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December 18, 2019

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Late-Filed Exhibits
Docket Nos. E-2, Sub 1197 and E-7, Sub 1195

Dear Ms. Campbell:

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies") respectfully submit this filing in response to the Commission's questions at the hearing on November 21, 2019 in the above-captioned dockets.

Piedmont Natural Gas Company. Inc. ("Piedmont") / Public Staff of North Carolina Utilities Commission ("Public Staff") Cost Study

During the November 21, 2019 hearing, Commissioner Brown-Bland asked the Companies' subject matter experts and witnesses about the cost study supporting Piedmont's Natural Gas Vehicle ("NGV") rate schedules approved by the Commission in Docket No. G-9, Sub 631. Attached as Attachment A is the Cost of Service Study for Piedmont Rate Schedules 142, 143, and 144 ("Piedmont Cost Study"). After additional review of the Piedmont Cost Study, Mr. Lang Reynolds, the Companies' witness and subject matter expert, determined that although he compared the Companies' current electric vehicle pilot to Rate Schedule 143 at the November 21, 2019 hearing, the Companies' proposed electric vehicle ("EV") Pilot is more analogous to Piedmont Rate Schedule 142. The Piedmont Cost Study shows that retail revenue does not cover the capital or operating expenses of public compressed natural gas stations under Rate 142; therefore, recovery of these costs occurs through inclusion in Piedmont's base rates. As this is substantially the same structure that the Companies have proposed for the DC Fast Charge Program, Rate Schedule 142 supports the Companies' proposed utility investment in public fueling stations through their EV Pilot.

State EV Expansion Activities (Updated from Application as Necessary)

The attached orders and filings document the expansion of EV infrastructure by certain other states at the time of the March 29, 2019 filing of the Application for Approval of Proposed Electric Transportation Pilot ("Application") and, in some cases, the Companies have attached updates to those references.

- **Florida**

In 2017, the Florida Public Service Commission approved a comprehensive settlement agreement between and among Duke Energy Florida, LLC ("DEF"), the Office of Public Counsel, the Florida Industrial Power Users Group, the Florida Retail Federation, White Springs Agricultural Chemicals, and the Southern Alliance for Clean Energy ("SACE"). The Florida Public Service Commission noted that "[t]he signatories to the 2017 Agreement are organizations that represent DEF's major consumer groups." Opinion, Docket Nos. 20170183-EI, 20100437-EI, 20150171-EI, 20170001-EI, 20170002-EG, 20170009-EI, Order No. PSC-2017-0451-AS-EU, 17 FPSC 11:224, 2017 Fla. PUC LEXIS 350 at **4. The settlement agreement provided that "DEF is authorized to purchase, install, own, and support Electric Vehicle Service Equipment ("EVSE") at DEF customer locations as part of a five-year EVSE pilot program. . . . DEF may incur up to $8 million plus reasonable operating expenses with a minimum deployment of 530 EVSE ports." *Id.* at *8. The Florida Public Service Commission determined that the settlement agreement was in the public interest and noted that the agreement "also provides benefits to DEF customers through the proposed Battery Storage Pilot Program and the Electric Vehicle Service Equipment Pilot Program." *Id.* at *9. (Attachment B)

- **New York**

Since at least 2018, in an ongoing project in New York, Con Edison is supporting the deployment of electric school and transit buses in addition to planned fast charging networks and residential customer charging research. On February 7, 2019, the New York Public Service Commission approved a Consensus Proposal from Con Edison, Central Hudson Gas and Electric Corporation, New York State Electric and Gas Association, Niagara Mohawk Power Corporation d/b/a/ National Grid, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, the New York State Energy and Research Development Authority ("NYSERDA"), the New York State Department of Transportation, the New York Power Authority, and the New York State Thruway Authority (collectively, the "Consensus Parties") that was designed on two principles: (i) direct current fast charging ("DCFC") should receive service under the appropriate, demand-metered service classification; and (ii) utility-specific programs should provide limited term cost relief and be designed with an appropriate size and scope to encourage the development of the DCFC infrastructure, consistent with the State's zero emission vehicle goals. *In re Regarding Electric Vehicle Supply Equipment and Infrastructure*, Opinion, Case 18-E-0138, New York Pub. Serv. Comm'n., February 7, 2019. (Attachment C at p. 4.) The New York Commission indicated that the maximum potential costs of the Consensus Proposal, over the seven-year life of the program, was approximately $28 million. The Consensus Parties proposed that the utilities be authorized to recover applicable incremental administrative costs of the program, with interest, in addition to other program costs. Per-plug incentive program costs, as modified by the Commission, were $31.6 million statewide. (Attachment C at 22.) A breakdown of the costs per utility are shown on page 25 of Attachment C.

- **Georgia**

From 2010 to 2014, Georgia became the fastest growing EV market in the nation. Georgia Power then identified critical unmet needs for this growing market and believed that meeting those needs would spur EV adoption and market growth in future years. Therefore, it launched a pilot that involved public education, providing community charging stations, including more charging options at Georgia Power facilities, and offering promotional rebates to residential and business customers for the installation of EV chargers. "The data obtained from the pilot informs an understanding of infrastructure needs, and provides valuable information to the Company and the [Georgia] Public Service Commission on how to best support and shape the growing EV market across the state." *Review of Georgia Power's Electric Transportation Pilot and Market Dynamics Driving Future Electric Vehicle Adoption Evaluation Report.* Aug. 4, 2017, at 3-4. (Attachment D) The cost of the pilot was initially projected to be $12 million, and the completed pilot cost $10 million. Georgia Power leveraged funding from Nissan North America, Inc. in support of certain programs included in the pilot. (*Id.* at 15-16.)

- **Michigan**

On January 9, 2019, the Michigan Public Service Commission issued an order approving Consumers Energy Company's request for a three-year pilot program to invest in EV charging infrastructure. The cost of the pilot was projected to be $7.5 million for the three-year program, and Consumers Energy Company was authorized to amortize the pilot program's deferred costs over five years and to include the recovery of the resulting amortization expense in rates. *In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for The Generation and Distribution of Electricity and Other Relief, Order*, Case No. U-201324, Mich. Pub. Serv. Comm'n., issued January 9, 2019, at 9; see https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000036VO3AAM. The Michigan Public Service Commission noted in its approval that the "modest" three-year pilot rebate proposal marked a beginning and that the program costs will not actually be recovered until they have undergone a future reasonableness and prudence review in a rate case. *Id.* (Attachment E)

- **Maryland**

On January 15, 2019, the Maryland Public Service Commission authorized the electric public utilities operating in that state to move forward with a modified, five-year pilot program of residential, workplace, and public charging stations. *In the Matter of the Petition of Electric Vehicle Work Group for Implementation of Statewide Electric Portfolio, Order No. 88997, Pub. Serv. Comm'n. of Md.*, issued January 14, 2019, available at https://www.psc.state.md.us/wp-content/uploads/Order-No.-88997-Case-No.-9478-EV-Portfolio-Order.pdf. On August 1, 2019, Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco" and together with Delmarva Power, the "PHI Utilities") (collectively, the "Exelon Joint Utilities"), filed with the Maryland Public Service Commission the *Semi-Annual Progress Report of Baltimore Gas and Electric Company, Delmarva Power and Light Company, and Potomac Electric Power Company Regarding Implementation of Approved Electric Vehicle Charging Program Offerings* in Case No. 9478 ("Semi-Annual Report"). (Attachment F). In the Semi-Annual Report, the Exelon Joint Utilities described their EV programs and their implementation to date, as well as their programs' budgets. See Semi-Annual Report, at 22-23. BGE's EVSmart Program budget for the components of its EV program totaled $23,927,126 (Semi-Annual Report at 22) and the Pepco and Delmarva Power EVSmart Program budgets totaled $21,063,623 (Semi-Annual Report at 23).

- **Other States**

With respect to other states' expansion of EV activities, the Companies respectfully refer to the North Carolina Clean Energy Technology Center, *The 50 States of Electric Vehicles: Q1 2019, Quarterly Report*, May 2019 ("Report"). This Report addresses several questions including: how are states addressing barriers to EV and charging infrastructure deployment, what policy actions are states taking to grow markets for EV and related infrastructure, how are utility companies designing rates and EV supply equipment companies designing charging equipment and controls to influence charging behavior of EV owners, and where and how are states and utilities proposing to deploy or pay for EV and EV charging infrastructure. Because of copyright concerns, the Companies did not attach it to this filing. However, the Executive Summary of the Report is available for viewing and the full report is available for purchase at https://nccleantech.ncsu.edu/wp-content/uploads/2019/08/Q2-19_EV_execsummary_Final.pdf.

Telecommunications Deregulation Dockets Supporting the Companies' Positions in their Reply Comments

In their Reply Comments, the Companies discuss the Commission's role in the development of a strong and viable zero emission vehicle marketplace. The Companies asserted that "[s]trong utility programs are one part of the larger holistic framework needed for EV growth to reach 80,000 by 2025." Reply Comments of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC at 11-12. In providing an example of the vital roles that both the Commission and the Companies could play in developing this market, the Companies noted the deregulation of the telecommunications industry in North Carolina. In opening the telecommunications market in North Carolina, the incumbent telecommunication companies competed with new market entrants under the Commission's oversight. *Id* at 12. Commissioner Duffley asked for the telecommunication dockets that the Companies referred to; attached as Attachment G is a list of the telecommunications proceedings at the North Carolina Utilities Commission, deregulating telecommunications.

Conclusion

The Companies have attached these documents as late-filed exhibits to their Application. If the Commission has additional questions or would like to review additional information, please do not hesitate to ask.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Late-Filed Exhibits, in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 18th day of December, 2019.

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Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Late-Filed Exhibits

Docket Nos. E-2, Sub 1197 and E-7, Sub 1195

Attachment A	Piedmont Natural Gas Company, Inc. Cost of Service Study for Rate Schedules 142, 143 and 144, filed October 31, 2016 in NCUC Docket No. G-9, Sub 631
Attachment B	Opinion, Docket Nos. 20170183-EI, 20100437-EI, 20150171-EI, 20170001-EI, 20170002-EG, 20170009-EI, Order No. PSC-2017-0451-AS-EU, 17 FPSC 11:224, 2017 Fla. PUC LEXIS 350
Attachment C	*In re Regarding Electric Vehicle Supply Equipment and Infrastructure*, Opinion, Case 18-E-0138, New York Pub. Serv. Comm'n., February 7, 2019
Attachment D	*Review of Georgia Power's Electric Transportation Pilot and Market Dynamics Driving Future Electric Vehicle Adoption Evaluation Report,* Aug. 4, 2017
Attachment E	*In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for The Generation and Distribution of Electricity and Other Relief, Order*, Case No. U-201324, Mich. Pub. Serv. Comm'n., January 9, 2019
Attachment F	*Semi-Annual Progress Report of Baltimore Gas and Electric Company, Delmarva Power and Light Company, and Potomac Electric Power Company Regarding Implementation of Approved Electric Vehicle Charging Program Offerings* in Case No. 9478, Maryland Pub. Serv. Comm'n, filed August 1, 2019
Attachment G	List of the proceedings deregulating telecommunications at the North Carolina Utilities Commission

Attachment A

October 31, 2016

Moore&VanAllen

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VIA ELECTRONIC FILING

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North Carolina Utilities Commission
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Raleigh, North Carolina 27603

Re: Docket No. G-9, Sub 631

Chief Clerk:

Pursuant to the Commission's *Order Granting Petition to Continue Service Under Existing Tariffs* that was issued on July 18, 2016 in the above-referenced docket, Piedmont Natural Gas Company, Inc. has attached the limited cost of service study for Rate Schedules 142, 143 and 144. Piedmont is supportive of the recommendations contained therein. Therefore, Piedmont proposes no modifications to Rate Schedules 142, 143 or 144 at this time.

Thank you for your assistance with this matter. If you have any questions regarding this filing, you may reach me at the number shown above.

Sincerely,

/s/James H. Jeffries IV
James H. Jeffries IV

JHJ/rkg

Enclosures

cc: Bruce Barkley
Pia Powers
Elizabeth Culpepper
Brian Franklin

Attachment A

Piedmont Natural Gas, Inc.
Natural Gas Vehicle Services

Cost Study Results and Recommendations

Prepared For:
Piedmont Natural Gas, Inc.

By:
Yardley Associates

October 2016

Table of Contents

I. Introduction

Piedmont Natural Gas, Inc. ("Piedmont" or the "Company") is a North Carolina corporation that principally engages in the local distribution of natural gas to end-use customers. Piedmont serves over one million natural gas distribution customers in the states of North Carolina, South Carolina and Tennessee. Piedmont's customer base is comprised primarily of residential and commercial customers. The Company also serves a limited number of large industrial and power generation loads. Recently, Piedmont developed new tariffs to serve Natural Gas Vehicle ("NGV") markets.

Piedmont retained Yardley Associates to perform an independent assessment of the rates for its North Carolina NGV services through a limited cost allocation study. The assessment complies with a requirement of the North Carolina Utilities Commission ("NCUC") for Piedmont to perform a cost of service study following the 2014 implementation of new experimental NGV services. This report describes the studies that were performed, presents the results and discusses recommendations.

Description of NGV Services

The use of natural gas as a transportation fuel is growing throughout the U.S. as natural gas offers advantages when compared to traditional gasoline or diesel fuels. Advantages include cost benefits, reduced emissions and an abundant domestic fuel. These benefits contribute to increased investment in NGV refueling infrastructure, which is an important driver of further penetration of natural gas in vehicle markets. Compressed natural gas ("CNG") vehicles include light and heavy-duty commercial vehicles, mass transportation vehicles and automobiles. The most common vehicle segment is commercial fleets that benefit from centralized refueling locations.

Piedmont, similar to other local distribution companies, implemented NGVs for its utility operations including the acquisition of CNG vehicles and construction of refueling stations. Today, Piedmont's fleet includes approximately 421 CNG vehicles and the Company operates six NGV refueling stations in North Carolina. Piedmont initially offered NGV service pursuant to Rate Schedule 142 – Natural Gas Vehicle Fuel, which is for refueling of CNG vehicles by the public at Company-owned stations. The pricing for Rate Schedule 142 service includes a base margin rate and a compression charge. In addition, applicable gas charges and tariff riders apply. Service provided to the public pursuant to Rate Schedule 142 is interruptible, allowing Piedmont to curtail public refueling if operations require it to do so for any reason.

In February 2014, Piedmont proposed two new rate schedules for NGV service along with tariff revisions applicable to Rate Schedule 142 service (the "2014 NGV Filing"). The 2014 NGV Filing reflected the input of the NCUC Public Staff and the Carolina Utility Customers Association. New Rate Schedule 143 – Experimental Motor Vehicle Fuel Service is for customers seeking to purchase or transport natural gas for use in CNG motor vehicles that are refueled at locations other than Piedmont-owned public stations. New Rate Schedule 144 – Experimental Medium General Motor Fuel Transportation Service provides transportation service to non-residential customers whose load is below the 50 dekatherm per day threshold otherwise required for Piedmont's tariff transportation services. These new rate schedules are intended to serve refueling facilities located on customer premises, which in most cases will be owned by customers. The rates and charges for Rate Schedule 143 and Rate Schedule 144 services mirror the rates and charges for the corresponding sales or transportation service for non-vehicular use. To the extent that Piedmont owns the compression facilities at the customer's location, a compression charge would also apply. A summary of the current applicable base rate charges for Piedmont's NGV Services is provided in Table 1.

Table 1
Summary of Piedmont's Current Base Rates for NGV Services

Rate Element	Rate Schedule 142	Rate Schedule 143			Rate Schedule 144
		Small	Medium	Large	
Monthly Fixed Charge		$22.00	$75.00	$350.00	$75.00
Monthly Demand Charge, Per Therm				$0.20000	
Per Therm (All)	$0.27376	$0.34778			
Winter (All)			$0.32660		$0.32660
Summer (All)			$0.27475		$0.27475
Winter-1st 15,000				$0.07571	
Winter-Next 30,000				$0.01821	
Winter-Next 90,000				$0.02271	
Winter-Next 165,000				$0.01101	
Winter-Next 300,000				$0.01171	
Winter-Over 600,000				$0.00871	
Summer-1st 15,000				$0.02623	
Summer-Next 30,000				$0.00123	
Summer-Next 90,000				$0.00373	
Summer-Next 165,000				$0.00073	
Summer-Next 300,000				$0.00123	
Summer-Over 600,000				$0.00973	
Compression Charge, Per Therm	$0.40	$0.40 1/	$0.40 1/	$0.40 1/	$0.40 1/

1/ Applies when Piedmont owns the compression and other related facilities downstream of the meter.

NGV Cost Study Requirement

The NCUC approved Piedmont's 2014 NGV Filing on April 28, 2014. The NCUC's approval included a requirement that Piedmont and the Public Staff agree upon "a methodology to evaluate the experimental rates, including a proposed schedule to file a cost of service study". The methodology was filed by Piedmont on July 3, 2014, which indicated the following: "Piedmont proposes and the Public Staff concurs to the utilization of a limited cost of service analysis, which focuses on the costs and revenues associated with the provision of natural gas services by the Company under the three vehicular natural gas rate schedules." As noted in the July 3, 2014 filing, Piedmont had recently performed a full cost of service analysis in conjunction with its recent rate case.

Traditionally, a full cost assessment of a utility's individual services is performed as part of a general rate proceeding. As is the case here, it is sometimes appropriate to perform a focused cost assessment in between rate cases to evaluate a specific matter of inquiry. While NGV loads remain a very small proportion of Piedmont's overall throughput, some important insights can be gained from an appropriate study of the costs of providing NGV services. Specifically, a cost study supports the consideration of the reasonableness of the rates and charges for NGV services based upon actual cost and usage information. This is an appropriate area of investigation as the rates and charges for Piedmont's NGV services were initially established without known costs or customer characteristics. Further, the new rate schedules, which are currently offered on an experimental basis, allow the Company to cease providing NGV services in the event that doing so would threaten or impeded its ability to satisfy its contractual obligations or to efficiently operate its system. The cost study described in this report is intended to provide an assessment of the reasonableness of the existing rates and identify any non-operational concerns associated with the continued provision of NGV services to customers.

II. NGV Cost Study Methodology

Important Considerations

The approach for the cost study of Piedmont's NGV services gives weight to several important factors. These considerations, which provide important context for the cost study, guide aspects of the design of the study and are noted as follows:

1. *NGV Rate Schedule Usage:* Aggregate NGV use for all Piedmont NGV Rate Schedules remains low in relation to other services. The combined NGV use is less than 0.2% of the Company's jurisdictional load. While NGV throughput remains low, it exhibits greater variability over time as NGV loads are increasing at a much higher annual growth rate than Piedmont's traditional distribution

services. Low and changing usage indicate that the existing usage patterns and customer characteristics may vary over time, which could affect future cost study results.

2. *Dual-Use of NGV Stations:* The NGV stations where Rate Schedule 142 customers obtain CNG also serve Piedmont's vehicle fleet that engages in utility operations for all customers. Moreover, the use of CNG refueling stations by utility vehicles has priority over non-utility vehicles. The shared use and distinct priorities of the Piedmont CNG refueling stations should be reflected in the cost study.

3. *Service Distinctions Among NGV Rate Schedules:* Piedmont's NGV services exhibit variations in respects that impact the cost study. The first of these is that service pursuant to Rate Schedules 143[1] and 144 is firm, while service under Rate Schedule 142 is interruptible. Second, Rate Schedule 142 includes compression service, while service under Rate Schedules 143 and 144 has not included compression service to date. Also, the pricing for all services varies, including several pricing variations for service provided pursuant Rate Schedule 143. The nature of these variations led to the need to evaluate each service separately through the cost study in order to capture a baseline understanding of the costs and revenues associated with each of Piedmont's NGV services and service pricing variations.

4. *Recent Full Cost Study:* A full cost study is a significant undertaking that is more readily accomplished concurrently with the preparation of a rate case when financial data are compiled and adjusted, as necessary, for ratemaking purposes. Piedmont's last cost allocation study was completed approximately 3 years ago in 2013 and provides a reasonable starting point for elements of this limited NGV cost study.

Embedded Cost Study Methodology

An embedded cost study examines the cost of providing service to a customer class or group using appropriate cost assignments and allocations to establish measures of investments, expenses and income. An embedded cost study evaluates both direct and indirect costs. Direct costs are incurred in order to provide a service or product, such as the costs for metering or a service pipe, and are typically readily assigned or allocated to customer groups. Indirect costs include both overhead costs that may vary with direct costs, such as maintenance of meters, and overhead costs,

[1] Service provided under Rate Schedule 143 can be firm or interruptible, depending on the commensurate companion Rate Schedule dictating the nature of the service and billing rates. To date, service to those customers under Rate Schedule 143 has been provided on a firm basis.

such as administrative salaries. Indirect costs incurred by a distribution utility are generally fixed over the short-run, but may vary with direct costs linearly or in some other way over the long-run.

In an embedded cost study, all utility costs are included in the cost to serve. In order to develop the limited cost study of Piedmont's NGV services, direct costs associated with NGV plant investments were determined using per books information and data regarding the facilities constructed to serve NGV customers. All indirect costs were estimated from the allocations underlying Piedmont's previous 2013 allocation study. Although the time period for the indirect costs precedes that for the direct costs, the level of indirect costs assigned through this approach is reasonably representative of what would result from the preparation of a new full cost allocation study.

Specific Embedded Cost Study Steps

The limited cost study of Piedmont's NGV Services required several steps to achieve a study that is, on balance, consistent with a full cost of service study analysis. The steps are summarized as follows:

1. The direct plant investments for NGV services were determined. This entailed obtaining the gross plant investments for Piedmont's CNG refueling stations and descriptive data regarding the type of meter and length of service connecting each NGV service customer with Piedmont's distribution system.
2. Direct operations and maintenance ("O&M") expense associated with the CNG refueling stations was also obtained.
3. CNG station costs were segregated between Piedmont fleet use and Rate Schedule 142 use.
4. Customer-specific meter and service data were utilized to calculate replacement costs for these investments on a basis consistent with that performed as part of the 2013 rate case cost study.
5. The embedded cost study analyzing actual per books information through February 2013[2] was relied upon as the basis for allocating indirect costs to NGV services for the limited cost study. The study was modified to incorporate the NGV Rate Schedules and associated direct plant investments and expenses.
6. The throughput and revenues for each NGV Rate Schedule and customer type were annualized to yield levels consistent with the annual costs reflected in the limited cost study.
7. Remaining allocation factors were updated to reflect the characteristics of each NGV Rate Schedule and customer type using information regarding direct facility investments, consumption patterns and customer counts.

[2] The cost study was prepared in response to Public Staff Discovery Request 4, Item 1 in Docket No. G-9 Sub 631.

Marginal Cost Study Methodology

An area of concern associated with the embedded cost study is attributable to the degree of influence that indirect costs play in determining the results of the study for the Piedmont-owned CNG refueling stations associated with Rate Schedule 142 service. A considerable level of indirect costs are allocated to the Rate Schedule 142 service in an embedded study due to the direct plant investments and direct O&M expenses also included in the study. This poses a potential concern given that the majority of direct station costs are incurred regardless of station use and both Piedmont fleet and customer use of existing stations is growing, thus contributing to revenue growth and improved profitability. A lesser concern is that the embedded cost study understates the benefits of accumulated deferred income taxes that are associated with the CNG refueling station investments.

A marginal cost analysis provides an important understanding of the reasonableness of the prices for Rate Schedule 142 service because it focuses on direct costs and revenues. This is particularly true given that the indirect costs which are allocated to Rate Schedule 142 service through the embedded cost analysis are fixed, i.e., not increasing, in the short-run.

A marginal analysis of Rate Schedule 142 service is straightforward and relies upon the same initial three steps of the embedded cost analysis in order to arrive at marginal costs. The resulting costs are compared with direct revenues to yield an assessment of return.

Cost Study Data Sources

Several categories of data were compiled in order to complete the limited cost study of NGV services. The first category pertains to investment costs associated with Piedmont's CNG refueling stations. The accumulated depreciation and deferred income taxes reflecting approved depreciation rates and tax bases for the various station assets were determined as of June 30, 2016. Fifty percent of station investments are associated with Rate Schedule 142 refueling service and 50 percent are associated with Piedmont fleet use. The equal proportions reflect the higher proportional use of the stations by Rate Schedule 142 customers and the higher priority of service by Piedmont fleet vehicles. Station investments are summarized in Table 2.

Table 2
Piedmont NGV Refueling Station Investments
(000)

Station	Gross Investment	Accumulated Depreciation	Accumulated Deferred Income Taxes	Rate Base
Charlotte	$3,158	($471)	($962)	$1,725
Greensboro	$2,867	($398)	($852)	$1,617
Winston Salem	$1,117	($182)	($356)	$579
High Point	$680	($148)	($210)	$322
Fayetteville	$995	($146)	($309)	$540
Goldsboro	$1,059	($146)	($311)	$602
Other	$217	($67)	($59)	$91
Total	**$10,093**	**($1,558)**	**($3,059)**	**$5,476**
Rate Schedule 142 – 50%	**$5,047**	**($779)**	**($1,530)**	**$2,738**

Table 3 provides the average replacement costs for meters and services for customers served under the experimental NGV Rate Schedules.

Table 3
Average Meter and Service Replacement Costs

Rate Element	Rate Schedule 143			Rate Schedule 144
	Small	Medium	Large	
Number of Customers	12	1	4	0
Average Meter Replacement Cost	$680	$1,533	$3,983	N/A
Average Service Replacement Cost	$366	$829	$458	N/A

Actual customers, throughput and revenue data for the twelve-month period were reviewed. The data were annualized to reflect the number of customers within each group as of the end of April, 2016. The adjusted data are provided in Table 4.

Table 4
Piedmont NGV Services
Customers, Throughput and Revenues

Rate Element	Rate Schedule 142	Rate Schedule 143			Rate Schedule 144
		Small	Medium	Large	
Number of Customers	N/A	12	1	4	0
Throughput (therms)	919,715	197,250	173,520	1,676,031	0
Adjustment	0	16,574	158,079	42,521	0
Total As Adjusted	**919,715**	**213,824**	**331,599**	**1,718,552**	**0**
Base Revenues	\$252,646	\$71,910	\$52,545	\$67,987	\$0
Adjustment	\$0	\$5,776	\$47,336	\$3,811	\$0
Total As Adjusted	**\$252,646**	**\$77,686**	**\$99,881**	**\$71,798**	**\$0**
Compression Revenues	\$367,886	\$0	\$0	\$0	\$0
Adjustment	\$0	\$0	\$0	\$0	\$0
Total As Adjusted	**\$367,886**	**\$0**	**\$0**	**\$0**	**\$0**

III. NGV Cost Study Results

Embedded Cost Study Results

The results of the limited embedded cost study provide a comparison of NGV costs and revenues. The costs include both direct and indirect costs. Since the limited cost study captures indirect costs from the 2013 full cost study, the results provide a good understanding of the expected income and rate of return on rate base for NGV services, but are less precise than if a full cost study were performed. Nevertheless, the results are sufficiently precise to consider the reasonableness of the NGV service pricing. The results of the embedded cost study of NGV services are presented in Table 5. Detailed results are provided as Appendix A.

Table 5
Embedded Cost Study Results
(000)

	Rate Schedule 142	Rate Schedule 143		
		Small	Medium	Large
Revenues	$632	$78	$100	$73
Expenses	$1,616	$18	$12	$53
Income	**($985)**	**$60**	**$88**	**$20**
Rate Base	**$3,851**	**$84**	**$81**	**$276**
Rate of Return	**(25.6%)**	**71.6%**	**108.6%**	**7.1%**

The comparison of embedded costs and revenues for Rate Schedule 142 indicates negative income and return. There are two important factors to consider when evaluating the prices for Rate Schedule 142 in light of the negative income shown. The first factor is that the embedded cost study assigns considerable overhead-related costs to Rate Schedule 142. The overhead costs associated with general plant, working capital and administrative and general expense reduce the income and increase the rate base associated with Rate Schedule 142 service. The impact of indirect overhead costs on the results of the limited cost study for Rate Schedule 142 necessitates evaluating the service through a marginal cost analysis as well.

A second factor to take into consideration when evaluating the results of the embedded cost study for Rate Schedule 142 is expected future changes in utilization of the service. Use of Piedmont's CNG refueling stations continues to grow both for Piedmont fleet use and by customers. This is not unexpected as NGVs continue to increase in share of the transportation market and the availability of an operational station increases the likelihood of conversions by nearby fleet customers. Increased use at existing stations contributes favorably to profitability as incremental revenues substantially exceeds incremental costs at existing stations. Therefore, the income and rate of return for Rate Schedule 142 should improve over time as the NGV market matures.

A comparison of embedded costs and revenues for Rate Schedule 143 services shows positive income and return, with results varying for different sizes of customer. Small and medium-size Rate Schedule 143 customers indicate higher returns than for large Rate Schedule 143 customers. The disparity is primarily the result of variations in per unit prices among the three sizes of customers. Given the small number of customers within each group, the results for each individual size of Rate Schedule 143 could shift somewhat as more customers are included in future studies.

Marginal Cost Study Results

A marginal cost analysis of Rate Schedule 142 service indicates that marginal revenues slightly exceed marginal costs as indicated in Table 6. As is the case with the embedded cost analysis, an increase in utilization of CNG refueling stations will lead to higher marginal cost returns also.

Table 6
Rate Schedule 142 Marginal Cost Study Results
(000)

	Rate Schedule 142
Revenues	**$621**
Non-Electric Expenses	$502
Electric Expenses	$89
Total Expenses	**$591**
Income before Income Taxes	$30
Income Taxes	$11
Net Income	**$18**
Rate Base	**$2,738**
Rate of Return	**0.7%**

IV. Recommendations

The limited cost study results provide important insights concerning the reasonableness of existing NGV service pricing. Based on these results and expectations regarding future growth in NGV markets, Yardley Associates recommends the following:

1. ***Piedmont should continue to offer the existing menu of NGV Services:*** NGV use is an important natural gas market that offers important economic benefits to businesses and consumers as well as environmental benefits. Services that promote NGV use by fleets using Piedmont-owned CNG refueling stations and by businesses that choose to own and operate their own CNG refueling stations all promote these benefits. The cost studies indicate that there is no material concern with continuing to offer both compressed NGV fuel pursuant to Rate Schedule 142 and uncompressed NGV fuel pursuant to Rate Schedules 143 and 144. Further, consultation with the Company indicates that there is no

operational concern associated with continuing all of its existing NGV services on a non-experimental basis.

2. ***The existing pricing for Piedmont's NGV services should be maintained until the Company's next rate case:*** The limited cost study shows that Rate Schedule 143 revenues are offsetting associated costs, and Rate Schedule 142 revenues are approaching the full incremental costs of providing service. Utilization of Piedmont's CNG refueling stations is expected to increase, improving profitability and reducing the potential for cost-shifting. Any increase in the price for Rate Schedule 142 could negatively impact volume growth due to increased competitive pressure.

3. ***Piedmont's next base rate case offers an opportunity to revisit NGV service pricing for all NGV Services:*** Although NGV throughput has increased over the last two years, it remains quite low at less than 0.2% of Piedmont's total throughput. It is anticipated that the proportion of throughput that NGV use comprises will gradually increase as the growth rate for NGV service is higher than for Piedmont's traditional markets. Piedmont's next base rate case provides an opportunity to reevaluate the pricing for its NGV Services in conjunction with a full cost allocation study and based on greater utilization of its service offerings.

Appendix A

NGV Limited Cost Study
Detailed Embedded Cost Results

Attachment A

OFFICIAL COPY

Dec 18 2019

NGV Limited Cost of Service Study
Appendix A - Results

Income and Rate of Return

	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Revenues				
Operating Revenues -	620,532	77,686	99,881	71,798
Other Operating Revenues.........	11,009	239	233	790
TOTAL OPERATING REVENUES.........	631,541	77,925	100,114	72,588
Operating Expenses				
Cost of Gas...........................	0	0	0	0
Operation & Maintenance...........	1,174,580	9,942	5,009	24,305
Depreciation Expense..............	229,942	4,124	3,265	15,466
Taxes Other Than Income................	86,409	1,176	884	4,172
Income Taxes - State................	22,108	481	467	1,587
Income Taxes - Federal............	104,203	2,267	2,201	7,478
Amortization of Investment Tax Credits	(759)	(17)	(16)	(54)
Total Operrating Expenses	1,616,484	17,974	11,810	52,954
Net Operating Income...............	(984,943)	59,951	88,304	19,634
Interest on Customer Deposits	0	0	0	0
Amortization of Debt Redempt Premium	0	0	0	0
Net Operating Income for Return.....	(984,943)	59,951	88,304	19,634
Rate Base.............................	3,850,984	83,771	81,354	276,378
Return on Rate Base	**-25.58%**	**71.57%**	**108.54%**	**7.10%**

NGV Limited Cost of Service Study
Appendix A - Results

Customer Related Rate Base

Description		Rate 142		Rate 143 Small (102 Rates)		Rate 143 Medium (152 Rates)		Rate 143 Large (113 Rates)
Net Gas Plant In Service		$132,725		$44,435		$9,777		$59,640
Working Capital:								
Stored Gas		0		0		0		0
LNG		0		0		0		0
Labor		378		4,045		875		7,061
Mains		580		271		333		1,720
Plant		(19,336)		(383)		(337)		(1,566)
TOTAL		(18,379)		3,932		871		7,214
Accumulated Deferred Taxes		(38,627)		(12,932)		(2,845)		(17,357)
Total Working Capital	$	(57,005)	$	(8,999)	$	(1,974)	$	(10,143)
Unamortized Debt Redemption Premium		0		0		0		0
Total Rate Base	$	75,720	$	35,436	$	7,803	$	49,498

NGV Limited Cost of Service Study
Appendix A - Results

Demand Related Rate Base

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Net Gas Plant In Service	$4,469,825	$46,838	$70,410	$313,120
Working Capital:				
Stored Gas	0	14,320	22,207	0
LNG	0	187	290	1,501
Labor	638,898	903	1,338	4,107
Mains	631	295	363	1,873
Plant	(24,332)	(483)	(424)	(1,971)
Total	$615,197	$15,222	$23,773	$5,511
Accumulated Deferred Taxes	(1,309,758)	(13,725)	(20,632)	(91,751)
Total Working Capital	$ (694,561)	$ 1,497	$ 3,141	$ (86,240)
Unamortized Debt Redemption Premium	0	0	0	0
Total Rate Base	$ 3,775,264	$ 48,335	$ 73,551	$ 226,880

NGV Limited Cost of Service Study
Appendix A - Results

Customer Related Net Plant

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Intangible Plant	7	0	0	1
Production Plant	0	0	0	0
Storage Plant	0	0	0	0
Transmission Plant	0	0	0	0
Distribution Plant:				
Mains	0	3,599	300	1,200
Services	0	16,058	3,031	6,698
Meters & Regulators	0	19,278	3,622	37,639
NGV Stations	0	0	0	0
All Other	0	2,868	512	3,354
Total Distribution Plant	0	41,803	7,465	48,891
General Plant	132,718	2,632	2,312	10,749
Total Gas Plant In Service	132,725	44,435	9,777	59,640
Construction Work in Progress	0	0	0	0
Total Gas Plant	132,725	44,435	9,777	59,640

NGV Limited Cost of Service Study
Appendix A - Results

Demand Related Net Plant

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Intangible Plant	0	0	0	0
Production Plant	0	0	0	0
Storage Plant	0	6,250	9,693	0
Transmission Plant	0	24,341	37,749	195,637
Distribution Plant:				
Mains	34,982	12,764	19,795	102,590
Services	0	0	0	0
Meters & Regulators	0	0	0	0
NGV Stations	4,267,366	0	0	0
All Other (Demand)	466	170	264	1,367
Total Distribution Plant	4,302,814	12,934	20,059	103,957
General Plant	167,011	3,312	2,910	13,526
Total Gas Plant In Service	4,469,825	46,838	70,410	313,120
Construction Work in Progress	0	0	0	0
Total Gas Plant	4,469,825	46,838	70,410	313,120

NGV Limited Cost of Service Study
Appendix A - Results

Customer Related Operation And Maintenance Expenses

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Purchase Gas				
Demand	$0	$0	$0	$0
Commodity	$0	$0	$0	$0
Total Purchase Gas	0	0	0	0
Other Gas Supply Expense	0	0	0	0
Production Expense	0	0	0	0
Storage Expense	0	0	0	0
Transmission Expense	0	0	0	0
Distribution Expense				
Mains	455	213	261	1,350
Services	0	273	51	114
Meters & Regulators	0	1,848	347	3,609
Customer Installment	0	150	13	50
NGV Stations	0	0	0	0
Other	0	59	11	69
Total Distribution Expense	455	2,544	683	5,192
Customer Accounting				
Uncollectible	0	0	0	0
Other	0	229	19	76
Total Customer Accounting	0	229	19	76
Sales Expense	0	90	7	30
Administration & General	457	4,894	1,059	8,544
Pro-Forma Adjustment				
Uncollectible	$0	$0	$0	$0
Other	$0	$0	$0	$0
Total Operating & Maintenance	$912	$7,757	$1,769	$13,842
Total O & M Including Cost Of Gas	912	7,757	1,769	13,842

NGV Limited Cost of Service Study
Appendix A - Results

Demand Related Operation And Maintenance Expenses

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Purchase Gas				
Demand	$0	$0	$0	$0
Commodity	0	0	0	0
Total Purchase Gas	0	0	0	0
Other Gas Supply Expense	311	72	112	582
Production Expense	0	0	0	0
Storage Expense	0	361	560	0
Transmission Expense	1,123	410	636	3,294
Distribution Expense				
Mains	496	232	285	1,471
Services	0	0	0	0
Meters & Regulators	0	0	0	0
Customer Installment	0	0	0	0
NGV Stations	398,585	0	0	0
Other	50	18	28	147
Total Distribution Expense	399,131	250	313	1,618
Customer Accounting				
Uncollectible	0	0	0	0
Other	0	0	0	0
Total Customer Accounting	0	0	0	0
Sales Expense	0	0	0	0
Administration & General	773,103	1,092	1,619	4,970
Pro-Forma Adjustment				
Uncollectible	0	0	0	0
Other	0	0	0	0
Total Operating & Maintenance	$1,173,668	$2,186	$3,240	$10,463
Total O & M Including Cost Of Gas	1,173,668	2,186	3,240	10,463

NGV Limited Cost of Service Study
Appendix A - Results

Depreciation Expense And Taxes Other Than Income

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Depreciation Expense				
Intangible Plant	$4	$0	$0	$0
Production Plant	$1	$0	$0	$0
Storage Plant	$0	$169	$262	$0
Transmission Plant	$0	$620	$961	$4,982
Distribution Plant				
Mains	$1,892	$885	$1,087	$5,612
Services	$0	$905	$171	$377
Meters & Regulators	$0	$763	$143	$1,489
NGV Stations	192,401	0	0	0
Other	$12	$76	$20	$119
TOTAL DISTRIBUTION	194,304	2,629	1,420	7,597
General Plant	$35,632	$707	$621	$2,886
Undistributed	0	0	0	0
Total Depreciation Expense	$229,942	$4,124	$3,265	$15,466
Taxes Other Than Income				
Property Tax	41,921	831	730	3,395
Payroll & Other	44,488	344	154	777
Total Taxes Other Than Income	86,409	1,176	884	4,172

NGV Limited Cost of Service Study
Appendix A - Results

Income Taxes - Existing Rates

Description	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)
Operating Revenues				
Sales	620,532	77,686	99,881	71,798
Other Operating Revenues	11,009	239	233	790
Total Operating Revenues	631,541	77,925	100,114	72,588
Operating Expenses				
Operation & Maintenance	$1,174,580	$9,942	$5,009	$24,305
Gas Supply Expense	$0	$0	$0	$0
Depreciation	$229,942	$4,124	$3,265	$15,466
Taxes Other Than Income	86,409	1,176	884	4,172
Total Operating Expenses	1,490,931	15,243	9,158	43,943
				0.017%
Gross Operating Income Before Taxes	(859,391)	62,682	90,956	28,645
Interest Deductions				
Interest onCustomer Deposits	0	0	0	0
Amortization of Debt Redemption Prem	0	0	0	0
Total	0	0	0	0
Net Income Before Taxes	(859,391)	62,682	90,956	28,645
Less: State Income Tax	22,108	481	467	1,587
Taxable Income For Federal	(881,499)	62,202	90,489	27,058
Federal Income Tax (Excluding ITC Amortization)	104,203	2,267	2,201	7,478
Amortization of Investment Tax Credits	(759)	(17)	(16)	(54)

Attachment A

NGV Limited Cost of Service Study
Appendix A - Allocation Factors

	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)	ALL OTHER
DT Throughput "Normal"	91,972	21,382	33,160	171,855	293,642,358
	0.031%	0.007%	0.011%	0.058%	99.892%
Firm Winter Sales	-	8,909	13,817	-	46,737,498
	0.000%	0.019%	0.030%	0.000%	99.951%
Design Day Demand	-	58.58	90.85	470.84	1,413,699
	0.000%	0.004%	0.006%	0.033%	99.956%
Peak Day & Average Day	0.00016	0.00006	0.00009	0.00046	0.99924
	0.016%	0.006%	0.009%	0.046%	99.924%
Total Number of Bills	-	144	12	48	8,212,835
	0.000%	0.002%	0.000%	0.001%	99.998%
Average Number of Customers	-	12	1	4	684,403
Rate 101 &102 Bills	-	-	-	-	8,199,252
	0.000%	0.000%	0.000%	0.000%	100.000%
Other Plant (Prod + Stor + Trans + Dist Plant)	4,302,814	85,329	74,965	348,485	1,519,666,597
	0.282%	0.006%	0.005%	0.023%	99.684%
Average Meter Cost (from Meter Study)	0	680	1,533	3,983	
Meter Value (Number of Customers x Average Meter Costs)	-	8,160	1,533	15,932	58,702,199
Meter Value % by Customer Class	0.000%	0.014%	0.003%	0.027%	99.956%
Distribution Mains	34,982	16,363	20,095	103,789	428,712,445
	0.008%	0.004%	0.005%	0.024%	99.959%
Service Unit Factor	-	366	829	458	
Service Unit Factor x Total Number of Bills	-	4,392	829	1,832	77,380,178
Services	-	4,392	829	1,832	77,380,178
	0.000%	0.006%	0.001%	0.002%	99.991%

NGV Limited Cost of Service Study
Appendix A - Allocation Factors

	Rate 142	Rate 143 Small (102 Rates)	Rate 143 Medium (152 Rates)	Rate 143 Large (113 Rates)	ALL OTHER
Rate Base less Amort of Debt Redemption Prem	3,850,984	83,771	81,354	276,378	1,311,626,589
	0.293%	0.006%	0.006%	0.021%	99.674%
Customer Labor Allocation	213	2,284	494	3,987	38,954,922
	0.001%	0.006%	0.001%	0.010%	99.982%
Demand Labor Allocation	360,759	510	755	2,319	7,308,926
	4.702%	0.007%	0.010%	0.030%	95.252%
Total Labor	360,972	2,794	1,250	6,306	46,263,848
	0.774%	0.006%	0.003%	0.014%	99.204%
NGV Station Direct Costs	1.00	-	-	-	-
	100.000%	0.000%	0.000%	0.000%	0.000%
Total Margins	620,532	77,686	99,881	71,798	406,264,662

Notes:

(1) Rate Schedule 142 and 143 usage and facility costs derived from current data

(2) 'All Other' usage and facility costs taken from Actual per Books information filed in response to discovery rrequest Staff 4-1 in Docket No. G-9, Sub 631

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the attached is being served this date upon all of the parties to this docket electronically or by depositing a copy of the same in the United States Mail, First Class Postage Prepaid, at the addresses contained in the official service list in the proceeding.

This is the 31st day of October, 2016.

/s/ Laida M. Alarcon
Laida M. Alarcon

2017 Fla. PUC LEXIS 350

Florida Public Service Commission

November 20, 2017, Issued

DOCKET NO. 20170183-EI; DOCKET NO. 20100437-EI; DOCKET NO. 20150171-EI; DOCKET NO. 20170001-EI; DOCKET NO. 20170002-EG; DOCKET NO. 20170009-EI; ORDER NO. PSC-2017-0451-AS-EU, 17 FPSC 11:224

FL Public Service Commission Decisions

Reporter
2017 Fla. PUC LEXIS 350 *

In re: Application for limited proceeding to approve *2017* second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.; In re: Petition for issuance of nuclear asset-recovery financing order, by Duke Energy Florida, Inc. d/b/a Duke Energy; In re: Fuel and purchased power cost recovery clause with generating performance incentive factor; In re: Energy conservation cost recovery clause; In re: Nuclear cost recovery clause

Core Terms

settlement agreement, revise, base rate, customer, energy, solar, retail, nuclear, tax reform, cycle, defer, cost recovery, asset-recovery, annualize, depreciate, calculate, income tax, tariff, fuel, surveillance, delivery, pilot, rate base, waive, effective date, storing, voltage, expiration, intervenor, terminate

Counsel

[*1] APPEARANCES: DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, On behalf of Duke Energy Florida, LLC (DEF); J.R. KELLY, and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, On behalf of the Citizens of the State of Florida (OPC); JON C. MOYLE, JR., ESQUIRE, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, On behalf of the Florida Industrial Power Users Group (FIPUG); ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308, On behalf of the Florida Retail Federation (FRF); JAMES W. BREW, ESQUIRE, Stone Mattheis Xenopoulos &

Brew, PC, 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007, On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate -- White Springs (PCS Phosphate); GEORGE CAVROS, ESQUIRE, 120 E. Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida, 33334, On behalf of the Southern Alliance for Clean Energy (SACE); KYESHA MAPP, MARGO DUVAL, [*2] and SUZANNE BROWNLESS, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, On behalf of the Florida Public Service Commission (Staff); MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission; KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850 Florida Public Service Commission General Counsel.

Panel: The following Commissioners participated in the disposition of this matter: JULIE I. BROWN, Chairman; ART GRAHAM; RONALD A. BRISE; DONALD J. POLMANN; GARY F. CLARK

Opinion

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by *Section 120.569(1), Florida Statutes*, to notify parties of any administrative hearing or judicial review of Commission orders that is available under *Sections 120.57* or *120.68, Florida Statutes*, as well as the procedures and time limits that [*3] apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by *Rule 25-22.060*, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ORDER [*4] APPROVING *2017* SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT

BY THE COMMISSION:

BACKGROUND

On August 29, *2017*, Duke Energy Florida, LLC (DEF) filed a Petition for a Limited Proceeding to approve its *2017* Second Revised and Restated Settlement Agreement (*2017* Agreement), Including Certain Rate Adjustments (Petition). The *2017* Agreement, with noted exceptions, seeks to replace and supplant the 2013 Revised and Restated Stipulation and Settlement Agreement (2013 Agreement) we approved by Order No. PSC-13-0598-FOF-EI and its three subsequent stipulated amendments approved by, Order Nos. PSC-15-0465-S-EI, PSC-16-0138-FOF-EI, and PSC-16-0425-PAA-EI. [1] The *2017* Agreement was signed and executed by DEF, the Office of Public

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[1] Order No. PSC-15-0465-S-EI, issued October 14, 2105, in Docket No. 15014-EI, In re: Petition for approval to include in base rates the revenue requirement for the CR3 regulatory asset, by Duke Energy Florida, Inc. and Docket No. 150171-EI, In re:

Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), the Florida Retail Federation (FRF), White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate (PCS Phosphate), and the Southern Alliance for Clean Energy (SACE) (collectively, the Parties). The signatories to the *2017* Agreement are organizations that represent DEF's major customer groups.

[*5]

Pursuant to the Petition, the Parties requested that we hold a limited proceeding in accordance with *Sections 366.06*(3) and *366.076*(1), and Chapter 120, Florida Statutes (F.S.), and Rule 25-28.301, Florida Administrative Code (F.A.C.), to consider the merits of the *2017* Agreement, which is appended to this Order in Attachment A. [2] We held an administrative hearing on this matter on October 25, *2017*. During the hearing, the Parties spoke in support of the *2017* Agreement. We provided DEF customers and interested persons with the opportunity to present public testimony and voice any concerns with the *2017* Agreement, and DEF sponsored witnesses who provided sworn testimony and answered questions pertaining to the *2017* Agreement.

[*6]

SETTLEMENT AGREEMENT

The *2017* Agreement provides DEF with a multi-year increase to base rates beginning with the first billing cycle of January 2019, and resolves outstanding issues in existing, continuing, and prospective dockets before this Commission. This includes the fuel and purchased power cost recovery clause, Docket No. 20170001-EI; the energy conservation cost recovery clause, Docket No. 20170002-EG; the nuclear cost recovery clause, Docket No. 20170009-EI; the securitization of the Crystal River Unit 3 (CR3) regulatory asset, Docket No. 150171-EI; and the fuel/power costs associated with the CR3 outage, Docket No. 100437-EI.

With respect to Docket No. 20170009-EI, the *2017* Agreement resolves, in a comprehensive manner, all remaining issues regarding the Levy Nuclear Project (LNP). The *2017* Agreement provides that DEF will not seek future recovery from retail customers of any combined operating licensing costs and associated carrying costs. DEF will write off all remaining but yet unrecovered LNP costs, whether incurred as of the date of this Commission's vote or to be incurred later. This includes $ 81,901,218 at issue in Docket No. 20170009-EI, and the $ 34 million [*7] termination fee ordered by the U.S. District Court for the Western District of North Carolina to be paid to Westinghouse, which is currently under appeal. As specifically stated in paragraph 11 of the *2017* Agreement, "To the extent DEF agrees to, or is obligated to pay or incur, any additional LNP-related costs of any type or nature whatsoever . . . DEF is forever barred from recovering said costs from retail customers . . . there will never be any LNP-related costs of any type or nature whatsoever recovered from DEF's retail ratepayers."

The *2017* Agreement also contains a provision whereby DEF may undertake the construction of approximately 175 megawatts (MW) per calendar year of solar generation projects, for a maximum of 700 MW throughout the term of the *2017* Agreement. These solar projects must reasonably be projected to go into service during the term of this

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Petition for issuance of nuclear asset-recovery financing order, by Duke Energy Florida, Inc. d/b/a Duke Energy ; Order No. PSC-16-0138-FOF-EI, issued April 5, 2016, in Docket No. 15014-EI, In re: Petition for approval to include in base rates the revenue requirement for the CR3 regulatory asset, by Duke Energy Florida, Inc. and Docket No. 150171-EI, In re: Petition for issuance of nuclear asset-recovery financing order, by Duke Energy Florida, Inc. d/b/a Duke Energy ; Order No. PSC-16-0425-PAA-EI, issued October 3, 2016, in Docket No. 160151-EI, In re: Petition for approval of stipulation to amend and revised and restated stipulation and settlement agreement by Duke Energy Florida, LLC.

[2] Due to its length, the Exhibits to the ***2017*** Second Revised and Restated Settlement Agreement are not physically attached to this Order. However, all terms and conditions within those attachments are incorporated by reference herein. See Document No. 07346-***2017***, filed August 29, ***2017***, in Docket No. 20170183-EI, Application for limited proceeding to approve ***2017*** second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.

agreement pending our approval of each project. DEF is also authorized to purchase, install, own, and support *Electric Vehicle* Service Equipment (EVSE) at DEF customer locations as part of a five year EVSE pilot program. The *2017* Agreement provides that DEF may incur up to $ 8 million plus reasonable operating expenses, [*8] with a minimum deployment of 530 EVSE ports. Of all the EVSE ports installed, the *2017* Agreement specifies that at least 10 percent of the EVSE ports must be installed in low income communities as that term is defined in *Section 288.9913(3), F.S.* Another pilot program provided for within the *2017* Agreement is the Battery Storage Pilot Program, which allows DEF to implement a 50 MW battery storage program designed to enhance service to retail customers or to enhance operations of existing or planned solar facilities.

DECISION

The standard for approval of a settlement agreement is whether it is in the public interest. [3] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole. [4]

[*9]

The *2017* Second Revised and Restated Settlement Agreement is a comprehensive, balanced, and fair resolution of a complex and far-ranging set of circumstances, that provide rate stability and predictability for DEF customers. One of the largest benefits of the *2017* Agreement is that it resolves years of controversy, and ensures that DEF customers will never be required to pay any additional costs associated with the Levy Nuclear Project. This prohibition includes known costs related to obtaining the combined operating license and potential costs that could result from the pending litigation between DEF and WEC. The *2017* Agreement also provides benefits to DEF customers through the proposed Battery Storage Pilot Program and the *Electric Vehicle* Service Equipment Pilot Program.

Based on our review of the *2017* Agreement, the exhibits entered into the record, the support of the Parties, the testimony provided by DEF witnesses Javier Portuondo and Ben Borsch, and the benefits to DEF customers, we find that the *2017* Second Revised and Restated Settlement Agreement, [*10] as a whole, is in the public interest. Therefore, the *2017* Second Revised and Restated Settlement Agreement is hereby approved.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the *2017* Second Revised and Restated Settlement Agreement is approved. It is further

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[3] Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; PSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of *Rule 25-6.0143(1)(c)*, (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[4] Order No. PSC-13-0023-S-EI, at p. 7.

ORDERED that all matters contained in the Exhibits attached to the *2017* Second Revised and Restated Settlement Agreement, and incorporated by reference, are approved. It is further

ORDERED that the new and revised tariff sheets implementing the *2017* Second Revised and Restated Settlement Agreement and reflecting the approved final rates and charges are approved. It is further

ORDERED in the event that no timely appeal is filed, Docket No. 20170183-EI and 100437-EI shall be closed. Docket Nos. 150171-EI, 20170001-EI, 20170002-EI, and 20170009-EI shall remain open for future disposition by this Commission.

By ORDER of the Florida Public Service Commission this 20th day of November, *2017*.

Attachment A

2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT

Contents

[*11]

2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, LLC ("DEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), (collectively referenced as the "Original Parties"), previously resolved certain issues in a Stipulation and Settlement Agreement, dated January 20, 2012 (the "2012 Settlement Agreement"), that was approved by the Florida Public Service Commission ("FPSC" or the "Commission") in Order No. PSC-12-0104-FOF-EI [1], issued on March 8, 2012 in Docket No. 120022-EI, as amended by Order No. PSC-12-0104A-FOF-EI; and

[*12]

WHEREAS, the Original Parties resolved additional issues in that certain Revised and Restated Stipulation and Settlement Agreement (the "2013 Settlement Agreement"), dated July 31, 2013, that was approved by the Commission in Order No. PSC-13-0598-FOF-EI, issued on November 12, 2013 in Docket No. 130208-EI; and

WHEREAS, on August 6, 2015, the Original Parties entered into a stipulation in Docket No. 150009-EI, in which the Original Parties agreed that DEF would make its final true-up filing of all known Levy Nuclear Project ("LNP") costs in the *2017* nuclear cost recovery clause ("NCRC") hearing cycle; and

WHEREAS, the Original Parties entered into three stipulations to amend the 2013 Settlement Agreement, which were approved by the Commission in Order Nos: PSC-15-0465-S-EI, issued on October 14, 2015 in Docket Nos.

150148-Eland 150171-El; PSC-16-0138-FOF-EI, issued on April 5, 2016 in Docket No. 150171-El; and PSC-16-0425-PAA-EI, issued on October 3, 2016 in Docket No. 160151-EI; and

WHEREAS, on December 22, 2016, DEF received a judgment in the litigation against Westinghouse Electric Company ("WEC") regarding termination costs associated with the cancellation of the Engineering, [*13] Procurement, and Construction ("EPC") contract associated with the LNP, in which the trial court ordered DEF to pay a $ 30 million termination fee (plus approximately $ 4 million in prejudgment interest), denied DEF's claim for the return of $ 54 million previously paid to WEC for goods not received, and denied the remainder of WEC's claim for approximately $ 482 million in additional termination costs. *(Duke Energy Florida, Inc. v. Westinghouse Electric Company*, in the United States District Court for the Western District of North Carolina, Charlotte Division, Civil Action No. 3:14-CV-00141-MOC-DSC); and

WHEREAS, WEC appealed that order on January 20, *2017*, DEF cross-appealed on February 1, *2017*, and the appellate cases were combined and at this time remain pending in the United States Court of Appeals for the Fourth Circuit (Case No. 17-1151 and 17-1087); and

WHEREAS, DEF petitioned for cost recovery of certain known costs, amounting to $ 81,901,218 (retail) , as identified in the May 1, *2017* pre-filed testimony of Christopher M. Fallon and Thomas G. Foster, related to the LNP in Docket No. 20170009-EI, and sought to reserve the right to seek future recovery of additional LNP [*14] costs related to the pending WEC appellate case; and

WHEREAS, DEF has not yet submitted any claim for cost recovery in Docket 20170009-EI for its future litigation costs, nor the above-referenced $ 34 million (system) and $ 482 million (system), plus interest, related to the WEC appeal but has expressed an intent to do so if and to the extent such costs become known and measureable and an obligation of DEF; and

WHEREAS, the Original Parties and the Southern Alliance for Clean Energy ("SACE") (collectively referred to as the "Parties") agreed that in light of those decisions and actions that it is in the public interest to attempt to resolve all remaining LNP-related issues in Docket No. 20170009-EI. as well as additional matters described herein; and

WHEREAS, the Parties have reached an agreement regarding the matters set forth in this *2017* Second Revised and Restated Stipulation and Settlement Agreement ("*2017* Second Revised and Restated Settlement Agreement"), dated August 29, *2017*; and

WHEREAS, unless the context clearly indicates otherwise, the term Party or Parties means a signatory to this *2017* Second Revised and Restated Settlement Agreement, and Intervenor Parties mean collectively [*15] OPC, FIPUG, FRF, and White Springs; and

WHEREAS, agreement on the matters and issues in this *2017* Second Revised and Restated Settlement Agreement will promote administrative efficiency and avoids the time, expense, and uncertainty associated with addressing the issues in the above-referenced Commission dockets and other matters; and

WHEREAS, the Parties further recognize and agree that this *2017* Second Revised and Restated Settlement Agreement fully and finally determines, in a comprehensive manner, the issues related to the circumstances surrounding the LNP as described herein, and, as it impacts customers, resolves uncertainties related to these issues; and

WHEREAS, nothing in this *2017* Second Revised and Restated Settlement Agreement is an admission of liability, imprudence, or fault; and

WHEREAS, the Parties have entered into this *2017* Second Revised and Restated Settlement Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida

Statutes ("F.S."), as applicable, and as a part of the negotiated exchange of consideration among the Parties to this *2017* Second Revised and Restated Settlement Agreement each has [*16] agreed to concessions to the others with the expectation, intent, and understanding that all provisions of this *2017* Second Revised and Restated Settlement Agreement will be enforced by the Commission as to all matters addressed herein with respect to all Parties upon Commission approval of this *2017* Second Revised and Restated Settlement Agreement.

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree and stipulate as follows:

1. This *2017* Second Revised and Restated Settlement Agreement incorporates the surviving terms and conditions of the 2013 Settlement Agreement and its Exhibits and, as a result, this *2017* Second Revised and Restated Settlement Agreement replaces and supplants the 2013 Settlement Agreement, Terms and conditions of the 2013 Settlement Agreement that are not expressly included in this *2017* Second Revised and Restated Settlement Agreement are extinguished and are of no further effect, except where the survival of a provision is a precedent for: (i) the determination by the Commission of the CR3 [*17] nuclear asset recovery costs (as defined in *Section 366.95 (1)(k), F.S.*) in Docket No. 150171-El; (ii) DEF's right to recover (on behalf of Duke Energy Florida Project Finance, LLC) the nuclear asset recovery charges (as defined in *Section 366.95(1)(j), F.S.*) in Docket No. 150171 - El; or (iii) the validity and issuance of nuclear asset recovery bonds pursuant to *Section 366.95, F.S.*, and Order No. PSC-15-0537-FOF-EI and except where such survival is otherwise expressly stated or necessarily implied herein to give force and effect to the intent of the parties in this *2017* Second Revised and Restated Settlement Agreement.

2. The provisions of this *2017* Second Revised and Restated Settlement Agreement will become effective upon Commission approval (the "Effective Date"), and continue through the last billing cycle for December 2021 (the "Term"), unless otherwise specified or provided for in this *2017* Second Revised and Restated Settlement Agreement. The Parties intend for the tariff sheets attached to this *2017* Second Revised and Restated Settlement Agreement to be effective [*18] on January 1, 2018, unless otherwise indicated in Paragraphs 29 and 30.

3. The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this *2017* Second Revised and Restated Settlement Agreement. However, no right reserved in the 2013 Settlement Agreement is waived or extinguished by virtue of this *2017* Second Revised and Restated Settlement Agreement replacing or supplanting the 2013 Settlement Agreement, unless such waiver is express on its face in this *2017* Second Revised and Restated Settlement Agreement. No waiver or release is given orally or by implication, and the only waivers and releases agreed to by any Party to this *2017* Second Revised and Restated Settlement Agreement are those that are expressly stated herein. The failure to specifically set forth a reservation of right(s) clause or an affirmative reservation of right(s) contained in this *2017* Second Revised and Restated Settlement Agreement in another portion of this *2017* Second Revised and Restated Settlement Agreement is not, and shall not, be interpreted as a waiver of any right(s) otherwise reserved by the Original Parties.

CR3:

4. It is the intent of the Original Parties [*19] and the Original Parties stipulate that this *2017* Second Revised and Restated Settlement Agreement resolves all remaining issues that were included in Docket No. 100437-EI (i.e., pertaining to the 2009 CR3 outage, subsequent repair attempts, and retirement) on the terms and conditions set forth herein and in Order Nos. PSC-12-0104-FOF-EI and PSC-13-0598-FOF-EI, including the amendments approved in Order Nos. PSC-15-0465-S-EI, PSC-16-0138-FOF-EI, and PSC-16-0425-PAA-EI. The Intervenor Parties have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the reasonableness or prudence of any DEF action, including inaction, or decision, of any kind, type, or nature, both prior to and subsequent to the Implementation Date of the 2012 Settlement Agreement, arising out of, or related or in any way connected to, directly or indirectly, any and all of the issues in Docket No 100437-EL Absent evidence of fraud, intentional

misrepresentation, or intentional misconduct by DEF, the Intervenor Parties cannot and will not challenge in any Commission or judicial [*20] proceeding the prudence of DEF's actions in connection with the issues from Docket No. 100437-EI.

5. a. Pursuant to the 2012 Settlement Agreement, as restated in the 2013 Settlement Agreement, DEF placed CR3 in extended cold shutdown effective January 1, 2011, at which time depreciation and other accruals were suspended and/or reversed until the unit was retired on February 5, 2013. DEF removed CR3 from rate base, and the revenue requirements for CR3 were excluded from the rates established in the 2013 Settlement Agreement effective the first billing cycle for January 2013. Consistent with the terms of the 2013 Settlement Agreement, DEF implemented deferral accounting through the creation of a regulatory asset to address the capital cost amounts and revenue requirements associated with all CR3-related costs, which was referred to as the "CR3 Regulatory Asset." As determined in Docket Nos. 150148-EI and 150171 -El, the Commission approved the amount of the CR3 Regulatory Asset to be recovered from customers and authorized the issuance of low-cost nuclear asset recovery bonds through securitization. Nothing in this *2017* Second Revised and Restated Settlement Agreement is intended to [*21] or does affect the Commission's Orders in these two dockets, or the applicability of *Section 366.95, F.S.*

(1). The projected dry cask storage ("DCS") facility costs. DEF shall be entitled to petition the Commission for approval of the reasonable and prudent projected DCS facility (also known as the Independent Spent Fuel Storage Installation or ISFSI) capital costs. The Parties are not precluded from fully participating in such a proceeding and do not waive any rights related to such participation or determination. DEF shall be entitled to petition for inclusion of the projected total (retail jurisdictional) value of the reasonable and prudent DCS facility capital costs in the Capacity Cost Recovery ("CCR") Clause using the pretax rate of return of 8.12%, pursuant to Exhibit 10 of the 2013 Settlement Agreement, subject to the amortization deferral approved in Order No. PSC-15-0027-PAA-EI, which costs shall be allocated to rate classes annually using a uniform percentage of the DCS costs to be recovered divided by the total forecasted retail base rate demand and energy revenues. The actual amounts recovered through the CCR Clause shall be [*22] subject to the Commission's standard clause true-up, review, audit, and approval processes; the Parties are not precluded from fully participating in such proceedings, for example and without limitation, to challenge the reasonableness and prudence of DEF's claimed DCS facility capital costs, and the Parties do not waive any rights related to such participation or determination. The Parties expressly agree that any proceeding to recover such costs associated with this Paragraph of this *2017* Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. DEF shall credit the CCR Clause with the retail portion of all applicable Department of Energy ("DOE") awards when they are received, and shall amortize the adjusted final DCS facility capital cost balance over the recovery period set forth in Subparagraph 5c, and 5.d., unless another recovery period is agreed to by all the Original Parties.

b. Matters regarding rate recovery of the CR3 Regulatory Asset [*23] were decided by the Commission in Order No. PSC-13-0598-FOF-EI (which approved the 2013 Settlement Agreement) , Order No. PSC-15-0465-S-EI (establishing the final amount of the CR3 Regulatory Asset), Order No. PSC-2015-0537-FOF-EI (the Financing Order for the CR3 securitized asset) and Order No. PSC-16-013S-FOF-EI (authorizing $ 38,103,444 of the CR3 Regulatory Asset to be recovered through the CCR Clause). The Intervener Parties have fully and forever waived, released, discharged and otherwise extinguished any and all of their rights to contest DEF's right to recover a return of and return on the deferred and accumulated CR3 investments, regulatory assets/liabilities, and carrying costs in the rate increase for the CR3 Regulatory Asset referenced above in Subparagraph 5a. of this *2017* Second Revised and Restated Settlement Agreement. The Intervenor Parties acknowledge that they have expressly waived, released, and have not retained the right to challenge the inclusion of, and the recovery of, the components of the CR3 Regulatory Asset that were at issue in Docket No. 100437-E1.

c. The Original Parties recognize that the CR3 nuclear asset-recovery costs (as defined in *Section 366.95(1)(k), F.S.* [*24]) are being recovered through the issuance of nuclear asset-recovery bonds (as defined in *Section 366.95(1)(i), F.S.*) and the recovery of nuclear asset recovery charges (as defined in *Section 366.95(1)(j), F.S*), all as approved by the Commission in Docket No. 150171-EI. The Intervener Parties acknowledge that they have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights to contest DEF's right to recover on behalf of Duke Energy Florida Project Finance, LLC, the nuclear asset-recovery costs and finance costs that are being recovered pursuant to the Commission's Order in Docket 150171-EI. Accordingly, the nuclear asset-recovery charge (as defined in *Section 366.95(1)(j), F.S.*) shall remain in effect until the nuclear asset-recovery bonds have been paid in full and the Commission-approved financing costs (as defined in *Section 366.95*(1)(e), F.S.) have been recovered in full, but in no event for a period longer than the close of the last billing cycle for the 276th month from inception [*25] of the nuclear asset-recovery charge, with the understanding that: (i) the nuclear asset-recovery bonds have been structured in a manner such that the scheduled final maturity date for the last maturing tranche of the nuclear asset-recovery bonds is as close as is reasonably possible to the dose of the last billing cycle for the 240th month from inception of imposition of the nuclear asset-recovery charge; and (ii) any portion of the recovery period beyond the scheduled final maturity date for the last tranche of the nuclear asset-recovery bonds shall be strictly limited to the purpose of recovery of charges pursuant to the true-up mechanism permitted under any Financing Order that may be issued by the Commission and any adjustments approved by the Commission (in accordance with *Section 366.95*(2)(c)4, F.S.).

d. The Original Parties continue to intend that retail rate recovery for the nuclear asset recovery charge shatl continue for a recovery period consistent with the last sentence in Subparagraph 5c, including a scheduled final maturity date for the last maturing tranche of the nuclear asset-recovery bonds as close as is reasonably possible [*26] to the close of the last billing cycle for the 240th month from inception of imposition of the nuclear asset-recovery charge.

e. DEF shall continue to exclude the following amounts related to CR3 from all earnings surveillance reports; (1) revenues associated with the recovery of the CR3 Regulatory Asset including the components referenced in Paragraph 9 and the amount of the excluded portion of the asset referenced in the first sentence of Paragraph 32; (2) rate base and Operating and Maintenance ("O&M") expense amounts (including, but not limited to, all amounts that have been deferred to or recorded in regulatory assets and liabilities); and (3) cost of capital accounts with specific adjustments for items including, but not limited to, deferred income taxes, with all other CR3-related items removed from capital structure on a pro-rata basis. All costs that are being recovered as part of the nuclear asset-recovery bonds shall be excluded from the earnings surveillance reports.

Fuel Adjustment Clause:

6. On June 13, *2017*, in Order No. PSC-*2017*-0219-PCO-EI, the Commission denied DEF's Petition for a Mid-Course Correction to its fuel factor and deferred the matters raised in that [*27] petition to the hearing scheduled for October 25, *2017* in Docket No. 20170001-El. The Parties agree that DEF shall recover the *2017* Actual/Estimated True-up under-recovery of fuel and purchased power costs that is finally determined by the Commission, and which is proposed in DEF's August 24, *2017* petition in Docket No. 20170001-El to be $ 195,503,774, over a two year period that begins January 1, 2018, i.e. fifty (50) percent in 2018 and fifty (50) percent in 2019. DEF shall continue to be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the unavailability of CR3 for any reason for the period beginning October 1, 2009. Thus, for the period beginning October 1, 2009, the unavailability of CR3 for any reason shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties have waived their rights to challenge DEF's recovery of such costs, except that the Intervenor Parties have reserved their rights to raise issues regarding the prudence and reasonableness of DEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the unavailability of CR3 for any [*28] reason.

Nuclear Decommissioning Trust:

7. If DEF determines that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3, DEF shall be allowed to petition to collect those additional funds through a surcharge in base rates. This surcharge will be the lesser of the Commission-approved annual contribution amount or $ 8 million. The $ 8 million limitation shall expire with the last billing cycle for December 2021. After the last billing cycle for December 2021, DEF shall be authorized to recover the actual Commission-approved annual contribution to the Nuclear Decommissioning Trust through a base rate surcharge, subject to the applicability of Subparagraph 12.a. and Exhibit 6, and that surcharge shall expire following the conclusion of DEF's next base rate case. If the Commission approves an annual contribution to the Nuclear Decommissioning Trust in excess of $ 8 million prior to the last billing cycle for December 2021, this incremental amount of the annual contribution in excess of what has been authorized for recovery in the base rate surcharge shall be deferred with carrying costs based on the Commission-approved [*29] allowance for funds used during construction ("AFUDC"), and recovered (including carrying costs) through the CCR Clause over a 4 year period beginning with the first billing cycle for January 2022, unless otherwise agreed to by the Original Parties. The Intervener Parties reserve their rights to challenge the prudence of any additional CR3 decommissioning costs (funding accrual) in appropriate proceedings before the Commission. The Original Parties expressly agree that any proceeding to recover costs associated with decommissioning CR3 under this Paragraph shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings

Crystal River 1 & 2 ("CRS") Retirement:

8. If DEF retires Crystal River coal units 1 & 2 ("Crystal River South" or "CRS"), as a compliance measure to meet Mercury and Air Toxics Standards ("MATS"), the Best Available Retrofit Technology ("BART"), and/or the National Ambient Air Quality Standards ("NAAQS"), DEF shall be permitted to continue the annual depreciation expense and depreciation [*30] rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Original Parties, any remaining CRS net book value existing as of December 31, 2020 through the CCR Clause.

CR3 Extended Power Uprate Project ("EPU" or "Uprate"):

9. As set forth in the 2013 Settlement Agreement, DEF has been recovering all CR3 EPU revenue requirements through the NCRC consistent with the provisions of *Section 366.93(6), F.S.*, and Commission *Rule 25-6.0423(6)*, Florida Administrative Code ("F.A.C."), in accord with the seven (7) year amortization recovery period established as 2013-2019 (the estimated unrecovered investment balance is $ 86,682,782 not including carrying costs as of December 31, *2017* subject to the addition of applicable carrying costs and other recoverable costs as set out in the statute and rule above). Any final true-up of these costs will occur through the CCR Clause after December 31, 2019 for any under or over-recovery. The Intervenor Parties [*31] have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the prudence of DEF's CR3 EPU investment and activities, except that the Intervenor Parties do not waive their rights to participate in the NCRC or other appropriate docket(s) for purposes of verification that DEF has fulfilled its obligation to minimize future costs of the abandoned Uprate Project. DEF shall in accord with its obligation to do so, minimize the costs of the CR3 EPU Regulatory Asset (as illustrated in Thomas G. Foster's Exhibit TGF-4, filed by DEF on May 1, *2017* in Docket No. 20170009-EI), and use reasonable and prudent efforts to curtail avoidable future costs or to sell or otherwise salvage assets that would have otherwise been included in the CR3 EPU Regulatory Asset. The Original Parties agree that CR3 EPU assets that were placed in-service and closed to electric plant in-service FERC 101, which amount equals $ 35,894,547 as of December 31, 2015 and includes carrying charges through December 31, 2015, have not been, nor shall be, included in, or recovered or further [*32] trued upas part of the CR3 Regulatory Asset but instead shall continue to be recovered in an amount estimated to be $ 38,108,444 as of December 31, 2016 (subject to true-up), through the CCR Clause

over the years *2017* and 2018 at a carrying cost rate of 3 percent, pursuant to Order No. PSC-16-0138-FOF-EI; and CR3 EPU assets never closed to electric plant in-service FERC 101 of $ 86,682,782, identified in the first sentence of this Paragraph, shall continue to be recovered, along with applicable carrying costs, as a part of the CR3 EPU Regulatory Asset as set forth in this Paragraph. DEF has discontinued and will forever cease active efforts to market CR3-related assets that are not in use, not usable or not otherwise encumbered, and shall only undertake to sell or salvage assets if clearly cost-effective sales or salvage opportunities are presented. If CR3 EPU assets are sold or salvaged, or costs are incurred that were not included in the *2017* Petition for rate recovery filed in Docket 20170009-EI by DEF, which are newly incurred after the Effective Date, then the retail portion of the sale or salvage proceeds and any newly incurred costs shall be recovered or returned, with carrying [*33] costs (debit or credit as applicable) at the rate prescribed in *Section 366.93(6), F.S.*, and *Rule 25-6.0423(6)*, F.A.C., through the CCR Clause.

Levy Nuclear Project ("LNP"):

10. By no later than January 1, 2019, DEF shall remove the Levy Land from rate base and earnings surveillance report results. Levy Land is defined as the land reflected in DEF's 2016 FERC Form 1, page 214, lines 6 and 8, specifically the Lybasse parcel (1,845 acres) in the amount of $ 27,667,950 (system) and the Rayonier/Lybasse parcel (3,105 and 94 acres, respectively) in the amount of $ 66,404,373 (system), for a total of $ 94,072,323 (system). Upon this initial removal of the Levy Land from rate base, DEF shall write off its actual post-2013 costs, in the amount of $ 36,621,816.70 (system) as estimated on July 31, *2017*, related to the LNP Combined Operating License ("COL"), including AFUDC. DEF agrees not to seek future recovery from retail customers of any of the LNP's COL-related costs, including carrying charges. DEF retains the right to maintain ownership of the Levy Land and to file a petition with the Commission in [*34] conjunction with its next general base rate case, or any other relevant proceeding during the Term of this *2017* Second Revised and Restated Settlement Agreement pursuant to Paragraph 15, for potential re-inclusion of any portion of such land into rate base, subject to approval by the Commission in DEF's next base rate proceeding or other relevant proceeding contemplated under this *2017* Second Revised and Restated Settlement Agreement. Parties reserve the right to object to inclusion of such land costs in rate base or rates. If DEF sells the Levy Land, DEF's shareholders will be permitted to retain any gain or loss on sale. Any Levy Land restored to rate base by Commission approval shall be thereafter subject to the Commission's policy on gains or losses on sales.

11. In the 2013 Settlement, the Original Parties supported DEF terminating the LNP EPC contract with WEC, because DEF was unable to obtain the LNP COL from the NRC by January 1, 2014. Consistent with the 2013 Settlement, DEF exercised the provisions of *Section 366.93(6), F.S.*, and elected not to complete the construction of the LNP. DEF terminated the EPC contract in January 2014. After [*35] termination, litigation with WEC ensued as to the amount of termination costs owed by DEF to WEC. Consistent with the terms of this *2017* Second Revised and Restated Settlement Agreement, DEF will write off all remaining but yet unrecovered LNP costs, whether incurred as of the Effective Date or later, including the $ 81,901,218 (retail) , as identified in the May 1, *2017* pre-filed testimony of Christopher M. Fallon and Thomas G. Foster (which includes historical litigation costs), at issue in Docket No. 20170009-EI, the $ 34 million (system) termination fee ordered by the trial court to be paid to WEC, WEC's pending appellate claims for additional cost recovery, and additional future litigation costs, through any and all appeals, for which DEF has not yet sought recovery in Docket 20170009-EI. To the extent DEF agrees to, or is obligated to pay or incur, any additional LNP-related costs of any type or nature whatsoever arising from any claim, legal action, regulatory or other proceedings before any governmental authority, transaction, or any other event whatsoever, including but not limited to any and all litigation costs, damages, regulatory costs, interest, fines, penalties, costs [*36] paid pursuant to any agreement or arbitration award, or additional termination costs ordered by the court in connection with the WEC appeal of the order issued in Civil Action No.: 3:14-cv-00141 (appellate case No. 17-1087, consolidated with 17-1151), or in any other litigation, arbitration, regulatory, or any other proceedings, whether currently pending or future, involving any party or entity whatsoever, DEF is forever barred from recovering said costs from retail customers. For clarity, it is the intent of all the Parties that, as a matter of

rights between and among the Parties and as a matter of law pursuant to FPSC approval of this *2017* Second Revised and Restated Settlement Agreement, after the Effective Date or December 31, *2017*, whichever is sooner, there will never be any LNP-related costs of any type or nature whatsoever recovered from DEF's retail ratepayers.

Base Rate Adjustments:

12.

a. DEF's base rate revenue requirements will change in 2018 pursuant to Paragraph 14. In addition, there will be an adjustment of base rates among customer rate classes to implement the changes in the delivery voltage credit referenced in Paragraph 21 and to implement the change referenced [*37] in Paragraph 24. The tariff sheets reflecting these and other relevant changes necessary to implement this *2017* Second Revised and Restated Settlement Agreement are attached as Exhibits 3 and 4 (clean and legislative, respectively). The Parties agree that all the tariffs in Exhibits 3 and 4 will have an effective date of January 1, 2018.

b. Effective with the first billing cycle for January 2019, DEF will be allowed a multi-year increase to its base rates as reflected in the chart below:

	Total Increase	Uniform% increase Method (1)	Uniform% increase Method (2)
2019	$ 67 million	$ 50 million	$ 17 million
2020	$ 67 million	$ 50 million	$ 17 million
2021	$ 67 million	$ 50 million	$ 17 million

Uniform % increase method (1): Amount to be recovered through a uniform percent increase to the customer, demand and energy base rate charges for all retail customer classes, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted.

Uniform % Increase Method (2): Amount to be recovered through a uniform percent increase to customer charges for all retail rate classes except the interruptible and curtailable [*38] rate classes.

c. If the applicable federal or state income tax rate for DEF changes before any of the increases provided for in Paragraph 7, 12, 14, 15, 21 , 24, or 37, DEF will adjust the amount of the base rate increase to reflect the new tax rate before the implementation of such increase, pursuant to the applicable methodology in Exhibit 6 (i.e. lines 1-14). Any base rate adjustments or changes that are implemented before the effective date of the Federal Corporate Income Tax Change will be adjusted as part of the overall method outlined in Paragraph 16 and Exhibit 6. The illustration of the methodology to be utilized for income tax changes described in this Paragraph 12 is shown in Exhibit 6. The Parties expressly agree that any proceeding to implement the base rate revenue increases associated with this Paragraph of the *2017* Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

d. Except for the base rate increases provided for in Paragraphs [*39] 7, 12, 14, 15, 21, 24, and 37, the Company shall freeze its base rates through the last billing cycle for December 2021. As a part of this base rate freeze the Company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Effective Date through and including December 31, 2021, which are of the type which traditionally or historically have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by the Parties.

13. DEF shall have an authorized return on equity of 10.5% with a range of reasonableness of +/-100 basis points for the purpose of addressing earnings levels, earnings surveillance and cost recovery clauses. The applicable annual AFUDC rate will be 744%, as provided for in the 2013 Settlement, through year-end 2018 and then will be updated periodically consistent with Commission practice going forward.

14. a. Consistent with the 2013 Settlement, DEF was authorized to petition the Commission for a need determination for additional generation, not to exceed 1800 MW, to be placed in service in 2018. DEF filed such [*40] a petition for construction of its Citrus County Combined Cycle Units, and the Commission granted that determination of need in Order No. PSC-14-0557-FOF-EI. If DEF constructs and places in service the Citrus County Combined Cycle Units in 2018, DEF's base rates shall be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). The Annualized Base Revenue Requirement shall reflect the costs pursuant to which the need determination was granted by the Commission. This base rate increase shall be referred to as the 2018 Generation Base Rate Adjustment ("GBRA"). The Intervener Parties retain all rights to challenge DEF's actions made or taken pursuant to Subparagraphs 14.a., 14.b., and 14.e., including, but not limited to, the right to challenge the need for, or prudence of any costs associated with, the construction of any additional generation placed in service in 2018 as well as the initial 2018 GBRA factor and any subsequent revisions to it pursuant to Rule 25.22.082(15), F.A.C., but have waived the right to argue that this *2017* Second Revised and Restated Settlement Agreement prevents DEF from seeking recovery [*41] for the costs described in this Paragraph that the Commission determines to be reasonable and prudent.

b. The initial 2018 GBRA factor shall be established by the application of a uniform percentage increase to the demand and energy charges reflected in the Company's base rate schedules existing at the time of the increase, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. The uniform percentage increase shall be calculated using the billing determinants included in the Company's most recent projection clause filing unless otherwise agreed to by the Original Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. DEF shall begin applying the 2018 GBRA to meter readings made on and after the commercial in-service date(s) of the 2018 Citrus County Combined Cycle Units.

c. The 2018 GBRA Annualized Base Revenue Requirement shall be calculated using a 10.5% ROE and DEF's projected 13-month average capital structure for the first 12 months of operation, including all specific adjustments consistent with DEF's then most recently filed December [*42] earnings surveillance report, and adjusted to include an Accumulated Deferred Income Tax ("ADIT") proration adjustment consistent with 26 C.F.R. Section 1.167(l)-1(h)(6). DEF will calculate and submit the 2018 GBRA rates for Commission approval using the billing determinants from the most recent projection clause filings.

d. In the event that the actual capital expenditures are less than the projected costs used to develop the initial 2018 GBRA factor, the lower figure shall be the new basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised 2013 GBRA factor shall be computed using the same data and methodology incorporated in the initial 2018 GBRA factor, with the exception that the actual capital expenditures shall be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. This credit shall be the difference between the cumulative base revenues since the implementation of the initial 2018 GBRA factor and the cumulative base revenues that would have resulted if the revised 2018 GBRA factor had been tn-place during the same time period and [*43] shall be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in *Rule 25-6.109*, F.A.C. On a going-forward basis, base rates shall be adjusted to reflect the revised 2018 GBRA factor.

e. In the event that the actual capital expenditures are higher than the projection on which the Annualized Base Revenue Requirement was based, DEF at its option may initiate a limited proceeding pursuant to *Section 366.076, F.S.*, limited to the issue of whether DEF has met the requirements of *Rule 25-22.082(15)*, F.A.C. If the Commission finds that DEF has met the requirements of *Rule 25-22.082(15)*, F.A.C, then DEF shall increase the 2018 GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, DEF's election not to seek such an increase in the 2018 GBRA shall not preclude DEF from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. [*44] No Party is precluded from participating in any such limited proceeding. The Original Parties expressly agree that any proceeding to recover costs associated with this Subparagraph of the *2017* Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

Solar Base Rate Adjustment:

15.

a. DEF projects that for purposes of the cost recovery set forth in this Paragraph, it will undertake construction of approximately 175 MW per calendar year of solar generation (for a maximum of 700 MW) reasonably projected to go into service during the Term of this *2017* Second Revised and Restated Settlement Agreement or within one year following expiration of the Term; provided, however, DEF will not implement a Commission-approved base rate adjustment as contemplated in this Paragraph at any time during 2018. Solar base rate adjustments may be authorized for solar projects for which DEF files for Commission approval pursuant to this Paragraph during the Term. [*45] For each solar project that is approved by the Commission for cost recovery pursuant to the process described in this Paragraph, DEF's base rates will be increased by the incremental annualized base revenue requirement (as defined in Subparagraph 15.e.) for the first 12 months of operation (the "Annualized Base Revenue Requirement"), but in no event before the facility is in service. The Commission's approval may occur before or after expiration of the Term. The projects constructed or acquired pursuant to this Paragraph must be scheduled and reasonably projected to be placed into service no later than one year following the expiration of the Term. DEF agrees that, during the Term of this *2017* Second Revised and Restated Settlement Agreement, it will not place any material solar projects into service that are not subject to the solar base rate adjustment process described in this Paragraph. During the Term of this *2017* Second Revised and Restated Settlement Agreement, the cost of the components, engineering and construction for any solar project constructed or acquired by DEF pursuant to this Paragraph shall be reasonable and cost effective and in no event shall the weighted average [*46] cost of all projects in any filing for Commission approval of the base rate adjustments as contemplated in this Paragraph exceed $ 1,650 per kilowatt alternating current ("kWac"). This cap is generally based on an assumption and current intent by DEF that a single axis tracking technology will be utilized as further described in this Paragraph. Additionally, this cap is intended as a protection for customers and is not intended to be a target or "build to" number; however, it is not intended to discourage DEF from engineering or designing projects in order to deliver the maximum efficiency and benefit to customers. DEF agrees that, for projects constructed or acquired by DEF, the following cost categories will be included in the $ 1,650 kWac cost cap, but that the cost cap is not limited to these categories of costs, and includes any and all construction costs attributable to the solar projects: Engineering, Procurement, and Construction ("EPC") costs, development costs including third party development fees, if any, permitting, land acquisition, taxes, and utility costs to support or complete development, transmission interconnection costs, Installation Labor and Equipment, Electrical [*47] Balance of System, Structural Balance of System, Inverters, and Modules. To the extent that the cost(s) of any of DEF's solar projects materially exceed total project cost(s) reflected in another Florida utility's similar solar base rate adjustment filing made after February 28, *2017*, DEF agrees to demonstrate the reasonableness of said difference(s), including a departure, if any, from the current intent to utilize single axis tracking technology, provided that DEF's explanation is subject to public availability of information about the other utility's project costs. It is DEF's current intent, but not a guarantee, to utilize single axis tracking technology, whenever possible and cost effective, in its solar projects subject to this Paragraph. This intent, however, may exclude certain projects originating from third parties. In implementing potential solar projects, DEF will utilize a reasonable competitive solicitation process(es) to select its contractors and to procure equipment and materials, and DEF will also consider buying out existing potential projects in any stage of development, as long as those projects meet DEF's reasonable standards, the cost cap, and the cost differential [*48] requirements of this Paragraph. Affiliate companies to DEF will not be allowed to participate as potential contractors in this competitive solicitation process. DEF agrees to file monthly reports that will provide the same information as that filed with the Commission in Docket No. 20170007-EI by another utility for its solar projects, in order to reflect the performance of the solar projects after they have been placed in-service.

b. For solar generation projects subject to the Florida Electrical Power Plant Siting Act (i.e., 75 MW or greater), DEF will file a petition for need determination pursuant to Chapter 25-22, F.A.C. If approved pursuant to the procedures described in this Paragraph and *Section 403.519, F.S.*, DEF will calculate and submit for Commission confirmation the base rate adjustment for each such solar project, consistent with Subparagraphs 15.e. and 15.f.

c. Solar generation projects not subject to the Florida Electrical Power Plant Siting Act (i.e., fewer than 75 MW), also will be subject to approval by the Commission as follows: (i) DEF will file a request for approval of the solar generation project in a separate docket; [*49] and (ii) the issues for determination are limited to: the reasonableness and cost effectiveness of the solar generation projects (i.e., will the projects lower the projected system cumulative present value revenue requirement "CPVRR" as compared to such CPVRR without the solar projects); the amount of revenue requirements; and whether, when considering all relevant factors, DEF needs the solar project(s). Any Party may challenge the reasonableness of DEF's actual or projected solar project costs. If approved, DEF will calculate and submit for Commission confirmation the base rate adjustment for each such solar project, consistent with Subparagraphs 15.e. and 15.f.

d. The maximum cumulative amount(s) of solar projects (in MW) for which DEF may recover through the base rate adjustment provided for in this Paragraph in any year covered by this *2017* Second Revised and Restated Settlement Agreement are as follows: 2019: 350 MW; 2020: 525 MW; 2021: 700 MW; 2022: 700 MW.

e. Each base rate adjustment allowed by or implemented pursuant to this Paragraph is to be reflected on DEF's customer bills by increasing customer demand and energy base rate charges by an equal percentage contemporaneously; [*50] however, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. The calculation of the percentage change in rates will be based on the ratio of (i) the forecasted jurisdictional Annualized Base Revenue Requirement for the solar project(s) covered by any single base rate increase to (ii) the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. The forecasted retail base revenues from the sales of electricity during the first twelve months of operation will be based upon DEF's billing determinants for the first 12 months following such project's commercial in-service date, where such sales forecast is that used in DEF's then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each such solar project's operation. DEF shall be authorized to begin applying the base rate charges for each adjustment authorized by this Paragraph to meter readings beginning with the first billing cycle on or after the commercial in-service [*51] date of that solar generation project.

f. Each base rate adjustment created by this Paragraph will be calculated using a 10.5% ROE and DEF's projected 13-month average capital structure for the first 12 months of operation, including all specific adjustments consistent with DEF's most recently filed December earnings surveillance report, and excluding the treatment of common equity and rate base (working capital) allowed in Paragraph 18 of the 2013 Settlement Agreement, and adjusted to include an ADIT proration adjustment consistent with 26 C.F.R. Section 1.167(l)-1 (h)(6) and adjusted to reflect the inclusion of investment tax credits on a normalized basis.

g. In the event that the actual capital expenditures are less than the approved projected costs, included in the petition for cost recovery and used to develop the initial base rate adjustment, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised base rate adjustment will be computed using the same data and methodology incorporated in the initial base rate adjustment, with the exception that the [*52] actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going-forward basis, base rates will be adjusted to reflect the revised base rate adjustment. The difference between the cumulative base revenues since the implementation of the initial base rate adjustment and the cumulative base revenues that would have resulted if the revised base rate adjustment had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in *Rule 25-6.109*, F.A.C.

h. Subject to the maximum cost of $ 1,650 per kWac set forth in Subparagraph 15(a), in the event that actual capital costs for solar generation projects in any filing are higher than the projection on which the Annualized Base Revenue Requirement was based, DEF at its option may initiate a limited proceeding per *Section 366.076, F.S.*, limited to the issue of whether DEF has met the requirements of *Rule 25-22.082(15)*, F.A.C. Nothing in this [*53] *2017* Second Revised and Restated Settlement Agreement shall prohibit a Party from participating in any such limited proceeding for the purpose of challenging whether DEF has met the requirements of *Rule 25-22.082(15)*, F.A.C, or otherwise acted in accordance with this *2017* Second Revised and Restated Settlement Agreement. If the Commission finds that DEF has met the requirements of *Rule 25-22.082(15)*, F.A.C, then DEF shall increase the base rate adjustment at issue by the corresponding incremental revenue requirement due to such additional capital costs, provided, consistent with Subparagraph 15(a) above, DEF is prohibited from recovering through this or any other mechanism or proceeding any costs greater than $ 1,650 per kWac (calculated as the weighted average cost of the projects submitted in the particular filing at issue) under any circumstances. However, DEF's election not to seek such an increase in base rates shall not preclude DEF from booking any incremental costs for surveillance reporting and ail regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. [*54] Nothing in this *2017* Second Revised and Restated Settlement Agreement shall preclude any Party to this *2017* Second Revised and Restated Settlement Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any such limited proceeding.

Federal Corporate Income Tax Changes:

16.

a. Federal or state corporate income tax changes ("Tax Reform") can take many forms, including changes to tax rates, changes to deductibility of certain costs, and changes to the timing of deductibility of certain costs. Therefore the impact of Tax Reform could impact the effective tax rate recognized by DEF in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capita! structure. When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, specified the method and period for returning to customers the portion of the resulting excess deferred income taxes [*55] attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule.

b. If Tax Reform is enacted before DEF's next general base rate proceeding, DEF will quantify the impact of Tax Reform on its Florida Jurisdictional base revenue requirement as projected in DEF's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective. DEF will also adjust base rate adjustments that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers, except that each year throughout the term of this *2017* Second Revised and Restated Settlement Agreement 40% of such impacts, up to $ 50 million pre-tax, would be recorded as an acceleration of depreciation expense associated with [*56] Crystal River Units 4 and 5, thereby reducing the FPSC-adjusted net operating income impact of Tax Reform by up to the after-tax impact of this accelerated depreciation. All remaining base rate impacts of Tax Reform will be flowed back to customers, within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the tax reform on base revenue requirements. This one-time adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges, excluding delivery voltage credits, for all retail customer classes. Any effects of tax reform on retail revenue requirements from the effective date through the date of the one-time base rate adjustment shall be flowed back to customers through the CCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit 6. If Tax Reform results in an increase in base revenue requirements, DEF will utilize deferral accounting as permitted by the Commission, thereby neutralizing the FPSC adjusted net operating income impact of the Tax Reform to a net zero, through the Term of this *2017* Second Revised [*57] and Restated Settlement Agreement. In this situation, DEF shall defer the revenue requirement impacts to a regulatory asset to be considered for prospective recovery in a change to base rates to be addressed in DEF's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the expiration of this *2017* Second Revised and Restated Settlement Agreement.

c. Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there is a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative regulatory [*58] liability is less than $ 200 million, the flow-back period will be five years; or (2) if the cumulative regulatory liability is greater than $ 200 million, the flow-back period will be ten years. DEF reserves the right to demonstrate by clear and convincing evidence that such five or ten year maximum period (as applicable) is not in the best interest of DEF's customers and should be increased to no greater than 50 percent of the remaining life of the assets associated with the Excess Deferred Taxes (referred to as the "50 Percent Period"). The relevant factors to support DEF's demonstration include, but are not limited to, the impact the flow-back period would have on DEF's cash flow and credit metrics or the optimal capitalization of DEF's jurisdictional operations in Florida. If DEF can demonstrate, by clear and convincing evidence, that limiting the flow-back period to the 50 Percent Period, in conjunction with the other Tax Reform provisions related to deferred taxes within this *2017* Revised and Restated Settlement Agreement, will be the sole basis for causing a full notch credit downgrade by each of the major rating agencies (i.e. Standard & Poor's and Moody's), the Commission [*59] shall be authorized to permit a longer flow-back period.

17. *Electric Vehicle* Charging Station Pilot Program:

a. Size and Scope

i. DEF is authorized to purchase, install, own, and support *Electric Vehicle* Service Equipment (EVSE) at DEF's customers' locations.

ii. DEF may incur up to $ 8 million plus reasonable operating and maintenance expense, with a minimum deployment of 530 EVSE, with the minimum numbers distributed as set forth in the attached Exhibit 7, in relation to this EVSE program. In the event that DEF is unable to find willing host sites for a given segment, program expenditures may be shifted to other segments identified in Subparagraph 17.b., or new segments proposed by DEF, as approved in advance by the Commission.

iii. The EVSE program will be a pilot program ("Pilot") for five (5) years.

iv. For purposes of this *2017* Second Revised and Restated Settlement Agreement, Level 2 refers to EVSE technology which delivers AC power at 208 or 240 volt, and DC Fast Charging refers to EVSE technology which delivers DC power at 44kW and above.

b. Targeted market segments and EVSE technologies

i. DEF must strategically deploy EVSE as set forth [*60] in Exhibit 7 subject to the exception provided for in Subparagraph 17.a.ii. above.

ii. At least ten (1 0) percent of the *charging stations* shall be installed in low income communities, as that term is defined in *Section 288.9913*(3), F .S.

c. Electricity pricing: Where EV drivers make purchases directly from DEF when using the EVSE, said drivers will pay the appropriate Commission-approved rates/prices for energy use at the EVSE. Total prices paid by EV drivers may include nominal administrative or processing fees.

d. Accessibility & interoperability

i. Level 2 EVSE shall be network ready and able to communicate with a network management system (NMS) and use Open Charge Point Protocol (OCPP 1.6 or later).

ii. EVSE vendors must provide a certified OpenADR 2.0b Virtual End Node (VEN or Client) that can interface with an OpenADR 2.0b server to interpret signals and manage charging.

iii. DEF shall conduct a Request For Proposal process in selecting EVSE hardware and network solution providers for each segment contained in the Pilot to create a competitive process open to all EVSE vendors.

e. Consumer education: DEF [*61] shall establish dedicated program funding for market education and outreach, to be capped at five (5) percent of $ 8 million.

f. Data collection and reporting

i. For the full term of the Pilot, DEF shall collect comprehensive data related to the Pilot, including but not limited to charging station deployment by market segment (e.g., multi-family, workplace, public, etc.) and technology type (e.g., Level 2 or Direct Current Fast Charger); installation cost by segment and technology type; segment level data regarding load growth, the potential for demand response, load profiles, electricity prices paid by EV drivers, and EV charging equipment providers.

ii. DEF shall report to the Commission and Parties on an annual basis in a report which includes, but is not limited to, the data points and metrics detailed in Subparagraph 17.f.i. above.

iii. DEF shall either initiate a separate proceeding for approval of a permanent *electric vehicle* charging station offering within 4 years of the Effective Date or shall make a filing with the Commission to explain why a permanent offering is not warranted.

iv. DEF shall coordinate with transit agencies to expand awareness of Zero Emission [*62] Buses.

g. Regulatory treatment and procedure

i. DEF shall be authorized to defer the recovery of its EVSE program capital costs and operating expenses (full revenue requirements) to a regulatory asset that will earn DEF's AFUDC rate. Revenues generated through the EVSE shall offset the amount of the costs to be deferred to the regulatory asset. At the time DEF makes the filing described above in Subparagraph 17.f.iii. above, but in no event sooner than the expiration of the Term, DEF will be authorized to recover the amount of the regulatory asset over a four year period through a uniform percent increase to the customer, demand and energy base rate charges, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted.

ii. The EVSE shall be subject to a depreciation rate of 20 percent.

iii. The Parties agree that the Commission retains the ability to make a determination about the appropriate regulatory treatment for the permanent EV offering, if DEF files it, at such time as DEF initiates the separate proceeding, and there shall be no presumption of correctness in that separate proceeding regarding how this *2017* Second [*63] Revised and Restated Settlement Agreement permits the treatment of costs for purposes of the Pilot.

Economic Development and Economic Re-Development Tariffs :

18. DEF shall make permanent the pilot Economic Development and Economic Re-Development Tariffs that were initially approved by the Commission in the 2013 Settlement Agreement, and approved for another three year period in Order No. PSC-16-0423-TRF-EI (consummating Order No. PSC-16-0497-CO-EI). The permanent tariffs are part of Exhibits 3 and 4.

Other Matters:

19. DEF shall be authorized, at its discretion, to accelerate in full or in part the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, 2009 Pension Regulatory Asset, and Interest on Income Tax Deficiency over the Term of this *2017* Second Revised and Restated Settlement Agreement. DEF will be authorized to continue making a specific adjustment to its common equity balance and rate base working capital balance for the purposes of calculation of rate base and the capitalization ratios used for surveillance reporting pursuant to *Rule 25-6.1352* [*64] , F.A.C., and pass-through clauses, prior to and including the December 2018 surveillance report. DEF shall be allowed to make this adjustment for purposes of setting the rates for the GBRA increase referenced in Paragraph 14 but it shall not be used for purposes of calculating the base rate adjustments pursuant to Paragraphs 7, 12, 15, 21, 24, or 37, or any Tax Reform adjustments applicable to prospective rate adjustments made pursuant to Paragraphs 7, 12, 15, 21, 24, or 37. For clarity the last time this adjustment will be made is December 2018. The calculation of this adjustment will be based on the methodology employed by Standard and Poor's Ratings Service ("S&P") in its determination of imputed off balance sheet obligations related to future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. The amount of the adjustment to common equity and rate base will fluctuate overtime with changes in the amount of future purchase power obligations. The Original Parties agree that the common equity and rate base adjustments set forth in this Paragraph are unique to the specific circumstances of DEF, as it relates to this *2017* Second Revised [*65] and Restated Settlement Agreement, and the treatment of DEF's common equity and rate base in this Paragraph shall not constitute binding Commission precedent or create a presumption of correctness as to the adjustment for future ratemaking in any future proceeding involving DEF or any other utility. Moreover, this adjustment and the Original Parties' agreement to such adjustment in this unique proceeding shall be without prejudice to any party advocating a different position in future proceedings not involving this *2017* Second Revised and Restated Settlement Agreement. The methodology employed by SSP shall not be taken into account for purposes of calculating interim rates or determining whether DEF can seek a base rate adjustment pursuant to Paragraph 37 of this *2017* Second Revised and Restated Settlement Agreement.

20. All other cost of service and rate design issues will be determined in accordance with Exhibit 1 to this *2017* Second Revised and Restated Settlement Agreement. The level of the credits specified in Exhibit 1 will not change during the Term. DEF agrees that the level of clause-recoverable credits, including IS, CS, and GSLM-2, will not change after the expiration of [*66] the Term absent a Commission order in a general base rate proceeding or a Demand Side Management goals and plan approval proceeding. As it has done since the first billing cycle for January 2014, DEF shall continue billing the Retail CCR Clause for demand rate classes on a kilo-watt ("kW") basis rather than the previously-used kilo-watt-hour ("kWh") method.

21. Effective with the first billing cycle after this *2017* Second Revised and Restated Settlement Agreement becomes effective, DEF shall increase the monthly delivery voltage credits for distribution primary delivery level customers from $ 0.41 /KW to $ 1.19/KW and for transmission delivery level customers from $ 1.55/KW to $ 5.95/KW. The cost of the increased delivery voltage credits shall be recovered from all DEF retail customers through a uniform percent increase to the other base rate charges, including customer, demand, and energy charges This uniform percentage increase was calculated using the billing determinants included as Exhibit 2 to this *2017* Second Revised and Restated Settlement Agreement for the projected year of 2018. The delivery voltage credits shall not be further changed during the Term of this *2017* Second [*67] Revised and Restated Settlement Agreement; specifically, the delivery voltage credits shall not change when calculating the effects of any change in rates provided for in this *2017* Second Revised and Restated Settlement Agreement, including the changes provided for in Paragraphs 7, 12, 14, 15, 16, 24, and 37. To the extent Tax Reform results in a reduction to the base rate revenue requirements after the Effective Date, DEF shall consider the then-current statutory federal corporate income tax rate in the determination of the delivery voltage credit proposed in the next base rate proceeding.

22. DEF will enter into no new financial natural gas hedging contracts effective January 1, 2018, throughout the Term. DEF shall be allowed to recover the costs associated with the financial hedges it has already executed prior to the Effective Date, through the normal course of Docket No. 20170001-El and subsequent fuel clause proceedings. DEF further agrees that, during the Term of this *2017* Second Revised and Restated Settlement Agreement, it will not seek to recover costs from customers related to investments in oil and/or natural gas exploration and/or production, including but not limited [*68] to investments in fracking.

23. DEF will be allowed to defer all O&M costs incurred in the development and implementation of the new Customer Information System ("CIS") to a regulatory asset that will not accrue an AFUDC carrying cost. DEF wilt amortize the regulatory asset over fifteen (15) years beginning in 2023. The Parties will not be precluded from challenging the reasonableness and prudence of such costs in the next base rate proceeding.

24. DEF will be allowed to transfer the net book value ("NBV") of all Mobile Meter Reading ("MMR") assets and the commercial Silver Springs Network ("SSN") meters to a regulatory asset and amortize these investments, starting with the Effective Date, at the current level of depreciation until fully recovered. The new Advanced Metering Infrastructure ("AMI") assets will be permitted a depreciable life of fifteen (15) years. Upon completion of AMI meter deployment, DEF will introduce a residential Time of Use rate. In addition, effective with the first billing cycle for January 2018, DEF will be allowed to move the commercial SSN meters from recovery in the Energy Conservation Cost Recovery Clause to recovery through base rates through a uniform [*69] percent increase to the demand and energy charges for all rate classes except the IS and CS rate classes, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. This uniform percentage increase shall be calculated using the billing determinants included as Exhibit 2 to this *2017* Second Revised and Restated Settlement Agreement for the projected year of 2018.

25. Regarding the University of Florida ("UF"), if UF expresses an intent to exercise or exercises its option to require DEF to retire the UF Cogeneration Plant, DEF will be allowed to continue the current level of depreciation expense on the UF Plant until it files its next base rate proceeding and will then be allowed to recover the remaining NBV of the UF Plant over a five (5) year period as part of its base rate filing.

26. In the event that DEF is required to implement settlement accounting for Pension Benefits Expense, DEF will be permitted to defer, to a regulatory asset, the impact associated with the Generally Accepted Accounting Principles ("GAAP") required recognition of the unrealized losses and amortize that regulatory asset over a period to be determined in [*70] the next base rate proceeding.

27. DEF may implement a 50 MW battery storage pilot program ("Battery Storage Pilot") designed to enhance service for retail customers, or to enhance operations of existing or planned solar facilities. The Parties to this *2017* Second Revised and Restated Settlement Agreement will work cooperatively regarding the location of the

battery storage projects; however, DEF shall ultimately be responsible for determining the projects and locations that provide the most benefits at the time of installation. The cost to install battery storage projects pursuant to this Paragraph shall be reasonable and, on average, shall not exceed $ 2,300 per kWac. The Parties to this *2017* Second Revised and Restated Settlement Agreement agree that the Battery Storage Pilot implementation in accordance with this *2017* Second Revised and Restated Settlement Agreement (and not in violation of any law) is a prudent investment to make and provides benefits for customers. DEF may request cost recovery for the Battery Storage Pilot in its next general base rate case, and the Parties to this *2017* Second Revised and Restated Settlement Agreement agree not to contest the prudence of the [*71] decision to make the investment that complies with this *2017* Second Revised and Restated Settlement Agreement. This *2017* Second Revised and Restated Settlement Agreement does not affect the right of Parties to challenge the reasonablenesses the costs incurred for the Battery Storage Pilot.

28. DEF shall include a capacity value for solar facilities in its Ten Year Site Plan to be filed April 1, 2018. DEF agrees to consider input from SACE or any other Party in the design of the data to be collected and will share the information with SACE and any other Party requesting it prior to filing its Ten Year Site Plan.

29. DEF will be allowed to offer a Shared Solar Tariff to its customers, attached as part of Exhibit 5, which shall be approved upon approval of this *2017* Second Revised and Restated Settlement Agreement, and will become effective after the completion of programming. The tariff sheet will be filed by the Company and may be administratively approved by Commission Staff at that time. A Party's execution or approval of this *2017* Second Revised and Restated Settlement Agreement does not necessarily signify an endorsement of the Shared Solar tariff, program design, or rates,

30. [*72] DEF will be allowed to offer a FixedBill program to its residential customers, as reflected in the attached FixedBill tariff, attached as part of Exhibit 5. DEF will determine the amount of FixedBill revenues for surveillance and other regulatory purposes by multiplying the actual energy used by FixedBill participants by the otherwise applicable tariff rates. This calculated amount will be reflected in base rates and recovery clauses on a monthly basis as though these were the revenues charged to customers for their usage. The difference between the calculated amount and what customers are actually billed under FixedBill will be treated as a below the line revenue or expense, along with any costs to implement and maintain the program. This proposed regulatory treatment will hold non-participants harmless as they wili not subsidize or be subsidized by the FixedBill program. The attached FixedBill tariff shall become effective on March 1, 2018.

31. The Parties agree that DEF shall be deemed to have satisfied the requirement that periodic servicing and administration fees in excess of DEF's incremental cost of performing those functions be included in DEF's cost of service, as required [*73] by Ordering Paragraph 80 of Order No. PSC-15-0537-FOF-EI in Docket Nos. 150148-Eland 150171-EI.

32. The cost of removal regulatory asset (excluding the $ 107,469 million related to CR3) will be recovered commencing on the earlier of the Company's next filed base rate proceeding or upon the completion and approval by this Commission of the Company's next depreciation study. Any recovery period of this regulatory asset shall be no longer than the average remaining service life of the assets, approved in the Company's most recent depreciation study. DEF shall file a Depreciation Study, Fossil Dismantlement Study, Storm Reserve Study, and Nuclear Decommissioning Study (collectively the "Studies") on or before March 31, 2022, or accompanying the next base rate case, whichever occurs first. In any event, DEF shall file the Studies at least 90 days before the filing of its MFRs and testimony in connection with its next base rate case, such that all issues arising from such studies can be litigated by the Parties in the next base rate case. For clarity, the Parties agree that this Paragraph revises the reference that DEF will file a new depreciation study and dismantlement study including [*74] the Osprey Plant by March 31, 2019, included in the Commission's Order No, PSC-16-0521 -TRF-El, issued November 21, 2016 in Docket No. 160178-E, such that DEF will file these studies, and include the Osprey Plant, no later than March 31, 2022.

33. During the Term of this *2017* Second Revised and Restated Settlement Agreement DEF commits to collect data on the economic and operational benefits and costs, to the extent such benefits and costs can be reasonably identified, from the use of demand-side solar on its system to support overall rate design, which may, during the Term of this *2017* Second Revised and Restated Settlement Agreement, entail the installation of meters on the demand-side solar generation at no cost to the customer. DEF agrees to consider input from SACE or any other Party in the design of the data to be collected, and will share the information with SACE and any other Party requesting it prior to any filing that involves changes in rate design. DEF commits, during the Term of this *2017* Second Revised and Restated Settlement Agreement, to not introduce any new tariffs that impact rates on customers that use demand-side solar, or any other tariff related to distributed [*75] energy resources, absent a cost of service study approved by the Commission or a directive by the Commission. No Parties are precluded from taking a position on such a filing or proceeding.

34. DEF may not petition for an increase in base rates and charges that would take effect prior to the first billing cycle for January 2022, except for the increases in base rates and charges provided for or allowed by the terms of this *2017* Second Revised and Restated Settlement Agreement, including, without limitation, the recovery of nuclear asset-recovery charges that are being recovered on behalf of Duke Energy Florida Project Finance, LLC, pursuant to Commission Docket No. 150171-El. In addition, the Parties agree that the base rate increases or charges that, pursuant to the terms of this *2017* Second Revised and Restated Settlement Agreement extend beyond the last billing cycle for December 2021 and survive the expiration of the Term or termination of this *2017* Second Revised and Restated Settlement Agreement, specifically include, without limitation, (A) the recovery of the nuclear asset-recovery charge until the nuclear asset-recovery bonds have been paid in full and the Commission-approved [*76] financing costs have been recovered in full, and for such a period consistent with the proviso in Subparagraph 5c. of this *2017* Second Revised and Restated Settlement Agreement; (B) the potential recovery of additional funds to fund the CR3 Nuclear Decommissioning Trust pursuant to Paragraph 7 of this *2017* Second Revised and Restated Settlement Agreement; (C) the potential recovery of the CRS net book value pursuant to Paragraph 8 of this *2017* Second Revised and Restated Settlement Agreement; (D) the recovery of solar facilities brought into service beyond the Term, as provided for in Subparagraph 15,a. of this *2017* Second Revised and Restated Settlement Agreement; (E) the recovery of the DCS facility capital costs through the Capacity Cost Recovery Clause, as reflected in Subparagraph 5a. 1. of this *2017* Second Revised and Restated Settlement Agreement; (F) the potential recovery of the UF NBV pursuant to Paragraph 25 of this *2017* Second Revised and Restated Settlement Agreement; (G) the recovery of the deferred CIS OSM pursuant to Paragraph 23 of this *2017* Second Revised and Restated Settlement Agreement; and (H) the recovery of EVSE pursuant to Paragraph 17 of this *2017* Second [*77] Revised and Restated Settlement Agreement. Notwithstanding the rate relief mechanism described in Paragraph 37, DEF is prohibited from seeking or implementing an interim rate increase pursuant to *Section 366.071, F.S.*, until the expiration of the Term of this *2017* Second Revised and Restated Settlement Agreement, The Parties likewise will neither seek nor support any reduction in DEF's base rates and charges, including limited, interim, or any other rate decreases, that would take effect prior to the first billing cycle for January 2022, except for any reduction requested by DEF or as otherwise provided for in this *2017* Second Revised and Restated Settlement Agreement. Unless expressly prohibited under this *2017* Second Revised and Restated Settlement Agreement, the Commission shall not be precluded, in the Company's next base rate proceeding, from reviewing any aspect of DEF's financial condition since its last rate case (2013).

35. Notwithstanding the expiration of the Term of this *2017* Second Revised and Restated Settlement Agreement, DEF's base rate and non-DSM credit levels applied to customer bills, including the effects of the base rate [*78] adjustments as implemented pursuant to this *2017* Second Revised and Restated Settlement Agreement (i.e., uniform percent increase for all rate classes applied to base rate revenues and charges), shall continue in effect until next reset by the Commission in a general base rate proceeding.

36. No Party to this *2017* Second Revised and Restated Settlement Agreement will request, support, or seek to impose a change to any provision in this *2017* Second Revised and Restated Settlement Agreement. This *2017*

Second Revised and Restated Settlement Agreement, and the attached exhibits and schedules, represent the entire and complete agreement between the Parties. The Parties consider each provision to be integral to their respective support for the *2017* Second Revised and Restated Settlement Agreement in its entirety, and no provision may be changed or altered without the consent of each signatory Party in a written document duly executed by all Parties to this *2017* Second Revised and Restated Settlement Agreement. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this *2017* Second Revised and Restated Settlement Agreement, the Parties agree [*79] to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution. Florida law will govern all terms, conditions, and provisions of this *2017* Second Revised and Restated Settlement Agreement, including, but not limited to, any disputes arising from this *2017* Second Revised and Restated Settlement Agreement.

37. If DEF's retail base rate earnings fall below a 9.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly earnings surveillance report during the Term of this *2017* Second Revised and Restated Settlement Agreement, DEF may petition the Commission to amend its base rates during the Term of this *2017* Second Revised and Restated Settlement Agreement. Such request by the Company shall be limited to an increase that would achieve a 10.5% ROE. No Party waives its right to participate in such a proceeding, and such participation will only be limited by the terms of this *2017* Second Revised and Restated Settlement Agreement. If DEF's retail base rate earnings exceed an 11.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly [*80] earnings surveillance report during the Term of the *2017* Second Revised and Restated Settlement Agreement, any Intervenor Party shall be entitled to petition the Commission for a review of DEF's base rates and charges. The Parties to this *2017* Second Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. This Paragraph shall not be construed to bar or limit DEF from any recovery of costs otherwise contemplated by this *2017* Second Revised and Restated Settlement Agreement, and all other provisions of this *2017* Second Revised and Restated Settlement Agreement shall remain in force and effect.

38. Nothing shall preclude the Company from requesting the Commission to approve the recovery of the following types of costs:

a. Costs that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or

b. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 12.d., DEF shall not seek to recover, nor shall DEF be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery [*81] clauses and charges, costs of any type or category that have historically and traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements: (ii) new or atypical costs that were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting DEF's operations; or (iii) costs that would otherwise be recoverable through base rates that the Florida Legislature has expressly authorized as clause recoverable by public utilities, as that term is defined in *Section 366.02(2), F.S.*

c. With respect to storm damage costs caused by a tropical system named by the National Hurricane Center or its successor, nothing in this *2017* Second Revised and Restated Settlement Agreement shall preclude DEF from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The Parties agree that recovery from customers for storm damage costs will begin, subject [*82] to Commission approval on an interim basis, sixty (60) days following the filing of a cost recovery petition with the Commission, and subject to true-up pursuant to further proceedings before the Commission, and will be based on a 12-month recovery period. All storm-related costs shall be calculated and disposed of pursuant to Commission *Rule 25-6.0143*, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, an estimate of incremental costs above the levei of storm reserve prior to the storm event, and replenishment of the storm reserve to the level as of the Implementation Date of the 2012 Settlement Agreement (as the term "Implementation Date" is defined in the 2012 Settlement Agreement) or approximately $ 132 million (retail) . The Parties to this *2017* Second Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations [*83] of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

39. The provisions of this *2017* Second Revised and Restated Settlement Agreement are contingent on approval of this *2017* Second Revised and Restated Settlement Agreement in its entirety by the Commission The Parties further agree that this *2017* Second Revised and Restated Settlement Agreement is in the public interest, and that they will support this *2017* Second Revised and Restated Settlement Agreement and will not request or support any order, relief, outcome, or result in express conflict with the terms of this *2017* Second Revised and Restated Settlement Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this *2017* Second Revised and Restated Settlement Agreement or the subject matter hereof. No Party will assert in any proceeding before the Commission that this *2017* Second Revised and Restated Settlement Agreement or any of the terms in the *2017* Second Revised and Restated Settlement Agreement shall have any precedential value. The Parties' agreement to the [*84] terms in the *2017* Second Revised and Restated Settlement Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving the *2017* Second Revised and Restated Settlement Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in a future proceeding nor shall any Party represent in any future forum that another Party endorses a specific provision of this *2017* Second Revised and Restated Settlement Agreement because of that Party's signature herein. It is the intent of the Parties to this *2017* Second Revised and Restated Settlement Agreement that the Commission's approval of all the terms and provisions of this *2017* Second Revised and Restated Settlement Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this *2017* Second Revised and Restated Settlement Agreement endorses a specific provision, in isolation, of this *2017* Second Revised and Restated Settlement Agreement because of that Party's signature herein.

40. All dollar values, [*85] asset determinations, rate impact values, or revenue requirements in this *2017* Second Revised and Restated Settlement Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

41. This *2017* Second Revised and Restated Settlement Agreement dated as of August 29, *2017* may be executed in counterpart originals, and a facsimile or PDF email of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this *2017* Second Revised and Restated Settlement Agreement by their signatures below.

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Re Regarding Electric Vehicle Supply Equipment and Infrastructure

New York Public Service Commission

February 7, 2019

Case 18-E-0138

NY Public Utilities Reports

Re Regarding Electric Vehicle Supply Equipment and Infrastructure

Core Terms

station, plug, customer, electric, infrastructure, deployment, per-plug, maximum, eligible, grid, energy, load, delivery, annual, incentive program, ratepayer, tariff, clean, technology, recommend, charger, interim, fleet, modify, peak, discount, network, standby, site, classification

Panel: Before Rhodes, chairman, and Sayre, Burman and Alesi, commissioners.

Opinion By: BY THE COMMISSION

Opinion

INTRODUCTION

On April 13, 2018, a "Joint Petition" was filed by the New York Power Authority (NYPA), New York State Department of Environmental Conservation (DEC), New York State Department of Transportation (DOT), and the New York State Thruway Authority (NYSTA) (collectively, Joint Petitioners), seeking rate relief to encourage the Statewide deployment of Direct Current Fast Charging (DCFC) facilities for electric vehicles (EVs). In particular, the Joint Petition requested that the Public Service Commission (Commission) direct investor-owned electric utilities (IOUs) to modify their tariffs such that DCFC customers would: i) qualify for service under a non-demand-billed service classification; ii) be exempt from any kilowatt (kW) or kilowatt hour (kWh) limit that would jeopardize their entitlement to take non-demand billed service; and, iii) be provided a one-time opportunity to elect to take service under the applicable demand-metered service classification.

On April 24, 2018, the Commission commenced this proceeding to consider various EV-related issues, such as those raised in the Joint Petition, as well as the role of the IOUs in providing infrastructure and rate design to accommodate the needs and electricity demand of EVs and electric vehicle supply equipment. [1] The Commission also directed Department of Public Service (Staff) to convene a technical conference to consider various topics. [2]

On July 18-19, 2018, Staff hosted a technical conference, in collaboration with the New York State Energy Research and Development Authority (NYSERDA), to solicit stakeholder input, identify issues to be addressed, and establish the scope of a subsequent Staff whitepaper. [3]

On August 16, 2018, the Secretary to the Commission issued a notice seeking post-technical conference comments and announcing a subsequent working group to address rate design principles to be applied to electric vehicle charging stations. [4] These discussions led to a subsequent stakeholder engagement process, which was led by NYPA and Consolidated Edison Company of New York, Inc. (Con Edison), and resulted in the development of a "Consensus Proposal" among several entities. On November 21, 2018, the Consensus Proposal was filed by Con Edison, Central Hudson Gas & Electric Corporation (Central Hudson), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), Rochester Gas & Electric Corporation (RG&E), NYPA, DEC, DOT, NYSERDA, and NYSTA (collectively, the Consensus Parties). The Consensus Proposal seeks to encourage Statewide deployment of new, publicly accessible DCFC Facilities by implementing an annual declining per-plug incentive program. The incentives, as proposed, would be available for each IOU to address the short-term economic challenges of installing publicly available and affordable DCFC stations, due to the nascent EV market in New York.

By this order, the Commission adopts the Consensus Proposal, with modifications, as discussed below. The Commission finds that the per-plug incentive programs developed by each utility are appropriately sized to encourage DCFC station development in a cost-effective manner. By directing an interim review process, the Commission will ensure that the deployment goals of these programs are met with the most efficient use of ratepayer funds, while providing the right system benefits in the most beneficial locations of the distribution grid, and in a manner best suited to accelerate market-based deployment. The DCFC facility deployments spurred by these incentives will help to achieve the State's Zero-Emission Vehicle (ZEV) goals, [5] and advance the State Energy Plan's targets of reducing greenhouse gas (GHG) emissions 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. [6]

BACKGROUND

The Joint Petition indicated that strategic deployments of DCFC facilities are key to reaching the State's ZEV goals. As the Joint Petitioners explained, slower-charging elements are developing in New York, but the pace of public DCFC station development has been inadequate. The Joint Petitioners stated that DCFC stations, going forward, will typically be rated at 50 kW or higher, and take service under a rate with both demand and energy charges. According to the Joint Petitioners, during this period of early adoption of EVs and low utilization of DCFC

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[1] Case 18-E-0138, Order Instituting Proceeding (issued April 24, 2018).

[2] *Id.*, pp. 4-5.

[3] Case 18-E-0138, Notice of Technical Conference (issued May 25, 2018).

[4] Case 18-E-0138, Notice of Working Group Meeting and Request for Post-Conference Comments (issued August 16, 2018).

[5] On October 24, 2013, Governor Cuomo entered into a Memorandum of Understanding with the Governors of California, Connecticut, Maryland, Massachusetts, Oregon, Rhode Island, and Vermont agreeing to coordinate and collaborate to promote effective and efficient implementation of ZEV regulations. The Memorandum of Understanding (MOU) is available at: *dec.ny.gov/docs/air_pdf/zevmou.pdf*

[6] Case 14-M-0094, *Clean Energy Fund*, Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016).

stations, demand charges impose a disproportionate cost on station operation and render any DCFC station business model infeasible.

As State agencies and authorities that share an interest in encouraging EV adoption and deployment, the Joint Petitioners requested that the Commission pursue a two-part strategy to address rates that unduly restrain DCFC deployment. Under the first part, the Joint Petitioners requested that the Commission direct each IOU to immediately modify their Service Classification 2 (SC-2) or Small-General non-demand-metered tariffs so that DCFC station customers: a) qualify for a non-demand-metered service classification; b) are exempt from any kW or kWh limit that would jeopardize their entitlement to take service under that tariff; and, c) have a one-time opportunity to elect to take service under the applicable demand-metered service classification. The Joint Petitioners explained that, by accommodating DCFC customers under a service classification without a demand charge, the economic viability markedly improves in this period of low utilization. Moreover, the Joint Petitioners stated, this immediate relief would constitute a timely recognition of the essential role that public DCFC stations play in alleviating concerns over EV range and supporting the larger public policy goal of rapidly increasing EV adoption.

As part of the second part of the strategy, the Joint Petitioners requested that the Commission address broader EV implementation plans and establish principles to guide IOUs in redesigning rates applicable to DCFC accounts in a newly-commenced proceeding. Joint Petitioners explained that, by granting both elements of relief, the Commission would enable the State to reach its ZEV deployment, environmental, and system planning objectives, while avoiding unduly burdening electric ratepayers.

According to the Joint Petitioners, a substantial increase in EVs can increase utility and system load factors and utilization of utility infrastructure, which can in turn increase utility revenue, and ultimately reduce rates for non-participating customers. The Joint Petitioners explained that several studies in utility service territories across the United States show that increased EV charging will grow the number of megawatt hours (MWh) that flow through the electric grid and contribute towards the costs to operate and maintain the transmission and distribution system, allowing for the reduction in rates for all ratepayers. Furthermore, the Joint Petitioners cited a study by M.J. Bradley & Associates estimating that, if New York's ZEV Mandate goals are achieved, the net present value (NPV) of annual utility net revenues would exceed the incremental costs to serve the EVs. According to the Joint Petitioners, increased EV adoption, made possible by increased penetration of DCFC facilities from eliminating demand charges, should yield net positive value of $ 109 to $ 175 million due to the increased demand and throughput in 2025 alone.

The Joint Petitioners argued that a significant concern for potential EV buyers is "range anxiety," which may be alleviated by strategic deployment of DCFC stations. Deploying DCFC capabilities would address actual range issues, as well as the perception that range is a problem for EVs, by being highly visible infrastructure, according to the Joint Petitioners. Further, the Joint Petitioners stated that there are presently only 78 DCFC plugs at 44 stations that are publicly available to all EV drivers, while New York will need approximately 1,500 total DCFC plugs to support the ZEV goals.

As discussed in the Joint Petition, operation and maintenance costs for DCFC stations include charges for electricity, software subscriptions, station management, billing, and preventative and corrective maintenance. However, according to the Joint Petitioners, the amount of electricity usage and the applicable electric tariff is the primary driver. The Joint Petitioners elaborated that when DCFC station utilization rates are very low, demand charges can account for 80 percent to 90 percent of a station's monthly electric bill. Because of this, the Joint Petitioners asserted that the NPV of a DCFC in New York is negative under many utilization levels, and that this discourages DCFC investment, particularly at this early stage of EV market development.

The Joint Petitioners further argued that rates applicable to DCFC stations are not cost-based because of the unique load profile and the currently limited costs these facilities impose on the electric system. Analogizing to customers with on-site generation taking service under standby rates, the Joint Petitioners suggested that the Commission recognize the low load factors of DCFC stations and change cost allocations.

As stated in the Joint Petition, shifting to a service class without a demand rate would likely incent DCFC facility development Statewide, except that in Con Edison's service territory an additional incentive would be required. In order to incent DCFC development in Con Edison's service territory, the Joint Petitioners suggested that the Commission authorize Con Edison to redirect its Business Incentive Rate (BIR) as a further discount on the SC-2 or Small General non-demand rate proposed for DCFC stations.

Reiterating their second request for relief, the Joint Petitioners suggested that a generic proceeding would enable the Commission and stakeholders to remedy the rate issues caused by DCFC facilities. Specifically, they suggested moving a substantial amount of revenue collection for shared distribution and transmission infrastructure from monthly demand charges to kWh charges. The Joint Petitioners suggested that rates to recover the costs of facilities far upstream from a customer, such as distribution substations and transmission lines shared by many customers, should be structured to enable a substantial portion of their cost recovery through kWh charges instead of through existing demand charges.

Finally, the Joint Petitioners asserted that utilities should be required to implement long-term DCFC rate plans to provide relative certainty regarding future demand charge operation costs for DCFC stations. In addition to stand-alone EV tariffs to make DCFC stations viable, the Joint Petitioners suggested that the Commission's generic proceeding could also consider medium and heavy-duty electric vehicle issues.

THE CONSENSUS PROPOSAL

The Consensus Parties state that their proposal would be implemented differently for each IOU, and is designed based on two principles. First, that DCFC stations should receive service under the appropriate, demand-metered, service classification. Second, that utility-specific programs should provide limited term cost relief and be designed with an appropriate size and scope to encourage the development of DCFC infrastructure, consistent with state ZEV goals.

According to the Consensus Parties, the Consensus Proposal would: 1) provide an annual declining per plug incentive to qualifying DCFC station operators for approximately seven years (i.e., 2019 --- 2025); 2) require service to be provided under a demand-metered classification; 3) pay the incentive on a per-plug basis for each plug with simultaneous charging capability of at least 50 kW; and, 4) provide a higher incentive for plugs capable of simultaneously charging at 75 kW and above, in order to provide a greater incentive to install plugs with faster charging capability. Further, the total number of plugs across all utility service territories that may receive an incentive would be limited to 1,074, and the maximum potential cost of the per plug incentives over the proposed seven-year term of the program would be approximately $ 28 million. The Consensus Parties request that the IOUs be authorized to recover the costs of this program with interest, including applicable incremental administrative costs.

The Consensus Proposal identifies common program parameters amongst the IOUs, including: 1) applicability to only new DCFC facilities that are publicly accessible (i.e., without site-specific physical access restrictions such as radio-frequency identification, security badge, or otherwise limited access); 2) eligibility and incentive levels based on when a service application is submitted; 3) the provision of incentive payments when the plugs are energized; 4) incentives that are available on a first-come basis; 5) qualifying plugs that must be capable of charging at 50 kW or more; and, 6) higher incentives for plugs rated at 75 kW or greater.

Further, the Consensus Parties state that each IOU would file an annual report with the Commission 60 days following the end of each calendar year providing the annual number of DCFC stations installed and the amount of incentive paid. The IOUs would also collectively develop a website, to be updated monthly, showing the remaining incentives available. Finally, the Consensus Proposal contains many IOU-specific program details, which are described below.

Central Hudson

Central Hudson proposes to provide an incentive for a maximum of 100 plugs, limited to 34 plugs in the first year, 68 plugs in year two, and 100 plugs in the following years. Central Hudson would conduct a study to determine the magnitude of any necessary system upgrades after an application is received. Customers would have 60 days to remit payment of their Contribution in Aid of Construction (CIAC), if required. Systems would be required to become energized within one year of a customer remitting a CIAC payment, or if no CIAC payment is required, within one year of such notification by the utility. Additionally, to limit and/or avoid infrastructure constraints and/or system reliability impacts, Central Hudson proposes that the siting of DCFC stations be subject to its approval.

The starting incentive proposed would be $ 11,000 per plug for plugs rated at 75 kW or greater, regardless of the year of participation, and would decline ratably over a maximum payment period of five years. The incentive for plugs rated between 50 kW and 75 kW would be 60 percent of what is paid to plugs rated at 75 kW and above. Incentive payments will be made 30 days following each successive twelve months of operation. If fully subscribed, Central Hudson states that the total cost of its proposal over the seven-year program period would be $ 3.3 million.

The utility proposes to recover program costs from ratepayers through its Revenue Decoupling Mechanism (RDM), although it proposes to initially defer a portion of the costs and reverse the deferral in later years of the program. Central Hudson notes that its proposal would require that customers participating in the program be excluded from its RDM targets in future rate proceedings until the program concludes.

Con Edison

Con Edison proposes to offer per plug and load factor incentives, designed to operate in conjunction with the current EV Quick Charging Station Program delivery rate reduction offered under its BIR. A customer would be required to meet the eligibility criteria of the EV Quick Charging Station Program component of the BIR to participate in the per plug incentive program. [7] NYPA or its customers seeking to participate in the BIR would be required to establish a Con Edison account in order to be eligible for the BIR EV direct current fast charging station program.

Con Edison proposes that customers be eligible to enroll in the per plug incentive program until 400 plugs are subscribed, or through December 31, 2025, whichever is earlier. Similarly, customers can enroll in the EV Quick Charging Station Program component of the BIR until December 31, 2025, or until a 30 MW cap on participation is reached. If cap limits are met for one program, customers may participate in the other program, if not fully subscribed and if the customer meets the eligibility criteria. In addition, customers would be allocated space in the program for a period of one year from the later of the date that the customer provides proof of a building permit or, if applicable, payment of an excess distribution facilities charge.

The Con Edison incentive is proposed to start at $ 4,000 per plug for plugs with simultaneous charging capability rated at 75 kW or greater, regardless of year of participation, and declines ratably, over a maximum payment period

[7] ***Con Edison*** proposes substantive changes to the Electric Vehicle Quick Charging Station Program component of BIR, including: 1) elimination of the government incentive requirement; 2) permitting government participation; and, 3) extending, to December 31, 2025, the date for delivery rate reductions from the current date of April 30, 2025.

of seven years. [8] The incentive for plugs rated between 50 kW and 75 kW is proposed to be 60 percent of that paid to plugs rated at 75 kW and above. Additionally, the Con Edison program includes bonus incentives of $ 500 and $ 1,500 per site for achieving a load factor of 5 percent and 10 percent, respectively.

Con Edison proposes that per-plug and load factor incentive payments would be made 60 days following each successive twelve-month period of operation. If fully subscribed, Con Edison states that the estimated maximum annual program costs of the per-plug incentive over the seven-year program period would be $ 6.4 million. This estimate does not include the load factor incentive. Con Edison proposes that program costs be deferred for future recovery.

NYSEG

NYSEG proposes to provide an incentive for a maximum of 160 plugs for up to seven years, depending on the year a customer qualifies for an incentive. Per its proposal, NYSEG will conduct a study to determine the magnitude of any necessary system upgrades after an application is received. Customers would have 60 days to remit payment of their CIAC payment, if required. Systems would be required to become energized within one year of a customer remitting a CIAC payment, or if no CIAC payment is required, within one year of such notification by the utility.

The proposed incentive for 2019 is $ 8,000 per plug for plugs rated at 75 kW or greater, and declines ratably over the seven-year program term, or by $ 2,286 per year. The year in which a customer qualifies for an incentive through a completed application would determine the program year incentive level for which that customer is eligible. The incentive for plugs rated between 50 kW and 75 kW is proposed to be 60 percent of that paid to plugs rated at 75 kW and above. If fully subscribed, NYSEG states that the total maximum cost of its proposal over the seven-year program period would be $ 5.12 million. The utility proposes to recover program costs through a class-specific non-by-passable charge (NBC).

Per the utility's proposal, participants would be paid up to the maximum annual per plug incentive. However, such payments will not exceed the total delivery costs for the twelve-month billing period in which the incentive is calculated. The difference between the maximum allowable incentive and the actual incentive payment would be added to the maximum allowable incentive for the following year, through 2022. However, from 2021 to 2022, the roll over will be limited to $ 6,000. No roll over would be allowed after 2022. Finally, NYSEG proposes to require that the DCFC stations be separately metered and that ancillary station load shall not exceed 10 kW.

National Grid

National Grid proposes to provide an incentive for a maximum of 300 plugs, with yearly limitations in the first three years of the program of 100 plugs in 2019, 200 plugs in 2020, and 300 plugs in years three through seven. National Grid, per its proposal, would conduct a study to determine the magnitude of any necessary system upgrades after an application is received and customers would have 60 days to remit CIAC payment, if required. Systems would be required to become energized within one year of a customer remitting a CIAC payment, and thereafter they could be removed from the program, subject to National Grid's discretion.

The 2019 incentive proposed is $ 7,500 per plug for plugs with simultaneous charging capability rated at 75 kW or greater, and declines ratably each year by $ 2,143, notwithstanding the year in which a customer begins to receive an incentive. The incentive for plugs with simultaneous charging capability rated between 50 kW and 75

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[8] ***Con Edison*** notes that the per plug incentives are designed to provide a combined benefit in conjunction with the delivery rate reductions offered under the BIR. If the BIR delivery rate reductions change during the program, ***Con Edison*** proposes that the per plug incentive be re-determined to maintain the combined value of the programs.

kW is proposed to be 60 percent of that paid to plugs rated at 75 kW and above. If fully subscribed, National Grid states that the total maximum cost of its proposal over the seven-year program period would be approximately $ 6.9 million. National Grid proposes to issue the annual incentive to eligible plugs in the first quarter of the subsequent calendar year.

In addition, National Grid proposes to recover program costs through a combination of its RDM and a deferral. National Grid would adjust the delivery revenues in its RDM reconciliation by subtracting the total incentives paid during the annual period of the RDM reconciliation, up to the total delivery charges incurred by participating customers' charging stations during the same year. National Grid notes that this provision would require a revision to its tariff. Any incentive payments above this amount would be deferred for future recovery from all customers. Additionally, National Grid proposes to defer the costs associated with any full-time employees or contractor added to administer the program; such deferred costs would be recovered in the future from all customers.

O&R

O&R's proposal is substantially similar to Con Edison's. O&R proposes to offer per plug and load factor incentives designed to operate in conjunction with a delivery rate reduction that would be offered to EV Quick Charging Stations under a newly-proposed component of its Economic Development Rider (EDR).

As part of the Consensus Proposal, O&R proposes to modify its EDR by creating an EV Quick Charging Station Program component to allow demand-billed participants that construct and own a publicly accessible charging station, with a minimum 65 kW of aggregate charging capacity, to receive a 20 percent delivery rate discount. O&R would allow up to 3 MW of aggregate electric vehicle charging load under the EV Quick Charging Station Program. The delivery rate discount would be available through December 31, 2025. Under the program, electric loads not associated with quick charging infrastructure would be limited to 10 kW per account. O&R proposes that, to be eligible for participation in the per plug incentive program, a customer must meet the eligibility criteria of the EV Quick Charging Station Program component of its EDR.

As proposed, customers would be eligible to enroll in the per plug incentive program through December 31, 2025, or until 40 plugs are subscribed, whichever is earlier. Similarly, customers could enroll in the EV Quick Charging Station Program component of the EDR until December 31, 2025, or until the 3 MW cap on participation is reached. If cap limits are met for one program, customers could participate in the other program, if not fully subscribed. Per O&R's proposal, customers would be allocated space in the program for a period that is the later of one year from the date that the customer provides proof of a building permit or, if applicable, one year from the date of payment of an excess distribution facilities charge.

The starting incentive proposed is $ 8,000 per plug for plugs with simultaneous charging capability rated at 75 kW or greater, regardless of year of participation, and declines ratably, over a maximum payment period of seven years. [9] The incentive for plugs with simultaneous charging capability rated between 50 kW and 75 kW is proposed to be 60 percent of that paid to plugs rated at 75 kW and above. Additionally, bonus incentives of $ 500 and $ 1,500 are proposed per site for achieving a load factor of 5 percent and 10 percent, respectively.

O&R proposes that the per-plug and load factor incentive payments be made 60 days following each successive twelve months of operation. If fully subscribed, O&R states that the maximum cost of the per-plug incentive over the seven-year program period would be $ 1.28 million, excluding the load factor incentive. The utility proposes

[9] O&R notes that the per plug incentives are designed to provide a combined benefit in conjunction with the delivery rate reductions offered under the EDR. If the EDR delivery rate reductions change during the program, O&R proposes that the per plug incentive be re-determined to maintain the combined value of the programs.

that program costs be recovered volumetrically, across all service classifications, through its Energy Charge Adjustment surcharge.

RG&E

RG&E's proposal is substantially similar to NYSEG's. RG&E proposes to provide an incentive for a maximum of 74 plugs and for up to seven years, depending on the year a customer qualifies for an incentive. Per its proposal, RG&E would conduct a study to determine the magnitude of any necessary system upgrades after an application is received, and customers would have 60 days to remit payment of their CIAC payment, if required. Systems would be required to be energized within one year of a customer remitting a CIAC payment, and thereafter could be removed from the program, subject to the discretion of RG&E.

The 2019 incentive proposed is $ 17,000 per plug for plugs with simultaneous charging capability rated at 75 kW or greater and declines ratably each year, or by $ 4,857, notwithstanding the year in which a customer begins to receive an incentive. The incentive for plugs with simultaneous charging capability rated between 50 kW and 75 kW is proposed to be 60 percent of that paid to plugs rated at 75 kW and above. If fully subscribed, RG&E states that the total maximum cost of its proposal over the seven-year program period is $ 5.032 million. The utility proposes to recover program costs through a class-specific NBC.

Per the utility's proposal, it would pay up to the maximum annual per plug incentive. However, such payments would not exceed the total delivery costs for the twelve-month billing period in which the incentive is calculated. The difference between the maximum allowable incentive and the actual incentive payment would be added to the maximum allowable incentive for the following year, through 2022. From 2021 to 2022, however, the roll-over would be limited to $ 12,750. No roll over would be allowed after 2022. Lastly, RG&E proposes that DCFC stations would be required to be separately metered and that ancillary load could not exceed 10 kW.

PUBLIC NOTICE

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) regarding the Joint Petition was published in the State Register on May 23, 2018 [SAPA No. 18-E-0138SP1]. The time for submission of comments pursuant to the Notice expired on July 23, 2018. Comments regarding the Joint Petition were received from nineteen parties. A Secretary's Notice Soliciting Comments regarding the Consensus Proposal was issued on November 23, 2018, requesting public comment by December 14, 2018. Comments regarding the Consensus Proposal were received from nineteen different parties.

LEGAL AUTHORITY

Pursuant to Public Service Law (PSL) §§5, 65, and 66, the Commission has the legal authority to take the actions prescribed in this order. The Commission has authority to direct utilities to formulate and carry out long-range programs, individually or cooperatively, with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources. Furthermore, the Commission has broad discretion and judgment in choosing the means of achieving statutory mandates, and has the authority to adopt different methodologies or combinations of methodologies in balancing ratepayer and investor interests. [10]

Pursuant to PSL §65, the Commission has authority to ensure that "every electric corporation and every municipality shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable." The Commission also has authority to prescribe the "safe, efficient and adequate property, equipment and appliances thereafter to be used, maintained and operated for the security and

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10 *Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).*

accommodation of the public" whenever the Commission determines that the utility's existing equipment is "unsafe, inefficient or inadequate." [11]

SUMMARY OF COMMENTS

Joint Petition

Comments regarding the Joint Petition were received from National Fuel Distribution Corporation (NFG); Advanced Energy Economy Institute (AEE Institute); EVgo; Tesla, Inc. (Tesla); the City of New York (the City); jointly by the Sierra Club and the Natural Resources Defense Council (NRDC); NYPA; PSEG Long Island; the Acadia Center (Acadia Center); Greenlots; ChargePoint, Inc. (ChargePoint); jointly by Central Hudson, Con Edison, NYSEG, National Grid, O&R and RG&E (collectively, the Joint Utilities); Electric Vehicle Charging Association (EVCA); General Motors (GM); EV Box North America Inc. (EVBox); Plug In America; Ford Motor Company (Ford); Lovely A. Warren, Mayor of the City of Rochester (the City of Rochester); Kevin J. Helfer, Parking Commissioner of the City of Buffalo (the City of Buffalo); and several individuals.

NFG filed a letter on April 18, 2018 and additional comments on July 20, 2018. According to NFG, the scope of this proceeding is inconsistent with fuel and resource diversity and should consider the environmental benefits of the enhanced use of natural gas vehicles (NGVs). Alternatively, NFG suggests that the Commission institute a proceeding that addresses all aspects of the transportation sector. Furthermore, NFG recommends using on-site natural-gas fired combined heat and power (CHP) to generate electricity at charging stations to alleviate rate, reliability, and infrastructure upgrade concerns.

AEE Institute almost fully supports the Joint Petition, with the additional recommendation that the Commission distinguish between DCFC-dedicated retail accounts and those DCFC accounts where the charging station's demand is coupled with the premises' overall demand (behind-the-meter applications).

EVgo supports the Joint Petition, stating that fast charging is key to widespread EV adoption and existing rate structures are the largest cost barrier to EV infrastructure deployment. Additionally, EVgo requests that the Commission consider the Joint Petition on a faster track than the generic proceeding.

Tesla identifies demand charges as a significant barrier to DCFC deployment and supports the Joint Petition. Tesla recommends the demand charge holiday model approved for Southern California Edison as the optimal path forward. Furthermore, Tesla asserts that increased EV adoption will lead to higher system utilization during off-peak hours, thereby increasing revenue to the utility and benefitting all ratepayers. Finally, Tesla recommends that the DCFC rate should be technology agnostic, available to new and existing stations, include manageable eligibility requirements, and be available to fleet and heavy-duty charging.

The City recognizes that as EV adoption increases and DCFC station utilization increases, non-demand-metered rates may no longer be appropriate. Nonetheless, the City recommends that the Commission adopt the Joint Petition and direct Con Edison to 1) modify its non-demand-metered rates to accommodate DCFC stations, and 2) expand Con Edison's BIR discount program to include DCFC facilities.

The Sierra Club and NRDC support the Joint Petition's near-term strategy to mitigate the impact of demand charges and the request for a generic proceeding to consider long-term principles. The Sierra Club and NRDC argue that existing demand charges fail to send a relevant price signal to encourage off-peak charging and do little to mitigate the impacts of peak load.

[11] PSL §66(5).

NYPA offers additional support for the Joint Petition and suggests that the Commission take a holistic view of the contributions EV drivers provide to the system costs when considering the requested change. Stating that the Commission should adopt its proposal, NYPA reiterates the merits of the near-term rate solution for DCFC facilities and suggests that the Commission study the load from existing stations in New York with any other public DCFC facility data to develop a long-term rate that reflects the impact DCFC stations have to the electric system.

PSEG Long Island supports the goal of adopting efficient rate designs and IOU programs to encourage EV adoption, and the Joint Petitioners' request for a generic proceeding. PSEG Long Island explains the set point incentive it developed to provide a monthly off-tariff rebate to the DCFC customers that effectively caps the delivery and power supply portions of the electric bill at a predetermined dollar per kilowatt hour set point, while keeping the DCFC customers on a standard commercial rate that includes demand charges. PSEG Long Island advises that transitioning all DCFC stations to SC-2 rates may set an unreasonable market expectation that energy-only rates are appropriate permanently, and make it difficult for the utilities to return DCFC customers to demand-based rates when incentives are no longer justified.

The Joint Utilities support addressing DCFC station deployment challenges, and state that a broader policy discussion is needed so that key considerations are not missed. The Joint Utilities recognize that the cost of electricity service is a significant component of the overall economics of a DCFC facility, and that action is needed to incentivize this infrastructure development.

The Joint Utilities suggest that a NYSERDA incentive may be appropriate to subsidize up-front costs, and that up-front interconnection costs may be reduced through utility make-ready programs. Eliminating demand charges entirely will remove the price signals needed to encourage DCFC owners to manage their impact on the electricity system, according to the Joint Utilities. Contrary to the Joint Petition's arguments, the Joint Utilities maintain that DCFC facilities will likely impact coincident and non-coincident demands in ways that will be additive at upstream facilities and impact system peaks. The Joint Utilities reiterate that any solution should preserve demand charges, as they are the mechanism to influence behavior in a way that reduces system impacts, and eliminating them may create a situation akin to net energy metering.

Additionally, the Joint Utilities suggest that DCFC issues may be addressed without conflicting with established rate design principles and in a complementary manner with ongoing initiatives, such as using a battery-based energy storage resource to manage demand charges. The Joint Utilities point out that a variety of funding sources are available to address the economics of DCFC stations, and in particular recommend that NYSERDA funds already collected on utility customer bills through surcharges could be used to provide transparent levels of support needed to satisfy DCFC station requirements.

The Acadia Center supports the Joint Petition's request to allow customers deploying DCFC stations to receive service on non-demand-metered tariffs in the short term, and recommends that the Commission examine an appropriate cost-based DCFC rate design in the long-term. Furthermore, the Acadia Center indicates that state regulations must be reformed to integrate new electric end use technologies as a resource capable of optimizing the electric system, and revenue mechanisms must be identified to fund appropriate infrastructure. Demand charges are a major impediment to DCFC deployment, according to the Acadia Center, and DCFC station visibility and availability are crucial to long-distance travel.

Greenlots encourages the Commission to explore potential near-term options for mitigating current costs associated with low utilization demand charges for successful ownership and management of DCFC infrastructure. Greenlots argues that the discussion has largely failed to adequately acknowledge available technology options to minimize or mitigate costs associated with demand charges. Greenlots points out that demand rates are also more attractive to DCFC infrastructure owners than volumetric rates at a certain level of utilization.

ChargePoint supports the Joint Petition's recommended near-term relief to DCFC site hosts and suggests that the Commission continue to address long-term issues. As an alternative to the demand charge relief, ChargePoint recommends that the Commission consider a variety of alternative rate design options. ChargePoint points out that the next generation of fast chargers, such as ChargePoint's Express Plus product line capable of charging vehicles up to 500 kW, will exacerbate DCFC issues, but are necessary to meet the needs of an evolving market.

EVCA encourages swift Commission action in support of the Joint Petition. According to EVCA, current utility tariffs are not designed with DCFC in mind and present significant barriers to investment.

GM explains that a network of DCFC stations is critical to growing the EV market and meeting state policy goals. Furthermore, GM states that this network is the key to attracting investment in increasingly advanced mobility services that will be built on EV technology, such as autonomous vehicle applications. GM supports the Joint Petition.

EVBox supports the Joint Petition but argues that a future proceeding should include all commercial and residential rates for EV users and not just be confined to DCFC facilities. EVBox suggests that the Commission immediately grant the Joint Petition's requests for relief, and explore alternative rate structures consistent with the modern principles of rate design.

Plug In America supports the Joint Petition, and suggests that demand charges may not be appropriate even when utilization increases. According to Plug In America, time-varying rates will be a better means of addressing system impacts than kW-based demand charges because the DCFC station peak demand may not align with the system peak and non-coincident peak demand does not impose as many costs on the grid.

The City of Buffalo strongly supports tariff revisions to reduce or eliminate the demand charges and encourages development of a broad statewide program to deploy this critical element of infrastructure needed. The City of Buffalo notes that it currently lacks any Level 3 charging options, but would like to continue the momentum gained from leveraging funds from Governor Cuomo and the DEC's ZEV Infrastructure Rebate program to build 16 charging stations with 32 ports in its downtown area.

The City of Rochester is actively engaged in promoting EVs and EV charging infrastructure, and strongly supports tariff revisions to reduce or eliminate DCFC station demand charges and encourages development of a broad statewide program. According to the City of Rochester, even with programs providing assistance with equipment and installation costs, demand charges far exceed the potential revenue stream from DCFC station utilization.

Ford fully supports the Joint Petition to provide immediate rate relief and future rate structure design guidelines for DCFC networks. Ford explains that in order to achieve mass EV adoption, substantial charging infrastructure challenges must be overcome. Among these challenges, Ford says, a highly visible public DCFC network is a necessary enabler for customers to overcome range anxiety and for long-distance travel.

Consensus Proposal

Comments regarding the Consensus Proposal were received from the Alliance for Transportation Electrification (ATE); Multiple Intervenors (MI); Natural Gas Vehicles for America (NGV America); jointly by the Utilities Workers Union of America, Local 1-2, and International Brotherhood of Electrical Workers, Local Unions 10 & 97 (collectively, the Local Unions); NYPA; Joint Utilities; the City; NFG; CALSTART; jointly by NRDC, Sierra Club and Acadia Center (collectively, the Clean Energy Parties); jointly by the Alliance of Automobile Manufacturers, the Association of Global Automakers, America Honda Motor Company, Audi of America, Ford Motor Company, General Motors, Hyundai Motor Company, Kia Motor Corporation, Mitsubishi Motor R&D of America, and Nissan North America (collectively, the Joint Automakers); AEE Institute; Tesla; Greenlots; jointly by EVgo, ChargePoint, and CALSTART (collectively, the Joint Commenters); Electrify America; the Capital District Transportation Committee (CDTC); the Clean Communities of Central New York (CCCNY); and EV Connect.

In addition to the Consensus Parties, the Consensus Proposal is supported by ATE, the City, CALSTART, Clean Energy Parties, Joint Automakers, Tesla, Greenlots, Joint Commenters, and Electrify America, although most supporters view it as a first or interim step and urge that the dialogue continue. MI notes that it is not opposed to the proposal.

ATE states that the Consensus Proposal is a creative means to assist in this early market development process without impinging on the Commission's consistent regulatory principles. That is, it addresses the widely recognized challenge presented by demand charges but without carving out one sector with a special and open-ended tariff. ATE states that the per plug incentive levels are appropriate because, while they are meaningful, they are not so large as to support installations that will be commercially non-viable in the long term.

MI supports the Consensus Proposal's reliance on a demand-based rate design and cost-based rates. MI states that demand charges: 1) help ensure that the rate design applied to DCFC stations is compensatory; 2) are consistent with cost causation principles; 3) are consistent with how similarly-situated customers are billed; 4) sends appropriate price signals that would maximize efficient utilization; and, 5) avoid awkward and/or controversial transitions from non-cost-based rate designs. MI comments that it does not challenge the projected cost of the Consensus Proposal and urges the Commission to consider an alternative funding source such as collected but uncommitted Clean Energy Fund dollars. MI cites over two dozen policy-oriented initiatives currently funded by customers and states that the Commission should strive to avoid or minimize the imposition of further, incremental obligations. MI states that, per NYSERDA's most recent quarterly report, it appears that there are currently more than $ 1 billion in unallocated Market Development' funds and approximately $ 285 million in unallocated Innovation & Research' funds. Thus, with a projected cost, at maximum participation, of approximately $ 30 million, the Consensus Proposal could easily be funded out of uncommitted Clean Energy Fund (CEF) dollars. MI explains that funding through the CEF would be appropriate, as one of the stated purposes of the CEF is to address areas where the private sector is unlikely or unable to develop energy-related environmental solutions, including transportation.

MI continues that if its proposal to fund the costs associated with the Consensus Proposal from uncommitted CEF funds is not adopted, the costs should be allocated and recovered from customers based on cost causation principles. MI claims that, based on such principles, all or most of the costs are appropriately allocated to mass market customers. MI rationalizes that the Consensus Proposal is intended to facilitate the growth of EVs which will be purchased and utilized mostly by mass market customers, that the perceived need to increase DCFC stations is in response to mass market customer range anxiety and that the proposed financial incentives are being offered to spur the development of additional stations for their benefit.

The Joint Utilities state that the design of the Consensus Proposal supports certain rate design and other principles adopted in the Commission's Reforming the Energy Vision (REV) Track Two Order including cost causation, fair value, economic sustainability, and policy transparency. Greenlots states that the Consensus Proposal avoids changes to the underlying rate structure, including demand charges, which send important price signals. It also notes that, with higher utilization, normal rate structures that include demand charges will likely become preferable to DCFC operators.

The Joint Commenters state that while the Consensus Proposal is an important interim step in addressing operational cost barriers, it urges the Commission against viewing it as a substitute for comprehensive rate reform. They recognize that the Commission may be concerned with providing a new technology with a distinct rate design but state that so long as EV charging rates are set above marginal costs, these new loads will benefit all ratepayers. The Joint Commenters state that the incentive levels should be reexamined to ensure that they are sufficient.

Similarly, Electrify America states its belief that the Consensus Proposal is a step in the right direction but also believes that demand and service fees should be kept to a minimum and only reflect the true aggregated incremental impact on system peak and grid infrastructure.

CDTC, CCCNY and EV Connect, while not specifically addressing the Consensus Proposal, state their support for the elimination of demand charges, and recommend treating DCFC stations as small commercial accounts subject to kWh charges.

AEE Institute is not supportive of the Consensus Proposal stating that it is crafted as an insufficient short-term subsidy, whereas it believes making accommodations using existing non-demand metered rates for stand-alone EV charging stations would provide a more sustainable near-term option while the Commission develops a longer-term solution. It also notes that, except for Con Edison's adder for higher utilization rates, the incentive level is not tied to performance, which could lead to inefficient allocation of program funds and may result in DCFC stations sitting idle or nearly idle, but still receiving utility payments. AEE Institute states that due to the relatively small size of the proposed program, funding may run out relatively quickly requiring the Commission to either authorize additional funding for the program or develop an alternative. It is concerned that the small size could create a rush to secure positions in the application queue or an attempt to fill the queue with many projects in hopes of securing some of them. It states that the situation may result in unnecessary delays in project implementation and lead to installations in poorly selected sites. AEE Institute also notes that, at the end of the incentive payment period, some DCFC station locations may become financially unviable.

AEE Institute, Tesla, and Electrify America raise concerns that only new DCFC chargers would be eligible for an incentive under the Consensus Proposal. They note that this limitation may put existing chargers at a competitive disadvantage compared to new chargers that receive an incentive. They state that mechanisms or rate designs covering all DCFC chargers, regardless of in-service date, are necessary and more equitable.

The comments of ATE, the Clean Energy Parties, AEE Institute, Tesla and Greenlots address the number of plugs eligible for the incentive under the Consensus Proposal. ATE states that many more DCFC plugs will be required over time though they will most likely not need incentives as utilization increases.

The Clean Energy Parties strongly recommend that the program size be expanded upward from 1,074 plugs, and modifying the incentive amounts accordingly, noting that if the program was scaled up commensurately to achieve the Joint Utilities' portion of the 4,717 plugs from the Electric Infrastructure Projection Tool (EVI-Pro) Lite [12] model assuming 75 percent home charging capability, it would increase to about 3,377 plugs. The Clean Energy Parties further state that vehicle fueling, and operational costs are pivotal in fleet operators' decisions to purchase EVs, and ensuring that medium-and heavy-duty vehicles have comparable market transformation opportunities as light-duty vehicles should be a core focus of this proceeding.

Greenlots states that the incentive payments to DCFC station operators are straight forward and relatively easy to understand, but that even if the proposed program is fully subscribed it represents only a small fraction of the DCFC infrastructure that will be needed. It emphasizes that New York must make sure not to lose momentum in seeking other activities, policies and programs with the capability of being much more impactful in accelerating the transition to transportation electrification.

In its comments, NYPA explains that the Electric Power Research Institute forecasts that starting in approximately 2019 there will be a much greater variety of EV models due to falling cost of batteries, and that most will have higher charging capacity than the current market. NYPA explains that growth in the Sport Utility Vehicle/Crossover

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[12] The EVI-Pro Lite tool is accessible on the U.S. Department of Energy's Alternate Fuel Data Center website at: *https://afdc.energy.gov/evi-pro-lite*.

vehicle type is forecasted to increase electric demand indicating that the Audi e-Tron is capable of charging at 150kW. NYPA concludes that "50kW and 75kW and above are appropriate tiers for the immediate and temporary relief proposed in the consensus proposal." In its comments, Electrify America states that it is creating future-ready stations to charge the next generation of higher charging power EVs through state-of-the-art 350kW-capable dispensers. Electrify America states that the Consensus Proposal creates a disincentive for investments in customer-friendly higher-powered charging above the 75kW threshold but encourages the Commission to approve the Consensus Proposal as a first step.

The Consensus Parties, using EVI-Pro Lite, calculate that more than 1,500 DCFC plugs are likely needed to support the charging needs of the State's target of 800,000 ZEVs by 2025.[13] The Clean Energy Parties comment that it is likely that the Consensus Parties kept EVI-Pro Lite's default assumption that 100 percent of EV drivers have access to home charging, which overstates the percentage of drivers that have access to EV home charging in a mature New York EV market and therefore significantly understates the amount of DCFC plugs needed to support 800,000 ZEVs. The Clean Energy Parties claim that assuming 75 percent of EV drivers have home chargers, the model finds that 4,717 DCFC plugs are needed to support 800,000 EVs in New York.

ATE, the Local Unions, the Joint Utilities, the Joint Automakers and Tesla address the Consensus Proposal's requirement that DCFC stations be available to the public. ATE states that DCFC that is easily accessible to the public is an essential prerequisite for widespread transportation electrification. The Local Unions state that the Consensus Proposal's rules, including the requirement that chargers are publicly available, appear to be reasonable and appropriate. The Joint Utilities state that having more DCFC stations available in publicly accessible areas may help to encourage customers to purchase EVs. The Joint Automakers state that a network of DC fast charging stations, which is highly visible to consumers and convinces them that EV charging infrastructure is everywhere consumers want to go, is critical to the successful growth of the plug-in EV market. The Joint Automakers further state that DCFC can be a critical enabler of transitioning commercial and Transportation Network Companies (TNCs) fleets to electrification.

The comments of ATE, CALSTART, the Clean Energy Parties, the Joint Automakers, Greenlots and the Joint Commenters encourage the Commission to consider the needs of fleet vehicles and TNCs as part of this proceeding. CALSTART states that because of the disproportionate impact of truck and bus traffic on public health, the electrification of these fleets is of critical importance for all ratepayers from public health and environmental justice perspectives. It continues that heavier vehicles have greater power and energy demands and are frequently charged in depot-style configurations. CALSTART maintains that commercial EV technologies are available now and currently in demand in New York, and states that the considerations for bringing commercial EV operations to cost parity with petroleum are distinct from those of light-duty passenger cars. It avers that a solution that works for the public DCFC use case is not necessarily conducive to commercial fleet electrification, maintaining that these customers likely require greater adjustments to non-demand charge portions of the utility bill, which along with demand charges constitute the fueling cost for an electric fleet. According to CALSTART, its experience in California suggests that a menu of rate options, including several time-of-use (TOU) options, will best support fleet electrification while also encouraging fleets to charge during lower-cost hours.

The Joint Commenters urge the Commission to utilize this opportunity to enable critically important use-cases for EV charging that are not always available to the public, such as state and local government fleets. The Joint Commenters state that shared-use mobility platforms including carshare and TNCs exist on the premise that shared vehicles are utilized much more robustly than personal vehicles and therefore can better overcome significant fixed costs associated with personal mobility.

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[13] *See* *http://www.dec.ny.gov/docs/air_pdf/zevmou.pdf*.

Tesla states that the fixed per plug incentive sends companies a signal to construct stations, but does not encourage high utilization of stations, except for Con Edison's and O&R's proposals. Tesla recommends replicating the design of Con Edison's and O&R's incentives, explaining that applying similar mechanisms statewide can strike a balance between fixed and variable cost considerations for operators, as well as the overall costs for the Consensus Proposal. Tesla notes that access to convenient public charging is an important factor for many drivers considering the purchase of an EV, and questions whether the number of plugs to be incentivized is sufficient. It states that charging stations are increasingly being built with more plugs which could effectively make the proposed program very short term despite nominally running through 2025.

NGV America comments that to assure fair competition, delivery rates for electric compressors in operation at natural gas fueling stations should be similarly discounted and qualify for the business incentive rates offered by utilities. It states that policies that favor only EVs could distort markets in New York and unfairly discourage the use of natural gas and other low-carbon solutions. If no incentives are provided to natural gas fueling stations, NGA America recommends that the Commission take steps to provide discounted rates or otherwise ensure natural gas fueling stations are not subsidizing EV infrastructure through the rates they are charged. NFG similarly states that the Commission should encourage the continued adoption of NGVs and support the development and submission of incentive and/or rate proposals for future Commission consideration.

On December 24, 2018 EVgo filed an out-of-time letter, focusing on the State's immediate investment approach for leveraging public funding to catalyze private sector investment. EVgo argues that NYPA's overwhelming focus on direct ownership and network development of DCFC infrastructure risks undercutting private market participants, potentially distorting consumer-facing pricing, and limiting the ability of public funding to maximize EV charging access. EVgo specifically cites these concerns as the reason why they did not submit a proposal for the John F. Kennedy Airport charging hub. They go on to suggest that a model such as that being used in the Commonwealth of Virginia to deploy Volkswagen Diesel Settlement "Appendix D" funds, where those funds were leveraged with a competitive procurement to build a statewide charging network. [14]

In response to EVgo, NYPA summarizes the Evolve NY program's portfolio approach and suggests that EVgo's letter is inappropriately filed in this docket. NYPA concludes its rebuttal by reiterating the fundamental issue that their efforts seek to address is that operating cost or demand charge relief is necessary to support the infrastructure needed to assist in electrifying the transportation sector and achieve New York's GHG emission goals.

DISCUSSION

Joint Petition

The Commission finds that placing DCFC stations on SC-2 or Small General non-demand-billed tariffs is unnecessary at this time. The Commission is not persuaded by the Joint Petitioners' claim that DCFC stations impose limited costs on the electric system. As State agencies work towards achieving New York's ZEV goals, utilization factors will increase and load profiles must develop in a way that is beneficial to the electric system. Allowing DCFC facilities to take service on non-demand-billed tariffs would shift costs and send the wrong price signals to DCFC station owners. Demand charges send the appropriate price signals to customers to influence behavior and operate in a manner that benefits the distribution grid.

Demand charge holidays in other jurisdictions have been temporary, and demand charges phased-in at the holiday's expiration. The Commission recognizes the economic challenges DCFC station developers currently face but declines to move away from cost-based rates by granting the Joint Petitioners' request to allow DCFC station

[14] NYPA filed responsive comments on December 27, 2018, specifically responding to EVgo's critical letter. As this reply letter, and the January 16, 2019 response of EVgo, discuss issues beyond the scope of the Joint Petition and the Consensus Proposal recommendations, the Commission declines to summarize those issues that are not relevant.

customers to qualify for a service classification without a demand charge. Given that the Consensus Proposal is expected to provide similar relief, while maintaining a rate that reflects cost-causation, a demand charge holiday in New York is unnecessary.

The Commission is similarly not persuaded by the Joint Petitioners' argument that precedent supports demand charge discounts in support of beneficial technology, evidenced by standby rate exemptions and flexible rate service contracts. Standby rate exemptions are applicable to customers with designated technologies including: fuel cells, wind, solar thermal, photovoltaics, sustainably-managed biomass, tidal, geothermal, and/or methane waste, and to customers with efficient Combined Heat and Power (CHP) generation assets. [15]

While the Commission agrees that standby service rates for customers with on-site generation are designed to accommodate and promote distributed generation, standby service rates established at each utility are designed to recover costs more accurately and granularly. Standby rates seek to align individual customers' contributions to system costs with the rates such customers pay, thereby sending accurate price signals to those customers. [16] This is accomplished through contract demand charges and as-used demand charges. [17] Customers that qualify for a standby rate exemption are billed under standard rates, which also include demand charges.

Regarding the Joint Petitioners' second request for relief, the Commission instituted this proceeding to remove inappropriate obstacles to EV adoption and ensure critical EV supply equipment and infrastructure (EVSE&I) is in place to support the State's ZEV targets. [18] Staff has been tasked with developing a whitepaper that addresses a range of EV topics including utility roles, and potential ownership models, supporting EVSE&I. The Commission expects Staff to continue to engage with stakeholders and issue a whitepaper for public notice and comment. The Joint Petitioners' requests are being addressed, and the Commission invites all parties to continue to engage in this effort.

The Commission is not addressing NFG's request to institute a proceeding that addresses all aspects of the transportation sector in this order; but, is adopting an incentive program specific to electric vehicles to support the State's ZEV deployment goals in a way that benefits and protects New York's ratepayers and our distribution grid.

Consensus Proposal

A. Ratemaking Principles

Delivery costs are a function of the resources needed to supply power to customers during the system peak and the individual customer's peak usage. The customer's proportion of these peaks are measured in the coincident and non-coincident demands customers register on the utilities' systems. The Consensus Proposal provides the needed support for DCFC stations during the early stages of EV adoption without disturbing the utilities' underlying cost-based rate structures. Placing DCFC stations on existing non-demand metered rates, as proposed by many commenters, would potentially result in charging such customers rates that are below cost in a non-transparent, not

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[15] Case 14-E-0488, *In the Matter of the Continuation of Standby Rate Exemptions*, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015).

[16] *See*, Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates (filed December 12, 2018) (Staff Standby and Buyback Whitepaper).

[17] Standby rates are comprised of customer charges (which are designed to recover customer specific costs like services and meters), contract demand charges (which are designed to recover the costs that are local to a customer) , and as-used demand charges (which are designed to recover upstream costs).

[18] Case 18-E-0138, Order Instituting Proceeding, p. 3.

readily quantifiable manner. More problematic, other customers in the same non-demand metered service classifications would be negatively affected because embedded cost of service studies would assign such classes increased demand-related costs with insufficient additional revenues to recover such costs, thereby reducing the non-demand metered classes' rates of return which can lead to above average rate increases in future rate plans.

By incentivizing DCFC stations through a transparent annual incentive instead of through a demand charge exemption as proposed by some commenters, the Commission is being consistent with past approaches to rate design.[19] Therefore, a per station delivery cost cap, as proposed by NYSEG and RG&E, is adopted. Since per-plug incentive payments are to be capped at the station's delivery cost it is appropriate to require that stations be separately metered and ancillary load be limited to 10 kW, as Proposed by NYSEG and RG&E. The Commission directs each IOU to cap the total DCFC station annual incentive payment at the lower of the station's aggregate per-plug incentive amount or the total delivery costs for the twelve-month billing period for which the incentive is being calculated.

B. Incentive Eligibility

1. New vs. Existing Chargers

Under the Consensus Proposal, 1,074 new plugs may be eligible to receive annual incentives. Ratepayer funds must be put to maximum benefit to accomplish the goals of the program, which is especially critical if the Clean Energy Parties are correct in arguing that nearly 5,000 DCFC plugs may be needed to support New York's ZEV target. Providing ratepayer-funded incentive payments to existing chargers is inconsistent with the program goal.

The Commission adopts the proposal that the per-plug incentive only be available to newly constructed chargers. The purpose of the program is to increase the number of publicly accessible chargers to address the range anxiety of potential EV drivers, thereby inducing EV sales to meet the State's ZEV goals. While existing infrastructure has great value in promoting EV adoption, the Commission declines to retroactively incent those developers. AEE Institute's comment that it is not clear if the incentive levels will be enough to move the market is well taken, and the Commission will evaluate the adequacy of, and potentially adjust, the incentive levels at an interim review discussed below.

2. Public Entity Eligibility

The Commission's REV initiative seeks to build a modern electric grid that is clean, reduces costs, and recognizes locational and temporal value. In order to meet the State's ZEV and GHG reduction targets, the Commission is leveraging and accelerating private investment while prudently investing ratepayer funds. For the limited purpose of deploying the DCFC infrastructure needed to support the State's public policy objectives, NYPA, the City, and Electrify America may be eligible for this per-plug incentive program as station developers. In their role as DCFC station developers, these entities are competing in the private market, and face the same nascent market concerns that have slowed private development in New York.[20]

In recognition of EVgo's legitimate concern that public entity ownership risks undercutting the private market, the Commission underscores that this per-plug incentive is limited in time and value. In order to capture the substantial

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[19] *See* Case 14-M-0101, *Reforming the Energy Vision*, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued February 26, 2015), p. 118.

[20] A recent report illustrates that the State faces one of the largest charging gaps, while EV uptake will grow most rapidly in markets like New York. *See* The International Council on Clean Transportation, Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets (January 2019), *https://www.theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf* .

public benefits that EV deployment will realize, as enumerated by the Clean Energy Parties and other commenters, the Commission will leverage the institutional capital and readiness to deploy exhibited by NYPA and the other public entities with unencumbered, NYSERDA legacy funds to build out New York's DCFC infrastructure. It is appropriate to utilize uncommitted, unencumbered, NYSERDA legacy funds for this infrastructure deployment that will spur EV deployment. Private market participants are encouraged to utilize this incentive program to deploy DCFC infrastructure in New York, where the market has so far failed to materialize.

In order to preserve the Commission's general beneficiary pays policy where benefits accrue to collection-paying customer classes, the Commission declines to allow NYPA to access a per-plug incentive funded exclusively with SBC funds. As discussed in greater detail below, the Commission directs the IOUs to develop and implement a surcharge mechanism for customer groups that did not contribute to the SBC, and add this collection to the NYSERDA legacy funds.

3. Number of Plugs Eligible

The Clean Energy Parties note that using EVI-Pro Lite's electric vehicle infrastructure projection tool with a modified assumption that 75 percent of EV drivers have home chargers, the model finds that 4,717 DCFC plugs are needed to support 800,000 EVs in New York, showing that more plugs need to be incentivized. However, the electric vehicle infrastructure projection tool is dependent on other factors which must be considered in addition to the percentage of drivers with access to home charging. Given the uncertainty of technological advances and the impacts of uncertain forecasting, as well as the reasonable expectation of cost declines, the maximum number of plugs eligible for an incentive will remain as proposed at 1,074 plugs. The Commission does not anticipate 1,074 incremental plugs will satisfy the DCFC charging needs in New York, but this incentive is designed to motivate market development. As more EVs are sold and the market develops, the economics for all DCFC stations should improve.

As discussed above, Central Hudson and National Grid included limitations on the plugs eligible for the per plug incentive in the first two years of the program to roughly 33 percent and 66 percent of the program total in years one and two, respectively. Such a limit does provide an opportunity to re-evaluate the programs and reduces the maximum incentive payout. However, the Commission finds that limiting the number of eligible plugs by year may unnecessarily slow DCFC station development. In as much as the 1,074 plugs eligible for an annual incentive and the magnitude of the annual incentives may not be set at optimal levels, an interim review will provide the Commission with the ability to correct such imprecise expectations. Central Hudson and National Grid's per-plug limitations are rejected. Instead, the Commission adopts an interim review process to better achieve the objectives of beneficial deployment and ratepayer benefits. The Commission expects this interim review will provide an opportunity to adjust this DCFC per-plug incentive program, if needed, to accelerate market-based deployment at the most efficient level of ratepayer support. [21]

This interim review is in-line with the spirit of Central Hudson's proposal that it reserve the right to seek Commission approval to reduce the incentives and/or end the program due to significant declines in DCFC equipment costs or lack of participation. The Commission declines to vest Central Hudson with the authority to independently reduce incentive levels beyond the declining amounts established by this order, but welcomes each utility to recommend such program changes in their annual reports.

At this time, the Commission also rejects Central Hudson's proposal that DCFC stations seeking eligibility under this program will be subject to the utility's approval. The Commission expects that developers and utilities will collaboratively site these DCFC stations in areas of the distribution system that will benefit from their increased

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[21] Such adjustments may include: modifying annual incentive payment levels; locational restrictions; approved vendor lists for eligible equipment; public entity eligibility; and, other prudent program improvements.

load. A developer may choose to site a DCFC facility with the station's long-term economic business case weighing more heavily than near-term distribution system upgrade costs, but the interconnecting utility can and should charge each developer an adequate contribution toward the cost of adding or upgrading utility facilities. [22] The Commission expects to pay particular attention to locational deployment lessons learned at the interim review, and adjust the program's locational deployment considerations, if warranted, based on data reported in the annual utility reports.

The Commission's interim review will begin by October 1, 2023, or when each utility has completed applications for 45 percent of the total number of plugs eligible in their territory, whichever is earlier. The purpose of this interim review process is to consider changes to the program that may include more efficient incentive structures, methods of better capturing system benefits, or acceleration of market-based deployment.

To inform this interim review, and as prudent reporting, the Commission directs each utility to submit a detailed annual report by March 1st after completion of each program year. The annual report must detail: the cumulative number of plugs for which the utility has received applications; the number of plugs in service and their geographic siting; the number of plugs under construction and their estimated in-service dates; station equipment type; installation costs; energy usage data including kWh dispensed, start/stop times, peak kW per charging station, amount of time each vehicle is plugged in, amount of time each vehicle is actually charging, and load curves; comparisons of peak DCFC station demand with local peak demand and system peak demand; usage fees; and, technologies used to manage demand. [23] This interim review will allow the Commission to evaluate the success of the per-plug incentive program, and make any prudent changes.

4. Data Availability

In addition to annual reports as proposed by the Consensus Parties and required by the Commission, a successful DCFC incentive program must provide station developers with useful information. Therefore, the Commission directs the Joint Utilities to add an electric vehicle charging station information page to their individual websites. The Joint Utilities are directed to include, at minimum, program applications, year-by-year incentive amounts, interconnection resources, queue status, and other useful information. The Joint Utilities should work with relevant stakeholders to identify the most useful content, format, and accessibility of this information and shall update their DCFC incentive program websites monthly.

5. Charging Capability

The requirement that plugs must be capable of simultaneously dispensing at 50 kW or more to qualify for the incentive is appropriate, as most of the ZEVs presently on the road can charge at 50 kW or less. [24] While there is no specified power consumption associated with DCFC, 50 kW is typical of level 3 charging. Generally available DCFC infrastructure of this level will lower charge time and range anxiety of current and potential ZEV owners. Simultaneous charging capability shall be defined as the nameplate rating of the charger divided by the number of plugs.

In the Consensus Proposal, the filing parties indicate that chargers with 75 kW of simultaneous capacity meet the maximum charging demand of many EVs currently on the road, but acknowledge that higher demand charging

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[22] For example, Central Hudson's currently effective Tariff Leaf: 98 provides for unusual conditions and increased loads cost recovery from the customer.

[23] In order for the electric utilities to compile such data, developers accessing this incentive must collect and report it to the utility.

[24] At 50 kW it takes approximately 20 minutes to provide enough charge to drive 50 miles.

capabilities will become commercially available and DCFC charging infrastructure will need to follow. [25] The Commission adopts the tiered incentive levels proposed, as a reasonable method of incentivizing DCFC technology. The per-plug incentive for each 50-74 kW DCFC shall be 60 percent of the total incentive, while each plug at 75 kW or greater shall receive 100 percent of the incentive payment. A station's incentive is capped at the lower of the sum of the individual plug incentives or the actual annual demand of the station.

6. Public Accessibility of Plugs

A common Consensus Proposal program parameter amongst the utility-specific designs included the requirement that DCFC stations be publicly accessible. While the Consensus Proposal defines publicly accessible DCFC stations as those allowing access without site-specific physical access restrictions (e.g., supermarkets, malls, retail outlets, rest stops, visitor centers, train stations, hotels, restaurants, and parking garages or lots where DCFC stations are open to the public and will be used by a wide variety of users), additional refinement as to what constitutes a publicly accessible charging station is necessary to ensure the largest possible pool of public benefits. For purposes of this incentive program, customers should not have to pay to access a participating DCFC station. The Commission recognizes that pay-to-park lots are commonplace, and may offer EV charging as a service, but a pay-to-park lot is not analogous to the public accessibility of a gas station and DCFC facility sited there may not receive this per-plug incentive without waiving the access fee for charging customers. [26]

For the purposes of this program, publicly accessible DCFC stations will be defined as those Level 3 stations that utilize both a Society of Automotive Engineers (SAE) Combined Charging System (CCS) [27] plug type commonly in use by American and European manufactures (e.g., Chevrolet, BMW, Mercedes, and Volkswagen) and a CHAdeMO [28] plug type commonly in use by Asian manufactures (e.g., Nissan and Mitsubishi). Tesla uses its own standard, not SAE CCS nor CHAdeMO, which the Commission does not recognize as publicly accessible for purposes of this incentive program. However, some Tesla vehicles can connect to CHAdeMO DCFC plugs with an adaptor. Tesla DCFC stations will become eligible for this per-plug incentive where their proprietary technology is coupled with plug types that enables use by EVs with Asian and European charging systems. [29]

There are about a dozen charging stations networks operating in the United States that require network membership as a condition of station use. To ensure maximum accessibility of DCFC stations by the public, stations eligible for an incentive under this program must be usable without requiring a paid membership in a charging station network. Networked stations that offer single per-use charging fees payable through a commonly accepted payment method such as cash, credit, or debit will satisfy this criterion. While payment through a smartphone application is permitted, in order to qualify as publicly accessible for purposes of this program, it may not be the only form of payment a DCFC station accepts. Regarding NGV America's and NFG's request for incentives and/or discounted electric rates for the fueling of NGVs, such considerations are inconsistent with the scope of this proceeding. This proceeding was instituted to support New York's ZEV sales mandate, which requires

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[25] "Next generation" charging stations will deliver as much as 350 kW of power, but most mass-market vehicles are not presently capable of accepting charges at this level. The Commission acknowledges some Tesla "Supercharging" stations deliver this level of charge to Tesla vehicles, but such proprietary technology is not eligible for this incentive.

[26] The Commission notes that customer utilization behavior strategies such as fees for dwell times when a vehicle is not actively charging are not considered access fees and a publicly accessible station may charge a dwell fee.

[27] SAE International Standards are used to advance mobility engineering throughout the world; the SAE CCS is a standardized charging environment.

[28] CHAdeMO is a direct current charging standard for EVs that enables communication between the car and the charger, developed and certified by CHAdeMO Association.

[29] The Commission is not prescribing that Tesla deploy a particular technology (*i.e.*, CHAdeMO versus SAE CCS).

manufacturers to sell approximately 800,000 to 1 million, plug-in hybrid, all-electric, or fuel cell vehicles in New York by 2025. The Commission declines NGV America and NFG's request at this time. The scope of this proceeding is properly focused on EVs, and the Commission will not incorporate NGVs at this time.

C. Incentive Level

The Consensus Parties indicate that the utilities' proposed incentive levels were derived using model electric bills assuming that DCFC stations received service under volume-based rates. They acknowledge, however, that even with the incentive proposed, the ultimate success of the business model will be largely driven by station utilization. As indicated by AEE Institute and Tesla, Con Edison's and O&R's proposals contain a performance component to encourage higher station utilization whereas Central Hudson, National Grid, NYSEG and RG&E eschew the load factor bonuses, opting instead for higher per plug incentives.

As evidenced by the need for this incentive, the capital and operating costs associated with owning and operating DCFC charging stations are not trivial. As such, DCFC station operators appear to have sufficient incentive to maximize their stations' utilization even without specific load factor incentives. The Commission therefore denies Con Edison and O&R's load factor bonus incentive. However, to ensure that the program is achieving the desired results, the incentive components and levels will be reviewed at the interim evaluation.

The Con Edison, O&R, and Central Hudson programs set the initial incentive level for qualifying applicants at the maximum level, independent of the year in which the applicants qualify. However, the NYSEG, RG&E, and National Grid proposals set the initial incentive level for qualifying applicant's depending on the year in which the applicants qualify. The Consensus Proposal used a model electric bill assuming volume-based rates for DCFC as a target in sizing and shaping the incentive. Providing incentives at the maximum level, independent of the year in which the applicants qualify, may overcompensate station owners. The Commission expects that DCFC station developers will be able to capture cost savings from technology cost declines and lessons learned through increased development, which justify establishing this declining annual incentive at the outset.

Therefore, the Commission directs Con Edison, O&R, and Central Hudson to modify their programs such that the initial incentive is based on the year in which the DCFC qualifies, consistent with the NYSEG, RG&E and National Grid proposals. An application shall be deemed complete, and the incentive level fixed, when the developer submits a completed application for the program. Program applications are to be deemed complete at the latter of when the station owner/developer provides proof of a building permit, or when the developer provides a CIAC payment for excess distribution facilities, if applicable. CIAC payments are to be remitted within 60 days of the utility communicating such a fee. An applicant that fails to remit payment for their CIAC within 60 days shall be removed from the program, barring exceptional circumstances that justify additional time in which the developer and utility may solve engineering difficulties.

As explained above, each of the utilities designed a seven-year incentive program, except for Central Hudson that established a five-year program. The Commission directs Central Hudson to modify its program so that DCFC station developers in their service territory may also participate in a seven-year program, consistent with the rest of the State.

As explained in Appendix E of the Consensus Proposal, the O&R per-plug incentives were designed to provide a combined benefit in conjunction with the delivery rate discount offered under the EDR, which is currently 20 percent. O&R proposes to re-calculate the per-plug incentive if the EDR delivery rate discount changes. This proposal makes the O&R program substantially similar to Con Edison's. However, such similarity is not necessary. The Commission finds it reasonable to leverage Con Edison's BIR, which is currently open to electric vehicle quick charging stations that have a minimum 100 kW publicly accessible capacity and is receiving government economic incentives, with this per-plug incentive to motivate the DCFC market. The Commission declines to extend this exception to the O&R EDR delivery rate discount, and will not authorize an EV quick charging component as proposed. To make the O&R program consistent with that of the other utilities, the EDR component is to be eliminated and the per plug incentive is to be recalculated to capture the expected 20 percent discount. [30]

The Commission adopts Con Edison's proposal to modify the eligibility requirement of the electric vehicle quick stations component of the BIR such that: 1) governmental customers are eligible; 2) the requirement that the station be receiving government economic incentives are waived; and, 3) the date for delivery rate reductions are extended from the current date of April 30, 2025, to December 31, 2025. The Commission finds that DCFC station deployment is a public benefit, and costs and benefits flow to both ratepayers and society at large. The design of this BIR applied to DCFC customer accounts is to provide site hosts the appropriate incentive to deliver this public good. In order to deliver the maximum public benefits, all developers shall be eligible for the BIR. Support for DCFC infrastructure is a special use case, and factually different from other use cases for economic development rates. Con Edison's BIR-eligibility expansion is appropriately targeted and narrow in terms of scope, as the BIR is only available if the DCFC station is built and serving the public, and is appropriately inclusive to site hosts that are providing a direct capital investment by building this critical infrastructure.

D. Program Costs and Recovery

According to many commenters, increased EV adoption will lower the average electric cost of service and reduce rates for ratepayers, due to incremental utility revenue from serving these new customers. The Commission cannot forecast if these comments will prove to be accurate, because EV deployment is uncertain. Nonetheless, the Commission recognizes the importance of meeting our State ZEV targets and commits electric ratepayer funds to incentivize the market to build the necessary infrastructure and capture the benefits those goals will realize.

As proposed, the maximum potential cost of the per plug incentives over the seven-year life of the program described in the Consensus Proposal is approximately $ 28 million. The Consensus Parties propose that the utilities be authorized to recover applicable incremental administrative costs of the program, with interest, in addition to the other program costs. Per-plug incentive program costs, as modified by the Commission, are $ 31.6 million statewide. [31]

The Commission is mindful of imposing incremental collections on ratepayers to motivate the DCFC market, and therefore adopts MI's recommendation to use CEF funds to fund DCFC plug incentives in principle. Because CEF budgets and goals are for the full ten-year period, MIs observation that the CEF has unallocated CEF funds at this time is accurate, although those funds will be deployed as the CEF portfolio is developed. Instead of CEF collections, the Commission directs the use of identified unencumbered, uncommitted NYSERDA legacy funds (i.e. remaining System Benefits Charges) to fund these DCFC per-plug incentives for those customer classes that have contributed to the SBC.

Early in the SBC proceeding, the Commission recognized that many SBC programs will deliver greater benefits and operate more effectively when operated on a Statewide basis. [32] Therefore, the Commission directed the IOUs to retain a portion of the revenues to fund certain utility-administered, unexpired public-benefit programs that predated the SBC, and transfer the remainder to NYSERDA to fund statewide administered public benefit programs. In order to realize the State's goals of transportation electrification and GHG emission reduction, the Commission has identified unencumbered legacy SBC funds that are available to fund this incentive. The Commission directs NYSERDA to transfer this funding, as outlined in Appendix A, to the respective utilities within 90 days of the

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[30] The Commission estimates the per-plug incentive will increase to 10,400 in year one of the program.

[31] Appendix A contains maximum program budgets per utility.

[32] Case 94-E-0952, *In the Matter of Competitive Opportunities Regarding Electric Service*, Opinion and Order Concerning System Benefits Charge Issues (issued January 30, 1998), p. 7.

effective date of this order. The utilities will be required to accrue carrying charges on unused funds at their respective pretax rates of return. Any funds remaining at the conclusion of the seven-year program shall be deferred for future disposition by the Commission.

Not all DCFC station developers who may be eligible for this per-plug incentive program have contributed to the SBC. In order to preserve the Commission's general policy of benefits accruing to the collection-paying participants, the IOUs are directed to develop a surcharge mechanism for customer groups that did not contribute to the SBC. The surcharge shall be developed by dividing total program costs by the total annual delivery kWh for each IOU. This surcharge shall be administered to all non-SBC paying customers for a period of one-year, beginning January 1, 2020. The funds collected using this surcharge shall be combined with the NYSERDA legacy dollars to fund the DCFC per-plug incentive program at each IOU. Each IOU shall file tariff revisions necessary to enable this surcharge by March 1, 2019.

The Commission declines to grant the IOU's request for explicit deferral and recovery authority for administrative costs of this per-plug incentive program. Processing new service interconnections is a core utility competency, and while DCFC stations pose a new technology application, the incremental administrative costs of this program are expected to be minimal. As always, if the incremental costs are in fact material, the IOU's may petition for deferral treatment.

Con Edison proposes to re-determine the per-plug incentive if the BIR delivery rate reductions change during the term of the program. However, charging stations may not necessarily take part in both the BIR and per-plug incentive programs. As proposed, if cap limits are met for one program, but there is still space in the other program, Con Edison would allow customers to participate in the remaining program. Since the per-plug program funding being provided by NYSERDA was developed using the incentive levels contained in the Consensus Proposal, Con Edison may not change its incentives without Commission approval.

E. Outstanding Issues

With respect to the electrification of fleet vehicles, fleet operators are afforded the opportunity to diversify demand and achieve higher charger utilization factors. As CALSTART indicates in its comments, such vehicles are frequently charged in depot-like configurations and fleet operators likely require greater adjustments to the non-demand charge portions of the utility bill. Currently, the electric utilities all offer Time-of-Use rate options, including the hourly pricing of supply, that may benefit fleet operators as CALSTART suggests. Additionally, supply may be procured from third party energy service companies operating in the utilities' service territories. To encourage further dialogue in this proceeding, Staff's forthcoming whitepaper should consider the needs of fleet vehicles and TNCs.

CONCLUSION

In furtherance of the State Energy Plan carbon reduction targets and the ZEV deployment goals, the Commission adopts the DCFC per-plug incentive program to support this critical public infrastructure. This statewide incentive program is intended to benefit the State's ratepayers, and as such, the Commission may adjust the program parameters to achieve maximum locational deployment benefits, the correct number of DCFC stations deployed, the most efficient system benefits, and other lessons that may be learned by the interim review.

The Commission orders:

1. The Commission adopts the Consensus Proposal with modifications as discussed in the body of this order.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to cap the total direct current fast charging

station annual incentive payment at the total delivery costs for the 12-month billing period for which the incentive is being calculated as discussed in the body of this order.

3. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to require that stations be separately metered and ancillary load be limited to 10 kW in order to qualify for the per-plug incentive, as discussed in the body of this order.

4. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall each file an interim report with the Department of Public Service Staff by October 1, 2023 or when 45 percent of the total number of completed applications for plug incentives in each service territory have been received, whichever happens first, as described in the body of this order.

5. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file a detailed annual report by March 1st, after completion of each program year as described in the body of this order.

6. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to add an electric vehicle charging station information page to their websites by March 1, 2019, to be updated monthly, as described in the body of this order.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc., are directed to modify their programs, such that the initial incentive is based on the year in which the direct current fast charging station qualifies for the program, as described in the body of this order.

8. Central Hudson Gas & Electric Corporation is directed to modify its program, so that the direct current fast charging station developers may participate in a seven-year program.

9. Orange and Rockland Utilities, Inc. is directed to modify its program to eliminate the Economic Development Rate component and to recalculate the per plug incentive, as described in the body of this order. Within 10 days of the issuance of this order, the Company is also directed to provide the New York State Department of Public Service Staff and the New York State Energy Research and Development Authority the maximum per-plug incentive payments of its program, assuming the revisions in this order.

10. Consolidated Edison Company of New York, Inc., shall file an updated Business Incentive Rate tariff, to become effective on not less than one day's notice on March 1, 2019.

11. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to develop a surcharge mechanism to be administered to all non-System Benefits Charge paying customers for a period of one year, beginning January 1, 2020, and to file tariff revisions necessary to enable this surcharge on ten days' notice by November 1, 2019.

12. Within 90 days of the issuance of this order, the New York State Energy Research and Development Authority shall transfer unencumbered, uncommitted legacy System Benefits Charge funds to each investor owned electric utility in the amounts listed in Appendix A to this order.

13. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1, related to newspaper publication of the tariff amendments described by ordering Clauses 10 and 11, are waived.

14. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

15. This proceeding shall be continued.

APPENDIX A

Utility	$
Con Edison	6,400,000
O&R	1,664,000
Central Hudson	4,400,000
NYSEG	5,120,000
RG&E	5,032,000
National Grid	9,000,000
Total	31,616,000

End of Document

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ATTACHMENT D

Georgia Power

August 4, 2017

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: Electric Transportation Initiatives, Non-Docket

Dear Mr. McAlister:

On October 24, 2014, Georgia Power Company ("Georgia Power") filed a letter informing the Georgia Public Service Commission (the "Commission") that it had begun the deployment of its Electric Transportation Initiatives pilot program. In that letter Georgia Power stated that it would provide the Commission with an update on the results of the program.

Enclosed for filing are the original and 15 copies of the Review of Georgia Power's Electric Transportation Pilot and Market Dynamics Driving Future Electric Vehicle Adoption Evaluation Report. Also enclosed is a CD containing the Evaluation Report.

Please call me at 404-506-3050 if you have any questions regarding this filing.

Sincerely,

Kyle C. Leach
Vice President, Regulatory Affairs

ATTACHMENT D

Georgia Power

Review of Georgia Power's Electric Transportation Pilot

and

Market Dynamics Driving Future Electric Vehicle Adoption

Evaluation Report

August 2017

Georgia Power

Georgia Power

Executive Summary

The Purpose of This Pilot

From late 2014 through December 2016[1], Georgia Power Company ("the Company" or "Georgia Power") piloted infrastructure initiatives, infrastructure incentives, and education and awareness efforts to assess their effect on Electric Vehicle ("EV") market development. This report provides an overview of the Georgia EV market that existed in 2014 and the pilot initiatives launched by the Company to stimulate growth in the EV market above then current trends.

This report highlights the program results, key insights, and lessons learned from the Company's most recent participation in the Electric Transportation ("ET") market. Readers of this report will be informed of key insights resulting from Georgia Power's ET Pilot, including insight into how to support ET market growth.

An Overview of the Georgia EV Market Leading to Georgia Power's ET Pilot Launch

From 2010 to 2014 Georgia became the fastest growing EV market in the nation. In 2014, statewide EV market share reached 1.6 percent through June, up 70% from 0.94 percent in 2013[2]. During this timeframe, Georgia also became the number one Nissan Leaf market in the United States[3].

While favorable driver economics, including the $5,000 state tax credit, drove the rapid growth of Georgia's EV market, Georgia Power identified critical unmet needs for the current market. The Company believed meeting these needs would spur EV adoption and market growth in future years. Those needs were primarily lack of awareness and availability of charging options.

In response, Georgia Power launched a pilot that involved promoting public education, providing community charging stations, including more charging options at Georgia Power facilities, and offering promotional rebates to residential and business customers for the installation of EV chargers. This pilot program evaluated such things as charging behaviors and patterns as well as utilization of charging options (i.e. residential, business, and community).

The data obtained from the pilot informs an understanding of infrastructure needs, and provides valuable information to the Company and Public Service Commission on how best to support and shape the growing EV market across the state. This pilot ultimately provided insight into the fundamental assumption that increased adoption drives benefits for the local economy, Georgia Power customers, and helps Georgia Power use assets more efficiently.

Description of the Georgia Power ET Pilot and Results

Georgia Power's ET Pilot was launched as a utility demonstration program. The pilot offered programs across five interdependent areas: (i) education and awareness, (ii) residential charging infrastructure,

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[1] Two community chargers were installed in the first quarter of 2017 due to scheduling issues
[2] IHS Automotive; http://www.cheatsheet.com/automobiles/the-7-states-adopting-electric-vehicles-fastest-in-america.html/?a=viewall
[3] IHS Automotive; http://insideevs.com/atlanta-now-2-market-plug-electric-vehicle-sales-us/; https://www.metroplugin.com/2014/09/atlanta-ev-sales-top/

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(iii) workplace charging infrastructure, (iv) Company charging infrastructure and, (v) community charging infrastructure. These programs were critical to raise awareness, support the existing market with necessary charging infrastructure, and support projected market growth in Georgia.

Vehicle sales declined six months into the pilot following elimination of the state tax credit. However, the Georgia Power team stayed abreast of changing market dynamics (e.g., state tax credit elimination) and took actions to manage program investments during the pilot to retain market participation and support existing EV drivers.

Georgia Power identified from the pilot program that residential and workplace rebate programs provided benefits for all customers as determined by the positive Ratepayer Impact Measure ("RIM") Test results. The education and awareness (including program costs) and community charging infrastructure programs ultimately cost more than the projected benefits attributable to those programs, resulting in negative RIM Test results.

Overall, the pilot was launched with an initial cost projection of $12M and completed pilot program efforts with total costs of $10M. Due to the reduction in EV sales and leases following the elimination of the state tax credit, projected benefits of $13M declined to $6M.

Overview of EV Market Dynamics During Pilot Program

The EV market in Georgia experienced rapid growth from 2010 to 2014 growing from three to 16,382 registered vehicles across the state[4]. Growth during this time frame resulted primarily from the state's $5,000 tax credit. During this timeframe Georgia was seen as one of the most EV friendly states in the nation.

The market dynamics changed mid-2015 when the state's tax credit was eliminated in July of 2015 (along with the introduction of a $200 EV registration fee). The elimination of the tax credit had an immediate and dramatic impact on EV growth in Georgia dropping new EV registrations by 71% when comparing EV sales in the first half versus the second half of 2015[5]. The elimination of the state tax credit and resultant drop in EV growth negatively impacted the Georgia Power ET Pilot. The effects on pilot results included: reduced impact of education awareness efforts, lowered utilization of community infrastructure, and lowered utilization of workplace infastructure.

While the elimination of the tax credit weakened EV sales and dampened ET pilot results, the pilot helped support the retention and continued growth of EVs in GA. By the end of the pilot in 2016, there were 25,780 registered EVs[6] across the state.

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[4] IHS Polk Registration Data, as of April 2017
[5] IHS Polk Registration Data, as of April 2017
[6] IBID

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Summary of Pilot Program Results

Program Areas	Cost	Benefit	RIM	Key Results	Impact
Education and Awareness	$4.14M	$2.06M	($2.08M)	– 124 M impressions – 10% increased consideration	– Increased EV awareness – Increased purchase consideration
Residential Infrastructure	$0.39M	$1.41M	$1.02M	– 819 Level 2 ("L2") chargers – 249 EV Ready Home installs	– Increased electric miles traveled – Improved driver convenience
Workplace Infrastructure	$0.99M	$1.06M	$0.07M	– 1305 L2 chargers – 261 Multi-family chargers	– Increased electric miles traveled – Improved driver convenience – Raised awareness of infrastructure
Company and Community Infrastructure	$4.92M	$1.33M	($3.60M)	– 37 charging islands (37 DC Fast Chargers ("DCFC"), 45 L2s, and 127 total charging ports) – 1,400 network members	– Increased EV awareness – Increased electric miles traveled – Raised awareness of infrastructure
Program Total	**$10.45M**	**$5.86M**	**($4.58M)**	--	--

Note: figures may not total due to rounding

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Key Insights from the Pilot

Seven important insights were gained from the Pilot:

Education and Awareness

1. Education and awareness efforts increased awareness and purchase consideration and helped influence market adoption
2. Experiential education and awareness efforts (e.g. testimonies, "ride & drives", etc.) were the most successful aspects of the Georiga Power Education and Awareness campaign, in terms of providing drivers with real-world EV experience
3. Social and digital media experienced the highest consumer engagement amongst the channels used in the ET Pilot

Residential and Workplace Infrastructure

4. Rebates (workplace and residential) supported EV adoption and provided benefits to non-participants as shown by the positive RIM Test results
5. Businesses valued EV charging as an amenity driving business rebate adoption

Community Infrastructure

6. Though critical for market growth, the usage and fees collected by users of the capital intensive community infrastructure is likely to continue to fall short of fully paying for the capital investments, as shown by the negative RIM Test results for this portion of the ET Pilot. Future deployments should be targeted and should consider leveraging external funding

EV Market Growth

7. Favorable EV environment (incentives, policy, high occupancy vehicles/high occupancy toll ("HOV"/"HOT") lane access, etc.) significantly increases adoption and is impactful to grow the EV market

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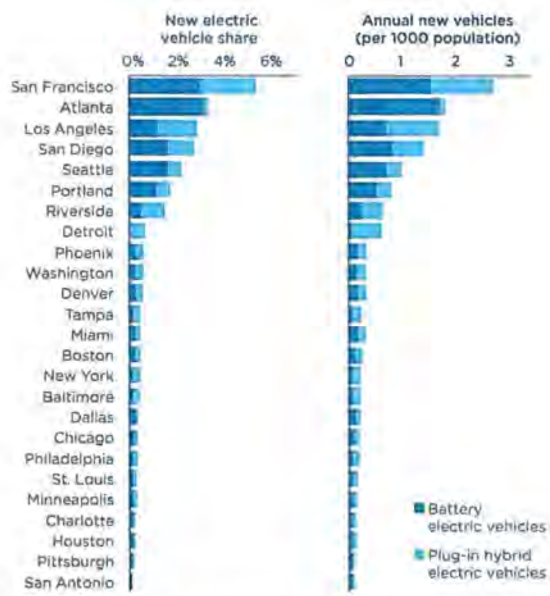
Overview of the Georgia EV Market and Its Influence on Georgia Power ET Pilot Program Participation

Between the years 2010 and 2014 Georgia became the fastest growing EV market in the nation. In 2014, statewide EV market share reached 1.6 percent through June, up 70% from 0.94 percent in 2013[7]. Georgia welcomed vehicle model offerings from ten automobile manufacturers[8] and became the number one Nissan Leaf market and the number two EV market in the United States[9], second only to California. This progress was accomplished without a mandate on EV adoption and without being one of the thirteen Zero Emission Vehicle ("ZEV")[10] or Low Emission Vehicle ("LEV")[11] states.

Atlanta, GA was recognized as the second-best city for EV adoption[12] and the fourth best city for workplace charging[13], and had the highest share of new vehicles that were battery electric vehicles ("BEV") per 1,000 people, amongst the 25 most populous US cities in 2014 (see Figure 1).

Georgia's monthly new EV registrations continued to grow through 2015 peaking at 1,338 registered EVs[14] in July 2015 (purchased or leased), and the Georgia EV market has consistently been referenced as a top EV market for registered EVs on the road. By the end of 2016, despite the elimination of the state tax credit in 2015, Georgia had 25,780 registered plug-in electric vehicles[15] ("PEV"s).

Figure 1: Electric vehicle shares and new registrations per 1,000 people across the 25 most populous US cities in 2014



Source: 2014 electric vehicle registration data provided by IHS Automotive

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[7] IBID
[8] From insideEVs – Nissan, Tesla, Ford, Mitsubishi, Smart, BMW, Porsche, Mercedes, Kia, VW
[9] IBID
[10] http://www.zevstates.us/
[11] https://www.arb.ca.gov/msprog/levprog/levprog.htm
[12] Comparing the Top 10 Cities for Electric Vehicle Adoption; http://www.fleetcarma.com/top-cities-electric-vehicle-sales/
[13] DOE Workplace Charging Challenge Progress Update 2016: A New Sustainable Commute
[14] IHS Polk Registration Data, as of April 2017
[15] IHS Polk Registration Data, as of April 2017

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EV growth in Georgia has already delivered benefits to customers and the local economy. Because of EV growth in Georgia, drivers have saved an estimated $11.8 million on fuel costs[16]. The financial savings for drivers, resulting from lower personal vehicle operational costs, have provided Georgians with the opportunity to inject income back into the local economy.

In addition to the economic results from EV adoption across the state, Georgia stood out amongst non-ZEV and non-LEV states, and demonstrated consumer demand exists for cost effective, cleaner transportation alternatives. The primary factors for this [increased] demand included the following:

- state tax credit ($5000),
- attractive lease programs,
- workplace charging,
- emerging public DCFC technology,
- driver convenience through HOV/HOT lane access, and
- Georgia Power's Time of Use - Plug-In Electric Vehicle Rate ("TOU-PEV-6") (approximately $0.55/gal gasoline equivalent[17]).

While the Georgia market experienced rapid growth, the market lacked broader awareness and critical charging infrastructure to support EV drivers' needs. The Company identified this void and decided to pilot an effort to address critical market needs and to support continued EV adoption.

[16] ScottMadden analysis
[17] https://www.georgiapower.com/pages/mobile/interests/electric-vehicles/what-rate-plan-is-best.cshtml

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Summary of ET Pilot Program to Support Existing Drivers and Encourage Market Growth

The Electric Transportation Initiatives Pilot was launched in the fourth quarter of 2014 as a utility demonstration program. The pilot was designed to address the critical market needs of broader EV awareness and a lack of critical charging infrastructure to support existing and future EV drivers.

In addressing these needs the pilot was to also provide Georgia Power with experiential knowledge of the EV market. These objectives and the execution of the pilot were critical to better serve Georgia Power customers and EV drivers across the state. The results offer insight into ways to support widespread adoption of EVs.

The Georgia Power Pilot program was designed around investments in five key dimensions with projected costs of $12 million:

Program Dimensions	Goals
Education and Awareness Campaign	Increasing consumer exposure, knowledge, and purchase consideration of EVs
Residential Infrastructure Initiative	Increasing available charging infrastructure in residences
Workplace Infrastructure Initiative	Increasing available charging infrastructure at workplaces and business establishments
Company charging infrastructure	Leverage Company infrastructure to provide charging infrastructure for use by the Company and the public
Community Infrastructure Initiative	Increasing available charging infrastructure in public locations for use by the public

Together the five program areas sought to address limited customer awareness and the need for charging infrastructure throughout the state.

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Programmatic Review of Pilot Program Results

The Georgia Power ET Pilot program was launched with an initial projected costs of $12 million and by the end of the pilot, final pilot costs totaled $10 million. Each program provided valuable market support and key experiential insights for Georgia Power and the state. The summary of the program results presented below highlight that residential and workplace infrastructure programs had positive RIM results, while the education and awareness and community infrastructure programs had negative RIM results.

Program Areas	Cost	Benefit	RIM	Key Results	Impact
Education and Awareness	$4.14M	$2.06M	($2.08M)	- 124 M impressions - 10% increased consideration	- Increased EV awareness - Increased purchase consideration
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Program Total	**$10.45M**	**$5.86M**	**($4.58M)**	--	--

Note: figures may not total due to rounding

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Education and Awareness

Increased consumer education and awareness of EVs was identified as a critical need in advancing the adoption of EVs. Studies indicate that EV adoption increases with the execution of focused education and awareness efforts[18]. Though the Georgia EV market showed tremendous growth, there existed and still exists, the need to raise awareness and educate consumers on EVs.

The Georgia Power Education and Awareness campaign focused on multiple messaging channels. These channels included TV and radio advertising, print media, digital and social media, and experiential education such as "ride and drive" events. All the efforts were coordinated between a handful of marketing agencies and delivered a common program message across multiple messaging channels.

The Education and Awareness Campaign focused on specific objectives each year of the pilot:

- 2014: Introduce Georgia Power EV programs
- 2015: Introduce benefits of EVs to customers
- 2016: Introduce and increase usage of public chargers

Beginning in fall of 2014, the Company participated in numerous marketing activation events, which were supported by the launch of the social media program, to introduce Georgia Power EV programs. These events provided drivers first hand experiential knowledge of EVs and educated them on the programs that Georgia Power offered to support EV adoption. The types of the events that Georgia Power participated in as part of the pilot are listed below:

- Professional sporting events
- Earth Day celebrations
- National Drive Electric Week
- Home and trade shows
- Charity walks and races
- Alternative Fuel Vehicles Roadshow
- City festivals

Beginning in 2015, Georgia Power launched radio, TV, digital media, and printed media programs to introduce benefits of EVs to customers. This broad reaching effort contributed to raising awareness and educating a broad base of consumers about EVs. The TV and digital programs featured testimonials and informative commercials that sought to demonstrate the financial benefit, driver convenience, and applicable EV technology, so that driver interest and EV consideration would be increased. These programs used the Georgia Power Pilot brand "Get Current. Drive Electric™".

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[18] http://www.theicct.org/sites/default/files/publications/Consumer-EV-Awareness_ICCT_Working-Paper_23032017_vF.pdf

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In 2016, Georgia Power continued the Education and Awareness campaign and focused efforts on the introduction and increased usage of public chargers. These efforts were executed primarily through social media channels and focused on raising awareness of available public infrastructure throughout the state.

Education and Awareness Campaign Results

Channel	Results	Comments
TV	10,047,900 impressions	broad public engagement and awareness
Radio	16,628,300 impressions	broad public engagement and awareness
Outdoor	7,397,793 impressions	broad public engagement and awareness
Digital	80,862,343 impressions	engagement exceeded benchmark
Interactive Banners	3,806,867 impressions	engagement exceeded benchmark
Video Units	5,063,947 impressions	engagement exceeded benchmark
Social Media	382,000 engagements	44,000 social media followers
Experiential Events	35 events	200,000 potential exposures

Source: Three Atlanta, GRM

By the end of 2016 the Education and Awareness campaign featured participation in over 35 events, drove over 44 thousand social media followers[19], 124 million customer impressions[20], and an additional estimated 1,994 vehicles sold. A customer survey[21] demonstrated a 10% increase in purchase consideration because of Georgia Power's ET Pilot initiatives.

19 social media followers tracked by GTM

20 includes TV, radio, and digital impressions tracked by Three Atlanta

21 online research performed by Three Atlanta which demonstrated a 10% increase in purchase consideration following the launch of Georgia Power's "Reverse Motion" TV education and awareness campaign

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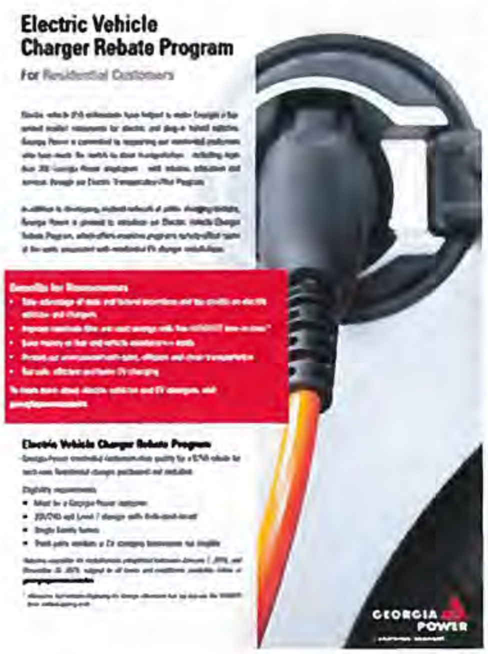
Residential Charging Infrastructure



The Residential Charging Infrastructure program focused on increasing the installation of L2 (240V) charging amongst Georgia Power residential customers, primarily through a $250 rebate following the installation of an L2 charger. The pilot confirmed previous research that found charging at home to be the dominant and most convenient charging location[22]. For reference, the EV Project[23] and an Idaho National Lab ("INL")[24] study show that the majority – between 57 and 85 percent – of charging events for EV drivers occurred at home. Having residential L2 charging most directly enables EV drivers to increase their electric miles driven as it recharges the car faster than historical Level 1 ("L1") charging and gets drivers back on the road more quickly.

In addition to offering $250 rebates to qualifying Georgia Power residential customers for the installation of Residential L2 chargers, the pilot also offered homebuilders $100 rebates for installing dedicated 240V circuits intended for the installation of L2 EV chargers. This builder rebate program was known as the EV Ready Homes[25] program.

Residential Charging Infrastructure Program Results

Channel	Target	Results	Comments
Level 2 Chargers	848	819	Residential L2 purchases are a secondary factor for driving vehicle sales; residential L2s increase electric miles driven
EV Ready Home Installs	152	249	Dedicated 240V circuit was an added amenity but adoption was limited
Total	1,000	1,068	

Georgia Power's Residential Infrastructure Program drove the installation of 819 residential L2 chargers and 249 EV Ready Homes.

[22] HTTPS://ENERGY.GOV/EERE/ELECTRICVEHICLES/CHARGING-HOME

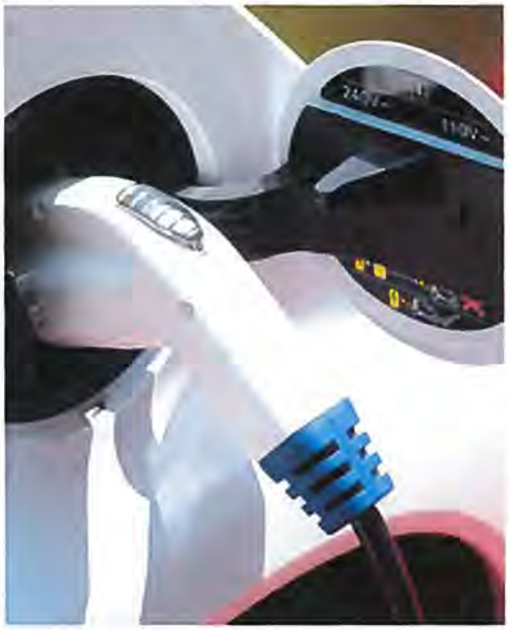
[23] ARRA EV Project: EV Project partnered with city, regional, and state governments, utilities, and other organizations in 16 cities to deploy about 14,000 Level 2 PEV chargers and 300 DC fast chargers. It also deployed 5,700 all-electric Nissan Leafs and 2,600 plug-in hybrid electric Chevrolet Volts. The research was conducted by Idaho National Laboratory.

[24] https://www.inl.gov/article/charging-behavior-revealed-large-national-studies-analyze-ev-infrastructure-needs/

[25] EV Ready homes come equipped with a dedicated 240-volt plug-in ready circuit including NEMA 14-50 outlet – Level 2 charger ready

Note: the total number of installed residential L2 chargers is currently unavailable as customers with EV Ready Home circuits were not required to report charger installations.

Workplace Charging Infrastructure



The Workplace Charging Infrastructure program focused on increasing the installation of L2 (240V) chargers among Georgia Power business customers, primarily through a $500 rebate following the installation of a L2 charger[26]. Workplace EV charging infrastructure is a key component to expanding EV adoption and supporting EV drivers in their daily commute. It is stated that workplace charging influences the purchase of EVs through increased awareness and infrastructure[27] and has been shown to meet as high as 39 percent of EV driver charging needs[28].

In addition to typical business customers, the business rebate program provided $500 rebates for multifamily dwellings. With the high concentrations of drivers residing at multi-family locations and the potential growth of EVs within those communities, it was critical to provide on-site EV charging to support these EV driver needs. Without EV charging on-site or in close-proximity, the adoption of EVs by residents in multi-family dwellings is challenged. The Company recognized this and targeted multi-family residences (common areas that are on business tariffs) to install EV chargers as part of the Workplace Infrastructure program. The pilot demonstrated that multi-family charging infrastructure is not only desired by drivers, but also by the communities themselves (EV charging was highlighted as an amenity)[29].

In addition to the $500 rebate provided through the Workplace Infrastructure program, Georgia Power also offered the PEV New Infrastructure program[30] which provided up to $10,000 per customer site for the installation of at least five with capacity for up to ten L2 chargers. This PEV New Infrastructure program was a subset of the Workplace Charging Infrastructure program.

Note: The DOE prioritized workplace charging as critical to EV adoption. Through an initiative launched under President Obama, EV Everywhere Grand Challenge, the DOE sought to expand workplace charging across the nation and ultimately drive increased EV adoption. (source: https://energy.gov/sites/prod/files/2016/05/f31/eveverywhere_blueprint.pdf)

[26] Both L1 and L2 charging have a role in expanding EV adoption, however with larger battery sizes and longer range vehicles, L2 charging will provide quicker charging and enable more EV miles driven.

[27] http://www.greencarreports.com/news/1093007_why-workplace-charging-is-important-it-sells-electric-cars

[28] https://www.inl.gov/article/charging-behavior-revealed-large-national-studies-analyze-ev-infrastructure-needs/

[29] https://cleancities.energy.gov/files/u/news_events/document/document_url/78/2_-_mud_challenges_successes_6-22-15.pdf

[30] https://www.georgiapower.com/about-energy/electric-vehicles/pdf/PEV_Infrastructure_Flyer.pdf

Workplace Charging Infrastructure Program Results

Channel	Target	Results	Comments
Workplace Chargers	1,236[31]	1044	Workplace L2 availability is a primary factor for driving vehicle sales; business L2s increase visibility of EV infrastructure and provide critical driver infrastructure
Multi-family Chargers	0[32]	261	Multi-family L2 availability is critical for multi-family residents and drives vehicle sales
Total	1,236	1,305	

The Georgia Power Workplace Infrastructure program drove the installation of 1,305 workplace chargers. These chargers were installed in workplace locations as well as in common areas of multifamily housing developments. As of June 2016, Atlanta, GA was ranked #4 in workplace charging[33] across the nation. The Georgia Power Workplace Infrastructure program contributed to the expansion of workplace charging across the state.

Georgia Power was also able to collaborate and leverage funding ($250,000) from Nissan North America, Inc.[34] to support the Georgia Power Workplace Infrastructure program. The collaboration with Nissan resulted in a matching funds rebate program entitled the Nissan Advantage program. This program offered up to $500 per charger[35] and was in addition to the $500 rebate being offered by Georgia Power to install workplace L2 chargers.

Community Infrastructure

A key influencer to the widespread adoption of EVs is the existence of public charging infrastructure. The Community Charging Infrastructure program sought to address critical public infrastructure needs

[31] An additional 104 workplace rebates were projected for L1 charging @ $250/rebate – L1 rebates were not applicable and none were redeemed

[32] initially there was no target established for multi-family residences, however during the course of the pilot the Company sought to expand the charging infrastructure at multi-family residences

[33] U.S. Department of Energy Workplace Charging Challenge Progress Update 2016: A New Sustainable Commute

[34] https://georgiapower.com/about-energy/electric-vehicles/pdf/Nissan%20EV%20Flyer-Agreement1-20-15.pdf

[35] Nissan provided Georgia Power with funds to pay participants who qualified and submitted the proper documentation to redeem the Nissan rebate

across the state. This infrastructure is needed to 1) provide drivers the capability of charging away from home or work, and 2) provide visual evidence to drivers which increases their confidence that charging on the go is possible, which reduces range anxiety[36].

Another impetus for Georgia Power deploying community charging was the low private participation in high-powered infrastructure[37] deployment. This program aimed to strategically deploy 60 charging islands across the state of Georgia. Each charging island consisted of one DCFC and at least one dual pedestal L2 charger.

The Community Charging Infrastructure program deployed 37[38] publicly available charging islands including 37 DCFCs and 45 dual-port L2 chargers – totaling 127 charging ports across the state. All the chargers deployed provided access for almost all vehicle types including those vehicles with only L2 charging connector technology and vehicles with DCFC charging connector technology (e.g. Combined Charging System("CCS") and CHArge de Move ("ChADeMo")[39]) – including Teslas with the appropriate adapter[40]. The universal access allowed EV drivers[41] to charge their vehicles while on the go within Georgia Power's service territory. These charging islands were deployed in a three-phase rollout from 2015 to early 2017.

Georgia Power was also able to collaborate and leverage funding ($90,000) from Nissan North America, Inc.[42] in support of the Georgia Power Community Infrastructure program. These funds were used in collaboration with Georgia Power funding to build out three community charging islands across the state – Augusta, Athens, and Savannah.

Three Phase Rollout:

- Phase 1: metropolitan areas to support locations with dense [existing] EV drivers
- Phase 2: rural areas to encourage market expansion beyond dense city centers
- Phase 3: interstate corridors to connect medium to long distance cities

The community chargers were initially offered at no cost to drivers for an introductory period followed by market based "fee-for-use" charging thereafter. The introductory period was offered to gain insight on charging behavior (including response to price signals), equipment reliability, network provider services, and repairs and maintenance. The collected charging behavior data informed adjustments throughout the pilot (e.g. pricing structure changes) and provided guidance for potential future deployments.

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[36] From the Oxford Dictionary, range anxiety is worry on the part of a person driving an electric car that the battery will run out of power before the destination or a suitable charging point is reached.
[37] Level 2 charging and above – 19+kW output
[38] thirty-five chargers installed by EOY 2016 with two additional completed by Q1 2017
[39] https://cleantechnica.com/2016/01/01/ev-charging-time-single-fast-charging-standard-now/
[40] https://shop.teslamotors.com/products/chademo-adapter
[41] applies to all EV drivers with the compatible charging technology (J1772, CHADeMO, or CCS) and who are part of the Georgia Power or Chargepoint network
[42] Funding from Nissan North America, Inc was used for site construction and installation of charging islands in Athens, Augusta, and Savannah, Georgia.

Georgia Power

In addition to the community charging infrastructure, Georgia Power created a network of Georgia Power EV subscribers. The network provided a medium for data exchange between network users and charging infrastructure. This data exchange supported increased customer satisfaction and equipment reliability. The Georgia Power Network provided drivers access to chargers within Georgia and additional chargers available nationwide[43].

Community Charging Infrastructure Program Results

Channel	Results	Comments
Charging Islands	37	Charging Islands equipped with one DCFC and at least one dual port L2 charger
Georgia Power Network Subscribers	1,400	Dedicated 240V circuit was an added amenity but adoption was limited

The observed charging behavior indicated the following:

Observed Charging Behavior	
Free charging	• When charging is free, EV drivers are less inclined to move their vehicles despite their vehicles being adequately charged – thus leading to charger congestion
Fee for Charge	• Pricing curtails usage despite market pricing being significantly less than the equivalent cost per gallon of gasoline • Applying market-based pricing influences charging behavior and reduces the time drivers spend charging their EVs
Variable pricing	• Applying variable pricing where the fee for charging increases after a set time, encourages drivers to move their vehicles to avoid increased incremental charging fees
Charging away from home	• Drivers use community charging secondary to either home or workplace charging

One key point is that Georgia Power successfully deployed 18 charging islands (49% of total Georgia Power deployments) along travel corridors and in locations with sparse EV ownership and/or limited charging infrastructure. These strategic deployments are critical because they: (i) extend the driving range for EV drivers allowing them to commute between major metropolitan areas, (ii) expand the market of potential EV drivers into areas where fewer EVs exist by providing charging infrastructure and encouraging EV adoption, and (iii) locate chargers where they don't currently exist.

The Community Charging Infrastructure Program was scaled back from the original program target (60 charging islands) in response to declining EV sales and deployments by other market participants such as EVGo, Tesla and the Georgia Environmental Finance Authority ("GEFA")[44]. In total, 1,473 public charging stations – 241 DCFCs and 1,232 L2s – have been deployed across the state through the efforts of Georgia Power and other market participants[45].

[43] chargers available outside of the Georgia Power service territory would have to be on the Chargepoint network to allow Georgia Power network drivers access

[44] GEFA (state agency) issued grants to install charging stations; https://gefa.georgia.gov/press-releases/2014-10-30/coming-soon-forty-four-new-electric-vehicle-charging-stations

[45] http://www.afdc.energy.gov/fuels/electricity_locations.html

Georgia Power

In addition to the physical hardware, the statewide charging network, with over 1,400 Georgia Power EV subscribers[46], allowed Georgia Power EV subscribers access to both Georgia Power community chargers and chargers available in the nationwide Chargepoint network[47].

Additional Program Results

The Georgia Power team continually monitored developments in the EV marketplace and curtailed program investments upon the expiration of the state tax credit which dampened EV demand. The negative RIM of public infrastructure resulted primarily from the high costs of DCFC infrastructure and the inability to achieve the targeted number of customer sessions per day. However, with the speed of innovation and increased competition[48], Georgia Power's cost of deploying public charging infrastructure decreased by roughly 40 percent[49].

As technology advances and the market matures, infrastructure costs are expected to decline further over the next five years. With continued stakeholder participation we expect that infrastructure costs will continue to decline providing more financial feasibility for additional deployments. And as with several other GPC programs that have proven to be positive and beneficial to all participating and non-participating customers, we intend to continue the infrastructure rebate programs that were RIM positive during the pilot period.

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[46] Georgia Power loyalty/network was powered by Chargepoint
[47] http://www.chargepoint.com
[48] EV Charging Roundup: Cheaper DC Options, Streetlight Chargers From BMW
[49] Charger installation costs decreased from $120k to $70k – reduced hardware needs, improved equipment, and streamlined install process

Georgia Power

Influencing Factors for EV Adoption

In addition to the eight key insights discussed earlier, the Company observed four key influencing factors that are critical for EV adoption:

Influencing Factor #1: Consumer awareness and education

Through the pilot, Georgia Power observed that improving consumer awareness and education regarding EVs can be accomplished by educating consumers on how EVs can be integrated into their lifestyles. This applies to individual EV owners and fleet applications as well. This pilot demonstrated that when customers are made aware of EVs and educated on the benefits [and limitations] of EVs, their perceptions of EVs change thus increasing both interest and purchase consideration.

Influencing Factor #2: Economics of ownership

At this stage of EV market growth the leading rationale for driving an EV is dominated by favorable ownership economics when compared to traditional gasoline-powered vehicles. Those economics are impacted by available incentives, acquisition costs, operational costs, and fuel costs. Georgia rose to be the second largest PEV market in the United States because of very favorable ownership economics – primarily due to the state tax credit. EV sales declined once the tax credit was eliminated. Drivers are dissuaded from purchasing an EV because of the generally higher up-front costs (barring incentives). However, over the life of an EV the economics still favor an EV vs. a traditional gasoline-powered vehicle due to the $7,500 federal tax credit and lower maintenance and fuel costs. The more favorable the economics of ownership the more likely a driver will switch to an EV. As a result, it will be key for industry stakeholders to successfully educate consumers on the favorable economics of ownership to facilitate adoption.

Influencing Factor #3: Availability of charging infrastructure

With the growth of EVs, there must also be commensurate growth of charging infrastructure. At the end of 2016 there were roughly 25,000 plug-in electric vehicles in Georgia with approximately 1,420 Level 2 and 240 DCFC public charging stations[50]. Based on these numbers the ratio of charging infrastructure to EVs is 0.05 for L2s and 0.01 DCFCs. These ratios are below the benchmark[51] to support a healthy EV market and contribute to the primary fear of EV drivers –range anxiety: the fear of running out of fuel (electricity). The lack of charging infrastructure across the state promotes range anxiety and suppresses EV growth.

Through the pilot, Georgia Power increased both publicly accessible EV charging infrastructure and private infrastructure available at workplace and residential locations. Additional efforts to expand infrastructure like the DOE EV Everywhere challenge, are vital to expanding EV adoption. While infrastructure alone does not grow the EV market, it is a critical component to market growth by providing necessary refueling infrastructure and confidence against range anxiety.

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[50] AFDC Electric Vehicle Charging Station Locations (Jul 2017). Data reported may not be exact – station count is collected manually. Generally excludes private charging locations – residential and workplace

[51] According to the EIA, "early estimates of adequate non-residential EVSE/EV ratios range from 0.08 to 0.3"; https://www.iea.org/publications/freepublications/publication/GlobalEVOutlook_2013.pdf

Georgia Power

Influencing Factor #4: Driver convenience

Traditional gasoline-powered vehicles have defined driver behavior and expectations for over a century. As such, perceived driver inconvenience and high barriers to switching are critical and negatively influence widespread EV adoption. Providing driver conveniences including, but not limited to, infrastructure to support established driving patterns (home, workplace, public), express lane access, dedicated parking, and interoperable charger network access will increase EV adoption. Since resistance to change is normal for most, increasing EV driver convenience will be critical in driving market adoption and driver satisfaction.

In addition to these four key factors, the pilot provided additional operational knowledge for continued market growth. This knowledge resulted from siting and installing public infrastructure, operating a charging infrastructure network, engaging and educating drivers, collaborating with industry stakeholders, and managing the ongoing operations of an electric transportation program. Through the pilot, we observed that there are opportunities to electrify additional areas of transportation beyond EVs, and reap benefits for the state of Georgia. Those benefits include job creation, reduced pollutants, and decreased dependency on foreign energy[52].

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[52] The Economic Opportunities of Electric Vehicles in Georgia; Greenlink, 2017

Georgia Power

Market Dynamics that Support Increased Growth and the Market Outlook

Despite barriers, EV market growth is forthcoming based on six primary drivers.

1. ***Load Smoothing*** – Utilities are continually searching for opportunities to reduce load volatility. Through the PEV rate, EV charging can be shifted to off-peak hours and improve the load factor for residential customers with PEVs.
2. ***Driver Economics*** – Drivers are interested in reducing their mobility expenses and EVs provide significant lifetime cost of ownership savings vs. traditional gasoline-powered vehicles[53].
3. ***Expansion of Vehicle Offerings*** – Original Equipment Manufacturers (OEMs) are expanding their product lines to include EVs both nationally and globally with future EV offerings aimed at being both affordable (in the $30,000's) and providing 200+ miles of range.
4. ***New Market Entrants*** – New and recent market entrants, such as Tesla and Future Faraday, are influencing innovation amongst traditional automakers and expanding the EV market to better meet the needs of all drivers.
5. ***Technology Advancement*** – Innovation in battery technology and reduced production costs reinforce the opportunity for EVs to reach mass adoption – battery pack costs are falling faster than projected and could be lower than $100/kWh by 2020[54].
6. ***Environmental Concerns*** – EVs provide good opportunities to reduce environmental pollution resulting from transportation[55].

Together load smoothing, driver economics, expansion of vehicle offerings, new market participants, technology advancements, and environmental concerns, provide the platform and opportunity for EV growth to continue.

[53] https://www.nerdwallet.com/blog/loans/electric-hybrid-gas-how-they-compare-costs-2015/
[54] http://gas2.org/2017/02/10/ev-battery-prices-falling-faster-expected/
[55] https://energy.gov/eere/electricvehicles/reducing-pollution-electric-vehicles

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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-20134

At the January 9, 2019 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner

ORDER

On May 14, 2018, Consumers Energy Company (Consumers) filed an application seeking authority to increase rates for the generation and distribution of electricity and requesting other regulatory approvals. Consumers indicated in its filing that it projected a $58 million jurisdictional revenue deficiency based on a calendar 2019 test year, which the utility later revised to a $44 million jurisdictional revenue deficiency.

Administrative Law Judge Sharon L. Feldman held a prehearing conference on June 1, 2018, where she granted petitions to intervene filed by, among others, the Michigan Department of the Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); the Michigan Environmental Council, the Natural Resource Defense Council, Sierra Club, and the Ecology Center (collectively MEC/NRDC/SC/EC); the Michigan Energy Innovation

Business Council (MEIBC); ChargePoint, Inc.; and the Environmental Law & Policy Center (ELPC). The Commission Staff (Staff) also participated.

Evidentiary hearings were held on October 11-12 and 15-18, 2018. Initial briefs were filed on November 9, 2018, and reply briefs were filed on November 21, 2018. The record in this case consists of 3,630 pages of transcript and 417 exhibits admitted into evidence.

On December 18, 2018, the majority of the parties filed an executed settlement agreement, and by December 19, 2018, all parties had either executed the settlement agreement or filed their non-objection to the settlement agreement. The settlement agreement is approved by the Commission in a separate order issued today. In the settlement agreement, the parties left one unresolved issue.

The parties agree to implementation of Consumers' proposed PowerMIDrive program as described in Attachment 3 to the settlement agreement, but indicate that they do not agree on the issue of Consumers' request to recover the costs of this program through a deferred accounting mechanism, stating as follows:

> This Settlement Agreement does not resolve the issue of Consumers Energy's request to recover its costs related to the electric vehicle program through a deferred accounting mechanism that allows the Company to earn a return on the costs until they are recovered in a subsequent rate case. The parties request the Commission to address this issue based upon the Initial and Reply Briefs filed pursuant to the schedule established by the Administrative Law Judge in this case. . . . [T]he parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement, except with respect to the issue regarding regulatory asset treatment of PowerMIDrive pilot program costs, which are to be determined by the Commission based on the parties' briefing in this case as set forth above in Paragraph 10.

January 9, 2019 order in Case No. U-20134, Exhibit A, ¶¶ 10, 28. In initial and reply briefs, 10 parties weighed in on this issue.

Positions of the Parties

Consumers proposed a three-year pilot foundational infrastructure program intended to support the growing electric vehicle (EV) market in the utility's service territory, known as the PowerMIDrive program (EV program). According to the testimony of Michael J. Delaney, Consumers' Executive Director for Corporate Strategy, EV adoption saves money for drivers, supports local industries, and reduces dependency on foreign oil, but also "puts downward pressure on electric rates by spreading fixed costs over increased electric load which would ultimately reduce electric rates for all customers" if the program is well-designed, that is, if it adopts incentives that move charging to off-peak times through the use of, among other things, time-of-use (TOU) rates. 4 Tr 1031-1032. This can result in utilizing excess distribution and generation capacity in a way that benefits all customers. Mr. Delaney stated that barriers to EV adoption in Michigan currently exist in the form of a gap in charging infrastructure, range anxiety, and a lack of public awareness. He stated that studies would suggest, for example, that Michigan should currently have about 1,095 Level 2 public chargers and 60 DC Fast Chargers (DCFCs) (assuming 15,000 EVs currently on the road in Michigan), but that the state actually has 467 public chargers and 16 DCFCs. Consumers' proposed program will not involve utility ownership of charging infrastructure, but will incentivize the reduction of these barriers through rebates and customer education. Mr. Delaney asserted that this is prudent action on the utility's part, because Consumers proposes to test out these incentives while statewide EV adoption is still low in order to be able to improve the program over time. Consumers argued that it seeks to avoid expensive, reactive adjustments to a growing EV market that would involve capital intensive solutions.

Consumers proposed a residential TOU rate for EV use called the Nighttime Savers Rate, that will encourage charging during 7:00 p.m. to 6:00 a.m. The EV program is intended to enable residential charging, Level 2 public charging, and DCFCs across the service territory for three years through a suite of rebates: $500 per vehicle for residential EV drivers who enroll in the Nighttime Savers Rate, $5,000 per charger for Level 2 public chargers (which includes public, workplace, and multi-dwelling unit chargers), and up to $70,000 per DCFC charger. The EV program also includes education and outreach components.

Consumers estimated the cost of the three-year program at $7.5 million, with about half of that amount being incurred in the first year. Exhibit A-75. In its service territory, Consumers calculates "a net benefit to the grid of approximately $1,900 - $2,300 per electric vehicle." 4 Tr 1051; Exhibit A-74. Thus, doubling the number of EVs in its service territory during the three-year pilot could bring a gross system benefit of $15 to $18 million. 4 Tr 1052. In light of the benefits, Consumers requested to treat the program costs as a regulatory asset and to record deferred amounts associated with the rebate and related operations and maintenance (O&M) costs until the costs are confirmed. Mr. Delaney testified:

> The regulatory asset approach allows the Company to invest in EV charging infrastructure now to benefit Consumers Energy customers and recover those costs at a later date. A regulatory asset approach allows for prudency review prior to collection through rates. This is well-suited for a pilot where Program participation may vary significantly from initial expectations. Further, this approach spreads the recovery of Program costs and the cost of capital over the life of the EV charger assets which smooths out the impact on customers and aligns well with the expected lifetime benefits of the EV program.

4 Tr 1054. Mr. Delaney noted that the Staff, ChargePoint, MEC/NRDC/SC/EC, and MEIBC support Consumers' accounting proposal, and argued that non-traditional ratemaking is necessary in this arena in order to "balance the disparity between capital and non-capital solutions." 4 Tr 1075. Mr. Delaney stated that the overall focus of Consumers' proposal is to shift EV load to off-peak times and to minimize the utility's capital investment in distribution and general infrastructure necessary to support expected growth in EV use.

Daniel L. Harry, Consumers' Director of General Accounting, testified that under Consumers' proposal the utility would amortize each annual deferred amount over 10 years beginning the year after the cost is incurred, the resulting expense would be included in rates, and the deferred cost would be subject to review in rate cases. 5 Tr 2126; Exhibit A-75. The deferred unamortized balance would be included in rate base and would earn a return. Consumers later agreed to the Staff's proposal to reduce the amortization period to five years. 5 Tr 2130. If the EV program is approved, Consumers requests that the Commission: (1) authorize the recognition of a regulatory asset to recognize deferred EV program costs; (2) authorize the amortization of deferred EV program costs over five years beginning the year after the cost are incurred; (3) include recovery of the resulting amortization expense in rates; and (4) include the deferred net unamortized balance of EV program costs in rate base. 5 Tr 2127, 2130. According to Mr. Harry, the alternative to this recovery approach is to include projected test year program costs in rates.

Karl R. Rábago, Principle of Rábago Energy LLC, testified on behalf of ELPC in opposition to Consumers' regulatory asset treatment proposal. He indicated that costs not directly related to the production, transmission, distribution, or sale of electricity would traditionally be considered operating expenses, which are recoverable on a dollar-for-dollar basis in rates; and that, if expected to vary, operating expenses can be subject to a tracker. Mr. Rábago stated that, in response to discovery, Consumers indicated that (applying certain assumptions) the $7.5 million estimated EV program budget would result in a total revenue requirement of about $10.7 million. Exhibit ELP-5; 4 Tr 776. Mr. Rábago notes that regulatory asset treatment will allow Consumers to earn a return on the cost of the rebates. He asserts that this is unnecessary:

> The Company proposal would result in the Company not bearing any capital risk in order to earn the load-building revenues associated with transportation electrification, and also earning a profit on rebates it pays to customers to encourage them to make the actual capital investments that the Company is not

> undertaking. The Company is proposing to earn profits on its rebate payments as if it were investing, risk-taking, and managing charging assets, but it is not.

4 Tr 777-778. He pointed out that ordinary expense treatment would also allow for current spending and subsequent recovery, would allow for tracking of the rebates, and would be subject to the same later prudency review. Mr. Rábago testified that capitalization results in unnecessary increased costs to customers, and that the utility should not require the incentive because the utility is not actually making any capital investments. He stated that the regulatory asset approach will not incentivize charging site owners, alleviate range anxiety, increase off-peak charging, or provide customer education. Mr. Rábago opined that Consumers has not adequately supported its accounting proposal, and that the very uncertainty associated with a pilot program should weigh against allowing a return on rebate expense. 4 Tr 784.

In rebuttal, Mr. Delaney asserts that ELPC's proposal would punish the utility, and that "shareholders would have been better off it [sic] the Company had simply made reactive system upgrades as increased EV demand created the need for increased utility capital investment." 4 Tr 1077. He contends that increased capital investment also costs ratepayers money and this is what the pilot is intended to avoid. Mr. Delaney contends that Mr. Rábago ignores the time-value of money, and that Consumers demonstrated that the net present value impact of the proposed regulatory asset treatment is less than $100,000 when compared to the revenue requirement associated with conventional ratemaking. Exhibit A-146; 4 Tr 1078. Mr. Delaney states that the uncertainty of customer participation in the pilot program aligns well with regulatory asset treatment because cost recovery will be determined on the basis of actual costs and not projected costs.

Initial and Reply Briefs

The briefs largely repeat the testimony. Consumers reiterates Mr. Delaney's testimony and notes the support of the Staff, ChargePoint, MEC/NRDC/SC/EC, and MEIBC, as well as its agreement to the changes proposed by the Staff, MEC/NRDC/SC/EC, and MEIBC. 4 Tr 1060-1063, 1080. Consumers contends that its accounting proposal is reasonable in that it partially offsets the disincentive for a utility to develop a proactive and innovative program that will reduce future capital investments. Consumers asserts that the EV program is not designed to build utility load, but rather to focus on incentivizing off-peak usage and reducing the type of capital investment that would be reactive to EV growth. Consumers indicates that if the regulatory asset proposal is rejected, the EV program will be re-evaluated.

The Staff indicates its support for the proposal as revised, and argues that it is time to implement an EV charging pilot.

MEC/NRDC/SC/EC indicate their support, stating that this "is a reasonable method to account for a new, market-driven program offering where rebate and [O&M] costs cannot be confirmed on the front-end." MEC/NRDC/SC/EC's initial brief, p. 89.

MEIBC's indicates its support for regulatory asset treatment.

ChargePoint argues that regulatory asset treatment for rebates is the best way to encourage customer investment in charging technologies and expansion of charging throughout Michigan, and that the potential for widespread grid benefits resulting from EV adoption supports approval of the proposed accounting treatment.

ABATE indicates that it is comfortable with whatever the Commission decides, because the proposed accounting approach will allow for a future prudency review in any case.

ELPC opposes the proposal, arguing that rebates are expenses and not capital investments because they are not involved in providing service, and thus should be subject to traditional ratemaking. ELPC argues that ordinary expense treatment will still allow Consumers to recover the costs subject to a prudency review, and that customers will pay less in the long run. ELPC contends that Consumers' proposal is simply another way to earn a profit and urges the Commission not to set this precedent. ELPC asserts that if the Commission finds that an incentive is required, it should be a performance-based incentive.

Discussion

The Commission agrees with Consumers, the Staff, MEC/NRDC/SC/EC, MEIBC, and ChargePoint, and finds that Consumers' regulatory asset accounting proposal, as revised to reflect a five-year amortization period, should be approved. ELPC objects to allowing Consumers to earn a return on the cost of the three-year pilot EV program rebates, but fails to provide a persuasive argument. The Commission finds that it is appropriate to incentivize the utility, at this stage of EV adoption, to think proactively and innovatively on this issue. Consumers' proposal is grounded in its desire to avoid reactive and expensive capital infrastructure investments in the future when EV adoption reaches the point where the utility must provide incremental generation, distribution, and transmission support. EV adoption is in its infancy in Michigan, but all indicators point to continued expansion. This expansion may result in increased load, but it may also result in more efficient use of excess generation and distribution capacity during off-peak hours to the benefit of all customers, as well as provide new modes of storage.[1] None of this will materialize until EV chargers become more prevalent and accessible.

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[1] The Commission has previously approved deferred accounting treatment for utility funding for residential EV customers similar to a rebate. *See,* August 10, 2010 order in Case No. U-16406.

Consumers' modest three-year pilot rebate proposal marks a beginning, and will likely provide data that should be useful in designing future programs intended to incentivize EV adoption. The conditions placed on the EV program rebates will ensure that customers can easily see the benefit to off-peak charging, and should encourage charging during those hours. The Commission notes that the program costs will not actually be recovered until they have undergone a future reasonableness-and-prudence review in a rate case. The Commission directs Consumers, at the conclusion of the pilot program, to examine whether there would be cost savings associated with the use of a tracker for future rebate programs (with O&M treatment) in comparison to regulatory asset accounting.

THEREFORE, IT IS ORDERED that:

A. Consumers Energy Company's application for regulatory asset treatment of costs associated with the PowerMIDrive pilot program, as described in this order, is approved.

B. Consumers Energy Company is authorized to amortize the PowerMIDrive pilot program deferred costs over five years beginning the year after the costs are incurred, and to include recovery of the resulting amortization expense in rates.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

By its action of January 9, 2019.

Kavita Kale, Executive Secretary

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-20134

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on January 9, 2019 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 9th day of January 2019.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

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**BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND**

IN THE MATTER OF THE PETITION	*	
OF THE ELECTRIC VEHICLE WORK	*	
GROUP FOR IMPLEMENTATION OF	*	CASE NO. 9478
A STATEWIDE ELECTIC VEHICLE	*	
PORTFOLIO	*	

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SEMI-ANNUAL PROGRESS REPORT OF BALTIMORE GAS AND ELECTRIC COMPANY, DELMARVA POWER & LIGHT COMPANY, AND POTOMAC ELECTRIC POWER COMPANY REGARDING IMPLEMENTATION OF APPROVED ELECTRIC VEHICLE CHARGING PROGRAM OFFERINGS

Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("Delmarva Power"), and Potomac Electric Power Company ("Pepco" and together with Delmarva Power, the "PHI Utilities") (collectively the "Exelon Joint Utilities"), hereby submit to the Maryland Public Service Commission (the "Commission") their semi-annual progress report in accordance with Commission Order No. 88997 issued on January 14, 2019 in the above-captioned matter. Through this filing, the Exelon Joint Utilities provide the Commission with reporting requirement information regarding implementation plans from January 14, 2019 through June 30, 2019 for the electric vehicle ("EV") charging program offerings approved by the Commission in Order No. 88997.

I. INTRODUCTION

The Exelon Joint Utilities file this semi-annual progress report in accordance with the Commission's directive in Order No. 88997 that the utilities shall file in the Commission's EV Portfolio public docket, semi-annual progress reports, with a Q1/Q2 Report due on August 1st and a Q3/Q4 report due on February 1st of the following year. Furthermore, as directed, a draft template for uniform EV Portfolio Reporting Guidelines was jointly reviewed and edited by Potomac Edison, BGE, and the PHI Utilities through several EV work group meetings and conference calls. Potomac Edison and the Exelon Joint Utilities have confirmed their understanding of the metrics as they pertain to their respective specific program offerings.

In Sections II and III below, the Exelon Joint Utilities describe their EV portfolio offers and implementation statistics as required for the time period spanning January 14, 2019 through June 30, 2019. Specific section headings and sub-headings track those contained on the approved EV Portfolio Reporting Guidelines template. Due to their EV programs opening on July 1, 2019, the Exelon Joint Utilities can only provide limited information and statistics. More comprehensive information will be available in the February 1, 2020 semi-annual progress report filing.

While the Exelon Joint Utilities issued common requests for proposals (“RFPs”) and selected common vendors for many components of the eligible EV charging equipment and network administration, and developed the same public EV charging market rates, joint marketing plans, and common websites, there will be some differences in program implementation based on services provided through in-house resources or third parties. The program budgets provided below summarize a detailed budget range per offer category, based on actual winning bids for program contract labor and materials by each Utility. Lastly, there may be minor additional changes to the Pepco and Delmarva Power budget tables, based on outstanding RFPs on some engineering work aligned with certain programs that will start in Q2 of 2020.

II. BGE EXECUTIVE SUMMARY

1. Program participation and Impact Highlights

a) Provide a summary of the portfolio offerings.

RESIDENTIAL PROGRAM OFFERINGS

BGE's approved residential program offerings include (1) a flat $300 rebate for 1,000 residential customers that purchase and install eligible Level 2 ("L2") EV smart chargers after July 1, 2019, and (2) an EV Only Time of Use ("TOU") rate. Rebate-eligible smart EV chargers include models from ChargePoint, eMotorWerks, and Siemens. Customers can apply for the rebate via an online portal or a fillable PDF application. Additionally, BGE is offering a dedicated Customer Care phone line for EV-related questions. BGE is also offering extensive educational tools on BGE.com to inform customers of the benefits of EVs, available EV and EV charging incentives, and a map of available EV chargers. BGE expects to offer the EV Only TOU rate to customers in 2020.

MULTIFAMILY PROGRAM OFFERINGS

BGE's approved multifamily offerings include a rebate for 50% of the cost of the eligible EV charging equipment and installation up to $5,000 per port for L2 EV chargers and $15,000 per direct current fast charger ("DCFC") station for a maximum incentive of $25,000 per site. Rebate-eligible EV chargers include models from ChargePoint, eMotorWerks, EVConnect, Greenlots, SemaConnect, and Siemens. Customers can apply for the rebate via an online portal or a fillable PDF application. BGE is offering a dedicated Customer Care phone line for EV-related questions. BGE will also offer a demand charge credit to multifamily, workplace, and fleet installations for 50% of the nameplate capacity for 30 months starting January 1, 2020.

PUBLIC PROGRAM OFFERINGS

BGE's public utility-owned EV charging network will include 500 EV chargers installed on government-owned or controlled sites throughout BGE's electric distribution service territory. BGE has been accepting applications from government entities since July 1, 2019. The RFP for a network provider and EV charging equipment is still open.

EDUCATION AND OUTREACH

BGE is working in concert with the PHI Utilities on all marketing activities. The Exelon Joint Utilities provided marketing materials and webpage designs for review and comment to the EV Work Group and the Maryland Zero Emission Electric Vehicle Infrastructure Council. BGE incorporated feedback received and released a new webpage to customers on June 20, 2019. Through BGE's EVsmart online toolkit, customers can apply for an EV charger rebate, learn the basics of EV charging, use savings calculators to compare the cost of gas-powered versus electric-powered vehicles, view state and federal tax incentives available for EV owners, and locate an EV dealer in their area. BGE's webpage also provides a link to MarylandEV.org in multiple areas.

The Exelon Joint Utilities conducted initial EV market research including a quantitative survey study of approximately 1,200 residential customers, and a qualitative study whereby customer focus groups, consisting of individuals who currently own an EV or would consider purchasing an EV in the next 12-18 months, answered various questions posed by the Exelon Joint Utilities and offered thoughts and impressions on test education and outreach materials.

The Exelon Joint Utilities will also be developing messaging with supporting imagery to illustrate the benefits of electric transportation based on customer research findings to be used in online messaging, brochures, talking points, press releases media outreach, employee communications, targeted customer emails, direct mail, paid search ads, digital media, social media, and customer outreach through the Exelon Joint Utilities' External Affairs teams.

MANAGED CHARGING DEMONSTRATION

BGE will use the EV charging infrastructure installed at BGE office locations to demonstrate managed charging. BGE is working with its vendors to schedule capacity reductions on EV chargers at various locations for different durations. BGE will use various messaging to employees to determine the most effective messaging for managed charging control.

EVALUATION, MEASUREMENT & VERIFICATION

BGE is collaborating with the PHI Utilities and Potomac Edison to draft and release an RFP to secure a common evaluation, measurement and verification ("EM&V") vendor for the EV programs.

b) Provide a list (or include as an Appendix, labeled as "Appendix A," etc.) of the chargers installed by county and zip code. Specify the type of charger (residential, MOU, etc.)

This data is not applicable for the time period January 1, 2019 through June 30, 2019 as BGE did not begin making the EV charger programs available until July 1, 2019.

c) Provide a highlight of the overall successes of the portfolio, while also including any major changes or issues encountered during the period. Report the percentage of offerings that have been installed, for example 100 of maximum 500 residential rebates, therefore 20%.

This data is not applicable for the time period January 1, 2019 through June 30, 2019, as BGE did not begin making the EV charger programs available until July 1, 2019.

2. Reporting Period Cost Breakdown

a) Discuss the overall costs, broken down by cost categories, charger type and sub portfolios (including capital costs and annual operations and maintenance costs). Also include, incentive costs, marketing costs, and any make ready costs such as distribution system upgrades.

Please see the estimated budget table attached hereto as Appendix A.

3. Commission Requests

a) Changes in incentives, design, budget, or implementation.

BGE has no Commission requests for this semi-annual report.

III. BGE Program Specifics

There is currently no available data for program specifics for the time period January 1, 2019 through June 30, 2019, except for the Program in Ramp-up Phase entry.

1. Programs in Ramp-up Phase

a. While programs are ramping up, discuss the following:

i. Program implementation progress and roll out activities to-date.

BGE reports the following:

- The BGE.com/ElectricVehicles webpage went live on June 20, 2019 providing program information and education tools for customers to learn more about the benefits of EVs.

- The residential and multifamily rebate programs, as well as the utility-owned public EV charging programs, all launched on July 1, 2019.

- BGE expects to begin demonstrating managed charging capabilities in 2019. BGE will run events to reduce the capacity of EV service equipment at BGE office locations at different levels and for different durations to determine the amount of load reduction and impacts to EV drivers, which can be used to develop a future customer facing program that will help minimize grid impacts when there is a more significant amount of EVs in Maryland.

- BGE has conducted outreach to all the county/local government entities in its electric distribution service territory to make them aware of the opportunity to have EV charging infrastructure installed on their property.

- BGE is working with the PHI Utilities to conclude the joint RFP that was issued to secure the EV charging stations and network provider. BGE, Pepco, and Delmarva Power will use the same network provider to ensure a consistent experience for customers that travel between the service territories.

- BGE reviewed public charging rates in Maryland to determine whether average market rates have changed since the initial tariff filing. BGE concluded that average market rates have not changed materially and no change to the Commission-approved tariff is necessary at this time.

ii. Explanations for changes in anticipated program implementation and provision of new/updated timelines, if necessary.

BGE reports the following:

- The budget for the BGE public EV charger program increased from the budget submitted to the Commission in the April 2019 compliance filing. The increase is necessary to account for a higher mix of DCFCs to meet market demand. BGE initially built a budget to support a public EV charger ratio of 90% L2 EV charger installations and 10% DCFC installations. BGE has learned through its outreach efforts with government entities that the demand for DCFCs is greater than initially expected. BGE has modified the program budget to support a revised mix of 80% L2 EV charger installations and 20% DCFC installations.

  BGE will be offering an EV Only TOU rate to residential customers using the interval data from participating EV chargers. BGE will need to complete enhancements to its billing system to be able to incorporate the EV charging data and calculate the EV Only TOU rate. BGE expects to be able to offer this rate to customers starting in 2020. In addition to data obtained directly from chargers, BGE is working with vehicle manufacturers to use telematics data from some EVs to provide the EV Only TOU rate to the broadest group of customers, including those from whom BGE will not be able to obtain data from a capable EV smart charger. The intent would be to allow, for instance, a Tesla Model 3 driver who relies on her vehicle's built in telematics for monitoring and managing charging, and who may have a Tesla charger installed at home, to still be able to participate in BGE's EV Only TOU rate offering.

2. Implemented Programs

a. For each program, the following should be included:

   i. Update on the status of the program. For example, expected date of construction of utility chargers at each site and when they will be operational.

   ii. Relevant metrics that support the status of the program, including percentage of deployment, etc.

   iii. Explanation for significant changes in participation, delivered measures, or costs from previous periods.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

3. Program Specific Metrics

a. For each program, the following should be included:

   i. Residential Programs

      1. Participants that switch to EV/TOU rate.
      2. Average frequency of daily charging.
      3. Average length of daily charging.
      4. Timing of daily charging, including hourly breakdown.
      5. Total number of customers that have participated in the program.
      6. Average itemized program cost per customer.
      7. For PHI's Smart Level 2 Chargers and EV-Only TOU Only:
         a. Total number of customers participating in Demand Response.
         b. Total number customers participating in Green Rider.
      8. EVSE Submetering:

a. Customer satisfaction survey, rating the following:[1]

   i. Accuracy of measurement of electricity used by customer's EV.

   ii. Accuracy of EV portion of customer bill.

   iii. Ability to control charging station remotely.

   iv. Availability of EV-only TOU rate.

   v. Overall satisfaction with submetering service (including customer billing).

b. Any technical, billing, or customer service-oriented challenges encountered by Utility

9. Comparison of energy use profiled between:

   a. Homes on the offered EV/TOU/Whole House rate with homes not on any EV/TOU/Whole house rate that receive an EV charger rebate, if applicable. Also a comparison of the various rate offerings against each other.

   b. Average customer energy costs per month for off peak and on peak charging, if applicable.

   c. Summary of charging on demand response events, if applicable.

ii. Non-Residential Programs:

1. The usage rate by charger type. Average time at charger, average kWh usage per charging session, amount of times each charger is used per day, time of day of charging, location of charging.

2. The charging load profiles (both aggregate and by site type).

3. The price per kWh and usage in kWh by price charged to EV drivers, if available.

4. Actual costs of implementation at each site. Discuss the overall costs, broken down by cost categories and charger type (including capital costs and annual operations and maintenance costs). Also include incentive costs and any "make ready" costs such as distribution system upgrades.

iii. Public Programs:

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[1] The customer satisfaction survey will include plain language and a straightforward rating scale to increase the likelihood and number of responses.

1. The usage rate by charger type. Average time at charger, average kWh usage per charging session, amount of times each charger is used per day, time of day of charging, location of charging.
2. The charging load profiles (both aggregate and by site type).
3. Actual costs of implementation at each site. Discuss the overall costs, broken down by cost categories and charger type (including capital costs and annual operations and maintenance costs). Also include incentive costs and any make ready costs such as distribution system upgrades.
4. The profit/loss at each site for the cycle and to date.
5. Location of all constructed and approved sites on a map.
6. Customer satisfaction survey, rating the following:[2]
    - i. Reliability of charging station.
    - ii. Safety of charging station.
7. EVSE Submetering:
    - a. For initial report only: Assessment of submeter functionality—*i.e.*, metrology testing procedure, standards, and result—supported by technical specification sheets associated with the EV charging station metering.[3]
    - b. Results of utility-owned chargers in-service performance testing:[4]
        - iii. Frequency of testing.
        - iv. Maximum allowable error tolerance.
        - v. Sample size of participating submeters.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

[2] The customer satisfaction survey will include plain language and a straightforward rating scale to increase the likelihood and number of responses.

[3] Comprehensive testing information may not be available until the February 1, 2020 semi-annual report. The utilities will work with the Commission's Engineering Division to provide all available testing information before using EV chargers for billing purposes.

[4] Where AMI data is not available, an equivalence test may be performed against data logger readings.

4. For the mid-course and final reports only: Portfolio Level Metrics

a. Total impact of EV chargers on utility's system peak demand (in kW) during system peak (for all chargers where data is collected).and broken down by residential, non-residential and public peak demand.

b. Total impact of EV charging on utility's retail sales (kWh) (for all chargers where data is collected). and broken down by residential, non-residential and public sales.

c. Total impact of EV charging on utility's revenue from retail sales ($) (for all chargers where data is collected)[5]and broken down by residential, non-residential and public charging stations.

d. Average increase in a charging station site host's electric demand (kW) and sales (kWh), by customer class (for all chargers where data is collected).

e. Hourly demand over a typical 24-hour weekday for all EV chargers for which data is collected, and broken down by residential, non-residential and public peak demand.[6]

f. Total percentage of EV charging occurring during off-peak hours (for all chargers where data is collected). and broken down by residential, non-residential and public charging stations.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

II. PHI UTILITIES EXECUTIVE SUMMARY

1. Program participation and Impact Highlights

a) Provide a summary of the portfolio offerings.

RESIDENTIAL PROGRAM OFFERINGS

The PHI Utilities' approved residential program offerings consists of three items: (1) an unlimited Whole House EV TOU rate (R-PIV rate), (2) 1,000 rebates of $300 each

[5] To be calculated using information from EV only time of use rate and public charging network programs. For other programs, estimates may be provided if possible.

[6] Utilities will also provide full 8760 usage data to Commission Staff and OPC.

to customers who purchase and install an eligible L2 EV smart charger, and (3) a discounted EV charger and installation for 137 SOS residential applicants with a mandatory on-bill separate time of use rate (PIV rate) using the second meter as a submetering device for billing and performing managed charging during peak energy saving days for the subscribed customers on residential accounts.

Customers can apply for the rebate online with a fillable PDF application. The PHI Utilities are offering a dedicated Customer Care phone line for EV-related questions. Pepco and Delmarva Power are also offering several educational tools on Pepco.com and Delmarva.com respectively to inform customers of the benefits of EVs, available incentives, and a map of available EV chargers. The PHI Utilities will offer the very limited discounted residential charger plus installation with an EV Only TOU rate to customers starting in Q2 2020.

Each offer may be voluntarily combined with the green rider adder to ensure a complete clean energy supply construct for residents that choose that option.

<u>COMMERCIAL PROGRAM OFFERINGS</u>

The PHI Utilities' approved commercial program offerings consist of two items: (1) a discounted L2 smart charger and one time free installation per site for 250 multifamily applicants with a voluntary green rider adder to ensure 100% clean energy use, and (2) a multifamily, fleet, and workplace demand charge credit on qualifying customer owned L2 or DCFC EV chargers for 30 months or until the end of December 2022. The fixed credit would be for 50% off any newly installed (post June 30, 2019) L2 smart chargers facility nameplate capacity demand charge. Due to the IT work that needs to be completed by the

PHI Utilities, Pepco and Delmarva Power plan to offer this credit beginning on January 1, 2020.

Customers can apply for the rebate online with a fillable PDF application. The PHI Utilities are offering a dedicated Customer Care phone line for EV related questions. Pepco and Delmarva Power are also offering several educational tools on Pepco.com and Delmarva.com respectively to inform customers of the benefits of EVs, available incentives, and a map of available EV chargers.

Each offer may be voluntarily combined with the green rider adder to ensure a full clean energy supply.

PUBLIC PROGRAM OFFERINGS

The PHI Utilities' approved public program offerings consist of two items: (1) installations for county and municipal public siting of utility owned, publicly available L2 smart chargers with a market based kWh rate for EV charging, including a mandatory green rider adder to ensure full clean energy supply, and (2) installations for county and municipal siting of utility owned, publicly available DCFCs and market based kWh usage rates for EV charging, including a mandatory green rider adder to ensure zero emissions energy supply for the public units. The PHI Utilities will procure and retire renewable energy credits from their Maryland renewable portfolio standard mix to cover the generation mix for these EV chargers. The total number of approved public installations for L2 and DCFC combined in the PHI Utilities' service territories is 350.

MANAGED CHARGING DEMONSTRATION

The PHI Utilities will use the second meter associated with the 137 discounted residential EV chargers offering to demonstrate managed charging. The PHI Utilities will schedule capacity reductions on those EV chargers at various locations for different durations. Pepco and Delmarva Power will use various messaging to residents to inform those EV program customers of an event and will begin this demonstration in Q2 2020 when the offer goes live.

EVALUATION, MEASUREMENT & VERIFICATION

The PHI Utilities are collaborating with BGE and Potomac Edison to draft and release an RFP to secure a common EM&V vendor for the EV programs.

EDUCATION AND OUTREACH

The PHI Utilities in concert with BGE have undertaken the following:

- Conducted initial EV market research in Delmarva, Pepco and BGE service territories, including a quantitative survey study of approximately 1,200 residential customers, and a qualitative study whereby customer focus groups, consisting of individuals who currently own an EV or would consider purchasing an EV in the next 12-18 months, answer various questions posed by the Exelon Joint Utilities and offer thoughts and impressions on test education and outreach materials.

- Developed messaging with supporting imagery to illustrate the benefits of electric transportation based on customer research findings to be used in online messaging, brochures, talking points, press releases media outreach, employee communications, targeted customer emails, direct mail, paid search ads, digital media, social media, and customer outreach through Pepco and Delmarva Power's External Affairs teams.

- Created a new webpage within Delmarva.com and Pepco.com where customers can submit rebate applications and learn more about the EV charging program as well as educate customers on the makes and models of EVs, gas comparison calculators, and advise on rates and other incentives available.

b) Provide a list (or include as an Appendix, labeled as "Appendix A," etc.) of the chargers installed by county and zip code. Specify the type of charger (residential, MOU, etc.)

This data is not applicable for the time period January 1, 2019 through June 30, 2019 as the PHI Utilities did not begin making the EV charger programs available until July 1, 2019.

c) Provide a highlight of the overall successes of the portfolio, while also including any major changes or issues encountered during the period. Report the percentage of offerings that have been installed, for example 100 of maximum 500 residential rebates, therefore 20%.

This data is not applicable for the time period January 1, 2019 through June 30, 2019 as the PHI Utilities did not begin making the EV charger programs available until July 1, 2019.

2. Reporting Period Cost Breakdown

a) Discuss the overall costs, broken down by cost categories, charger type and sub portfolios (including capital costs and annual operations and maintenance costs). Also include, incentive costs, marketing costs, and any make ready costs such as distribution system upgrades.

Please see the estimated budget tables attached hereto as Appendix B.

The PHI Utilities' categories contain the following costs:

- Incentives – direct incentives through rebate or discounted equipment and installations
- Utility Administrative Costs – utility full time employee costs to overseeing and administering the program
- Material Costs – construction costs
- Labor Costs – labor associated with construction costs
- Network Costs – costs for receiving charging data through the network
- Program Implementation Costs – costs for administering the rebate program and digital platform vendor.

Program costs are higher due to increased cost projections for public site analysis, design, and installations based on RFP responses to statement of work and labor costs.

3. Commission Requests

a) Changes in incentives, design, budget, or implementation.

The Commission approved in full the PHI Utilities' compliance plan on June 19, 2019, except for the off-bill, off-peak, TOU credit which would have applied to the 1,000 PHI Utilities residential rebate customers. Therefore, the off-bill credit was deleted from the filed tariffs and program offers, to be considered at a later date for refiling.

III. <u>PHI Program Specifics</u>

There is currently no available data for program specifics for the time period January 1, 2019 through June 30, 2019 except for the Program in Ramp-up Phase entry.

1. Programs in Ramp-up Phase

a. While programs are ramping up, discuss the following:

i. Program implementation progress and roll out activities to-date.

- Pepco.com/ElectricVehicles and Delmarva.com/ElectricVehicles applications and educational web sites went live on June 20, 2019.
- Residential rebate, multifamily discount, and public EV charging programs went live on July 1, 2019.
- The PHI Utilities finalized all EV charger manufacturer and network vendor submissions that submitted a bid in response to the RFP.
- The PHI Utilities are working to conclude the joint RFP that was issued to secure an EV charging station network provider. BGE and the PHI Utilities will use the same network provider to ensure a consistent experience for customers that travel between the two service territories.
- The PHI Utilities and BGE will continue to review the current market rates for public EV charging to determine materiality. A recent review in late July 2019 yielded no material change in filed public charging rates.

ii. Explanations for changes in anticipated program implementation and provision of new/updated timelines, if necessary.

The PHI Utilities' residential discounted EV charger program for 137 customers will go live in Q2 of 2020 to coincide with BGE's EV Only TOU rate, and to provide adequate time to build out the EV Only Rates into the billing system.

2. Implemented Programs

a. For each program, the following should be included:

   i. Update on the status of the program. For example, expected date of construction of utility chargers at each site and when they will be operational.

   ii. Relevant metrics that support the status of the program, including percentage of deployment, etc.

   iii. Explanation for significant changes in participation, delivered measures, or costs from previous periods.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

3. Program Specific Metrics

a. For each program, the following should be included:

   i. Residential Programs

      1. Participants that switch to EV/TOU rate.
      2. Average frequency of daily charging.
      3. Average length of daily charging.
      4. Timing of daily charging, including hourly breakdown.
      5. Total number of customers that have participated in the program.
      6. Average itemized program cost per customer.
      7. For PHI's Smart Level 2 Chargers and EV-Only TOU Only:

         a. Total number of customers participating in Demand Response.
         b. Total number customers participating in Green Rider.

      8. EVSE Submetering:

a. Customer satisfaction survey, rating the following:[7]

   i. Accuracy of measurement of electricity used by customer's EV.

   ii. Accuracy of EV portion of customer bill.

   iii. Ability to control charging station remotely.

   iv. Availability of EV-only TOU rate.

   v. Overall satisfaction with submetering service (including customer billing).

b. Any technical, billing, or customer service-oriented challenges encountered by Utility

9. Comparison of energy use profiled between:

   a. Homes on the offered EV/TOU/Whole House rate with homes not on any EV/TOU/Whole house rate that receive an EV charger rebate, if applicable. Also a comparison of the various rate offerings against each other

   b. Average customer energy costs per month for off peak and on peak charging, if applicable.

   c. Summary of charging on demand response events, if applicable.

ii. Non-Residential Programs:

1. The usage rate by charger type. Average time at charger, average kWh usage per charging session, amount of times each charger is used per day, time of day of charging, location of charging.

2. The charging load profiles (both aggregate and by site type).

3. The price per kWh and usage in kWh by price charged to EV drivers, if available.

4. Actual costs of implementation at each site. Discuss the overall costs, broken down by cost categories and charger type (including capital costs and annual operations and maintenance costs). Also include incentive costs and any "make ready" costs such as distribution system upgrades.

iii. Public Programs:

[7] The customer satisfaction survey will include plain language and a straightforward rating scale to increase the likelihood and number of responses.

1. The usage rate by charger type. Average time at charger, average kWh usage per charging session, amount of times each charger is used per day, time of day of charging, location of charging.
2. The charging load profiles (both aggregate and by site type).
3. Actual costs of implementation at each site. Discuss the overall costs, broken down by cost categories and charger type (including capital costs and annual operations and maintenance costs). Also include incentive costs and any make ready costs such as distribution system upgrades.
4. The profit/loss at each site for the cycle and to date.
5. Location of all constructed and approved sites on a map.
6. Customer satisfaction survey, rating the following:[8]
    - i. Reliability of charging station.
    - ii. Safety of charging station.
7. EVSE Submetering:
    - a. For initial report only: Assessment of submeter functionality—*i.e.*, metrology testing procedure, standards, and result—supported by technical specification sheets associated with the EV charging station metering.[9]
    - b. Results of utility-owned chargers in-service performance testing:[10]
        - i. Frequency of testing.
        - ii. Maximum allowable error tolerance.
        - iii. Sample size of participating submeters.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

[8] The customer satisfaction survey will include plain language and a straightforward rating scale to increase the likelihood and number of responses.

[9] Comprehensive testing information may not be available until the February 1, 2020 semi-annual report. The utilities will work with the Commission's Engineering Division to provide all available testing information before using EV chargers for billing purposes.

[10] Where AMI data is not available, an equivalence test may be performed against data logger readings.

4. For the mid-course and final reports only: Portfolio Level Metrics

a. Total impact of EV chargers on utility's system peak demand (in kW) during system peak (for all chargers where data is collected).and broken down by residential, non-residential and public peak demand.

b. Total impact of EV charging on utility's retail sales (kWh) (for all chargers where data is collected). and broken down by residential, non-residential and public sales.

c. Total impact of EV charging on utility's revenue from retail sales ($) (for all chargers where data is collected)[11]and broken down by residential, non-residential and public charging stations.

d. Average increase in a charging station site host's electric demand (kW) and sales (kWh), by customer class (for all chargers where data is collected).

e. Hourly demand over a typical 24-hour weekday for all EV chargers for which data is collected, and broken down by residential, non-residential and public peak demand.[12]

f. Total percentage of EV charging occurring during off-peak hours (for all chargers where data is collected). and broken down by residential, non-residential and public charging stations.

This data is not applicable for the time period January 1, 2019 through June 30, 2019.

Respectfully submitted,

Daniel W. Hurson
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Baltimore, MD 21201
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Counsel to Baltimore Gas and Electric Company

[11] To be calculated using information from EV only time of use rate and public charging network programs. For other programs, estimates may be provided if possible.
[12] Utilities will also provide full 8760 usage data to Commission Staff and OPC.

Douglas E. Micheel /DWH

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Counsel to Delmarva Power & Light Company and Potomac Electric Power Company

August 1, 2019

Appendix A

BGE EVsmart Program Budget

Residential Incentives	$	300,000
Multifamily Incentives	$	4,200,000
Public Charging - Material	$	6,766,667
Public Charging - Labor	$	8,391,667
Public Charging - Network	$	792,500
Utility Admin	$	107,668
Program Implementation	$	2,229,237
Education and Outreach	$	1,139,387
EM&V		Unknown
Program Total	**$**	**23,927,126**

Appendix B

Pepco and Delmarva Power EVsmart Program Budgets

Delmarva Power EV Budget Summation		
Residential Rebate Incentives	$	75,000
Residential Discount Incentives	$	111,000
Commercial Discount Incentives	$	500,000
Utility Admin	$	289,930
Material Costs	$	1,497,250
Labor Costs	$	2,526,920
Network Costs	$	464,650
Program Implementation Costs	$	267,358
Education & Outreach	$	276,418
EM&V		TBD
	$	6,008,525

Pepco EV Budget Summation		
Residential Rebate Incentives	$	225,000
Residential Discount Incentives	$	300,000
Commercial Discount Incentives	$	2,000,000
Utility Admin	$	811,078
Material Costs	$	3,606,250
Labor Costs	$	6,288,840
Network Costs	$	775,913
Program Implementation Costs	$	317,358
Education & Outreach	$	710,659
EM&V		TBD
	$	15,035,098

REFERENCES TO TELECOMMUNICATIONS DEREGULATION DOCKETS SUPPORTIVE OF POSITIONS OUTLINED IN REPLY COMMENTS FILED BY DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS IN DOCKET NOS. E-7, SUB 1195 AND E-7, SUB 1197

P-100, Sub 24

General Investigation of Interconnection of Subscriber-Provided Equipment with Telephone Companies Under Jurisdiction of the Commission

P-100, Sub 31

Order of Investigation of Interconnection of Subscriber-Provided Equipment with Telephone Network of Telephone Companies Under Jurisdiction of Commission

P-100, Sub 56

Memorandum: Provision of Inside Wiring by Telephone Subscribers and Others

P-100, Sub 73

Southern Bell's Proposed Tariff Re: Sharing and Resale of Local Exchange Service

P-100, Sub 76

Petition for Declaratory Judgment (Resale of Telecommunications) NC Long Distance Association

P-100, Sub 90

Memo to All Regulated Telephone Companies Re: Deregulation of Inside Wiring

P-100, Sub 133D

Proceeding to Determine Permanent Pricing for Unbundled Network Elements

P-100, Sub 133H

Petition for Collaborative Process to Expedite Local Competition

P-100, Sub 133J

Provisioning of Collocation Space

P-7, Sub 723

Request to Amortize Reserve Deficiency for Outside Plant Cable Accounts

P-7, Sub 693

Petition to Accelerate Amortization of Station Connections and Withdraw Undertaking