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

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

IN RE: THE UNBUNDLING OF THE ASSETS OF THE PUERTO RICO ELECTRIC POWER AUTHORITY	**CASE NO.:** NEPR-AP-2018-0004 **SUBJECT:** Report on Cost Allocation Methods and Unbundling; Requirements for Information and Production of Documents.

ORDER

I. Introduction

On December 11, 2019, the Energy Bureau of the Puerto Rico Public Service Regulatory Board ("Energy Bureau") issued Regulation 9138 on Electric Energy Wheeling. This Regulation sets the legal and regulatory framework required to develop a system for electric energy wheeling in Puerto Rico, enable eligible entities to exercise choice and control over their electric service, protect non-subscribers from being affected by wheeling, and spur the transformation of the electric energy sector in Puerto Rico.

The Energy Bureau adopted Regulation 9138 pursuant to Act 57-2014,[1] Act 17-2019,[2] and Act 38-2017,[3] which provides the Energy Bureau with the authority to implement wheeling. Act 57-2014, as recently affirmed by Act 17-2019, states that the Energy Bureau has the power and duty to "regulate the wheeling mechanism in Puerto Rico in accordance with the applicable laws."[4] Moreover, the Energy Bureau has the power and duty to "oversee and ensure the execution and implementation of the public policy on the electric power service in Puerto Rico."[5] The Energy Bureau also has "all those additional, implicit, and incidental powers that are pertinent and necessary to enforce and carry out, perform, and exercise the powers granted by law and to achieve the energy public policy."[6]

[1] *The Puerto Rico Energy Transformation and RELIEF Act*, as amended.

[2] *The Puerto Rico Energy Public Policy Act.*

[3] *The Uniform Administrative Procedure Act of the Government of Puerto Rico* ("LPAU" for its Spanish acronym), as amended.

[4] Section 6.3(g) of Act 57-2014.

[5] Section 6.3(a) of Act 57-2014.

[6] Section 6.3 of Act 57-2014.

The Energy Bureau adopted Regulation 9138 for the purpose of establishing rules and conditions to implement a system that allows an exempt business described in Section 2(d)(1)(H) of Article 1 of Act No. 73-2008, as amended, known as the "*Economic Incentives Act for the Development of Puerto Rico,*" or similar provisions in other incentive laws, as well as electric power service companies, microgrids, energy cooperatives, municipal ventures, large scale industrial and commercial consumers and community solar and other demand aggregators, to purchase electric power from other entities through wheeling services. Regulation 9138 is also designed to ensure that wheeling does not affect in any way whatsoever nonsubscribers of wheeling services.

On December 28, 2018, the Energy Bureau issued an Order commencing this proceeding with the initial purpose of obtaining the information that would be necessary for the unbundling of rates. The Energy Bureau noted the importance of this proceeding and the need to develop an updated cost of service study ("COSS").

II. Unbundling of Rates

A. Cost of Service Study

This proceeding to implement electric energy wheeling will require the Puerto Rico Electric Power Authority ("PREPA") to unbundle its rates and allocate costs by function (distribution, transmission, and generation) and by customer class (residential, commercial, industrial, etc.) as well as to identify any non-bypassable charges (such as the transition charge) and stranded costs, if any. Because PREPA's last Cost of Service Study was based on data from 2014, it was necessary to develop a new COSS with updated data to the extent available and more importantly, an improved cost allocation methodology that could be used to unbundle rates. To that end, the Energy Bureau engaged a consultant, Resource Insight, Inc., to prepare a Report on Cost Allocation Methods and Unbundling Issues ("Unbundling Report") which is attached to this Order as Appendix A.[7] The Cost Allocation and Unbundling Report focuses on three major issues:

1. Cost allocation methods that could be applied in determining class cost responsibilities for PREPA;
2. Using the best available data to identify the portion of the class cost responsibilities associated with each major function, and particularly the generation function, which some customers may be allowed to procure from a supplier other than PREPA; and
3. Estimating the portion of PREPA's generation costs that would be stranded costs if some customers were to switch to another power supplier and not pay for any of PREPA's generation costs.

Before requiring PREPA to file unbundled rates that conform to the the methodologies set forth in the Cost Allocation and Unbundling Report, the Energy Bureau is

[7] Note that this Report was completed prior to the issuance of the Order in the IRP and therefore, there may be a few minor items that will need to be revised going forward.

providing stakeholders an opportunity to provide comments on the Unbundling Report. Comments will be due within three weeks from the notification date this Order. Reply comments will be due two weeks thereafter. Attached as Appendix B to this Order is a list of questions on which the Energy Bureau is specifically interested in obtaining feedback from PREPA and other interested stakeholders; however, PREPA and stakeholders are invited to provide comments on any aspect of the Unbundling Report.

B. Informational Requirements of the Bureau to PREPA

As noted above, the last COSS performed by PREPA was based on data from 2014. In addition, the Unbundling Report notes that PREPA has not been able to provide more recent cost and load data and does not necessarily track costs or customer load data in a manner best suited for use in a model cost of service study. Where relevant and possible, the Unbundling Report has incorporated updated data from other proceedings, including the Integrated Resource Plan.[8]

However, the Unbundling Report notes that the application of consistent timeframes for data are important. Selectively using newer data can provide misleading results. The Energy Bureau is also mindful of the conclusion in the Unbundling Report that some aspects of PREPA's general data-collection and cost-tracking practices fall short of the standards set for major utilities in the United States. This also created impediments to ensuring consistent and up-to-date data for the purposes of unbundling. In order to remedy this, the Energy Bureau is requiring PREPA to provide the data set forth in Appendix C, along with certain questions regarding the potential and timeframes for the collection of additional data, within three weeks of the issuance of this Order.

C. Next Steps

Once the Energy Bureau receives comments from the stakeholders and the responses from PREPA regarding data updates and issues, the Energy Bureau will issue an Order setting forth next steps of this proceeding. The goal is to move expeditiously towards an Order requiring PREPA to file unbundled rates which will then trigger the commencement of a proceeding to determine the appropriate costs for distribution, transmission and generation, along with a determination of whether there are stranded costs and if so, the amount. This will be an adjudicative proceeding, in which the rates for unbundled services will be determined to provide the price information that customers who participate in electric energy wheeling will need. This will be addressed in more detail in a procedural Order that the Energy Bureau will issue setting forth the process for this proceeding.

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[8] *See In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*, Case No. CEPR-AP-2018-0001.

III. Conclusion

The Energy Bureau **ORDERS** PREPA to file comments on the Unbundling Report, using Appendix B as guidance and respond to the data requests set forth in Appendix C, within three weeks of the notification date of this Order. The Energy Bureau also invites all stakeholders and interested parties to file comments on the Unbundling Report, using Appendix B as guidance, no later than three weeks of the notification date of this Order. All reply comments regarding PREPA's responses and to the filed comments, should be provided two weeks thereafter.

Be it notified and published.

Edison Avilés Deliz
Chair

Ángel R. Rivera de la Cruz
Associate Commissioner

Lillian Mateo Santos
Associate Commissioner

Ferdinand A. Ramos Soegaard
Associate Commissioner

CERTIFICATION

I hereby certify that the majority of the members of the Puerto Rico Energy Bureau has so agreed on September 4, 2020. I also certify that on September 4, 2020 a copy of this Order was notified by electronic mail to the following: astrid.rodriguez@prepa.com, jorge.ruiz@prepa.com, n-vazquez@aeepr.com and c-aquino@prepa.com. I also certify that today, September 4, 2020, I have proceeded with the filing of the Order issued by the Puerto Rico Energy Bureau.

For the record, I sign this in San Juan, Puerto Rico, today September 4, 2020.

Wanda I. Cordero Morales
Clerk

NEGOCIADO DE ENERGÍA DE PUERTO RICO
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APPENDIX A

Report on Cost Allocation Methods and Unbundling Issues for Puerto Rico

April 27, 2020

Paul Chernick
Resource Insight, Inc.

Acknowledgements –Janine Migden-Ostrander and Mark LeBel of the Regulatory Assistance Project were invaluable in reviewing, editing and shepherding the report; as were Max Chang and his colleagues at Synapse Energy Economics for assistance in providing data and materials used in this report. Thanks to them for their willingness to discuss issues and provide insights from their work in Puerto Rico that were relevant to this report.

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1. Introduction

This report provides recommendations to the Puerto Rico Energy Bureau (the Energy Bureau) regarding three issues:

- Cost allocation methods that could be applied in determining class cost responsibilities for the Puerto Rico Electric Power Authority (PREPA);
- Identifying the portion of the class cost responsibilities associated with each major function, and particularly the generation function, which some customers may be allowed to procure from a supplier other than PREPA; and
- Estimating the portion of PREPA's generation costs that would be stranded costs if some customers were to switch to another power supplier and not pay for any of PREPA's generation costs.

The last Cost of Service Study (COSS) performed for PREPA was based on 2014 data, which was provided for this report. Since that time PREPA, as well as the Commonwealth of Puerto Rico more generally, has faced numerous difficulties and was not able to provide more recent cost and load data. Where relevant and possible, this report has incorporated newer data from other proceedings, including the Integrated Resource Plan, as referenced in this document. This report provides a foundation for certain upcoming decisions, including a proceeding in which PREPA's generation assets are to be unbundled to permit retail wheeling as permitted by Act 57-2014, Act 17-2019 and Regulation 9138 of the Energy Bureau. This foundation will need to be refined as updated cost and load data become available and as the current uncertainties in PREPA's operational, financial and regulatory situation are resolved.

Some aspects of PREPA's general data-collection and cost-tracking practices fall short of the standards set for major utilities in the United States. Many of those data issues are mentioned throughout this report. Section 4 of this report further elaborates on how the Energy Bureau might consider improving future cost of service studies, which can be done in parallel with other important decisions, and integrating those improvements with advances in system planning and rate design.

2. Cost Allocation

2.1. The Role of Cost Allocation

Conceptually, ratemaking can be described as a sequential process. For our purposes, it is useful to divide the process into three steps. A general rate proceeding starts with the determination of the utility's **revenue requirement**, which is the total amount that the rates will be intended to collect.

The second step is **cost allocation,** which typically has two parts. Part one is a **cost-of-service study**, which divides each component of the utility's revenue requirements among the tariff classes. These cost-of-service studies (COSSs) can be computationally complex, but they rely on a mix of analysis and judgment. A COSS does not bind the regulator—many regulators will review multiple COSSs without accepting any particular study—but a well-thought-out COSS should inform the regulator's decisions about the revenues to be collected from each tariff. Part two involves the application of the **regulator's judgement** in setting a final cost allocation that may take into account the magnitude of the revenue requirement, the effect of increases on particular tariff classes, gradualism, and other policy considerations in addition to the cost-of-service study results.

The third step is the development of a **rate design** for each tariff, setting charges—a fixed charge per month, a charge per kWh (energy charge), and perhaps charges for maximum hourly load (demand charge) or other factors—that are expected to collect from the customers in each class the revenue responsibility allocated to that class.

This report, with its cost-of-service analysis, addresses only with the first part of the second step, the technical part of cost allocation. The methods recommended and used in this report would be applied to the revenue requirement that the Bureau determines for PREPA, to inform the final cost allocation and perhaps aspects of the third step (rate design).

2.2. The Cost-of-Service Study Process

The cost-of-service study process starts with assembling cost data by account. The costs in each account are then functionalized by type (e.g., generation, transmission, distribution, retail, overheads) and subfunctionalized more narrowly, as necessary for responsible cost allocation. Each function or subfunction is then classified in terms of the factors (e.g., energy, peak loads, customer number) that drive the need for the function.[1] For each classified function, an allocation factor must then be developed, to determine the share attributable to each customer class. The next four sections discuss costs, functionalization, classification and factor allocation, respectively.

For most utilities, some costs will be recovered through a ratemaking mechanism other than the setting of base rates in a general rate case. PREPA (like most utilities) recovers its fuel and purchased power costs through a separate reconciling monthly cost-recovery mechanism. It is also likely that some costs of legacy debt (particularly under the ongoing restructuring process) will be transferred to a special-purpose entity to separate it from any future financial constraints that PREPA may experience and guarantee recovery of the debt. Those restructured costs would be recovered through a separate reconciling charge on PREPA bills.

Some COSSs are limited to the costs that will be recovered through base rates. Any costs that are recovered through reconciling adjustments are allocated among customer costs as provided by statutory and regulatory guidance for the specific costs. Those allocations are usually implemented as a constant ¢/kWh of sales, ¢/kWh of energy at the generator (i.e., sales plus a class-specific estimate of line losses), $/customer month, or a percentage adder.

We have taken the second common approach, which is to allocate all costs in the COSS. That option gives the Energy Bureau greater flexibility in cost allocation, since the reconciling costs can be allocated in a manner different from the mechanism selected for recovery of those costs. For example, a fuel adjustment mechanism may collect fuel costs on an equal cent-per-kWh rate, for simplicity, but the Energy Bureau may decide

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[1] These allocation drivers are similar, but not identical, to the billing determinants used in designing rates. The energy allocator will be based on the class's contribution to energy use at the generator, while energy charges are measured per kWh delivered at the meter. Some utilities use an energy allocator weighted by time of use, even if the tariffs do not have separate energy rates by time of use; conversely, the allocator may be computed from class total energy use, even if the tariff energy charges are time-differentiated. For many customer classes, energy charges are set to recover costs that are allocated on various measures of demand—many tariffs do not have charges that track high load hours for the customer, class or system—and on various measures of customer number, since even customer-allocated costs may be larger for customers who use more energy. The demand allocators (contribution to system peak hours, annual class non-coincident peak are usually entirely different from the demand billing determinants (the customer's maximum demand in the month, or in the peak pricing period of the month).

that the fuel costs should be allocated by time of use in the COSS. To the extent that costs are recovered through other mechanisms (such as PREPA's riders for fuel and purchased power, or the eventual recovery mechanism for restructured debt), the expected revenues from those mechanisms can be subtracted from the allocation to each class in the COSS results.

2.3. Cost Data and Approach

Any COSS must start with data on the utility's costs. These costs take two distinct forms: capital investment (also called "plant") and, expenses. The capital investment results in revenue requirements to pay back the investment and to pay for interest on the remaining balance. Those costs for investor-owned utilities are usually described as depreciation and return, respectively; PREPA, like many publicly-owned utilities, may combine them into a single category of debt service. PREPA also includes some cash expenditures for new capital investments, since it has limited ability to borrow to finance those investments.

Expenses include fuel and purchased power; operation and maintenance of generation, transmission, and distribution equipment; metering and billing; administration and management; and overhead costs (e.g., pensions, payroll taxes, insurance) associated with the other functions.

This study uses the best available consistent cost data, which are the costs presented by PREPA in the 2015 rate case.[2] PREPA's financial difficulties and the effects of the 2017 hurricane limited the quality of the updates that PREPA was able to provide in response to the Energy Bureau's Requirements for Information. Each investor-owned US utility with sales over 1 million MWh,[3] files a FERC Form 1 report annually, which includes cost by account at a fairly detailed levels, as well as other information on the composition of costs (e.g., generation investment and expenses by unit, transmission investment and expenses by line or group of lines, and payroll taxes; distribution of wages and salaries by function). Investor-owned and public utilities generally maintain more detailed accounts, with investments and expenses disaggregated further by asset (e.g., individual power plant or transmission line), type of mass plant (e.g., line

[2] CEPR-ROI DRR CEPR-PC-02-028_Attach 12 (CONFIDENTIAL) in CEPR-AP-2015-0002.

[3] PREPA sells approximately 16 million MWh annually, but like most publicly-owned utilities, does not file FERC Form 1 reports.

transformers versus voltage regulators) and/or activity (e.g., breakdown of customer assistance among mass advertising, call centers, and account representatives for large customers).

In order to differentiate costs among classes, most utilities either track costs in still greater detail or perform special studies to distinguish costs. For example, they:

- Track investments in services and meters by customer type (e.g., rate class, tariff, voltage level), or review actual (or typical example) installation costs for various groups to determine the ratio of costs at recent price levels, which can be applied to the embedded costs to estimate embedded cost by class or other billing group.
- Track units (such as feet) of conductors and other distribution equipment by voltage level (primary and secondary) or analyze representative sections of the distribution system to estimate the fraction of conductors at each level.

PREPA does not maintain data on these cost splits and has not performed the analyses necessary to estimate the splits. Considering PREPA's financial condition and the disruption from hurricane Maria and the recent earthquakes, PREPA has not been in a position to remedy these deficiencies in recent years. In short, PREPA did not provide updated data for this analysis.

In light of the limited availability of more recent data, we used the cost data by account from PREPA's 2016 cost-of-service study, prepared by Navigant using data from 2014.[4] Some of the cost inputs may be very different in the 2020s than before Hurricane Maria. For example:

- PREPA's plant in service is likely to be very different following the destruction and replacement of much of the transmission and distribution system in Hurricane Maria and the damage (principally to the Costa Sur power plant) from the recent earthquakes, and the rebuilding since those events, as well as the pending retirements of generation units.
- Bond interest costs were uncertain in 2014, and remain uncertain today, pending resolution of bondholder claims and debt restructuring.

[4] This is the only recent PREPA COSS. It used data from 2014, in a proceeding docketed in 2015 (CEPR-AP-2015-0002), and was filed in 2016. We refer to the vintage of the data (2014) and the vintage of the study (2016), as well as to date of the proceeding, depending on the context.

- The composition of operating costs is also likely to change, due to changes in PREPA's infrastructure.
- The rules for provision of free service to municipalities, styled as contributions in lieu of taxes (CILT), have changed since 2014, reducing that component of the allocation.

The cost inputs should be updated as soon as better data become available.

2.3.1. Purchased Power Breakdown

The 2016 Navigant cost-of-service study did not distinguish among the types of purchased power: AES coal, EcoEléctrica LNG and renewables (mostly solar and wind). In response to discovery in the 2015 rate case, PREPA provided the breakdown of purchased power reproduced in Table 1.[5]

Table 1: Breakdown of Purchased Power Cost, 2014 ($M)

	Energy	Capacity	Total	Percentage
AES	$197.4	$150.4	$347.8	43.0%
EcoEléctrica	$212.5	$208.7	$421.2	52.1%
Renewables	$32.3	$6.6	$39.0	4.8%
Total	$442.2	$365.8	$808.0	

2.3.2. Contributions in Lieu of Taxes and Subsidies

In this study, we allocate the entire cost of service among classes based on the characteristics (load and customer number) for the entire class. By law and policy, PREPA is not expected to collect all of the costs attributable to each class from that class. There are two groups of intentional variation from full cost recovery: intentional subsidies built into the structure of specific rates—such as for low-income and other special-needs residential customers, targeted businesses (hotels and downtown businesses), and public lighting—and contributions in lieu of taxes (CILT), under which PREPA provides municipalities with limited amount of energy at no charge.

After the full cost of service is allocated among classes, we subtract the revenues foregone due to CILT and subsidies from the classes that receive those benefits and

[5] Discovery response CEPR RS-05-15 b in CEPR-AP-2015-0002.

reallocate the costs to all classes, based on their energy consumption, while sheltering some intentionally subsidized tariffs from the reallocation.

2.4. Functionalization

The Navigant 2016 cost-of-service study adequately functionalized most costs among Generation, Transmission, Distribution, Customer and Overhead functions.

- Generation—the power plants and supporting equipment, such as fuel supply and interconnections.
- Transmission—high-voltage lines (for PREPA, 38 kV, 115kV, and 230kV) and the substations connecting those lines, moving bulk power from generation to the distribution substations.
- Distribution—lower-voltage primary feeders (for PREPA, primarily 4.16kV and 13.2kV) that run for many miles, mostly along roadways, and the distribution substations that step power down to distribution voltages; line transformers that step the primary voltages down to secondary voltages (mostly the 120V and 240V); and the secondary lines from the transformers to the point at which secondary customers connect to the distribution system.
- Customer (or Retail)— service drops from the distribution system to the customer, meters, meter reading, billing, responding to customer inquiries, collecting and writing off bad debt.
- Overhead—Costs support all the other functions: Administrative and General Expenses, such as labor adders (employment taxes, pensions, insurance), management, public relations, human resources, and legal staff, and General Plant (buildings and equipment).[6]

Navigant called the fourth function "Customer," which invites confusion over the use of customer number in some allocation factors. We describe that function as Retail.

[6]Some cost of service studies treat overhead as a function and allocate those costs to classes in proportion to the total costs (or a portion of costs, such as plant or expenses) allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions. We take that approach. Others functionalize a portion of each category of general plant and overhead expense to each of the other four functions. The same ultimate cost allocation can be achieved either way; the structure of the cost of service need not constrain or distort the allocation of overhead costs.

2.4.1. Sub-Functions of Generation

PREPA's generation resources are listed in Table 2.

Table 2: PREPA Generation Resources

Plant	Unit	MW	In-Service Date	Technology	Fuel	Notes
Aguirre	1	450	1971	Steam	RFO	
Aguirre	2	450	1971	Steam	RFO	
Costa Sur	3	85	1960	Steam	RFO/NG	Off line since earthquakes
Costa Sur	4	85	1962	Steam	RFO/NG	Off line since earthquakes
Costa Sur	5	410	1969	Steam	RFO/NG	Off line since earthquakes
Costa Sur	6	410	1972	Steam	RFO/NG	Off line since earthquakes
Palo Seco	1	85	1959	Steam	RFO	
Palo Seco	2	85	1959	Steam	RFO	
Palo Seco	3	216	1967	Steam	RFO	
Palo Seco	4	216	1968	Steam	RFO	
San Juan	7	100	1964	Steam	RFO	
San Juan	8	100	1964	Steam	RFO	
San Juan	9	100	1966	Steam	RFO	
San Juan	10	100	1965	Steam	RFO	
Aguirre CC	1	296	1976	CC	DFO	
Aguirre CC	2	296	1975	CC	DFO	
San Juan CC	5	220	2008	CC	DFO	
San Juan CC	6	220	2008	CC	DFO	
Cambalache	1	83	1997	CT	DFO	
Cambalache	2	83	1997	CT	DFO	
Cambalache	3	83	1998	CT	DFO	
Mayagüez	1	55	2009	CT	DFO	
Mayagüez	2	55	2009	CT	DFO	
Mayagüez	3	55	2009	CT	DFO	
Mayagüez	4	55	2009	CT	DFO	
Frame 5	18 units	378	1971-73	CT	DFO	
Hydro	21 units	100	1921-53	CT	DFO	only 34 MW in service
AES	2 units	454	2002	CFB	Coal	Purchased power
EcoEléctrica		507	2000	CC	LNG	Purchased power
Renewables				Various		Purchased power

Source: PREPA. Puerto Rico Integrated Resource Plan 2018-2019. June 7, 2019. Pages 4-1,4-2, and 4-3.
CFB= circulating fluidized bed
RFO = residual fuel oil
DFO = distillate fuel oil
LNG = liquified natural gas

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PREPA's generation resources serve different operating roles, with costs driven by different factors. For the purpose of this COSS, we sub-functionalized PREPA's generation resources into the following eight groups:

- Small steam units: Palo Seco 1–2, San Juan 7–10, Costa Sur 3-4
- Medium steam units: Palo Seco 3–4,
- Large steam units: Aguirre 1–2, Costa Sur 5–6.

- Old combined-cycle units: Aguirre CC 1–2
- Newer PREPA combined-cycle units: San Juan 5 and 6
- Combustion turbines
- PREPA hydro
- The AES coal-plant purchase
- The EcoEléctrica LNG-fueled combined-cycle purchase
- Purchased renewables, principally wind and solar.

These cost categories are generally clearly differentiated in PREPA's cost reporting. However, PREPA reports certain costs not as expenses but as "subsidies." One such item appears to be generation-related: the $4.152 million annual subsidy of the irrigation district. This appears to be a cost associated with PREPA's acquisition of the hydro facilities, so we functionalize it as part of the hydro expense.

2.4.2. High-Voltage Transmission and Subtransmission

The Navigant 2016 COSS treated subtransmission (operating at 38kV) as a sub-function of transmission and allocated no subtransmission costs to the small number of customers served at higher transmission voltages (115 kV and 230 kV).[7] PREPA describes the use of the three transmission voltages as follows:

- Three 230 kV loops in the West, East, and Central pa rts of the island
- 115 kV lines serve all the major load centers on the island
- 38 kV sub-transmission system serve more inaccessible interior regions, as well as most major industrial and commercial customers

The 38 kV subtransmission lines complement the high-voltage transmission, serving the same types of direct customers and substations. The 38 kV lines serve distribution substations that step power down to primary distribution voltage, just as do the 115 kV lines. Where load is relatively low, the utility can serve it with the less-expensive subtransmission; where load is high, the utility may need to upgrade to the more-expensive high-voltage equipment. A new energy-intensive factory that is willing to deal with stepping down transmission voltages to its end-use voltages will usually be

[7] PREPA does not appear to know the actual cost of its 38 kV lines, as opposed to the higher voltages (PREP-PREPA-01-11). It is not clear how Navigant estimated the sub-transmission portion of the transmission function.

able to take power in a range of voltages, depending on what voltage is available at its site.

PREPA estimates that the cost of building transmission lines is $1 million/mile for 38 kV lines, , $1.6 million/mile for 115 kV lines and $1.8 million/mile for 230 kV lines.[8] At those prices, the cost of PREPA's transmission system would have been about 27% higher if it had built the 1,549 miles of 38 kV transmission at 115 kV instead.

It is likely that subtransmission reduces costs, compared to a situation in which all loads are served directly at high transmission voltage or from distribution lines originating from substations served at high-voltage transmission. Building out high-voltage transmission to all substations would require construction of many more miles of high-voltage lines, which require higher towers and are more expensive than sub-transmission lines. All customers classes are better off paying for their load-based share of the mix of 38 kV, 115 kV and 230 kV transmission than for their share of a more expensive system in which all transmission were at 115 kV or 230 kV.

We therefore treat transmission as single function.[9]

2.4.3. Primary and Secondary Distribution

Cost-of-service studies generally sub-functionalize distribution plant between primary equipment (operating at voltages, in the case of PREPA, 4.2–13.2 volts) and secondary equipment (carrying 120, 208, 240 or 440 volts). All distribution customers (that is, any customer not served at transmission voltages) use the primary system, which runs from the distribution substations to near every customer. Some large non-residential customers take service directly from a primary line and use their own line transformers to step the voltage down to the secondary voltage at which most end-use equipment operates. Less than 1% of PREPA's 1.5 million customers are served at primary, but they amount to about a quarter of PREPA's sales. For the vast majority of PREPA's customers, including all residential customers, most small commercial and most lighting

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[8] Response to PREB-PREPA-01-11 in NEPR-AP-2018-0004.

[9] In principle, we would prefer to functionalize as generation-related, some of the transmission that is required to interconnect generators to the transmission system, as well as part of the cost of the lines from the excess of generation on the south coast (Costa Sur, AES and EcoEléctrica) to the load centers in the north. PREPA does not appear to have a breakdown of the costs of the various transmission facilities, so we have not pursued this potential improvement in cost allocation.

customers, PREPA supplies a transformer to step down the voltage to secondary voltages and secondary lines to carry power from the transformer to the point where the customer connects to the system.

Since some classes are served at primary voltage, any incremental cost of providing the secondary equipment should not be allocated to those classes. Hence, we need to split the distribution accounts (capital and expense) into portions that serve all distribution customers (the primary equipment) and the additional costs imposed by providing line transformers and secondary lines.

Some of this analysis is straight-forward. The distribution substations step power down from transmission or subtransmission voltage to primary distribution voltage; substations serve all distribution load and are in the primary sub-function. Accounts 360 to 363 are primarily or entirely related to substations and are thus shown in Table 3 as primary. Line transformers are needed only for secondary customers and are in the secondary sub-function.

The subfunctionalization of lines (consisting of poles, conductors, conduit and associated equipment) cannot be derived from the standard cost accounts, which do not subdivide the costs by the voltages they serve. Nor does PREPA have cost data directly relevant to dividing these costs between primary and secondary sub-functions.

Pole Sub-Functionalization

Some distribution poles carry only primary equipment, some carry both primary and secondary, and a small number carry only secondary (e.g., from the last transformer on a street to the last few poles farther down the street). The cost of adding secondary lines to a pole that would have been needed to carry primary lines is minimal. Poles carrying only secondary lines can be shorter and less robust, and thus less expensive, than those carrying primary. If a customer served by a secondary-only pole had been served at primary instead, the primary pole would have been more expensive and that higher cost would have been allocated to all distribution customers. Secondary poles (unlike line transformers and most secondary lines) are lower-cost alternatives to some primary poles. Thus, treating secondary poles as an additional cost of serving secondary customers would be inappropriate, and we sub-functionalize poles as primary, to be borne by all distribution load.

Table 3: Distribution Plant Accounts

Account	Description	Sub-Function
360	Land and Land Rights	Primary
361	Structures and Improvements	Primary
362	Station Equipment	Primary
363	Storage Battery Equipment	Primary
264	Poles, Towers, and Fixtures	Primary
365	Overhead Conductors and Devices	Split
366	Underground Conduit	Split
367	Underground Conductors and Devices	Split
368	Line Transformers	Secondary

Sub-Functionalization of Lines

With the substation, poles and line transformers dealt with, we are left with three line-related cost categories. PREPA (unlike some utilities) does not maintain data on the feet of conductors or conduit that is used for the secondary system. The PREPA 2016 cost-of-service study assumed, without any support, that the share of line (and pole) investment that was required for secondary service was equal to the share of distribution load served at secondary voltage. That assumption essentially ensured that the costs allocated to each kW of secondary load would be twice that of the cost of serving customers at primary.

Lacking PREPA-specific data, we borrowed data from other utilities. As reported in

Table 4 we assembled estimates reported by sixteen utilities of the percentage of their distribution line investment that is used at secondary.

Where possible, we used just the plant associated with accounts 365 through 367; in some cases, the utility did not differentiate poles from lines, so we used the aggregate value. Where the utility classified some of the distribution plant as customer-related, we computed both the demand-related and total line investment and reported the average of those percentages. Some of these estimates are based on accounting data and others are based on engineering estimates for typical installations.

Table 4 also shows the percentage of distribution load that is delivered at secondary, either from the data in the utility cost-of-service study or from the sales by class in its FERC Form 1 report, pages 300–301. As shown in

Table 4, we computed the ratio of the utility estimate of the percentage of plant that is secondary to the percentage of load that is secondary. That ratio ranges from 0.13 to 0.55, with an average of 0.30 and a median of 0.26.

Table 4: Utility Estimates of Secondary of Distribution Load and Lines

Utility	State	% of Plant at Secondary	% of Load at Secondary	Ratio	Sales (GWh)	Customers
		a	*b*	*c = b÷a*		
Pasadena Water & Power	CA	12%	94%	0.13	1,033	64,574
Georgia Power	GA	11%	60%	0.18	85,492	2,536,685
Duke Energy Indiana	IN	22%	91%	0.24	28,631	830,270
Indiana Michigan Power	IN	41%	82%	0.50	15,629	465,774
Baltimore Gas & Electric	MD	26%	91%	0.29	30,224	1,290,931
Delmarva Power	MD	15%	72%	0.21	4,281	205,848
Potomac Electric Power	MD	24%	89%	0.27	14,482	574,924
New York State Elec & Gas	NY	21%	65%	0.33	15,716	898,688
Rochester Gas & Electric	NY	18%	64%	0.28	7,219	381,326
PPL Electric Utilities Corp	PA	23%	79%	0.25	37,489	1,440,559
Narragansett Electric	RI	41%	75%	0.55	20,409	1,905,143
El Paso Electric Co	TX	21%	95%	0.22	6,352	323,297
PacifiCorp	UT	31%	92%	0.33	24,514	915,252
PacifiCorp	WA	47%	86%	0.55	3,949	131,453
Northern States Power Co	WI	16%	89%	0.18	6,847	250,408
Appalachian Power Co	WV	20%	84%	0.24	13,115	423,900
Average		24%	82%	0.30	19,711	789,940
Median		22%	85%	0.26	15,056	520,349
Puerto Rico Electric Pwr Auth	PR		66%		16,374	1,473,230

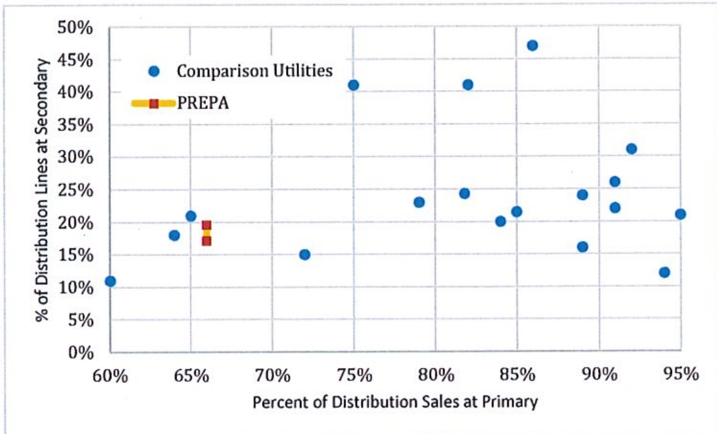
While the sixteen utilities were chosen due to availability of the COSSs (either in our files or publicly available online) and the ability to extract the necessary information, they represent a wide range of climate, customer mixes, portion of load served at secondary, and (as shown in

Table 4) sizes.[10] About 66% of PREPA's distribution load is served at secondary, which is less than all but three of the comparison utilities. Since PREPA provides secondary equipment for a smaller share of its distribution load, the share of its distribution plant that is dedicated to secondary service would also be lower than the typical comparison utility. At the average plant-to-load ratio, about 20% (0.3 x 0.66) of PREPA's distribution lines would operate at secondary; at the median, 17% (0.27 x 0.66) of PREPA's distribution line plant may be dedicated to secondary service.

[10] For comparison, PREPA serves about 1.5 million customers and 16 - 18 million MWh.

Figure 1 compares those estimates for PREPA to the data from the comparison utilities.

Figure 1: Secondary Share of Distribution Load and Lines



Four utilities in our sample have secondary sales that are less than 75% of their total distribution sales; they report secondary line plant averaging 16% of distribution line plant.

We use the high end of the extrapolation range—20%—to subfunctionalize the secondary portion of accounts 365–367.

2.4.4. Retail Function

We included the following cost accounts in the retail function:

- Service drops (Account 369)
- Meters (Account 370)
- Installations on Customer Premises (Account 371)
- Meter operation and maintenance (Accounts 586 and 597)

- Customer billing expenses (Accounts 901–917)[11]

PREPA (like other utilities) records service drops and meters (and associated expenses) as distribution costs: we include them in the retail function because they are so intimately associated with serving individual customers.

2.4.5. Overhead Function

We included the following cost accounts in the overhead function:

- General Plant (Accounts 389–399)
- Intangible Plant
- Unclassified Construction
- Administrative and General Expenses (Accounts 920–935)
- Bad Debt Expense (Account 414)

As noted in the Regulation for Wheeling, intangible plant that serves specific functions (such as licenses for software used to dispatch power plants, monitor transmission condition, or control distribution switches) should be directly assigned to those functions. We have not seen any breakdown for the makeup of intangible plant in the 2014 data; that problem should be corrected as PREPA updates the cost data. Some of the intangible plant is likely to be properly functionalized as General Plant, such as licenses for word-processing, spreadsheet, on-line security, communications, and other applications used by all parts of the utility.

Similarly, Unclassified Construction should be functionalized to the underlying functions. When PREPA updates the cost inputs, it should determine the nature of the unclassified construction and divide it among functions appropriately.

As noted above, PREPA reports certain costs not as expenses but as subsidies. One such cost is the Energy Bureau annual assessment, which is an overhead cost, normally booked as a regulatory expense. We functionalize that cost as overhead.

[11] The 2015 PREPA COSS treated these accounts as a single expense category: the individual accounts include Meter Reading Expenses, Customer Records and Collection Expenses, Uncollectible Accounts, Customer Assistance, Sales Expenses, and Supervision of those activities.

2.5. Classification

2.5.1. Thermal Generation Energy and Demand

Since the 1960s, utilities have been able to meet their generation requirements by building (or purchasing power from) a range of power generation technologies. The least expensive plants to build and maintain were the combustion turbines, while steam and combined-cycle plants were more expensive, but produced energy at lower cost, by being more efficient and (at least for the steam units) allowing the use of lower-cost fuels. Hence, it is reasonable to think of the fixed costs of a peaking combustion turbine as representing the cost of providing reliable power supply (mostly driven by demands in a small fraction of annual hours) and the additional costs of steam and combined-cycle plants as being justified by the desire to provide lower-cost energy throughout the year. This approach is called the Equivalent Peaker Method for classification of generation fixed costs. A portion of the capital and/or fixed operating costs of each plant that is equal to a similar-vintage combustion turbine is classified as demand-related, and the remainder is classified as energy-related.

PREPA does not have disaggregated information on its historical investment in its existing individual units or plants and does not have costs for building combustion turbines in Puerto Rico at the same time that most of its other thermal plants were built.[12] We therefore relied on industry cost estimates.

We estimate the portion of the thermal plant cost that is demand-related by estimating the fraction of the cost for each type of plant that would have been required just for the demand function. For the combustion turbines, that is one hundred percent (100%). For the steam and combined-cycle plants, we relied on industry estimates of the costs of similar plants and of combustion turbines around the time the PREPA plants were built. Due to the unique challenges of construction in Puerto Rico, particularly transportation costs, the PREPA plants were probably all more expensive than typical contemporaneous installations on the mainland, but we assume the cost ratios would have been similar.[13] In other words, for a particular vintage, if mainland peaking combustion

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[12] Energy Bureau Requirement of Information (ROI) to PREPA No. 01-03 in Case No. NEPR-AP-2018-0004.

[13] In the 2019 IRP, Siemens assumed that construction costs are about 16% higher on Puerto Rico than the mainland (p. 6-11).

turbines cost eighty percent (80%) as much as mainland steam plants, we assume that Puerto Rico combustion turbines would have costs eighty percent (80%) as much as Puerto Rico steam plants.

It is important to have consistent data for the costs of each category of plant and roughly contemporaneous combustion turbines. Various sources report costs for different in-service dates, with different cost inputs (e.g., inflation, interest rates, contingency) and on different bases (constant or nominal dollars, overnight costs or full ratemaking costs). There is no single source for actual power plant costs over time, especially for the relatively old power plants of the vintage of PREPA's plants. Most of the mainland oil-fired steam plants have been retired or sold to merchant generation companies, so data on the current costs of comparable units are limited.

For the older thermal plants, we used the New England Power Pool (NEPOOL) Generation Task Force Planning Assumptions for 1976, as shown in

Table 5. This is the earliest such report we have been able to locate. The capacity-weighted average age of the steam plants is 1968, while Aguirre CC entered service in 1975 and 1976.

Table 5: Capital Cost Estimates for New Power Plants, 1976

Plant Type	$/kW	Ratio of Cost to CT Cost	Demand-related Portion
CT 50 MW	$236.7	1.00	1.00
CC 600 MW plant, multiple units	$300.0	1.27	0.79
Oil Steam 200 MW	$560.7	2.37	0.42
Oil Steam 400 MW	$452.5	1.91	0.52

The last column of

Table 5 is the ratio of the combustion turbine cost to the cost of the particular kind of plant (the inverse of the ratio of the plant cost to combustion turbine cost). Based on these data, we thus assumed that the Aguirre combined-cycle capacity could have been built as combustion turbines at seventy-nine percent (79%) of its actual cost, large steam plants could have been built as combustion turbines at fifty-two percent (52%) of their actual cost, and medium steam plants at forty-two percent (42%) of their actual cost. The NEPOOL data show substantial economies of scale (which we would expect) for steam plants, with costs per kilowatt rising about twenty-four percent (24%) as size is halved. We did not have any cost estimates for the smallest steam units (85–100 MW). If the costs per kilowatt doubled again from 200 MW to 100 MW, the 100 MW units would have cost about 2.9 times as much as combustion turbines and the demand-related portion would be about thirty-four percent (34%). We assumed a more modest increase in the relative cost per kilowatt, resulting in forty percent (40%) of the small steam plants being demand-related.

The only non-peaker PREPA plant constructed much later than the mid-1970s was the San Juan CC plant in 2008. The 2008 Annual Energy Outlook from the Energy Information Administration (Table 38) reports that a conventional 250 MW oil-fired CC would cost $717/kW (overnight cost, in 2006$) and a conventional 160 MW oil-fired combustion turbine would cost $500/kW, or seventy percent (70%) of the cost of the combined-cycle.

The demand-related shares are summarized in

Table 6, along with the capacity of the plants in each category and the ratio of the cost of the plant category to the cost of contemporaneous combustion turbines .

The bottom portion of

Table 6 shows the cost of PREPA's entire thermal fleet at a relative cost per megawatt of 1.00 (which would be 2,998 MW) and the total cost at the ratio of the category cost to the combustion turbine cost (4,770 MW). The cost of the PREPA thermal fleet is thus about 1.76 times the cost of the same capacity of the same vintages, if all the capacity were combustion turbines. Stated differently, the cost of the hypothetical combustion turbine system would be about fifty-seven percent (57%) of the cost of the actual system.[14]

Table 6: Summary of Demand-Related Generation Plant Share

Units	Size	Vintage	MW	Demand Share	Cost as CT multiple

[14] This ratio does not take into account the effect of the larger sizes of the steam and CC units. All else equal, fewer megawatts of small units are required to provide the same reliability as more megawatts of large units. Both for PREPA and generally, combustion turbines are smaller than steam and combined-cycle units. The PREPA combustion turbines range from 21 to 83 MW, while the steam plants range from 85 MW to 450 MW and the combined-cycle units are 220 to 300 MW.

Steam	Costa Sur 3–4, Palo Seco 1–2, San Juan 7–10	≤100	1959-65	740	40%	2.50
	Palo Seco 3-4	~200	1967-68	432	42%	2.37
	Aguirre 1–2, Costa Sur 5–6	~400	1967-71	1,720	52%	1.91
CC	Aquirre CC 1-2	~300	1976	592	79%	1.27
	San Juan 5–6	~220	2008	440	70%	1.43
CTs				846	100%	1.00
Total	Cost if peakers			2,998		
	Cost at category multiple			4,770		
	Demand share			57%		

We did not perform a similar analysis for non-fuel operating and maintenance (O&M) costs of the various types of plants, but the costs of running a combustion turbine are also much lower than the costs of running combined-cycle and especially oil steam units.

The fuel costs for all plants are driven by energy use.

As the thermal plants are retired, the legacy debt burden that they caused will probably be restructured. That change in the recovery of the costs does not affect the reason that the costs were incurred, and the cost allocation should not change with recovery.

2.5.2. Hydro Generation Classification

PREPA does not recognize any capacity value of the hydro generation. The hydro units currently provide little if any firm supply in the highest-load months, because these units are run-of-river with limited storage. As a result, we treat them as entirely energy-related. It is very likely that the hydro generation provides some contribution to reliability, but PREPA has not conducted the analysis to estimate that value, either for the Integrated Resource Plan (IRP) or for cost allocation. Future improvements to the existing hydro resources may increase whatever reliability contribution they currently have.

2.5.3. Purchased Power Classification

Our approach to classification of the costs of the large IPP contracts is similar to that for PREPA's thermal plants.

The AES plant is a 450 MW fluidized-bed coal plant that entered service in 2002. Comparing the capital cost per kilowatt for combustion turbines ($332/kW) to that for new scrubbed pulverized-coal units ($1,102/kW) from the 2000 Annual Energy Outlook, we estimated that 33% portion of that coal plant cost was demand-related. We were not able to find consistent contemporaneous estimates of the costs of fluidized-bed and CT plants, but various sources report that the capital costs of fluidized-bed and pulverized-coal units were similar through that period.[15]

EcoEléctrica is a 507 MW LNG-fired CC unit that entered service in 2000. The 2000 Annual Energy Outlook estimated that pipeline-fueled gas combined-cycles would have cost $449/kW, thirty-five percent (35%) more than the $332/kW for combustion turbines; the combustion turbines cost seventy-four percent (74%) as much as the combined-cycle units. EcoEléctrica's capital and operating cost would be higher than the cost of a similar pipeline-supplied plant, due to the LNG unloading and storage facilities. We assumed that EcoEléctrica cost fifty percent (50%) more than a pipeline-fed mainland combined-cycle.[16] That adjustment would bring the cost of EcoEléctrica to about twice ($1.35 \times 1.5 = 2.03$) the cost of combustion turbines. Assuming that the EcoEléctrica capacity charges recover the fixed costs, half of the capacity charges would be demand-related.

As for hydro, we understand that PREPA does not give solar or wind any capacity value. Hence, we assume that the costs of the existing renewable PPAs were incurred

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[15] See Lockwood, T. "Techno-economic analysis of PC versus CFB combustion technology," EA Clean Coal Centre, Table 8 (www.usea.org/sites/default/files/102013_Techno-economic%20analysis%20of%20PC%20versus%20CFB%20combustion%20technology_ccc226.pdf) and Ghosh, D., "Assessment of Advanced Coal-Based Electricity Generation Technology Options for India: Potential Learning from U.S. Experiences," September 2005, Energy Technology Innovation Project Report 2005-02, p. 12 (www.belfercenter.org/sites/default/files/legacy/files/ghosh200502.pdf). Ghosh found that circulating fluidized bed (CFB) was slightly less expensive than scrubbed pulverized coal (PC) generation, but only about 13 of the 49 US coal plants over 50 MW that were completed since 1995 have used CFBs, and half of them burn fuels such as waste coal and waste tires for which CFB units are well suited.

[16] A recently approved revision in the EcoEléctrica contract would shift more of the costs from the capacity charge to the energy charge, which may reflect the reality that the capacity charge has included a substantial portion of the cost of the LNG facilities. Once those rates are in effect (in late 2020 or 2021), the capacity charges should be split seventy-four percent (74%) to demand and twenty-six percent (26%) to energy; that change would be offset by the increase in energy charges.

entirely for energy-related purposes. In the future, with the addition of storage and better analysis, PREPA is likely to find that both solar and wind resources contribute to reliability and reduce the need for retaining or building thermal generation and storage.

Weighting the capacity charges of the PPAs in FY 2014 by the demand-related fractions estimated above results in a total demand-related component that is forty-two percent (42%) of the capacity charges and nineteen percent (19%) of total purchased power expense.[17]

2.5.4. Transmission

As noted above, we are not able to disaggregate the portion of PREPA's transmission investment that was necessary to meet energy requirements, whether for connection of the southern generation to the northern load or due to sizing equipment to tolerate long hours of usage at high loads. We therefore classify transmission plant as entirely (100%) related to demand. As discussed below, our measure of demand is rather broad and will capture some of the hours-use considerations.

2.5.5. Distribution

As is true for transmission, some distribution costs are driven by energy use, which determines the heating and hence the required sizing (and the lifetime of undersized equipment) for transformers and lines. Lacking detailed data on PREPA's distribution equipment and sizing guidelines, and recognizing that the sizing of existing equipment is the result of a history of changing circumstances, we classify all distribution plant as demand-related (which we will allocate on a broad peak-hours allocator, as discussed on page 29, capturing some energy-related effects), other than services and meters.

2.5.6. Retail

We classify all services and meters and related expenses as customer-related (most customers require a service drop and a meter). We reflect the variation in service and meter costs across classes in the weighted allocator.

[17] The data are from CEPR RS-05-15(a) in CEPR-AP-2015-0002. This computation assumes that the capacity charges are designed to cover the fixed costs of the IPPs and that the energy charges cover the fuel and other variable costs.

2.5.7. Overheads

We do not directly classify overheads. As explained below, we construct an overhead allocator from the labor allocator, plant in service, and fuel and purchased power.

2.6. Allocation Factors

2.6.1. Generation Energy

We understand that the short-term running costs of the PREPA system do not vary significantly among time periods in the day or year, and thus allocate energy-related generation costs among classes in proportion to their annual energy consumption, including line losses.

Over time, the mix of generation will become more diverse, with the addition of renewables (particularly solar). The allocation of generation energy costs over time periods should be reexamined as the system evolves, probably resulting in the allocation of most of the solar costs to the mid-day period and fuel costs being more heavily weighted to evening and night-time hours.

2.6.2. Generation Demand

The Puerto Rico electric system has two characteristics that result in a large number of peak hours. First, the load shape is relatively flat, with about one percent (1%) of hours within five percent (5%) of annual peak load, mostly spread over the hours ending 20, 21, and 22, but with a significant number of the high hours falling between 11 AM and 3 PM (the hours ending 12 to 15). About ten percent (10%) of hours are within ten percent (10%) of annual peak, with about half those hours in the late morning or afternoon. The consistency in Puerto Rico's weather does not produce needle peaks found in many mainland utilities.

Figure 2 shows the hourly distribution of system load over the hours of the day. The hourly data are for two periods: calendar 2008 through 2014 and January 2017 through June 2019.[18] We computed the ratio of the hourly load to the peak load for the year and then counted the number of loads over ninety-five percent (95%) and ninety percent

[18] From CEPR RS-05-15(a) in CEPR-AP-2015-0002 and PREB-PREPA-01-08 in CEPR-AP-2018-004, respectively.

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
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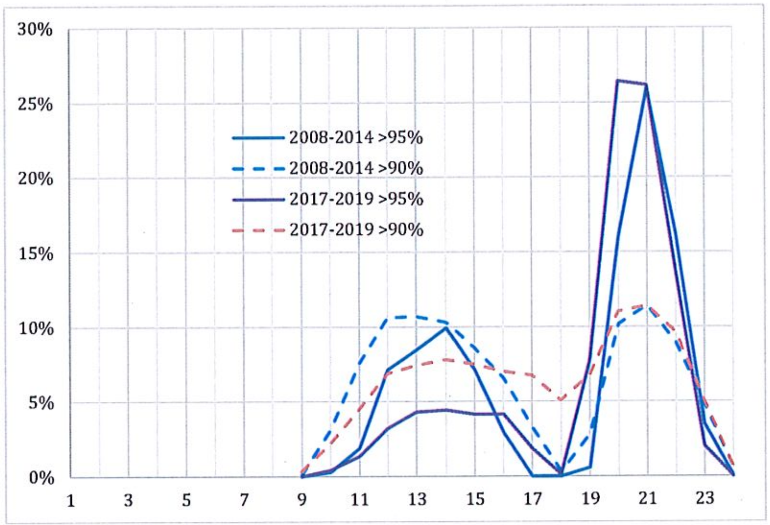
(90%). The data from 2017–2019 are more recent, but are less representative, due to the effects of Hurricane Maria in 2017, the recovery through 2019, and the incomplete data for 2019. Nonetheless, the share of the highest system load in each hour is remarkably consistent between the two periods. None of the hours with loads within ten percent (10%) of annual peak occurred in hours ending 1–9.

Figure 2: Share of PREPA System Hours over 90% or 95% of Annual Peak



Second, PREPA has several units that are very large compared to its load. Palo Seco 3&4 and San Juan 7&8 are 200 MW or larger, the Aquirre CC units are about 300 MW and the Aquirre steam units are 400 MW each. Since PREPA's annual peak load is about 2,700 MW and its average load is about 80% of that (or 2,200 MW), several individual units are seven percent (7%) to fourteen percent (14%) of peak. Hence, a load five percent (5%) or ten percent (10%) less than the annual peak can become as stressed as the peak-load hour, if even a single large unit is out of service. And there are many such hours: in 2008–2014, Puerto Rico had an average of 98 hours per year higher than ninety-five percent (95%) and 873 hours greater than ninety percent (90%) of peak.[19]

[19] Retirement of the largest PREPA units and replacement with much smaller units would tend to concentrate more of the outage risk in the highest-risk months.

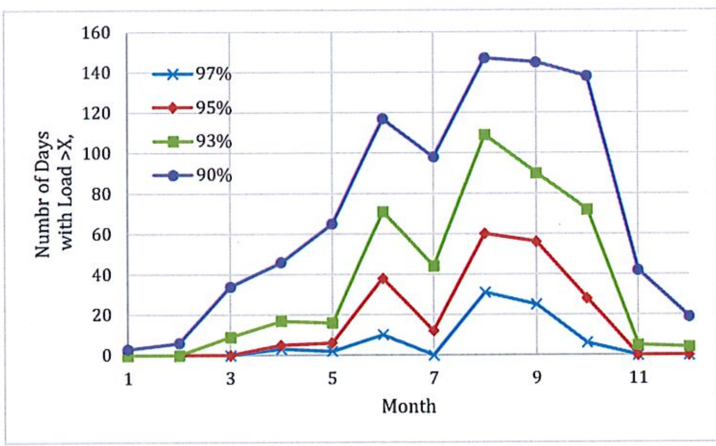
For comparison, ISO New England is a relatively small system by mainland standards, with

- a peak load of about 25,000 MW, 23 hours over ninety-five percent (95%) of peak, and 93 hours over ninety percent (90%) of peak,
- two large units of 1,200 MW, less than five percent (5%) of peak, and no others larger than about three percent (3%) of peak, and
- about 2,000 MW of benefits from its interconnections with other systems.

Nova Scotia has a firm peak load of about 2,000 MW, similar to Puerto Rico, but limits the size of its generation units to about 150 MW (with one of 170 MW). And Nova Scotia has a small transmission connection with the rest of North America.

As shown in Figure 3, most of the high-load hours in 2008–2014 were in May through October. The monthly patterns for 2017 through 2019 are too affected by the hurricanes and the subsequent recovery to be representative of future load patterns.

Figure 3: Number of High-Load Hours by Month, 2008–2014



The load data suggests that peak stresses would occur from May through October, in hours ending 20 to 22 and to a lesser extent the hours ending 11–17.

In addition to the load data, we also have data on the timing of customer outages due to generation outages, from PREPA ROI 4-9 in CEPR-AP-2018-0001. PREPA has provided the date and time of each outage, as well as the minutes of resulting outage on the transmission system and the larger number of minutes of outage on the distribution system.

Figure 4 shows that all three of those measures are concentrated in hours ending 14 and 15, with smaller but significant portions in the mid-morning (hours ending 9 and 10 am), the late afternoon going into the evening (hours ending 16–20), and (surprisingly) the hours ending at 1 am and 2 am. Figure 5 shows that these outages have occurred throughout the year, but are more common in July through September. Some of the daily and seasonal variation is undoubtedly due to luck and to insufficient operating reserves, rather than installed reserve above load or other underlying factors, but these results are directly consistent with the load data described above.

Figure 4: Hourly Distribution of Generation-related Outages, 2014–2019

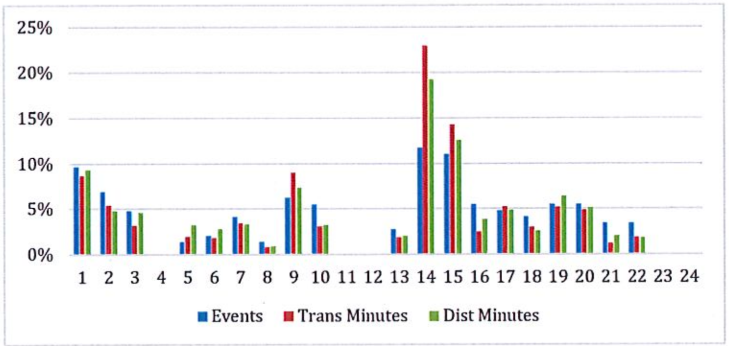
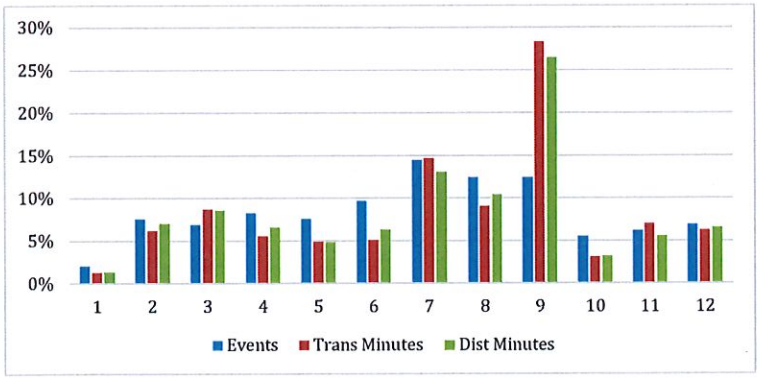


Figure 5: Monthly Distribution of Generation-related Outages, 2014–2019



Considering these data, we used a broad measure of coincident peak (CP), hourly and monthly load patterns, and times of lost load due to insufficient generation. Specifically, we use a measure of CP defined as weighted average of loads in May to October:

- Seventy-five percent (75%) evening average load (hours ending 20 to 22)
- Twenty-five percent (25%) midday average load (hours ending 11 to 17)

The evening in this summer period would include about 550 hours, so each hour would contribute 0.136% (= 75% ÷ 550) of the CP weight. The midday period would include about 1,290 hours, each of which would contribute about 0.019% (= 25% ÷ 1,290) of the CP weight.

The high loads occur primarily on non-weekend days, but as explained below, we do not have data that could readily be used to determine class contribution to weekend load, since the class load data are drawn from studies in different years.

Loads in the midday high-load period will decline as solar is added behind customer meters, or in locations of the distribution system where PREPA may count them as reductions in generation requirements. Other solar installations will reduce (and eventually eliminate) the need for other generation in the midday. In the future, we would expect the reliability need for generation resources to gradually shift entirely into the evening.

Computation of Class CP allocator

In Case CEPR-AP-2015-0002, PREPA provided load data for most of the major rate codes, from load resource samples in various years. We could not scale those samples up to the entirety of the classes, since the resulting totals would not reflect the loads in any past or projected year. Instead, we started with the 8,760-hour load curve that PREPA reported for each rate code and normalized the hourly loads to the load sample's average load for the sampled year. Where PREPA provided load data for multiple rate codes in each tariff (such as the commercial code and the industrial code within the tariff), we constructed a weighted load shape for the tariff class. There is no point in computing multiple allocators for codes within a tariff, since all the customers on the tariff will be charged the same rates.

For a few codes and tariffs, PREPA was not able to provide a load shape; in those cases, we extrapolated from the data that were available.

Some PREPA rate-design practices complicate the process of matching tariff-class loads, revenues and costs. Three ratemaking provisions allow non-residential customers to be billed on the residential GRS rate, rather than the traditionally higher GSS, GSP and GST rates that would otherwise apply. These provisions cover houses of worship and social welfare organizations (about 80% of this category), condominium common areas (about 20%), and rural aqueducts (only about $1,000 annually). These customers are not on separate rates, and PREPA does not have any load research data for these groups. PREPA implicitly assumes that these customers have the same load shapes as its load-research samples for the non-residential tariff they are grouped with, and treats these tariff provisions as subsidies (see Section 2.7.2, below). The costs resulting from these customers are estimated as if they had typical load shapes for the applicable non-residential tariff (GSS, GSP, GST), but they produce revenues at the GRS rate.

We understand that legislation requires the billing of houses of worship, social welfare organizations and condominium common areas on the GRS tariff. We do not know whether these provisions were ever intended to reflect the load characteristics of these groups, but they may well have been. It is likely that these groups have load shapes more like the residential GRS tariff than the rest of the GS non-residential classes.

- The condominium common areas are probably much like other residential loads (lighting, water heating, clothes washing) that stretch over more than the typical business day.
- Houses of worship are harder to characterize, but many would have disproportionate use on the weekends and earlier in the day than the concentration of peak load hours.
- The rural aqueducts may have higher coincident load factors than do general non-residential loads, although that would depend heavily on the type of water uses and the configuration of the aqueduct systems, such as storage capacity. Their sales are too small to warrant much effort at the allocation level.

So long as these customers are billed at the GRS rate, it would be more transparent to treat sales under these special rate provisions as part of the GRS class. We thus subtracted their loads from the non-residential classes and added them to the GRS class.

From those adjusted data, we computed each tariff's contribution to the broad-CP hours, for whichever year PREPA reported data contribution, and used the average load in those hours to compute a CP load factor (average load divided by CP) for the tariff.

Table 7 shows the derivation of each class's generation demand allocator for 2014 (the year for which we have costs for the COSS) in three steps. First, we derive a provisional broad CP peak contribution for each class as the annual sales in GWh (millions of kWh), divided by the CP load factor and 8.76.[20] We then summed the CPs across tariff classes to develop a provisional total broad CP peak and divided each class CP contribution by the total CP peak to determine the tariff's share of the generation demand allocator.

Table 7: Generation Demand Allocator

Tariff	Class	Voltage	Description	Load Factor	2014 Sales GWh	Implied MW	Allocator
				a	*b*	*c = b÷[a×8.76]*	*d = c ÷ c_total*
RH3	R	S	Gov't Housing	91.7%	21.1	2.6	0.12%
RFR	R	S	PHA Housing	86.3%	246.8	32.6	1.47%
LRS	R	S	Low Income	86.3%	570.3	75.4	3.41%
GRS special	R	S	Fuel Discount	85.1%	433.5	58.2	2.63%
GRS	R	S	Gen Residential	95.5%	4,905.6	586.2	26.47%
GSS	C/I	S	Secondary	85.8%	2,165.3	288.0	13.00%
GSP	C/I	P	Primary	83.7%	4,497.9	613.7	27.71%
GST	C/I	T	Transmission	91.0%	3,228.7	405.1	18.29%
TOU-P	C/I	P	TOU Primary	107.4%	7.6	0.8	0.04%
LIS	C/I	T	EHV Transmission	102.1%	214.1	23.9	1.08%
PPB	C/I	T	IPP Backup	75.1%	1.4	0.2	0.01%
TOU-T	C/I	T	TOU Trans	97.3%	618.2	72.5	3.28%
GAS	Agr	S	Agriculture	74.2%	26.4	4.1	0.18%
Lights/Unmetered		S	24-hour	100%	17.5	2.0	0.09%
Lights/Unmetered		S	Dusk to Dawn	66.6%	258.0	44.2	2.00%
LP-13		P	Sport fields	33.3%	2.7	0.9	0.04%
PLG 424		S	Parks	50.0%	19.4	4.4	0.20%
System					17,234.7	2,214.9	100.00%

Classes: R = residential, C/I = commercial, industrial and other public, Agr = agriculture
Voltage: S = secondary, P = primary, T = transmission

2.6.3. Transmission

The transmission system is sized, in large part, by the need to meet loads in high hours with various combinations of generators, to allow for forced outages, maintenance, and units that are unavailable due to long start-up times. We represented those needs by using the generation broad-CP allocator for transmission.

[20] The 8.76 factor represents the 8,760 hours in the year, divided by 1,000 GW per MW.

2.6.4. Primary Distribution

The computation of the distribution allocators is similar to the computation of the generation demand allocator, with some important differences. First, the distribution allocators exclude the load from the transmission classes.

Second, the hours in which distribution equipment is stressed are more widely distributed than the hours in which the generation or transmission system is stressed. In particular, depending on the mix of classes and loads served on each feeder or substation, that local equipment may experience its peak load at an hour that is not particularly high-load in other parts of the island, including even neighboring areas with different customer mixes.

PREPA provided the time and data of annual peak loads in 2014 and 2015 on most of its substations.[21]

Table 8 shows the distribution of those peak loads across hours and months, for the ninety-two percent (92%) of peaks that occurred on weekdays. The underlying data are the MVA of substation peaks that occurred in each hour.

[21] CEPR-ROI DRR CEPR-PC-02-028_Attach 12 (CONFIDENTIAL) in CEPR-AP-2015-0002.

Table 8: Distribution of Weekday PREPA Substation Peaks by Month and Hour

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1								0.6%					0.6%	
2														
3														
4														
5												0.1%	0.1%	
6														
7														
8					0.2%								0.2%	
9						0.2%						0.1%	0.3%	
10	0.0%						0.4%	0.5%	0.5%	0.1%		0.2%	1.7%	
11	0.1%				0.1%	0.4%	0.1%	0.2%	0.1%	1.1%			2.0%	
12	0.5%	0.1%	0.1%	1.3%	0.6%	0.5%	0.5%	0.6%	0.5%	1.5%	0.3%	0.4%	7.0%	
13	0.9%	0.0%	0.0%	0.3%	0.1%	0.1%	0.2%	0.6%	0.1%	2.1%		1.0%	5.4%	
14	0.1%	0.9%	0.1%	1.8%	0.7%	0.3%	0.3%	1.9%	0.7%	2.2%	0.6%		9.6%	26.3%
15	0.2%	0.6%		0.3%		0.4%		0.4%	0.3%	1.3%	0.2%	0.6%	4.3%	
16	0.1%	0.3%				0.4%	0.8%	0.0%		0.7%	0.5%		2.9%	
17		0.1%			0.9%	0.1%			0.1%	0.3%		0.2%	1.7%	
18					0.1%		0.0%		0.4%	0.5%		0.1%	1.1%	
19	0.6%	0.3%	0.1%	-	0.4%			0.2%	1.0%	0.6%	0.3%	0.7%	4.1%	
20	0.2%	0.7%	0.3%	0.6%				1.4%	1.0%	1.8%	0.3%	2.2%	8.6%	30.5%
21	0.7%	0.2%	1.8%	2.0%	0.3%	0.1%	0.3%	6.4%	1.5%	5.5%	1.1%	0.6%	20.5%	
22	0.1%	0.2%		1.7%	0.3%	0.3%	1.4%	6.2%	3.9%	2.8%	0.9%		17.7%	13.6%
23		0.1%		0.2%	0.2%	0.3%	0.9%	0.6%	0.4%	0.8%	0.2%		3.6%	
24								0.6%					0.6%	
Total	3.6%	3.6%	2.4%	8.2%	3.9%	3.2%	4.9%	20.0%	10.5%	21.4%	4.4%	6.0%	92.1%	
Peak periods	2.7%	2.8%	2.3%	8.1%	1.4%	1.3%	0.9%	17.4%	8.0%	17.3%	3.4%	4.7%	70.4%	

The hours in the solid block (hours ending 20 to 22 in August to October) total 30.5% of the substation peaks, the hours in the dashed box (HE 12 to 15, all months) total 26.3% of the peaks, and the hours in the double-line boxes (hours ending 20 to 22 in November to April) total 13.6% of the peaks. Those weekday hours account for over 70.4% of the substation peaks.

The remaining 29.6% of the substation peaks occur on both weekends and weekdays. Table 9 shows the distribution of the peaks on any day of the week, net of the weekday hours flagged in Table 8.

Table 9: Distribution of Residual PREPA Substation Peaks by Month and Hour

	1	2	3	4	5	6	7	8	9	10	11	12	Total	Grouped
1								0.6%					0.6%	
2														
3														
4			0.1%										0.1%	
5												0.1%	0.1%	
6														
7														
8					0.2%	0.1%							0.3%	
9						0.4%						0.1%	0.5%	
10	0.0%		0.2%				0.4%	0.5%	0.5%	0.1%		0.2%	1.9%	4.5%
11	0.1%				0.2%	0.4%	0.1%	0.2%	0.1%	1.6%		0.0%	2.6%	
12					0.2%	0.1%							0.2%	
13	0.2%		0.1%			0.1%				0.2%			0.6%	
14														
15		0.1%						0.3%					0.4%	
16	0.1%	0.3%				0.4%	0.8%	0.0%		0.7%	0.5%		2.9%	
17		0.1%			0.9%	0.1%			0.1%	0.3%		0.2%	1.7%	
18			0.3%		0.2%		0.0%		0.4%	0.5%	0.1%	0.1%	1.6%	
19	1.2%	0.3%	0.1%		0.4%			0.2%	1.0%	0.6%	0.3%	0.7%	4.7%	21.2%
20	0.0%	0.0%	0.1%	0.1%	0.1%	0.2%							0.5%	
21			0.3%		0.3%	0.1%	0.3%	0.1%					1.3%	
22	0.3%				0.5%	0.3%	1.6%	0.3%	0.3%	0.2%			3.4%	
23		0.1%		0.6%	0.2%	0.3%	2.0%	0.6%	0.4%	0.8%	0.2%		5.1%	
24						0.1%	0.4%	0.6%					1.0%	
Total	1.9%	0.9%	1.2%	0.7%	3.0%	2.7%	5.7%	3.3%	2.8%	4.8%	1.1%	1.4%	29.6%	
Peak Periods	1.6%	0.8%	0.7%	0.7%	2.5%	1.9%	5.4%	1.9%	2.8%	4.7%	1.1%	1.0%	25.0%	

The hours in the solid block (hours ending 16 to 23, all months) total 21.2% of the substation peaks, the hours in the lighter box (HE 10 to 11, June to October) total five percent (5.0%) of the peaks. Combined with the weekday-specific hours, these hours cover 96.6% of the peaks and all the hours that contribute more than one percent (1%) of the substation peak loads.

From these data, we constructed a distribution allocator as the weighted class contribution to average load in the various blocks of hours that include most of the substation annual peak loads. This allocator reflects the occurrence of substation loads (in descending order) late weekday evenings in August to October, in the midday hours of weekdays throughout the year, afternoon and evenings throughout the year, late weekday evenings in January to April, and late mornings June to October. A total of about one in seven annual hours receive some weight. As shown in Table 10, each hour in late August–October weekday evenings is weighted 4.5 to 20 times as much as the other hours.

Table 10: Hours for Distribution Demand Allocators

Total Allocation	Time Period	Hourly Allocation
35%	M-F, HE 20-22, Aug-Oct	0.72%
25%	M-F, HE 12-15, 12 months	0.10%
25%	All days, HE 16-23, 12 months	0.03%
10%	M-F, HE 20-22, Jan-Apr	0.15%
5%	All days, HE 10-11, June-Oct	0.04%

2.6.5. Secondary Distribution

The secondary demand allocator is the same as primary, excluding the load of the primary classes.

Table 11 shows the derivation of the class distribution allocators. The computation is similar to that for the generation allocator, using the distribution load factor for each tariff class, computed as the ratio of weighted average load in the distribution peak hours to the tariff's average load during the year. The tariffs served at transmission voltage do not contribute to distribution load, and tariffs served at primary voltage do not contribute to secondary load.

The load factor for the TOU-P class is greater than one hundred percent (100%); at least in the year for which PREPA had data, this class's loads were lower in the hours with substation peaks than in the year on average.

Table 11: Distribution Allocators

Tariff	Class	Voltage	Load Factor	2014 Sales GWh	Implied MW		Allocators	
					Primary	Sec	Primary	Sec
RH3	R	S	88.4%	21.1	2.7	2.7	0.16%	0.25%
RFR	R	S	81.2%	246.8	34.7	34.7	2.04%	3.15%
LRS	R	S	81.2%	570.3	80.1	80.1	4.71%	7.29%
GRS--Discount	R	S	80.2%	433.5	61.7	61.7	3.62%	5.61%
GRS	R	S	92.8%	4,905.6	603.3	603.3	35.43%	54.85%
GSS	C/I	S	90.0%	2,165.3	274.8	274.8	16.14%	24.99%
GSP	C/I	P	85.9%	4,497.9	597.6		35.10%	
GST	C/I	T						
TOU-P	C/I	P	113.0%	7.6	0.8		0.04%	
LIS	C/I	P						
PPB	C/I	T	98.4%	1.4	0.2		0.01%	
TOU-T	C/I	T						
GAS	Agr	S	83.2%	26.4	3.6		0.21%	
Lights/Unmetered		S	100%	17.5	2.0	2.0	0.12%	0.18%
Lights/Unmetered		S	80.0%	258.0	36.8	36.8	2.16%	3.35%
LP-13		P	40.0%	2.7	0.8		0.04%	
PLG 424		S	60.0%	19.4	3.7	3.7	0.22%	0.34%
System Total				17,234.7	1,702.7	1,099.8	100.0%	100.0%

2.6.6. Meters

Utilities install different types of meters for different types of customers. The cost of meters tend to rise for:

- higher voltage delivery,
- higher capacity (in kVA or kW),
- three-phase, rather than single-phase, power delivery, and
- more complex data collection (demand measurement, TOU metering).

Various utilities track the cost of the meters used by each class, track the mix of meters used by each class, or estimate the mix of meters used by each class based on recent installations or sampling. In the latter cases, a provisional cost of meters for each class is estimated by multiplying the class's number of each type of meter by a measure of the cost of that meter type, such as current prices. The total of those provisional estimates must then be reconciled to the actual cost of meters in service. As a result, the important result of these analyses is a set of relative meter costs by class.

Table 12 summarizes the relative meter weights that Navigant proposed for PREPA in 2016.[22] The trend of metering costs generally rises with customer size, with voltage, and TOU metering.

Table 12: Relative Meter Costs in Navigant COSS

Tariff Code	Voltage	Navigant Estimate
Metered Lighting (PLG)	S	0.86–1.07
Residential	S	1.00
GS Secondary (GSS)	S	1.15–1.45
GS Primary (GSP)	P	1.41–1.43
GS Transmission (GST)	T	1.52–1.57
Lighting Primary (LP-13)	P	1.33
Agriculture (GAS)	S	1.34
TOU Primary (TOU-P)	P	1.57
TOU Transmission (TOU-T, LIS)	T	1.48–1.57
IPP Transmission (PPBB)	T	19.67

The values in Table 12 do not show as much variation as we would expect, from other COSSs we have seen. Navigant was not able to explain how it developed these meter cost ratios.[23] It does not appear that PREPA maintains data on meter costs by class or type of meter. Hence, we needed to turn elsewhere for meter weights.

In Table 13, we present the relative meter costs from six utility COSSs. The relative meter costs will vary across utilities due to differences in the composition of their rate classes, as well as the utilities' decisions about meter selection and perhaps cost accounting.

[22] CEPR-AP-2015-0002, Schedule G-1, G-2,Tab G-5e.

[23] CEPR-AP-2015-0002, CEPR-PC-11-01

Table 13: Meter Weights Reported by Various Utilities

	Secondary				
	Residential	Small GS	Large GS	Primary	Transmission
PSNH	1.00	1.00	4.70	11.53	87.36
National Grid RI	1.00	3.01	4.30	9.29	
PacifiCorp WA	1.00	1.00	2.15	103.00	268.79
PPL Energy	1.00	1.79	9.95		392.54
MidAmerican	1.00	1.56	2.99	72.88	278.66
El Paso Electric	1.00	1.43	11.98	191.05	596.90
Average	1.00	1.63	6.01	77.55	324.85
Median	1.00	1.50	4.50	72.88	278.66

We apply the median weights for the residential and primary general service tariffs, and the average of the median large and small secondary general service tariffs (3.0). We also assume that the meters for the secondary metered lighting tariffs cost the same as the residential meters, that the LP-13 meters have the same cost as other primary meters (73), and that PREPA transmission meters have a cost that are the average of the median primary and transmission meter costs from the sample, or 175 times the residential cost.[24] We assume that the transmission-voltage meters serving the IPPs cost 279 times as much as the residential meters.

Table 14: Meter Weights Used

Tariff Code	Weight
Metered Lighting (PLG)	1
Residential	1
GS Secondary (GSS)	3
GS Primary (GSP)	73
GS Transmission (GST)	175
Lighting Primary (LP-13)	73
Agriculture (GAS)	4.5
TOU Primary (TOU-P)	73
TOU Transmission (TOU-T, LIS)	175
IPP Transmission (PPBB)	279

[24] Some of the other utilities may have transmission customers that are much larger than PREPA's transmission customers.

2.6.7. Services

Services are generally treated similarly to meters. The cost of a customer's service drop varies with a number of factors that differ by class: customer load (which affects the required capacity of the service), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer), and whether the customer requires 3-phase service. In general, these factors will tend to rise in the same manner as the meter costs, with customer size and voltage.

The utility portion of service costs also varies among utilities, depending on the utility's interconnection policies. If the utility requires new customers or developers to install the service drops for some classes or in some situations, the book cost of services will be low or zero, at least for some classes.

Our review of a couple of COSSs in which the utilities estimate a service-drop costs for a range of customer types indicates that the costs of services rise more slowly than the costs of meters. In Table 15, we compute the service weight by assuming the excess of service-drop cost for a class (over the residential class) is one third of the excess of the meter weight for that class. For example, the meter weight for GSP is 73, or 72 more than residential. One third of 72 is 24, so the GSP service weight is 25 (24 + 1).

Table 15: Summary of Meter and Service Weights

Tariff Code	Meter Weight	Service Weight
Metered Lighting (PLG)	1	1.0
Residential	1	1.0
GS Secondary (GSS)	3	1.7
GS Primary (GSP)	73	25.0
GS Transmission (GST)	175	59.0
Lighting Primary (LP-13)	73	25.0
Agriculture (GAS)	4.5	2.2
TOU Primary (TOU-P)	73	25.0
TOU Transmission (TOU-T, LIS)	175	59.0
IPP Transmission (PPBB)	279	93.7

The number of services is smaller than the number of customers in the residential class (and to some extent small commercial), since several customers can share a service drop in multi-family housing and some commercial buildings.

Table 16 shows the estimation of the number of service drops required for PREPA's residential customers.

Table 16: Estimate of Residential Services

Units in Structure	Assume Average	Housing Units	Buildings and Services
1-unit, detached	1	1,069,670	1,069,670
1-unit, attached	1	179,133	179,133
2 units	2	54,899	27,450
3 or 4 units	3.5	52,411	14,975
5 to 9 units	7	65,701	9,386
10 to 19 units	14.5	43,286	2,985
20 or more units	50	90,304	1,806
Mobile home	1	6,312	6,312
Boat, RV, van, etc.	1	86	86
Total		1,561,802	1,311,802

Our estimate is that the number of services is about eighty-four percent (84%) of the number of customers. Hence, we reduce the residential service weight (from Table 15) to 0.84.

2.6.8. Allocation of Other Retail Costs

The retail function includes meter reading, billing, and customer service, along with other smaller cost components. These costs tend to rise with the size of the customer (since utilities spend more time and attention on a large customer than a small one) and the complexity of billing. We use the meter weights for the retail allocation.

2.6.9. Overhead Allocations

Overheads are costs that cannot be directly assigned to particular functions, including the capital costs that PREPA records as General Plant in Accounts 389-399 (which includes office buildings and warehouses) and the O&M expenses that PREPA records as Administrative and General (A&G). The 2016 cost-of-service study provided a breakdown of General Plant by account, but did not do the same for A&G.

Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For example, pension expenses and other employee benefits vary with the number of employees and/or salaries.

On the other hand, many of the standard A&G accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the law department, purchasing, and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance), and most by a mix of labor, fuel procurement, non-fuel expenses, and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety, and many other activities.

Rather than consider these overhead costs separately on an account-by-account basis, which is the approach typically used by utilities, Navigant functionalized and classified General Plant and A&G on a single labor factor, ignoring how overhead costs support all other aspects of utility operation.

We allocate half of the overhead costs on the labor allocator (to reflect employee benefits and taxes) and the remainder equally on plant in service (to reflect insurance and especially all the management time devoted to planning, siting, financing, regulation, and public relations associated with generation, transmission and distribution) and on fuel and purchased power (to reflect the associated planning, regulatory, financing, negotiation, and legal expenses).

PREPA continues to list the Puerto Rico Energy Bureau Assessment of $5,800,000 as a subsidy, even though it is an overhead expense. We allocate the Energy Bureau expense 50% on energy and 50% on plant in service, to spread the expense over the range of costs that may be affected by the Energy Bureau's oversight.

2.7. Adjustment for CILT and Subsidies

Regardless of the manner in which the costs are attributed to the various classes, the Puerto Rico government has specified that some tariffs, or individual customers within tariffs, should be charged less than their allocated costs. These provisions fall into two groups: limited amounts of free service for each municipality in lieu of taxes and explicit subsidies for vulnerable populations and preferred loads.

2.7.1. Contributions in Lieu of Taxes (CILT)

PREPA reports that CILT totaled $70 million in FY 2017/18. For most utilities, CILT represents payments (or credits) to municipalities that would otherwise be assessed on some measure of the value of the utility's plant in each municipality, such as in the form of a property tax. Hence, we allocate the CILT in proportion to plant in service.

Unlike actual property taxes, CILT is not an additional expenditure, but a reduction in the revenue collection targeted for specific municipal customers. We therefore credit the CILT revenue to the rate tariffs for which the municipalities receive credits. Table 17 summarizes the portion of CILT attributable to each tariff.[25]

Table 17: Summary of CILT Credits by Tariff

Tariff	Energy (MWh)	Revenue Credit ($1,000s)
GSS	84,602	$30,457
GSP	173,299	$39,166
GST	6,595	$1,411

Table 18: Summary of CILT Charges by Tariff

	Plant in Service Allocator	CILT Allocation
Residential	40.34%	$28,658
Commercial and Industrial		
Secondary	14.03%	$9,965
Primary	24.67%	$17,522
Transmission	13.06%	$9,278
Agriculture	0.19%	$134
Lighting & Unmetered	7.71%	$5,478

2.7.2. Subsidies

PREPA counts 15 types of intentional rate subsidies, including the following eight that are clearly subsidies to protect vulnerable customers or encourage particular activities:[26]

- free electricity and other services provided to municipalities for public lighting and related functions;[27]

[25] Table 17 relies on the CILT energy by municipality in PREB-PREPA 1-16a, divided among tariffs based on the split by municipality in CEPR-PC-01-25 in CEPR-AP-2015-002.

[26] Energy Bureau Requirement of Information (ROI) to PREPA 01-04.

[27] Public lighting services will be provided without charge and the costs will be collected in the subsidy charge, while the remainder of municipal electric consumption are subject to an energy cap for each municipality and the costs will be collected in the CILT charge.

- rates for three residential tariffs (RFR, RH3, and LRS) that are less than the rate for standard residential service (GRS);
- the residential fuel-oil credit for customers on the LRS and RH3 tariff, and those on GRS tariff code 111 (students, the elderly and the handicapped using less than 425 kWh in the month);
- discounts for fixed amounts of energy for residential customers on life-preserving equipment; and
- discounts for two types of business—downtown businesses and hotels—which appear to be designed, at least in part, to increase sales.[28]

These eight provisions are structured to reduce the revenue requirements for the specific classes.[29] We therefore reduce the allocation of costs to the classes receiving the benefit, and reallocate the revenue requirement to all classes, except that the we do not reallocate costs to the lighting, RFR, RH3, and LRS classes, which are entirely or mostly subsidized.

As explained in Section 2.6.2, we concluded that three rate provisions that PREPA considers to be subsidies (billing on the GRS rates for churches and social welfare organizations, condominium common areas, and rural aqueducts) are actually just a mismatch between the definition of loads. We exclude them from our consideration of subsidies.

PREPA counts as subsidies another four items that do not appear to be subsidies for the purpose of cost allocation: the Energy Bureau assessment, the irrigation district deficit, the Direct-Debit billing discount, and the agricultural rate.

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[28] Act 22-2016 notes that "although the energy subsidy granted to the hotel sector has helped it bear high energy costs, such sector has increased its energy consumption after being granted the subsidy" and "With the purpose of revitalizing the tourist industry as a source of jobs and income for our people, the Electric Power Authority is hereby authorized to grant a credit on the monthly power consumption bill to every hotel, condo-hotel or parador duly qualified by the Puerto Rico Tourism Company." Act 169-2009 established the downtown commercial discount enable existing businesses to remain in business and to "foster [the] maximum development" of urban centers.

[29] To the extent that the business discounts increase sales and revenues, they benefit all the other classes.

- The Energy Bureau Assessment is not a subsidy, but an operating cost. We include it in overhead expenses and allocate it on two broad allocators, energy and plant in service.
- The irrigation district is not a rate reduction or credit on any customer's electric bill. Instead, it represents the difference between the cost of operating the irrigation district and the revenues from irrigators. As noted above, this burden appears to be associated with PREPA's acquisition of the hydro facilities and is thus a generation-related cost.
- The Direct-Debit billing discount is not a subsidy. It is a rate design feature intended to reflect a reduction in PREPA's costs and should be taken into account (or modified) in designing the residential rates.[30]
- The agricultural rate (GAS) is not required to include a discount by law. It is lower than the GSS rate under which non-agricultural businesses are billed, but that may be a cost-based differential, or an accident of historical ratesetting. Whether the Energy Bureau wishes to maintain this historic practice will be determined by the Energy Bureau's subsequent decision regarding the final cost allocation.[31]

Table 19 provides a summary of the subsidies we have identified, from PREB-PREPA-01-14.

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[30] PREPA agreed to recategorize the direct debit as an operational expense rather than a subsidy in CEPR-AP-2015-0001 (Oct 31, 2016 Conference Call), but still lists it as a subsidy.

[31] The Energy Bureau may decide to set the cost allocation for any particular class below the allocated cost determined in this cost of service study, whether for purposes of gradualism, prevention of rate shock or long-term provision of support for a particular consumer group (such as the agricultural sector).

The RH3 tariff is also not required by law and could be treated similarly to the treatment of the GAS tariff. The RH3 tariff is generally accepted as a subsidy for that particular group of public-housing customers, and the discount has explicitly been recognized as a subsidy.

Table 19: Summary of Subsidies (FY 2018, $1,000s)

Category	Total	RH3	RFR	LRS	GRS	GSS	GSP	GST	Lighting
Life-Preserving Equipment	$1,427	$5			$1,422				
Low-Income Consumer Subsidies									
LRS Tariff	$8,926			$8,926					
RH3 Tariff	$624	$624							
RFR Tariff	$28,712		$28,712						
Hotel 11% Discount	$3,833					$10	$2,627	$1,195	
Residential Fuel Subsidy	$16,897	$321		$7,542	$9,034				
Downtown 10% Commerce Subsidy	$1					$1			
Public Lighting	$108,588								$108,588
Total	$169,007								

We allocate these subsidies to the other classes in proportion to sales, excluding the fixed block of the RFR tariff, per current practice, and the energy for unmetered lighting tariffs (rate codes 01–61), since most of the lighting load is municipal and is not billed.[32]

3. Allocation Results

3.1. Aggregate Cost Allocation

Table 20 shows the allocation of costs by major tariff schedule. We excluded a number of small classes, including public lighting.

Table 20: Initial Cost Allocation

Class	Residential									
Tariff	RH3	RFR	LRS	GRS	GSS	GSP	GST	LIS	TOU-T	GAS
Production Energy	$ 2,672,689	$ 31,201,315	$ 72,100,517	$ 674,960,072	$ 273,735,412	$ 538,872,500	$ 353,252,111	$ 23,182,671	$ 66,942,371	$ 3,341,057
Production Demand	$ 574,593	$ 6,707,874	$ 16,470,590	$ 140,677,776	$ 62,868,832	$ 126,978,580	$ 76,544,186	$ 4,475,447	$ 13,567,011	$ 887,855
Transmission	$ 305,570	$ 3,567,265	$ 8,759,103	$ 74,812,816	$ 33,433,812	$ 67,527,547	$ 40,706,402	$ 2,380,055	$ 7,214,973	$ 472,164
Dist - Primary	$ 595,545	$ 6,952,468	$ 17,488,571	$ 145,104,767	$ 59,962,628	$ 117,122,596				$ 791,624
Dist - Secondary	$ 224,430	$ 2,620,020	$ 6,590,525	$ 54,682,374	$ 22,596,769	-				$ 298,322
Services	$ 58,670	$ 354,111	$ 1,481,006	$ 9,708,814	$ 3,011,693	$ 6,844,487	$ 913,194	$ 2,922	$ 27,950	$ 46,997
Meters and Retail	$ 495,633	$ 2,991,473	$ 12,511,311	$ 82,018,559	$ 14,134,621	$ 19,801,770	$ 2,600,896	$ 8,322	$ 79,604	$ 191,159
Public Lighting										
Overheads	$ 223,438	$ 2,221,986	$ 6,112,600	$ 49,644,757	$ 18,115,872	$ 32,952,735	$ 13,381,118	$ 814,345	$ 2,405,047	$ 238,491
PREB Assessment	$ 7,958	$ 90,098	$ 219,959	$ 1,941,335	$ 788,671	$ 1,466,080	$ 798,278	$ 50,673	$ 148,158	$ 10,132
Subtotal	$ 5,158,525	$ 56,706,611	$ 141,734,181	$ 1,233,551,269	$ 488,648,311	$ 911,566,294	$ 488,196,185	$ 30,914,436	$ 90,385,113	$ 6,277,800
CILT Credit					$ (30,456,573)	$ (39,165,595)	$ (1,411,125)			
CILT Charge	$ 89,461	$ 83,532	$ 2,413,358	$ 22,592,354	$ 9,162,509	$ 19,032,507	$ 13,804,716	$ 905,954	$ 2,616,036	$ 111,832
Subsidy Credit	$ (950,215)	$ (28,711,642)	$ (16,468,329)	$ (10,455,268)	$ (11,715)	$ (2,627,445)	$ (1,194,649)			
Subsidy Charge	$ 212,851	$ 198,746	$ 5,742,029	$ 53,753,294	$ 21,800,075	$ 45,283,459	$ 32,845,135	$ 2,155,509	$ 6,224,255	$ 266,079
Total Allocation	$ 4,510,621	$ 28,277,246	$ 133,421,239	$ 1,299,441,649	$ 489,142,607	$ 934,089,220	$ 532,240,262	$ 33,975,898	$ 99,225,405	$ 6,655,712
Average $/kWh	$0.213	$0.115	$0.234	$0.243	$0.226	$0.208	$0.163	$0.159	$0.160	$0.252

[32] In its updated data filing, PREPA should specifically exclude the municipal lighting energy.

3.2. Netting out Revenue from Adjustment Mechanisms

The allocation results above (updated to current prices and sales) will include all the costs of service allocable to each tariff class. Some of those allocated costs are actually recovered through four adjustment mechanisms:

- Rider FCA—Fuel Charge Adjustment
- Rider PPCA—Purchased Power Charge Adjustment
- Rider CILTA—Contributions in Lieu of Taxes (CILT) –Municipalities
- Rider SUBA-HH—Help-to-Humans Subsidies
- Rider SUBA-NHH—Non-Help-to-Humans Subsidies

These riders are all assessed on a single rate per kWh of sales for all eligible customers, other than the fixed-price block of the RFR rate.

Once a portion of PREPA's debt is restructured, it is likely to be recovered through a reconciling charge that will be collected through another rider. As that occurs, those revenues should also be netted from the allocated revenues.

Error! Reference source not found. nets from total allocated costs those costs in the 2016 COSS that would have been collected through riders, under current rules.

Table 21: Allocation of Base Rates

lass		Residential					Commercial and Industrial			Agriculture
ariff	RH3	RFR	LRS	GRS	GSS	GSP	GST	LIS	TOU-T	GAS
otal Allocated Cost	$4,510,621	$28,277,246	$133,421,239	$1,299,441,649	$489,142,607	$934,089,220	$532,240,262	$33,975,898	$99,225,405	$6,655,712
nergy w/o RFR fixed block	0.126%	0.118%	3.398%	31.805%	12.899%	26.794%	19.434%	1.275%	3.683%	0.157%
Fuel	$1,407,113	$1,313,866	$37,959,383	$355,352,069	$144,115,851	$299,359,714	$217,132,494	$14,249,628	$41,147,281	$1,758,995
PPA	$50,044	$46,728	$1,350,031	$12,638,146	$5,125,501	$10,646,770	$7,722,348	$506,790	$1,463,409	$62,559
CILT	$89,461	$83,532	$2,413,358	$22,592,354	$9,162,509	$19,032,507	$13,804,716	$905,954	$2,616,036	$111,832
Subsidy	$212,851	$198,746	$5,742,029	$53,753,294	$21,800,075	$45,283,459	$32,845,135	$2,155,509	$6,224,255	$266,079
'otal Riders	$1,759,469	$1,642,871	$47,464,801	$444,335,864	$180,203,935	$374,322,450	$271,504,693	$17,817,881	$51,450,982	$2,199,466
ase Cost Allocation	$2,751,152	$26,634,375	$85,956,438	$855,105,785	$308,938,672	$559,766,769	$260,735,569	$16,158,018	$47,774,423	$4,456,246

4. Directions for Future COSSs

We have performed a cost allocation study using the data reasonably available and conceptual approaches that meet or exceed current standards, but the COSS described in this report will need to be updated to reflect five categories of changes:

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

Improved cost allocation methods, and the supporting data, can be integrated into the broader efforts to improve the regulation of the electric system. The Energy Bureau should keep this in mind during other proceedings to take advantage of such synergies.

4.1. Updating Cost and Sales Data

For the purpose of consistency, this report relies almost entirely on data from the 2016 COSS filed in the 2015 rate case. Even in normal times, this data should be updated before being used in setting rates for 2021 or beyond. Those updates would include plant in service by account (or groups of accounts), fuel, purchased power, other operating expenses, the cost of debt, tariff-class data on customer number and sales, and other items.

Of course, these have not been normal times for PREPA, as discussed in Section 4.3. At this point, it is not clear how well PREPA can estimate its costs for a future year.

4.2. Improving PREPA Input Data

As noted through the sections above, PREPA is missing some important data that other utilities routinely compile. As a result, we have needed to borrow data from other utilities, or assemble estimates from whatever data are available. For example, we used tariff-class load research data from different years and needed to interpolate the load shape for one tariff class, as discussed in Section 2.6.2. As opportunities arise (in terms of funding and staffing), PREPA should assemble these data. Some of the additionally desirable information and data has been mentioned throughout the cost of service study section, including the following:

- Consistent hourly load data for all major classes, from the same year, either through a new and more complete load-research sample or use of data from advanced metering.

- Improved information on the split of equipment used at the primary distribution level versus the secondary distribution level, probably from analysis of a sample of representative sections of the system (urban, rural, suburban; residential, commercial).
- Estimates of the relative costs of meters and service lines by class, again probably by way of a sample.
- A loss of energy expectation study that would more accurately characterize the year-round reliability needs used to allocate generation capacity costs (and also help with resource planning).
- The costs of the transmission equipment that connect individual generators to the broader shared network and generation-rich areas (such as the south coast) to load centers.
- Data on the timing of maximum loads and maximum reliance on various parts of the transmission system.
- Data on peak loads on distribution feeders and other high-load hours on feeders and substations, and how those load patterns interact with decisions on equipment sizing decisions, once PREPA is in a position to make such decision without crippling constraints on funding and timing.
- Contribution of PREPA hydro and renewable PPAs to reliability.

Most of these data would be useful beyond cost allocation, such as for rate design and broader system planning purposes.

4.3. The Effects of Restructuring and Recovery

PREPA is undergoing substantial change in its circumstances, which will affect numerous aspects of the COSS, including:

- Recovery of equipment and load from the 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 system.

These changes will require periodic reworking of the COSS.

4.4. Bureau Policy Decisions

In addition to the changes to the PREPA system as a result of system recovery, restructuring and improvement, the Energy Bureau may change portions of the ratemaking process. For example:

- The Energy Bureau may determine that some costs (such as subsidies or CILT) should be recovered from a different set of classes than we assumed.
- The Energy Bureau may create additional tariff classes, such as to formalize the special ratesetting for houses of worship, or realign customer classes to better reflect cost difference among classes, such as differentiating the GSS and GSP classes by customer size.

4.5. Further Modernization of the COSS

Embedded cost of service studies, such as the one we have performed here, have evolved significantly over the last 50 years. The Puerto Rico Energy Bureau should consider how to improve the techniques used in this study and enable more cutting-edge approaches that reflect modernized system planning and the effects of new technology, such as battery storage and demand response.

While we have endeavored to reflect modern allocation approaches, depending on the additional data available (on the use of various types of transmission and distribution, hourly usage by tariff classes, and the correlation of customer loads by tariff on each transmission and distribution element and on high-stress and high-cost system load hours) and other studies performed, future cost of service studies could incorporate a wide range of improvements, such as (1) hourly classification and allocation approaches that allow for more comprehensive and accurate treatment of costs and (2) reflection of PREPA's future equipment sizing guidelines.

5. Stranded Costs

5.1. Introduction

Under the Bureau's Regulation for Wheeling, pursuant to Act 73-2008 and Act 57-2014, a variety of competitive service providers (CSPs)—including electric power service companies, microgrids, energy cooperatives, municipal ventures, large industrial and commercial consumers, and community solar and other demand aggregators—will be allowed to participate in electric wheeling.[33] Each delivery customer that procures electricity through wheeling will pay its service provider for generation services but will no longer pay PREPA for generation services. If PREPA could simply avoid paying for the generation services no longer needed to serve the delivery customers (e.g., by ceasing to pay for fuel, purchased power, capital and operating costs; transferring those responsibilities to the CSP; or selling the power resources at cost into a wholesale power market), billing of the competitive customers would be simple. The PREPA energy charge would be removed from the delivery customer's bill, and the competitive service provider's charge would be added.

Unfortunately, PREPA cannot avoid all those costs as customers switch to competitive suppliers. To the extent that PREPA needs to generate less energy, it will be able to burn less fuel and may be able to reduce maintenance as plants are less heavily loaded. Lower responsibility for meeting load may also allow PREPA to:

- retire more existing generating units due to loss of generation load to competitive supply, reducing operating and maintenance costs and allowing PREPA to reuse or sell the plant site;
- avoid the capital costs of rehabilitating plants, as well as the costs of running the plants;
- avoid building or purchasing power from new units, avoiding capital and operating costs; and
- sell some generation capacity and/or output to competitive service suppliers, to serve their customers.

In most cases, the costs of PREPA's existing power plants and purchase contracts will not be the same as the costs avoided by the loss of generation load. The avoided costs may be less than the lost generation cost recovery from the competitive customers, resulting in stranded costs.[34] Or the avoided costs may be greater than the lost generation cost recovery from the competitive customers, resulting in stranded benefits.

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[33] Regulation 9138, Regulation on Electric Wheeling, CEPR-MI-2018-0010, September 16, 2019; Wheeling Rule § 1.03.

[34] Some of the existing debt incurred due to the power plants is likely to be recovered through a non-bypassable restructuring charge.

Whether restructuring results in a gain or a loss depends on the costs of PREPA's generation resources and the value of those resources. If generation investments have mostly been paid off, if power purchase agreements are inexpensive, if PREPA can save a lot of operating expenses by retiring resources, or if PREPA can reuse or resell the generation at a profit, the stranded costs will be negative. If the opposite conditions apply—investments were expensive and have not been paid off, legacy power purchase agreements are expensive, and PREPA cannot save much by retiring or repurposing the resources—costs will be stranded.

In most of the states that opened their electric systems to generation competition, the utilities determined the value of their generation assets by auctioning them off to third parties and the value of their purchased-power contracts by some combination of assigning them to third parties, negotiating contract buyouts, or computing annual avoided costs as the difference between the contract costs and market values.[35]

This process was facilitated by the existence of competitive wholesale energy markets (including some forward markets), which allowed counterparties to estimate the future value of owning and operating the resources.

In the absence of divestiture, alternative methods for estimating stranded costs include:

- comparison of projected revenues and costs and present-valuing the projected cash flow, or
- extrapolating the sales prices of other similar resources (comparables).

The first approach requires a market to define the projected revenues and costs. The second approach requires comparable sales.

Puerto Rico does not have a competitive wholesale market, and the form of any future market is not yet clear. The uncertainties regarding future market structure include the following issues:

- How competitive service suppliers would firm up the energy supply they offer to customers.

[35] This description applies (with some minor exceptions and delays) to Massachusetts, Connecticut, Maine, New Hampshire, Rhode Island, New York, Texas, California, Montana, the District of Columbia and parts of Illinois, New Jersey, Pennsylvania and Maryland.

- How CSPs would dispose of any excess energy they may have available in a particular hour.
- How CSPs will be assessed responsibility for installed generation capacity, operating reserves, and other ancillary services.
- How PREPA will be able to sell energy or capacity to the competitive service suppliers (or their customers) to back up their renewable resources.
- Whether PREPA will be able to sell underutilized generation resources to suppliers.
- Whether the competitive suppliers will be allowed to own fossil generation to firm up their supply.
- Who will own or operate PREPA's current generation fleet and future generation.
- Who will coordinate generation commitment and dispatch.

Thus, any estimate of stranded costs at this point must be considered to be provisional, subject to modification as the nature of the competitive market is resolved.

There have been many sales of generation resources since the late 1990s, first by the utilities that divested generation as part of restructuring in the late 1990s and early 2000s, and then by merchant generators selling plants to one another and to the remaining vertically integrated utilities. Unfortunately, those sales are not easily mapped onto the PREPA units, for three reasons. First, market conditions in 2020 in Puerto Rico are very different than at other times and in other places. For example, in 2000 in New England or the Mid-Atlantic, merchant generators could purchase utility power plants and sell into an existing energy market and some sort of transitional capacity market. Oil prices were comparable to gas prices, so oil-fired units were roughly as valuable as gas and dual-fueled units, all else equal.

Second, sales of power plants have often included bundles of resources, including some mix of different vintages; steam, combustion turbine, combined-cycle and hydro capacity; of coal, oil and gas-fired units; and sometimes both owned resources and power purchases. Teasing out the value of an individual unit (or group of similar units) from a larger bundle can be very difficult.

For the most part, we will extrapolate the remaining value of PREPA's generation resources from comparable sales. These values should be revisited once more information is available regarding the future of Puerto Rico's market structure.

It is important to remember that our estimates of stranded costs are based on what we know today. These estimates could change due to development of the Puerto Rico power markets (e.g., creation of a mechanism for hourly sales of energy between PREPA and competitive suppliers, establishment of requirements for capacity and operating reserves) and market conditions (in particular, the impact of the COVID-19 recession on demand and the extraordinary uncertainty in future oil prices). The development of a robust wholesale energy market with significant trading to set a benchmark on prices is probably some years into the future. Since Puerto Rico is an island, with costs and other conditions substantially different from the various portions of the continental United States, sales prices for resources elsewhere may not carry over to Puerto Rico, limiting the ability to extrapolate value from comparable sales. Some components of stranded costs may be amenable to final determination, such as when PREPA retires or sells a resource, but most will need to be updated over time, through a reconcilable non-bypassable stranded-cost rider.

We assume that transmission, distribution and retail functions (e.g., metering, billing) will remain monopoly services, probably under PREPA ownership, but possibly under the management by a third party. We expect that all customers will still need to pay PREPA for those services, so none of those costs will be stranded.

5.2. Estimated Value of PREPA Generation Assets

5.2.1. Steam Units and the Aguirre Combined-Cycle

Based upon the IRP proposals and the performance of the plants, we assume that the steam units at Aguirre, San Juan 1-4, Palo Seco, and Costa Sur will be retired as soon as new generation resources can be brought on line. Some IRP cases assume that at least one Aguirre combined-cycle unit will remain in service for reserves and emergency support.[36] The Aguirre combined-cycle units are no more efficient than most of the combustion turbines or steam plants, and require expensive #2 oil, and thus do not appear to be attractive resources.

Freeing up capacity at these units through reductions in PREPA generation sales may result in the units being retired somewhat sooner (avoiding some O&M costs) but will not result in any sales to the competitive service providers. PREPA will be left with

[36] IRP, page 8-12 and 4-5.

the retired plant sites, which may be sold for redevelopment (perhaps for battery storage for Energy Service Companies, or for industrial development or other non-generation uses), used for development of PREPA generation, or leased to third party developers to build generation for sale to PREPA. Based upon a review of the sales prices for retired generation sites and power plants that were economically marginal and likely to retire in the near term, we estimate a value for these plant sites of $50/kW, which would be about $145 million for the 2,900 MW of steam and $30 million for the 590 MW Aguirre combined-cycle plant.

5.2.2. Frame 5 Combustion Turbines

In the IRP, PREPA assumes that new combustion turbines will be built to "allow PREPA to retire the 18 existing old and unreliable Frame 5 GTs (21 MW each)."[37] On discovery, PREPA and Siemens explained the desire to retire the Frame 5 CTs as follows:

> The Frame 5 Gas Turbines are units that were put in service around 1972, this means that these units have been in service for almost 48 years. This is an extraordinary length of time for this type of units and they should have been retired in the early 2000's.
>
> Gas Turbine economic life is considered to be about 25 years considering their operating conditions characterized by frequent starts and stops, the design and technological obsolescence, Thus these units have been in service for about twice their economic life and Moreover, they have operated under harsh conditions both from an environmental point of view (marine environment) and the electric system point of view due to frequency excursions voltage fluctuations typical of smaller systems. These facts make these units unreliable (all components are well beyond their design life), inefficient which can be a factor when fuel deliveries are limited due to post hurricane conditions and in general not worth investing in extending further its life due to its obsolescence and general condition of the units.[38]

The focus on the alleged 25-year design life of these units is somewhat confusing, since most of the Frame 5 and other combustion turbines from the early 1970s are still operating. The EIA Form 860 database for 1990 listed 687 combustion turbines that

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[37] *Id.*, page 1-9. The same technology is referred to as combustion turbines (CTs) and gas turbines (GTs), whether they use liquid or gaseous fuel.

[38] PREB-PREPA-09-02 in CEPR-AP-2018-0001.

entered service in various US states in 1970 to 1974. Since those units were only about 16 to 20 years old in 1990, the 687 units are probably close to the total installed.[39] The 2018 version of the database lists 438, or 64% of those units still being in service, at 44 to 48 years of age.[40] The 2018 report lists 221 other combustion turbines that entered service in 1957 to 1969, over half of the 421 such units listed in 1990.

The generation industry does not consider Frame 5 turbines from the late 1960s and early 1970s to be generically obsolescent in design and technology, or to have been in service for beyond their economic life. For example, the *Combined-Cycle Journal* praised the old Frame 5 units as follows:

> If the energy industry has an iconic gas turbine (GT), the consensus view probably would be GE Power & Water's durable Frame 5. It certainly has stood the test of time: The first unit in this model series shipped from the OEM's Schenectady factory 55 years ago and Frame 5s are still being built today…
>
> Frame 5s continue to serve their owners well—even engines dating back to the early 1960s. And in view of the high value placed on GTs that can "fill in" for intermittent renewables and provide other ancillary services, the operating lives of many engines are being extended. With a nominal 8- to 10-min start, Frame 5s satisfy the fast-start requirement grid organizations demand, with time to spare in some cases. Although rated capacities and efficiencies of the early units, in particular, are relatively low by today's standards, a paid-for asset capable of operating on low-cost gas and/or No. 2 (distillate) fuel oil for a few hours when required has a place in the generation mix.
>
> As the value of Frame 5s increases in many locations, investments to assure high availability and starting reliability—and possibly to reduce emissions—may be prudent.[41]

Nova Scotia Power, with roughly the same peak load as PREPA, limited import transmission capacity, and a high penetration of wind generation (almost 30% of firm

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[39] This count excludes CTs that are part of CC plants. At least two Frame-5 CTs from the 1960s are still in service as part of CCs.

[40] Some of the CTs that were installed in the early 1970s were intended to provide black-start capability for steam units; as the older coal-, oil-, and gas-fired steam units have been retired, many of their black-start CTs have also been retired.

[41] https://www.ccj-online.com/3q-2012/special-report-the-venerable-frame-5-gas-turbine/

peak load), has seven combustion turbines of 24 to 33 MW, dating from 1971 to 1976. Over the last several years, in addition to routine O&M and replacements, Nova Scotia Power received regulatory permission to spend:

- $9.6 million to replace the generator and refurbish the rest of Burnside #4, to restore it to service a decade after it failed.
- $2.9 million to replace the Burnside #2 generator.
- $2.6 million to refurbish the generator and $2 million more to refurbish the turbine of Burnside #3.
- $2.5 million to disassemble and repair offsite three Burnside turbines.
- $3.8 million for replacement of the Tusket generator, $2 million for an upgrade to the fuel system and $2.1 million for the turbine replacement.
- $0.6 million to replace the Victoria Junction fire-suppression system.

Many of these projects were justified by favorable comparison with the cost of new peaking capacity.

Considering PREPA's continuing need for quick-start reserves and back-up capacity, it seems probable that many of the Frame 5 combustion turbines will continue to operate.

We therefore do not assume the retirement of all the Frame 5 combustion turbines. According to PREPA discovery in the IRP proceeding, of the 18 units, 10 are available, two require minor repairs, four require major overhauls (which appear to be part of the standard maintenance cycle), and two require major repairs.[42] For purposes of this COSS, we assume that PREPA will want to continue to operate 16 of the 18 units.

Our review of the sales of combustion turbines indicates that prices have exceeded $100/kW. We therefore value the Frame 5 CTs at $100/kW. For 16 units of 21 MW each, this would be $33.6 million, plus $2 million in reuse value for the sites of the retired units. This value should be updated once plans for retirement of the Frame 5 units are clearer.

5.2.3. Cambalache Combustion Turbines

The three 83 MW units at Cambalache are not particularly old, having entered service in 1997 and 1998. The Cambalache units are relatively inefficient (11.6

[42] PREB-PREPA ROI 9-02, Attachment 1 in CEPR-AP-2018-0001.

MMBtu/MWh) and inflexible. They require 40 minutes to reach full load or ramp down to zero load, seven hours of runtime before shutdown, and seven hours of downtime before restarting. (IRP Exhibit 4-5) These are not particularly useful units for backing up either the large thermal units or renewable resources. Each unit is about 4% of PREPA's peak load.

A half-dozen power-plant sales in the last few years have been dominated by CTs of roughly the same vintage, 1999 to 2002. Collectively, they include 56 units and 4,800 MW at a dozen plants. While two of the transactions included pre-1975 CTs, those are only about 18% of the units and 5% of the capacity in these sales. In 2018, the 1999–2002 units operated at an average heat rates of about 11.4 MMBtu/MWh and capacity factors averaging about 5%.

These sales are listed in Table 22.[43]

Table 22: Recent Sales of Combustion Turbines

Seller	Buyer	Units	State	Average ISD	MW	Date Announced	$ Million	$/kW
Southwest Generation	PS Colorado	Valmont 7&8	CO	2000.5	82	7/25/19	$19.9	$243
FirstEnergy	Starwood Energy Group	West Lorain 1A&B	OH	1973	120	1/9/19	$144	$264
		West Lorain 2-6	OH	2001	425			
Dayton P&L	Rockland Power Partners	Hutchings 7	OH	1968	25	9/6/17	$241	$235
		Yankee St. 1-7	OH	1969.5	101.3			
		Montpelier 1-4	IN	2001	236			
		Tait 1-7	OH	2002	665			
Dynegy	Rockland Capital	Lee 1-8	IL	2001	625	7/12/17	$180	$288
Dynegy	LS Power	Troy 1-4	OH	2002	750	2/27/17	$480	$319
		Armstrong 1-4	PA	2002	753			
Rockland Capital	Carlyle Group	Tilton 1-4	IL	1999	180	12/14/16	$400	$395
		Rocky Road 1-4	IL	1999.3	349			
		Elgin 1-4	IL	2002	484			
Simple Average								$291
MW-Weighted Average								$305

The average price of those sales was about $300/kW. PREPA projects a heat rate for Cambalache of about 11.6 MMBtu/MWh, very similar to the average of the similar-

[43] The data are from the Power Finance & Risk Generation Sale Database, http://www.powerfinancerisk.com/AuctionSalesData.html. We excluded sales that included resources other CTs.

vintage plants in the sales data. Cambalache is less valuable on the PREPA system than similar units would be on most other systems. Hence, we took $250/kW to be the typical value of units similar to Cambalache.

Cambalache Unit 1 appears to have been out of service since FY 2013, and the IRP treats it as having been retired.[44] We accept that assumption and thus value Cambalache as the sum of two times 83 MW times $250/kW, or $41.5 million, plus 83 MW times $50/kW for the Unit 1 site and interconnection, or $4.2 million, for a total of $46 million.

5.2.4. Mayagüez Combustion Turbines

Mayagüez was built more recently than Cambalache (2009 versus 1997–1998), is considerably more efficient (full-load heat rate of about 9.3 MMBtu/MWh, compared to 11.6 for Cambalache) and is more flexible (able to reach full load in less than 10 minutes, rather than 40 minutes, and without any minimum run time or down time, compared to Cambalache's 7 hours for each).

The Mayagüez units are eleven years old but are nearly as useful as brand new combustion turbines. Some peaking capacity is likely to be useful for many years into the future, as backup for renewables and storage. Hence, we value these units at the average cost of the combustion turbines for which the EIA reports costs in its Construction Cost Data for Electric Generators Installed, which has been published for units entering service in 2013–2017.[45] Table 23 summarizes the combustion turbine data from those reports.

Table 23: Recently Constructed US Combustion Turbines

Year	Average Construction Cost ($/kW nameplate)	Constr'n Cost ($M)	Total Capacity (MW) at Plants that are: New	Existing	Total	Average Unit Capacity (MW) at: New	Existing	Total	Number of Units at: New	Existing	Total
2013	$736	2,787	2,432	1,355	3,787	101	80	92	24	17	41
2014	$1,103	570	152	365	516	12	41	23	13	9	22
2015	$759	1,179	1,110	443	1,553	74	49	65	15	9	24
2016	$717	2,506	820	2,676	3,496	82	122	109	10	22	32
2017	$1,084	1,195	258	844	1,102	29	53	44	9	16	25
Total	$788	8,237	4,772	5,683	10,454	67	78	73	71	73	144

[44] IRP, page 4-6. On the other hand, the EIA 860 database lists Cambalache Unit 1 as "operating," rather than "out of service."

[45] https://www.eia.gov/electricity/generatorcosts/.

Share	46%	54%

The average cost of the five years was \$788/kW, with no obvious time trend. There is a trend in Table 23 for years (such as 2014 and 2017) with smaller average unit sizes to have higher costs per kilowatt, so a plant with 55 MW units is likely to be somewhat more expensive than the \$788/kW average. The equivalent plant in Puerto Rico would be somewhat more expensive,[46] but Mayagüez has undoubtedly experienced some wear and tear, increasing its future operating costs and reducing its value somewhat. We use a value of \$800/kW for Mayagüez, or \$176 million.

5.2.5. Recent Combined-Cycle Units

The most valuable PREPA units are likely to be the San Juan 5&6 combined-cycle units. They entered service in 2008 and have a full-load heat rate under 8 MMBtu/MWh. They ramp fairly fast for a combined-cycle plant (reaching full power in a little over an hour) but are not very flexible, since they have a minimum run time of 5 days and minimum down time of 2 days before restarting.

As shown in Table 24, from the EIA summaries cited above, combined-cycle plants completed in 2013–2017 cost an average of \$950/kW. Costs were highest in the years with the smallest units. Generators the size of San Juan's 200 MW would likely cost around \$1,200/kW on the mainland and more in Puerto Rico.

Table 24: Recent Combined-Cycle Construction Costs

		Average Construction Cost ($/kW nameplate)	Constr'n Cost ($M)	Total Capacity (MW) at Plants:			Average Unit Capacity (MW) at:			Number of Units at:		
				New	Existing	Total	New	Existing	Total	New	Existing	Total
2013	CC	$1,139	$4,125	2,160	1,461	3,621	234	487	295	6	3	9
	CT	$1,040	$2,292	1,408	795	2,203	108	265	138	13	3	16
	CA	$1,293	$1,833	752	666	1,418	125	222	158	6	3	9
2014	CC	$1,003	$8,437	4,773	3,640	8,413	542	437	492	6	5	11
	CT	$1,066	$5,530	2,822	2,364	5,186	217	182	199	13	13	26
	CA	$901	$2,906	1,951	1,276	3,227	325	255	293	6	5	11
2015	CC	$780	$3,707	2,519	2,236	4,755	630	745	679	4	3	7
	CT	$834	$2,404	1,526	1,355	2,881	218	226	222	7	6	13
	CA	$695	$1,303	993	881	1,874	199	294	234	5	3	8
2016	CC	$1,015	$4,029	2,047	1,924	3,969	516	360	415	3	6	9
	CT	$1,011	$2,453	1,250	1,176	2,425	250	235	243	5	5	10
	CA	$1,021	$1,576	797	748	1,544	266	125	172	3	6	9
2017	CC	$896	$8,189	6,767	2,375	9,142	595	495	565	8	4	12
	CT	$955	$4,971	4,024	1,183	5,207	252	197	237	16	6	22
	CA	$818	$3,218	2,743	1,192	3,935	343	298	328	8	4	12
Average	CC	$953	$28,487	18,266	11,636	29,900	677	554	623	27	21	48

[46] Siemens assumed the PR capital-cost premium to be sixteen percent (16%) (IRP p. 6-9).

As for Mayagüez, we assume that the value of the San Juan combined-cycle plant would be reduced due to their age, roughly offsetting the Puerto Rico premium. At $1,200/kW, the plant would be worth about $720 million.

5.2.6. Hydro

The hydro units probably have some capacity value, but that appears to be quite limited. The units are run-of-the-river, with very limited storage and a great deal of variability in precipitation. The primary function of the hydro units in PREPA planning is the provision of renewable energy. The IRP estimates output of 45 GWh from 34 MW in 2019, rising to 172 GWh from 70 MW in 2021, following $100 million of refurbishment. (IRP Exhibit 4-6) The actual annual hydro energy output in 2018 and 2019, from PREPA's monthly reports, was about 40 GWh.

We value this energy at the price of new solar energy, which from Siemens estimates in the IRP to be about $67/MWh levelized in real terms for new solar installed in 2020–2022. For the 45 GWh output level, that would be worth about $3 million annually. However, 2014 hydro O&M was about $4 million; if that expense level continued into 2019, the hydro system would be losing money. Including the incremental overheads required to support the hydro system would make the losses even larger.

With the 172 MWh annual output and a value of $67/MWh, the hydro system would be worth about $11.6 million annually, minus about $4 million in operating costs and some overheads, or about $7 million in net operating margin. That operating benefit would come with a capital cost of $100 million; at a 6.86% real interest rate (or 9% nominal, from IRP, p. 8-2), the annual debt repayment would be about $8 million. Once again, the hydro system would cost more than it is worth.

Since PREPA should eventually be able to finance at lower interest rates, and since hydro may be worth a little more than solar, considering the benefit of diversity in supply, the hydro system may operate roughly at breakeven. We assume no net value for the hydro assets. This assessment should be updated if the hydro plants are slated for refurbishment.

5.3. Stranded Costs of PREPA Purchases

5.3.1. EcoEléctrica

PREPA has recently renegotiated its contracts with EcoEléctrica into a gas supply contract and a tolling contract through 2032. Since the original EcoEléctrica would have expired in 2022, EcoEléctrica should not have been able to exert much leverage in the renegotiation, the new contract should reflect the value of the contract to PREPA. We therefore assume no stranded cost or benefit from the EcoEléctrica contract, for the near term.

There certainly may be some stranded costs from EcoEléctrica, depending on the prices of oil and gas and the dispatch of EcoEléctrica. IRP Exhibit 6-20 projects that the levelized cost of EcoEléctrica would be about $0.09/kWh, depending on the unit's capacity factor.[47] As discussed in the next section, the avoided prices of oil-fired plants may be considerably higher or lower than this value.

Over time, the value of the contract may decrease (if, for example, large amounts of renewable energy and storage are available) or increase (e.g., if oil prices rise before most of the oil generation is converted to gas or replaced by renewables). The stranded costs of the EcoEléctrica contract should be reviewed annually. Prior to each rate period (which would likely be a year), PREPA should provide a forecast of the expected costs of the contract and the expected benefit (in avoiding alternative fuel burn, increasing sales to competitive suppliers, etc.), as well as a reconciliation of the estimate from the previous period.[48]

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[47] The cost of EcoEléctrica energy will also depend on the price of its fuel, which is tied to the price of gas at Henry Hub.

[48] PREPA will not have the actual data for the end of the current period in time to perform the reconciliation prior to the start of the next period. If the pricing period is short (e.g., a month or a quarter), the reconciliation can be lagged one period; for example, the stranded-cost rate for the third quarter can be set in the second quarter, including a reconciliation of the estimated and actual data from the first quarter. If the pricing period is longer, such as a year, the reconciliation can be partially lagged, such as by covering months one to ten of the current year, plus months eleven and twelve of the previous year. The reconciliation may also include an updated forecast for the remainder of the current period (months eleven and twelve, in the previous example).

5.3.2. AES

The value of the AES contract will be the sum of its energy value and its capacity value. The energy value, at least in the near terms, will be either the avoided fuel cost (and some variable O&M) of PREPA's marginal thermal plants (probably mostly residual-oil steam units) or the price at which PREPA can sell excess energy to the Energy Service Companies. Since the pricing of PREPA's sales to Energy Service Companies has not yet been determined, we use an estimate of the marginal energy cost.

Table 25 summarizes our computation of the 2018 average fuel cost for PREPA's steam plants (excluding the damaged Costa Sur) and the San Juan combined-cycle plant. These plants operated at average capacity factors of 23% to 47% in fiscal years 2013–2018, with an output-weighted average of 39%. All the other PREPA plants averaged capacity factors under 10% in fiscal years 2013–2018, and much of their output would have occurred during ramping periods, when the larger steam units could not follow changes in load or capacity availability. For comparison, AES's capacity factor in that period was 78%; the low-capacity-factor peaking units are not representative of the fuel that AES would back out.

Table 25: Average 2018 Fuel Cost for Non-Peaking Plants[49]

	2018 MWh	2018 Heat Rate	Capacity Factor 2013–2018	Fuel + VOM $/kWh
Aguirre Steam	2,945,857	10,693	40%	$0.136
San Juan Steam	557,340	11,435	34%	$0.133
San Juan CCGT	2,323,272	8,957	47%	$0.152
Palo Seco Steam	932,865	11,174	23%	$0.136
Weighted Average		10,224		$0.141

That estimate of the 2018 marginal cost price is considerably higher than the levelized contract price for AES, which appears to be in the range of $0.08 to $0.09/kWh, from IRP Exhibit 6-20, at the capacity factors at which AES operated over 2013–2018. As shown in IRP Exhibit 4-13, Siemens projects that the charge for AES capital will decline after 2020; the total AES charge appears to be over $0.09/kWh through 2021, falling to about $0.085/kWh for the last few years of the remaining contract, at a typical

[49] Data from IRP Exhibit 4-1 and Exhibit 4-5.

AES capacity factor of 84%. The cost of AES would be higher at lower capacity factors, such as the 63% capacity factor in 2018.

But oil prices were considerably higher in 2018 (about $12/MMBtu for residual oil and $17/MMBtu for distillate) than in early 2020.[50] As of April 24, 2018, New York Harbor 1% sulfur residual oil futures were around $4/MMBtu for the rest of 2020, $5.50/MMBtu for 2021 and $6.40/MMBtu for 2022.[51] The corresponding futures for distillate are about $6/MMBtu for the rest of 2020, $8/MMBtu for 2021 and $9/MMBtu for 2022. Those futures prices for 2021 would imply avoided oil costs a little below $0.06/kWh in 2020, $0.08/kWh in 2021, and $0.09/kWh in 2022. Thus, based on just its energy value, AES would roughly break even in the next couple years. The energy value of the contract may rise after 2022 (perhaps back to 2018 levels), and the IRP indicates that the contract price will decline, which would result in the contract producing net benefits in later years. On the other hand, if the San Juan combined-cycle plant is successfully converted to natural gas, and if LNG prices are low, the energy benefits of AES may decline.

AES will also have some capacity value, perhaps allowing PREPA to retire some thermal plants earlier than it would have without AES. The marginal thermal retirements may be drawn from Costa Sur 5 and 6 (which are being considered for repairs following the 2019–2020 earthquakes), Aguirre steam (which the IRP assumes would be retired in the first ten years of the filed IRP), the other steam plants (San Juan or Palo Seco in 2021 through 2025), or the Aguirre combined-cycle plant (one unit of which the IRP assumes would be retired within ten years).

The average fixed O&M cost for the five plants, from IRP Exhibit 4-5, is $37/kW-year, or about $0.005/kWh at an 84% capacity factor. This value is small compared to the range of uncertainty in the stranded costs or benefits from the energy market.

From the information above, we estimate that the excess cost of AES falls in the range of –$0.06/kWh to +$0.01/kWh. At AES's average output of about 3 million MWh, this would be somewhere between a net benefit of $200 million and net costs of $30 million, mostly depending on the price of oil (and to a lesser extent the cost of gas, the amount of gas on the PREPA system, and AES output).

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[50] IRP Exhibit 4-1.

[51] Intercontinental Exchange FOW Contract, New York 1% Fuel Oil Future.

In each year, PREPA should propose a computation of the stranded cost from the AES contract. So long as no functional power market will exist, that computation would consist of a forecast of avoided fuel and variable O&M (which will depend mostly on oil prices, perhaps eventually gas prices, as well as AES operation and other factors), and determining which thermal units were retired as a result of the continued operation of AES. The forecast should be reconciled as part of the next year's stranded-cost determination.

A similar process should be pursued to update any stranded costs from the EcoEléctrica contract.

5.3.3. Renewables

Table 26 summarizes the contract prices and projected energy from PREPA PPOAs with renewable energy producers. The average price of the PPOAs is around $137/MWh. These purchases have value for PREPA, which would otherwise need to purchase renewables. However, for the purposes of this analysis, we assume new solar PPOAs would only cost around $67/MWh in the next few years, about half of the legacy contract costs ($38 million annually) would be uneconomic and stranded.

Table 26: Stranded Cost from Renewable PPOAs

Project Type	Contract Price $/MWh	MWh	Annual Cost $M
Solar PV	$150	296,377	$44
Wind	$125	205,772	$26
LFG	$100	33,638	$3
Total		535,788	$74
New Solar	$67	535,788	$36

The stranded costs of the legacy renewable costs should be computed for each pricing period, with the forecasts reflecting contract termination dates, landfill gas depletion and other foreseeable changes, and the reconciliation also accounting for in actual deliveries from these contracts, such as due to weather conditions. The value of the legacy renewable contracts should be updated to the best available measure of renewable energy, which may be a market value for trading of renewable energy (if a transparent market exists) or the real-levelized costs of recent renewable PPOAs.

5.4. Summary of Stranded Costs

The initial projection of stranded costs would consist of a fixed component for PREPA assets and a variable component for the purchased-power agreements.

5.4.1. Fixed Component

Our initial estimate of the fixed component consists of the following items:

- $1,296 million in net plant for the steam plants, minus $145 million in assumed salvage value for reuse or sale of the sites, for a stranded cost of $1,151 million.
- $507 million for the combustion turbines and combined-cycle units (listed as "other production", minus $1,008 million in values, for a net benefit of $501 million.:
    - $30 million in salvage value for the Aguirre combined-cycle site
    - $720 million in value for the San Juan combined-cycle,
    - $34 million for the operating Frame 5 units,
    - $2 million for the retired Frame 5 units,
    - $46 million for Cambalache, and
    - $176 million for Mayagüez
- $59 million for the hydro plants, which we do not believe have any value in excess of their operating costs, so the entire current and future investment is stranded.

The net plant values are from PREB-PREPA-01-03, for June 2018. The gross plant values may be somewhat higher today. On the other hand, PREPA may have paid down some of the debt for these plants, so it is difficult to estimate the net plant for 2020 or 2021,[52] and some debt may be written off as part of the restructuring process.

In any case, our total estimate of fixed stranded costs is $709 million (= $1,151 – $501 +$59). That value should be adjusted downward, to the extent that the outstanding debt for power plants is written off by lenders and adjusted up or down if PREPA actually sells any of the assets or sites. The stranded capital costs must be converted to an annual cost. The IRP assumes an 9% interest rate.[53] Over a period of 15 years, a 9%

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[52] As of December 2019, PREPA's monthly Financial Report showed $5,717 million in net plant, and $8,898 million in debt, excluding construction financing and the bank lines of credit for fuel financing.

[53] IRP page 8-2.

interest rate requires an annual payment of 12.4%. For a stranded cost of $709 million, that would be $88 million annually, or about $0.0056/kWh of PREPA sales, excluding the first block of the RFR rate. The Bureau may select a longer or shorter amortization period, and may estimate a different cost of debt, until PREPA is able to access the capital markets and has an actual cost of capital.

5.4.2. Variable Stranded Costs

The variable stranded costs consist of the above-market payments for the legacy renewable contracts, about $36 million annually, plus the cost of AES and EcoEléctrica in excess of their value. For EcoEléctrica, we assume no stranded cost in the short term, since the contract has been renegotiated. The recent dramatic fall in oil prices, if sustained, may produce some stranded costs from EcoEléctrica. Conversely, if oil prices rise dramatically in a particular year, the EcoEléctrica contract may produce net benefits in that year.

The stranded costs of AES are highly variable, depending on the price of oil, which determines the avoided energy value of most resources in Puerto Rico. The AES contract might produce over $100 million in benefits in some years, and perhaps $30 million in net costs in other years.

The total annual stranded costs from PREPA's generation resources could be over $150 million ($88 million from fixed costs, $36 million from renewable contracts, $30 million from AES, and perhaps some from EcoEléctrica, if oil prices are low), but the net benefit may be as much as $80 million ($200 million benefit from AES, net of loses of $88 million from fixed costs and $36 million from legacy renewable contracts). As a baseline, we assume that AES and EcoEléctrica break even, leaving about $124 million of annual stranded costs in the next couple of years.

5.4.3. Allocation

The potential stranded costs are all generation costs, and most of the potential stranded costs are associated primarily with the provision of energy (the steam plants, Aguirre CC, hydro facilities, and AES).

Table 27 shows the stranded generation cost allocation by class, for the stranded costs estimated above. While the stranded cost allocation would ideally be based on the contribution of each class to the factors that resulted in the stranded costs—generation energy requirements and to some extent generation demand—the stranded-cost rate is likely to be a single cent-per-kWh charge for all classes. Table 27, shows the allocation of stranded costs are allocated in proportion to either sales or energy at generation, both adjusted to remove the energy served by the RFR fixed-price blocks.

Alternatively, the Bureau may decide to allocate the stranded costs per kilowatt-hour at the generation level, in which case there would be separate rates per kWh for secondary, primary and transmission customers, reflecting their different line losses. That approach would charge more for residential, lighting and secondary business customers and less for primary and transmission customers.

Table 27: Stranded Cost by Class

Class	Residential				Commercial and Industrial					Agriculture
Tariff	RH3	RFR	LRS	GRS	GSS	GSP	GST	LIS	TOU-T	GAS
Sales w/o RFR fixed block	0.126%	0.118%	3.398%	31.805%	12.899%	26.794%	19.434%	1.275%	3.683%	0.157%
	$156,168	$145,819	$4,212,904	$39,438,576	$15,994,628	$33,224,292	$24,098,344	$1,581,488	$4,566,711	$195,221
Energy w/o RFR fixed block	0.132%	0.124%	3.573%	33.446%	13.564%	26.702%	17.504%	1.149%	3.317%	0.166%
	$164,223	$153,340	$4,430,215	$41,472,907	$16,819,667	$33,111,009	$21,705,568	$1,424,459	$4,113,273	$205,291

Table 28 shows the remaining costs that may be recovered from base rates from each tariff class, assuming the costs we used in this analysis and that the Bureau decides to recover from each class the costs allocated to that class.

Table 28: Non-stranded Allocated Cost by Class

Class	Residential				Commercial and Industrial					Agriculture
Tariff	RH3	RFR	LRS	GRS	GSS	GSP	GST	LIS	TOU-T	GAS
Allocated Costs	$4,510,621	$28,277,246	$133,421,239	$1,299,441,649	$489,142,607	$934,089,220	$532,240,262	$33,975,898	$99,225,405	$6,655,712
Stranded Costs	$156,168	$145,819	$4,212,904	$39,438,576	$15,994,628	$33,224,292	$24,098,344	$1,581,488	$4,566,711	$195,221
Non-Stranded Costs	$4,354,454	$28,131,427	$129,208,336	$1,260,003,073	$473,147,980	$900,864,928	$508,141,918	$32,394,410	$94,658,694	$6,460,490

A portion of the restructuring charge should be credited to stranded costs, since part of the restructuring charge will represent the debt on stranded generation investment, as well as past operating deficits, and perhaps some non-stranded generation investment and transmission and distribution investments. Since the amount of the restructuring charge and its allocation among functions remains to be determined, we have not computed this adjustment. In any case, the Bureau will probably choose to recover the restructuring charge and the stranded-cost charge through similarly structured non-bypassable charges. The major concern in coordination of these charges is to avoid either double counting the non-bypassable charges, undermining the legislative intent to allow competitive power supply, or undercounting those costs, resulting in bundled customers paying for more than their share of stranded costs of generation and legacy debt.

APPENDIX B

Questions for Stakeholders

General Issues

1. What time periods (e.g., months) in the last 5 years have been disrupted by natural disasters or other significant events (including COVID-19) in Puerto Rico such that electric system and customer load data would not be representative of reasonably normal conditions?
2. Are there updates to the Cost Allocation and Unbundling Report that need to be made in light of the recently issued Integrated Resource Plan order or other developments?

Cost Allocation and General Ratemaking Issues

1. Should the Energy Bureau consider adjusting certain customer class definitions, consolidating classes, or creating new classes?
2. Should cost allocation continue to make a distinction between transmission and subtransmission? If so, why?
3. Should the Energy Bureau consider changing how certain subsidies (e.g., discounts from otherwise applicable residential or commercial rates) are recovered?
4. Should the Energy Bureau reconsider the nature of or rate design for standby service in light of unbundling and other related developments?

Unbundling Issues

1. How should the Energy Bureau ensure that wheeling customers contribute appropriately to overall resource adequacy and are not relying on other ratepayers unfairly?
2. How should the Energy Bureau ensure that there is a level-playing field between supply service offered by PREPA and new competitive service provider options?
3. Is the creation of a wholesale market and resource adequacy mechanisms necessary to evaluate stranded costs or otherwise set rates for unbundling?
4. Does the unbundling proceeding need to include a nondiscriminatory transmission access tariff for new generation?

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APPENDIX C

Information Requests for PREPA

1. Please provide (in spreadsheet form) separately each cost account and sub-account recorded on PREPA's books for Fiscal Years 2018-2019 and 2019-2020, using FERC accounts or PREPA's cost accounts at a similar level of detail.

2. Please provide (in spreadsheet form) for Fiscal Years 2018-2019 and 2019-2020, the relevant cost information for PREPA's generation units at the most granular level of detail available:

   a. Plant in Service
   b. Non-fuel fixed operations and maintenance expense
   c. Variable operations and maintenance expense
   d. Book life for each unit
   e. Monthly availability data, including forced outage hours, planned outage hours, maintenance outage hours, and derating hours.

3. Please provide in spreadsheet form, for Fiscal Years 2018-2019 and 2019-2020, sales (kWh) and revenue by tariff at the annual level as well as the monthly level.

4. Please provide in spreadsheet form PREPA's hourly load for each hour from July 1, 2019 to June 30, 2020.

5. Please provide in spreadsheet form any customer outages since July 1, 2019 due to inadequacy of generation resources, and the date, duration, and lost load (MW and MWh) for each such outage.

6. Please provide updated data on PREPA's distribution substations for FY 2018-2019 and 2019-2020, including a list of substations where technical characteristics have changed in the last year (e.g., capacity or voltage on either side).

7. Please provide PREPA's estimate of the dollar value of each subsidy in FY 2018-2019 and 2019-2020.

8. Please provide PREPA's estimate for FY 2018-2019 and 2019-2020 for each rate class for the amount of each statutory subsidy that flows to customers on that rate (e.g., the distribution of the residential fuel subsidy and the life-preserving equipment discount across residential tariffs, the distribution of the hotel discounts across commercial tariffs).

9. Please provide the following information by municipality for FY 2018-2019:

   a. CILT dollars.
   b. CILT MWh.

c. Sales to customers in the municipality, by tariff.

10. Please provide, to the extent available, the cost of the transmission lead line for each generation unit, along with the voltage of that line and its length. If such information is not currently available, please describe the level of effort that would be necessary to ascertain and provide such information.

11. Does PREPA currently maintain data on the usage of individual transmission lines or segments of transmission lines? If so, please describe such data.

12. To the extent that such data is not already tracked and available, please describe the level of effort and cost that would be entailed in beginning to track all generation costs by unit.

13. Is PREPA currently doing load sampling by customer class? If so, please provide all available load sampling data for the last three fiscal years. If not, describe the level of effort and cost that would be necessary to begin load sampling for each customer class by January 2021.

14. Has PREPA analyzed metering costs by customer class in the last decade? If so, provide such analysis. If not, describe the level of effort and cost that would be entailed in either (1) analyzing a sample of customers from each customer class or (2) starting to comprehensively collect metering cost data.

15. Does PREPA track metering types and technologies, either for customer classes or in the aggregate? If so, please provide the available data. If not, please describe the level of effort and cost that would be entailed by beginning to track metering types and technologies.

16. Please describe the level of effort and cost that would be entailed in sampling each customer class to estimate service line costs.

17. Please describe the current extent to which distribution lines and equipment are tracked separately based on primary versus secondary voltage. If such distinctions are not currently tracked, please describe the level of effort and cost that would be entailed in (1).

18. Please describe the extent of the data that is currently tracked for individual line transformers. For line transformers that serve a single customer, is that counted and tracked by customer class? For line transformers that are shared, are the number of customers and customer classes counted and tracked? If not, please describe the level of effort and cost to begin to track such data.