NEPR

Received:

May 17, 2021

1:47 PM

GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: THE UNBUNDLING OF THE ASSETS OF THE PUERTO RICO ELECTRIC POWER AUTHORITY	**CASE NO.:** NEPR-AP-2018-0004 **SUBJECT:** Direct Testimony; Revised default unbundling tariff

MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER ENTERED ON MAY 13, 2021

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COMES NOW, the Puerto Rico Electric Power Authority (the "Authority"), through its undersigned counsel and, in compliance with the *Resolution and Order* entered on May 13, 2021 submits the following documents

a. *Direct Testimony of Mrs. Margot Everett, Director for Guidehouse Inc.,* dated May 14, 2021. Exhibit A.

b. *Revised Table 2-4. "Default" Retail Energy Supply Credit* of the Proposal for Unbundled Tariff Report dated May 10, 2021. Exhibit B.

WHEREFORE, the Authority respectfully requests the Puerto Rico Energy Bureau of the Public Service Regulatory Board to note the Authority's compliance with the Order.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 17th day of May 2021.

/s Katiuska Bolaños Lugo
Katiuska Bolaños Lugo
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TSPR 18,888

/s Joannely Marrero Cruz
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CERTIFICATE OF SERVICE

It is hereby certified that, on this same date, I have filed the above motion with the Office of the Clerk of the Energy Bureau using its Electronic Filing System at https://radicacion.energia.pr.gov/login, and a courtesy copy of the filling was sent via e-mail to hrivera@oipc.pr.gov, ramonluisnieves@rlnlegal.com; manualgabrielfernandez@gmail.com; ccf@tcm.law.

In San Juan, Puerto Rico, this 17th day of May 2021.

/s Joannely Marrero Cruz
Joannely Marrero Cruz

Exhibit A

GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: THE UNBUNDLING OF THE ASSETS OF THE PUERTO RICO ELECTRIC POWER AUTHORITY	**CASE NO.:** NEPR-AP-2018-0004

Direct Testimony of
Mrs. Margot Everett
Director, Guidehouse Inc.
May 14, 2021

Q1. Please state your name, business address, title, and employer.

A1. My name is Margot Everett. My business address is 101 California Street, Suite 4100, San Francisco, California 94111. I am a Director for Guidehouse, Inc ("Guidehouse").

Q2. On whose behalf are you testifying before the Puerto Rico Energy Bureau (the "Energy Bureau").

A2. My testimony is on behalf of the Puerto Rico Electric Power Authority (PREPA) in as part of the Commonwealth of Puerto Rico Public Service Regulatory Aboard Puerto Rico Energy Bureau (Energy Bureau) proceeding No. NEPR-AP-2018-0004, The Unbundling of the Assets of the Puerto Rico Electric Power.

Q3. Are there any exhibits attached to your testimony?

A3. Yes, there are six exhibits attached to my testimony

a. My current resume. Exhibit A

b. 2021 Cost of Service Study dated May 10, 2021. Exhibit B

c. Proposals for Unbundled Tariffs Report dated May 10, 2021. Exhibit C

d. Proposal for Uniform Services Agreement Report dated May 10, 2021. Exhibit D

e. PREPA UnbundlingRate_Filing_Working Papers.xlsx. Exhibit E

f. Revised Default Unbundled Tariff Sheet. Exhibit F

Q4. What is your educational background?

A4. I have a Master of Science and Bachelor of Science in Applied Economics from University of California, Santa Cruz. I also have a Bachelor of Arts in Economics from the University of California, Santa Cruz.

Q5. What is your professional experience?

A5. With over thirty-five years in the energy industry, I have held many differing roles from evaluation and design of customer programs, wholesale power contract structuring, wholesale market fundamental analysis and price forecasting, credit and enterprise risk management and

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cost of service and rate design. With Guidehouse I have focused on cost of service studies and subsequent rate designs. My engagements have included development of the first ever cost of services study for Abu Dhabi region, with subsequent rate design, as well as computing the avoided costs related to alternative generation options for customers, such as NEM.

Q6. How long have you been employed by Guidehouse Inc.

A6. Two years.

Q7. Please describe your work prior experience prior to joining Guidehouse.

A7. I have worked for several utilities and consulting firms throughout my career. I started my career with Pacific Gas and Electric Company (PG&E) working on demand side management programs. In 1994, I joined PacifiCorp in Portland Oregon, where I worked in various roles for 12 years, which included leading the renewable development structuring desk as well setting up and leading the retail pricing desk upon the unbundling of the California and Oregon markets in the late 1990s. I then transitioned to Constellation Energy where I held roles leading the Enterprise Risk function as well as the wholesale market middle office function. I then served as Chief Risk Officer of the $4.5B joint venture between Electricity de France and Constellation, an responsible for the structuring of wholesale power transactions with the parent companies. Most recently, I spent five years leading Pacific Gas and Electric's ("PG&E") electric and gas rates, load forecasting, and cost of service departments. In that role, I led the development of time of use rates and transition of all customers moving to time of use rates as well as the development and design of alternative rate designs for distributed energy resources, such as a net energy metering ("NEM") tariff.

Q8. Do you hold any professional licenses?

A8. No.

Q9. Have you previously testified or made presentations before the Energy Bureau?

A9. Yes, I have testified before the Energy Bureau in this same proceeding as follows:

ME

a. March 15, 2021- Technical Conference

b. April 15, 2021- Technical Conference

Q10. Please describe the extent of the work performed for PREPA?

A10. Guidehouse conducted a cost of services study as well as developed frameworks for both unbundling rates and developing a uniform services agreement. The results of this work are documented, to some degree, in the presentations included in the technical conference as well as the subsequent reports included in this filing. These include the following three reports included as exhibits.

a. 2021 Cost of Service Study dated May 10, 2021. Exhibit B

b. Proposals for Unbundled Tariffs Report dated May 10, 2021. Exhibit C

c. Proposal for Uniform Services Agreement Report dated May 10, 2021. Exhibit D

d. PREPA UnbundlingRate_Filing_Working Papers.xlsx. Exhibit E

Q11. Did you consider the Energy Bureau's December 23, 2020 and February 5, 2021 Resolution and Orders.

A11. Yes. The Energy Bureau required the development of a cost of services study and subsequent unbundled rates, including a supply credit, based on the results of the marginal cost of service study. The filing included a default tariff that considered the marginal cost of service studies. However, the Energy Bureau also asked for a supply credit in the unbundled tariff filing that was equal to the sum of the FCA and PPCA. PREPA's submission of the default unbundled tariff did not propose this option, but rather used the marginal cost results, in part because of the requirement to provide an unbundled rate based on the cost of service study. Nevertheless, as part of this written testimony, I propose that if the Energy Bureau were to consider that the final unbundled rate supply credit should equal the sum of the FCA and PPCA, that sum can easily replace the calculation in the proposed default tariff by setting the allocation factors included in marginal cost calculation (e.g., ratio of FCA allocated to margin costs plus ratio of PPCA allocated to marginal costs) to one such that the Marginal Energy Costs are equal to the FCA and PPCA. This change has been submitted in the revised default tariff sheet provided as

Exhibit F. PREPA encourages the Energy Bureau to consider the results of the marginal cost of services study in the development of the supply credit. Further, the Resolution and Orders also prescribed the general terms and conditions of the Uniform Services Agreement. Our proposed filing for the Default Uniform Services Agreement is consistent with the Energy Bureau's Resolution and Order while our alternative proposal fine tunes the agreement to account for more stringent credit terms as well as considering potential future costs related to ancillary services.

Q12. What are the purposes and subjects of your Direct Testimony?

A12. As noted above, my testimony covers the submission of a cost of services study, unbundled tariff with supply credit and uniform services agreement. Each are discussed in more detail below.

a) 2021 Cost of Service Study.

b) Proposals for Unbundled Tariffs Report.

c) Proposal for Uniform Services Agreement

Q13. Please describe the methodology and conclusions of the 2021 Cost of Service Study?

A13. Guidehouse conducted a cost-of-service study to assess the marginal costs related to PREPA's operations with the intended purpose of determining an appropriate unbundling supply credit, as well as costs that remain regardless of avoided costs and subsequent 'stranded costs' related to lost sales. The result of that work is included in the attached Exhibit B, 2021 Cost of Service Study dated May 10, 2021. The approach used was a Discounted Total Investment Method (DTIM) that relies on the development of a numerical relationship between costs related to load growth and the driver of that load growth. Guidehouse determined that measuring marginal costs of energy was the appropriate approach to developing unbundled rates and an appropriate supply credit that represents the avoided costs of a customer leaving PREPA's system for an alternative energy supply.

Q14. What other documents or data analysis if any were examined by you to develop of the 2021 Cost of Service Study?

A14. Guidehouse reviewed the previous cost of service studies conducted in 2017 as well as recent planning documents from PREPA.

Q15. What information did you receive from the Energy Bureau's experts during the Technical Conferences that helped in the development of the 2021 Cost of Service Study?

A15. We received limited feedback during the Technical Conferences regarding the cost of services results, but we listened to the questions and tried to address some of those questions directly in our proposal.

Q16. Please describe the methodology and conclusions of the Unbundled Tariffs?

A16. Using the Cost-of-Service Study Results, Guidehouse then developed a framework for unbundling costs. Foundational to this framework is the development of marginal cost-based rates and the relevant driver of those marginal costs by customer class. Using those results, Guidehouse calculated marginal cost revenues to represent the amount of revenues that would be collected if all customers were charged marginal costs. Using the marginal cost revenues and total revenue requirements we then calculated the residual, or remaining costs, that would not be collected if customers only paid marginal costs, representing stranded costs related to lost sales. Finally, using the marginal and residual revenues, marginal and residual rates can be calculated. Ultimately, because load is declining and planned costs have been identified as being for resiliency and recovery, not load growth, marginal costs for capacity are zero, while marginal energy costs are related to the average costs of the incremental cost of serving load in each hour of the year. In conclusion Guidehouse prepared two unbundled rate options. The first included a rate option that uses the marginal costs developed from the cost of service study, consistent with the approach advocated by the Energy Bureau. The second proposed a slight modification to the default by adding changes related to the calculation of the Fuel Cost Adjustment (FCA) and Power Purchase Cost Adjustment (PPCA) rate riders to address the recommendation of the implementation of a true-up mechanism. The description of the unbundling framework as well as both of the proposed rate options are included in Exhibit C, Proposals for Unbundled Tariffs Report dated May 10, 2021.

Q18. What other documents or data analysis if any were examined by you to develop the Unbundled Tariffs?

A18. PREPA reviewed the Resolutions and Orders from the Energy Bureau, including the Unbundling Report.

Q19. What information did you receive from the Energy Bureau's experts during the Technical Conferences that helped in the development the Unbundled Tariffs?

A19. We received limited feedback during the Technical Conferences regarding the unbundled rates, but we listened to the questions and tried to address some of those questions directly in our proposal.

Q20. Please describe the methodology and conclusions of the Uniform Services Agreement?

A20. Lastly, Guidehouse prepared a framework and subsequent recommendations for the design of Uniform Services Agreement. Guidehouse developed this framework and prepared the terms and conditions of the Default Uniform Services Agreement that was in compliance with the Energy Bureau's orders as well as an Alternative Uniform Services Agreement that addressed additional issues and refined the terms and conditions to further protect PREPA's customers. The description of the Uniform Services Agreement framework and the two proposals is included in Exhibit D, Proposal for Uniform Services Agreement Report dated May 10, 2021.

Q21. What other documents or data analysis if any were examined by you to develop the Uniform Services Agreement report?

A21. PREPA reviewed the Resolutions and Orders from the Energy Bureau.

Q22. What information did you receive from the Energy Bureau's experts during the Technical Conferences that helped in the development of the Uniform Services Agreement?

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A22. We received limited feedback during the Technical Conferences regarding the unbundled rates, but we listened to the questions and tried to address some of those questions directly in our proposal.

Q23. How do the reports conform to the Energy Bureau's Orders and recommendations?

A23. The submissions in this filing meet the requirements of the Energy Bureau's Resolutions and Orders with one exception, the Unbundled Supply Credit. The Energy Bureau's orders required the development of a cost of service study to derive the appropriate unbundled rates and subsequent supply credits, which PREPA performed and followed in the proposed filing. However, the Energy Bureau also required setting the default tariff to the sum of the FCA and PPCA. Despite this deviation, PREPA's default tariff is consistent with the latter because the cost of service study examined the costs included in the FCA and PPCA and developed adjustment factors to those factors to account for the contribution of marginal generation assets to the average costs. Included in the calculation was a ratio of generation from the generation stack that respond to load (dispatchable generation) and total generation capacity (non-dispatchable plus dispatchable generation). To develop a generation marginal energy cost estimate consistent with the sum of the FCA and PPCA, these ratios can be set to one.

Q24. Have you prepared a revised Default Unbundled Tariff that sets the supply credit equal to the FCA plus the PPCA?

A24. Yes. Exhibit F includes the revised Default Unbundled Tariff sheet, which replaces Table 2.4 in the Proposals for Unbundled Tariffs Report dated May 10, 2021 (Exhibit C). Specifically, the Default Supply Charge Credit (DSSC) is based on the following formula:

$$DSCC = \frac{MEC * Class\ Sales + MGCC * CCP * ACC}{Class\ Sales}$$

Where:

$$MEC = FCA * FCP + PPCA * PPCP$$

FCA = The current Fuel Charge Rider, which adjust quarterly

FCP = Fuel Charge Rider factor equal to the percent of capacity related to dispatchable PREPA owned generation assets divided by all PREPA owned generation capacity. Currently set to 100%, however Cost of Service (COS) study recommends setting to 73%. This value is updated when PREPA files an updated Cost of Service Study.

PPCA = The current Purchase Power Charge Rider, which adjust quarterly.

PPCP = Purchase Power Charge Rider factor equal to the percent of capacity related to dispatchable PPAs divided by all PPA owned generation capacity. Currently set at 100%, however the COS study recommends setting to 9%. This value is updated when PREPA files an updated Cost of Service Study.

MGCC = Cost Reflective Marginal Generation Capacity Cost rate, based on latest COS Study.

CCP = Class specific contribution to Coincident Peak

ACC = Avoided Capacity Contribution, based on the contribution to capacity that can be avoided by a customer taking energy from an alternative supplier. Currently set at 0% to avoid double counting capacity costs in the FCA and PPCA, however can be set to 100% if marginal energy costs are exclusively energy related.

Class Sales = Class specific retail sales (energy delivered by PREPA - kWh)

Using this approach and the 2017 data, the supply credit would equal 11.218 cents per kWh. Table 1 below shows these values for both 2017 and using the most recently filed rates that apply for April 2021 through June 2021

Table 1: Revised Default Supply Charge Credit

	PPCA	FCA	DSCC
2017 Rates	0.04748	0.06470	0.11218
Indicative Rate (As of 3/31/21, Applied from April 2021 to June 2021)	0.02961	0.09545	0.12506

Q25. What were some of the challenges you identified in producing these studies for PREPA and how were they resolved?

A25. First, detail and reliable data were limited for all aspects of the study. Though a cost of service study could be conducted for marginal costs, the details on costs related to marginal energy costs was contradictory and didn't apply to the dispatch curve. Second, the sector structure remains in flux and thus formulating a methodology for both tariffs and the uniform services agreement was challenging. For this reason, PREPA's proposal and Guidehouse's support work focused on developing frameworks that can be easily adopted to new rule changes. Finally, it is difficult to forecast the implications of the unbundling and how many ESPs will formulate and which customers will choose alternative suppliers. Therefore, the extent of the implications on non-participating customers is difficult to predict. That is, at this time, the cost savings and implications are somewhat hypothetical, thus supporting any rate structure becomes problematic.

Q26. In brief, what are your conclusions and recommendations?

A26. First, the cost of service study concluded marginal capacity costs are zero and will continue to be so as long as load growth in Puerto Rico continues to either stay constant or decline. Second, the appropriate supply credit should equal marginal costs, which can be less than average costs particularly if average costs include fixed costs (such as the pricing in PPAs). Guidehouse respectfully disagrees with the conclusion that marginal costs would be necessarily lower than average costs precisely because these average costs include PPAs which can be 'take or pay' and include fixed costs. That is, PPAs include costs to recover building the resource and margin for the wholesale supplier to invest in those resources as well as the marginal costs to dispatch those plants. These contracts typically also include a price per kWh but that price per kWh is not always used in the dispatch decision. As a result, average costs can be higher than marginal costs because the average cost is not an average of the marginal costs. Third, the Unbundled Tariff should include true-up mechanisms to account for 'system costs' that are not easily priced individually and thus must be socialized across all customers. These costs include congestion, marginal losses and ancillary services. Fourth, the structure currently allows for customers to effectively take partial service from a generation source, particularly if that generation source supplies energy to the grid for their customers as the generation is created rather than following their customer's load profiles. This load following function is embedded in costs and included in the average costs included in FCA and PPCA. For this reason, PREPA's filing supports a supply credit that is less than those to rate components because each include this load following service.

Q27. Does this complete your direct testimony?

A27. Yes.

ATTESTATION

Affiant, Mrs. Margot Everett, being first duly sworn, states the following:
The prepared Direct Testimony constitutes my direct testimony in the above-styled case before the Puerto Rico Energy Bureau. Affiant states that she would give the answers set forth in the Direct Testimony if asked the questions that are included in the Direct Testimony. Affiant further states that, facts and statements provided herein is her direct testimony and to the best of her knowledge are true and correct.

Affidavit No._____

Acknowledged and subscribed before me by Mrs. Margot Everett, in her capacity as Director of Guidehouse Inc., who is personally known to me or whom I have identified by means of her driver's license number F3346990 in San Francisco, California, this 15 day of May 2021.

Public Notary

G. CABEBE
Notary Public - California
San Francisco County
Commission # 2327674
My Comm. Expires May 8, 2024

Direct Testimony

Exhibit A

Guidehouse

Margot Everett

Director

margot.everett @guidehouse.com
San Francisco, CA
Direct: +1.410.627.1118

Professional Summary

As a Director at Navigant Consulting's Energy Practice, Ms. Everett provides strategic and analytic regulatory consulting services to investor and publicly owned utilities, market participants and regulators in the electric and gas. Ms. Everett has nearly 35 years of experience in the energy and utility sector leading risk management, rate and regulatory analytics and wholesale contract structuring organizations. Most recently led Pacific Gas and Electric Company's Regulatory Analytics and Rates departments, responsible for rate design, cost allocation, customer bill impact analyses and load forecasting for both the gas and electric business. Prior to PG&E, Ms. Everett was the Chief Risk Officer for Constellation Energy Nuclear Group, Vice President of risk controls at Constellation Energy, and Managing Director of Structuring and Pricing at PPM. Ms. Everett has a proven ability to analyze complex issues and develop clear and actionable analytics.

Areas of Expertise

- **Rate Innovation** - Accomplished in both day-to-day electric and gas rate model operations and improvements, as well as assessment and development of future rate design changes, forecasts, trends and strategies for investor and publicly owned utilities. Ms. Everett developed and delivered effective utility rate assessments and innovative rate design recommendations reflecting consideration of revenue recovery, declining load, rate affordability, customer equity, emerging technologies, and competitive pressures. Ms. Everett has also led several cost-of-service studies yielding both marginal and embedded costs.
- **Analytics Redesign** – Proven record to design and implement comprehensive updates to existing analytic frameworks or develop new analytic infrastructure to establish state-of-the-art analytics platforms. Experience includes developing and enhancing rate design, cost-of-service, revenue allocation and load forecasting tools, and establishing one of the largest and most comprehensive smart meter usage databases and analytics capability in the industry.
- **Wholesale and Retail Product Structuring** – Designed and priced industry's first shaping and firming products for renewable projects. Structured contracts and established Profit & Loss Models for development projects for second largest wind developer in the US.
- **Customer Program Evaluation** – Performed evaluation and monitoring assessments for numerous commercial, industrial, and residential demand side management and energy efficiency programs for over five utilities. Designed market transformation evaluation framework to estimate the impact of adoption of energy efficiency technologies by non-participants as a direct or indirect result of a technology focused customer program.
- **Risk Management and Compliance**– In numerous roles, established and implemented risk management policies and procedures, mapped processes, designed controls and stood up new organizations such as a Compliance and Continuous Improvement group within Regulatory Affairs of PG&E, a Middle Office function for EdF/Constellation Energy Joint Venture, and Enterprise and Operational Risk function at Constellation Energy.

Margot Everett
Director

- **Experienced Witness** – Testified in regulatory proceedings at the California Commission on numerous issues including cost recovery, program policy, and innovative rate design.

Relevant Experience

Experience with Guidehouse

- **Abu Dhabi Distribution Company, Cost of Service and Rate Design.** Developed end-to-end electric, water, and recycled water rates. This project included reviewing financial plans, identifying marginal costs, developing billing determinants, conducting cost of service analysis, and designing end use rates by customer class.
- **Dominion Energy.** Developed and sponsored testimony regarding value of solar and cost benefit analysis approach to NEM rates. Also developed and sponsored testimony regarding a NEM successor tariff based on that value of solar, to include rebuttal to other proposals. Finally, as part of the fuel cost proceeding, develop and sponsored testimony regarding cost of service and, in particular, avoided costs related to alternative supply for customers.
- **Duquesne Light Company.** Led a comprehensive review of the client's pricing portfolio and developed a strategy for migrating to a cost recovery and pricing portfolio that embraces new technologies and the evolving market. Developed and sponsored rates for standby service, residential subscription and community development.
- **New York State Energy Research and Development.** Reviewed cost of service studies from the six New York investor owned utilities and the application of those studies to the development of Standby tariffs. Prepared a whitepaper developing a standardized approach that uses a decision tree approach to allocating costs to drive the appropriate rate design for standby tariffs particularly considering alternative supply options, such as storage.
- **San Diego Gas & Electric, NEM Rate Analysis.** Developed a model to analyze various netting options for the client's net energy metering program and the estimated cost savings associated with changing netting periods (i.e., annual, monthly, hourly, TOU) as well as studying cost of service of NEM and potential NEM successor rates.
- **Los Angeles Department of Water and Power, EV Rates.** Led team to develop innovative EV rates for both Commercial and Residential customers.

Experience with Utilities

Risk Management and Compliance

- Led risk management programs and developed risk capabilities, including:
  - Developed a detailed risk and compliance assessment, mapped 110 core processes, identified and assessed existing controls, established controls testing protocols and developed policies and procedures.
  - Developed and enhanced market and credit risk management capabilities and designed and enforced trading controls and risk management metrics for natural gas and electric procurement

Margot Everett
Director

  - Design and implement Enterprise Risk program to include operational risk identification and assessment, development of risk controls and policies and implementation of a governance risk and control system.
  - Stood-up middle office and risk management function in six months implementing a trade capture system, creating position and profit and loss reporting, and developing risk policies.
  - Expanded and enhanced tools, metrics and controls for commodities trading and asset management, including design, implementation and management of trading and deal entry controls, position reporting, daily P&L reporting, collateral management, and trader surveillance

Rate Innovation

- Developed and supported specific rate, pricing and policy initiatives for submission to the CPUC on specific rate design initiatives, including:
  - Cost of Service-based and time-variant rate options
  - Specific end-use rates, including electric vehicle, economic development, net energy metering and community solar option
  - Minimum bills and fixed charges for residential gas and electric customers
  - Development of revenue requirements, rate design, rate data analytics and load forecasting functions for both gas and electric businesses

Analytics Redesign

- Developed and implemented analytical infrastructure to support risk management, structured contract valuation, rate design, regulatory analytics, and customer program evaluation:
  - Developed risk management metrics to measure value at risk, daily earnings at risk, capital adequacy, credit risk, and collateral at risk as well as position reporting, trader surveillance and price curve validation.
  - Develop techniques and models to develop short- and long-term forward curves based on both production cost models and market quotes.
  - Led establishment of production grade models for calculating rates and cost of service.
  - Built and implemented stochastic pricing models for contract evaluation including incorporating state of the art techniques such as mean reversion and jump diffusion methodologies.

Wholesale and Retail Product Structuring

- Led pricing and structuring teams to assess the risks and confirm the appropriate pricing for structured transactions
- Developed and lead load forecasting and load research modeling design.
- Built contract and plant evaluation models to include pro-forma financial models and risk adjusted net present value models

Margot Everett
Director

Customer Program Evaluation

- Led and performed evaluation of DSM and energy efficiency programs.
- Led stakeholder process for establishing evaluation methodologies and approving evaluation results that included regulators across seven jurisdictions, environmental and social justice agencies and consumer advocates.

Experienced Witness

- Sponsored, supported or directed expert testimony related to gas and electric rate design, cost of service and rate policy; cost recovery of operational costs associated with risk management systems and regulatory operations; cost recovery mechanisms for nuclear decommissioning expenses; distributed energy resource rate alternatives; and, innovative commercial electric vehicle options.

Thought Leadership

- Developed *Modern Rate Architecture* framework and co-authored a white paper on this Framework, published in the November 2018 issue of Public Utilities Fortnightly. Designed an innovative rate structure for commercial electric vehicles that leverages these architecture principles and framework.
- Co-authored "Understanding Enterprise Risk Management for Utilities" in 2007, which was one of the first the applications of ERM practices to the utility industry and done in conjunction with the Committee of Chief Risk Officers.

Recent Work History

Director, Guidehouse	2019 – Present
Senior Director, Rates and Regulatory Analytics, PG&E	2014 – 2019
Senior Director, Market and Credit Risk Management	2011-2014
Chief Risk Officer, CNEG	2010-2011
Vice President, Trading Controls, Constellation Energy	2006-2010
Managing Director, Structuring and Pricing, PPM Energy/PacifiCorp	2000-2006

Education

Bachelor of Arts, Economics	1982-83, University of California, Santa Cruz
Master of Science, Applied Economics	1983-85, University of California, Santa Cruz
United States Military Academy	1980-1982, Honourable Discharge

Direct Testimony

Exhibit B

2021 Cost of Service Study

Prepared for:

Puerto Rico Electric Power Authority

Submitted by:

Guidehouse Inc.
Metro Office Park
1 Valencia Way, Suite 200
Guaynabo, PR 00968

May 10, 2021

Table of Contents

Figures

Tables

Summary of the Cost of Service Study

Cost of Service (COS) studies are employed for three main purposes. The first is to aid in unbundling costs into service categories and allow for charging separately for specific services. The second is to develop a means for allocating costs among customer classes in accordance with each class's contribution to the cost of service. The third is to inform rate design and create rates that reflect costs.

COS studies can be used to determine whether a customer or group of customers is covering their cost of service through their bill payments. This application assists in identifying 'cost shifts' resulting from rate structures where some customers are paying far less of their cost of service while others are paying far more. For example, even when rates and allocations are based on the total or average of the class, there are customers within each class that have usage patterns that are different from the class average. COS studies help identify if a rate design is consistently penalizing one type of customer versus another because the rate may not fully reflect cost drivers.

There are two types of COS studies typically employed by the utility industry: Marginal Cost and Embedded Cost. Given the needs of Puerto Rico, PREPA engaged Guidehouse Inc. (Guidehouse) to conduct a Marginal Cost of Service (MCOS) study. As such, this report references Guidehouse's work on behalf of PREPA. This report also reviews the most recent Embedded COS (ECOS) study performed by PREPA in 2016 to compare, where possible, the results of the two studies.

Marginal Costs

MCOS studies examine the incremental, or marginal, costs of supplying or delivering energy to a customer. These marginal costs can be for generation capacity, energy, transmission capacity, distribution capacity, and meter to cash services. Marginal capacity COS studies are designed to create a statistical relationship between capital costs and change in capacity for the same period of time. Table E-1 shows the final marginal cost results by cost component.

Table E-1. Marginal Costs

	Generation Capacity	Energy	Transmission Capacity	Distribution Capacity	Other*
	($/kW)	($/kWh)	($/kW)	($/kW)	($/kW)
Marginal Cost	0	0.05127	0	0	0

*Other includes buildings, IT, and environmental costs

The results of this study show that, due to declining load, marginal capacity costs are zero for the foreseeable future. However, this study also shows several scenarios where this may not be the case. An estimate of zero marginal generation capacity costs is recommended for the unbundled tariff; however, this should be revisited with each rate case to ensure the changing dynamics, as contemplated in the scenarios, are incorporated into future rates. Nevertheless, the framework established as part of this study will withstand these potential changes and ease the process of making any future updates.

Cost-Reflective Rates

This study relies on developing cost-reflective rates to create allocation factors and unbundled rates. Cost-reflective rates are simply a per unit of cost that can be applied to class level units, where units can be energy (kWh), customers, and demand (kW); and where demand can be further divided by system Coincident Peak (CP) and Non-Coincident Peak (NCP). Cost-reflective rates are computed for each unbundled service: Generation, Transmission, Distribution, and Billing. Further, there are two cost-reflective rates for each service: marginal cost, which is based on the results of the cost of service study, and residual, which is the difference between marginal costs and average total cost. Guidehouse computes cost-reflective rates by first taking the results of the MCOS Study and computing rates based on the driver of each cost component. Marginal Cost Revenues are then computed by taking the total marginal costs multiplied by the system level cost drivers. Finally, Residual Costs are computed by taking the total revenue requirement less marginal cost revenues for each component. The results are shown in Table E-2.

Table E-2. Cost-Reflective Rates

	Generation Capacity	Energy	Transmission Capacity	Distribution Capacity
	($/kW of CP)	($/kWh)	($/kW of CP)	($/kW of NCP)
Marginal Cost Rate	0	0.05127	0	0
Residual Rate	206.46	0.06091	96.26	207.06

Sensitivity Analysis

Finally, to ensure a deep understanding of the range of cost of service results given sensitivities to key assumptions, Guidehouse ran several cost scenarios. Scenarios run were as follows:

Load Scenarios:

- **Base Case:** Assumes PREPA's current load forecast
- **Recovery Case:** Assumes that load recovers to 2020 levels by 2030
- **Growth Case:** Assumes that load remains constant over the next 5 years and Puerto Rico experiences moderate load growth (1%) from 2025 through 2030

Return on Investment (ROI) Scenarios:

- **Base Case:** Assumes PREPA has access to capital markets in 2025
- **Low Case:** Assumes PREPA has no access to capital markets for 10 years
- **High Case:** Assumes PREPA must include capital costs as of 2021 to reflect future replacement costs

Results are shown in Table E-3.

Table E-3. Marginal Costs by Scenario

	Generation Capacity	Energy	Transmission Capacity	Distribution Capacity	Other
	($/kW of CP)	($/kWh)	($/kW of CP)	($/kW)	($/kW)
Base Load	0	0.05127	0	0	0
Recovery Load	0	0.05127	0	0	0
Growth Load	0	0.05127	0	0	0
Base ROI	0	0.05127	0	0	0
Low ROI	0	0.05127	0	0	0
High ROI	0	0.05127	0	0	0

1. Introduction

1.1 Requirements for Cost of Service

PREB has ordered a full Cost of Service (COS) Study be completed by PREPA for purposes of informing an appropriate Unbundled “Wheeling” Tariff. Specifically, on December 23, 2020, PREB issued the Procedures for the Development of an Unbundling Rate in Case No. NEPR-AP-2018-0004. On Page 4, PREB ordered PREPA to file the following proposed studies:

> ***A fully unbundled cost of service study based upon the general techniques used in the Unbundling Report, with updated data as feasible and an explanation of any different methodologies used. This study shall allocate revenues among classes, and within each class, allocate revenues among at least the following three categories:***
>
> 1. ***All non-generation costs, not subject to competition from wheeling***
> 2. ***Generation costs avoidable by wheeling-related reduction in PREPA generation requirements***
> 3. ***All other generation costs that will be stranded by reduction in sales***

This Marginal Cost of Service (MCOS) study complies with this order by:

1. Providing cost-reflective marginal and residual rates for each unbundled service as defined below:
    a. Generation Capacity
    b. Energy
    c. Transmission Capacity
    d. Distribution Capacity
2. Providing class-level drivers
3. Providing marginal cost rates for each cost component by rate class, as a representation of avoidable costs with wheeling-related reductions in generation requirements
4. Providing residual cost rates for each cost component by rate class, as a representation of stranded costs, defined as residual costs that are not recovered with a loss of sales

1.2 Purpose of Cost of Service Studies

Cost of Service (COS) studies are employed for three main purposes. The first is to aid in unbundling costs into service categories and allow for charging separately for specific services. The second is to develop a means for allocating costs among customer classes in accordance with each class’s contribution to the cost of service. The third is to inform rate design and create rates that reflect costs.

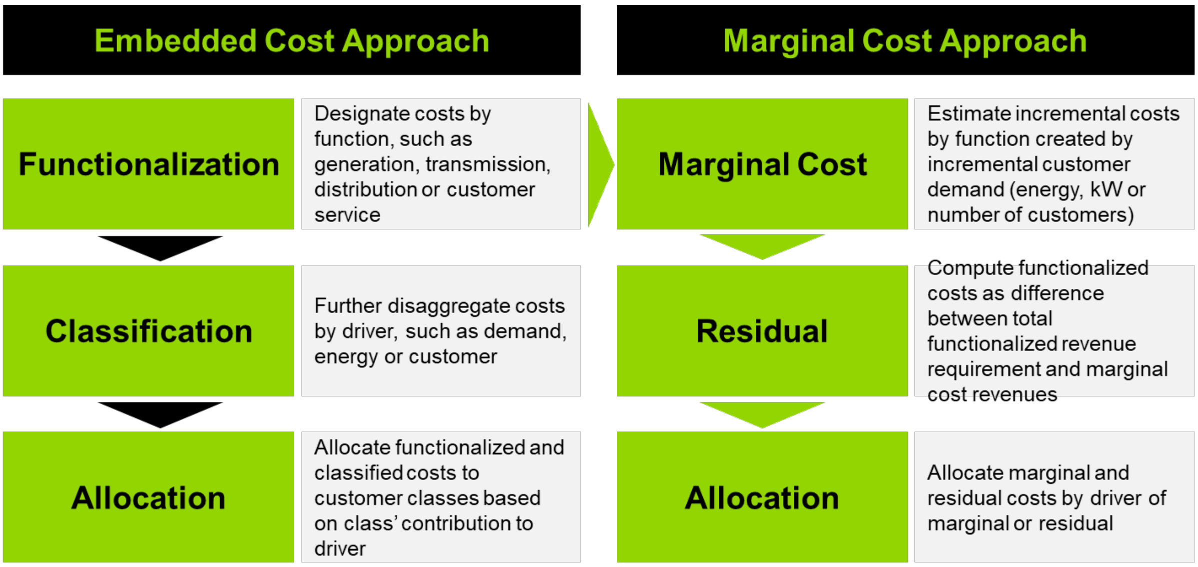
COS studies can also be used to determine whether a customer or group of customers is covering their cost of service through their bill payments. This application assists in identifying ‘cost shifts’ resulting from rate structures where some customers are paying far less of their cost of service while others are paying far more. For example, even when rates and allocations are based on the total or average of the class, there are customers within each class that have usage patterns that are different from the class average. . COS studies help identify if a rate design is consistently penalizing one type of customer versus another because the rate may not fully reflect cost drivers.

1.3 Types and Uses of Cost of Service Studies

There are two types of COS studies typically employed by the utility industry: Marginal Cost and Embedded Cost. Given the needs of Puerto Rico, PREPA contracted with Guidehouse Inc. (Guidehouse) to conduct a MCOS study. Common to both techniques is the first step of functionalizing costs. Once that step is complete, the second step of the Embedded Cost approach is to classify costs by cost driver. These results then allow for allocation of costs among customer classes. One key shortcoming of the Embedded Cost approach is that it cannot be used to determine those costs that would be avoided if a customer no longer requires an incremental unit of service.

For the Marginal Cost approach, the second step is the computation of incremental costs, by function, created by an incremental unit demanded by a customer. The third step is quantifying remaining costs to be collected ("residual") or costs over-collected if all customers pay marginal costs per unit. Finally, the last step in the Marginal Cost approach is to allocate costs depending on the cost driver of each cost for the class. Figure 1-1 shows the basic steps with a brief summary of each.

Figure 1-1. Types of Cost of Service Studies



Generally speaking, COS studies are used to allocate the revenue requirement to different customer classes from which those revenues would be collected. These studies can also be used to inform rate design decisions by designating costs by driver and then setting individual rate components based on those drivers (e.g., customer charge vs. demand charge). Finally, COS studies can be used to determine if customers are paying their fair share of costs as costs are 'unbundled' and certain costs are identified as 'avoidable' because they are marginal costs that can be eliminated or delayed by a customer consuming less energy or demand. Both types of studies are useful for all three purposes, but one type is typically preferable to the other for specifics. For example, marginal cost COS are better for rates design to send customers prices signals to modify behavior while not reducing their contribution to fixed costs while embedded cost COS studies are preferred for allocating costs to class.

An ECOS study is backward looking and focuses on historical actual costs or forecasted costs for a specific year (e.g., ‘historic test year’ or ‘future test year’). The study then segments all these costs based on the function (e.g., generation, transmission, or distribution) and category (e.g., distribution demand, customer billing, etc.). These studies also identify the driver of the costs, such as demand (kW), energy (kWh), or customer (customer month). Ultimately, the ECOS study yields average costs by driver.

The result of an ECOS study is a set of ‘allocators’ by customer class for different types of costs that can be used to determine the level of revenues to collect from each customer class. These allocations are then applied to the utilities authorized revenue requirement (note that this can mean that the total costs used in the cost of service, which is based on a test year, may vary from the utilities’ authorized revenue). Embedded cost studies are a useful way of understanding how a customer class has ‘contributed’ to the costs to serve and thus a common means for revenue allocation. The ECOS study can also provide the level of costs associated with a function (generation, transmission, etc.) included in the revenue requirement allocated to the customer class. This informs the rate design, helping distinguish which costs are best recovered from monthly charges, demand charges, energy charges or even subscription charges. Therefore, ECOS is very useful, and generally preferred, for allocating costs from a ‘test year’ and thus identifying which costs are recovered through which classes and rate mechanisms.

Marginal cost studies examine the incremental costs of supplying or delivering energy to a customer. These marginal costs can be for generation capacity, energy, transmission capacity, distribution capacity, and meter-to-cash services.

Marginal cost studies require understanding the costs a utility is planning to spend to meet future load growth (generation, transmission, and distribution capacity needs) that can be avoided if the load growth is no longer expected. Specifically, the costs included in a marginal cost study should only relate to load growth, not cost associated with lifecycle replacements, grid hardening, grid modernization or grid restoration and repair. Therefore, the level of costs included in a MCOS study can be far less than total planned costs. Ultimately the MCOS study yields marginal costs by cost driver (e.g., demand or kW and energy or kWh).

The results of a MCOS study can also be used to develop a set of ‘allocators’ by customer class for different types of costs that can be used to determine the level of revenues to collect from each customer class. This is done by computing marginal cost revenues by customer class by taking the marginal costs times the cost drivers for the class (e.g., marginal generation capacity costs multiplied by system peak load before losses). However, marginal cost revenues seldom add up to total embedded costs. Therefore, marginal costs are scaled to total revenues. These scaled marginal costs are then used to allocate revenue requirement to each customer class.

MCOS studies are useful in allocating cost but also in determining the expected incremental cost to serve individual customers, and conversely the value of avoiding a kW or kWh of growth. Finally, marginal costs are useful in informing rate design. Rate design can be structured to incent avoiding the costs, creating price differentials that result in limited costs shifts from changes in customer behavior because the customer’s change in load corresponds to the change in the utility’s cost.

Marginal costs can also be used for rate design to provide customers with clear and actionable price signals that, if they change their behavior in response, save them and the utility money. Marginal costs also are a key input into wheeling rates to ensure that customers are incented to act in ways that reduce the utility’s costs while not shifting costs that cannot be avoided to other customer groups. Therefore, Marginal COS studies are preferred for rate design and developing estimates of ‘avoided costs.’ Regardless of which method is preferred, Guidehouse recognizes these tools are available and worked with the available data to best define marginal costs that can be avoided through Unbundling and allowing customers to take supply from Energy Service Providers (ESPs) rather than PREPA, reducing PREPA's costs. Throughout this report, Guidehouse first looks to Marginal Costs to inform unbundling, but when data are not available, looks to Embedded Costs.

1.4 Previous Cost of Service Studies

This is the first full COS study performed since 2016. Since 2016, there have been four major catastrophic events that have impacted Puerto Rico's electricity infrastructure as well as load profile:

- Hurricane Maria in September 2017
- Hurricane Irma in September 2017
- 2020 Earthquake in January 2020
- COVID-19 from March 2020-Present

The previous COS study was performed by Navigant Consulting, Inc. (now Guidehouse) on behalf of PREPA in 2016 in support of the 2015 Electric Rate Adjustment.

1.4.1 Previous Marginal Cost of Service Studies

The results of the 2016 Marginal COS study are shown in Table 1-1.

Table 1-1. 2016 Marginal Cost Results

	Generation Capacity	Energy	Transmission Capacity	Distribution Capacity
	($/kW of CP)	($/kWh)	($/kW of CP)	($/kW of NCP)
Marginal Costs	24.33	0.0604	0	70.12

1.4.2 Previous Embedded Cost of Service Studies

In addition to the ECOS and MCOS studies conducted for the 2015 Electric Rate Adjustment, in 2020 Resource Insights, Inc. conducted an ECOS study on behalf of PREB. This study used cost data from 2014. Table 1-2 shows the results of this ECOS study.

Table 1-2. 2020 Embedded Cost Results ($M)

	Generation Capacity	Energy	Transmission Capacity	Distribution Capacity	Other
Embedded Costs	450	2,040	239	436	396
Percent of Costs	13%	57%	7%	12%	11%

Although useful in understanding the cost structure at the time, much has changed in the past 8 years in the needs of PREPA's customers, PREPA's operations, and the structure of the electricity sector in Puerto Rico. Further, recovery from the hurricanes and the longer-term economic implications of both the natural disasters and the COVID-19 pandemic is ongoing and expected to persist for several more years. These recovery implications are both on the supply and demand side, meaning they impact not just electricity infrastructure but also customer needs and load profiles. Finally, the restructuring of the electricity sector has also led to major changes in roles and responsibilities across the sector and could have implications on the sector’s cost structure and thus cost of service.

2. Cost of Service

As noted above, there are two types of COS studies typically employed by the utility industry: Embedded cost and Marginal cost. COS studies are used for several purposes throughout the rate setting process. The first, and most common, application of a COS study is to allocate the revenue requirement to different customer classes from which those revenues would be collected. Next, COS studies inform rate design decisions by designating costs by driver and then setting individual rate components based on those drivers (e.g., customer charge vs. demand charge).

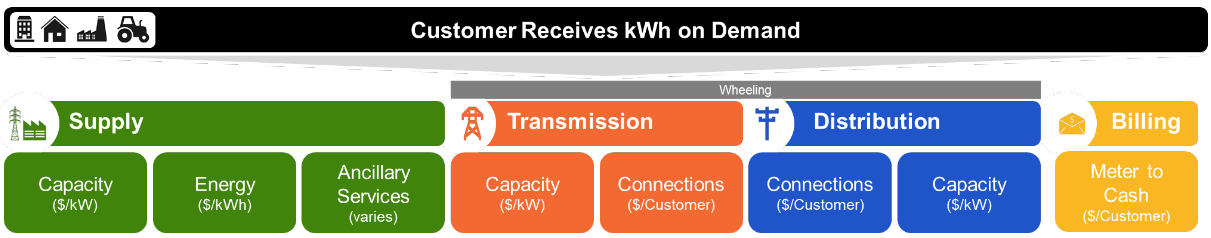
Finally, COS studies can be used to determine whether a customer or group of customers is covering their COS through their bill payments. This last application assists in identifying 'cost shifts' resulting from rate structures where some customers are paying far less of their COS while others are paying far more (either as a class or even individual customers). This occurs because rates and allocations are based on the total or average of the class and there are customers within each class that have usage patterns that are different from the class average.

This chapter first discusses the functionalization of costs and related cost drivers for each of these costs. It then details the Marginal Cost and Embedded Cost analyses conducted and reviewed.

2.1 Functionalization of Costs

Functionalization is the first step in both COS approaches. Functionalization is consistent with unbundling and thus, the functionalization of costs also serves as the designation of unbundled costs. Figure 2-1 shows the unbundling of costs by function.

Figure 2-1. Unbundling of Costs by Function



Supply costs are related to generating energy to meet customer loads. Transmission costs are those costs related to delivering energy from generators to load centers, while Distribution costs move electricity from the points of interconnection with the transmission system to each indivdiual customer's premise. Finally, Billing costs are those costs related to reading meters, billing, collecting revenues, and providng customer service.

Capacity costs, whether they are supply, transmission, or distribution related, are the costs of creating the ability to generate or transmit energy. Capacity costs are driven by peak needs for both the system and individual customer groups. Energy costs are related to those variable costs that are incurred to create a kWh to simultaneously meet customer loads. Finally, Connection costs are those, generally, one-time costs related to connecting new customers to the grid. In this case, "customers" is a broader term. For transmission, customers are either generators who require connection to be able to deliver electricity to the grid, or load centers, or those distribution 'systems' that have energy delivered to meet the loads of all the customers within that load center. Connection costs specifically are not included in this report.

2.2 Cost Drivers

Each cost component, whether it is computed using an Embedded or Marginal cost methodology, has an associated cost driver. A cost driver is the unit of measure that drives the cost. For embedded costs, it is the driver that created the cost in the first place while for marginal costs it is the incremental unit that drives the increase in cost. For the most part, the driver is the same among cost components regardless of COS method. Table 2-1 shows the driver by function that will be used for both the Embedded and Marginal cost studies.

Table 2-1. Cost Drivers by Function

Function	Driver	Description
Generation Capacity	**Net Load Coincident Peak (kW)**	• Net Load Coincident Peak (NLCP) is the maximum demand of a system at a moment in time. • Measured by taking total load less all must run generation, such as renewables. • Generally, CP is the annual maximum demand and is related to date and hour of that maximum. • Not available for Puerto Rico, therefore System CP was used.
Energy	**Energy consumed (kWh)**	• Total energy consumed each hour of the year (8760). • Energy costs may be further segmented by Time of Day (ToD) or Time of Use (TOU) if costs vary by time of delivery.
Transmission Capacity	**Coincident Peak (kW)**	• CP is the maximum demand of a system at a moment in time. • Generally, CP is the annual maximum demand and is related to date and hour of that maximum.
Distribution Capacity	**Non-Coincident Peak (kW)**	• Maximum capacity for a subgroup of customers or an individual customer. • NCP for the system is the same as Coincident demand. • NCP is best used for distribution because demands are locationally driven.

2.3 Marginal Costs

As noted in Section 1, marginal cost studies examine the incremental costs of supplying or delivering energy to a customer and are very useful in measuring avoided costs. As a result, Guidehouse focused on marginal costs for this COS, although in some instances does rely on embedded cost information to fill gaps.

There are several methods used across the electricity industry to quantify marginal costs, each with their own positives and challenges. Guidehouse reviewed and assessed three standard methodologies for quantifying marginal costs.

2.3.1 Asset Value

This methodology relies on the hypothetical marginal cost of building an incremental level of capacity given the average cost of the technology. Typically used for generation assets, this method estimates the incremental cost of a particular technology solution to meet capacity a hypothetical unit increase in capacity (e.g., cost to build a new fossil plant or storage facility).

Asset value works well for generation as it is easily defined, follows least cost principles, and is adaptable for jurisdictions that also include policy decisions in their integrated resource planning efforts thus forcing selection of more expensive resources on the margin, such as renewables or storage.

The challenge of the Asset Value method is twofold. First, it does not work well for distribution because there is no clearly defined distribution asset to be built for capacity growth. That is, distribution system needs vary between feeders, substations, power lines and other types of equipment. The needs of the type of equipment will vary depending upon the reason for and timing of the need. The same can be said for transmission capacity, particularly if transmission expenses are to accommodate load growth for the purpose of avoiding congestion rather than simply having enough transmission capacity to move generation to load reliably. Second, the Asset Value method assumes the capacity is needed, which is not always the case. That is, if capacity is not needed, the marginal capacity costs of a new kW of generation may be positive but the need is zero, and thus the actual avoided costs are zero.

2.3.2 Regression Method

This method relies on using historical and future data to create a relationship between current or expected capital expenditures and projected load growth. This technique is widely accepted and commonly used but has the downside of both relying on historical capital and load growth, which may not be representative of future capital expenditures and load growth, and creates a one-for-one relationship between load and capital on an incremental, usually one year, basis. This can contribute to odd results if there are large investments going online in one year, but the load materializes over several years, which is commonly the case when it comes to major capital expenditures for capacity.

2.3.3 Total Investment Method (Discounted or Undiscounted)

Like the regression method, this approach relies on creating a relationship between current or expected capital expenditures and projected load growth. It differs, however, by looking at the total expenditures versus total growth over time. This has the benefit of 'smoothing' investments versus load growth over a period of time, rectifying the major issue with the Regression Method. It also allows for both a forward and backward analysis such that you can use both historical and forecasted or just forecasted, or planning, data. This allows for an analysis that looks at the future irrespective of the past, which is particularly beneficial for a region that has experienced dramatic events or a major shift in structure, both of which are true for Puerto Rico.

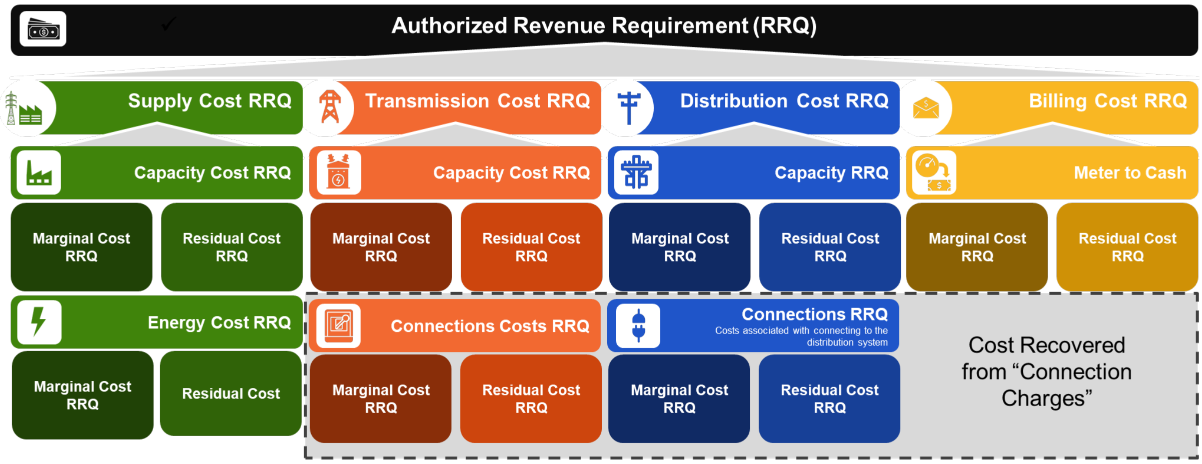
Table 2-2 provides a summary of the different methodologies considered, their pros and cons as well as their relevance to Puerto Rico. After this review, Guidehouse and PREPA determined the Discounted Total Cost Method (DTIM) was the most appropriate method for determining marginal costs for Puerto Rico. Specifically, this method, which calculates marginal costs as the ratio of the forecasted discounted capital additions to the forecasted discounted capacity additions, is a forward-looking methodology, and the resulting marginal cost rates will reflect the planned costs for capacity additions. Therefore, it provides the best means for determining what planned projects can actually be avoided, either entirely or for a period of time, creating the best measure of what costs the utility can avoid going forward.

Table 2-2. Summary of Marginal Cost Methodologies

Method	Asset Value	Future Marginal Cost (DTIM)	Historical Marginal Cost (Regression)
Description	Estimate cost to build an incremental unit of capacity based on average technology costs for that capacity	Discounted total investment method takes the ratio of the forecasted discounted capital increases to the forecasted discounted capacity increases.	Cost determination based upon the statistical relationship between dependent variables such as cost, and independent variables such as load, customer connections etc.
Pros	• Clean and defensible for average costs of technology • Common practice for Generation	• Leading practice (e.g. USA, UK, Canada) • Most forward looking methodology • Applicable for all functions (generation, transmission, and distribution) • Directly links cost savings with customer reaction to price signals	• Can be used to predict future impact of multiple independent variables on costs if the variables are statistically significant
Cons	• Ignores need for capacity and thus losses link between capital expenditures and capacity • Difficult to apply to transmission and even less applicable to distribution	• Highly dependent on planning estimates • Excludes historical relationship of cost and load growth • Marginal cost revenues differ from total revenue requirement creating residual	• Regressions are typically linear and thus cannot account for variability, especially when considering flat or declining load, or large and infrequent capital expenditures. • Furthermore, regressions with declining load may result in the slope (marginal costs) being negative, which may not be indicative of the future.
Relevance for Puerto Rico	• Not recommended for Puerto Rico because load growth is declining and thus determination of need year is particularly problematic	• Recommended for Puerto Rico because represents all planned investments but can also allow for focus on those investments needed for load growth. • DTIM is also more forgiving regarding the ‘timing’ of load changes versus costs, which is best for Puerto Rico given the timing of investments is changing as the sector restructuring continues.	• Not recommended for Puerto Rico because historical marginal costs have been highly influenced by significant catastrophic events over the past five years and thus not reflective of future investments that can be avoided with customer behavior changes

As noted in the methodology above, the difference between marginal costs and the total revenue requirement is the residual cost. This further breakdown of costs by function is detailed in Figure 2-2.

Figure 2-2. Service Unbundling Framework



2.3.4 Load Growth

As noted above, marginal cost estimation methodologies all require an understanding of expected load growth. PREPA prepared a 10-year load forecast by customer class through 2030. Load factors and coincident factors by customer class from PREPA's 2019 Integrated Resource Plan were used to calculate coincident and non-coincident peak demand by year for the forecasted period. Table 2-3 shows the peak demand forecast and change in peak demand by year. Because of the assumption of dramatic decline in load growth, Guidehouse also developed two alternative load scenarios to test the sensitivity of the assumptions of load growth marginal costs. The first, Recovery Case, assumes that load recovers to 2020 levels by 2029. The second, Growth Case, assumes that load remains constant over the next five years and Puerto Rico experiences moderate load growth (1%) from 2025 through 2030.

Table 2-3 shows forecasted coincident peak demand (MW) for the three load scenarios.

Table 2-3. Forecasted System Coincident Peak (MW)

	Base Case		Recovery Case		Growth Case	
Year	Load Forecast	Load Change	Load Forecast	Load Change	Load Forecast	Load Change
2020	2,236		2,236		2,236	
2021	2,200	-36	2,200	-36	2,236	0
2022	2,089	-111	2,089	-111	2,236	0
2023	1,965	-123	1,965	-123	2,236	0
2024	1,887	-78	1,887	-78	2,236	0
2025	1,843	-44	1,922	35	2,258	22
2026	1,830	-13	1,957	35	2,281	23
2027	1,760	-70	1,993	36	2,304	23
2028	1,719	-41	2,029	37	2,327	23
2029	1,663	-56	2,067	37	2,350	23

Table 2-4 shows forecasted non-coincident peak demand (MW) for the three load scenarios.

Table 2-4. Forecasted System Non-Coincident Peak (MW)

	Base Case		Recovery Case		Growth Case	
Year	Load Forecast	Load Change	Load Forecast	Load Change	Load Forecast	Load Change
2020	2,634		2,634		2,634	
2021	2,598	-37	2,598	-37	2,634	0
2022	2,467	-131	2,467	-131	2,634	0
2023	2,323	-144	2,323	-144	2,634	0
2024	2,231	-92	2,231	-92	2,634	0
2025	2,178	-53	2,272	41	2,661	26
2026	2,162	-16	2,313	42	2,687	27
2027	2,077	-85	2,356	42	2,714	27
2028	2,025	-52	2,399	43	2,741	27
2029	1,957	-68	2,443	44	2,769	27

The DTIM method requires calculating the net present value of these load profiles. Using a discount rate of 5%, the NPV of load and load change is shown in Table 2-5.

Table 2-5. Net Present Value of Peaks (MW)

Peak Type	Forecast Case	Total Peak	Change in Peak
Coincident Peak			
	Base Load Forecast	14,213	-487
	Recovery Load Forecast	15,044	-187
	Growth Load Forecast	16,933	85
Non-Coincident Peak			
	Base Load Forecast	16,781	-574
	Recovery Load Forecast	17,778	-213
	Growth Load Forecast	19,951	100

2.3.5 Loading Factor

Critical to computing marginal costs is the ability to convert marginal capital cost to an annualized revenue requirement that represents these marginal costs. To do this a ‘loading factor’ approach is taken. The loading factor incorporates incremental costs related to O&M as well as depreciation and any potential return on investment. Accordingly, there are three key assumptions for this calculation. First is the depreciation life for an asset. The second is the assumed return on investment. The third is the incremental O&M that is needed to maintain the asset once the capital project is built. The loading factor is then computed by estimating the levelized revenue requirement given a $100,000 investment using the depreciation and return on investment assumptions. The percent of incremental O&M to capital spend is then added to the levelized investment.

For deprecation life, the life varies by asset type. Generally, a 40-year life is assumed for transmission and distribution assets while 30 is used for generation. For ROI, three scenarios were developed because it is expected that, for the next 3 years, at a minimum, PREPA will not have access to capital markets and all capital projects will be funded by FEMA grant funds or available cash. Once PREPA is able to access capital markets, this ROI is no longer zero. Since it is unclear what the ROI will be at that time, a return of 7.5% was assumed. Given this complication of needing to layer in return on capital over time, a modified approach is necessary.

For this analysis, Guidehouse created a base case with a weighted loading factor based on the introduction of capital costs in 4 years. However, for computing sensitivities, a weighted loading factor that uses zero capital costs was also computed (“low” case). Another sensitivity was computed where the capital costs are incurred starting in 2021 (“high” case). This is to reflect the potential replacement costs of the capital in the future.

Table 2-6 shows the loading factors by function and for each scenario. Because the same service life was chosen for all three factors, as well as the O&M factor, all three functions have the same loading factor.

Table 2-6. Loading Factors by Asset Type

	Base	Low	High
Function	**Return on Capital starting 2025**	**No Return on Capital**	**Return on Capital starting 2021**
Generation	6.38%	3.94%	8.51%
Distribution	6.38%	3.94%	8.51%
Transmission	6.38%	3.94%	8.51%

2.3.6 Generation Capacity Costs

Marginal Generation Capacity Costs (MGCC) reflect changes in generation costs associated with customer’s usage coincident with peak demand (i.e., capacity costs). The MGCC is based on the incremental cost to build a kW of capacity to meet load. As a result, the estimate is dependent upon the costs to build a generation unit as well as when incremental capacity is needed to serve customer load. Further, MGCC must reflect potential policy costs, such as renewable energy capacity needed to meet any Renewable Portfolio Standards (RPS).

The methodology for calculating MGCC applied for this COS study was the DTIM method described above. This methodology best meets the needs of Puerto Rico because it reviews planned costs and creates the relationship between planned capital additions for load growth and load growth. Guidehouse used PREPA’s 10 year capital plan, which includes estimates of capital additions to 2030. The first step was to filter on those projects designated by PREPA to be generation related. The second step was to designate each capital project into one of five categories:

- **Load Growth:** Capital projects to meet load growth needs
- **Restoration:** Capital projects needed to restore assets after damages from various events over the past five years (e.g., earthquake or hurricane Maria)
- **Resilience:** Capital projects needed to improve Puerto Rico’s electricity infrastructure to both withstand extreme events and modernize to improve operations
- **Lifecycle Replacement:** Capital projects needed to replace aging infrastructure
- **Policy:** Capital projects needed to meet policy objectives, such as environmental remediation

Table 2-7 shows the total annual generation capacity projects by category and in total. The costs include Generation and Hydro, Dams, and Irrigation.

Table 2-7. Generation Capital by Year by Category ($000)

Year	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy	Total
2021	0	17	0	0	0	17
2022	0	7,200	49,000	0	0	56,200
2023	0	34,872	330,500	0	0	365,372
2024	0	139	0	0	0	139
2025	0	74,595	280,800	0	0	355,395
2026	0	49,200	0	0	0	49,200
2027	0	3,383	5,000	0	0	8,383
2028	0	238,343	572,400	0	0	810,743
2029	0	11,178	0	0	0	11,178
Total	**0**	**418,926**	**1,237,700**	**0**	**0**	**1,656,626**

As shown, for the next 10 years there are no identified capital projects related to load growth. This is consistent with the results showing the decline in load over the next 10-year period. Most costs, or 75% of the total $1.65B of capital costs over the next 10 years, are targeted for resilience, while 25% are for restoration.

Calculating the MGCC requires two steps. The first is calculating the ratio of net present value of capacity to net present value of load growth. The second is developing a loading factor that converts capital costs to annual revenue requirement. Table 2-8 shows this calculation for each generation capacity cost category by scenario.

Table 2-8. Marginal Generation Capacity Costs ($000)

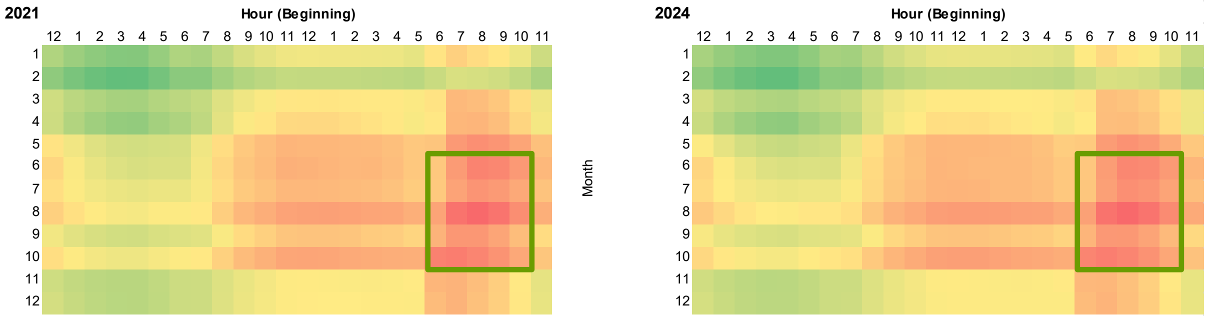
	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy
NPV Capital ($000)	0.00	285,025	904,758	0.00	0.00
Net Investments by Load Scenario					
Base	0.00	20.05	63.66	0.00	0.00
Recovery	0.00	18.95	60.14	0.00	0.00
Growth	0.00	16.83	53.43	0.00	0.00
Marginal Costs by ROI & Load Scenarios					
Marginal Cost – Base Case ROI					
Base	0.00	1.28	4.06	0.00	0.00
Recovery	0.00	1.21	3.84	0.00	0.00
Growth	0.00	1.07	3.41	0.00	0.00
Marginal Cost – Low Case ROI					
Base	0.00	0.79	2.51	0.00	0.00
Recovery	0.00	0.75	2.37	0.00	0.00
Growth	0.00	0.66	2.11	0.00	0.00
Marginal Cost – High Case ROI					
Base	0.00	1.71	5.42	0.00	0.00
Recovery	0.00	1.61	5.12	0.00	0.00
Growth	0.00	1.43	4.55	0.00	0.00

As shown, the Marginal Generation Capacity Costs (Load Growth) are all zero, as are the Lifecycle Replacement and Policy marginal costs. This is due to the lack of capital forecasted for these categories.

2.3.7 Generation Energy Costs

Generation Marginal Energy Costs (MEC) is the cost of procuring electricity to meet one additional kWh of load. PREPA uses Aurora, an electric modeling forecasting and analysis software that models the current electric system and predicts, on an hourly basis, the potential marginal unit, thus developing the expected marginal cost in each hour. MEC is driven by three factors: system load, supply stack, and transmission congestion. Guidehouse reviewed hourly load forecasts for 2021 and 2024 to understand expectations on the hourly loads and how they may change during that period. Figure 2-3 shows heat maps by hour (hour beginning) and month for 2021 (left) and 2024 (right).

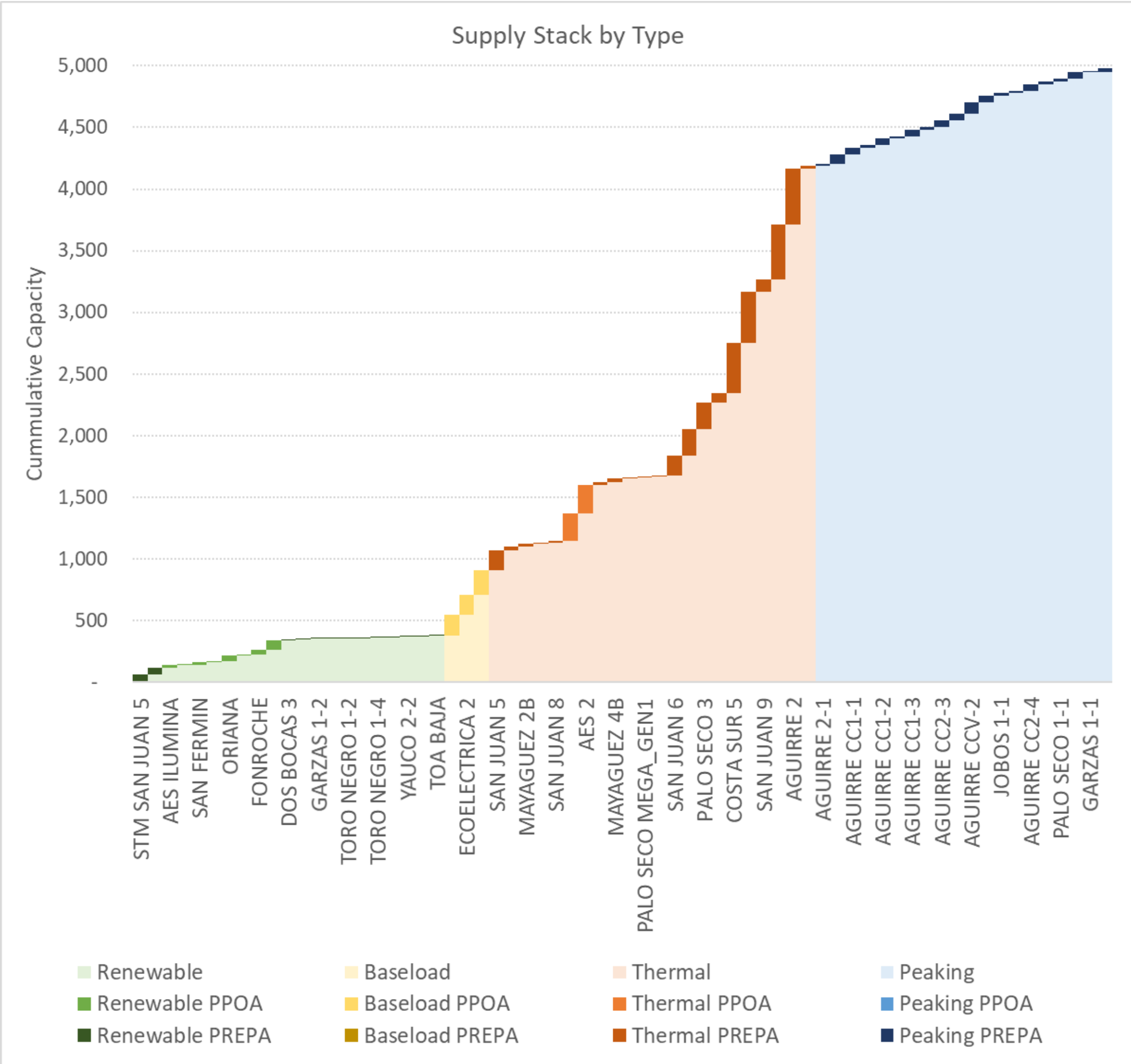
Figure 2-3. System Load Heat Maps 2021 and 2024



As Figure 2-3 shows, peak load occurs typically during the five-hour period between 6pm and 11pm, with the highest peaks occurring during that time in the summer months (June through October.) This pattern does not change from 2021 to 2024.

The Aurora model is then used to simulate system load against the supply stack. The supply stack is shown in Figure 2-4, with the stack sequencing driven by heat rate as individual plant cost data are not available. This figure shows the supply stack by individual plant but also by types of plants (renewable, baseload, thermal and peaking).

Figure 2-4. Plant Dispatch Curve



Given the plant stack and load forecast, the Aurora model run provides an estimate of the MEC. Figure 2-5 shows similar heat map as in Figure 2-3, with the variable being the total marginal cost for that hour in that month. However, this figure shows a very different pattern. This can happen with models like Aurora that are highly dependent upon baseline assumptions regarding plant availability and renewable production; however, the lack of a consistent pattern between MEC and load is concerning. Normally, a review against actual marginal costs would help calibrate results, but these data have not been collected in the past and the most recent history (e.g., 2020) would not be representative given the impact from COVID-19.

Regardless, the heat map does support the need for time-differentiated prices for marginal energy costs. However, due to data limitations, creating that granularity could cause issues and thus Guidehouse recommends reviewing load weighted MEC until such time that hourly pricing can be computed more reliably and calibrated with actual costs. Table 2-9shows these load weighted marginal costs from 2021 through 2024. The results in Table 2.9 show that the marginal costs are increasing between 2021 and 2022 then hovering around 8.2 to 8.4 cents/kWh thereafter.

Figure 2-5. Load Weighted Marginal Energy Costs

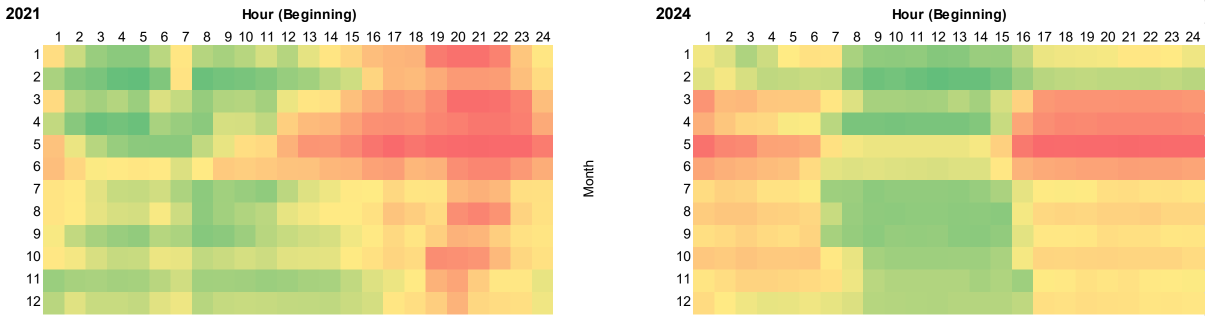


Figure 2-5 also shows there are expected differences in pricing based on season and time of day.

Table 2-9. Load Weighted Marginal Energy Costs

	2021	2022	2023	2024
Weighted MEC ($/kWh)	0.0692	0.0873	0.0816	0.0838

Because the breakdown in the correlation between MEC and load is concerning, Guidehouse derived a proxy for energy prices that could possibly be used in computing the avoided energy costs. This proxy is based on an embedded cost approach. First, Guidehouse calculated the capacity contribution of each type of asset type as shown in Figure 2-4. Guidehouse created eight categories of plants and then computed the percent of capacity in each category. First, plants were divided by ownership where each plant is classified as either a Purchases Power Agreements (PPAs) or Utility Owned Generation (UOG).

Next, each plant was designated as being Renewable (As Generated), Baseload, Thermal, and Peaking. These results are shown in Table 2-10. Assuming Thermal Units and Peaking Units will be the units used to respond to load, they are therefore the ‘marginal plants’ that drive marginal energy costs for Puerto Rico. As shown, approximately 9% of PPA units and 73% of UOG units can be classified as flexible and thus drive marginal costs.

Table 2-10. Capacity Weighting of Generation Plants

	PPA Units	UOG Units	Total	PPA Units	UOG Units	Total
	(MW)	(MW)	(MW)	(%)	(%)	(%)
Renewable (As Generated) Units	222	156	378	4%	3%	8%
Baseload Units	534	-	534	11%	0%	11%
Thermal Units	454	2,820	3,274	9%	57%	66%
Peaking Units	-	790	790	0%	16%	16%
Total	**1,210**	**3,766**	**4,976**	**24%**	**76%**	**100%**

From a revenue requirement perspective, PPA Units are captured in the PPCA rider while UOG Unit costs are captured in FCA rider. Reviewing the actual costs per kWh currently in rates for PPCA and FAC will provide further insights to the avoided costs related to energy. Table 2-11 shows these current rates.

Table 2-11. Current FCA and PCCA Rider Costs and Rates

	Total Cost ($000)	Percent of Costs (%)	Cost per kWh ($/kWh)
Fuel (FCA)	1,117,273	58%	0.064701
Purchased Power (PPCA)	819,907	42%	0.04748
PREPA F&PP Revenue Requirement	1,937,180		0.11218
MWh	17,268,325		

Table 2-11 shows that FCA related costs are approximately 58% of the total costs and that the average PPCA and FCA riders together are about 11.2 cents per kWh. These costs may include Prior Period Reconciliation per the tariff and could slightly distort the value. Nevertheless, it is the basis of rates. Therefore, using the percentages from Table 2-10 and the values in Table 2-11, one can calculate four cost categories, as shown in Table 2-12.

Table 2-12. Current FCA and PCCA Rider Costs and Rates

	PPA Units	UOG Units	Total
2017 Rates	(MW)	(MW)	(MW)
Rates	0.04748	0.06470	0.11218
Dispatchable Percentage	9%	73%	
Non-dispatchable Percentage	91%	27%	
Dispatchable Rates	0.00433	0.04694	0.05127
Non-Dispatchable Rates	0.04315	0.01776	0.06091
Check	0.04748	0.06470	0.11218
Indicative Rate (As of 3/31/21, Applied from April 2021 to June 2021)			
Dispatchable Percentage	0.02961	0.09546	0.12506
Non-dispatchable Percentage	0.00266	0.06968	0.07235
Dispatchable Rates	0.02694	0.02577	0.05272
Non-Dispatchable Rates	0.02961	0.09546	0.12506
Check			

Allocating 2017 FCA and PPCA rates to Dispatchable results in a rate equal to 0.05127, with the remaining 0.06091 being the Non-Dispatchable rates. The fact that Non-Dispatchable rates are higher than Dispatchable is not uncommon and, based on the data, expected. As noted in Table 2-11, 58% of the costs are related to FCA while 73% of capacity in FCA is Dispatchable. Conversely, the other 48% of costs are in PPCA, which is 91% Non-Dispatchable. This is, in part, because PPA costs can be a per kWh basis but include the capacity costs within that pricing for convenience and cashflow – particularly when a plant exports as generation is produced (like with most renewable plants). For purposes of this study, the annual rate from 2017 rate case is used as an estimate of the marginal energy cost.

To demonstrate how this rate may change over time and to link to the quarterly process, Guidehouse took rates for FCA and PPCA recently adopted (3/31/2021) by PREB and calculated an indicative rate of $0.07235. This indicative rate, also shown in Table 2-12, that, if applied today, would be for April through June of 2021, per the FCA and PPCA filing.

Using the combination of 2021 MEC and the 2021 FCA and PPCA rates, a MEC value of approximately 5 to 7 cents/kWh is reasonable. Since the FCA and PPCA are already part of the rate setting process, for this study, Guidehouse recommends using this allocation of embedded cost approach energy costs as a placeholder for MEC until data quality and modeling are expanded.

Lastly, Guidehouse reviewed how the various scenarios would change the proposed marginal energy costs. Table 2-3 show the peak ranges from 2,566 MW in 2021 from the Base Case to 2,697 MW in 2029 for the Growth Case, and in all cases the peak in 2021 is 2,566 MW. Because the difference in peaks is only about 130 kW, and the plant on the margin at 2,566 MW, as shown in Figure 2-4, covers these peaks, it is not expected that marginal costs, on average, would change from one load scenario to another. Further, because the load is the same for 2021, there is no reason to assume the load sensitivities would change the MEC costs. Further, because the current rates only reflect costs for April through June 2021, the annual costs from 2017 will be used and therefore the MEC in all scenarios is $0.05127/kWh.

2.3.8 Transmission Capacity Costs

Marginal Transmission Capacity Costs (MTCC) reflect changes in transmission costs associated with customer's usage coincident with peak demand (i.e., capacity costs). The MTCC is based on the incremental cost to build a kW of capacity to meet load. As a result, the estimate is dependent upon the costs to build transmission assets needed to serve customer load. As with MGCC, PREPA applied the DTIM method matching changes in transmission capital costs outlined in PREPA's capital plan with coincident peak. Table 2-13 shows the capital costs by year by category and in total. The costs reflect costs labeled in the 10-year plan as related to Transmission and Substation.

Table 2-13. Transmission Capital by Year by Category ($000)

Year	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy	Total
2021	0	10,214	0	0	0	10,214
2022	0	860,490	0	0	0	860,490
2023	0	371,503	11,000	0	0	382,503
2024	0	49,700	10,000	0	0	59,700
2025	0	0	0	0	0	0
2026	0	7,000	195,000	0	0	202,000
2027	0	323,290	2,911,010	0	0	3,234,300
2028	0	0	1,968,900	0	0	1,968,900
2029	0	2,172,600	0	0	0	2,172,600
Total	**0**	**3,794,797**	**5,095,910**	**0**	**0**	**8,890,707**

Again, for the next 10 years, there are no identified capital projects related to load growth. This is consistent with the results that show the decline in load over the next 10-year period. Nevertheless, significant capital expenditures are expected over the next 10 years, totaling approximately $8.9 billion, with about 25% of that occurring in the next 5 years.

Like the MGCC, calculating the MTCC requires two steps. The first is calculating the ratio of net present value of capacity to net present value of load growth. The second is developing a loading factor that converts capital costs to annual revenue requirement. Table 2-14 shows this calculation for each transmission capacity cost category by scenario.

Table 2-14. Marginal Transmission Capacity Costs ($000)

	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy
NPV Capital ($000)	0.00	2,652,239	3,303,142	0.00	0.00
Net Investments by Load Scenario					
Base	0.00	186.61	232.41	0.00	0.00
Recovery	0.00	176.29	219.56	0.00	0.00
Growth	0.00	156.63	195.07	0.00	0.00
Marginal Costs by ROI & Load Scenarios					
Marginal Cost – Base Case ROI					
Base	0.00	11.91	14.83	0.00	0.00
Recovery	0.00	11.25	14.01	0.00	0.00
Growth	0.00	9.99	12.45	0.00	0.00
Marginal Cost – Low Case ROI					
Base	0.00	7.36	9.17	0.00	0.00
Recovery	0.00	6.95	8.66	0.00	0.00
Growth	0.00	6.18	7.70	0.00	0.00
Marginal Cost – High Case ROI					
Base	0.00	15.88	19.78	0.00	0.00
Recovery	0.00	15.00	18.68	0.00	0.00
Growth	0.00	13.33	16.60	0.00	0.00

As shown, the Marginal Transmission Capacity Costs (Load Growth) are all zero, as are the Lifecycle Replacement and Policy marginal costs. This is due to the lack of capital forecasted to be spent for these categories.

2.3.9 Distribution Capacity Costs

Marginal Distribution Capacity Costs (MDCC) reflects changes in distribution costs associated with customer's peak demand (i.e., capacity costs). The MDCC is based on the incremental cost to build a kW of capacity to meet load. As a result, the estimate is dependent upon the costs to build distribution assets needed to serve customer load. As with MGCC, Guidehouse applied the DTIM method matching changes in distribution capital costs outlined in PREPA's capital plan with peak demand. However, unlike both the MGCC and the MTCC, distribution costs are more closely linked to non-coincident peak. Table 2-15 shows the capital costs by year by category and in total. The costs reflect costs labeled in the 10-year plan as related to Distribution.

Table 2-15. Distribution Capital by Year by Category ($000)

Year	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy	Total
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	404,100	0	0	0	404,100
2024	0	143,800	0	0	0	143,800
2025	0	0	0	0	0	0
2026	0	0	0	0	0	0
2027	0	1,452,851	0	0	0	1,452,851
2028	0	4,357,595	0	0	0	4,357,595
2029	0	2,694,078	0	0	0	2,694,078
Total	**0**	**9,052,425**	**0**	**0**	**0**	**9,052,425**

The only planned investments for distribution are for Restoration.

Applying the two step DTIM approach, as done with MGCC and MTCC, the ratio of net present value of capacity to net present value of load growth was calculated and then a loading factor was applied that converts capital costs to annual revenue requirement. Table 2-16 shows this calculation for each distribution capacity cost category by scenario.

Table 2-16. Marginal Distribution Capacity Costs ($000)

	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy
NPV Capital ($000)	0.00	5,684,347	0	0.00	0.00
Net Investments by Load Scenario					
Base	0.00	338.73	0.00	0.00	0.00
Recovery	0.00	319.73	0.00	0.00	0.00
Growth	0.00	284.91	0.00	0.00	0.00
Marginal Costs by ROI & Load Scenarios					
Marginal Cost – Base Case ROI					
Base	0.00	21.61	0.00	0.00	0.00
Recovery	0.00	20.40	0.00	0.00	0.00
Growth	0.00	18.18	0.00	0.00	0.00
Marginal Cost – Low Case ROI					
Base	0.00	13.36	0.00	0.00	0.00
Recovery	0.00	12.61	0.00	0.00	0.00
Growth	0.00	11.24	0.00	0.00	0.00
Marginal Cost – High Case ROI					
Base	0.00	28.83	0.00	0.00	0.00
Recovery	0.00	27.21	0.00	0.00	0.00
Growth	0.00	24.25	0.00	0.00	0.00

As shown, the Marginal Distribution Capacity Costs (Load Growth) are all zero. This is due to the lack of capital being forecasted to be spent in this category. Further, the only positive marginal costs are those associated with Restoration.

2.3.10 Other Costs

In addition to Generation, Transmission, and Distribution costs identified in the plan, there are several other costs that cannot be functionalized. These include Buildings, IT, Telecommunications, and Environmental. These costs should then be allocated across the functions on an equal dollar basis. Table 2-17 shows these capital costs by year.

Table 2-17. Other Capital by Year by Category ($000)

Year	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy	Total
2021	0	760	0	0	3,533	4,293
2022	0	311	0	0	11,653	11,964
2023	0	32,300	0	0	0	32,300
2024	0	9,686	0	0	0	9,686
2025	0	0	0	0	0	0
2026	0	0	0	0	0	0
2027	0	0	0	0	0	0
2028	0	159	0	0	0	159
2029	0	1,470	0	0	0	1,470
Total	**0**	**44,686**	**0**	**0**	**15,187**	**59,873**

Again, the two step DTIM approach the ratio of net present value of capacity to net present value of load growth was calculated and then a loading factor was applied that converts capital costs to annual revenue requirement. Table 2-18 shows this calculation for each "Other" capacity cost category by scenario.

Table 2-18. Marginal Other Capacity Costs ($000)

	Load Growth	Restoration	Resilience	Lifecycle Replacement	Policy
NPV Capital ($000)	0.00	38,042	0	0.00	14,114
Net Investments by Load Scenario					
Base	0.00	2.27	0.00	0.00	0.86
Recovery	0.00	2.14	0.00	0.00	0.81
Growth	0.00	1.91	0.00	0.00	0.72
Marginal Costs by ROI & Load Scenarios					
Marginal Cost – Base Case ROI					
Base	0.00	0.14	0.00	0.00	0.05
Recovery	0.00	0.14	0.00	0.00	0.05
Growth	0.00	0.12	0.00	0.00	0.05
Marginal Cost – Low Case ROI					
Base	0.00	0.09	0.00	0.00	0.03
Recovery	0.00	0.08	0.00	0.00	0.03
Growth	0.00	0.08	0.00	0.00	0.03
Marginal Cost – High Case ROI					
Base	0.00	0.19	0.00	0.00	0.07
Recovery	0.00	0.18	0.00	0.00	0.07
Growth	0.00	0.16	0.00	0.00	0.06

As shown, there are marginal costs associated with "Other" for Restoration and Policy.

Direct Testimony

Exhibit C

Proposals for Unbundled Tariffs Report

Prepared for:

Puerto Rico Electric Power Authority

Submitted by:

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May 10, 2021

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Summary of PREPA Filing

PREPA is submitting two Unbundled Tariff Proposals:

- ***Default Primary Unbundled Tariff*** that is consistent with requirements from PREB Order
- ***Alternative Unbundled Tariff*** that deviates purposefully from the Default Primary Unbundled Tariff to address learnings from the COS study as well as implementation challenges.

The primary default unbundling tariff and structure, as dictated by previous PREB orders, consists of a "Retail Supply Credit" equal to the Fuel Cost Allocation (FCA) factor plus the Purchase Power Cost Allocation (PPCA) factor. PREPA understands that this was a suggestion and not an order and that the COS study should drive the supply credit. Therefore, PREPA proposes using the results of Guidehouse's 2021 COS study. To that end there are two key inputs from the 2021 COS study:

- Cost Reflective Marginal Generation Capacity Cost Rate (Cost Reflective MGCC); and
- Cost Reflective Marginal Energy Cost Rate (Cost Reflective MEC), which is computed as a function of the dispatchable resources and the FCA and PPCA factors.

To calculate actual class rates, each component is calculated as follows. First, the Cost Reflective MGCC rate is multiplied by each class's contribution to coincident peak[1] to quantify MGCC Revenues. Similarly, the Cost Reflective MEC is multiplied by the volume of kWh for each customer class. Next, the sum of those revenues is divided by the total energy (kWh) of the class to compute a per kWh rate. Energy in kWh is used at this time because capturing customer demand is currently limited and thus demand charges are problematic at this time.

The Default Primary Unbundled Tariff focuses on creating a Retail Supply Choice Credit based on the FCA and PPCA. The Alternative Unbundled Tariff expands the Default Primary Unbundled Tariff to include a true-up mechanism that includes prior period adjustments, currently in the FCA and PPCA, and subsequently redefines the FCA and PPCA to exclude the 'prior period adjustments'.

Table E-1 shows this calculation and subsequent rates by rate class. Normally the total Generation Credit rate would vary by rate class because the MGCC allocated to each class is driven by the class' contribution to CP. However, MGCC from the 2021 COS study are zero, thus rate variability does not materialize at this time.

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[1] Contribution to peak is used here because the cost driver of the Cost Reflective Marginal Generation Capacity Cost is CP.

Table E-1. Calculated Rates by Rate Class

	Contribution to Coincident Peak (MW)	Cost Reflective MGCC ($/kW)	MGCC ($/kW)	Energy (MWh)	Cost Reflective MEC ($/kWh)	MEC Revenues ($000)	Total Revenues ($000)	Rate ($/kWh)
Residential	1,066	0.00	$0.00	6,248,753	0.05127	320,374	320,374	0.05127
Commercial	820	0.00	$0.00	7,202,526	0.05127	369,274	369,274	0.05127
Industrial	234	0.00	$0.00	1,959,373	0.05127	100,457	100,457	0.05127
Public Lighting	72	0.00	$0.00	312,720	0.05127	16,033	16,033	0.05127
Agriculture	5	0.00	$0.00	24,974	0.05127	1,280	1,280	0.05127
Other	2	0.00	$0.00	40,328	0.05127	2,068	2,068	0.05127

The proposed rate structure requires only the addition of a Retail Energy Supply Credit Rider that applies to all rate schedules and a Generation Capacity Credit that applies to each rate class, as shown above. Customers would continue to stay on their standard retail rate but if a customer signs up with an ESP, then this rider would apply. This creates ease of implementation and does not require creating two sets of rates for every class rate now in effect. Further, it creates transparency for the customer on the actual credit versus their rate from the ESP.

Despite the fact that this rate is cost reflective and offers a simplistic approach to implementation, there are few shortcomings that are of concern. The first is that the FCA and PPCA (which are included in the MEC calculation) include prior period adjustments. These adjustments can be caused by several issues, such as actual plant performance and customer loads. Because these adjustments are a pass through of actual costs, they are not avoidable and thus should be excluded from the Retail Supply Credit. Further, these adjustments can also be caused by load variability or extreme weather events, also costs that are not avoidable as they have already occurred. PREPA proposes that PREB therefore consider PREPA's alternative proposal for an unbundled tariff.
As authorized by PREB, PREPA also proposes an Alternative Unbundling Tariff. This alternative proposal is consistent with the Default proposal as it includes the calculation of a supply credit and currently uses the same values. However, there are few additional aspects of the Alternative Tariff:

1. Remove the current FCA factor Rider and create a new Fuel Cost (FC) Rider that is based on the costs currently included in the FCA less prior year adjustments. Like the FCA factor, the FC Rider is computed as these costs divided by kWh delivered.
2. Remove the current PPCA factor Rider and create a new Purchase Power Cost (PPC) Rider that is based on the costs currently included in the PPCA less prior year adjustments. Like the PPCA factor, the PPC Rider is computed as these costs divided by kWh delivered.
3. Addition of an Energy Cost True-up (ECT) Rider that is a prior period adjustment rider that equals the difference between actual revenues collected from the FC rider and the PPC rider and actual costs allocated that tie to the FC and PPC riders. This rider applies to all load regardless of supplier.

This alternative tariff proposal addresses the primary shortcoming of the "Primary Default Unbundling Tariff" by addressing any incremental costs from all customers using the grid beyond the expectations built into rates and recovering that deviation from all customers, while excluding the deviation from the Retail Supply Credit. This is done by redefining the FCA and PPCA riders to only include forecasted costs and putting the prior period adjustments included in those riders in a separate rider applied to all customers. This also keeps the marginal energy costs forward looking versus a mix of forward and backward-looking costs, as they are today.

1. Introduction

This Proposals for Unbundling Tariffs Report includes information regarding the procedural background of this regulatory proceeding as well as the recommendations for Unbundled Tariffs. The summary of the 2021 Cost of Service Study is contained in a separate report as is the Proposal for Uniform Services Agreement.

1.1 Procedural Background

On December 11, 2019, Regulation 9138 was issued and sets the legal and regulatory framework and process for electric energy wheeling in Puerto Rico and enabled eligible entities such as Electric Power Service Companies (EPSCs), Microgrids, Energy Cooperatives, Municipal Ventures, large scale industrial and commercial consumers, community solar and demand aggregators to exercise choice and control over their electric service. The regulation also established the need for protecting non-subscribers from being adversely impacted by wheeling.

In October and November 2020 there were two Technical Conferences. The first discussed PREPA's fuel and purchased power costs, any potential credit for wheeling customer for avoided generation capacity; and PREPA's recommendations for a charge to cover its costs associated with the implementation of wheeling. The second addressed operational and technical issues that would need to be resolved in order to implement wheeling. Further, on October 30, 2020, PREB received comments from PREPA and the National Public Finance Guarantee Corporation (NPFGC), with reply comments provided on November 13, 2020. From these proceedings PREB found 'there does not need to be a distinction between and "interim" unbundled rate for wheeling customers and a "full" unbundled rate." Specifically, PREB noted:

> *"The issues raised in the Resource Insight Report on Cost Allocation Methods and Unbundling Issues ("Unbundling Report") cover a wide range of potential reforms, many of which may be desirable in their own right but not strictly necessary for unbundling. However, the Energy Bureau determines that these reforms can be implemented over time, and that does not prevent the approval of an unbundled rate for wheeling in the shorter term, so long as the unbundled rate mees the relevant legal requirements."*

In addition, with respect to the setting of the unbundled rate, PREB found:

> *"…it is important to recognize that current rate structures, including the fuel cost adjustment ("FCA") and purchased-power cost adjustment ("PPCA") are based on average cost. However, the fair and efficient compensation to a wheeling customer using non-PREPA generation, as well as the impacts on non-participating customers, are determined by the marginal costs imposed or avoided. The cost avoided by customer replacing PREPA supply with third-party generation would normally be higher than the FCA, since the FCA represents the cost of serving only a fraction of the load (with the rest served by purchased power), and since a reduction in PREPA's load should allow it to turn down the most expensive plants operating in each hour, not just the average mix of plants.*
>
> *From a review of the historical value of the FCA and PPCA and the marginal fuel and variable operation and maintenance ("O&M") costs of the fossil plants most likely to be marginal, it appears that the sum of the FCA and PPCA is a reasonable administrative proxy for marginal costs that are variable in the short run. The fact that the PPCA includes purchased power is not necessarily germane to that analysis, so long as a fair analysis shows that the sum of the FCA and PPCA reasonable follow*

PREPA's short-term marginal costs, and do not overstate PREPA's savings or burden non-wheeling customers.

Finally, in response to comments regarding data availability and quality, PREB determined:

"Finally, while we appreciate concerns about the need for the up-to-date utility data, we must continue to exercise the Energy Bureau's regulatory responsibilities with the data and information that we have available today. The Energy Bureau will consider steps to required PREPA, LUMA Energy, LLC ("LUMA") and other entities to collect track, disclose and utilize all the data that a modern utility should collect, track, disclose and utilize. However, those processes will take time. Current rates are built on the data that is available now that there is no evidence thus far to demonstrate that using that data now for the purpose of unbundling rates and establishing a wheeling rate will adversely impact PREPA or its wheeling and non-wheeling customers. For the purposes of setting a wheeling rate that does not increase costs to non-wheeling customers the unbundling of costs among distribution, transmission and stranded generation costs is not critical, so long as the avoidable costs are reasonably estimated."

As a result, PREB issued an order to move forward with an Unbundled Tariff and outlined procedural requires for developing the tariff.

1.2 Requirements for Unbundled Tariff

In the December 23, 2020 order, PREB outlined the procedure for unbundling of rates.

The Energy Bureau has determined that it is in the public interest to proceed to the unbundling of PREPA's rates as expeditiously as possible so that eligible wheeling customers can purchase their power from a certified EPSC or other eligible wheeling customers can purchase their power from a certified EPSC or other eligible independent power producers. Therefore, the Energy Bureau is ordering PREPA to file, no later than February 1, 2021[2], on or more proposals for an unbundled rate for wheeling, along with a uniform service agreement between PREPA and the independent power producer and any other pertinent policy details.

Although PREPA may choose to file more than one proposal, PREPA must file a proposal based upon the tariff structure discussed in this docket to date, originally set forth in the Energy Bureau in Appendix A of the October 14 Resolution as modified and described further below, henceforth the "default unbundling tariff and structure". Based on preliminary analysis, the Energy Bureau believes that avoided short-run generation costs from new independent power producers is conservatively estimated by the sum of the fuel cost adjustment and purchase-power cost adjustment, as adjusted for hourly balancing between load and supply. Independent power producers likely avoid additional costs in the longer term, including costs related to capital investments and operation and maintenance costs for generation capacity, which could be fairly included in a wheeling credit but may be more difficult to estimate. However, these estimates can and should be examined in a thorough manner.

The Energy Bureau intends to determine the appropriate rates for unbundling through an evidentiary proceeding. That proceeding will explore at a minimum the following issues:

[2] In February 2021, PREB modified this date to May 10, 2021.

- *The unbundled rate proposal or proposals filed by PREPA, including the default unbundling tariff and structure;*
- *Whether a capacity credit is appropriate and the level at which it should be set;*
- *Whether the unbundled rate is fair and reasonable for all customers and avoids subsidies of wheeling customer by non-wheeling customers;*
- *The uniform wheeling services agreement for PREPA's services to EPSC who wish to participate in wheeling;*
- *The charges by PREPA to the EPSC for wheeling services rendered;*
- *Non-discriminatory access and fair and reasonable interconnection protocols for ESPC's*[3]
- *Any proposals offered in testimony by the intervenors;*
- *Compliance with Act 57-2014, Act 17-2019, and Regulation 9138; and*
- *Any other issues that the Energy Bureau determines should be addressed in the proceeding.*

Specifically, the Energy Bureau ordered PREPA to file the following proposed studies and proposals by May 10, 2021:

A. *A fully unbundled cost of service study based upon the general techniques used in the Unbundling Report, with updated data as feasible and an explanation of any different methodologies used. This study shall allocate revenues among classes, and within each class, allocate revenues among at least the following three categories:*
    1. *All non-generation costs, not subject to competition from wheeling;*
    2. *Generation costs avoidable by wheeling-related reduction in PREPA generation requirements; and*
    3. *All other generation costs that will be stranded by reduction in sales.*

B. *A proposed unbundled tariff and structure consistent with the default unbundling tariff and structure, as originally set forth in Appendix A of the Energy Bureau's October 14 Resolution and further modified below; and*

C. *Any other proposed unbundling tariffs and structures, containing unbundled rates based on the cost of service study.*

PREB also noted that PREPA "may file one or more additional proposals". These proposals "need not conform to the structure for the default unbundled tariff and structure" but will be evaluated based on 'the ratemaking principles of simplicity, feasibility, equitable allocation of costs, and efficient pricing."

Finally, PREB noted that the 'basic outline and structure of the proposal outlined in Appendix A of the October 14 Resolution is reasonable' and that the 'it is likely that the unbundled credit for customers engaged in wheeling will be no less than the sum of the FCA and the PPCA". PREB also determined modifications and clarifications for the unbundled tariff and structure:

1. *PREPA will continue to meter and bill each wheeling customer based on the current rate classes, with a credit set at the sum of the fuel cost adjustment and purchase power cost adjustment for that customer during that billing period.*
2. *The unbundled rate for wheeling shall be available to:*
    i. *Customer meters with existing hourly metering;*
    ii. *Customers who pay PREPA to install the proper metering; and*
    iii. *Customers whose hourly loads can be estimated from other data.*

[3] Connection charges is not considered as part of this filing because it does not impact generation costs, but rather transmission and distribution costs filing.

2. Path to Unbundling

2.1 Approach to Unbundling

As presented at the April 15, 2021 Technical Conference, a ten step approach to unbundling rates was outlined. Figure 2-1 shows these steps.

Figure 2-1. Unbundling Rates – Step by Step

Step 1: Determine 'Bundles' Services	Identify distinct functions needed to fully serve load (Generation, Transmission, Distribution, Billing)
Step 2: Determine 'Marginal Costs' for each Service	Using PREPA's forecasted data, determine cost drivers and then calculate marginal costs by service
Step 3: Determine Marginal Cost RRQ	Determine total drivers by customer class and calculate marginal costs revenues by service
Step 4: Determine "Residual" Cost RRQ	Using approved revenue requirement, determine remaining, or 'residual' revenue requirement not recovered
Step 5: Determine Costs Avoided by PREPA	Identify which marginal and residual costs by service are avoided by PREPA if a customer chooses alternative supply
Step 6: Determine Incremental Costs to PREPA	Identify which marginal and residual costs by service may increase if a customer chooses alternative supply
Step 7: Calculate Cost Reflective Rates & Allocate Costs	Determine cost driver by customer class, calculate cost reflective rate & use cost reflective rate to allocate costs to class
Step 8: Determine Billing Determinants	Determine cost driver by customer class, calculate cost reflective rate & use cost reflective rate to allocate costs to class
Step 9: Calculate End-User Rates	Calculate rates by rate component and aggregate to end-user rates
Step 10: Calculate General & Wheeling Rates	Bucket components for Wheeling and calculate appropriate rates by class

Each step is described in more detail below. Note that the results of some of these steps have been presented in the 2021 Cost of Service Study. Fundamental to this step-wise approach is determining:

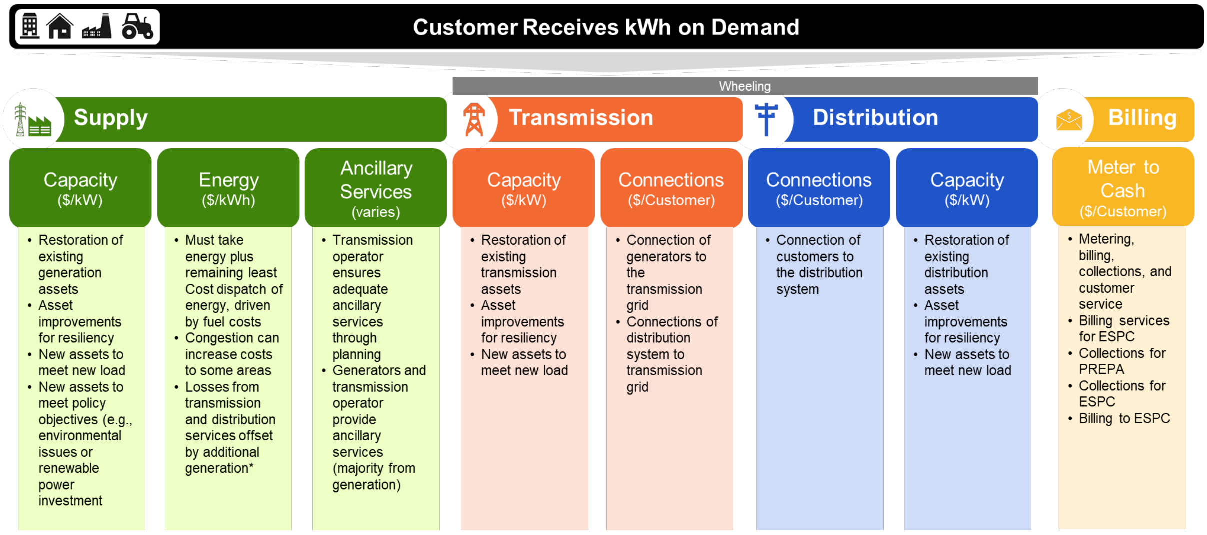
- What costs can be avoided by PREPA if a customer chooses an alternative supplier?
- How might those costs change over time?
- How does PREB ensure that costs are not shifted from one group of customers who choose an alternative supplier to those who don't or cannot?

These questions help focus the rate design process on defining both avoidable costs and the drivers of those avoidable costs. The underlying premise is that the incremental cost to serve a customer's need can be avoided if that customer selects an alternative supplier. In other words, the cost of the next unit of capacity to deliver electricity to a customer, also termed 'marginal cost', is the appropriate measure of value to supply switching and thus the best basis for determining wheeling rates that are fair, sustainable and avoid any cost shifting or subsidization.

2.1.1 Determine "Bundles' of Service

The primary objectives of unbundled rates and subsequent cost based wheeling rate design is to allow PREPA's customers to be well informed of the options for supply and to provide clear and transparent price signals to both potential ESPCs and customers regarding their choices for supply. Figure 2-2 shows the unbundling of rates.

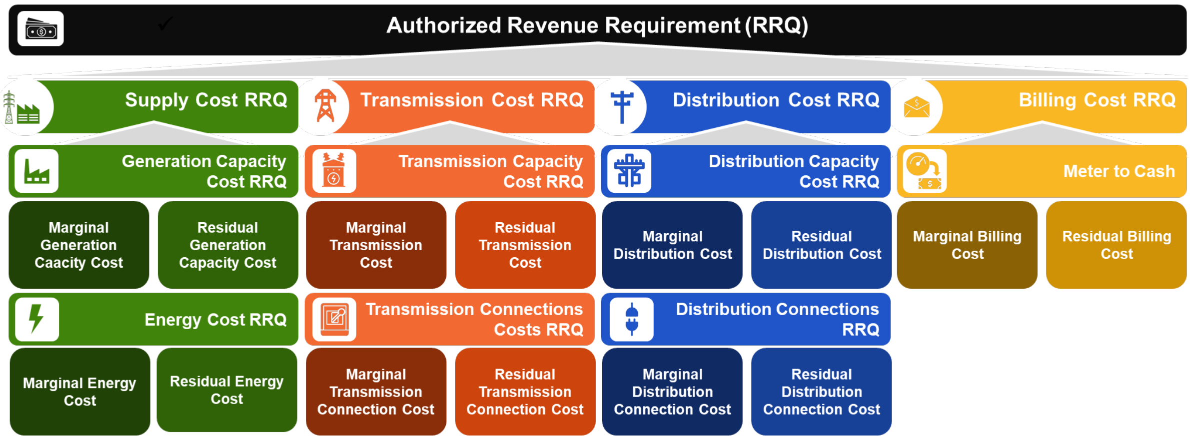
Figure 2-2. Functionalization of Costs



The first step is to identify distinct functions needed to fully serve load. This is consistent with the first step of any Cost of Service study where costs are functionalized by service, such as generation, transmission, or distribution. As Figure 2.2 shows, the main functional areas are Supply, Transmission, Delivery and Billing. The COS study also considers overheads, but that is not a service and thus should be considered an adder to costs. The Unbundling Report correctly identifies that these overhead costs should be allocated to function whenever possible. Many utilities track overhead costs by function and have a separate 'Administrative and General' (A&G) category of costs. These A&G costs should then be allocated across the functions in a manner that is transparent and equitable. Many jurisdictions use a percent of revenues approach where the percent of each services revenues relative to total revenues, less A&G, is used to allocate A&G. This approach is a reasonable and simplistic approach for Puerto Rico as well.

Included in this step is the fact that all cost components can be broken down into two subcomponents: Marginal and Residual. Marginal costs are costs incurred with an incremental increase in demand for that service while Residual is the difference between the total actual costs to provide that service and the marginal costs. Figure 2-3 shows this breakdown in more detail.

Figure 2-3. Unbundling Costs Framework



Each component is described below.

Authorized Revenue Requirement (RRQ): Total revenue authorized by PREB for PREPA to collect, less costs 'avoided' by alternative supplies for energy and generation capacity

Generation Capacity Cost RRQ: Costs associated with building existing or future generation capacity.

<u>Marginal Generation Capacity Cost</u>: Costs associated with building incremental generation capacity to meet demand.

<u>Residual Generation Capacity Cost:</u> Remaining 'embedded costs' associated with building & maintaining generation capacity. Includes capacity and fixed costs associated with ancillary services, such as capacity for black start.

Energy Cost RRQ: Costs associated with generating a unit of energy (kWh).

<u>Marginal Energy Cost</u>*:* Incremental costs to generate electricity to serve customer load and compensate for transmission and distribution losses.

<u>Residual Energy Cost:</u> Remaining operating or embedded costs associated with providing reliable and stable power. Includes costs associated with providing spinning reserves and voltage support ancillary services.

Transmission Cost RRQ: Costs associated with building existing or future transmission capacity.

<u>Transmission Capacity:</u> *Cost* Capacity Costs associated with building incremental transmission capacity to meet Service Driver.

<u>Transmission Residual Cost:</u> Remaining 'embedded costs associated with building & maintaining transmission capacity.

Transmission Connection Cost RRQ: Costs associated with connecting to the transmission system.

<u>Marginal Transmission Connection Cost:</u> Incremental costs associated with connecting a generator or customer to the transmission system.

<u>Residual Transmission Connection Cost:</u> Costs associated with connections that are not collected in connection charges. Could include cost associated with exports from behind the meter generators that require additional upgrades to the system to ensure continued reliable operation of the grid. In many cases, these residual costs become part of the residual transmission capacity costs and collected in the same manner as those costs

Distribution Capacity Cost RRQ: Costs associated with building existing or future distribution capacity

Marginal Distribution Capacity Cost: Costs associated with building incremental distribution capacity to meet Service

Residual Distribution Capacity Cost: Remaining 'embedded costs associated with building & maintaining distribution capacity

Distribution Connection Cost RRQ: Costs associated with connecting to the distribution system

Marginal Distribution Connection Cost: Incremental costs associated with connecting a customer to the transmission system. Many distribution connection charges are fixed per connection and don't' reflect the actual costs but rather the actual average cost.

Residual Distribution Connection Cost: Costs associated with connections that are not collected in connection charges. Like with transmission, this could include costs related to grid enhancements to accommodate behind the meter generation that is exported onto the grid. In many cases, these residual costs become part of the residual distribution capacity costs and collected in the same manner as those costs.

Billing Cost RRQ: Costs associated with metering customer use, billing, collecting, and addressing service issues

Marginal Billing Costs: Incremental costs of billing due to specialization, manual operations or ad hoc requirements

Residual Billing Costs: Average embedded costs of systems and operations to perform billing

2.1.2 Determine "Marginal Costs" for Each Service

Using PREPA's forecasted data, this step involves determining cost drivers and then calculating marginal costs by service. The 2021 Cost of Service Study includes the details of this calculation. Table 2-1 shows a summary of the final Marginal Costs for reference.

2.1.3 Determine "Marginal Cost Revenue Requirement

Given the cost drivers and the marginal costs, Marginal Cost Revenue Requirement can be calculated. This is simply done by taking the marginal costs times the number of drivers for the system (e.g., kWh, CP etc.). The basic assumption is that all customers are 'charged' the marginal cost even though not all customer actually 'experience' the marginal cost. The 2021 Cost of Service Study includes the details of this calculation. Table 2-2 shows a summary of the final Marginal Cost Revenues for reference.

2.1.4 Determine "Residual" Cost RRQ

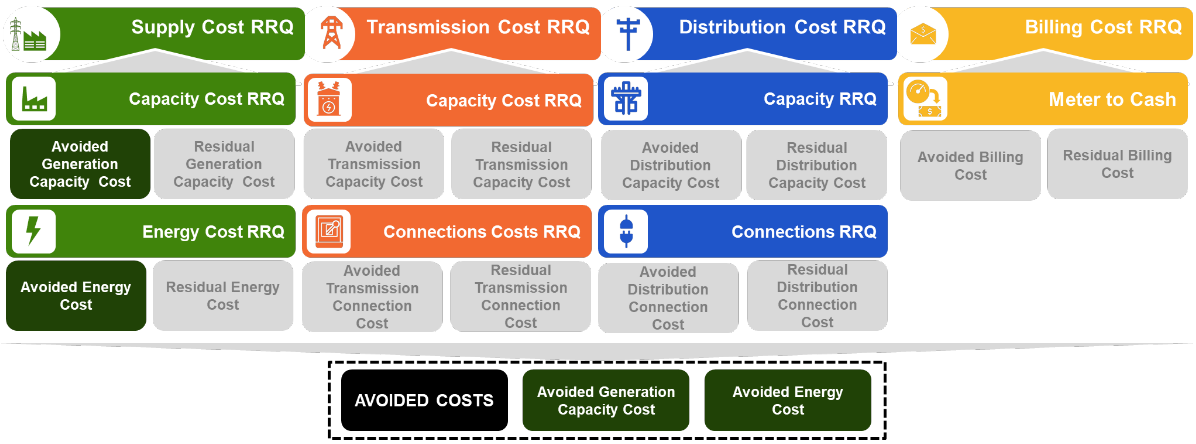
With both the Total Service Revenue Requirement and the Marginal Cost Revenue Requirement, the Residual Costs Revenue Requirement can be calculated. Residual is the Total Service Revenue Requirement less the Marginal Cost Revenue Requirement. This difference can be positive (meaning Total Service Revenue Requirement is greater than the Marginal Cost Revenue Requirement) or negative (meaning Total Service Revenue Requirement is more than the Marginal Cost Revenue Requirement). Only in very rare instances, such as regions with significant capacity constraints, is this different negative. Usually the difference is positive, and that positive difference can be interpreted as 'fixed costs' that cannot be avoided.

One important caveat to the Marginal and Residual cost approach is that marginal costs can approach zero as customer supply demands change and thus marginal cost revenues are, in some ways, overstating what is 'variable.' That is, without any load growth, the Total Service Revenue Requirement is the Residual Cost Revenue Requirement because Marginal Cost Revenue Requirement approaches zero. Therefore, both the Marginal Cost Revenue Requirement and Residual Cost Revenue Requirement should be updated regularly to account for changes in marginal costs.

2.1.5 Determine Costs Avoided By PREPA

The fifth step is to identify which marginal and residual costs by service are avoided by PREPA if a customer chooses alternative supply. Using the framework, certain costs categories can be designated as potentially avoidable. Figure 2-4 shows those costs that can be avoided if a customer receives supply from an ESP. Each component is discussed in more detail below. In summary, only Avoided Generation Capacity Costs and Avoided Energy Costs can be saved by PREPA with an ESPC's supply to a customer.

Figure 2-4. Determination of Avoided Costs



Avoided Generation Capacity Costs: If PREPA is able to avoid building new generation to accommodate Service Driver supplied by ESPC or self-supplied by customer, then generation capacity costs can be avoided. This is highly driven by expectations for the need of additional generation to meet increased load demand. It should be noted that PREPA's load forecast for the next five to ten years shows a decline in load, therefore, as the results discussed later in this report show, this avoided generation capacity cost is computed as zero for the next several years.

Avoided Energy Costs: PREPA is able to avoid producing an incremental kWh because Service Driver is avoided through energy efficiency, customer receives supply from ESPC or customer self-supplies.

Residual Energy Costs: These costs cannot be avoided because they are incurred whether or not the customer consumes a kWh but may require a kWh (e.g., spinning reserves for ESPC or customer supply). These residual costs then also include any 'marginal cost revenues' that are not avoidable but considered marginal.

Avoided Transmission Capacity Costs: PREPA is able to avoid building new transmission capacity to accommodate Service Driver self-supplied by customer.

Residual Transmission Capacity Costs: These costs cannot be avoided because they have either already been incurred or they are expected to be incurred to benefit all customers (e.g., restoration or resilience). These residual costs then also include any ‘marginal cost revenues’ that are not avoidable but considered marginal.

Avoided Transmission Connection Costs: Connection costs are incurred for any source of generation that will export onto the grid, either from a wholesale generator or excess from a customer generator. This is highly driven by expectations for the need of transmission to bring additional generation to load. As noted above, PREPA’s load forecast shows a decline in load therefore generation capacity need is zero, thus transmission capacity need is also zero. Transmission connection costs only exist if a customer actually wants to connect and utilities typically structure connection charges to directly recover these costs from the customer connecting. Therefore, these costs are not avoidable.

Residual Transmission Connection Cost: These costs cannot be avoided because they have either already been incurred or they are expected to be incurred to benefit all customers (e.g., restoration or resilience).

Avoided Distribution Capacity Costs: PREPA is able to avoid building new distribution capacity to accommodate Service Driver self-supplied by customer.

Residual Distribution Capacity Cost: These costs cannot be avoided because they have either already been incurred or they are expected to be incurred to benefit all customers (e.g., restoration or resilience). These residual costs then also include any ‘marginal cost revenues’ that are not avoidable but considered marginal.

Avoided Distribution Connection Cost: Connection costs are upfront costs that allow for power to flow. Regardless of final flow, infrastructure costs are incurred and hence there are no avoided distribution connection costs.

Residual Distribution Connection Cost: These costs cannot be avoided because they have either already been incurred or they are expected to be incurred to benefit all customers (e.g., restoration or resilience).

Avoided Billing Costs: Costs avoided as new customers directly connect to supply and thus requires no services from PREPA.

Residual Billing Costs: These costs cannot be avoided because they have either already been incurred or they are expected to be incurred to benefit all customers (e.g., billing systems). These residual costs then also include any ‘marginal cost revenues’ that are not avoidable but considered marginal.

Avoided costs are not always equal to marginal costs, depending on how marginal costs were computed. Using an approach discussed in the 2021 Cost of Service Study termed Asset Based approach is one such example. In this case, marginal costs are determined by examining the costs that would be incurred if an incremental kW of capacity (generation, transmission, or distribution) were to be built. This is the approach taken in the earlier cost of service studies for Puerto Rico, particularly for generation. The issue is that, though it can be true that there are costs per kW to build generation, it does not incorporate whether an incremental kW is needed.

This is precisely why the 2021 Cost of Service Study used the Discounted Total Investment Method (DTIM) for marginal costs for all services because this method relies on the utility’s plans to build assets to meet load growth. If, for whatever reason, load growth does not materialize, those assets are not needed and therefore can be avoided.

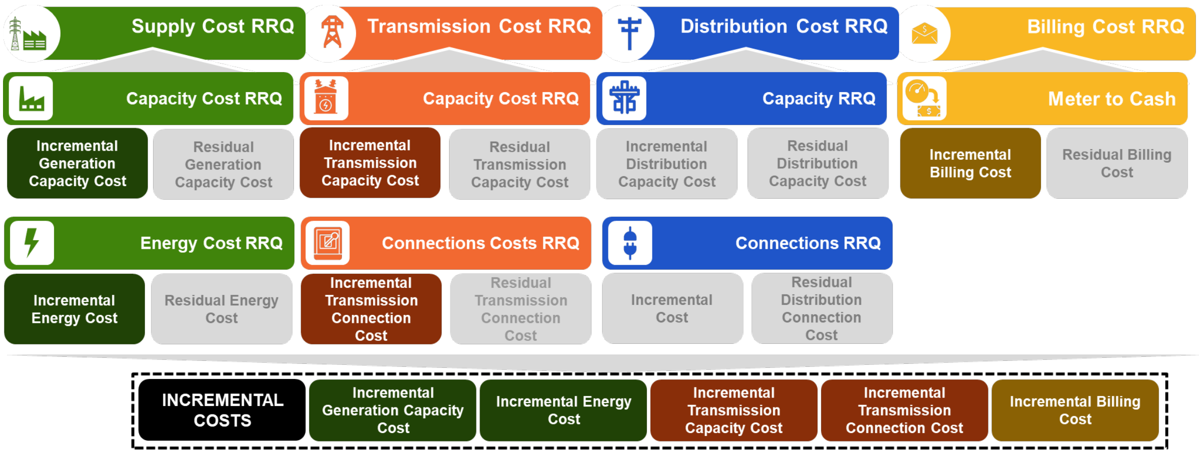
The 2021 Cost of Service Study shows that marginal costs for all service levels using the DTIM approach is zero, largely driven by expectations that load is flat to declining over the next four years and, even with reasonable recovery (see sensitivities) would not exceed current loads in the foreseeable future. One important caveat is whether there will be a need to build renewable generation to meet policy goals. Though there is legislation regarding Renewable Portfolio Standards, costs related to complying are not in PREPA's current forecasts due to other, higher priority, capital spend needs and no access to capital markets or strict rules on application of FEMA grant funds.

However, there may be incremental costs to meeting an RPS. The framework presented allows for this eventuality by creating the ability to estimate and apply a Marginal Renewable Energy cost adder that can be easily applied to either a supply credit or a stand-alone RPS rider. However, until such policies are solidified and the means by which those requirements are met are determined, the Marginal Renewable Energy cost is also zero.

2.1.6 Determine Incremental Costs to PREPA

Step Six involves identifying which marginal and residual costs by service may increase if a customer chooses alternative supply. Figure 2-5 illustrates these costs relative to the framework. Each component of incremental cost is described in more detail below.

Figure 2-5. Identification of Incremental Costs



Incremental Generation Capacity: Additional capacity costs for ancillary services for renewables and capacity needs as customer returns from ESP. There is a connection between Avoided Generation Capacity Costs and Incremental Generation Capacity costs. If a customer can come back to PREPA at a moment's notice, the previously claimed Avoided Generation Capacity Costs would be zero.

Incremental Energy Cost: PREPA is able to avoid producing an incremental kWh because Service Driver is avoided through energy efficiency, customer receives supply from ESPC or customer self-supplies.

Incremental Transmission Capacity Cost: PREPA may experience incremental transmission capacity needs resulting from customer generation exports to other Service Driver centers or 'market.'

Incremental Transmission Connection Cost: Incremental transmission upgrades may be needed to accommodate new generation facilities, which may or may not be explicitly included in connection charges.

Incremental Billing Cost Costs: Created as new billing structures to accommodate wheeling charges and additional metering and reporting.

Note incremental costs are only created for residual if Marginal costs are not appropriately collected. Therefore, care must be made to ensure that all marginal costs are paid for by the ESPC or the ESPC supplied customer rather than included in any residual costs that are paid for by all customers.

2.1.7 Determine and Calculate Cost Reflective Rates & Allocate Costs

Determine cost driver by customer class, calculate cost reflective rate & use cost reflective rate to allocate costs to class. Table 2-1 shows the Cost Reflective Rates based on the results of Guidehouse's 2021 Cost-of-Service report.

Table 2-1. Calculated Rates by Rate Class

Component	Cost ($M)	Cost Driver Type	Cost Driver	Cost Reflective Rate ($/Driver)
Marginal Generation Capacity Cost	0.00	System Coincident Peak (kW)	2,199,628	0.00
Incremental Generation Capacity Cost	0.00	System Coincident Peak (kW)	2,199,628	0.00
Residual Generation Capacity Cost	454.14	System Coincident Peak (kW)	2,199,628	206.46
Avoided Energy Cost	809.49	Total Energy (kWh)	15,788,673,644	0.05127
Incremental Energy Cost	0.00	Total Energy (kWh)	15,788,673,644	0.00000
Residual Energy Cost	1,127.69	Total Energy (kWh)	15,788,673,644	0.07142
Avoided Transmission Capacity Cost	0.00	System Coincident Peak (kW)	2,199,628	0.00
Incremental Transmission Capacity Cost	0.00	System Coincident Peak (kW)	2,199,628	0.00
Residual Transmission Cost	211.74	System Coincident Peak (kW)	2,199,628	96.26
Avoided Distribution Cost	0.00	Non-Coincident Peak (kW)	2,597,711	0.00
Incremental Distribution Cost	0.00	Non-Coincident Peak (kW)	2,597,711	0.00
Residual Distribution Cost	537.89	Non-Coincident Peak (kW)	2,597,711	207.06
Avoided Customer Charge Cost	0.00	Number of Customers	1,466,074	0.00
Incremental Customer Charge Cost	0.00	Number of Customers	1,466,074	0.00
Residual Customer Cost	85.33	Number of Customers	1,466,074	58.21

2.1.8 Determine Billing Determinants

Determine cost driver by customer class, calculate cost reflective rate & use cost reflective rate to allocate costs to class. Table 2-2 shows the billing determinants by class.

Table 2-2. Class Billing Determinants

Billing Determinant	Total Energy (kWh)	System Coincident Peak (kW)	Non-Coincident Peak (kW)	Number of Customers
Residential	6,248,753,109	1,066,260	1,066,260	1,342,266
Commercial	7,202,525,952	819,864	1,171,234	119,963
Industrial	1,959,372,607	234,140	275,459	577
Public Lighting	312,719,924	72,411	72,411	2,174
Agriculture	24,974,431	5,004	6,255	1,090
Other	40,327,621	1,949	6,092	2

2.1.9 Calculate End-User Rates

Calculate rates by rate component and aggregate to end-user rates. Since the Unbundling efforts don't include modifying all end-user rates, the assumption is that rates will stay the same for all customers and introduce a supply credit based on the avoidable generation supply costs. The framework, however, provides a useful means for updating all rates in the future.

2.1.10 Calculate General and Wheeling Rates

As noted above, PREPA's proposal for wheeling rates is to keep current retail rates and add a supply credit. The supply credit should vary by customer class as avoidable generation capacity costs would vary by class because these costs are allocated based on each class' contribution to coincident peak. However, because the avoidable generation capacity costs are zero, the supply credit subsequently is equal to just the avoidable energy component, assumed to be the Marginal Energy Cost provided in Guidehouse's 2021 Cost of Service Study, or $0.05127/kWh.

2.2 Primary Default Unbundling Tariff

Using the Stepwise process and proposed Unbundling Framework, PREPA submits the following "Primary Default Unbundling Tariff."

The primary default unbundling tariff and structure, as dictated by previous orders, consists of a "Retail Supply Credit" equal to the Fuel Cost Allocation factor plus the Purchase Power Cost Allocation factor. PREPA understands that this was a suggestion and not an order and that the COS study should drive the supply credit. Therefore, PREPA proposes using the results of Guidehouse's 2021 COS study and applying these costs to the Unbundling Framework discussed above. To that end there are two key inputs from the 2021 COS study:

- Cost Reflective Marginal Generation Capacity Cost Rate (Cost Reflective MGCC); and
- Cost Reflective Marginal Energy Costs Rate (Cost Reflective MEC).

To calculate actual class rates, each component is calculated as follows. First, the Cost Reflective MGCC rate is multiplied by each class's contribution to coincident peak[4] to quantify MGCC Revenues. Similarly, the Cost Reflective MEC is multiplied by the volume of kWh for each customer class. Next, the sum of those revenues is divided by the total energy (kWh) of the class to compute a per kWh rate. Energy in kWh is used at this time because capturing customer demand is currently limited and thus demand charges are problematic at this time.

Table 2-3. shows this calculation and subsequent rates by rate class. Normally the total Generation Credit rate would vary by rate class because the MGCC allocated to each class is driven by the class' contribution to CP. However, MGCC from the 2021 COS study are zero, thus rate variability does not materialize at this time.

Table 2-3. Calculated Rates by Rate Class

	Contribution to Coincident Peak (MW)	Cost Reflective MGCC ($/kW)	MGCC ($/kW)	Energy (MWh)	Cost Reflective MEC ($/kWh)	MEC Revenues ($000)	Total Revenues ($000)	Rate ($/kWh)
Residential	1,066	0.00	$0.00	6,248,753	0.05127	320,374	320,374	0.05127
Commercial	820	0.00	$0.00	7,202,526	0.05127	369,274	369,274	0.05127
Industrial	234	0.00	$0.00	1,959,373	0.05127	100,457	100,457	0.05127
Public Lighting	72	0.00	$0.00	312,720	0.05127	16,033	16,033	0.05127
Agriculture	5	0.00	$0.00	24,974	0.05127	1,280	1,280	0.05127
Other	2	0.00	$0.00	40,328	0.05127	2,068	2,068	0.05127

The proposed rate structure requires only the addition of a Retail Energy Supply Credit Rider that applies to all rate schedules and a Generation Capacity Credit that applies to each rate class, as shown above. Customers would continue to stay on their standard retail rate but if a customer signs up with an ESP, then this rider would apply. This creates ease of implementation and does not require creating two sets of rates for every class rate now in effect. Further, it creates transparency for the customer on the actual credit versus their rate from the ESP.

Despite the fact that this rate is cost reflective and offers a simplistic approach to implementation, there are few shortcomings that are of concern. The first is that the FCA and PPCA include prior period adjustments. These adjustments can be caused by several issues, such as actual plant performance and customer loads. Because these adjustments are a pass through of actual costs, they are not avoidable and thus should be excluded from the Retail Supply Credit. Further, these adjustments can also be caused by load variability or extreme weather events, also costs that are not avoidable as they have already occurred. PREPA proposes that PREB therefore consider PREPA's alternative proposal.

Below in Table 2-4. is a full description of the Default Unbundled Tariff Proposal Retail Supply Credit (Default SCC) as would be represented in a Tariff Sheet.

[4] Contribution to peak is used here because the cost driver of the Cost Reflective Marginal Generation Capacity Cost is CP.

Table 2-4. "Default" Retail Energy Supply Credit

"DEFAULT" RETAIL SUPPLY CHOICE CREDIT	
DESIGNATION:	SCC
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Retail Supply Choice Credit (SCC) rider mechanism which provides a credit to customer for choosing alternative supply from PREPA's services. The SCC shall apply to all of PREPA's rates if the customer has confirmed with PREPA that they are receiving supply from an ESPC and that ESPC is qualified under the Uniform Services Agreement to supply this customer.
Rate	The formula to calculate the Supply Choice Credit is: $SCC = \frac{MEC * Class\ Sales + MGCC * Contribution\ to\ CP}{Class\ Sales}$
MEC	Marginal Energy Costs as computed as function of the dispatchable resources and the FCA and PPCA
FCA	The current Fuel Charge Rider, which adjust quarterly
FCP	Fuel Charge Rider factor equal to the percent of capacity related to dispatchable PREPA owned generation assets divided by all PREPA owned generation capacity. Currently set at 73%, this value is updated when PREPA files an updated Cost of Service Study.
PPCA	The current Purchase Power Charge Rider, which adjust quarterly.
PPCP	Purchase Power Charge Rider factor equal to the percent of capacity related to dispatchable PPAs divided by all PPA owned generation capacity. Currently set at 9%, this value is updated when PREPA files an updated Cost of Service Study.
MGCC	Cost Reflective Marginal Generation Capacity Cost rate, based on latest Cost of Service Study
Contribution to CP	Class specific contribution to Coincident Peak
Class Sales	Class specific retail sales (energy delivered by PREPA - kWh)
Quarterly Filing	PREPA shall make a filing for a proposed SCC Rider at the same time making a filing for both the FCA Rider and PPCA Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised SCC is not approved the previous quarters' SCC Rider shall remain in effect until a new Rider is approved.

2.3 Alternative Unbundling Tariff

As authorized by PREB, PREPA also proposes an Alternative Unbundling Tariff. Under the proposed structure, and until additional costs related to Ancillary Services and Congestion can be captured in separate charges, these costs roll into the FCA, PPCA and the prior period adjustments. To better accommodate these potential challenges, PREPA is proposing an Alternative Unbundling Tariff. This Alternative Tariff is also consistent with the Unbundling Framework proposed above with a few distinct differences from the recommendations from the Unbundling Report. This alternative proposal is consistent with the Default proposal as it includes the calculation of a supply credit and currently uses the same values. However, there are few additional aspects of the Alternative Tariff:

1. Remove the current FCA factor Rider and create a new Fuel Cost (FC) Rider that is based on the costs currently included in the FCA less prior year adjustments. Like the FCA factor, the FC Rider is computed as these costs divided by kWh delivered. Table 2-5 shows the Fuel Charge Rider “Tariff Sheet” inputs.
2. Remove the current PPCA factor rider and create a new Purchase Power Cost (PPC) Rider that is based on the costs currently included in the PPCA less prior year adjustments. Like the PPCA factor, the PPC Rider is computed as these costs divided by kWh delivered. Table 2-6. shows the Purchase Power Charge Rider “Tariff Sheet” inputs.
3. Addition of an Energy Cost True-up (ECT) Rider is a prior period adjustment rider that equals the difference between actual revenues collected from the FC rider and the PPC rider and actual costs allocated that tie to the FC and PPC riders. This rider applies to all load regardless of supplier. Table 2-7 shows the ECT Rider “Tariff Sheet” inputs.

Table 2-5. Fuel Charge Rider Tariff Sheet Inputs

FUEL CHARGE RIDER	
DESIGNATION:	FC
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Fuel Charge (FC) is a rider mechanism which recovers the cost of expected fuel costs from PREPA's generating units on an annual basis. The FC shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.
Rate	The formula to calculate the Fuel Charge Rider is: $$FC = \frac{Total\ Fuel\ Cost}{Applicable\ Retail\ kWh\ Sales}$$
<u>Total Fuel Cost</u>	The cost of fuel purchased for all PREPA's generating facilities for the three (3) forecasted months in the quarterly time period. The cost estimates shall be presented on a monthly basis and include all detail on the type of fuel forecasted to be consumed.
<u>Applicable Retail kWh Sales</u>	Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.
<u>Quarterly Filing</u>	PREPA shall make a filing for a proposed FC Rider before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised FC Rider is not approved the previous quarters' FC Rider shall remain in effect until a new factor is approved.

Table 2-6. Purchase Power Charge Rider Tariff Sheet Inputs

PURCHASE POWER CHARGE RIDER	
DESIGNATION:	PPC
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Purchase Power Charge (PPC) is a rider mechanism which recovers the cost of expected costs from purchase power agreements on an annual basis. The PPC shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.
Rate	The formula to calculate the Purchase Power Charge Rider is: $$PPC = \frac{Total\ Purchased\ Power\ Costs}{Applicable\ Retail\ kWh\ Sales}$$
Total Purchase Power Cost	The cost of purchased sources of energy and capacity for the three forecasted months in the quarterly time period. The cost estimates shall be presented on a monthly basis and include all detail on the type of power forecasted to be purchased by PREPA.
Applicable Retail kWh Sales	Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.
Quarterly Filing	PREPA shall make a filing for a proposed PPC Rider before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised PPC Rider is not approved the previous quarters' PPC Rider shall remain in effect until a new factor is approved.

Table 2-7. Energy Cost True-Up

ENERGY COST TRUE-UP	
DESIGNATION:	ECT
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Energy Cost True-up (ECT) is a reconciling rider mechanism which recovers the prior period adjustments for both Fuel Costs and PPA costs. The ECT shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.
Rate	The formula to calculate the Energy Cost True-up Rider is: $$ECT = \frac{Prior\ Period\ Adjustments}{Applicable\ Retail\ kWh\ Sales}$$
Prior Period Adjustments	Adjustments for prior periods for the Fuel Cost Adjustment and Purchase Power Cost Adjustment costs *Fuel Cost Adjustment Prior Period Adjustment:* The under- or over-recovered funds for the first two (2) months of the current quarterly time period and the last month of the prior quarterly time period. PREPA shall provide the reconciling balance with each proposed quarterly filing of the FC. *Purchase Power Prior Period Adjustment:* The under- or over-recovered funds for the first two months of the current quarterly time period and the last month of the prior quarterly time period. PREPA shall provide the reconciling balance with each proposed quarterly filing of the PPAC.
Applicable Retail kWh Sales	Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.
Quarterly Filing	PREPA shall make a filing for a proposed ECT Rider at the same time making a filing for both the FC Rider and PPC Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised ECT is not approved the previous quarters' ECT Rider shall remain in effect until a new Rider is approved.

This alternative proposal addresses the primary shortcoming of the “Primary Default Unbundling Tariff” by addressing any incremental costs from all customers using the grid beyond the expectations build into rates and recovering that deviation from all customers, while excluding the deviation from the Retail Supply Credit. This is done by redefining the FCA and PPCA riders to only include forecasted costs and putting the prior period adjustments included in those riders in a separate rider applied to all customers. This also keeps the marginal energy costs forward looking versus a mix of forward and backward-looking costs, as they are today.

2.4 Consistency with Unbundling Report Recommendations

This framework is consistent with the approach outlined in the Unbundling Report as follows:

1. The Unbundling report designates functions consistent with the framework, specifically, distinguishing among costs for generation, transmission, distribution, and billing (retail). Note that overhead costs are spread across 'residuals' for each function.
2. Allocation of costs to customer classes are based on the class's contribution to the costs.
    a. Generation Capacity is based on contribution to coincident peak (CP)
    b. Transmission Capacity is based on contribution to CP, like generation.
3. Allows for collection of costs through riders versus base rates

The approach taken in the Unbundling Report applied a complex review of substation loads and time of use factors. PREPA's proposal deviates from this approach by proposing the use of class non-coincident demand (NCP). This approach is more simplistic but consistent with cost allocation approaches in many jurisdictions while enabling the appropriate allocation of primary and secondary charges. That is, primary and secondary costs are first designated and then allocated to classes distinguished by service level using the NCP.

The Unbundling Report outlines five "Directions for Future COSS":

1. PREPA current or projected cost data and sales data by tariff for a consistent period.
2. Improving PREPA's data for COSS inputs that are routinely collected by other utilities.
3. Reflecting the outcome of the ongoing restructuring and recovery.
4. Additional policy decisions that the Energy Bureau may make.
5. Further modernization of the COSS.

The Unbundling report was issued less than six months ago and during that time limited progress can be made for improving data collection. However, the 2021 COS Study prepared as well as the above framework makes good progress towards these recommendations. First, the COS study includes modern updates to the COS approach by relying on a marginal cost estimation methodology that provides insights and informs PREB on costs that can be avoided in the event that a customer demands less supply from PREPA. This improvement specifically addresses Direction No. 5. Further, this approach also relies on more updated data from PREPA focused on future plans, thus, in part, addressing Direction No. 1 and 2.

Second, the framework allows for progress towards Direction No. 3 by allowing for categorizing costs consistently regardless of sector structure. That is, functionalized costs remain within the service provided and by understanding which costs are marginal and residual helps to define what costs are 'stranded' or can be 'avoided' with reduced sales.

Third, the framework also allows for improvements toward Directive No. 4. As additional policy decisions at the Energy Bureau are made they can be designated as costs to be incurred by function and, if PREPA is required to deliver regardless of energy supplier, designated as 'residual' and thus not included in credits or possibly bypassed by a customer that chooses an alternative supply source.

Finally, as data sources expand and improve the quantification of COS can be improved. In short, the proposed Unbundling Framework provides for delivery against the “Directions”.

2.5 Primary Default Unbundled Tariff Sheets

Appendix A provides a term sheet describing the various riders that will need to be implemented to offer a Primary Default Unbundled tariff.

2.6 Alternative Unbundled Tariff Sheets

Appendix A provides a term sheet describing the various riders that will need to be implemented to offer an Alternative Unbundled tariff.

3. Unbundled Tariff Implementation Considerations

While the first step in moving towards unbundled tariffs is to quantify the cost of service and appropriately functionalize costs (e.g., costs are unbundled into function such as generation, transmission, and distribution), there are several challenges to the presumption that if a customer leaves PREPA then PREPA's costs go down by an amount equal to marginal costs. The first is that PREPA customers do not pay marginal costs but rather average costs. The second is that marginal costs can be hypothetical and thus not represent the actual avoided costs. Both are discussed in more detail below.

3.1 Previously Identified Challenges

Many of the challenges to implementing an Unbundled Tariff were outlined in the Unbundling Report. Specifically, on Page 45 the reported noted the following:

> PREPA is undergoing substantial change in its circumstances, which will affect numerous aspects of the COSS, including:
>
> - Recovery of equipment and load from effects of Hurricane Maria.
> - The conversion of some legacy debt to restructuring bonds, to be paid off through a non-bypassable charge outside of base rates.
> - Some write-offs of legacy debt.
> - Changing access to new debt.
> - Sales of some PREPA generation assets and/or sites.
> - Retirement of other generation.
> - New PPAs.
> - New agreements for operation of the transmission and distribution systems.

3.2 Additional Challenges Identified in Develop Tariffs

In addition to these challenges, there are numerous other considerations that will impact PREPA's COSS over the next five to ten years. These include, but are not limited to:

- Extreme load loss as residents and businesses leave Puerto Rico due to challenging living and economic conditions.
- Persistent impact of COVID-19 that will impact major industries such as tourism.
- Decommissioning costs for existing resources that may be in excess of expected costs and/or have not previously been collected in rates.
- Implications of meeting renewable energy standards, particularly any efforts to 'catch-up' to meet requirements established for 2025.
- Provisions for Provider of Last Resort that will require PREPA to be prepared for the return of any customer at any time.
- Integrated Resource and system planning responsibilities, whereby PREPA may be required to ensure reliability of Puerto Rico thus incurring costs to ensure generation capacity availability.
- Future costs associated with Ancillary Services to meet potential implications of significant adoption of renewable power that is intermittent and the resulting need for flexible resources.
- Expansion of existing Independent Power Producer capacity if that enables them to both serve PREPA under a PPA as well as qualify as an ESP.

- Potential variability in costs by time of day or season, creating need to better match generation sources from ESPCs to customer loads or developing a framework to ensure ESPC served customers incur those time differentiated costs.

Lastly, there are numerous considerations for operations that must be addressed. These include but are not limited to:

- Representation of charges on the customer's bill.
- Adaptability of billing system to implement more complex rate structures that reflect a more complex cost structure.
- Robust Meter Data Management Systems (MDMS) that allow both collection and access to more granular data at a significant scale.
- Revenue tracking to ensure that PREPA continues to collect revenues consistent with costs and properly track whether all customers pay their fair share of rates and eliminate cost shifts.
- Consumer protection processes that ensure customers are not inadvertently subscribed to an ESPC or to multiple ESPCs and provide provisions for customers to easily address fraudulent practices.

3.3 Risks of Cost Shift

PREPA notes that the National Public Finance Guarantee Corporation ("National") acknowledged many of the data shortcomings noted above and further states in the October 30, 2020 comments that "National also observed that it would not be appropriate to proceed with unbundling until these deficiencies are addressed."

PREPA submits these proposals in accordance with the Resolution and Order from PREB but also acknowledges National's concerns and echoes said concerns in the development of a tariff. That is, the proposals provided in this report provide a strong framework for determining an unbundled tariff and a sustainable foundation that can be used over time once data issues are resolved. However, PREPA recognizes that the reliability of actual values provided are suspect and highly debatable. To that end, though PREPA has made genuine efforts to estimate potential tariffs shown in this report, these values should be considered indicative and, without more reliable and detailed data, cannot guarantee that those customers that remain with PREPA would not experience additional costs driven by other customers having the wherewithal to accept supply from ESPCs or other suppliers. That is, PREPA believes that without more detailed cost data and many of the provisions in the Alternative Unbundled Tariff, the Default Primary Unbundled Tariff may create unintended cost shifts from customers who are served on the new tariff to those customers who remain with PREPA.

3.4 Wholesale Generation vs. Self-Supply

Another consideration is that the original order notes that the tariff would apply to the following:

- Electric Power Service Companies (EPSCs)
- Microgrids
- Energy Cooperatives
- Municipal Ventures

- Large scale industrial and commercial consumers
- Community solar
- Demand aggregators

While PREPA agrees that a supply credit can apply equally to each of these types of suppliers, there is a key assumption that must be considered. That is, the supply is at the Transmission level and is 'wheeled' to the customer. To the best of Guidehouse's knowledge the issues related to Self-Supply have not been fully addressed and can create a significant unintended cost shift to non-participation customers. Specifically, by allowing a customer to install behind the meter generation to both meet their facility energy needs as well as enough to meet needs of other customers they can 'wheel' to, additional cost shift issues arise, particularly with rate structures that rely solely or predominantly on energy volumetric (kWh) charges.

The issue is that these customers can reduce their on-site energy consumption and export energy onto the grid for another customer reducing their volumetric charges dramatically. For the on-site generation, this reduction is equal to the entire retail rate, which includes both the supply and delivery portions of the bill. Then, for the exports to other customers, the self-supply customer gains the revenues from those sales to further offset generation costs.

Despite the fact that energy is being produced, the self-supply customer continues to lean on the grid for capacity, both generation and delivery, when their generator is not running. This can occur daily (e.g., if the customer has a solar facility behind the meter) or during outages (e.g., for any combined heat and power generator). If that customer is not charged for their 'standby' power, then revenues that apply to grid costs are lost and that creates a cost shift to other customers who must now pay for the 'residual' transmission and distribution costs.

This can be addressed through demand charges that are either linked to a customer's potential annual maximum demand or the size of the generator. Without addressing these other rate design issues, however, there can be a significant cost shift due to the rate design challenges of collecting costs through volumetric rates versus demand rates, customer charges, or some other 'subscription' or 'grid access' type charges.

3.5 Firm vs. Intermittent Supply

The 'product' end-user customers, or those customers receiving energy from a grid, are buying a product that is available when they demand, regardless of the conditions of any one generator. That is, every hour the product is reliably available up to the level committed to. This, in wholesale market terms, is known as firm supply. No stand-alone generator can provide firm supply. Rather a fleet of generators is needed to ensure sufficient back-up in cases where the single generator is not able to produce up to their full capacity. Further, load brings in another dimension where the load can be sporadic. For a generator to provide 'load following' the generator must be able to immediately, as in seconds, respond to a customer's needs. Again, this is best accommodated with a fleet of generators.

This is an important concept that must be considered as PREB considers allowing wholesale generators to supply individual customers. The unbundling tariffs contemplated assume the generation backup and load following services can be accommodated by the PREPA system and as long as the energy values balance out over the year and costs associated with imbalances are settled then costs are covered. However, this is not altogether true, and will become even more problematic as the generation mix in Puerto Rico changes and costs start to vary more significantly by time of day and season.

Further, customer self-supply or aggregated behind-the-meter supply to sell to other customers also creates a cost difference between firm and intermittent supply. If the supply is intermittent because it is dependent upon both a customer's use and the same customer's behind the meter self-supply performance, the PREPA system is effectively doing double duty by supplying stand-by service to both the customer with the self-supply and the "ESPC customers" buying from that self-supplying customer.

Emphasis must be focused on the fact that current costs analyzed in all the cost of service studies are aggregated, average costs that include those costs for converting several non-firm generation supply sources into a firm load following product for the customer. That is, the supply credit should be based on the non-firm product the supplier is providing or there should be firming charges that apply to the ESPC to make the product they offer commensurate with the firm load following product being delivered to the customer.

3.6 Uniform Policy Rules for Supply

One last consideration is policy requirements related to supply. Specifically, in order to truly create options for customers to competitively choose supply while also not creating unintended cost shifts, policies must be uniformly applied to all suppliers or separately designated as the responsibility of PREPA with appropriate cost recovery mechanisms. One significant example of this issue are costs related to Renewable Portfolio Standards. The issues around RPS are twofold. First, all suppliers should be required to meet the level of RPS dictated, meaning if an ESPC serves 10,000 MWh of load and the RPS requirement is 30% then the ESPC must demonstrate they have 3,000 MWh of generation that complies with the RPS standard. In this case, PREPA's obligation is also reduced by the 3,000 MWh during the time the ESPC serves those customers. Conversely, PREPA should not include an 'adder' to the supply credit for renewable supply unless

- Those costs are actually included in retail rates and thus avoidable (this is not currently the state) and
- Is equal the benefit, which is percent of RPS requirement avoided

This distinction is important because there may be instances that the ESPC supplies more renewable power than the RPS requires. The fact that this supply to their own customers is greater than the RPS does not alleviate the RPS requirements that apply to PREPA's POLR obligation.

To also eliminate arbitrage, PREB should consider rules regarding level of ESPC service and Self-supply. That is, a customer that installs a renewable generation behind the meter could sell all but the "RPS" percentage, and lean on PREPA's system for the remainder (particularly during the transmission phase where PREB's offering that ESPC initially only need to meet 40% of their committed load, reducing to 20%).

In short, unless wholesale suppliers are required to provide the same products (e.g., firm as discussed above) and experience the same policy rules, a truly competitive market will not emerge and customers that stay with PREPA will most likely be burdened with cost shifts as creative players arbitrage these opportunities.

Appendix A. Tariff Sheets

FUEL CHARGE RIDER

DESIGNATION: FC

AVAILABLE:
Everywhere in Puerto Rico

APPLICABLE:
To all tariffs except for the fixed block of Tariff RFR.

The Fuel Charge (FC) is a rider mechanism which recovers the cost of expected fuel costs from PREPA's generating units on an annual basis. The FC shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.

The formula to calculate the Fuel Charge Rider is:

$$FC = \frac{Total\ Fuel\ Cost}{Applicable\ Retail\ kWh\ Sales}$$

<u>Total Fuel Cost</u>
The cost of fuel purchased for all PREPA's generating facilities for the three (3) forecasted months in the quarterly time period. The cost estimates shall be presented on a monthly basis and include all detail on the type of fuel forecasted to be consumed.

<u>Applicable Retail kWh Sales</u>
Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.

<u>Quarterly Filing</u>
PREPA shall make a filing for a proposed FC Rider before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised FC Rider is not approved the previous quarters' FC Rider shall remain in effect until a new factor is approved.

PURCHASE POWER CHARGE RIDER

DESIGNATION: PPC

AVAILABLE:
Everywhere in Puerto Rico

APPLICABLE:
To all tariffs except for the fixed block of Tariff RFR.

The Purchase Power (PPC) is a rider mechanism which recovers the cost of expected costs from purchase power agreements on an annual basis. The PPC shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.

The formula to calculate the Purchase Power Charge Rider is:

$$PPC = \frac{Total\ Purchased\ Power\ Costs}{Applicable\ Retail\ kWh\ Sales}$$

<u>Total Purchase Power Costs</u>
The cost of purchased sources of energy and capacity for the three forecasted months in the quarterly time period. The cost estimates shall be presented on a monthly basis and include all detail on the type of power forecasted to be purchased by PREPA.

<u>Applicable Retail kWh Sales</u>
Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.

<u>Annual Filing</u>
PREPA shall make a filing for a proposed PPC Rider before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised PPC Rider is not approved the previous quarters' PPC Rider shall remain in effect until a new factor is approved.

ENERGY COST TRUE-UP

DESIGNATION: ECT

AVAILABLE:
Everywhere in Puerto Rico

APPLICABLE:
To all tariffs except for the fixed block of Tariff RFR.
The Energy Cost True-up (ECT) is a reconciling rider mechanism which recovers the prior period adjustments for both Fuel Costs and PPA costs. The ECT shall apply to all of PREPA's rates with the exception of the base usage contained in RFR Rate.

The formula to calculate the Fuel Charge Rider is:

$$ECT = \frac{Prior\ Period\ Adjustments}{Applicable\ Retail\ kWh\ Sales}$$

<u>Prior Period Adjustments</u>
Adjustments for prior periods for the Fuel Cost Adjustment and Purchase Power Cost Adjustment costs

> *Fuel Cost Adjustment Prior Period Adjustment:* The under- or over-recovered funds for the first two (2) months of the current quarterly time period and the last month of the prior quarterly time period. PREPA shall provide the reconciling balance with each proposed quarterly filing of the FC.
>
> *Purchase Power Prior Period Adjustment:* The under- or over-recovered funds for the first two months of the current quarterly time period and the last month of the prior quarterly time period. PREPA shall provide the reconciling balance with each proposed quarterly filing of the PPC.

<u>Applicable Retail kWh Sales</u>
Energy sales to all classes of customers, including the net inflow (i.e. inflow - outflow) to all net metering customers.

<u>Quarterly Filing</u>
PREPA shall make a filing for a proposed ECT Rider at the same time making a filing for both the FC Rider and PPC Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised ECT is not approved the previous quarters' ECT Rider shall remain in effect until a new Rider is approved.

DEFAULT RETAIL SUPPLY CHOICE CREDIT

DESIGNATION: DSSC

AVAILABLE:
Everywhere in Puerto Rico

APPLICABLE:
To all tariffs except for the fixed block of Tariff RFR.
The Default Retail Supply Choice Credit (DSCC) rider mechanism which provides a credit to customer for choosing alternative supply from PREPA's services. The DSSC shall apply to all of PREPA's rates if the customer has confirmed with PREPA that they are receiving supply from an ESPC and that ESPC is qualified under the Uniform Services Agreement to supply this customer.

The formula to calculate the DSSC is:

$$DSCC = \frac{MEC * Class\ Sales + MGCC * Contribution\ to\ CP}{Class\ Sales}$$

<u>MEC</u>
<u>Marginal Energy Costs as computed as function of the dispatchable resources and the FCA and PPCA</u>, which adjust quarterly

<u>Class Sales</u>
kWh of sale by class

<u>MGCC</u>
Marginal Generation Capacity Costs.

<u>Contribution to CP</u>
Class contribution to Coincident Peak.

<u>Quarterly Filing</u>
PREPA shall make a filing for a proposed DSSC Rider at the same time making a filing for both the FCA and PPCA. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised DSSC is not approved the previous quarters' DSSC Rider shall remain in effect until a new Rider is approved.

RETAIL SUPPLY CHOICE CREDIT

DESIGNATION: SSC

AVAILABLE:
Everywhere in Puerto Rico

APPLICABLE:
To all tariffs except for the fixed block of Tariff RFR.
The Retail Supply Choice Credit (SCC) rider mechanism which provides a credit to customer for choosing alternative supply from PREPA's services. The SSC shall apply to all of PREPA's rates if the customer has confirmed with PREPA that they are receiving supply from an ESPC and that ESPC is qualified under the Uniform Services Agreement to supply this customer.

The formula to calculate the SSC is:

$$SCC = FC * FCP + PPC * PPCP$$

<u>FC</u>
The current Fuel Charge Rider, which adjust quarterly

<u>FCP</u>
Fuel Charge Rider factor equal to the percent of capacity related to dispatchable PREPA owned generation assets divided by all PREPA owned generation capacity. Currently set at 73%, this value is updated when PREPA files an updated Cost of Service Study.

<u>PPC</u>
The current Purchase Power Charge Rider, which adjust quarterly.

<u>PPCP</u>
Purchase Power Charge Rider factor equal to the percent of capacity related to dispatchable PPAs divided by all PPA owned generation capacity. Currently set at 9%, this value is updated when PREPA files an updated Cost of Service Study.

<u>Quarterly Filing</u>
PREPA shall make a filing for a proposed SSC Rider at the same time making a filing for both the FC Rider and PPC Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised SSC is not approved the previous quarters' SSC Rider shall remain in effect until a new Rider is approved.

Direct Testimony

Exhibit D

Proposal for Uniform Services Agreement Report

Prepared for:

Puerto Rico Electric Power Authority

Submitted by:

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May 10, 2021

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Figures

Tables

Summary of Uniform Services Agreement Proposals

PREPA has reviewed the requirements for the Uniform Services Agreement as outlined by PREB. PREB provides guidelines for the agreement and offers that PREPA may propose an alternative. To that end, PREPA proposes both a Default Uniform Services Agreement that fully aligns with PREB's order as well as an Alternative Uniform Services Agreement. PREPA outlines the components of a Uniform Services Agreement and describes its proposal for the Default and Alternative Agreements with Energy Service Provider Companies (ESPCs). The proposals are outlined in "term sheets" shown in Table E-1.

Table E-1. Term Sheets for Default and Alternative Uniform Services Agreements

Component	Default	Alternative
ESPC Eligibility	Required to sign the Uniform Services Agreement without alterations	Same as Default
ESPC Notification of Customer Enrollment	• ESPC notifies PREPA of a customer switching to ESPC service • Supplies accounts and meter information for each customer	Same as Default
Notification Timing	Silent	Notification occurs no less than 5 business days from the end of the customer's billing period
Transfer Timing	Silent	• Customer transitions to ESPC service at the start of their next billing period from the date of notification • If notifications by ESPC occurs within five business days of the end of the customer's billing period, the transition occurs at the end of the following month's billing period
PREPA Customer Notifications	PREPA will verify with customer that the customer has chosen to take service from the ESP and confirm the accounts and meters	Same as Default
Imbalance Provisions	• Hourly differences between supply and customer load, adjusted for losses are tracked • Positive differences (Generation > load plus losses) is credited to ESPC at 95% of the Imbalance Rate • Negative differences (Generation < load plus losses) charged to ESPC at the Imbalance Rate	Same as Default

Hourly Imbalance Rate	• Computation on an hourly basis from the fuel and variable O&M rate for the marginal generation unit, which would be turned up if PREPA's load were higher or turned down if PREPA's load were lower • If PREPA cannot identify the marginal generation unit or its costs, the marginal generation cost in a given hour will be deemed to be the average cost per MWh of fuel and variable O&M for steam oil plants operating at that hour	• Computation of forecasted hourly marginal costs based on IRP modeling • Variations in actual costs versus forecasted marginal costs will be computed and addressed in the True-Up Mechanism
Imbalance Performance Provisions	• Calculate the total annual imbalance as the absolute value of the difference between the generation delivered to PREPA by the EPSC and the metered load and line losses of its wheeling customers • An imbalance dead zone which shall be defined by year as follows: ○ Year 1 = 60% ○ Year 2 = 50% ○ Year 3 = 40% ○ Year 4 = 30% ○ Year 5 and beyond = 20% • Performance charge based on the positive difference between 1 minus the bandwidth times total annual customer load less annual imbalance. This positive balance is then multiplied by 10% of the average fuel cost adjustment and purchased-power cost adjustment for the IPP's customers in the given year	• Calculate the total annual imbalance as the sum of each hourly imbalance amount for the year times the Hourly Imbalance Rate • An imbalance dead zone which shall be defined by calendar year as follows ○ 2022 = 60% ○ 2023 = 50% ○ 2024 = 40% ○ 2025 = 30% ○ 2026 and beyond = 20% • Performance charge based on the positive difference between 1 minus the bandwidth times total annual customer load less Annual Imbalance. This positive balance is then multiplied by 10% of the total Annual Imbalances times 1 minus the bandwidth
Losses Rate	For the purposes of both the hourly energy balancing provisions and the annual imbalance charge, line losses adders shall be set at the values used in the Cost of Service Study filed in Case No. CEPR-AP-2015-0001, or an updated value as available	Same as Default

Losses Adder	Silent	ESPC is responsible for scheduling supply to meet customer load plus losses as defined by the Losses Rate
Credit Terms	Letter of credit for an estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment	Letter of credit or cash collateral for four times the estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment times the credit collateral requirement percentage
Credit Rating	Silent	Provide for ESPC's credit rating by reducing credit requirements for good credit quality using "Big Three" credit ratings as follows: ○ P1 = 5% ○ P2 = 25% ○ P3 = 50% ○ Not Prime = 100%
Scheduling	Silent	ESPC is required to submit a schedule to PREPA electronically a day ahead with forecasted hourly load requirements adjusted for losses as well as hourly supply forecast
Ancillary Services	Silent	• Proposed charges for the following Ancillary Services: ○ Scheduling ○ Reactive Supply and Voltage Control ○ Regulation and Frequency ○ Operating Reserve – Supplemental ○ Response Operating Reserve – Spinning • Values for each service are set to zero until such time that they can be quantified and separated from costs currently embedded in PREPA's generation costs and thus included in the supply credit and the ESPC starts to pay for these costs directly

Standby Services	Silent	• PREPA and ESPC agree to a Contract Demand level • The ESP then pays a monthly charge of the Contract Demand times Marginal Generation Capacity Cost • If actual standby services exceed the Contract Demand, Contract Demand level is automatically adjusted to equal actual demand shortfall
True-Up Mechanism	Silent	Propose tracking of actual costs versus actual revenues associated with ESPC service to customers (including imbalances) and true-up these costs annually, resulting in a credit or charge to the ESPC with an equal but opposite charge or credit to PREPA's customers

PREPA's Default Uniform Services Agreement is in compliance with the PREB Order for Uniform Services Agreement. PREPA's Alternative Uniform Services Agreement provides additional granularity to the agreement and, PREPA believes, remains consistent with PREB's Order.

PREPA, therefore, submits this report regarding the Uniform Services Agreement in compliance with PREB's order. PREPA also respectfully requests that PREB delay any decisions regarding the Uniform Services Agreement until such time that the market rules are understood and PREPA is able to track the necessary costs and compute, on a cost basis, the necessary fees included in the agreements; and until several policy issues (such as responsibilities for Renewable Portfolio Standard compliance) are resolved. PREPA also encourages the establishment of a series of workshops with key stakeholders to draft the final legal terms of the agreements.

Regardless of the above concerns, PREB may choose to move forward and implement a Uniform Services Agreement at this time. If such is the case, PREPA requests PREB's approval of the Alternative Uniform Services Agreement in whole. However, PREPA's proposal in the Alternative Uniform Services Agreement also offers separate and distinct components, as shown in Table E-1. This provides PREB the option to adopt certain components from either the Default or the Alternative Agreements. While PREPA recommends adopting the Alternative Uniform Services Agreement proposal in whole, PREPA encourages PREB to consider many of the components and not reject them in whole but consider creating a 'hybrid' Uniform Services Agreement.

1. Introduction

This Uniform Services Agreement Report includes information regarding the procedural background of this regulatory proceeding as well as the proposals for both a Default Uniform Services Agreement and Alternative Uniform Services Agreement. The summary of the 2021 Cost of Service Study is contained in a separate report as is the Proposal for Unbundled Tariffs Report.

1.1 Procedural Background

On December 11, 2019, PREB issued Regulation 9138, setting the legal and regulatory framework and process for electric energy wheeling in Puerto Rico and enabling eligible entities such as Electric Power Service Companies (ESPCs), Microgrids, Energy Cooperatives, Municipal Ventures, large scale industrial and commercial consumers, community solar and demand aggregators to exercise choice and control over their electric service. The regulation also established the need for protecting non-subscribers from being adversely impacted by wheeling.

In October and November 2020, PREB held two Technical Conferences. The first discussed PREPA's fuel and purchased power costs, any potential credit for wheeling customers for avoided generation capacity, and PREPA's recommendations for a charge to cover its costs associated with the implementation of wheeling. The second addressed operational and technical issues that would need to be resolved in order to implement wheeling. Further, on October 30, 2020, PREB received comments from PREPA and the National Public Finance Guarantee Corporation (NPFGC), with reply comments provided on November 13, 2020. From these proceedings, PREB found that "there does not need to be a distinction between an 'interim' unbundled rate for wheeling customers and a 'full' unbundled rate." Specifically, PREB noted:

> *"The issues raised in the Resource Insight Report on Cost Allocation Methods and Unbundling Issues ("Unbundling Report") cover a wide range of potential reforms, many of which may be desirable in their own right but not strictly necessary for unbundling. However, the Energy Bureau determines that these reforms can be implemented over time, and that does not prevent the approval of an unbundled rate for wheeling in the shorter term, so long as the unbundled rate meets the relevant legal requirements."*

In addition, with respect to the setting of the unbundled rate, PREB found:

> *"…it is important to recognize that current rate structures, including the fuel cost adjustment ("FCA") and purchased-power cost adjustment ("PPCA") are based on average cost. However, the fair and efficient compensation to a wheeling customer using non-PREPA generation, as well as the impacts on non-participating customers, are determined by the marginal costs imposed or avoided. The cost avoided by customer replacing PREPA supply with third-party generation would normally be higher than the FCA, since the FCA represents the cost of serving only a fraction of the load (with the rest served by purchased power), and since a reduction in PREPA's load should allow it to turn down the most expensive plants operating in each hour, not just the average mix of plants.*
>
> *From a review of the historical value of the FCA and PPCA and the marginal fuel and variable operation and maintenance ("O&M") costs of the fossil plants most likely to be marginal, it appears that the sum of the FCA and PPCA is a reasonable administrative proxy for marginal costs that are variable in the short run. The fact that the PPCA*

includes purchased power is not necessarily germane to that analysis, so long as a fair analysis shows that the sum of the FCA and PPCA reasonable follow PREPA's short-term marginal costs, and do not overstate PREPA's savings or burden non-wheeling customers.

Finally, in response to comments regarding data availability and quality, PREB determined:

"Finally, while we appreciate concerns about the need for the up-to-date utility data, we must continue to exercise the Energy Bureau's regulatory responsibilities with the data and information that we have available today. The Energy Bureau will consider steps to required PREPA, LUMA Energy, LLC ("LUMA") and other entities to collect track, disclose and utilize all the data that a modern utility should collect, track, disclose and utilize. However, those processes will take time. Current rates are built on the data that is available now that there is no evidence thus far to demonstrate that using that data now for the purpose of unbundling rates and establishing a wheeling rate will adversely impact PREPA or its wheeling and non-wheeling customers. For the purposes of setting a wheeling rate that does not increase costs to non-wheeling customers the unbundling of costs among distribution, transmission and stranded generation costs is not critical, so long as the avoidable costs are reasonably estimated."

As a result, PREB issued an order to move forward with an Unbundled Tariff and accompanying Uniform Services Agreement and outlined procedural requirements for developing the tariff.

1.2 Requirements for Uniform Services Agreement

The December 23, 2020 PREB Order sets forth requirements for a Uniform Wheeling Services Agreement. Specifically, the order requires:

1. *Provision of meter data from PREPA to the EPSC to allow separate billing from the ESPC to the wheeling customer for their supply.*
2. *An initial fee per EPSC to set up a new wheeling account and an annual fee for ongoing account maintenance.*
3. *An initial charge for each meter transferred and an ongoing monthly fee per meter per month for the costs of transferring billing data.*
4. *A process for transfer of customers to the unbundled rate for wheeling, including customer approval and verification of the relevant accounts and meters.*
5. *Hourly energy balancing provisions shall include:*
    i. *Computation on an hourly basis from the fuel and variable O&M rate for the marginal generation unit, which would be turned up if PREPA's load were higher or turned down if PREPA's load were lower. If PREPA cannot identify the marginal generation unit or its costs, the marginal generation cost in a given hour will be deemed to be the average cost per MWh of fuel and variable O&M for steam oil plants operating at that hour.*
    ii. *If the hourly metered load and line losses of an EPSC's wheeling customer exceeds the output of its generation sources, the EPSC's wheeling customers exceeds the output of its generation sources, the EPSC shall be charged for excess load at the marginal hourly generation costs as computed above.*

   iii. *If the hourly output of an EPSC's generation sources exceeds the metered load and line losses of its wheeling customers, the Independent Power Producer (IPP) shall be credited for excess generation at 95% of the marginal hourly generation cost as computed above.*

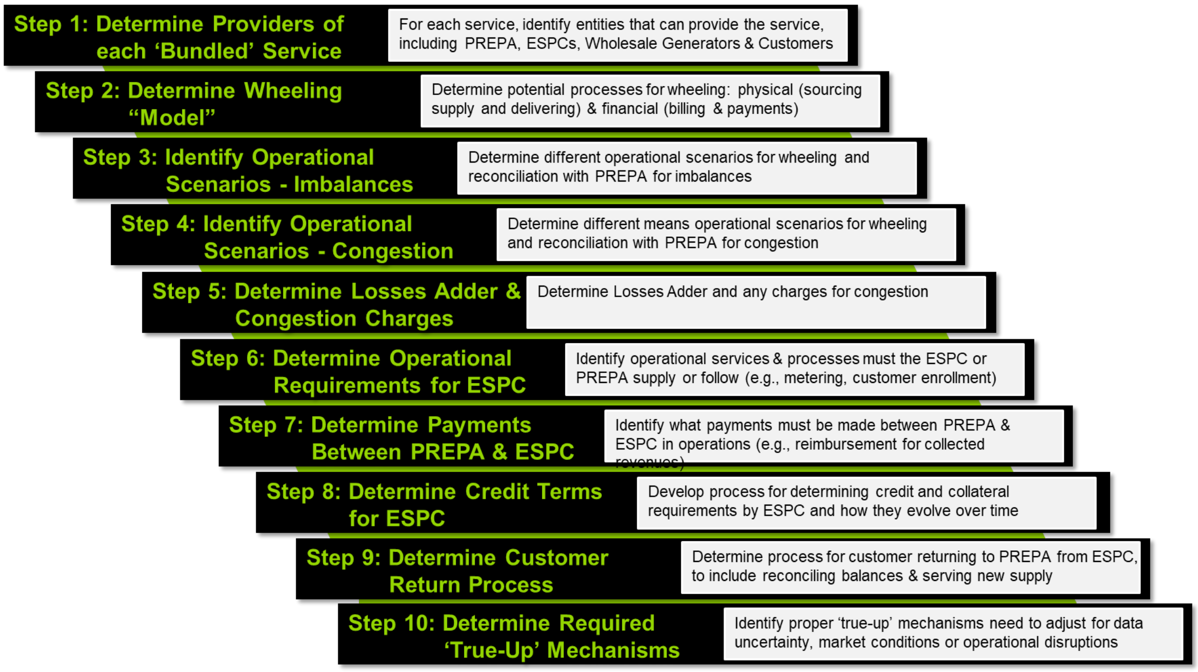
6. *An annual imbalance charge provision shall include:*
   i. *Calculation of the total annual imbalance as the absolute value of the difference between the generation delivered to PREPA by the EPSC and the metered load and line losses of its wheeling customers.*
   ii. *An imbalance dead zone which shall be defined s 60% of the metered load and line losses of an EPSC's wheeling customers in the first year following interconnection, 50% for the subsequent year, 40% in the third year, 30% in the fourth year, and 20% thereafter.*
   iii. *If the total annual imbalance exceeds the calculation imbalance dead zone for the given year, the EPSC shall pay an annual imbalance charge defined as the (a) difference between the total annual imbalance and the calculated imbalance dead zone, multiplied by (b) 10% of the average fuel cost adjustment and purchased-power cost adjustment for the IPP's customers in the given year.*
6. *For the purposes of both the hourly energy balancing provisions and the annual imbalance charge, line losses adders shall be set at the values used in the Cost of Service Study filed in Case No. CEPR-AP-2015-0001, or an updated values available.*
7. *IPP credit requirement*
   a. *Letter of credit for an estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment.*

This report addresses these requirements and the challenges associated with their implementation in the following sections.

2. Uniform Services Agreement Framework

For this filing, PREPA has developed an overall framework shown in Figure 2-1 that will allow for the design of a Uniform Services Agreement that can be changed according to updates to regulatory rules and requirements. The components included in the both the Default Uniform Services Agreement and Alternative Uniform Services Agreement presented are consistent with this framework and Regulation 9138 rules as issued on December 11, 2019. Each step is described in more detail below.

Figure 2-1. Stepwise Framework for Uniform Service Agreement

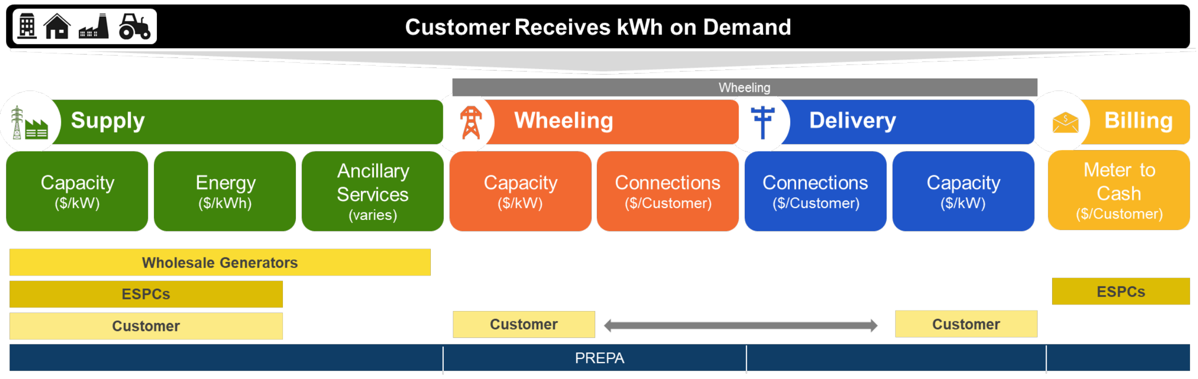


On April 23, 2021, PREB issued proposed redline changes to Regulation 9138 and requested comments within 30 days. As such, PREPA anticipates that the regulation will change after the submission of this proposal, and such changes will most likely require changes to the proposed Uniform Services Agreements.

2.1 Determine Providers of Each "Bundled" Service

The first step is to identify which entities can provide each of the unbundled services, including PREPA, ESPs, Wholesale Generators, and Customers. Figure 2-2 shows the unbundled services and the identified entities that can provide the various services.

Figure 2-2. Providers of Each "Bundled" Service



As shown, there are four types of entities that can provide various services. Each entity is described below.

2.1.1 Wholesale Generators

Wholesale generators provide energy and ancillary services supply through power purchase agreements (PPAs) to either Energy Service Providers (ESPs) or PREPA. Only certain generators can provide certain ancillary services. As such, some generators only provide energy services.

2.1.2 Energy Service Providers

An ESPC delivers energy to PREPA to deliver to the ESPC's customer on PREPA's grid. ESPC supply can be from new assets or PPAs from wholesale generators. ESPCs will also bill and collect for supply or for all services, with the ESPC paying PREPA for charges incurred but not billed and collected by PREPA.

2.1.3 Customers

Customers can self-supply with on-site generation, and on-site generation requires no wheeling or delivery for that generation. Note that the current Regulation 9138 specifies that unbundling applies to ESPCs and further notes that customers with access to Net Energy Metering services do not apply. As such, the Uniform Services Agreement does not contemplate customers signing such agreements.

2.1.4 Provider of Last Resort

PREPA is the Provider of Last Resort (POLR), meaning PREPA has responsibility for serving any customer who cannot or chooses to not self-supply or procure supply from an ESP. PREPA is also the Transmission Operator and thus wheels power from generation source to Service Driver center. The Transmission Operator is also responsible for planning for adequate transmission capacity and connecting generators to the transmission grid. In addition, PREPA is responsible for the delivery of power to customers and the design, planning and maintenance of the distribution grid. Finally, PREPA provides meter-to-cash services that include metering of load, billing, and collections. With unbundling, PREPA will also be responsible for providing ESPCs with encrypted metering data for each of the ESPC's customers.

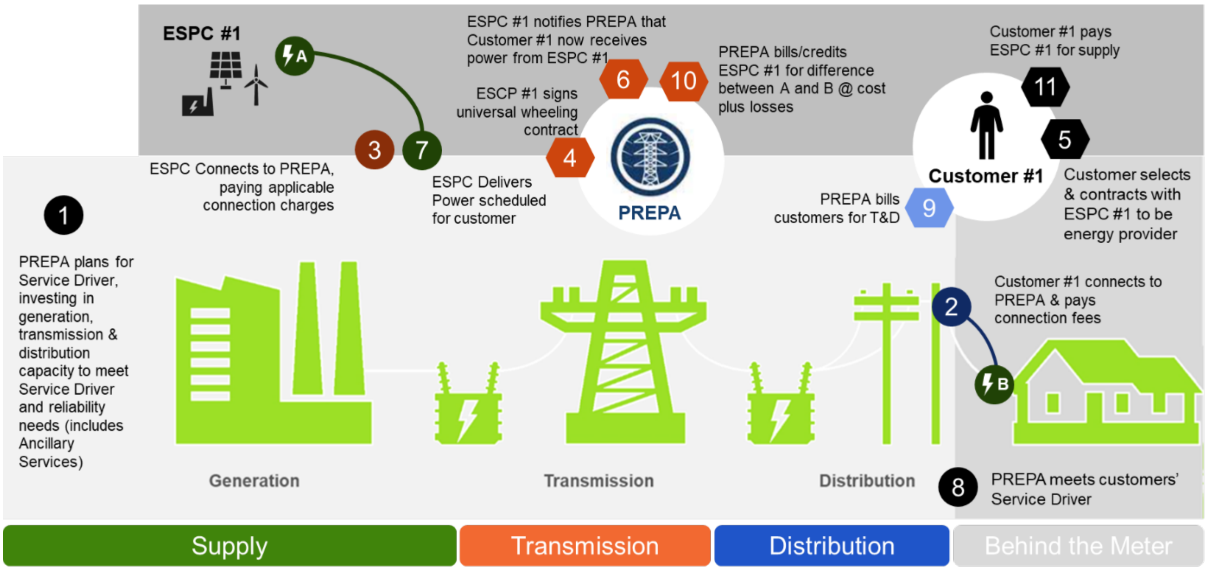
Currently, Regulation 9138 implies supply can be provided by an ESPC to a retail customer that is connected to the grid at the transmission level. Therefore, the Uniform Services Agreement proposed only contemplates costs and benefits associated with supply and billing related costs. If supply is to be provided at the distribution level, as potentially contemplated in the proposed rule changes, additional charges may apply and additional terms and conditions in the Uniform Services Agreement will be needed to address operational considerations. Such considerations can be very complex and must have sufficient detail to ensure the safety of the grid and ensure a reliable grid for all customers.

2.2 Determine Wheeling Model

Regulation 9138 provides specific rules as well as general guidelines on the implementation of unbundling and offering a wheeling agreement. To develop a sustainable Uniform Services Agreement, PREPA determined a wheeling model, as shown in Figure 2-3. Because Regulation 9138 provided guidelines on specific modeling considerations, PREPA had to make three key decisions:

1. **Billing:** The ESPC bills and collects for services from the ESPC's customer while PREPA bills and collects for services from the ESPC's customer.
2. **Losses:** The ESPC provides supply to cover losses (rather than financial settlement at marginal costs) to limit credit risk.
3. **Congestion:** PREPA will 'socialize' congestion costs until PREPA is able to measure and account for congestion in separate charges.

Figure 2-3. Proposed Wheeling Model



The wheeling model considers 11 key roles and responsibilities, defined below.

Step 1: The POLR, assumed to be PREPA, is responsible for planning for sufficient generation, transmission, and distribution capacity to serve all loads. This is a key consideration, specifically for generation. It is possible that the sector may be restructured to consider the generation services be served by a separate entity, hereafter referred to as "GenCo." If that were to occur, the POLR company would retain planning responsibility for transmission and distribution while coordinating with GenCo for generation capacity planning. However, this plays out the planning for adequate supply is critical, particularly in the absence of sector rules that require all load serving entities be responsible for ensuring adequate capacity for their customers. The current structure contemplated with Regulation 9138 is that the supplier (ESP) provides energy services but is not required to incorporate long term plans for serving that customer or meeting future load growth. Therefore, this planning function must fall upon an entity that continues to be accountable to PREB and thus incur costs on behalf of the sector to ensure adequate capacity. This also implies that the Uniform Services Agreement must either charge for capacity services on behalf of the ESPC customers or include such costs in the base rates to all customers. For simplicity, in part due to some ambiguity on this issue, PREPA is proposing to charge for these rates in base rates and, therefore, mindfully exclude such costs from any supply credit.

Step 2: The POLR, or PREPA, is responsible for ensuring retail customers are able to connect to the transmission or distribution system and receive load following (on demand) electricity service. Costs to connect are collected through either connection related charges or retail rates.

Step 3: Similar to Step 2, the POLR, or PREPA, is responsible for ensuring wholesale generators, also referred to as the POLR's wholesale customer, are able to connect to the transmission system and, potentially, deliver power on behalf of a customer or provide energy to PREPA through a PPA.

Step 4: Once a generation supply entity is connected to the grid, the entity can qualify as an ESP. This is done by signing the Uniform Services Agreement with PREPA. The Uniform Services Agreement applies to an ESPC regardless of the number of customers the ESPC serves.

Step 5: A customer can then elect service from a qualified ESPC. The customer signs a contract with the ESPC for supply services, to include the terms and conditions for pricing.

Step 6: The ESPC then notifies PREPA that a certain customer has elected to take supply from the ESPC and provides PREPA with account information. PREPA then confirms with the customer that the customer has chosen to take service from the ESP, in part to provide a consumer protection service to ensure an ESP is not signing up customers without that customer's consent.

Step 7: The ESPC provides supply to meet the customer's load at the point of interconnection between the ESPC's generation resource and PREPA's transmission system. The Uniform Services Agreement includes provisions for scheduling of supply and tracking of actual supply provided.

Step 8: PREPA meets the customer's actual loads, including following their needs to ensure fully responsive and uninterrupted services despite the performance of the customer's ESPC.

Step 9: PREPA charges the customer for basic service, that includes all costs associated with serving the customer that PREPA incurred, as determined by the unbundled tariff. Specifically, PREPA charges the customer for all costs that exclude the supply credit. The customer's actual bill will differ by the amount of the supply credit and the pricing for supply determined by the agreement between the customer and the ESPC.

Step 10: PREPA charges the ESPC for the following:

- Imbalances related to the difference between hourly energy provided by the ESPC and the customer's hourly loads, plus losses

- Incremental charges related to the ESPC's delivery performance relative to their customer's hourly loads
- Fees related to providing the ESPC with metered data and managing customer transitions
- Fees related to incremental costs for setting up processes for providing unbundled services
- Potential fees to address congestion resulting from the location of an ESPC's generator relative to the customer's load

Step 11: The customer is billed by the ESPC for the supply and services provided by the ESPC according the agreement between the ESCP and the customer.

It is important to note that the proposed model outlined in Figure 2-3 assumes the ESPC is separately billing for their services and, similarly, PREPA charges the customer directly for services PREPA provides. The potential revisions contemplated by Regulation 9138 recently submitted may require PREPA to provide billing services for the ESPC. This would create significant changes to the proposed Uniform Services Agreements presented in this filing.

2.3 Identify Operational Scenarios – Imbalances

Step 3 looks at the operational scenarios where the ESPC does not directly meet the customer's load. These scenarios result in different levels of imbalances. The purpose of the scenarios outlined here is to make clear that the intent is for the ESPC to fully supply the needs of their customer and not rely on PREPA's generation system. This is because the supply credit is based on the costs to PREPA for providing generation supply and thus crediting these costs. If the ESPC and, eventually, the customer on ESPC service, does not pay these costs, these costs are then exclusively the burden of PREPA's customers who do not take ESPC service. PREPA identified three scenarios:

1. **Base Case**: ESPC fully meets the hourly loads plus losses in an hour
2. **Long Case:** ESPC supplies more than the customer's load plus losses in an hour
3. **Short Case:** ESPC supplies less than the customer's load plus losses in an hour
4. **Outage Case:** ESPC is unable to supply due to an outage at the plant and PREPA fully covers the customers load for that hour.

The Long and Short Cases result in additional costs to PREPA to generate the electricity or to turn down generators to accommodate the variability in the ESPC's supply relative to the ESPC's load requirements. These scenarios presume the ESPC scheduled supply in good faith and the customer's load deviated from that projected amount. The same can be true for supply, in that the customer load was what was predicted but the ESPC's generator did not perform as expected.

Figure 2-4 shows the case where the customer's load is less than expected but generation performed to schedule, thus the "Long Case." Note the "Long Case" can also result if the generator produces more energy than forecasted and simply 'puts' that electricity onto the grid and thus needs to be absorbed by PREPA. As shown, PREPA must back down Generator #1 by the difference between A and B plus losses. Similarly, if generation is greater for ESPC #1 but Customer 1 load does not deviate from forecast, Generator #1 must also back down to accommodate the additional supply, regardless of whether ESPC #1's supply is more or less expensive than Generator #1's costs.

Figure 2-4. Imbalances – Long Case

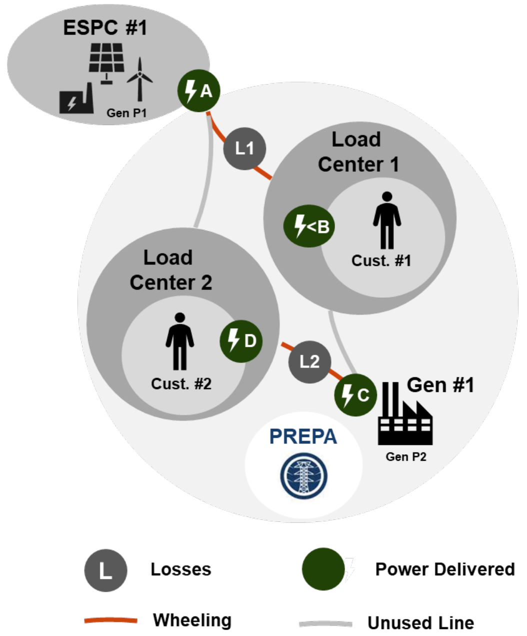
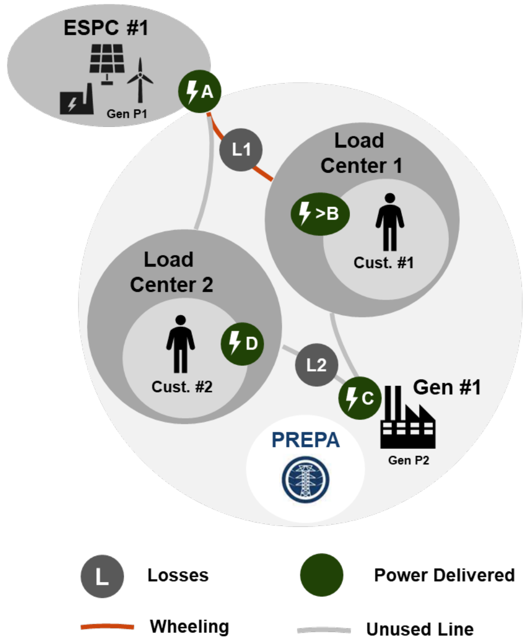


Figure 2-5 shows the Short Case scenario where the customer's load (B), plus losses (L1) are greater than ESPC #1 Generation (A) and thus PREPA must dispatch Generator #1 to make up the difference. Since Generator #1 is the 'marginal unit', it appropriately represents the costs of the difference in supply and load of the ESP. Figure 2-5 shows this scenario in terms of the customers load (B) being greater than forecasted. However, the same result occurs when ESPC #1 produces less than forecasted (A) in that hour.

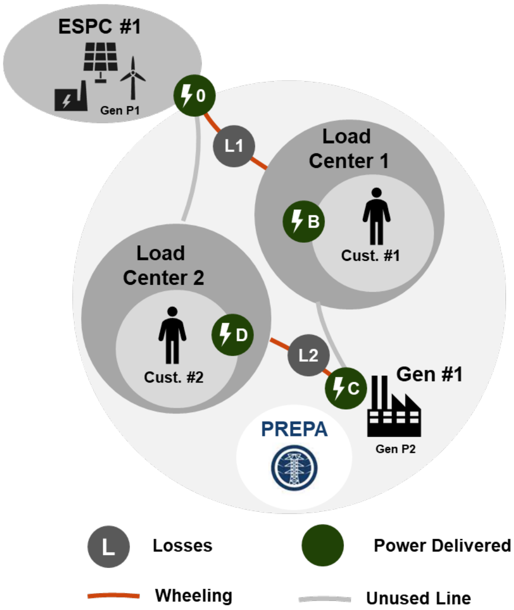
Figure 2-5. Imbalances – Short Case



Finally, Figure 2-6 shows the Outage Case scenario where ESPC #1 is not able to generate any supply in that hour. The Outage Case scenario can occur for only one hour but typically persists for more than an hour as seldom can a plant recover from a forced outage in such a short time. Further, if the outage was planned, the supply could be absent for several days to several months, depending on the nature of the planned outage. While Regulation 9138 contemplates the need for a Standby Rate, PREB's order regarding the Uniform Services

Agreement is silent on this issue, implying that all supply shortfalls can be met with imbalance charges. This is further substantiated by the proposal that a dead zone be established for the Annual Imbalance Charges. PREPA recommends establishing a Standby Rate for the ESPC that results in demand charges equal to the ESPC's capacity and is equal to the Marginal Generation Capacity Cost (MGCC). The billing determinant of the Standby Rate is a Contracted Demand, which is agreed to under the Alternative Uniform Services Agreement and equal to or less than the ESPC generator's nameplate capacity. In the event that the Standby services actually provided in a given month exceed the Contract Demand, the Contract Demand will be automatically ratcheted to that level of service for at least 12 months.

Figure 2-6. Imbalances – Outage Case



2.4 Identify Operational Scenarios – Congestion

Step Four looks at the operational scenarios where the ESPC's supply cannot reach its customer's load center, and thus PREPA must dispatch a plant to meet that customer's load. There are two potential scenarios for Congestion:

- **Scenario 1:** ESPC Supply Path to Customer is Congested
- **Scenario 2:** ESPC Supply Path to Any Load is Congested

Figure 2-7 shows Scenario 1. In this scenario, the ESPC still generates enough energy to supply its customer's load, however PREPA redirects that supply to a different load center (Load Center 2), allowing PREPA to reduce deliveries from Generation #1 to Load Center 2. In turn, PREPA directs Generation #1 supply to Load Center 1. In this case, the system loads are met by the ESP and Generation #1 in proportions equal to those that would apply if there was no congestion. Therefore, costs don't change as long as:

- Generation #1 is able to supply Load Center 1 to meet the ESPC's customer's load and was planned to serve Load Center #2, which is not supplied by the ESPC.
- Losses between supply and load are the same, that is L1 and L2 are the same.

Because these costs cannot be tracked at this time, PREPA proposes to rely on the True-Up Mechanism to account for differences in costs for congestion. This may result in some cost shift; however, this is necessary if the roll-out of unbundling occurs before PREPA has implemented plans for capturing these costs such that cost based charges can be generated and charged to each ESPC.

Figure 2-7. Congestion – ESPC Supply Path to Customer Congested

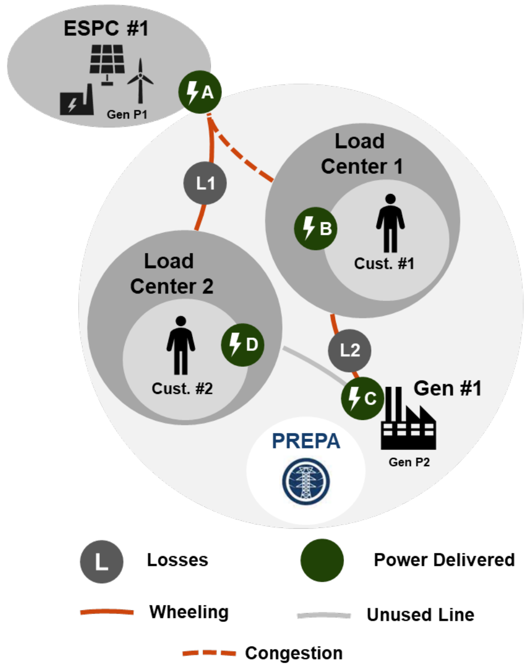
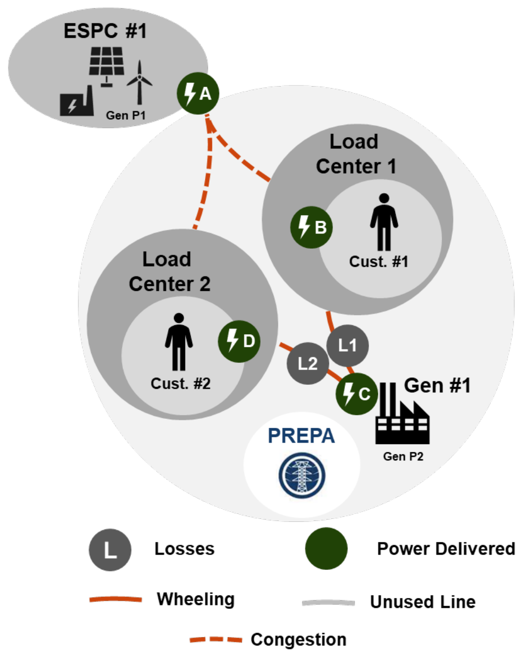


Figure 2-8 shows Scenario 2. In this case, the ESPC cannot get their supply to either Load Center 1 or Load Center 2, leaving Generation #1 to fully supply the ESPC's load. The delivered energy by the ESPC (A) is effectively zero and the ESPC must back down their plant. In this case, Generator #1 is providing enough supply to meet Load B, Load D, and L1 and L2 losses.

Figure 2-8. Congestion – ESPC Supply Path to Load Congested



2.5 Determine Losses Adder and Congestion Adder

In addition to costs related to energy and generation, transmission, and distribution capacity, there are other operating costs related to losses, congestion, and, potentially, other ancillary services. Any such incremental costs to the ESPC must be collected from the ESPC. Further, the costs required by ESPCs must be consistent with the Unbundling Tariff and related supply credit. Currently, the proposed Unbundled Tariff includes costs related to losses, ancillary services, and congestion. This is because the tariff is based on cumulative variable generation costs, which include the costs for providing these services. The handling of each of these are discussed in more detail below.

2.5.1 Losses

PREB's Order specifies that PREPA may charge for losses based on the Line Loss Adder established in the Cost of Service Study filed in Case No. CEPR-AP-2015-00001 until such time that PREPA files updated values that are subsequently approved by PREB. PREPA is proposing the application of a Losses Adder based on this reference as noted. However, PREPA may update this adder with subsequent rate cases where detailed assessments of distribution and transmission losses are performed and justify a change to the Losses Adder.

The Losses Adder is used in two ways. First, the Losses Adder is used in the calculation of scheduled supply to be delivered by the ESPC. That is, the ESPC will take its estimates of customer load and multiply that forecast by the Losses Adder and add that quantity to the scheduled load.

Second, the Losses Adder will be applied to the actual loads of the ESPC customers, again by multiplying actual load by the Losses Adder then adding that quantity to the customer's actual loads. The losses scaled load is then compared to the actual delivered energy by the ESPC to determine the number of imbalances.

PREPA is proposing that the ESPC supply losses for three reasons. First, it is consistent with the ESPC meeting the customer's supply needs and the supply credit takes this service cost into consideration. That is, the supply credit in the Unbundling Tariff is based on costs PREPA, or potential GenCo, incurs to supply for load and is based on the volumes actually delivered to the grid by each generator. Therefore, these costs are included in the Unbundled Tariff. Second, it simplifies the charging structure, especially if a separate GenCo is established. In this case, PREPA (the grid operator) must schedule adequate energy supplies from resources under PPAs and GenCo meets captive customer load plus losses. Alternatively, the grid operator, presumed to be PREPA throughout this filing, would be responsible for purchasing losses. Third, supply of losses from ESPCs limits credit exposure between the ESPC and PREPA. Otherwise, the losses are part of the imbalance charges, where the imbalances are increased by the amount of losses, resulting in a larger payment owed by the ESP.

2.5.2 Ancillary Services

Ancillary services, for the most part, are provided by generators. Currently, these services are embedded in the costs included in the Fuel Cost Allocator and the PPA Cost Allocator. Further, the data limitations on services provided and costs provided by each generator limits the ability to compute Ancillary Services and, thus, charge separately for those charges. Therefore, the Unbundled Tariff includes the costs of Ancillary Services. This requires the assumption that ancillary services costs are equally incurred regardless of the customer's load or ESPC's delivery profiles.

As data granularity improves for PREPA's system, a separate charge for Ancillary Services could be contemplated and removed from the base services tariffs, added to the supply credit then separately charged to the ESP. At this time, however, these costs are accounted for in the unbundling tariff so Ancillary Services charges are assumed to be zero.

2.5.3 Congestion

PREPA is proposing the establishment of a Congestion Adder as a per kWh charge applied to the ESPC's customer's load and charged to the ESPC to account for additional costs by PREPA for accommodating congestion between the ESPC's generator and the ESPC's customer. However, at this time, PREPA is proposing to set this adder to zero because incremental congestion costs will not be known until future generation sources built by ESPC go live. PREPA, and the planned grid operator, LUMA, plan to improve data collection of operational costs. Specifically, tracking of the marginal costs at points of connection of generators and load centers can lead to the computation of congestion charges. In some markets, load pays the load center price while generators get the nodal price at the point of interconnection. However, the congestion pricing adder would account for the cost difference between the ESPC's generation interconnection point and the ESPC's load.

As noted above, PREPA will set the Congestion Adder to zero until such time that PREPA files the Congestion Adder Methodology as well as a demonstration of capabilities to reliably compute the Congestion Adder, and PREB approves the proposed methodology.

2.6 Determine Operational Requirements for ESP

Step 6 in the development of the Uniform Services Agreement is to identify the operational process and thus operational requirements for an ESP. The key steps to this process are outlined in Table 2-1.

With these steps the requirements the ESPC must follow can be defined and thus included in the Uniform Services Agreement. These requirements ensure consumer protection and minimal cost shifting from customers that choose an ESPC versus services from PREPA. These include, but are not limited to, requirements that the ESPC provide ample notice for switching suppliers and provisions for automatically defaulting a customer to PREPA's service in the event the ESPC repeatably underperforms or does not pay PREPA for those charges applied via the Uniform Services Agreement.

Table 2-1. Operational Process for ESPs

No.	Step	Description
1	**Generator Qualifies as ESP**	• Generator meets ESPC requirements • Generator installs meter at point of interconnection with PREPA • Generator signs Uniform Services Agreement, becoming an ESPC • ESPC notifies PREPA of all names under which the ESPC will market supply services to PREPA customers
2	**ESP Recruits Customer**	• ESPC notifies PREPA that customer will now be served by ESPC • ESPC provides PREPA with customer's account number and start date • PREPA confirms customer agreement to be supplied by ESPC • PREPA switches customer to class specific wheeling rate as of start date

No.	Step	Description
3	**ESPC Supplies Customer**	• ESPC schedules day ahead supply to meet forecasted load of all ESPC customers PLUS losses • If ESPC also has a PPA with PREPA, ESPC separately schedules supply to PREPA • ESPC delivers energy hourly per day ahead schedule unless curtailed by PREPA for operational reasons • PREPA meets customer's usage needs
4	**Customer Billed**	• PREPA provides ESPC with customer billing data through secured portal or monthly encrypted files (provided weekly with goal of providing through secured portal daily) • ESPC bills customer separately for energy received based on contract terms • ESPC is responsible for customer collections for ESPC services • PREPA bills customer for wheeling services based on tariff and meter reads • PREPA is responsible for customer collection for PREPA's services
5	**Returning Customer**	• In the event that the ESPC no longer serves a customer, the ESPC informs PREPA that the customer will be returned to PREPA • PREPA confirms with the customer that the ESPC will no longer be the customer's provider and the customer wishes to return to PREPA • In some instances, the customer may choose to move from one ESPC to another, and in that case PREPA should receive a notice from both the current and future ESP of the customer's choice and PREPA will confirm
6	**Defaulting ESPC**	• If the ESPC is no longer able to supply (e.g., closes operations) the customer automatically is returned to PREPA • Ideally the ESPC will notify the customer of the change, however, PREPA will confirm. In rare instance the ESPC cannot inform the customer, PREPA will inform the customer of the change in supplier • If the ESPC does not pay PREPA for charges due past 60 days, PREPA may retain the right to revert the customer to service from PREPA to reduce future credit risk

2.7 Determine Payments Between PREPA and the ESP

With the defined process in Step 6, Step 7 involves determining the actual fees and other charges that would apply to cover the costs related to the ESPC's supply of energy to a customer as well to incent the ESPC to perform in accordance with the Uniform Services Agreement. PREPA has identified five charges or fees, as shown in Figure 2-9. Each fee is described below with an explanation as to how it is determined.

Figure 2-9. ESP Fees and Charges

1	ESPC Fees	PREPA to establish cost-based fees to recover incremental administrative and metering costs associated with enabling an ESPC to supply a PREPA customer, such as account tracking, data transfers and billing of ESPC capabilities
2	Imbalance Payments	PREPA to establish a mechanisms to charge the ESPC for the difference between the energy volumes supplied by the ESPC to PREPA and actual energy volumes delivered to the customer by PREPA
3	Performance Charges	PREPA to establish a mechanisms to incent the ESPC to more closely match their customer's loads with their generation to avoid cost shifting to PREPA's customers or unwanted arbitrage opportunities
4	Late Payments	PREPA to establish a mechanisms to incent the ESPC pay PREPA balances due in a standard and timely fashion while minimizing credit risk among counterparties (the ESPC and PREPA)
5	Congestion Charges	PREPA to establish a mechanisms for charging for any congestion created by ESPC supply relative to ESPC customer's load.
6	Ancillary Services	PREPA to establish a set of charges to ensure the ESPC pays for the Ancillary Services related to both their generation supply and customer load These include, but not limited to, spinning and non-spinning reserves and voltage support.

2.7.1 ESPC Fees

ESPC fees are cost-based fees to recover incremental administrative and metering costs associated with enabling an ESPC to supply a PREPA customer, such as account tracking, data transfers and billing of ESPC capabilities. Because the infrastructure to provide these services is not yet designed or built, these costs cannot be quantified. It should be noted that these costs tend to be fixed up-front costs with minimal administrative and operating and maintenance costs. That is, whether there is one or twenty ESPCs, the initial costs to establish the ESPC framework may be independent of number of customers (e.g., process for transmitting meter data). Therefore, the total costs to recover is not yet known.

Further, it is difficult to predict the number of ESPCs or the number of customers who will choose this service option. As such, there is no means for developing a billing determinant. Therefore, at this time PREPA proposes ESPC fees be set to zero and these costs be updated once the incremental costs are well known, there are established ESPCs, and customers have enrolled with ESPCs. Until then, these costs will be assumed to be "Policy" related and recovered from all customers.

2.7.2 Imbalance Payments

PREB's Order requires the inclusion of Imbalance Payments in the Uniform Services Agreement. To provide this service, PREPA must identify when a difference occurs between the scheduled and the actual delivery of energy by the ESPC to the ESPC's customer over a single hour (plus losses). Specifically, the deviation of the ESPC's customer's load compared to the ESPC's Scheduled load is the basis of the Imbalance Charge.[1] PREB's order requires charging for imbalances based on the following with respect to Imbalance Payments:

ii. *If the hourly metered load and line losses of an EPSC's wheeling customer exceeds the output of this generation sources, the EPSC's wheeling customers exceeds the output of its generation sources, the EPSC shall be charged for excess load at the marginal hourly generation costs as computed above.*

iii. *If the hourly output of an EPSC's generation sources exceeds the metered load and line losses of its wheeling customers, the Independent Power Producer (IPP) shall be credited for excess generation at 95% of the marginal hourly generation cost as computed above.*

Therefore, on both the Default and Alternative Uniform Services Agreements, PREPA proposes Imbalance Payments consistent with the PREB guidelines. Specifically, positive differences in imbalances (generation greater than load) are credited at 95% of the marginal hourly generation cost, while negative balances are charged the full marginal hourly generation cost.

Currently, forecasting and measuring actual hourly generation costs is problematic and unreliable. Therefore, hourly imbalance rates will be set based on Aurora modeling runs. The deviation from actual costs to this forecast can then be recovered through an annual true-up charge. The current PREB filing specifies the hourly generation rate is calculated as follows (Item 5):

i. *Computation on an hourly basis from the fuel and variable O&M rate for the marginal generation unit, which would be turned up if PREPA's load were higher or turned down if PREPA's load were lower. If PREPA cannot identify the marginal generation unit or its costs, the marginal generation cost in a given hour will be deemed to be the average cost per MWh of fuel and variable O&M for steam oil plants operating at that hour.*

This specifies that the rate can be the average cost per MWh of fuel and variable O&M for the steam oil plants operating in a given hour. This order implies this rate is dynamic and based on actual costs. Therefore, the approach of applying a set hourly rate and then a true up is consistent with this order and thus included in both the Default and Alternative Uniform Services Agreements.

2.7.3 Performance Charges

To encourage ESPCs to more closely match customers' loads with their generation, to avoid cost-shifting to PREPA's customers or unwanted arbitrage opportunities, PREB's Order contemplates additional performance requirements:

6. *An annual imbalance charge provision shall include:*

   i. *Calculation of the total annual imbalance as the absolute value of the difference between the generation delivered to PREPA by the EPSC and the metered load and line losses of its wheeling customers*

   ii. *An imbalance dead zone which shall be defined s 60% of the metered load and line losses of an EPSC's wheeling customers in the first year following*

[1] PREPA's recommendation for Scheduling requirements were defined previously in Section 2.7.

interconnection, 50% for the subsequent year, 40% in the third year, 30% in the fourth year, and 20% thereafter.

iii. *If the total annual imbalance exceeds the calculation imbalance dead zone for the given year, the EPSC shall pay an annual imbalance charge defined as the (a) difference between the total annual imbalance and the calculated imbalance dead zone, multiplied by (b) 10% of the average fuel cost adjustment and purchased-power cost adjustment for the IPP's customers in the given year.*

PREPA proposes Performance Charges consistent with this guidance but creates more specificity to ensure clarity. Table 2-2 shows the Performance Charges. PREPA recognizes that some of this clarity may go beyond PREB's specific guidance for the Default Uniform Services Agreement, therefore Table 2-2 also shows how this applies to both the Default and Alternative Uniform Services Agreements.

Table 2-2. Performance Charges for Default and Alternative

Charge Component	Default	Alternative
Bandwidth	Year 1: 60% Year 2: 50% Year 3: 40% Year 4: 30% Year 5 and Beyond: 20%	2022: 60% 2023: 50% 2024: 40% 2025: 30% 2025 and Beyond: 20%
Charge	Absolute Value of Difference between delivered and metered load (adjusted for losses) * (1-Bandwidth) * 10% * Average Supply Credit	Hourly Imbalance * Hourly Imbalance * 10% * (1 - Bandwidth)

The two proposed changes for the Alternative Uniform Services Agreement are necessary to provide consistency across all ESPCs and ensure minimal cost shifting while encouraging the ESPC to provide services closely aligned with the customer's load. First, PREPA proposes to apply the bandwidth by calendar year (could be fiscal year if more appropriate) to avoid 'grandfathering' of bandwidths based on the customer sign-up and or the ESPC's certification. It is also consistent with addressing a maturing sector.

The second deviation is defended by the fact that cost shifts can occur under the PREB defined charge because it does not account for the timing of imbalances (e.g., an ESPC may not match load at times when prices are high). For this reason, PREPA maintains the 10% charge and the bandwidth concept but looks at cumulative annual hourly Imbalances. This also creates simplicity in billing in that PREPA would take the total annual Imbalance Payments and apply the charge accordingly. This also eliminates a surprise for the ESPC as they know their Imbalances to date and thus can predict any such charges.

2.7.4 Late Payments

The PREB Order does not specify payment terms. Therefore, PREPA proposes as part of the Alternative Uniform Services Agreement to include payment terms and establish a mechanism to incent the ESPC to pay PREPA balances due in a standard and timely fashion while minimizing credit risk among counterparties (the ESP and PREPA). First, PREPA proposes that the ESPC pay for fees as presented in a monthly bill to the ESPC within 30 days of receipt of that bill. PREPA then offers a 30-day grace period for payment, effectively creating a 60-day payment period. Once an ESPC goes beyond 60 days, it is possible the ESPC is financially unstable and thus creates a risk for PREPA. To mitigate, once an ESPC does not provide payment beyond 60 days, PREPA could declare the ESPC defaulting on payments, with an additional 30 days to make that payment but with penalty. PREPA proposes that this penalty equate to short term credit and thus a charge of 5% on the bill balance will be assessed if payment is not received within 60 days. Finally, if payments are not received within 90 days, PREPA should have the right to default the customer back to PREPA's service, particularly if imbalance payments are significant.

PREPA urges PREB to consider this provision regardless of whether the Alternative Uniform Services Agreement is adopted in full.

2.7.5 Congestion Charges

Congestion arises when the transmission path between the least-cost generation asset and the load center is constrained. As a result, a different generator must be dispatched, increasing the cost to serve that load center. Generally, one can compute the cost of congestion by considering the most efficient plant is always dispatched and comparing that to the actual dispatch costs (e.g., compare marginal dispatch costs) as generation and distribution interconnection points. If there is no difference, no congestion exists. Currently congestion costs, if any, are included in the FCA and PPAC. Since these costs cannot be computed or specifically excluded from the FCA and PPAC, PREPA proposes they continue to provide congestion relief services. However, these congestion costs cannot be fully computed; therefore, there is a risk that these costs could shift from ESPC customers to PREPA's customers because they are included in the FCA and PPAC.

To attempt to mitigate this, in part, PREPA proposes a true-up mechanism that spreads deviations between revenue collected and actual costs related to FCA and PPAC, as is done today, but separate those incremental costs and exclude from the credit and include in a separate rider that applies to all customers. This approach benefits both the ESPC and PREPA customer because it accounts for deviations in costs separate from the Supply Credit and provides all incremental savings and costs to all customers.

2.7.6 Ancillary Services

Ancillary services are those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. These ancillary services include:

Scheduling, System Control, and Dispatch: Scheduling, System Control, and Dispatch are required to schedule the movement of power through, out of, within, or into PREPA's transmission grid. PREPA provides this service. The electricity sector transition currently appears to rely on PREPA continuing this service. However, with ESPCs providing supply to meet load, the requirements for Scheduling must be established. Normally a Uniform Services Agreement would outline the Scheduling requirements. These requirements typically involve the ESPC providing the transmission operator with a day ahead schedule with the estimated load from all the ESPC's customers and their expected generation supply. However, currently systems that can actively gather this information and proactively use this information to manage the grid are limited. Therefore, PREPA proposes in both the Default and Alternative Uniform Services Agreements that PREPA continue to provide this service and charge through standard rates. Additionally, PREPA proposes that Scheduling Fees be established and charged on a per schedule basis. However, this value is currently set to zero as there is no basis for setting this rate at this time. As Puerto Rico's electricity sector advances in its maturity, further distinguishing scheduling costs can be revisited. Once these charges are determined and this value is non-zero, those costs would be included in the supply credit and the ESPC pays these costs directly.

Reactive Supply and Voltage Control: In order to maintain transmission voltages on PREPA's transmission grid within acceptable limits, PREPA operates resources capable of providing this service to produce (or absorb) reactive power. The amount of Reactive Supply and Voltage Control is determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region. Currently, PREPA's customers pay for this service through standard rates. These costs are driven by capacity and thus tend to be in terms of $/kW. As Puerto Rico's electricity sector advances in maturity, further distinguishing who should pay for reactive supply and voltage control can be revisited. For this reason, PREPA's Default and Alternative Uniform Services Agreement proposals include such a charge, but at this time set that value to zero, assuming those costs continue to be recovered in standard rates. Once these charges are determined and this value is non-zero, those costs would be included in the supply credit and the ESPC pays these costs directly.

Regulation and Frequency Response: The Regulation and Frequency Response Service, also referred to as "Load Following Services" in this report, provides for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at required levels for Puerto Rico. It is accomplished by committing online generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the PREPA as the transmission operator. To do this, PREPA must consider the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements. It is possible for an ESPC to self-supply these services. However, at this time, this service will be provided by PREPA and charged through standard rates as it is today. Nevertheless, because such services can be offered by the supplier, PREPA is proposing to create a placeholder for this Ancillary Service but set the value to zero. This rate is set on a $/kW basis, consistent with the need to have generation capacity available to perform this service. As with other Ancillary Services, as the electricity sector matures for Puerto Rico, this charge can be effectively quantified and this placeholder can be easily adjusted without changing the Uniform Services Agreement and, once this value is non-zero, those costs would be included in the supply credit and the ESPC pays these costs directly.

Energy Imbalance: Imbalances are contemplated above in Section 2.1.3.

Operating Reserve – Spinning: PREPA supplies Spinning Reserve Services to serve load, and this service may also be provided by generating units that are online and loaded at less than maximum output and by non-generation resources capable of providing this service. These charges are capacity driven and thus are generally $/kW. PREPA proposes including a "Spinning Reserves" charge, but setting that value to zero, assuming those costs continue to be recovered in standard rates. This is because being able to quantify these costs reliably with current data tracking systems is limited and not sufficient to provide basis for such a charge. Once these charges are determined and this value is non-zero, those costs would be included in the supply credit and the ESPC pays these costs directly.

Operating Reserve – Supplemental: PREPA provides a Supplemental Reserve Service as needed to serve load. Operating reserves are not available immediately to serve load. but rather within a short period of time. This Service may be provided by generating units that are online but unloaded, by quick-start generation, or by interruptible load or other non-generation resources capable of providing this service. Like Spinning Reserves, Operating Reserve is capacity driven thus the charges are generally $/kW. PREPA proposes including a "Supplemental Reserves" charge, but, like Spinning Reserve, set that value to zero, assuming those costs continue to be recovered in standard rates. This is because being able to quantify these costs reliably with current data tracking systems is limited and not sufficient to provide basis for such a charge. Once these charges are determined and this value is non-zero, those costs would be included in the supply credit and the ESPC pays these costs directly.

2.8 Determine Credit Terms for ESP

PREB's Order contemplates credit terms as follows:

a. *Letter of credit for an estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment.*

PREPA adopts this credit term in whole for the Default Uniform Services Agreement but proposes more extensive credit terms in the Alternative Uniform Services Agreement. These extended terms are deemed necessary by PREPA to protect PREPA's customers from the credit risks associated with ESPs. Specifically, PREPA proposes two refinements:

1. Collateral should be adjusted based on customers' established credit ratings (by "Big Three" rating agencies).
2. Collateral requirement should be based on four times the 'average costs times average load' to account for months where costs could be well above average (as opposed to a potential maximum bill) as well as 90-day payment terms.

Both are discussed in more detail below:

2.8.1 Credit Rating Based Collateral

PREPA understands that credit risk can be, in part, reflected by the entity's credit rating and it is common practice to recognize that entities with good credit ratings reduce credit risk and thus credit costs for companies that contract with those high credit quality entities. Similarly, entities with poor credit ratings pose significant risk and potential cost to PREPA. Therefore, PREPA proposes requiring collateral based on the ESPC's credit rating.

Specifically, PREPA will classify each ESPC into one of four short term credit classifications consistent with Moody's short-term credit ratings. PREPA will then use the established mapping of Fitch and S&P's ratings as shown in Table 2-3. If the ESPC has established "Big Three" credit ratings (Moody's S&P and/or Fitch), PREPA will use the lowest available credit rating for the ESP. Further, if an ESPC has no "Big Three" credit rating, PREPA will classify that customer as "Not Prime."

Table 2-3. Big Three Credit Ratings Comparison

Moody's Short-term	S&P Short-term	Fitch Short-term
P-1	A-1+	F1+
	A-1	F1
P-2	A-2	F2
P-3	A-3	F3
Not Prime	B	B
	C	C
	/	/

If an ESPC experiences a late payment, PREPA will reset the ESPC's credit rating to "Not Prime" and that rating will be in effect for one year, and if ESPC has no further late payments the PREPA credit score will reset.

Using these credit ratings, PREPA proposes that higher rated entities should be asked to pay less collateral than those with poor credit. Table 2-4 shows PREPA's proposal for these collateral changes.

Table 2-4. Collateral Requirements by Credit Rating

PREPA Credit Rating	Percent Collateral
P-1	5%
P-2	25%
P-3	50%
Not Prime	100%

2.8.2 Collateral Requirements

PREB's requirement, as shown above, is for the ESPC to provide a letter of credit based on the estimate of one month of the ESPC's customers 'supply credit.' This is designed to ensure that if the ESPC defaults and does not provide any supply in a given month, there is collateral to recover those potential Imbalance charges. While this is a sound recommendation, PREPA is concerned about the lag between identifying if an ESPC is defaulting. As noted above, payment terms have not been specified, and thus PREPA has proposed such terms.

PREPA recognizes the linkage between the payment terms and collateral requirements. Further, the average difference misses the potential that the ESPC will default during a high price period. Therefore, PREPA proposes as part of the Alternative Uniform Services Agreement to require up to four times the ESPC's customers' average monthly loads (in kWh) times the average annual Hourly Imbalance Rate from the previous year. This accounts for the fact that some periods may be higher cost than others and that the ESPC potentially can continue 'serving' the customer for up to 90 days without paying PREPA for imbalances and actually providing energy to PREPA for the customer. That is, four times was determined to be the possible exposure to both high use months (up to two times the 'average') and the fact that customers have 60 days to pay, and potentially 90 days with minimal penalty, exposing PREPA to effectively 3 months of back payments.

Finally, the actual collateral requirements will be based on this calculation and the ESPC's credit rating.

2.9 Determine Customer Return Process

While PREB's Order was silent on the process and potential implications of returning customers, Regulation 9138 does provide some guidance.

To start, it is important to remember that the supply credit is based on the assumption that the credit includes avoided costs to PREPA for a third party providing supply to PREPA's customers rather than PREPA serving those customers, to include avoiding the investment in additional capacity. Although the current Marginal Generation Capacity Costs (MGCC), as outlined in the 2021 Cost of Service Report, are zero, these costs may not always be zero and thus the proposed Unbundling Tariff Framework outlined in the Unbundled Tariffs Report could result in these costs being included in the supply credit. When a customer returns, PREPA may not have the capacity to serve that customer as they did not make the required investment (otherwise the avoided MGCC should not be included in the supply credit). Therefore, when a customer returns to the "POLR" it is common practice to put that customer on different rates that reflects the incremental costs, particularly capacity, that are required to serve the customer.

PREPA has determine three scenarios for customer return:

- **Customer Choice:** Customer chooses to return to PREPA and voluntarily leaves the agreement with the ESP.

- **ESPC Choice:** The ESPC, for various reasons, terminates its contract with the customer and the customer returns to PREPA with no choice of the customer.
- **ESPC Default:** The ESPC no longer serves the supply due to various reasons, including financial default, thus shifting the customer back to PREPA upon that default.

PREPA's Alternative Uniform Services Agreement proposes refinements based on the following principles:

1. Customer who chooses to return should be limited from opting for ESPC supply for 12 months to ensure customer does not arbitrage at the expense of PREPA's remaining customers.
2. Customer who returns due to ESPC default or ESPC choice would be eligible for opting for ESP supply after a 30-day period to settle and address administrative issues.

As a result, PREPA determined six rules needed to be defined for each of the three scenarios. These six rules are:

1. **Return Charges:** Who pays for the costs to revert a customer from an ESPC to PREPA is determined by whether the customer returns on their own or is driven by the ESPC.
2. **Eligibility:** The ability for the customer to elect service from another ESPC after returning voluntarily is limited. To avoid a customer gaming the system, PREPA proposes that a customer is not able to leave PREPA's service for 12 months after choosing to return to PREPA. This avoids opportunities for the customer to flip from one ESPC to another and take service at average rate from PREPA during high priced periods and return to an ESPC during low priced periods. This is a common practice, particularly when the POLR has the obligation to serve from their own resources and has not been able to shift that supply risk to the POLR's supplier.
3. **Service Dates:** The dates on which a customer returns will follow the same requirements for initial enrollment by a customer. Specifically, PREPA proposes that the customer start and end ESPC services at the end of the customer's billing period. This facilitates meter reading and ensuring no additional costs are created for switching a customer. This will hold for all customers who either choose to return or return based on ESPC's choice. However, since ESPC default will be rare and potentially immediate, a customer may be switched back to PREPA at a moment's notice in this case.
4. **Return Rates:** Customers will return to a rate that reflects current marginal costs, including marginal capacity costs, to ensure these costs that may be incurred due to the customer returning are paid for by that customer who is returning. This is also common in many forms. For some jurisdictions it is an alternative rate, while in others it may be in the form of up-front buyout provisions. Regardless of form, this structure is necessary to protect PREPA's customers who have not left.
5. **Notification:** The notification process must also be specified such that all stakeholders have transparency on the shifting responsibilities.
6. **ESP Settlement:** Finally, a clear settlement process to ensure full payments of costs owed to PREPA are paid in full. This includes considerations for calling on collateral in the event that the ESPC has defaulted.

Table 2-5 shows the customer return options PREPA proposes as part of the Alternative Uniform Services Agreement.

Table 2-5. Customer Return Options

	Customer Choice	ESPC Choice	ESPC Defaults
Return Charges	Customer pays one-time fee to return to PREPA based on PREPA's cost to administer	ESPC pays one-time fee to return to PREPA based on PREPA's cost to administer	ESPC pays one-time fee to return to PREPA based on PREPA's cost to administer
Eligibility	Customer returns to appropriate retail rate and is not eligible for ESPC services for 12 months	Customer returns to appropriate retail rate and is eligible for ESPC services from any ESPC but the one they after 30 days from return	Customer returns to appropriate retail rate and is eligible for ESPC services after 30 days from return
Service Dates	Service converts from ESPC to PREPA at the end of the customer's billing period	Service converts from ESPC to PREPA at the end of the customer's billing period	Service converts from ESPC to PREPA on date of default
Return Rates	Customer returns to a rate that is based on the forecasted Hourly Imbalance rates for up to 12 months	Customer returns to a rate that is based on the forecasted Hourly Imbalance rates for up to 12 months	Customer returns to a rate that is based on the forecasted Hourly Imbalance rates for up to 12 months
Notification	Customer requests service change from PREPA; PREPA notifies ESPC to include end date of customer service; ESPC confirms customer transition	ESPC notifies PREPA of customer return; PREPA confirms customer return with customer	PREPA notifies customer of ESPC default and conversion to PREPA full service
ESP Settlement	PREPA terminates meter data transfers as of customer's service date; PREPA submits final billing for balance of costs to ESPC within 30 days of customer transition	PREPA terminates meter data transfers as of customer's service date; PREPA submits final billing for balance of costs to ESPC within 30 days of customer transition	PREPA terminates meter data transfers as of customer's service date; PREPA submits final billing for balance of costs to ESPC, including return fees, net of collateral held within 30 days of customer transition

2.10 Determine Required “True-Up” Mechanisms

Many aspects of the Uniform Services Agreement require accurate calculations of actual costs that can be tracked over time and compared to revenues received. True-up mechanisms allow for this tracking of actual costs against actual revenue and ensure under or overcollections are appropriately reallocated back to customers. The Unbundled Tariff proposal includes a true-up mechanism rider to account for many of the costs that cannot be currently tracked. The Alternative Uniform Services Agreement aligns with this mechanism, specifically establishing charges for these costs but, because they cannot be computed at this time, sets these values to zero and notes that they can be captured through the true-up mechanism.

Nevertheless, even after these charges are implemented, there may still be a need for a true-up mechanism that tracks actual costs against actual revenues and includes this mechanism’s costs in an additional charge under this agreement. At this time, however, this true-up charge is set to zero and is expected to remain at zero until such time as the actual proposed charges are implemented and costs and revenues tracked. This again is done to ensure the Uniform Services Agreement is sustainable through the sector’s transition.

3. Proposed Uniform Services Agreements

PREPA is proposing Default and Alternative Uniform Services Agreements. PREPA further proposes that the technical language of these agreements be worked out with stakeholders through a series of technical conferences. As such, PREPA is only including Term Sheets in this filing that outline the main terms and conditions of these agreements. Table 3-1 shows these term sheets.

Table 3-1. Term Sheets for Default and Alternative Uniform Services Agreements

Component	Default	Alternative
ESPC Eligibility	Required to sign the Uniform Services Agreement without alterations	Same as Default
ESPC Notification of Customer Enrollment	• ESPC notifies PREPA of a customer switching to ESPC service • Supplies accounts and meter information for each customer	Same as Default
Notification Timing	Silent	Notification occurs no less than 5 business days from the end of the customer's billing period
Transfer Timing	Silent	• Customer transitions to ESPC service at the start of their next billing period from the date of notification • If notifications by ESPC occurs within five business days of the end of the customer's billing period, the transition occurs at the end of the following month's billing period
PREPA Customer Notifications	PREPA will verify with customer that the customer has chosen to take service from the ESP and confirm the accounts and meters	Same as Default
Imbalance Provisions	• Hourly differences between supply and customer load, adjusted for losses are tracked • Positive differences (Generation > load plus losses) is credited to ESPC at 95% of the Imbalance Rate • Negative differences (Generation < load plus losses) charged to ESPC at the Imbalance Rate	Same as Default

Hourly Imbalance Rate	• Computation on an hourly basis from the fuel and variable O&M rate for the marginal generation unit, which would be turned up if PREPA's load were higher or turned down if PREPA's load were lower • If PREPA cannot identify the marginal generation unit or its costs, the marginal generation cost in a given hour will be deemed to be the average cost per MWh of fuel and variable O&M for steam oil plants operating at that hour	• Computation of forecasted hourly marginal costs base on IRP modeling • Variations in actual costs versus forecasted marginal will be computed and addressed in the True-Up Mechanism

Imbalance Performance Provisions	• Calculate the total annual imbalance as the absolute value of the difference between the generation delivered to PREPA by the EPSC and the metered load and line losses of its wheeling customers
	• An imbalance dead zone which shall be defined by year as follows:
	  ○ Year 1 = 60%
	  ○ Year 2 = 50%
	  ○ Year 3 = 40%
	  ○ Year 4 = 30%
	  ○ Year 5 and beyond = 20%
	• Performance charge based on the positive difference between 1 minus the bandwidth times total annual customer load less annual imbalance. This positive balance is then multiplied by 10% of the average fuel cost adjustment and purchased-power cost adjustment for the IPP's customers in the given year
		• Calculate the total annual imbalance as the sum of each hourly imbalance amount for the year times the Hourly Imbalance Rate
		• An imbalance dead zone which shall be defined by calendar year as follows
		  ○ 2022 = 60%
		  ○ 2023 = 50%
		  ○ 2024 = 40%
		  ○ 2025 = 30%
		  ○ 2026 and beyond = 20%
		• Performance charge based on the positive difference between 1 minus the bandwidth times total annual customer load less Annual Imbalance. This positive balance is then multiplied by 10% of the total Annual Imbalances times 1 minus the bandwidth

Losses Rate	For the purposes of both the hourly energy balancing provisions and the annual imbalance charge, line losses adders shall be set at the values used in the Cost of Service Study filed in Case No. CEPR-AP-2015-0001, or an updated value as available	Same as Default

Losses Adder	Silent	ESPC is responsible for scheduling supply to meet customer load plus losses as defined by the Losses Rate
Credit Terms	Letter of credit for an estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment	Letter of credit or cash collateral for four times the estimate of one month of the IPP's customers' avoided fuel cost settlement and purchased power cost adjustment times the credit collateral requirement percentage
Credit Rating	Silent	Provide for ESPC's credit rating by reducing credit requirements for good credit quality using "Big Three" credit ratings as follows: o P1 = 5% o P2 = 25% o P3 = 50% o Not Prime = 100%
Scheduling	Silent	ESPC is required to submit a schedule to PREPA electronically a day ahead with forecasted hourly load requirements adjusted for losses as well as hourly supply forecast
Ancillary Services	Silent	• Proposed charges for the following Ancillary Services: o Scheduling o Reactive Supply and Voltage Control o Regulation and Frequency o Operating Reserve – Supplemental o Response Operating Reserve – Spinning • Values for each service are set to zero until such time that they can be quantified and separated from costs currently embedded in PREPA's generation costs and thus included in the supply credit and the ESPC starts to pay for these costs directly

Standby Services	Silent	• PREPA and ESPC agree to a Contract Demand level • The ESP then pays a monthly charge of the Contract Demand times Marginal Generation Capacity Cost • If actual standby services exceed the Contract Demand, Contract Demand level is automatically adjusted to equal actual demand shortfall
True-Up Mechanism	Silent	Propose tracking of actual costs versus actual revenues associated with ESPC service to customers (including imbalances) and true-up these costs annually, resulting in a credit or charge to the ESPC with an equal but opposite charge or credit to PREPA's customers

Justification for deviations from the Default proposed in the Alternative are outlined in Section 2. PREPA's Default Uniform Services Agreement is in compliance with the PREB Order for Uniform Services Agreement. PREPA's Alternative Uniform Services Agreement provides additional granularity to the agreement and, PREPA believes, remains consistent with PREB's Order.

PREPA, therefore, submits this report regarding the Uniform Services Agreement in compliance with PREB's order. If PREB chooses to move forward and implement a Uniform Services Agreement at this time, PREPA requests PREB approve the Alternative Uniform Services Agreement in whole. However, PREPA's proposal in the Alternative Uniform Services Agreement also offers separate and distinct components. This provides PREB the option to adopt several components from either the Default or the Alternative Agreements. While PREPA recommends adopting the Alternative Uniform Services Agreement proposal in whole, PREPA encourages PREB to consider many of the components and not reject them in whole but consider creating a 'hybrid' Uniform Services Agreement.

4. Implementation Considerations

PREPA files the Default and an Alternative Uniform Services Agreements as required by the PREB's orders. However, in the process of developing these agreements, PREPA identified three key challenges. These challenges and proposed resolutions are listed in Table 4-1.

Table 4-1. Implementation Challenges

Challenge	Proposed Resolution
Sector Restructuring Sector restructuring creates uncertainty. Namely, the creation of a GenCo that will own and operate PREPA's legacy generation assets and sell supply to PREPA could result in a change in agreements depending on the GenCo's compensation structure, role, and responsibilities, and 'transfer pricing' to PREPA.	The underlying assumption of the future structure of the sector is that there will be a GenCo that will own and operate PREPA's legacy generation facilities. Then PREPA evolves to a "GridCo" that is responsible for PREPA's legacy PPAs plus any new contracts created through RFP processes or other mechanisms where a third party sells energy to the GridCo. In this structure, energy costs would be segmented between GridCo PPAs and GenCo Legacy generators. This assumption has several implications. First, supply credits will need to be driven by both factors, and thus impact the final rates. Second, since imbalances and losses are also a function of the combined costs of the GenCo and GridCo energy costs, this cost structure also needs to be considered. Specifically: 1. Imbalances would be based on the incremental GridCo's costs to meet that load in any hour, regardless of source (e.g., PPA or generator). 2. Losses Adder would be based on the actual difference between GenCo delivered energy and metered loads. Once GenCo is established, a separate agreement between generators may be required and could drive fees in the Uniform Services Agreement. Load-related GenCo and GridCo PPA ancillary services charges will be included in PREPA's charges, while generation-related GenCo and GridCo PPA ancillary services will be charged to each generator.
Legal Terms Terms and Conditions require legal input and review.	PREPA files Uniform Services Agreement "Term Sheet" on May 10 and conducts a series of workshops and Technical Conferences after May 10 to solicit input from both PREB and other stakeholders on actual legal terms and conditions.
Policy Compliance Other policy and market rules, including restructuring, remain unclear and create additional uncertainty.	Emphasize an Unbundled Tariff Framework that is able to accommodate market changes. Determine who is responsible for meeting Renewable Portfolio Standard requirements and addressing unexpected costs related to plant retirements and environmental provisions, for example.

4.1 Sector Restructuring

Currently, the electricity structure in Puerto Rico is transitioning and the final end-state is not altogether clear. Many assumptions had to be made regarding roles and responsibilities in the wheeling operating model, as noted in Section 2. It is for this reason PREPA first and foremost requests that PREB delay any decisions regarding the Uniform Services Agreement until such time that both the sector market rules are understood and PREPA is able to track the necessary costs and compute, on a cost basis, the necessary fees included in the agreements.

4.2 Legal Terms

Legal terms have not been drafted for this filing, in part because PREPA believes the rules will soon change due to the recent PREB Order. PREPA encourages the establishment of a series of workshops with key stakeholders to further define and draft the agreements. To reach final terms, PREPA recommends a series of workshops as follows:

- **Alignment on Terms and Conditions:** Workshop where stakeholders work collaboratively to finalize the scope and terms of the agreement.
- **Draft of Agreement:** Series of smaller workshops where a subgroup of stakeholders, led largely by legal and contract experts, draft a full agreement (Draft Agreement).
- **Alignment on Agreement:** Workshop where stakeholders work collaboratively to review and redline the Draft Agreement.
- **Final Agreement:** One or two smaller workshops where the subgroup of stakeholders who crafted the Draft Agreement address redlines and produce a Final Agreement.
- **Technical Workshop:** Technical workshop where representatives of the subgroup submit the Final Agreement and inform all stakeholders of the terms and conditions and address challenges to those terms and conditions.

4.3 Policy Compliance

Currently, there are several policy issues that still need resolution, including but not limited to compliance with Renewable Portfolio Standard (RPS) and unexpected costs related to plant retirements and environmental provisions. Specifically, it is not clear who is responsible for meeting the RPS requirements and whether ESPCs have the same level of requirements as PREPA. Further, if the generation assets fall under a GenCo, it is not clear if the GenCo takes on these requirements or if it will be the ESPCs plus the POLR (PREPA). Since ESPCs are not regulated by PREB directly, then clarity on how these RPS requirements are met must be provided and incorporated into the agreement. This includes consideration of imbalances that result in insufficient supply for load and also insufficient supply of RPS-compliant resources.

Direct Testimony

Exhibit E

https://diazvaz-my.sharepoint.com/:f:/g/personal/jmarrero_diazvaz_law/Ei_lIa_kHbFEjb03bBDA-VoBC6py-_HjjnFeq_OMTWdvXQ?e=9cv2eF

Direct Testimony

Exhibit F

Revised Table 2-1. “Default” Retail Energy Supply Credit

“DEFAULT” RETAIL SUPPLY CHOICE CREDIT	
DESIGNATION:	DSCC
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Retail Supply Choice Credit (SCC) rider mechanism which provides a credit to customer for choosing alternative supply from PREPA’s services. The SCC shall apply to all of PREPA's rates if the customer has confirmed with PREPA that they are receiving supply from an ESPC and that ESPC is qualified under the Uniform Services Agreement to supply this customer.
Rate	The formula to calculate the Supply Choice Credit is: $$DSCC = \frac{MEC * Class\ Sales + MGCC * CCP * ACC}{Class\ Sales}$$
MEC	Marginal Energy Costs as computed as function of the dispatchable resources and the FCA and PPCA as follows: $$MEC = FCA * FCP + PPCA * PPCP$$
FCA	The current Fuel Charge Rider, which adjust quarterly
FCP	Fuel Charge Rider factor equal to the percent of capacity related to dispatchable PREPA owned generation assets divided by all PREPA owned generation capacity. Currently set to 100%, however Cost of Service (COS) study recommends setting to 73%. This value is updated when PREPA files an updated Cost of Service Study.
PPCA	The current Purchase Power Charge Rider, which adjust quarterly.
PPCP	Purchase Power Charge Rider factor equal to the percent of capacity related to dispatchable PPAs divided by all PPA owned generation capacity. Currently set at 100%, however the COS study recommends setting to 9%. This value is updated when PREPA files an updated Cost of Service Study.
MGCC	Cost Reflective Marginal Generation Capacity Cost rate, based on latest COS Study.
CCP	Class specific contribution to Coincident Peak
ACC	Avoided Capacity Contribution, based on the contribution to capacity that can be avoided by a customer taking energy from an alternative supplier. Currently set at 0% to avoid double counting capacity costs in the FCA and PPCA, however can be set to 100% if marginal energy costs are exclusively energy related.
Class Sales	Class specific retail sales (energy delivered by PREPA - kWh)
Quarterly Filing	PREPA shall make a filing for a proposed SCC Rider at the same time making a filing for both the FCA Rider and PPCA Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised SCC is not approved the previous quarters' SCC Rider shall remain in effect until a new Rider is approved.

Exhibit B

Revised Table 2-1. "Default" Retail Energy Supply Credit

"DEFAULT" RETAIL SUPPLY CHOICE CREDIT	
DESIGNATION:	DSCC
AVAILABLE:	Everywhere in Puerto Rico
APPLICABLE:	To all tariffs except for the fixed block of Tariff RFR.
Description	The Retail Supply Choice Credit (SCC) rider mechanism which provides a credit to customer for choosing alternative supply from PREPA's services. The SCC shall apply to all of PREPA's rates if the customer has confirmed with PREPA that they are receiving supply from an ESPC and that ESPC is qualified under the Uniform Services Agreement to supply this customer.
Rate	The formula to calculate the Supply Choice Credit is: $DSCC = \frac{MEC * Class\ Sales + MGCC * CCP * ACC}{Class\ Sales}$
MEC	Marginal Energy Costs as computed as function of the dispatchable resources and the FCA and PPCA as follows: $MEC = FCA * FCP + PPCA * PPCP$
FCA	The current Fuel Charge Rider, which adjust quarterly
FCP	Fuel Charge Rider factor equal to the percent of capacity related to dispatchable PREPA owned generation assets divided by all PREPA owned generation capacity. Currently set to 100%, however Cost of Service (COS) study recommends setting to 73%. This value is updated when PREPA files an updated Cost of Service Study.
PPCA	The current Purchase Power Charge Rider, which adjust quarterly.
PPCP	Purchase Power Charge Rider factor equal to the percent of capacity related to dispatchable PPAs divided by all PPA owned generation capacity. Currently set at 100%, however the COS study recommends setting to 9%. This value is updated when PREPA files an updated Cost of Service Study.
MGCC	Cost Reflective Marginal Generation Capacity Cost rate, based on latest COS Study.
CCP	Class specific contribution to Coincident Peak
ACC	Avoided Capacity Contribution, based on the contribution to capacity that can be avoided by a customer taking energy from an alternative supplier. Currently set at 0% to avoid double counting capacity costs in the FCA and PPCA, however can be set to 100% if marginal energy costs are exclusively energy related.
Class Sales	Class specific retail sales (energy delivered by PREPA - kWh)
Quarterly Filing	PREPA shall make a filing for a proposed SCC Rider at the same time making a filing for both the FCA Rider and PPCA Rider. This filing will occur before the end of the second week of the third month of each quarter with the Puerto Rico Energy Bureau (PREB) which will be proposed to go into effect with the first billing cycle of the first month of the following quarter. If a revised SCC is not approved the previous quarters' SCC Rider shall remain in effect until a new Rider is approved.