case[86] and, therefore, should replicate the methodology employed in that case.

Mr. Daniel actually followed his own advice, accepted the fully-allocated cost of distribution service determined by Company witness Gorman, and calculated a rate of $2.41 per kW.[87] Mr. Crist, on the other hand, paid lip service to replicating the methodology used in the 2013 case but, nonetheless, ended up proposing a dramatically lower rate for Rider No. 16 (36 cents per kW, on an "as used" basis) than either Mr. Daniel's or the current Rider No. 16 rate. Mr. Crist achieved this anomalous result by treating as precedent the part of the 2013 case he liked (i.e., multiplying the fully-allocated cost of service by a factor that discounts the back-up service rate) while walking away from the part of the 2013 he did not like (the load factor multiplier of 30%).[88] DII mirrors this schizophrenic approach in its Initial Brief (*see* pp. 32-33), where it claims the 2013 case stands for the proposition that the fully allocated cost of distribution service should be multiplied by a "load factor" – but *not* the load factor the Commission actually used in that case.

The challenge Mr. Crist faced was to get the end-result he wanted (a much lower Rider No. 16 rate) while still claiming to duplicate the methodology attributed to the Company's 2013 case. To that end, Mr. Crist decided to substitute a very low multiplier (5%) that, in reality, is the average "forced outage rate" for what Mr. Crist contends are very reliable CHP units, while, at the same time, calling that figure a "load factor" – something it clearly and demonstrably is not. In short, Mr. Crist's (and DII's) position in this case is based on a rhetorical sleight of hand;

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[86] Peoples Statement No. 2, pp. 9-10; DII Statement No. 1, p. 25.

[87] See DLC Initial Brief, p. 6. As noted, Mr. Daniel did not, however, explicitly reflect the "roll-in" of the distribution system improvement charge, which would add about 12.5 cents to his figure (bringing it to $2.62 per kW).

[88] DII Statement No. 1, p. 25.

claiming to replicate the method used in the Company's 2013 base rate case, while renaming his low-ball multiplier a "load factor" to make it appear that he is doing something that has already been approved by the Commission. Of course, nothing could be further from the truth.

The ALJ and the Commission should see DII's argument for what it is – a result-oriented approach that cherry-picks what DII likes from the Company's 2013 case while trying to substitute an entirely different figure (5%) and a totally different concept underlying that figure (a forced outage rate) for the figure (30%) and the concept (load factor) actually used in the 2013 case. The ALJ and the Commission should reject this transparent attempt to tailor the facts (and the interpretation of a prior case) to fit Mr. Crist's and DII's predetermined outcome.

D. DII Has Misrepresented The Findings And Conclusions Of The Brubaker/RAP Study

DII relies extensively on the Brubaker/RAP Study to support its position and, in particular, its proposal to multiply the fully-allocated cost of distribution service by a "forced outage rate of the customers' generators" to recognize "diversity."[89] However, the part of the Brubaker/RAP Study that DII tries to rely upon has nothing to do with the development of rates for distribution service. To the contrary, the Brubaker/RAP Study clearly states that forced outage rates are used only to calculate "generation reservation charges:"

> The appropriate percentage of the demand charge for generation for full-requirements customers to be assessed to standby customers could be developed using historical data, if available, regarding the FORs [forced outage rates] of standby customers in the utility's service area. Specifically, the standby generation reservation charge would be calculated as the product of the FOR and the demand related generation costs underlying the applicable full-requirements electricity rate.[90]

[89] DII Initial Brief, p. 7.

[90] Brubaker/RAP Study, p. 13.

The very same point (i.e., that the forced outage rate should be applied to fully-allocated costs of *generation* service to calculate the *generation* reservation charge) is repeated throughout the Brubaker/RAP Study.[91] Moreover, the Brubaker/RAP Study also finds that even the need for *generation* reservation charges is eliminated in states (like Pennsylvania) that have "unbundled" generation from T&D services.[92]

In summary, DII's reliance on the Brubaker/RAP Study is misplaced because DII has conflated rate design criteria that only apply to generation reservation charges with the criteria that govern the design of distribution rates. Because the cost of distribution service does not vary with the frequency of a customer's use – unlike generation supply charges, which are a function of customer usage – it is fundamentally incorrect to use a forced outage rate to discount fully-allocated distribution costs in the manner that Mr. Crist and DII propose and that they erroneously attribute to the Brubaker/RAP Study.

E. DII Has Misrepresented The Holdings Of Utility Regulatory Commission Decisions From Other States; Those Decisions Do Not Support DII's Position In This Case

DII claims that commission decisions from Michigan and Minnesota "lowered" proposed "standby" charges to reflect a "force outage rate" or "outage rates for CHP systems."[93] In each instance, the commissions were addressing back-up *generation* charges, yet DII has tried to represent the commissions' holdings as if they applied to back-up *distribution* service.

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[91] *E.g.,* Brubaker/RAP Study, p. 18 ("This standby generation charge can be calculated by multiplying the best FOR by the demand charge in the customer's otherwise applicable full-requirements tariff."); p. 18 ("standby generation charge" for AEP Ohio should be set based on FOR and fully-allocated generation demand charge).

[92] Brubaker/RAP Study, p. 11: "In competitive electricity markets, market prices determine the charges for standby service from electricity suppliers. Generally the electricity costs of back-up power (distinct from the delivery costs) is determined by the market price at the time of the customer-generator's outage."

[93] DII Initial Brief, pp. 38-39.

DII claims that the Michigan PSC, in a 2018 decision,[94] "rejected DTE's proposal for a reservation charge of 16% of the full-time use power supply reservation charge" and "lowered the reservation charge to 10% for unscheduled standby use and 5% for scheduled standby use (based on a 5% forced outage rate).[95] DII implies that these criteria were applied to back-up distribution rates when, in fact, that is not the case. The Michigan PSC's Order plainly states that "DTE Electric provides *bundled* retail standby service to self-service power customers under its Standard Contract Rider 3 (R3)."[96] "Bundled," of course, means that DTE is vertically integrated and provides back-up service under Rider 3 that is *not* functionally separated into generation, transmission and distribution service. No part of the Michigan PSC's discussion of DTE Rider 3 pertained to charges for distribution service. To the contrary, every part of the Michigan PSC's decision that DII purports to rely upon dealt with generation service. This is evident even from language DII quotes in its Initial Brief, which clearly states that the commission was using a "forced outage rate" to calculate a "power supply reservation charge" (i.e., a generation charge), not a distribution charge.[97]

DII also claims that the Michigan PSC "rejected a proposed increase in standby rates by Consumers Energy Company and pointed out the Company's failure to reflect the different characteristics of back-up and maintenance power, as well as its unclear proration language."[98] However, the holding that DII summarizes deals only with Consumers Energy's proposal to

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[94] *In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority*, Case No. U-18255, 2018 Mich. PSC LEXIS 122 (Apr. 18, 2018) ("*Application of DTE Electric*")

[95] DII Initial Brief, p. 38.

[96] *Application of DTE Electric* at *116 (emphasis added).

[97] *Application of DTE Electric* at *126 ("The Commission finds that it is reasonable to approve an R3 standby tariff that sets a monthly *power supply reservation* charge based on the forced outage rates of the best performing generators . . ." (emphasis added).

[98] DII Initial Brief, p. 38 n.124.

increase its “power supply demand charge”[99] – a generation charge, not a distribution charge. In this case, however, DII’s dereliction is even more egregious because the Michigan PSC’s decision actually does address back-up distribution charges. The Michigan PSC affirmed a methodology for calculating back-up distribution charges that is indistinguishable from the methodology Mr. Gorman recommended in this case as the basis for the Company’s originally proposed (and subsequently withdrawn) Rider No. 16 charge of $8.00 per kW:

> The Staff explained that a customer’s use of the distribution system is currently measured by the non-coincident peak demand for rate design purposes. The Staff stated that class peak at a given level of the system, on the other hand, is used to allocate costs to each class. The Staff recommended that, “for now distribution charges for GSG-2 [Consumer Energy’s rate for standby service] continue to be charged in the manner that they historically have been, but [the Staff] reserves the right to recommend changes in the future, potentially including the recommendations in the [standby rate working group] SRWG Report.”[100]

DII also neglected to mention that the Michigan PSC approved a Delivery Standby Charge (i.e., distribution charge) of $4.21 per kW.[101]

DII contends that “the Minnesota Public Utilities Commission recently approved a negotiated settlement reducing Xcel Energy’s standby reservation fee from 12% to 7.4% of the amount included in base tariff demand rates to better reflect outage rates for CHP systems, which was reported by commenters in that proceeding to be 5%.”[102] To begin with, the Minnesota PUC’s decision does not include the “5%” figure DII alludes to, nor does DII identify what “commenters” allegedly provided that number. However, and even more importantly, DII’s

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[99] *Application of Consumers Energy* at *174 (“ABATE/Gerdau objected to the company’s proposed adjustment, arguing that Consumers . . . would more than double the *power supply* demand charge” (emphasis added)).

[100] *Application of Consumers Energy* at *175.

[101] *Application of Consumers Energy* at *340.

[102] DII Initial Brief, pp. 38-39.

summary reflects the deletion of two key words: "generation and transmission." DII, once again, tries to pawn off a holding that applies to "generation and transmission" as if it addressed a back-up rate for distribution service. The exact language in the Minnesota PUC's Order states: "The proposed terms agreed to by the parties in the modified Standby Service Rider include the following: . . . (3) Reduce the share of *generation and transmission* costs included in the standby reservation demand rate from 12 percent to 7.4 percent of the amount included in base tariff demand rates."[103] The language DII relies upon is not applicable to distribution rates and does not support its position in this case.

DII also cites an unpublished decision of the Rhode Island Public Utilities Commission[104] accepting a settlement providing that the Distribution Charge per kW for Retail Delivery Service would be "$5.22 per kW, multiplied by a factor of 10%, representing the likelihood that, on average, an outage of an individual customer's generator will occur coincident with the Company's distribution system peak demand approximately 10% of the time." As noted, this decision accepted a settlement. In any event, this is another case where DII's discussion of a decision is remarkable for what it leaves out.

As stated in the portion of the decision quoted above, the 10% multiplier reflected an "*estimated* coincidence factor."[105] DII did not, however, explain that the Order committed National Grid to "examine the accuracy of this assumption and propose a tariff revision if in fact it determined this assumption was not entirely accurate."[106] Additional, the Order provides that,

[103] *In the Matter of a Commission Inquiry Into Standby Service Tariffs*, Docket No. E-999/CI-15-115, 2018 Minn. PSC LEXIS 139 *11-12 (Apr. 20, 2018).

[104] *Narragansett Electric Company d/b/a National Grid's Petition for Review of the Use of Back-Up Rates*, Docket No. 4232 (July 12, 2013) ("*National Grid*"). See DII Initial Brief, pp. 37-38 and n.122.

[105] *National Grid*, slip op., p. 6 (emphasis added).

[106] *National Grid*, slip. op., p. 8.

if National Grid determined that the assumed "coincidence factor" was inaccurate, it could recover "any lost revenue resulting from the inaccuracy . . . through the revenue decoupling mechanism" that was already in place for National Grid.[107] In short, the assumed 10% coincidence factor was a placeholder, and National Grid was permitted to reconcile the revenues recovered in its back-up rates with the actual performance of its standby customers' generators.[108] Clearly, the *National Grid* decision was subject to conditions and qualifications that do not make it the kind of clear delineation of standby rate design that DII claims it is.

In addition, DII also failed to mention that, for larger CHP facilities (i.e., customers with 3,000 kW or more of monthly peak demand), National Grid imposes a Customer Charge of $17,000 per month.[109] Obviously, that is a very high charge and needs to be considered in conjunction with the demand charges that the parties agreed to and the commission approved in that case. Additionally, by approving a customer charge of that magnitude, the Rhode Island Public Utilities Commission provided greater assurance that the customer-cost component of back-up distribution service would be recovered under the rates adopted in the settlement. There is no similar assurance that the steeply-discounted back-up rates proposed by Mr. Crist would recover even the customer-cost component of distribution service, because he did not analyze that important issue.[110]

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[107] *Id*.

[108] *Id*.

[109] *National Grid*, slip op., R.I. P.U.C. No. 2077 (Rate B-62).

[110] Tr. at 592.

F. DII's Reliance On The Federal Energy Regulatory Commission's Regulations Implementing The Public Utility Regulatory Policies Act Is Misplaced

DII's reliance on the Federal Energy Regulatory Commission's ("FERC") regulations implementing the Public Utilities Regulatory Policies Act ("PURPA") is misplaced. The rate design criteria that Mr. Crist attempted to reply upon, which DII repeats in its Initial Brief,[111] do not apply to electric distribution service. As explained in Duquesne Light's Initial Brief, Mr. Crist's (and DII's) interpretation of the PURPA regulations confuses rate design criteria applicable to generation rates with rate design criteria appropriate for distribution rates.[112] The PURPA regulations do not support DII's position for the reasons set forth in the Company's Initial Brief.

G. DII's Contention That Rider No. 16 Should Be Revised To Provide That The Rate For Back-Up Distribution Service Should Apply Only To "As Used" Demand Should Be Rejected

Contrary to DII's assertions, the design of Rider No. 16, which applies the current $2.50 per kW rate to the back-up contract demand a customer agrees to in its service agreement with the Company, is entirely consistent with the "best practices" design criteria for back-up distribution rates that have been identified in this case. Specifically, the EPA Standby Rates Study[113] explicitly provides that back-up rates for distribution service may properly be applied to "an agreed-on contract demand."[114] Consequently, Rider No. 16 conforms to applicable, and accepted, design criteria for back-up *distribution* rates.

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[111] DII Initial Brief, pp. 35-36.

[112] DLC Initial Brief, pp. 30-34.

[113] Peoples Exhibit No. JWS-9, p. B-6: "The distribution demand charge is multiplied by the customer's billing demand, which is one of several quantities (or some variation on them): the customer's monthly noncoincident peak demand, its maximum potential demand, or an agreed-on contract demand. . . . [T]he negotiated contract demand might be accompanied by the customer's promise not to exceed it . . ."

[114] The EPA Standby Rates Study (p. B-6) also provides that the back-up distribution demand rate could properly be applied to a customer's "maximum potential demand," which would require a back-up customer to pay the back-up

DII offers three purported reasons why the Rider No. 16 demand charge should be applied only on an "as used" basis. First, DII contends that the as-used application "encourages efficient operation of the CHP system" by incenting customer-generators to "avoid outages." This argument clutches at straws. Irrespective of back-up distribution charges, CHP customers have to replace the *generation* their generating units do not provide when those units experience outages. The generation replacement costs are substantial – over $49 per MWH as Mr. Fisher calculated (and no party contested).[115] Back-up distribution charges (calculated based on contract demand), in contrast, are only a small fraction (less than 3%-4%) of a representative CHP customer's total electric bill.[116] The cost of purchasing electricity to replace what it would otherwise generate for itself provides all the incentive a customer needs to operate its generator efficiently and "avoid outages." The replacement cost of generation dwarfs any incremental difference in distribution charges that might result from applying the Rider No. 16 rate on an "as used" basis.

DII also contends that back-up demand charges should be applied on an "as used" basis because that is the way demand charges are applied for general service rates.[117] This argument overlooks several important facts. First, because they are applied on an "as used" basis, the demand rates for general service are much higher than the $2.50 per kW rate under Rider No. 16.[118] Second, if a customer with CHP or other distributed generation believes it can operate its

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rate on the sum of the maximum demands of all of the electrical equipment it operates. Allowing a customer to choose a back-up contract demand (as the Company does, under Rider No. 16) gives the customer the flexibility to select a billing demand that is less than its maximum potential demand and adjust its operations to remain within its contract demand parameters.

[115] DLC Statement No. 16-R, p. 30 (Revised Figure 4). *See also* DLC Statement No. 16-R, p. 28 (Figure 3).

[116] DLC Initial Brief, p. 13 and n.54.

[117] DII Initial Brief, p. 46.

[118] The Company's existing Rate GL demand charge is over $8.00 per kW (and over $9.00 for the first 300 kW of demand). Duquesne Light Tariff Electric – Pa. P.U.C. No. 24, p. 47.

generator efficiently, avoid outages occurring during on-peak periods, and, therefore, benefit from an "as used" application of a demand, it has the flexibility to remain on its general service rate without electing Rider No. 16 and achieve the savings DII claims would be realized from the "as used" approach. Third, the "spikes and dips" in *usage* that general service customers exhibit is not a measure of the peak demand that the system must be designed to meet. Solid evidence from actual operating data presented in this case shows that back-up customers can, and do, experience their peak demands at the same time class and system peaks occur.[119] Distribution system capacity must be available to meet those back-up service demands whenever they occur.

Finally, DII argues that applying the demand charge to "as used" demand is necessary to conform Rider No. 16 to the billing practice for the existing Rider No. 16 customer. That argument ignores the fact that under the MOU with Duquesne University (the existing Rider No. 16 customer), the demand charge will apply to the university's *contracted* demand charge.[120] Revising Rider No. 16 to change the application of the rate from contract demand to "as used" demand would depart from the terms of the MOU. Currently, the terms of Rider No. 16 and the MOU are consistent, and both should be approved.

H. There Is No Valid Cost-Of-Service Basis To Charge A Lower Back-Up Distribution Rate When A Customer's Generator Is Out Of Service For "Maintenance"

DII criticizes Rider No. 16 for not distinguishing between "maintenance" outages, which DII claims can always be "planned," and "unplanned" (or "forced") outages.[121] DII contends that this distinction is needed because "maintenance" outages can be scheduled to occur off-peak

[119] DLC Statement No. 14-R, p. 30.

[120] DLC Initial Brief, pp. 8-9; DLC Exhibit No. CJD-1-R; DLC Statement No. 1-R, p. 11.

[121] DII Initial Brief, pp. 47-48.

– unlike unplanned outages, which can occur at any time, including during on-peak periods.[122] DII also asserts that setting a lower rate for "maintenance" outages will encourage customers to schedule maintenance during off-peak periods.

DII's arguments are wrong because, once again, DII ignores the fundamental difference between generation service and distribution service. DII's error is highlighted by the Brubaker/RAP Study, which DII has relied upon as an authoritative source. The Brubaker/RAP Study concluded that in states where generation has been "unbundled" and customers can purchase generation at market-based prices, there is no valid basis for charging different rates for distribution service provided during "back-up" and "maintenance" outages:

> Under Schedule OAD-SBS, the customer purchases maintenance power not from Ohio Power Company [the incumbent electric distribution company] but through a third-party supplier. This largely eliminates the utility cost savings that could be realized by scheduling maintenance power during off-peak periods. For this reason, the study assumes that the charges for back-up and maintenance distribution service would be identical under this schedule.[123]

All of the benefit that DII claims would accrue from scheduling maintenance outages during "off-peak" periods are generation-related; they do not impact the cost of providing distribution service, as the Brubaker/RAP Study properly concluded. Because an electric utility must meet a back-up service customer's peak demand whenever it occurs and irrespective of whether it is caused by planned or unplanned outages of the customer's generator, there is no difference in the cost to the utility if some of the customer's generator outages occur off-peak. The electric utility must reserve sufficient distribution system capacity to meet the customer's

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[122] DII Initial Brief, pp. 47.

[123] Brubaker/RAP Study, p. 34.

peak demand whenever it occurs. Unplanned outages of customers' generators can – and do – occur during on-peak periods, and the customer's peak demand during unplanned outages establishes the level of distribution capacity that must be reserved for back-up distribution service. The fact that "maintenance" outages may be "planned" for off-peak periods does not reduce the level of distribution capacity that must be reserved to meet unplanned, randomly-occurring demands the customer will experience when its generator has a "forced" outage (including during on-peak periods). The Company must, therefore, have distribution capacity available at all times to furnish back-up distribution service whenever outages occur, whether they are planned or unplanned. As Mr. Crist conceded: "There will always be an outage. I don't know when the unpredicted outages are, that's why they're called unpredicted."[124]

DII also errs in claiming that a lower rate for "maintenance" outages is necessary to encourage customers to schedule those outages during off-peak periods.[125] As previously explained, when a customer's generator is out of service for any reason, the customer must replace the electricity it otherwise would have generated with power from an external source. Replacement power purchased from external sources is more expensive (frequently much more expensive) if needed during on-peak periods as compared to off-peak periods. The difference in cost – particularly in light of the fact that generation is such a large part of a customer-generator's bill – far outweighs the cost of back-up distribution service and provides all the "incentive" a customer needs to save considerable generation costs by scheduling maintenance outages during off-peak periods.[126]

[124] Tr. at 612, lines 20-22.

[125] DII Initial Brief, pp. 47-48.

[126] *See* DLC Initial Brief, p. 13 and n.54.

I. Back-Up Service Does Not Constitute A Separate Rate Class And Should Not Be Treated As Such For Cost-Allocation Purposes

In its Initial Brief,[127] DII largely repeats the assertions of its witness, Mr. Crist, that, if the number of back-up customers increases in the future, those customers should be treated as a separate "class" for purposes of allocating the cost-of-service among customer classes. However, as even DII acknowledges, there are not enough back-up customers to justify doing what Mr. Crist suggested. Although Mr. Crist's recommendation has no impact on this case, it is, nonetheless, incorrect for several reasons, all of which have been set forth in the Company's Initial Brief[128] and, therefore, will not be repeated here.

It is important to note, however, that there is a very important cascading effect if DII's recommendation were to be implemented in the future. Currently Duquesne Light and all other major Pennsylvania electric distribution companies do *not* treat back-up service as a separate customer class.[129] Those customers are members of a general service customer class determined by reference to their overall peak loads, which is the theoretically correct way to assign a customer to a class.[130] Therefore, any misalignment between the cost of back-up distribution service and the rates for back-up distribution service produces subsidies that remain in, and are paid by, the members of those general-service classes and are not spread across the entire customer base. Treating back-up service customers as a separate class, however, would shift the revenue-requirement not recovered from back-up service customers to all other customer classes, including residential and small commercial customers. This is another very important factor that weighs against treating back-up service customers as a separate class.

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[127] DII Initial Brief, pp. 48-49.

[128] DLC Initial Brief, pp. 34-36.

[129] *Id*.

[130] DLC Statement No. 14-R, pp. 31-32.

IV. CONCLUSION

All of the parties to this case, except certain members of DII, either support or do not oppose Duquesne Light's proposal to maintain the existing Rider No. 16 rate of $2.50 per kW. As explained above and in the Company's Initial Brief, the consensus that has been achieved to maintain the existing Rider No. 16 rate is based on substantial record evidence and should be approved by the ALJ and the Commission.

The proposal advanced by certain members of DII to establish a rate for back-up service that is less than 5% of the fully allocated cost of providing distribution service is not supported by the evidence in this case. DII's proposed rates would create improper intra-class and inter-class subsidies that ultimately would be borne by all distribution customers, and would provide erroneous price signals that could lead to the installation of uneconomic customer-owned generation and higher costs for all customers.

Therefore, the ALJ and the Commission should reject DII's proposal to exempt customers on Rider No. 16 from paying over 95% of the fully allocated cost of the distribution service that is incurred to reserve distribution capacity on Duquesne Light's distribution system on a 24-7-365 basis to meet customer-generators' peak demands whenever they occur.

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