BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
Georgia Power Company's	)	**Docket No. 44280**
2022 Rate Case	)	

REDACTED – PUBLIC VERSION

Direct Testimony and Exhibits

of

Jeffry Pollock

On Behalf of

Georgia Association of Manufacturers

October 20, 2022

J. POLLOCK
INCORPORATED

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Exhibit	Description
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JP-2	Traditional Ratemaking Versus Securitization
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GLOSSARY OF ACRONYMS

Term	Definition
1CP	One Coincident Peak (or Annual System Peak)
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
ARP	Alternate Rate Plan
CBL	Customer Baseline Load
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residual
CCOSS	Class Cost-of-Service Study
DA	Day Ahead Pricing
DSM	Demand Side Management
ECCR	Environmental Compliance Cost Recovery
FCR	Fuel Cost Recovery
GAM	Georgia Association of Manufacturers
GPC or Company	Georgia Power Company
HA	Hour Ahead Pricing
IRP	Integrated Resource Plan
kW/kWh	Kilowatt, Kilowatt-Hour
MW/MWh	Megawatt, Megawatt-Hour
NPV	Net Present Value
O&M	Operation and Maintenance
PPA	Power Purchase Agreement
ROE	Return on Equity
RTP	Real Time Pricing

DIRECT TESTIMONY OF JEFFRY POLLOCK

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHO ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University in St. Louis, Missouri. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The members of GAM are customers of Georgia Power Company (GPC). They consume large quantities of electricity, primarily for manufacturing under a variety of tariffs. GAM members purchase nearly 11% of GPC's retail energy sales.

Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A This is the first of many rate increases that the Commission will decide over the next three years, which I will discuss initially. I am also addressing:

- The proposed Alternate Rate Plan (ARP);
- Cost recovery for regulatory assets;
- Class revenue allocation; and
- Other tariff terms and conditions.

Q ARE ANY OTHER WITNESSES APPEARING ON BEHALF OF GEORGIA ASSOCIATION OF MANUFACTURERS?

A Yes. My colleague, Ms. Billie S. LaConte, will address the issues raised by GPC witness, James M. Coyne, in determining the return on equity (ROE) and capital structure. Dr. Roger Tutterow will address the state of manufacturing in Georgia.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I'm sponsoring **Exhibits JP-1** through **JP-9**. These exhibits were prepared by me or under my supervision and direction.

Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF THE POSITIONS OF GEORGIA POWER COMPANY, OR OTHER PARTIES, ON THESE ISSUES?

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of GPC's or other parties' proposals in this proceeding.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and conclusions are as follows:

This Case in Perspective

- GPC is on the precipice of a "perfect storm" of at least seven rate increases that could result in cumulative rate increases of up to $2.9 billion over the next three years.
- Even before the first of three step increases is implemented under GPC's proposed ARP, customers taking service under the Real Time Pricing (RTP) rates have already experienced double-digit rate increases.
- Higher RTP prices have generated $565 million of contributions to fixed costs during the current ARP through July 2022. Thus far in 2022, the fixed cost contributions through July 2022 alone ($191 million) exceed the $95 million of fixed cost contributions included in GPC's test-year revenue requirement.
- To offset future rate increases, the Commission should identify alternatives to traditional ratemaking — securitization in particular — that would allow the Company to recover its capital costs while minimizing rate impacts on customers.
- Securitization is an accepted practice for recovering large capital investments (retired plant) and other major unexpected costs (storm damage) to alleviate the upward rate pressures facing GPC's customers. The cost of securitizing utility assets is only a fraction of GPC's pre-tax cost of capital under traditional ratemaking. Further, securitization bonds can extend cost recovery for periods ranging from four to over 20 years, thereby further alleviating upward rate pressure.

Alternate Rate Plan

- The proposed ARP would implement three step increases effective on January 1, 2023, 2024, and 2025. However, the vast majority of the increase would occur on January 1, 2023.
- The three step increases are based entirely on three projected test years. Use of three projected test years requires accurate projections of future sales, revenues, investments, expenses and interest rates. Such projections are inherently inaccurate, particularly, in this case, for the 2nd and 3rd years of the proposed ARP.

- GPC's past projections have allowed it to earn above the authorized midpoint ROE in each of the last ten years. In six of those years, the earned ROE exceeded the upper end of the authorized ROE band.
- In light of past experience, the base rate and Environmental Compliance Cost Recovery (ECCR) increases should be implemented in three steps, and GPC should be required to update its base rate and traditional ECCR projections prior to implementing the 2nd and 3rd years of the ARP.

Cost Recovery of Major Assets

- Higher depreciation and amortization expenses are a major driver of the proposed base revenue increase. These higher expenses are a direct result of GPC's Integrated Resource Plan (IRP) to retire/early retire major power plants (i.e., Wansley, Scherer, Bowen Units 1-2) with over $3.1 billion of remaining (unrecovered) investment.
- GPC is also seeking recovery of the costs of the six capacity power purchase agreements (PPAs). Excluding Bowen Units 1-2 (for which a retirement decision was deferred), the capacity of these PPAs roughly offsets the capacity of the retired/early retired plants.
- GPC is proposing to earn a return on both the retired/early retired plants and as a result of the additional sums on the six capacity PPAs.
- The simultaneous recovery of both retired/early retired plants and the six capacity PPAs effectively charges retail customers for redundant capacity.
- Retired plants no longer provide electricity to the public. Thus, the costs of retired plants are not used and useful. A utility should not earn a return on equity on investments in facilities that are not used and useful.
- To avoid placing unnecessary upward pressure on rates, GPC should amortize its investment in Scherer Unit Nos. 1, 2 and 3 over their current remaining lives, which range from 20-25 years.
- GPC is proposing to continue deferred recovery of coal combustion residual (CCR) costs, thereby earning a return on any amounts that have not been recovered in rates.
- GPC is projecting to incur $986 million in CCR costs during the ARP. This is in addition to the CCR costs that have been incurred but not yet recovered in rates.

- Securitizing the remaining investments in Plant Wansley and the as-incurred/projected CCR costs would place less upward pressure on rates than under traditional ratemaking.
- Until securitization is authorized, GPC should not earn a return on equity on the regulatory assets (i.e., Plant Wansley, CCR costs).

Class Revenue Allocation

- GPC's proposed equal percentage base rate increase would not result in moving rate groups closer to parity.
- Any base rate increase authorized by the Commission should continue the policy established in the 2010 rate case and continued in the 2013 and 2019 rate cases to continue moving each rate group closer to parity.

Other Tariff Terms and Conditions

- GPC's proposed Rule 9 would absolve it of any liability for damages sustained by customers, even if outages or equipment failures were the result of gross negligence. Further, GPC is proposing to limit its liability for damages to the net book value of the customer's equipment.
- A customer's damages from electricity outages can be much more extensive than the net book value of the equipment or personal property. For example, outages can result in lost product, lost sales, additional maintenance expense and potentially higher replacement costs for new equipment.
- Consistent with best practices, Rule 9 should be revised so that GPC is liable for damages caused by willful misconduct and gross negligence. The amount of damages should, at a minimum, be sufficient to replace the customer's damaged equipment and/or personal property.

2. THE RATE CASE IN PERSPECTIVE

Q WHAT IS THE COMPANY REQUESTING IN THIS CASE?

A GPC is asking the Commission to continue the process of a three-year ARP with a one-time "levelized" base rate increase taking effect on January 1, 2023 and two additional step increases for specific cost components that would become effective on January 1, 2024 and January 1, 2025. Originally, GPC requested a one-time $738 million levelized base revenue increase. However, in its Supplemental filing it increased the request to $762 million. The $37.6 million additional base revenue increase reflects various items included in the final Order approved in the 2022 IRP and Demand Side Management (DSM) proceedings.

Q ARE THESE THE ONLY RATE INCREASES THAT GEORGIA POWER COMPANY WILL BE SEEKING FROM THE COMMISSION?

A No. As I have testified in past cases, we are on the precipice of a "perfect storm" of rate increases that will occur over the next three years. Table 1 provides an estimate of the potential impact of the seven future rate increases. As Table 1 reveals, GPC will be seeking cumulative rate increases of up to $2.9 billion over the next three years.

Table 1
Upcoming Rate increases

Date	Increase	Amount ($ Millions)
Jan. 2023	ARP Step 1	$889
Spring 2023	Vogtle 3 Net of FCR Decrease	$190
Spring 2023	Fuel Cost Recovery	$1,100
Fall 2023	Vogtle 3-4 Up to Certified Amount Net of FCR Decrease	$600
Jan. 2024	ARP Step 2	$107

Table 1 Upcoming Rate increases		
Date	**Increase**	**Amount ($ Millions)**
2024	Vogtle Prudence Review & Increase	Unknown
Jan. 2025	ARP Step 3	$45
Total Net Rate Increases		$2,931

As can be seen, the proposed ARP is but one component of the upcoming rate increases. GPC will be adjusting rates to recognize the commercial operation of Vogtle Unit 3 when it is placed in commercial operation in the spring of 2023 and further in the fall of 2024, and when fuel is loaded into Vogtle Unit 4 in the fall of 2023. In addition, GPC reported a $948 million fuel cost recovery (FCR) under-collection in June.[1] The balance has continued to grow significantly despite the Interim Fuel Rider that was implemented on January 1, 2022. Assuming gas prices remain at current high levels, the FCR rate increase could exceed $1.1 billion.

In summary, retail customers are potentially facing $2.9 billion in rate increases over the next three years.

Q HAVE ANY RETAIL CUSTOMERS ALREADY EXPERIENCED SUBSTANTIAL RATE INCREASES?

A Yes. Even before Step 1 of the proposed ARP takes effect, customers taking service under the RTP rate schedules have already experienced and will continue paying record high prices.

[1] Georgia Power Company, Docket No. 3382-U, *Report of Retail Fuel Cost Recovery for August 2022* (Sept. 19, 2022).

Chart 1



The much higher prices can be attributed to much higher replacement fuel costs (particularly natural gas) and hotter than normal weather.

Q WHAT HAS BEEN THE IMPACT OF THE HIGH RTP PRICES?

A Higher RTP prices have resulted in much higher contributions to fixed costs by RTP customers. The fixed cost contributions consist of:

- A Reliability adder that reflects the marginal cost of generation capacity;
- A Transmission adder that reflects the marginal cost of transmission capacity; and
- Risk adders ranging from $1 to $3 per megawatt-hour (MWh) for Day Ahead (DA) and Hour Ahead (HA) pricing.

The Reliability and Transmission adders apply when demand approaches and exceeds the projected Southern Company system peak, and the Risk adders apply to all hours.

As a result of the higher prices, RTP customers have paid $565 million in fixed cost contributions during the current ARP through July 2022. In 2022 alone, they contributed $191 million to fixed costs through July, which is twice GPC's projected ($95 million) test-year fixed cost contributions. Thus, it is clear that a large segment of GPC's retail customers has already experienced substantial rate increases, even before base rates are adjusted. Further, GPC's non-RTP customers have benefitted and continue to benefit from the fixed costs that RTP customers pay.

Q RECOGNIZING THE PERFECT STORM OF UPCOMING RATE INCREASES AND THE MUCH HIGHER RTP PRICES, WHAT STEPS SHOULD THE COMMISSION TAKE TO PROTECT THE INTERESTS OF RETAIL CUSTOMERS?

A The objective should be to minimize future rate impacts while affording GPC a *reasonable* opportunity to earn a *reasonable* return on the facilities that are used and useful in providing electricity service to the public.

Q HOW CAN THE COMMISSION ACHIEVE THIS OBJECTIVE?

A First, the Commission should thoroughly scrub each of the three projected test years used to support GPC's proposed ARP.

Second, recognizing that GPC's proposed 11% ROE is approximately 150 basis points above the national average, the Commission should, at a minimum, establish an ROE and capital structure based on the specific corrections to Mr. Coyne's testimony as recommended by Ms. LaConte.

Third, the Commission should identify alternatives to traditional ratemaking that would allow the Company to recover its capital costs while minimizing rate impacts on customers. For example, $297 million of the proposed revenue requirement reflects changes in depreciation rates.[2] As discussed later, GPC is proposing to accelerate the recovery of certain assets due to recent retirement decisions and extend the depreciable lives of other assets. Accelerated/extended depreciation can alleviate rate pressure. However, this option is not cost-free because GPC would continue to earn a return on the unamortized balance. The only alternative that would both alleviate rate pressure and reduce the overall revenue requirement is securitization.

Q WHAT IS SECURITIZATION?

A Securitization is a financing mechanism that provides timely recovery of certain regulatory assets by issuing a type of debt that would significantly lower the carrying costs of the assets relative to the costs that would be incurred using traditional ratemaking practices. Specifically, a special purpose entity would be created whose sole purpose is to issue transition bonds that are used solely for purposes of reducing the amount of recoverable regulatory assets and any other amounts as determined by the Commission through the refinancing or retirement of utility debt or equity. This special purpose entity would be entitled to the revenues collected by the utility through a separate cost recovery mechanism in an amount sufficient to timely recovery of the debt services associated with securitization bonds.

[2] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-5, Schedule 1).

Under this structure, securitization bonds would be "AAA" rated and carry the lowest possible interest rate. For example, recently issued securitization bonds have had an average interest rate of 3.6%. This is substantially below GPC's proposed 9.8% pre-tax cost of capital. The much lower cost reflects the fact that there is no equity and no federal and/or state income taxes associated with securitized financing. Further, securitization bonds issued to date have maturities ranging from four to over 20 years. Therefore, securitization financing would be the most economical means of recovering the costs of long-term regulatory assets, such as retired coal plants and CCR obligations.

Q IS SECURITIZATION WIDELY USED?

A Yes. **Exhibit JP-1** shows that 27 states, the District of Columbia and Puerto Rico have enacted utility securitization laws. Thus, securitization is authorized in the majority of states.

Q HOW IS SECURITIZATION FINANCING TYPICALLY USED?

A Initially, securitization was used to recover utility assets that became stranded when generation was no longer subject to price regulation. More recently, securitization has become more widely used to recover retired coal plant assets, to finance major storm damage, and to recover extraordinary costs incurred during Winter Strom Uri.

Q CAN SECURITIZATION BE BENEFICIAL FOR CUSTOMERS?

A Yes. If the legislation is properly drafted, securitization can be a more cost-effective means of recovering retired assets and other obligations than under traditional ratemaking. To demonstrate, **Exhibit JP-2** provides an illustration of the impact of securitizing $1.5 billion of assets. The illustration shows the annual revenue

requirement in both nominal and net present value (NPV) dollar costs to customers under traditional ratemaking (the solid green and dashed black lines) and securitization (the orange bars). For purposes of the illustration, I have used GPC's proposed cost of capital, current state/federal income tax rates and both accelerated (9-year) and nominal (20-year) amortization. Finally, I assumed an average interest rate of 3.61% with upfront costs of 2% of the securitizable amount. The interest rate assumption was based on a securitization issued by Entergy Texas, Inc., on March 25, 2022.

Q HOW DOES SECURITIZATION COMPARE WITH TRADITIONAL RATEMAKING?

A The vertical axis shows the annual revenue requirement. The higher the annual revenue requirement, the higher the rate impact.

As can be seen, the annual revenue requirement for securitizing $1.5 billion of regulatory assets is less than $150 million per year over the 14-year average life of the securitization bonds. By contrast, the annual revenue requirements under traditional ratemaking (for either a nine or 20-year amortization period) would be higher than for securitization. Table 2 below compares the net cost to retail customers under those options.

Table 2
Net Cost to Retail Customers
$3 Billion Securitization Vs. Traditional Ratemaking
($ Billions)

Scenario	Nominal Cost	NPV Cost
Traditional Ratemaking:		
9 Year Recovery	$2.3	$1.7
20 Year Recovery	$3.0	$1.9
Securitization	$2.0	$1.5

Thus, not only would securitization place less upward pressure on rates, it would be less costly for customers on both a nominal and NPV basis.

Q HAVE CREDIT RATING AGENCIES EXPRESSED ANY OPINIONS ON THE USE OF SECURITIZED FINANCING?

A Yes. For example, Moody's Investors Service opined that utility cost recovery through securitization is credit positive provided that it is not over-used. A copy of Moody's assessment is provided in **Exhibit JP-3**. The key takeaways are:

- Securitization typically benefits utilities and their current customers because utilities receive an immediate source of cash and are ensured recovery of large costs in a timely manner, and because the cost of securitized debt is lower than the utility's all-in pre-tax cost of capital, it reduces the impact on customers' monthly bills.
- Utility cost recovery charge securitization has become more versatile and prevalent. It is now used to recover costs associated with storm restoration and environmental costs, utility restructuring, deferred fuel costs and renewable energy projects.
- State law and financing orders strongly protect securitization assets which ultimately protect the assets backing the bonds.
- Too much securitization can have negative consequences such as impacting customer bills substantially while hurting the utility's financial flexibility and ability to raise rates for other reasons.

Regulatory Research Associates, a subsidiary of S&P, recently observed that there has been a rekindled interest in securitization, stating:

> This financing method allows utilities to include the revenue stream to repay the bonds within customer bills as a separate, non-bypassable surcharge that is subject to true-up. Amounts collected by the company through the surcharge are remitted to a special purpose entity, which then disburses the payments to investors.
>
> While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded to the securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a

state commission. In RRA's experience, no state utility regulatory commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to reduce the customer rate impacts related to the recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond as compared to the utility's WACC, which includes both equity and debt components, or even the interest rate applied to typical utility corporate bonds, which are generally rated BBB and carry higher interest rates.

At the same time, ***securitization reduces the investment risk for the utility by providing the utility up-front recovery of its investment*** in what are usually non-revenue-producing assets — assets that are not dedicated to providing service to current ratepayers. The company can then redeploy those investment dollars elsewhere.[3]

Q IS SECURITIZATION POSSIBLE UNDER THE CURRENT REGULATORY AND LEGAL ENVIRONMENT IN GEORGIA?

A No. It is my understanding that securitization would require both a change in law and regulations. I also understand that a securitization bill has been drafted and reviewed by several parties, including GPC. Thus, there is no reason why a securitization bill could not be introduced and enacted in the next legislative session.

Q WHAT CAN THE COMMISSION DO TO FACILITATE SECURITIZATION?

A This rate case provides an opportunity to identify the capital assets that would most likely be candidates for securitized financing. For example, as discussed later, GPC is seeking full recovery of the now-retired Plants Wansley and Boulevard. GPC continues to defer CCR costs and is seeking to recover $986 million of additional CCR

[3] S&P Capital IQ, RRA Regulatory Focus*, Kan. commission OK's storm cost bond issuance for Atmos Energy* (Oct. 14, 2022). Emphasis added.

costs over the duration of the ARP.[4] Both the retired plants and unrecovered/expected CCR costs would be ideal candidates for securitization.

Therefore, I recommend that the Commission quantify and set-aside the portion of costs associated with Plant Wansley and the unrecovered/expected CCR costs in this proceeding. Setting aside these specific costs will facilitate a timely rate adjustment once GPC issues securitization bonds to finance these costs, while avoiding double-recovery.

Q HOW SHOULD THESE COSTS BE RECOVERED PRIOR TO SECURITIZATION?

A As previously stated, Plant Wansley was retired and the investment is not used and useful. Further, the CCR costs that are associated with Plant Wansley and other retired power plants are also not used and useful. Under these circumstances, the Commission should not allow a return on the unamortized balance. However, recognizing GPC's need to finance regulatory assets, the Commission should authorize a return capped at GPC's cost of long-term debt.

[4] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) at 6.

3. ALTERNATE RATE PLAN

Q HOW IS GEORGIA POWER COMPANY PROPOSING TO IMPLEMENT ITS ALTERNATE RATE PLAN?

A The proposed ARP is shown in Table 3. Also shown for comparison is the annual revenue increase for the test period, as well as the three step increases under the ARP.

Table 3
Alternate Rate Plan
($ Millions)

Rate Component	Test Period	Levelized	1/1/23	1/1/24	1/1/25
Base Rates	$318	$762	$478	$269	$359
CCR	$60	N/M	$64	$78	$47
ECCR	$44	$5	$33	($38)	($12)
DSM	$37	N/M	$37	$27	($2)
Total Excl MFF	$460		$612	$336	$392

Sources: APA-SPA-ADH-MBR-1, Schedules 1, 2 and 3 Supplemental.

As previously stated, GPC is proposing to implement a one-time levelized increase in base rates and the traditional ECCR rate. Alternatively, GPC could have proposed three smaller base rate increases.

Q DO YOU HAVE ANY CONCERNS REGARDING GEORGIA POWER COMPANY'S ALTERNATE RATE PLAN?

A Yes. The proposed ARP is based entirely on three projected test years: calendar year 2023, calendar year 2024, and calendar year 2025. None of these projections reflect GPC's official corporate budgets, which were prepared last fall. Use of three projected test years requires accurate projections of future sales, revenues, investments,

expenses and interest rates. Such projections, particularly in the 2nd and 3rd years of the proposed ARP, are inherently inaccurate.

Q IS GEORGIA POWER COMPANY PROPOSING TO UPDATE ITS PROJECTIONS PRIOR TO IMPLEMENTING THE 2ND AND 3RD YEAR INCREASES UNDER THE PROPOSED ALTERNATE RATE PLAN?

A No. With the exception of the CCR and DSM rate components, which would be updated in November prior to the following rate year, the base rate and ECCR components would be fixed based on the three projected test years.

Q WHY DO YOU ASSERT THAT GEORGIA POWER COMPANY'S FORECASTS ARE INHERENTLY INACCURATE?

A **Exhibit JP-4** shows GPC's earned ROE for the past 10 years under the then-applicable Accounting Orders. Under these Accounting Orders, GPC was authorized to earn a mid-point ROE ranging from 10.5% to 11.15%. The ceiling ROE ranged from 12% to 12.25%, and the ROE floor ranged from 9.5% to 10.25%.

As can be seen in **Exhibit JP-4**, reliance on GPC's projections has resulted in GPC consistently earning a ROE above the mid-point in each of the last 10 years. Further, GPC earned above the upper end of the ROE range in six of the last 10 years. At no time did GPC's earnings ever fall below the ROE mid-point or, obviously, the ROE floor.

Thus, based on this past experience, GPC's projections have either overstated future costs, or understated future sales and/or revenues.

Q WHAT DO YOU RECOMMEND?

A Recognizing the other substantial rate increases likely to occur in 2023 (as listed in Table 1), prior experience as discussed earlier, and to provide a more gradual rate path, GAM members strongly prefer a three-stepped increase over GPC's proposed levelized increase. GPC should be required to update its base rate and traditional ECCR projections prior to implementing the 2nd and 3rd years of the ARP. Thus, for the years 2024 and 2025, new base rates should be set using updated test-year projections based on GPC's then-official corporate budgets. The updated budget projections should be filed within 60 days prior to the effective date of new rates. This would provide the Commission and parties ample time to review the projections prior to the rates becoming effective.

Q HAS THE COMMISSION PREVIOUSLY APPROVED STEPPED BASE RATE INCREASES IN AN ALTERNATE RATE PLAN?

A Yes. In the last rate case, GPC also requested a levelized base rate increase. However, the Commission approved a settlement between GPC, the Commission Staff, GAM and other parties authorizing three stepped base rate increases.

4. COST RECOVERY OF MAJOR ASSETS

Q ARE CHANGES IN THE TIMING OF COST RECOVERY FOR CERTAIN MAJOR ASSETS A DRIVER OF THE PROPOSED BASE REVENUE INCREASE?

A Yes. As a result of the decisions in the IRP case, GPC is proposing to transfer the remaining investments of Plants Wansley and Boulevard to a regulatory asset account.[5] Both plants were removed from service this year. GPC is also proposing to accelerate the recovery of plants that will be retired early, prior to the lifespans established in the last rate case. This includes Plants Scherer Unit Nos. 1, 2, and 3 and Bowen Units 1 and 2. In these cases, GPC would continue to earn a full return on the amortized balances of the affected assets.

Q ARE ANY OTHER DECISIONS MADE IN THE INTEGRATED RESOURCE PLANNING CASE ALSO AFFECTING THE PROPOSED BASE REVENUE INCREASE?

A Yes. During the ARP, GPC will begin incurring purchased capacity costs under the six capacity PPAs approved in the IRP. This includes purchases from Wansley Unit No. 7, Harris Unit No. 2, Monroe Unit Nos. 1 and 2, and Dahlberg Unit Nos. 2, 6, 8, 9 and 10. GPC will also recover an additional sum on these expenses. The additional sum is the financial equivalent of a return on equity.

[5] The remaining net book value of Plant Boulevard is negligible. *Georgia Power Company's 2022 Integrated Resource Plan;* Docket No. 44160, GPC Response to STF-LA-2-51 (Feb. 8, 2022).

Q WILL THE AMOUNT OF CAPACITY PROVIDED BY THE POWER PURCHASE AGREEMENTS APPROXIMATELY OFFSET THE CAPACITY PREVIOUSLY SUPPLIED BY THE RETIRED/EARLY RETIRED PLANTS?

A Yes. Table 4 summarizes the approved plant retirements and capacity additions.

Table 4
Approved Capacity Decertifications and Additions

Resource	Effective Date	Capacity Retired (MW)	Capacity Added (MW)
Wansley Units 1-2/CT	8/31/22	933	
Boulevard (Oil)	8/31/22	19	
Wansley 7/Harris 2/Monroe 1 & 2	12/1/24		1,567
Dahlberg 2, 6, 8, 9, 10	6/1/25		380
Dahlberg 1, 3, & 5	1/1/28		228
Gaston Units 1-4/CT (Gas)	12/31/28	460	
Scherer Units 1, 2, and 3	12/31/28	648	
Total		2,060	2,175

Source: IRP Main Document at 11-77 and A-137.

Bowen Unit Nos. 1 and 2 were excluded because the Commission deferred a decision to retire these units. As Table 4 demonstrates, the capacity added by the six PPAs will slightly exceed the capacity retired.

Q WILL THE PROPOSED BASE RATES INCLUDE THE RECOVERY OF BOTH THE CAPITAL COSTS OF THE RETIRED/EARLY RETIRED PLANTS AND THE SIX CAPACITY POWER PURCHASE AGREEMENTS?

A Yes. The proposed base rates include recovery of the retired/early retired plants as well as the replacement purchased power capacity. As previously stated, GPC will earn a return on both the retired/early retired plants and the six capacity PPAs.

Retired/Early Retired Plant

Q DO THE RETIRED/EARLY RETIRED PLANTS REPRESENT A SIGNIFICANT INVESTMENT?

A Yes. Table 5 shows that GPC has approximately $3.3 billion of investment in Plants Wansley, Bowen Unit Nos. 1 and 2, and Scherer Unit Nos. 1, 2 and 3.

Table 5
Net Book Value of Retired/Early-Retired Plants
($Millions)

Resource	Amount At 12/31/21	Recovery Period	Remaining Life as of 1/1/23
Wansley Units 1-2/CT	$472.2	8	8
Scherer Units 1, 2, and 3	$934.5	9	20-25
Bowen Units 1-2	$1,858.8	9	8
Total	$3,265.5		

Source: IRP Case, GPC Response to STF-LA-1-29.
Amounts for Scherer Units 1 & 2 are estimated.

GPC is proposing to recover Plant Wansley over eight years. This coincides with the remaining life as determined in the last rate case. However, GPC is proposing to recover the investments in Scherer Unit Nos. 1, 2 and 3 and Bowen Unit Nos. 1 and 2 over nine years. The Scherer units have remaining lives ranging from 20 to 25 years. Thus, GPC's proposal to accelerate the recovery of Scherer Unit Nos. 1, 2 and 3 will place upward pressure on rates.

Q DO YOU HAVE CONCERNS WITH THE COMPANY'S COST RECOVERY PROPOSALS?

A Yes. First, retail customers would be charged for redundant capacity. Second, Plant Wansley (and after 2028, Scherer Unit Nos. 1, 2 and 3) is no longer used and useful. A utility should not expect to earn a return on investment for facilities that are no longer used and useful in providing electricity to the public. Third, abruptly changing the depreciation schedule for Scherer Unit Nos 1, 2, and 3 is unfair to GPC's current ratepayers.

Q IS THERE ANY PRECEDENT FOR DENYING A RETURN ON A PLANT THAT IS NOT USED AND USEFUL?

A Yes. In Docket No. 46449, the Public Utility Commission of Texas denied a proposal by a utility to include its investment in the then-retired Welsh Unit 2 in rate base, thereby denying a return on the unamortized balance. In rejecting the utility's proposed ratemaking treatment, the Commission stated:

> 68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on that remaining investment.
>
> 69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.
>
> 70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh unit 2 over the 24-year remaining lives of Welsh units 1 and 3.[6]

[6] *Application of Southwestern Electric Power Company for Authority to Change* Rates, Docket No. 46449, Order on Rehearing at 20 (Mar, 19, 2018).

Q WHAT DO YOU RECOMMEND?

A First, as previously discussed, the remaining investment in Plant Wansley should be securitized. This would allow GPC to immediately recover its capital without an additional return. This is appropriate because, as previously stated, Plant Wansley is no longer used and useful. In the interim, Plant Wansley regulatory asset should be amortized over eight years with no return on equity.

Second, to avoid placing unnecessary upward pressure on rates, GPC should amortize its investment in Scherer Unit Nos. 1, 2 and 3 over their current remaining lives, which range from 20-25 years, with a return on the unamortized balance. However, once Scherer Unit Nos. 1, 2 and 3 have been retired, the remaining investments should be securitized.

CCR Costs

Q IS GEORGIA POWER COMPANY PROPOSING TO CONTINUE ITS RECOVERY OF COAL COMBUSTION RESIDUAL COSTS?

A Yes. GPC is proposing to continue the recovery of CCR costs while earning a return on the unamortized CCR obligation. In 2021, GPC recovered $166 million of CCR costs in rates.[7] By 2025, GPC projects that the CCR annual revenue requirement would reach $386 million.[8] Thus, it is a significant and growing component of GPC's overall revenue requirement. But for the sheer magnitude of the CCR obligation, which GPC estimates at $6.8 billion, these costs would be expensed, and GPC would not earn a return on the unamortized CCR balance.[9]

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[7] *Georgia Power Company's 2021 Annual Surveillance Report*, Docket No. 42516, Schedule 15, at 2. (Mar. 15, 2022).

[8] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) at 6.

[9] Docket No. 42516, Schedule 15, at 3. (Mar. 15, 2022).

Q IS A RETURN ON UNAMORTIZED BALANCE THE ONLY COST ASSOCIATED WITH COAL COMBUSTION RESIDUAL COST RECOVERY?

A No. The return applied to the unamortized CCR obligation includes a return on equity. Further, because equity is taxable, retail customers are paying not only an additional return to shareholders, they are also funding the income tax liability associated with the shareholder return. The inclusion of both a return on equity and associated income taxes places unnecessary upward pressure on rates.

Q HOW CAN THIS UNNECESSARY UPWARD PRESSURE BE ALLEVIATED?

A GPC should securitize all unrecovered CCR expenses, as well as a substantial portion of the CCR expenses that will be incurred during the ARP. As previously stated, securitization is a less expensive alternative to traditional ratemaking because it is financed solely by much lower debt cost. Further, securitization bonds can be issued with extended maturities at a cost that is less than 50% of GPC's pre-tax cost of capital. Prior to securitization, the CCR regulatory asset should earn a return based on GPC's long-term cost of debt.

5. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

Q HOW IS GEORGIA POWER COMPANY PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A GPC is proposing to spread the proposed base revenue increase by applying an approximately equal percentage increase to current base revenues. This is shown in **Exhibit JP-5**.

Q WOULD AN EQUAL PERCENTAGE INCREASE MOVE RATE GROUPS CLOSER TO PARITY?

A No. As discussed later, the class cost-of-service study (CCOSS) results show that the rate groups are not currently at parity. Some rate groups are below parity while other rate groups are above parity. Moving rates toward parity means applying above-average base revenue increases to those rate groups that are currently below parity and below-average base revenue increases to those rate groups that are currently above parity.

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each class's responsibility for a utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly

serve many customers. For purposes of revenue allocation and rate design, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures typically used in a CCOSS are described in more detail in **Appendix C**.

Q HAS GEORGIA POWER FILED A CLASS COST-OF-SERVICE STUDY IN THIS CASE?

A Yes. GPC filed four CCOSSs – two studies were based on calendar year 2021 (the historical test period) and two studies were based on the test year ending July 31, 2023. One set of studies was presented by rate group and by rate schedule while the other set of studies was presented by customer class.

Q DID GEORGIA POWER ACKNOWLEDGE AN ERROR IN THE FILED CLASS COST-OF-SERVICE STUDIES?

A Yes. GPC acknowledged that there was an error in the filed CCOSSs. Specifically, the filed studies overstated the revenues from the Medium Business rate group and understated the revenues from the Marginally Priced rate group. A corrected CCOSS was provided.

Q DOES THE CORRECTED CLASS COST-OF-SERVICE STUDY GENERALLY COMPORT WITH ACCEPTED INDUSTRY PRACTICE?

A Yes. The corrected CCOSS generally comports with accepted industry practice. Specifically, it recognizes the different types of costs incurred by the utility, as well as the different ways electricity is delivered to, and used by, the various types of customers. In particular:

- All production and transmission plant costs and related expenses were classified to demand.
- A portion of the distribution network was classified as a customer-related cost.
- For the Marginally Priced rate group, production/transmission demand allocation factors were based on the customer baseline load (CBL), which is the load that GPC must plan to serve.

Thus, GPC's CCOSSs are consistent with the principles of cost causation; that is, costs are allocated to rate groups based on the degree that each rate group caused GPC to incur each specific cost.

This is in stark contrast to theoretical studies that allocate production plant costs on energy usage on the mistaken belief that some investment is incurred to save fuel costs or that individual power plants benefit certain customer classes more than others and, therefore, should be allocated differently, rather than as a unified generation fleet. A more in-depth assessment of GPC's CCOSSs and these other competing allocation theories is provided in **Appendix C**.

Q ARE THERE DIFFERENCES BETWEEN THE TWO SETS OF COST STUDIES?

A Yes. The CCOSSs used the same methodologies except for the allocation of production and transmission plant and related expenses. GPC's preferred CCOSS allocates production and 20% of transmission plant and related expenses using the twelve coincident peak (12CP) method. The remaining transmission costs were allocated to classes using the four coincident peak (4CP) method.

Q PLEASE DESCRIBE THE 12CP AND 4CP METHODS.

A Under 12CP, each class's share of allocated costs is based on the demand that occurs coincident with the system peak in all 12 months. GPC also filed a second CCOSS

using the 4CP method. Like 12CP, the 4CP method allocates costs based on the demand that occurs coincident with the system peak during the summer months, June through September.

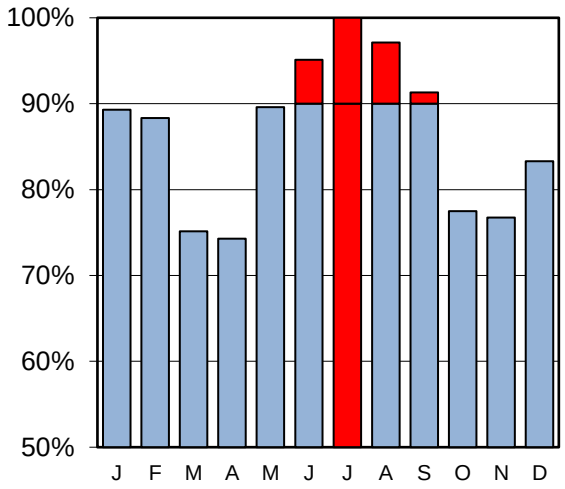
Q WHAT IS THE RATIONALE FOR USING A SPECIFIC DEMAND ALLOCATION METHOD, SUCH AS 12CP OR 4CP.

A The choice of an allocation method should reflect the load characteristics of the utility. For example, 4CP is appropriate for a utility that is primarily summer peaking, while 12CP is appropriate for a utility that has no discernable peak periods. The rationale for using 12CP and 4CP is discussed in more detail in **Appendix C**.

Q IS GEORGIA POWER COMPANY A SUMMER PEAKING UTILITY?

A Yes. Chart 2 below compares the monthly system peaks as a percent of GPC's annual system peak. The red bars denote when the annual system peak occurs. The red/blue bars show the months when the system demand is close to the annual system peak. The other months are shown in the blue bars.

Chart 2
Monthly Peak Demands as a Percent of
GPC's Historical and Test Year Annual System Peak



As Chart 2 demonstrates, GPC is summer-peaking. However, GPC's winter peaks are growing faster than its summer peaks, and as a consequence, GPC will have both summer and winter peaks in future test years.

Q ARE THERE DIFFERENCES IN THE SHARE OF PRODUCTION/TRANSMISSION COSTS ALLOCATED TO EACH RATE GROUP UNDER THE 12CP AND 4CP METHODS?

A Yes. **Exhibit JP-6** provides a comparison of the allocation factors for each rate group under 12CP (column 1) and 4CP (column 3). Recognizing the convergence between the summer and winter peaks, I have also quantified the allocation factors based on an average of the four summer and two winter system peaks (column 2). As can be seen, each method allocates a different share of production/transmission costs to rate groups.

Q WHICH OF THE ALLOCATION METHODS SHOWN IN EXHIBIT JP-6 BEST FITS GEORGIA POWER COMPANY'S SYSTEM LOAD CHARACTERISTICS?

A Currently, the 4CP method best reflects GPC's load characteristics. However, in the future the average of the four summer/two winter CP method will become a better fit as the summer and winter peaks converge. As can be seen in **Exhibit JP-6**, the allocation factors under this approach more closely resemble 4CP than the 12CP. demand allocation factors.

In any event, the 12CP method is not reflective of GPC's load characteristics. Thus, the results of GPC's preferred CCOSS are not an accurate reflection of the parity ratios. The additional flaws with the 12CP method are discussed in **Appendix C**.

Q DESPITE THE DIFFERENCES IN THE VARIOUS ALLOCATION METHODOLOGIES SHOWN IN EXHIBIT JP-5, DO THE RESULTS OF THE CORRECTED CLASS COST-OF-SERVICE STUDIES CONFIRM THAT CERTAIN RATE GROUPS ARE EITHER ABOVE OR BELOW PARITY?

A Yes. **Exhibits JP-7** and **JP-8** present the corrected CCOSS results at present rates under the 12CP/4CP and 4CP methods described above. The results are summarized in **Table 6** below. If the rates were at parity, each rate group would have a parity ratio (or relative rate of return) of 100%. As Table 6 demonstrates, the Medium and Large Business groups are well above parity, while the Domestic and Government/Institution groups are well below parity.

Table 6
Parity Ratios Derived From
Georgia Power Company's
Class Cost-of-Service Studies
At Present Rates By Rate Group

Rate Group/ Methodology	12CP/4CP	4CP/4CP
Domestic	83	81
Small Business	116	107
Medium Business	144	140
Large Business	137	146
Agricultural	100	146
Government/Institution	59	63
Lighting	126	139
Marginally Priced	105	118

Q REFERRING TO EXHIBITS JP-7 AND JP-8, PLEASE EXPLAIN THE TERMS RATE OF RETURN, RELATIVE RATE OF RETURN, AND SUBSIDY.

A The rate of return (column 3) is the net operating income (*i.e.,* revenues less allocated expenses – column 2) divided by the allocated rate base (column 1). The relative rate

of return or parity ratio (column 4) measures each rate group's rate of return (column 3) as a percent of the 6.31% Total Retail rate of return (line 9, column 3). The subsidy (column 5), measures the difference between actual revenues and the allocated costs. Thus, a negative amount means that a class is providing revenues less than its allocated costs, while a positive amount means that a class is providing revenues above its allocation costs.

Q DO YOU HAVE ANY FURTHER OBSERVATIONS ABOUT THE CORRECTED CLASS COST-OF-SERVICE STUDY RESULTS?

A Yes. The results for the Marginally Priced rate group are significantly affected by the test-year contribution to fixed costs by RTP customers. This is because RTP customers are included in this class, and the contributions to fixed costs is a large portion of the revenue stream from RTP sales. As discussed previously (in Section 2), fixed cost contributions from RTP sales during the test-year were only $95 million, which was only 50% of the ($191 million) of fixed cost contributions in the first seven months of 2022. Thus, the net revenues and rates of return from the Marginally Priced rate group are clearly under-stated. This group is clearly much more profitable to GPC than is indicated in the corrected CCOSSs.

Q DOES THE COMMISSION HAVE TO APPROVE A SPECIFIC CLASS COST-OF-SERVICE STUDY TO DETERMINE AN APPROPRIATE CLASS REVENUE ALLOCATION?

A No. Despite the different methodologies, the CCOSS results are relatively consistent. The rate groups that are below parity under GPC's preferred CCOSS are also below parity under each of the alternative CCOSSs, and vice versa.

Q WOULD RATES MOVE CLOSER TO PARITY UNDER GEORGIA POWER COMPANY'S PROPOSED CLASS REVENUE ALLOCATION?

A No. The movement to parity is shown in **Exhibit JP-9** using GPC's preferred CCOSS for illustrative purposes. As can be seen, GPC's equal percent base increases applied to each rate group would, for the most part, result in higher subsidies. Thus, rates would not move closer to parity.

Q HAS THE COMMISSION ENDORSED MOVING RATES CLOSER TO PARITY?

A Yes. In the 2010, 2013, and 2019 rate cases, the Commission approved class revenue allocations that moved rates closer to parity. In each case the Commission approved parity adjustments ranging from 75% to 125% of the system average base revenue increase.[10] For example, in 2010 the Commission found:

> …the allocation of costs and rate design contemplated and specified in the Stipulation are reasonable and in the best interests of all customer groups, and represent a balanced and fair settlement of the positions advocated by the parties in this docket.[11]

Furthermore, in the 2013 rate case the Commission stated:

> The resulting rate increases will be allocated by rate group using the revenue distribution method recommended by Staff Witness Watkins, with some exceptions and with the spread adjusted for balancing. (Panel Rebuttal Testimony, p.19). The exceptions are based on testimony by the Company and several intervenors with regard to further movements towards parity and the importance of the RTP rate to remain as currently designed and for further RTP tariff availability. (Panel Rebuttal Testimony, p 19-20). In order to further address rate parity issues, in particular with respect to the TOU-MB rate, that

[10] *Georgia Power Company's 2010 Rate Case*, Docket No. 31958, Direct Testimony and Exhibits of Glenn A. Watkins, Exhibit GAW-11, page 1, column 2 (Oct. 22, 2010); *Georgia Power Company's 2013 Rate Case*, Docket No. 36989, Joint Direct Testimony and Exhibits of Glenn A. Watkins and Jamie C. Barber, Staff Exhibit ___ (GAW/JCB-8), column 2 (Oct. 18, 2013).

[11] Docket No. 31958, *Final Order* at 15 (Dec. 29, 2010).

> group will receive a rate increase of 80% of what would otherwise be allocated Watkins' proposed revenue distribution method.[12]

In the most recent (2019) rate case, the Commission stated:

> The Proposed Agreement provides that beginning in 2021, with the adjustment to traditional base rate tariff, the rate increase shall be allocated by rate group, except as otherwise provided in Proposed Agreement, with adjustments for balancing. Rates in Medium Business and Large Business rate groups will receive 85% of the overall base rate increase with the resulting revenue deficiency being spread to the other rate groups excluding the Small Business, Lighting and Marginal rate groups which will receive the overall base rate increase (Agreement Provision 17). The Commission finds this provision of the Proposed Agreement to be just and reasonable, and is hereby approved.[13]

Q SHOULD RATES CONTINUE TO MOVE TOWARD PARITY?

A Yes. Base revenues should reflect the actual cost of providing service to each rate group as closely as practicable. Cost-based rates are fair (because each class's rates reflect its cost to serve, no more and no less); they are efficient (because, when coupled with a cost-based rate design, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility); they enhance revenue stability (because changes in revenues due to changes in sales will translate into offsetting changes in costs); and they encourage conservation (because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions).

Q ARE THERE ANY OTHER COMPELLING REASONS TO SET RATES CLOSER TO COST IN THIS PROCEEDING?

A Yes. As Dr. Tutterow testifies, manufacturing is essential to creating wealth for local

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[12] Docket No. 36989, *Order Adopting Settlement Agreement* at 10 (Dec. 17, 2013).

[13] *Georgia Power Company's 2019 Rate Case*, Docket No. 42516, Order Adopting Settlement Agreement as Modified at 13 (Feb. 6, 2020).

communities. However, economic activity has been slowing, industrial production has decreased modestly in three of the past five quarters, and inflation pressures are persuasive through the economy. Many businesses will face challenges because in a competitive global marketplace, it is difficult to pass along higher production costs, such as the cost of electricity. Further, as previously discussed, much higher RTP prices have already resulted in higher electricity costs. For all of these additional reasons, minimizing base rate increases to the Medium and Large Business and Marginally Priced classes is critical to retaining and potentially increasing manufacturing jobs (and the attendant economic benefits) in Georgia.

Q WHAT DO YOU RECOMMEND?

A Based on the CCOSS results shown in **Table 6** and **Exhibit JP-9**, I recommend that the Commission continue to move rate groups closer to parity. **Table 7** summarizes my recommended target parity adjustments.

Table 7
GAM Recommended
Target Relative Increases Excluding FCR

Rate Group	Relative Increase	With 7% Increase
Domestic	128%	9.0%
Small Business	77%	5.4%
Medium Business	77%	5.4%
Large Business	77%	5.4%
Agricultural	99%	6.9%
Government	128%	9.0%
Outdoor Lighting	77%	5.4%
Marginally Priced (Excluding RTP)	82%	5.7%

For example, if GPC receives a 7% base rate increase, the target base rate increases to each class before FCR charges would range from 5.4% to 9%. The specific parity adjustments will need to be refined to yield the Commission-approved revenue requirement.

Acknowledging gradualism, the target parity adjustments constrained to between 0.77 times and 1.28 times the system average revenue increase excluding FCR. These adjustments were applied to each rate group based on the current rate of return. Rate groups with current parity ratios above 100% would receive below system-average increases, while rate groups with current parity ratios below 100 would receive above system-average increases.

Q SHOULD THE SAME PARITY ADJUSTMENTS BE APPLIED IN DETERMINING THE 2024 AND 2025 BASE RATE INCREASES UNDER GEORGIA ASSOCIATION OF MANUFACTURERS' RECOMMENDED ALTERNATE RATE PLAN?

A Yes.

Q IF THE COMMISSION APPROVES LOWER BASE REVENUE INCREASES THAN GEORGIA POWER COMPANY IS PROPOSING, HOW SHOULD THESE LOWER INCREASES BE ALLOCATED BY RATE GROUP?

A The same parity adjustments should be applied.

6. OTHER TARIFF TERMS AND CONDITIONS

Q IS GEORGIA POWER COMPANY PROPOSING ANY CHANGES IN ITS TARIFF RULES?

A Yes. GPC is proposing Rule 9 be added to its Rules and Regulations for Electric Service, Contract and Enforcement Regulations, on January 1, 2023. Proposed Rule 9 states:

> Without restricting the limitations of liability provided elsewhere within these rules, to the extent a cognizable claim arises, the customer waives any right to consequential, special, indirect, treble, exemplary, incidental, punitive, loss of business reputation, interruption of electric service or loss of use (including loss of revenue, profits, or capital costs) damages in connection with any outage, surge, voltage fluctuation, disturbance or other variation or failure of electric service, or the Company's equipment, even where such variation, interruption, or failure of electric service was reasonably foreseeable, contemplated, or avoidable. To the extent the Company is liable under an agreement, and to the extent allowed by applicable law, the Company's liability is expressly limited to proven direct damages. The Company's liability for damage to personal property will be limited to the depreciated value of such personal property.[14]

Q WHAT IS THE REASON FOR HAVING A LIMITATION OF LIABILITY PROVISION?

A Limitation of liability provisions are designed to protect the utility from the risks of incurring costs caused by equipment failures and/or outages. Through Rule 9, GPC aims to limit its liability to compensate the customer based on net book value of the property damaged by an equipment failure or outage, even when damages are due to gross negligence.

Q WHAT IS NET BOOK VALUE?

A Net book value is an asset's original cost minus its accumulated depreciation.

[14] Application, MFRs, Traditional, F1 at 1.60.

Q WHAT ARE YOUR CONCERNS WITH THE PROPOSED RULE 9 LANGUAGE?

A Rule 9 absolves GPC of responsibility for any damages, even if equipment failures or outages were the result of gross negligence. Further, limiting damages to the net book value of the customer's damaged equipment is not a sufficient remedy.

Q WHAT IS GROSS NEGLIGENCE?

A Black's Law Dictionary defines gross negligence as: A conscious, voluntary act or omission in reckless disregard of a legal duty and of the consequences to another party, who may typically recover exemplary damages.[15]

Q HOW WOULD THE PROPOSED RULE 9 ABSOLVE GEORGIA POWER COMPANY OF LIABILITY DUE TO GROSS NEGLIGENCE?

A Rule 9 would waive GPC's liability, "even where such variation, interruption, or failure of electric service was reasonably foreseeable, contemplated, or avoidable."[16] This language demonstrates GPC's intent to leave customers defenseless against gross negligence through Rule 9.

Q SHOULD GEORGIA POWER COMPANY BE ABSOLVED OF ANY RESPONSIBILITY DUE TO GROSS NEGLIGENCE?

A No. GPC should be held accountable for its decisions and actions so that it does not prioritize its self-interest over the safety and well-being of customers. Further, it is well within the Company's direct control to avoid actions that could be deemed to be willful

[15] West Group, Bryan A. Garner, editor-in-chief, *Black's Law Dictionary*, 1st pocket ed. (1996).

[16] Application, MFRs, Traditional, F1 at 1.60.

misconduct or grossly negligent. Otherwise, customers would be placed in an unfairly vulnerable position.

Q WHY IS LIMITING COMPENSATION FOR DAMAGES BASED ON THE NET BOOK VALUE OF THE CUSTOMER'S DAMAGED EQUIPMENT CONCERNING?

A Net book value decreases an asset's worth through accumulated depreciation, which is the depreciation or amortization expense per year multiplied by the number of years. If GPC were to damage a fully depreciated asset, the asset's owner could not claim any compensation under Rule 9.

Q IS THE VALUE OF DAMAGED PROPERTY OR EQUIPMENT THE ONLY DAMAGES A CUSTOMER MAY INCUR AS A RESULT OF EQUIPMENT FAILURES OR SERVICE OUTAGES?

A No. Any service disruption (for whatever reason) can be costly to a customer. For example, product can be lost, order fulfillment delayed, and equipment may require additional maintenance and/or replacement. Some processes may require many hours or days to restore production to pre-outage levels.

Q WHY ARE YOU ASSERTING THAT THE PROPOSED RULE 9 IS NOT CONSISTENT WITH INDUSTRY BEST PRACTICES?

A I conducted a survey of electric utility tariffs to determine whether other utilities have a similar rule to Rule 9. Through this survey, I came to the conclusion that GPC's Rule 9 proposal is overly protective.

First, several utilities have specific language addressing gross negligence. For example:

- El Paso Electric Company states: "the **Company will be liable** to the Customer for any damages occasioned by such suspension only when the damages are the result of **gross negligence or willful misconduct** on the part of the Company."[17]

- Public Service Company of Oklahoma (PSO) states: "PSO will not be liable for any damages, whether direct or consequential, including without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by fluctuations or interruptions **unless it be shown PSO has not made reasonable provisions to supply steady and continuous electric service,** consistent with the customer's class of service or in compliance with Oklahoma Corporation Commission Electric Utility Rules."[18]

- PECO Energy Company states: "the liability of the Company to customers or other persons for damages, direct or consequential, including damage to computers and other electronic equipment and appliances, loss of business, or loss of production caused by any interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity shall in no event, **unless caused by the willful and/or wanton misconduct of the Company,** exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs."[19]

- Duke Energy Florida states: "The Customer shall indemnify, hold harmless and defend the Company from and against any and all liability, proceedings, suits, costs or expense for loss, damage, death or injury to persons or property, in any manner directly or indirectly connected with, or growing out of the use or disposition of electricity by the Customer at or on the Customer's side of the Point of Delivery, **unless such loss, damage, death or injury shall result from the sole negligence of the Company**.[20]

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[17] El Paso Electric Company, *Rules and Regulations Regarding Electric Service*, Section 2, Sheet No. 2, 13th Revision at 10-11 (Nov. 3, 2021). Emphasis added.

[18] Public Service Company of Oklahoma, *Electric Service Rules, Regulations and Conditions of Service*, Sheet No. 2-1, 8th Revision at (Jan. 31, 2022). Emphasis added.

[19] PECO Energy Company, Electric Service Tariff, Electric PA. P.U.C. No. 5, *Rules and Regulations*, Section 12.1 (Eff. Jan. 1, 2016). Emphasis added.

[20] Duke Energy, *Terms and Conditions of Service*, Part IV, Section 4.05 (Apr. 29, 2013).

Further, to the extent the utility is found to have been grossly negligent, the damages paid are not limited to the net book value of the customer's equipment. For example:

- CenterPoint Energy Houston Electric states: "Company will not be liable for any damages, whether direct or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity, occasioned by fluctuations or interruptions unless it be shown that Company has not made reasonable provision to supply steady and continuous Delivery Service, consistent with the Retail Customer's class of service, and in the event of a failure to make such reasonable provisions, whether as a result of negligence or otherwise, Company's liability shall be limited to the ***cost of necessary repairs of physical damage proximately caused by the service failure to those electrical delivery facilities of Retail Customer*** which were then equipped with the protective safeguards recommended or required by the then current edition of the National Electrical Code."[21]
- El Paso Electric Company states, "in the event of the Company's gross negligence or willful misconduct, the Company's liability under this paragraph will be limited to the **cost of necessary repair or replacement of tangible property damaged or destroyed** by the interruption or fluctuation."[22]

While the above examples specify a broad range of damage, the vast majority of tariffs are not specific about the amount of any damages. Therefore, the damages can be determined by litigation on a situational basis.

Q WHAT DO YOU RECOMMEND?

A I recommend that Rule 9 be revised to require that GPC be liable for damages from equipment failures or outages that are demonstrated to be the result of GPC's gross negligence. Further, the compensation to customers for such outages should be sufficient to at least replace any damaged equipment. Alternatively, the Rule should not limit the amount of the damages, consistent with industry practice.

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[21] CenterPoint Energy Houston Electric, LLC, *Tariff for Retail Delivery Service*, Section 5.2.1, Sheet No. 5.1 (Jan. 15, 2015).

[22] El Paso Electric Company, *Rules and Regulations Regarding Electric Service*, Section 2, Sheet No. 2, 13th Revision at 10-11 (Nov. 3, 2021).

7. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A The Commission should make the following findings:

- Securitization is a lower cost option than traditional recovery of retired assets and CCR costs.
- The remaining costs of Plant Wansley and the CCR costs incurred through 2022 but not yet recovered in rates, and up to 50% of the CCR costs GPC expects to occur in the ARP, should be identified and separated from the costs recovered in base rates and the ECCR.
- The base rate increases should be implemented in three steps.
- To alleviate rate pressure and to mitigate the amount of redundant capacity recovered in rates, GPC should amortize its remaining investment in Scherer Units 1, 2, and 3 over their current remaining lives.
- The authorized base rate increases should be spread to customer groups in a manner that continues the movement toward parity.
- The proposed Rule 9 should be modified so that GPC will be liable for damages that are determined to be the result of willful misconduct and gross negligence, and the amount of damages either should not be specified, or should be sufficient to at least replace the customer's damaged equipment and/or personal property.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY		10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Capacity Reservation Charge; Backup Power Charge; Maintenance Power; Distribution Capacity Costs	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021

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EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021

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ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020

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ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20165	Direct	MI	Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism	10/15/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design	10/1/2018
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Initial Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	9/27/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study; Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment	8/13/2018

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PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surrebuttal	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge	8/8/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Revenue Requirements; Tax Cuts and Jobs Act; Riders	8/1/2018
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/5/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation	6/26/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study; Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study; Revenue Allocation	5/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Surrebuttal	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins; Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM	11/21/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	10/3/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power Station	3/31/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues; Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas	3/3/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation	3/3/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016

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METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015

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ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015

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WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015

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WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014

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NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
SHARYLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013

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GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
SHARYLAND UTILITIES	Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebuttal	IA	Class Cost-of-Service Study	10/1/2013
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Exemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013

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MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental	TX	Competitive Generation Service Tariff	2/1/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental	TX	Competitive Generation Service Tariff	1/11/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012

APPENDIX C

Assessment of Georgia Power Company's Class Cost-of-Service Study

Procedures for Conducting a Class Cost-of-Service Study

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that

a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

Q DOES GEORGIA POWER COMPANY'S CLASS COST-OF-SERVICE STUDY GENERALLY FOLLOW THE ABOVE PROCEDURES?

A Yes. In particular, GPC classifies all production and transmission plant and related operating expenses as demand-related costs, and it also recognizes that a portion of the distribution network is a customer-related cost. The classification of these costs not only comport with generally accepted cost of service principles, they are consistent with cost causation and system planning criteria.

For example, GPC classified a portion of its distribution network investment as customer-related. This is consistent with the purpose of the distribution system, which is to deliver power from the transmission grid to the customer, where it is eventually

consumed. Certain investments (*e.g.,* meters, service drops) must be made just to attach a customer to the system. These investments are customer-related.

Classification of Distribution Network Costs

Q WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?

A The distribution "network" consists of GPC's investment in poles, towers, fixtures, overhead lines, and line transformers. These investments are booked to FERC Accounts 364, 365, 366, 367, and 368.

Q WHY IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?

A Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a physical connection and voltage support to allow electricity to be delivered to each and every customer regardless of the customer's peak demand or energy consumed. Further, that path and the required voltage support must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must be sized to provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.,* a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

Further, it is a recognized and accepted practice. For example, the National Association of Regulatory Utility Commission Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles,

> conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[23]

For this reason, many utilities and state regulatory commissions have approved CCOSSs in which a significant portion of the distribution network is classified as a customer-related cost.

Classification and Allocation of Production Plant

Q YOU PREVIOUSLY STATED THAT GEORGIA POWER COMPANY CLASSIFIED ALL PRODUCTION PLANT AS A DEMAND-RELATED COST. IS THIS PRACTICE CONSISTENT WITH COST CAUSATION?

A Yes. Classifying all production plant as a demand-related cost is consistent with system planning principles. It recognizes a utility's obligation to provide reliable service at the lowest reasonable cost. It also recognizes that once an investment is made to meet peak demand, that same investment can be used to meet demand throughout the year. The latter is a bi-product of meeting peak demand. Meeting peak demand is the cost-causer.

Further, proposals to classify production plant as energy-related are both overly simplistic and fraught with internal inconsistencies. For example, advocates of energy-based allocations often cite the lower cost of operating base load units as a reason to allocate the higher capital costs on an energy basis. However, such advocates often fail to allocate the lower fuel costs to those customer classes that purportedly benefit more from base load capacity. The reality is that all classes are served from system resources. Any methodology that is premised on an assumption that each customer

[23] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 90 (Jan. 1992).

class is served from a different mix of resources that does not also address the allocation of both capital costs and operating costs is, at best, an over-simplification of the planning process and is inherently flawed.

Q ARE THERE ANY ASPECTS OF GEORGIA POWER COMPANY'S CLASS COST-OF-SERVICE STUDY THAT DO NOT REFLECT COST-CAUSATION PRINCIPLES?

A Yes. GPC's preferred CCOSS allocates production and a portion of transmission costs using the 12CP method. The 12CP method allocates costs to customer classes based on their contribution to each of the 12 monthly system peaks. The 12CP method gives equal weight to all 12 monthly peaks. That is, March and April (which are always low demand months) are treated the same as July and August (which are always high demand months). This equal weighting fails to recognize that GPC has pronounced peaks in the summer.

Q DOES THE 12CP METHOD VIOLATE THE PRINCIPLE OF COST CAUSATION?

A Yes. Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate demand-related costs. If a utility is to fulfill its obligation to provide continuous service, it must install sufficient generation capacity to meet the expected peak demands of its customers and to provide an adequate reserve margin.

Thus, consistent with cost causation, a utility that has a high summer peak demand relative to the demands in other seasons should allocate production plant costs relative to each customer class's contribution to that summer peak (or peaks). Summer peak demands are still the primary driver in determining how much capacity is needed by GPC to provide reliable service.

Thus, either the 4CP or Annual System Peak (1CP) methods would explicitly recognize the seasonal (summer-peaking) nature of GPC's load and would be more appropriate and better reflect cost causation than the 12CP method.

Q GEORGIA POWER COMPANY IS EXPERIENCING A GROWING CONVERGENCE BETWEEN ITS SUMMER AND WINTER SYSTEM PEAKS. DOES THIS JUSTIFY USING THE 12CP METHOD?

A No. Despite the recent winter peaks, which are due to extreme cold weather, GPC is still projecting to be a summer-peaking utility on a weather-normalized basis. Thus, GPC continues to plan resources to meet the summer peak because the summer peaks are higher and more prolonged in nature than the recently experienced winter peaks. I would also observe that the entire southeast region remains summer-peaking.

Q IS THERE AN ALLOCATION METHODOLOGY THAT WOULD GIVE SOME WEIGHT TO THE GROWING WINTER PEAK DEMAND?

A Yes. As an alternative to 12CP, a methodology similar to what Santee Cooper uses (*i.e.,* the average of the summer and winter peaks) would give explicit weight to both the growing winter peak demand as well as the summer peak demand, which is still the primary planning criteria. Based on GPC's test-year load characteristics, the highest peak demands are projected to occur in the months January, June, July, August, September, and December. Thus, a method that reflects both seasonal peak demands would give weight to GPC's growing winter peak.

Marginal Cost Rates

Q HOW DOES GEORGIA POWER COMPANY HANDLE MARGINAL COST RATES, SUCH AS REAL TIME PRICING, IN ITS CLASS COST-OF-SERVICE STUDY?

A GPC's CCOSS includes both embedded costs and revenues, as well as marginal costs and revenues for RTP customers. Thus, GPC's CCOSS is a hybrid study which incorporates both embedded and marginal costing principles due to the inclusion of marginal cost-based rates (*i.e.,* RTP). GPC's hybrid treatment parallels the design of RTP in which a portion of the service (*i.e.,* the CBL) is priced under a standard tariff, which reflects average or *embedded* costs, while the incremental load is priced to reflect *marginal* costs. In GPC's CCOSS, embedded production and transmission costs are allocated to the CBL portion of the RTP loads using the same allocation methods as apply to all non-RTP classes. For the incremental loads, GPC allocates distribution costs for service provided at distribution voltage, and it directly assigns the marginal or incremental costs to the RTP classes. The latter step is accomplished by assuming that the test period incremental cost of serving RTP customers is equal to the expected incremental revenue, which is based on the revenue GPC expects to receive during the test period from customers on RTP rates.

Q IS IT REASONABLE TO ALLOCATE EMBEDDED COSTS ONLY TO THE CUSTOMER BASELINE LOAD PORTION OF REAL TIME PRICING?

A Yes. Embedded production and transmission costs are not allocated to the incremental RTP load because the incremental load is capable of responding to price under appropriate circumstances. Further, real time prices recover *marginal* production, transmission, and system energy costs. Therefore, it would be inappropriate to allocate

embedded production, transmission, and system energy costs to the incremental RTP load. To do so would charge RTP customers twice for these services.

Q SHOULD AN EMBEDDED CLASS COST-OF-SERVICE STUDY BE USED TO DETERMINE THE COST OF PROVIDING REAL TIME PRICING SERVICE?

A No. An embedded CCOSS should not be used to measure the cost of providing RTP service. This is because hourly (RTP) prices are based on *marginal* costs. An embedded CCOSS allocates average, rather than marginal costs, to customer classes. Thus, using an embedded CCOSS to determine the cost of providing RTP service would create an economic mismatch because the revenues are based on marginal cost, while the allocated costs are based on average costs. Incremental RTP load should be priced using marginal cost principles, and not allocated embedded costs.

Q DOES GEORGIA POWER COMPANY'S TREATMENT OF THE REAL TIME PRICING RATES IN ITS CLASS COST-OF-SERVICE STUDY RECOGNIZE THAT REAL TIME PRICING IS A MARGINAL COST-BASED RATE?

A Yes. GPC's adjustments appropriately recognize that a full allocation of embedded costs should only apply to the CBL component of the RTP usage, while incremental costs should be directly assigned to the marginal loads. The Commission should reject any attempt to allocate full embedded costs to loads which are priced through marginal cost methodologies.

Why Production Plant Costs Are Not Energy-Related

Q WHY DO SOME ANALYSTS RECOMMEND ALLOCATING A PORTION OF PRODUCTION PLANT COSTS ON AN ENERGY BASIS?

A Energy-based allocation methods are based on a theory that the "extra" investment

associated with certain types of generation (*i.e.*, units that are operated as base load and/or load following) provides fuel cost savings. Since fuel costs are typically allocated on an energy (or kWh) basis, the assumption is that this investment is also driven by kWh sales. This theory is referred to as Capital Substitution. Capital Substitution overlooks four realities:

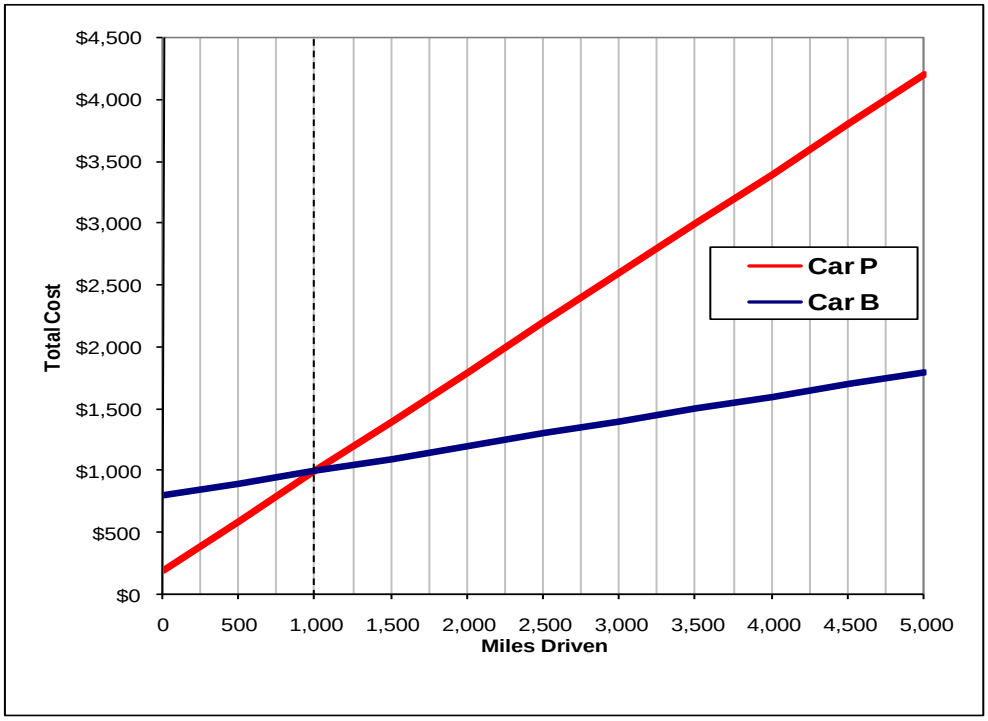
- The need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate a portion of production plant that GPC considers demand-related does not recognize the peak demands that drive capacity needs.
- Fuel savings are not a cost driver. All new plants save fuel costs because of improvements in generation technology, not because they are more capital intensive. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lower overall cost and not solely to lower fuel costs.
- Combined cycle gas turbines (CCGTs) have become the technology of choice not because they have lower fuel costs but because they can provide flexible load following capabilities needed to balance loads and resources in real time and meet operating reserve requirements.
- An energy allocation assumes all hours are critical to the choice of generation. However, not all production from a specific plant determines the type of capacity to install. **Thus, allocating investment to all hours is contrary to cost causation.**

Q HOW IS ALLOCATING INVESTMENT TO ALL HOURS CONTRARY TO COST CAUSATION?

A The following simplified example of how an energy allocation is contrary to cost causation. Let us suppose two drivers are required to rent cars from a fleet that contains only two types of cars, "**Car P**" and "**Car B**":

	Car P	**Car B**
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high mileage (like a base load plant), while **Car P** has a low fixed charge but gets poor mileage (like a peaker). The graph below shows total cost of both cars over a range of miles driven.



The total cost is also calculated in the following table. As can be seen, the *break-even point* between **Car P** and **Car B** is 1,000 miles.

Miles Driven	Total Cost			Best Choice
	Car P		Car B	
0	$200		$800	P
500	$600		$900	P
1,000	$1,000		$1,000	P or B
1,500	$1,400		$1,100	B
2,000	$1,800		$1,200	B
2,500	$2,200		$1,300	B
3,000	$2,600		$1,400	B
3,500	$3,000		$1,500	B
4,000	$3,400		$1,600	B
4,500	$3,800		$1,700	B
5,000	$4,200		$1,800	B

That is, **Car B** has a lower total cost per mile than **Car P** if it is operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose to drive **Car B**. In other words, the decision to drive **Car B** was based on whether the car would be driven at least 1,000 miles. It doesn't matter how many miles over 1,000 it will be driven.

The same break-even construct applies to electric utilities. For example, assuming the break-even point between Base Load and Peaking capacity is 1,000 hours per year, it doesn't matter whether the Base Load plant will operate 5,000 hours, 6,000 hours, of 8,000 hours per year. Thus, ***load duration*** can affect the decision of whether to install Base Load or Peaking capacity. However, once the decision is made, duration beyond the break-even point is irrelevant.

Energy-based allocation methods ignore this fundamental planning construct because investment would be allocated to all kWh usage. *This is at odds with Capital Substitution because the extra investment in base load generation can be justified by load duration up to the economic break-even point between Base Load and Peaking capacity*. That is, once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then a load following or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

Q WHY ELSE ARE ENERGY-BASED ALLOCATION METHODS WRONG?

A Energy-based allocation methods also suffer from the lack of symmetry in how plant and fuel costs are allocated (*i.e.*, the "Fuel Symmetry" problem) and average demand is double-counted (i*.e.*, the Double-Counting" problem).

The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s (see for example Docket No. 5560; Docket No. 5700; Docket Nos. 7460 and 7172; Docket No. 8032).

For example, in Docket No. 7460, the Commission adopted the Hearing Examiner's Report, which cited the apparent lack of "fuel symmetry" in rejecting capital substitution, and energy-based allocation method.

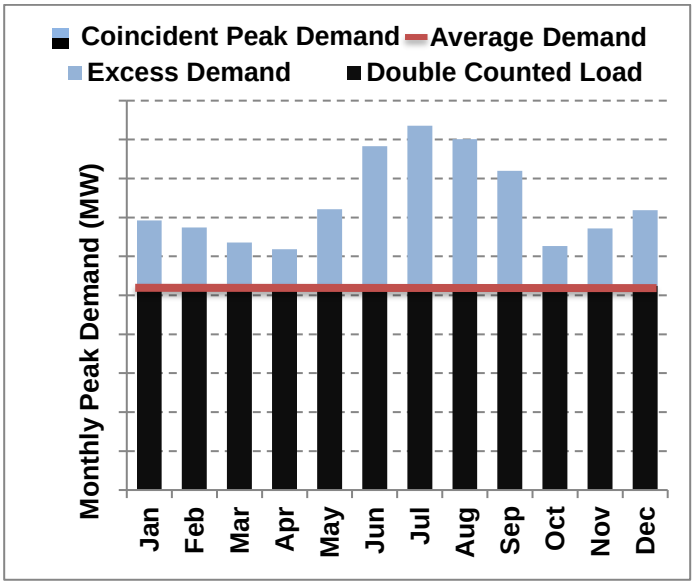
> The Examiner's find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal, the high load factor classes, which will bear the higher cost responsibility for base load units will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[24]

Q WHAT IS THE DOUBLE-COUNTING PROBLEM INHERENT IN AN ENERGY-BASED ALLOCATION METHOD?

A Double-counting can occur when plant-related costs are properly allocated partially on a coincident peak basis and an average demand (or energy) basis. Average demand is annual energy consumption divided by 8,760 hours. It is also a component of

[24] *Application of El Paso Electric Company for Authority to Change Rates* and *Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Consolidated Docket Nos. 7460 and 7172, Examiner's Report, at 238 (Jun. 16, 1988), adopted in Second Order on Rehearing (May 10, 1989), 14 Tex. P.U.C. Bull. 929.

coincident peak demand. This is illustrated in the following figure for a hypothetical summer peaking utility.



Average demand is equivalent to the black shaded area of the chart. Coincident peak demand is represented by the combined black and blue shaded areas. Double-counting occurs because coincident peak demand incorporates average demand.

By allocating some plant-related costs relative to average demand and some relative to coincident peak demand, energy usage is counted twice in the allocation process: once by itself and a second time as a subset of coincident peak demand. If you presume that base load units are built to meet average year-round demand, then it follows that the only time load-following (*e.g.*, intermediate and peaking) units would be needed is when system demands exceed the average demand. Capital Substitution proponents would allocate the cost of this additional capacity relative to coincident peak demand (*i.e.*, the entire bar including both the black and blue portions of the bars), rather than just the excess demand (*i.e.*, the blue portion of the bar).

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLOW IN ENERGY-BASED ALLOCATION METHODOLOGIES?

A Yes. For example, both the Iowa Utilities Board and the Public Utility Commission of Texas have cited the double-counting problem in numerous cases. Specifically, the Public Utility Commission of Texas states:

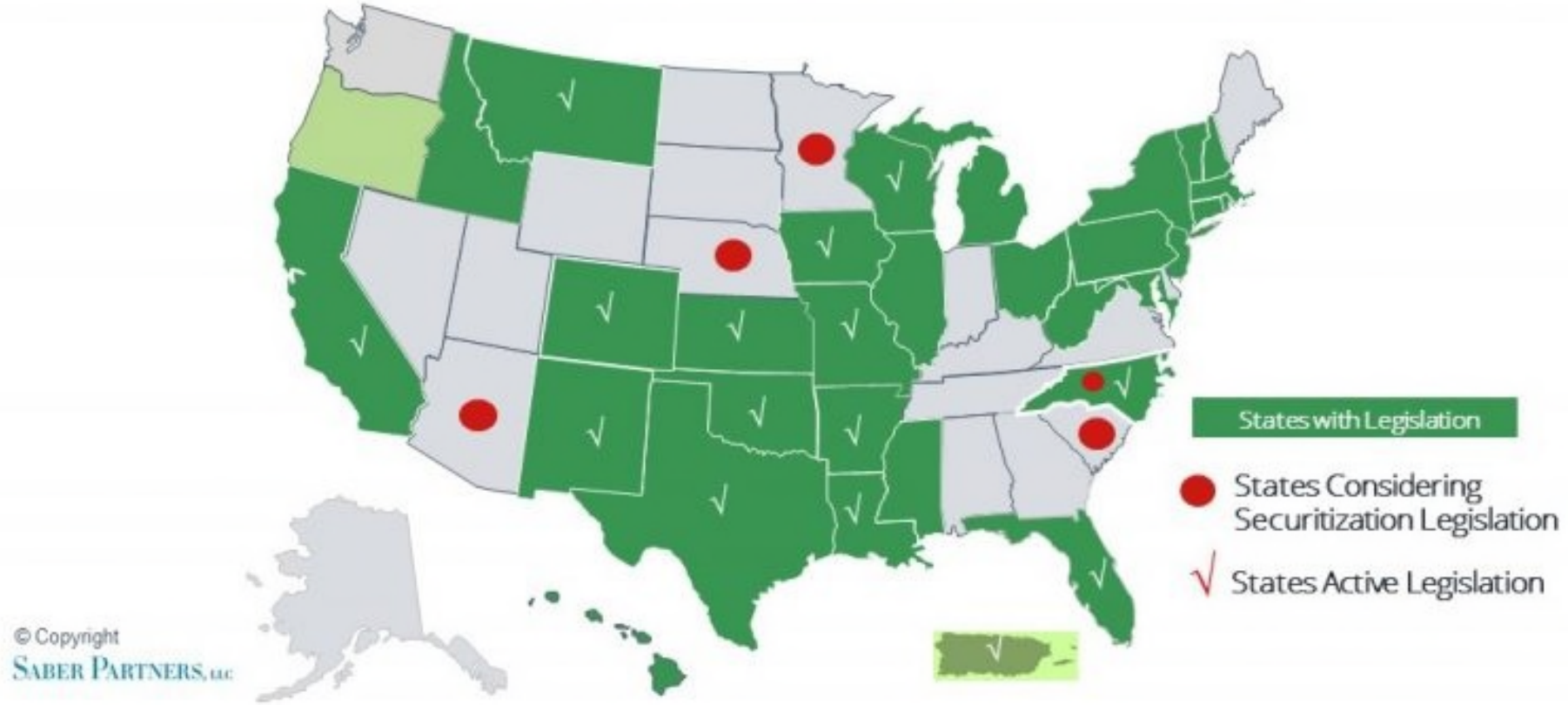
> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak energy usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and this "double dipping" is taking place.[25]

[25] *Id.* at 199.

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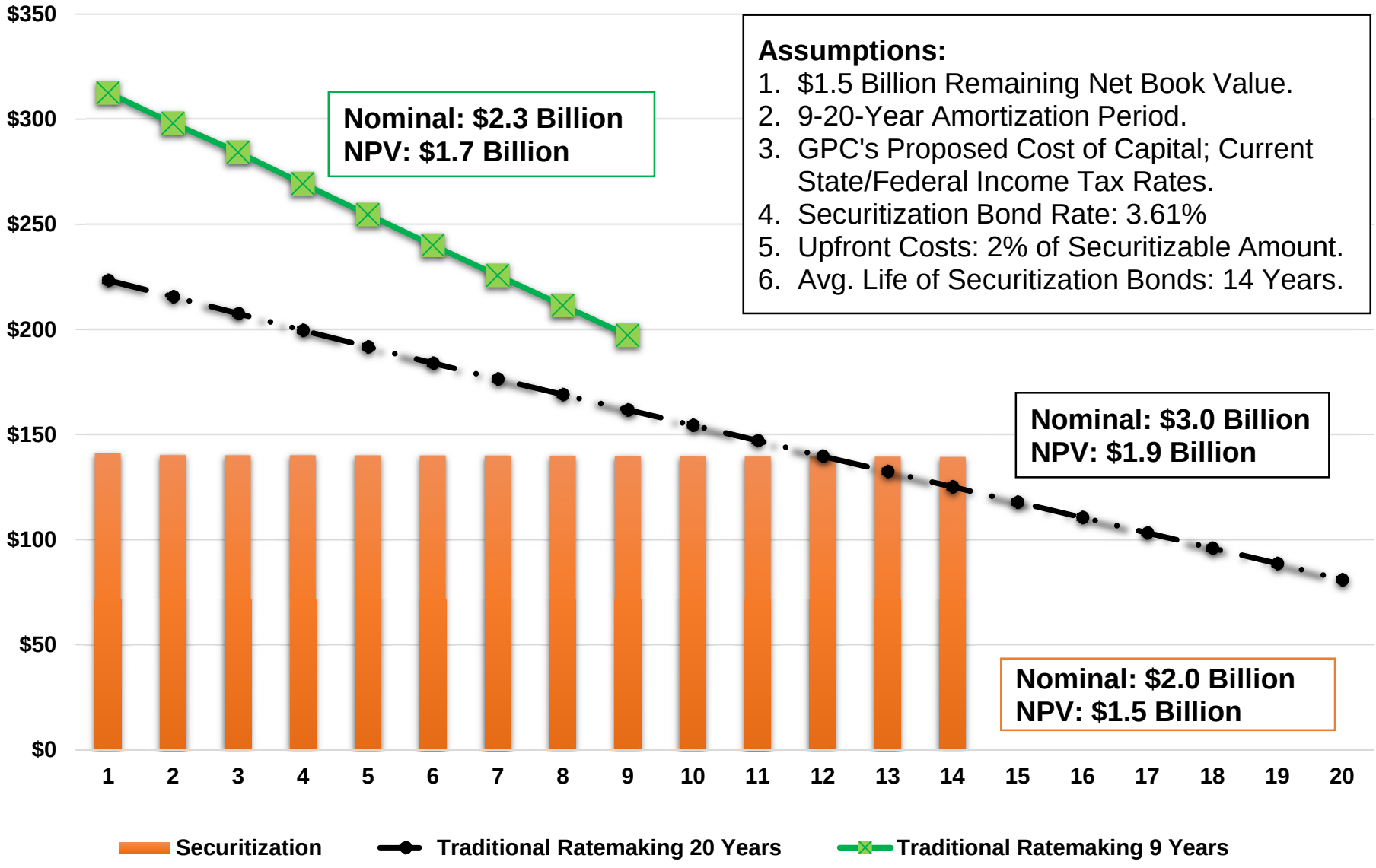
Utility Securitization as of June 2021

Since 1997 Ratepayer-Backed Bond Laws: 27 States + DC + Puerto Rico
15 Active and Can Issue Now, 5 Considering Legislation



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Regulated utilities - US

Utility cost recovery through securitization is credit positive

Utility cost recovery charge (UCRC) securitization, a financing technique used to recover stranded costs, storm costs and other expenses, can be a credit positive tool for regulated utilities. UCRC securitization, whereby utilities issue bonds with lower financing costs that are paid back through a special customer charge, is typically underpinned by state legislation and in recent years has become more versatile and widespread. The ability to use securitization as a tool to recover, often significant, costs related to large or unforeseen developments allows utilities to avoid potentially credit negative events. However, though the mechanism typically benefits utilities and their customers, too much securitization can have negative consequences.

» **Securitization typically benefits utilities and their current customers.** Utilities benefit because they receive an immediate source of cash from the securitization proceeds and are ensured recovery of large costs in a timely manner that may, otherwise, be recovered over a lengthy period of time or denied recovery altogether. Current utility customers benefit because the cost of the securitized debt is lower than the utility's cost of debt, which reduces the impact on their monthly bills.

» **UCRC securitization has become more versatile and prevalent.** Utility securitization became widespread for the recovery of stranded costs following deregulation of the sector in the late 1990s. It is now used to recover costs associated with storm restoration and environmental costs, utility restructuring, deferred fuel costs and renewable energy projects.

» **State law and financing orders strongly protect securitization assets.** There are three major components of a UCRC securitization—state legislation, a financing order and a true-up mechanism—which ultimately protect the assets backing the bonds.

» **Too much securitization can have negative consequences.** The use of securitization removes the utility's opportunity to include the corresponding asset in its rate base and the ability to earn a return on that asset. A significant amount of securitization debt could impact customer bills substantially while hurting the utility's financial flexibility and ability to raise rates for other reasons, such as to recover future costs and investments.

Securitization typically benefits utilities and their current customers

UCRC securitization was widely used after the deregulation of the utility sector in the late 1990s as a way to finance so-called stranded costs—the shortfall between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation assets. In UCRC securitization, utilities issue bonds with lower financing costs that are paid back through a discrete customer charge. We typically view use of the technique as credit positive for utilities.

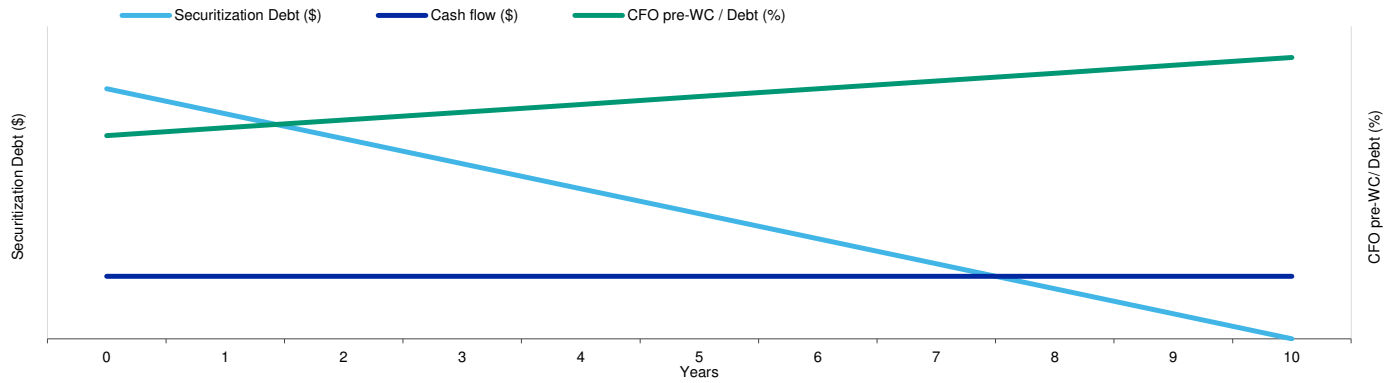
A utility benefits from the securitization because it receives an immediate source of cash. The ability to use securitization generally means the utility is allowed to recover all or most of the costs in question in a timely manner. The ability to use securitization as a tool to recover costs related to large or unforeseen developments allows utilities to avoid potentially credit negative events. The utility's ratepayers benefit because customer rates are lower than if the securitization was not utilized and in many cases avert the need for a substantial rate increase. Under state legislation, the utility must show that the savings to its customers on a net present value basis will be higher than they would have been without securitization.

The savings result from the cost of the securitized debt being lower than the utility's unsecuritized cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery. The special surcharges involved are also spread out over a long period, typically corresponding to the maturity of the securitization bonds. This eases the impact on customer bills when compared with requesting cost recovery from customers through a one-time payment.

Exhibit 1 shows an illustrative example of the potential impact over time on a utility's ratio of cash flow from operations pre-working capital changes (CFO pre-W/C) to debt, all else being equal. Depending on the size of the securitization debt as a proportion of total debt, the impact on a utility's financial metrics can vary. If the securitization is a significant component of total debt then a utility's ratio of CFO pre-W/C to debt could be severely negatively affected.

Exhibit 1

Illustrative example of the impact UCRC securitization can have on a utility's ratio of CFO pre-W/C to debt



Source: Moody's Investors Service

In the presentation of securitization debt in our published financial ratios, we make our own assessment of the appropriate credit representation, but in most cases we follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most cases, utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

We typically view securitization debt of utilities as on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's financial ratios by including the securitization debt and related revenues in our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of financial ratios that

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exclude securitization debt and related revenues to ensure that the benefits of securitization are not ignored. Since securitization debt amortizes mortgage-style, including it makes financial ratios look worse in early years, when most of the revenue collected goes to pay interest, and better in later years, when most of the revenue collected goes to pay principal.

CenterPoint Energy Houston Electric has a long history of issuing securitization bonds

In 1999, the Texas legislature adopted the Texas Electric Choice Plan, under which integrated utilities operating within the Electric Reliability Council of Texas, Inc. (ERCOT, Aa3 stable) were required to unbundle their operations into separate retail sales, power generation, and transmission and distribution companies. The legislation provided for a transition period and a true-up mechanism for the utilities to recover stranded and certain other costs resulting from the transition. Those costs were recoverable, after approval by the Public Utility Commission of Texas (PUCT), either through the issuance of securitization bonds or through the implementation of a competition transition charge as a rider to the utility's tariff.

In the early 2000s, CenterPoint Energy Houston Electric, LLC (CEHE, A3 stable) restructured its business in accordance with the new law and its generating stations were sold to third parties. Over the years that followed, CEHE has worked with regulators to obtain recovery of most its stranded assets and associated costs through the use of securitization bonds and other regulatory mechanisms.

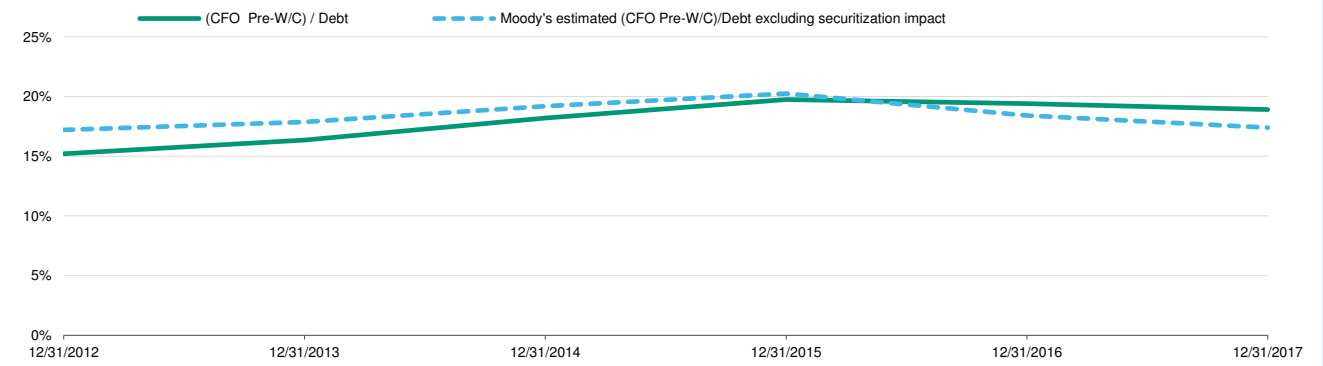
In October 2011, PUCT approved a final order that allowed CEHE to recover an additional $1.695 billion of stranded costs through the use of securitization bonds. In January 2012, CEHE created a new special purpose subsidiary, CenterPoint Energy Transition Bond Company IV, LLC, which issued $1.695 billion of securitization bonds in three tranches with interest rates ranging from 0.9012% to 3.0282% and final maturity dates ranging from April 15, 2018 to October 15, 2025. The securitization bonds will be repaid over time through a charge imposed on customers in CEHE's service territory.

The overall time-weighted interest rate of approximately 2.5% for the securitization bonds was substantially lower than the average rate on CEHE's unsecuritized debt of about 7.66% at that time. The PUCT estimated that the reduced interest charges from the securitization of the stranded costs resulted in savings for CEHE's customers of more than $700 million over the life of the bonds.

Exhibit 2 shows our estimate of the impact on CEHE's ratio of CFO pre-W/C to debt from 2012 through 2017 due to the impact of the $1.695 billion securitization debt. We estimate that the securitization debt had at most a 200-basis-point impact on CEHE's ratio of CFO pre-W/C to debt either positive or negative, depending on the year.

Exhibit 2

How CEHE's ratio of CFO pre-W/C to debt was impacted by securitization debt from 2012 through 2017



Source: company's filings, Moody's Investors Service

UCRC securitization has become more versatile and widespread

UCRC bonds were created after the deregulation of utilities in the late 1990s as a way to finance stranded costs. To date, more than 20 states have used this model to recover not only stranded costs but also costs associated with storm recovery and to a lesser degree environmental restoration, utility restructuring, deferred fuel costs and renewable energy projects.

In June 2005, for example, Section 366.8260 of the Florida Statutes was enacted through Senate Bill 1366, allowing the Florida Public Service Commission to authorize the state's utilities to securitize storm recovery costs. Following Hurricanes Katrina, Rita and Wilma in 2005, Arkansas, Louisiana, Mississippi and Texas joined Florida by passing special legislation giving utilities operating in their jurisdictions the option of utilizing securitization for recovery of storm costs. Recently in California, legislators are considering an amended version of Assembly Bill 33 which, as amended, would allow securitization to be used for prudently incurred costs arising from wildfires, a credit positive step for utilities dealing with potentially significant wildfire-related liabilities. Exhibit 3 shows a list of securitizations completed by utilities in recent years.

In each case, with the exception of the Entergy New Orleans LLC's (ENO, Ba1 stable) bond issuance (Aa1 (sf)) in 2015, we rated the securitization bonds Aaa (sf) owing to the strength of the state legislation, including the state's non-impairment pledge, the irrevocable financing order typically from the state public utility commission, credit enhancement consisting of a statutory uncapped true-up adjustment mechanism, the manageable size of the cost recovery charge and the remote likelihood of a successful legal, political or regulatory challenge, among other factors.

The Aa1 (sf) rating on ENO's securitization bond issuance, which is one-notch lower than the typical Aaa (sf) rating, reflects the relative small size and concentration of the ratepayer base from whom the storm recovery charge will be collected. The bonds are exposed to the risk of declines in the rate payer base in the service area of ENO in case of severe events, such as anther severe hurricane.

Exhibit 3

Moody's rated UCRC securitizations issued since 2012

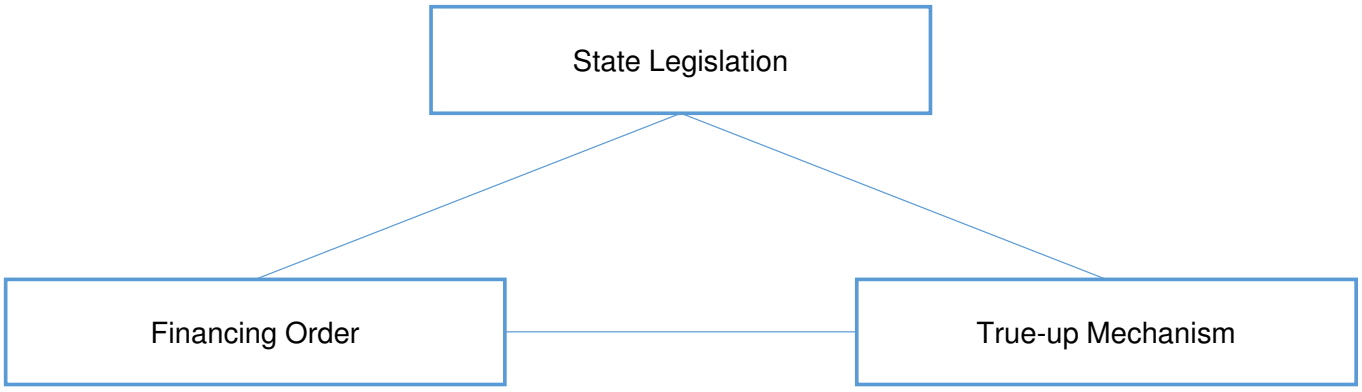
Deal Name	Servicer	Issuance ($ millions)	Year Completed	Rating (sf)	State
PSNH Funding LLC 3, Series 2018-1	Public Service Co. of New Hampshire	$636	2018	Aaa	New Hampshire
Utility Debt Securitization Authority Restructuring Bonds, Series 2017	Long Island Power Authority	369	2017	Aaa	New York
Utility Debt Securitization Authority Restructuring Bonds, Series 2016B	Long Island Power Authority	469	2016	Aaa	New York
Duke Energy Florida Project Finance, LLC	Duke Energy Florida LLC	1294	2016	Aaa	Florida
Utility Debt Securitization Authority Restructuring Bonds, Series 2016A	Long Island Power Authority	637	2016	Aaa	New York
Utility Debt Securitization Authority Restructuring Bonds, Series 2015	Long Island Power Authority	1002	2015	Aaa	New York
Entergy New Orleans Storm Recovery Funding I, L.L.C.	Entergy New Orleans LLC	99	2015	Aa1	Louisiana
State of Hawaii Department of Business, Economic Development, and Tourism - Green Energy Market Securitization Bonds, 2014 Ser. A	Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited	150	2014	Aaa	Hawaii
Louisiana Local Government Environmental Facilities and Community Development Authority - System Restoration Bonds (Louisiana Utilities Restoration Corporation Project/EGSL), Ser. 2014 (Federally Taxable)	Entergy Gulf States Louisiana, L.L.C.	71	2014	Aaa	Louisiana
Louisiana Local Government Environmental Facilities and Community Development Authority - System Restoration Bonds (Louisiana Utilities Restoration Corporation Project/ELL), Ser. 2014 (Federal Taxable)	EL Investment Company, LLC	244	2014	Aaa	Louisiana
Consumer 2014 Securitization Funding LLC - Senior Secured Securitization Bonds, Series 2014-A	Consumers Energy Company	378	2014	Aaa	Michigan
Utility Debt Securitization Authority Restructuring Bonds Series 2013T and Series 2013TE	Long Island Power Authority	2022	2013	Aaa	New York
Appalachian Consumer Rate Relief Funding LLC - Senior Secured Consumer Rate Relief Bonds	Appalachian Power Company	380	2013	Aaa	West Virginia
Ohio Phase-In-Recovery Funding LLC	Ohio Power Company	267	2013	Aaa	Ohio
FirstEnergy Ohio PIRB Special Purpose Trust 2013	Cleveland Electric Illuminating Company (The), Ohio Edison Company, Toledo Edison Company	445	2013	Aaa	Ohio
AEP Texas Central Transition Funding III LLC, Senior Secured Transition Bonds	AEP Texas Central Company	800	2012	Aaa	Texas
CenterPoint Energy Transition Bond Company IV, LLC, Series 2012 Senior Secured Transition Bonds	CenterPoint Energy Houston Electric, LLC	1695	2012	Aaa	Texas

Source: Moody's Investor Service

State law and financing order strongly protect the securitization assets

There are three major components of a UCRC securitization: state legislation, a financing order and a true-up mechanism, as shown in Exhibit 4. The securitization law and financing order legally protect the assets backing the bonds.

Exhibit 4
UCRC securitization has three major components



Source: Moody's Investors Service

The state legislature typically passes a law authorizing the utility to finance the recovery of certain costs through the issuance of securitization bonds. The legislation authorizes the creation of a property right allowing the issuer to collect special charges from customers which are used to repay the bonds. Bondholders receive protection through a non-impairment pledge, under which the state pledges that it will not take any actions that alter the charges or the law until the bonds have been repaid in full.

The legislation also mandates an irrevocable financing order, typically issued by the state public utility commission, which means the state cannot change or revoke the financing order once it is issued. The order authorizes the transaction servicer, typically the utility, on behalf of the issuer of the debt, to charge and collect the special surcharges from the utility's ratepayer base.

The securitization law and the financing order mandate a true-up adjustment mechanism under which the servicer must adjust the charges at least annually to ensure the collection of adequate funds to provide for timely payments on the securitization bonds. The securitization law also establishes the issuer of the debt as a bankruptcy-remote special purpose entity (SPE), and the utility sells the securitized asset (the property right) to the SPE via a true sale transaction. The assets are thus legally isolated from the utility. The SPE issues the bonds and uses the proceeds to acquire the asset. The SPE then uses the charge collected from the utility's customers to pay debt service until the bonds are repaid in full. The utility receives the proceeds from the bond issuance.

Too much securitization can also have negative consequences

While the use of securitization does provide more timely recovery of costs for the utility, there can be some downside. In cases where utilities use securitization to recover stranded costs, the mechanism requires utilities to give up the opportunity to include the corresponding asset in its rate base as well as the ability to earn a return on that asset. This diminishes the utility's future earnings power and cash flow generation.

A significant amount of securitization debt could represent a substantial portion of the utility's customer bills. This would not only raise customer rates but could also prevent regulators from approving rate increases in the future, out of concern that rates are rising too much. This could in turn affect the utility's capital investments and the ability to add any such investments to rate base and earn on a return on them.

In addition, since the surcharge on customer bills used to pay off the securitization bonds will typically exist for several years, any new customers in the utility's service territory will be subject to this surcharge. As a result, future customers will be paying for costs related to historical occurrences, which may deter new commercial and industrial businesses from moving into the service territory if rates become less competitive.

Further, customer rates or cash flow used to service securitization debt is senior and has a higher legal priority to the utility's remaining cash flow generation. As such, securitization bondholders would have a senior claim in a liability waterfall during times of financial distress. So a significant amount of securitization debt within a capital structure could put secured and unsecured debt holders at risk of less than full recovery in a bankruptcy filing.

Pacific Gas & Electric's securitization during bankruptcy in the early 2000's demonstrates the enforceability and resiliency of the legal structure

In 1997, Pacific Gas & Electric Company (PG&E, A3 negative) issued $2.9 billion of securitization bonds after obtaining approval by the California Public Utility Commission to recover stranded asset costs associated with the state's utility deregulation. When PG&E filed for bankruptcy on 6 April 2001, both the company and bankruptcy court respected the bankruptcy-remote structure of the securitization that the parties had established in order to isolate the assets of PG&E's securitization from PG&E's bankruptcy estate. PG&E remained the servicer of the transaction and continued to collect and remit the securitization payment. The securitization cash flows were not affected by the bankruptcy due to a build-up in the reserve fund and the base level of customer consumption used to calculate the 2001 tariff remained relatively stable. For these reasons among others, the Aaa (sf) rating on PG&E's stranded costs recovery securitization bonds was maintained throughout the company's bankruptcy.

The bankruptcy remoteness of securitization transactions is stronger than that of other, purely corporate asset-backed securities for several reasons including the explicit recognition, by state legislation, of the right to collect the special surcharge from customers as well as the first lien on the asset that is often granted by statute upon its transfer. The consumption-based fee is imposed on ratepayers and is not dependent on a particular electrical supplier. The fee is not affected if the servicer becomes bankrupt. The underlying legislation usually requires that any successor to the original utility (due to bankruptcy, reorganization, merger, or acquisition) must satisfy all obligations of the original utility, including the collection of the special surcharge. The right to collect the special surcharge is irrevocable and cannot be altered by either the state utility commission or the state.

In January 2005, PG&E issued $1.9 billion of securitization known as energy recovery bonds (ERBs). The securitization financing accelerated the company's collection of the regulatory asset that was created as part of PG&E's bankruptcy. A second securitization financing was completed in late 2005 which enabled PG&E to largely recover the entire regulatory asset. This was another example where securitization was used as a tool to significantly reduce the uncertainty and length of time in the recovery of significant costs, a credit positive, while also reducing costs for customers by keeping rates lower over the long-term.

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» Cross-Sector – US: FAQ on the Credit Impact of New Tax Law 24 January 2018

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» Regulated Electric & Gas Utilities – US: Insulating Utilities from Parent Contagion Risk is Increasingly a Focus of Regulators 18 September 2017

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» 2001 Review and 2002 Outlook: Stranded Utility Costs Securitization Credit Issues In Spotlight; "Lights Out?" 11 January 2002

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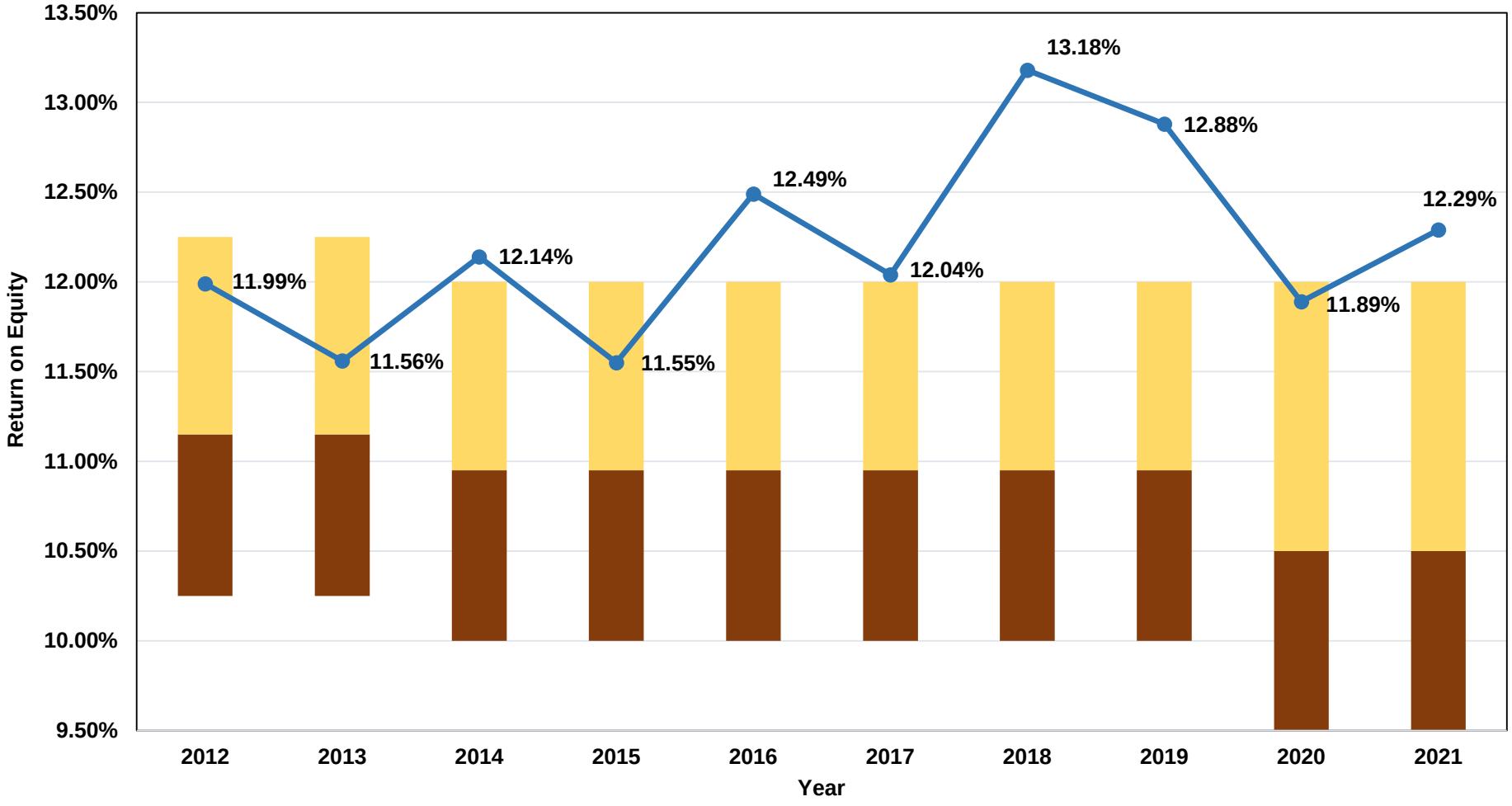
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REPORT NUMBER 1128247

GEORGIA POWER COMPANY
Authorized Versus Earned Return on Equity



ROE Range									
	10.25%	11.15%	12.25%	10.00%	10.95%	12.00%	9.50%	10.50%	12.00%

Source: Annual Surveillance Reports.

GEORGIA POWER COMPANY
GPC's Proposed Class Revenue Allocation
Test Year Ending July 31, 2023
(Dollar Amounts in Thousands)

Line	Rate Group	Revenue at Present Rates Excl. FCR	Proposed Increase Amount ($000)	Proposed Increase Percent
		(1)	(2)	(3)
1	Domestic	$2,934,736	$428,026	14.6%
2	Small Business	646,878	95,689	14.8%
3	Medium Business	989,821	145,195	14.7%
4	Large Business	216,955	31,452	14.5%
5	Agricultural	14,316	2,100	14.7%
6	Government/Institution	117,104	17,224	14.7%
7	Outdoor Lighting	120,753	17,602	14.6%
8	Marginally Priced	1,050,893	114,512	10.9%
9	Total Retail	$6,091,456	$851,800	14.0%

GEORGIA POWER COMPANY

Comparison of Demand Allocation Methods

Line	Rate Group	Average of 12 Monthly Coincident Peaks	Average of 4 Summer/ 2 Winter Monthly Coincident Peaks	Average of 4 Summer Coincident Peaks
		(1)	(2)	(3)
1	Domestic	50.36%	52.24%	51.12%
2	Small Business	7.86%	7.97%	8.44%
3	Medium Business	16.65%	16.19%	16.99%
4	Large Business	4.18%	4.01%	4.01%
5	Agricultural	0.21%	0.17%	0.14%
6	Government/Institution	2.84%	2.79%	2.76%
7	Outdoor Lighting	0.14%	0.11%	0.00%
8	Marginally Priced	17.76%	16.53%	16.53%
9	Total Retail	100.00%	100.00%	100.00%

Source: GPC Response to STF-TAI 1-1, Attachments A and C.

GEORGIA POWER COMPANY

Corrected Class Cost-of-Service Study Results
At Present Rates By Rate Group
12CP/4CP Method
Test Year Ending July 31, 2023
(Dollar Amounts in Thousands)

Line	Rate Group	Rate Base	Operating Income at Present Rates	Rate of Return	Relative Rate of Return	Subsidy
		(1)	(2)	(3)	(4)	(5)
1	Domestic	$12,839,314	$669,011	5.21%	83	($189,392)
2	Small Business	2,320,075	169,126	7.29%	116	30,430
3	Medium Business	3,546,941	321,763	9.07%	144	131,237
4	Large Business	797,199	69,074	8.66%	137	25,147
5	Agricultural	56,311	3,558	6.32%	100	6
6	Government/Institution	582,289	21,638	3.72%	59	(20,255)
7	Outdoor Lighting	415,504	33,059	7.96%	126	9,163
8	Marginally Priced	3,460,494	228,591	6.61%	105	13,664
9	Total Retail	$24,018,127	$1,515,820	6.31%	100	$0

GEORGIA POWER COMPANY

Corrected Class Cost-of-Service Study Results
At Present Rates By Rate Group
4CP Method
Test Year Ending July 31, 2023
(Dollar Amounts in Thousands)

Line	Rate Group	Rate Base	Operating Income at Present Rates	Rate of Return	Relative Rate of Return	Subsidy
		(1)	(2)	(3)	(4)	(5)
1	Domestic	$12,921,507	$657,717	5.09%	81	($211,484)
2	Small Business	2,383,491	160,412	6.73%	107	13,386
3	Medium Business	3,583,468	316,744	8.84%	140	121,420
4	Large Business	778,999	71,574	9.19%	146	30,039
5	Agricultural	49,161	4,541	9.24%	146	1,927
6	Government/Institution	573,773	22,808	3.98%	63	(17,966)
7	Outdoor Lighting	399,991	35,191	8.80%	139	13,333
8	Marginally Priced	3,327,737	246,833	7.42%	118	49,345
9	Total Retail	$24,018,127	$1,515,820	6.31%	100	$0

GEORGIA POWER COMPANY

Movement to Parity Using GPC's Proposed Class Revenue Allocation

12CP/4CP Method

Test Year Ending July 31, 2023

(Dollar Amounts in Thousands)

		Present Rates			Proposed Rates			
Line	Rate Group	Rate of Return	Relative Rate of Return	Subsidy	Rate of Return	Relative Rate of Return	Subsidy	Movement to Parity
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Domestic	5.21%	83	($189,392)	7.70%	86	($216,711)	-14%
2	Small Business	7.29%	116	30,430	10.37%	116	43,838	-44%
3	Medium Business	9.07%	144	131,237	12.13%	135	150,641	-15%
4	Large Business	8.66%	137	25,147	11.61%	130	28,326	-13%
5	Agricultural	6.32%	100	6	9.10%	102	109	-1761%
6	Government/Institution	3.72%	59	(20,255)	5.92%	66	(23,682)	-17%
7	Outdoor Lighting	7.96%	126	9,163	11.12%	124	12,030	-31%
8	Marginally Priced	6.61%	105	13,664	9.07%	101	5,450	60%
9	Total Retail	6.31%	100	$0	8.96%	100	$0	-11%