BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

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

REDACTED – PUBLIC DISCLOSURE VERSION

DIRECT TESTIMONY OF KEVIN LUCAS AND THATCHER YOUNG

Presented as a panel on behalf
of the Georgia Solar Energy Industries Association,
Solar Energy Industries Association, and Vote Solar

October 20, 2022

Table of Contents

I. Introduction and Qualifications 1
II. The Commission and the Public Are Harmed by the Inability of Intervenors to Propound Discovery on the Company 7
III. Georgia Power's Proposed $200 Flat Interconnection Fee Should be Rejected 15
The Company's Proposal is Overly Vague 16
The Company's Interconnection Fee Analysis Contains Inconsistent, Unsupported, and Erroneous Data 17
The Company's Hearing Witness Directly Contradicted GPC's Testimony and Discovery Answers and Was Unable to Provide Additional Details 22
Under the Company's Proposal, Customers with Small Systems Would Subsidize Customers with Larger Systems 26
There is Precedent for Tiered Fees and Reducing or Eliminating Interconnection Fees for Small Customers 29
IV. Georgia Power's Net Metering Revenue Adjustment is Flawed and Lacks Context 32
The Company Does Not Incorporate Demand or Energy Reductions from Exported RNR Generation in its COSS Model 33
The $1.4 million NEM Adjustment Pales in Comparison to the Company's Pending Revenue Requests and Billions of Dollars of Excess Revenue Collection 37
V. Georgia Power's Demand-Based "Smart Usage" Tariff is Flawed and Should Not be the Default Rate for New Premises 48
The Smart Usage Tariff is Improperly Designed and Should be Modified 49
Low Use Customers are Substantially Overcharged on the Smart Use Tariff 57
New Customers are Disproportionately Low Use Customers and are Being Harmed by the Default Rate 64
VI. The Commission Should Strive to Increase Fairness and Transparency in Rate Cases and Optionality in Rate Design 73
The Residential and Nights and Weekends Tariffs Should Remain Available 73
Georgia Power is Misleading Customers about the Plug-In EV Rate and Should be Stopped 79
The Default Rate Should be Changed to the Nights and Weekends Tariff 86
The Commission Should Direct Georgia Power to Create a Robust Bill Comparison Tool 87
The Solar Adviser Tool is Biased and Should Be Overhauled 88
The Company Should Explain Why its AMI Data is "Not Precise Enough" for Universal Use 95
The Commission Should Approve the 4CP Production Cost Allocator 99
The Commission Should Set Aside Funding for Transmission Planning Studies 103
VII. Conclusion 105

List of Tables and Figures

Table 1 - GPC Interconnection Costs 18
Table 2 - Interconnection and Study Counts 21
Table 3 - Interconnection Fees by Project Size 28
Table 4 - GPC Excess Revenue Collection 43
Table 5 - Residential Impact of Revenue Above ROE & Below Upper ROE Band 45
Table 6 - Summary of Rate Impacts for Residential Customer 46
Table 7 - TOU-RD Revenue Split 51
Table 8 - GPC Expense Breakdown 52
Table 9 - Rate Comparison Peak Usage Sensitivity 61
Table 10 - DTE Energy Individual Peak Hour Coincidence Analysis 63
Table 11 - Customer Changes on the TOU Rates 66
Table 12 - TOU-RD vs. R 2021 Monthly Average Usage 69
Table 13 - TOU-REO and TOU-PEV Rate Comparison 76
Table 14 - SAT Results by Size and Tariff 93
Table 15 - AMI vs. Load Research kWh Totals 98

Figure 1 - TOU-RD vs. R Total Bill Increase 59
Figure 2 - TOU-RD vs. TOU-REO Total Bill Increase 60
Figure 3 - TOU-RD vs. TOU-PEV Total Bill Increase 60
Figure 4 - TOU-RD Customer Average Monthly Load Factor 62
Figure 5 - Cumulative Residential Customer Additions from January 2021 66
Figure 6 - New TOU-RD vs. Residential Usage 68
Figure 7 - January and December Billing Demand Distribution 70
Figure 8 - Average Monthly Bill of New TOU-RD Customers 71
Figure 9 - TOU-PEV Premium Over TOU-REO 77
Figure 10 - TOU-PEV vs. TOU-REO vs. R Hourly Usage 80
Figure 11 - GPC EV Resources Webpage 82
Figure 12 - GPC TOU-PEV and Related Webpages 83
Figure 13 - Solar Adviser Tool Launch Page 89
Figure 14 - SAT Analysis Results 91
Figure 15 - GPC CPs 2017-2021 101

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. [Mr. Lucas] My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

A1. [Mr. Young] My name is Thatcher R. Young. I am Vice-President of Business Development of Velo Solar, LLC ("Velo Solar"). My business address is 154 Krog Street, N.E., Suite 140, Atlanta, Georgia 30307.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. [Mr. Lucas] I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 30% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education, and advocacy.

As Senior Director of Utility Regulation and Policy, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on net energy metering and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy ("Alliance") from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service

providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

A2. [Mr. Young]: I have been with Velo Solar since 2019. Velo Solar's business is predominately focused on developing BTM DG projects in Georgia and, to a lesser extent, the rest of country. Velo Solar also develops stand-alone DG projects most of which are located in Georgia.

I hold a Bachelor of Arts degree in Philosophy and a Master's Degree in Environmental Public Policy and Natural Resources Management from Georgia State University. From 2016 through January of 2019, I was the Vice President of Business Development with Radiance Solar. Before that, from 2008-2016, I was Vice President of Sustainability and Strategy for Ignition/Havas.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A3. [Mr. Lucas] Yes, I have. I testified in Georgia Power Company's 2022 Integrated Resource Planning and Demand Side Management docket (collectively, the "2022 IRP Proceeding").[1]

A3. [Mr. Young] Yes, I testified in the 2022 and 2019 IRP Proceedings.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. [Mr. Lucas] Yes. I have submitted testimony in rate cases, integrated resource plans, utility merger proceedings, and renewable portfolio and energy efficiency resource standards before the Maryland Public Service Commission, Public Utility Commission of Texas, the Public Utility Commission of Nevada, the Arizona Corporation Commission, the North Carolina Utilities Commission, the Public Service Commission of South Carolina, and the Virginia State Corporation Commission. My complete CV is attached to my testimony.[2]

A4. [Mr. Young] No, I have not.

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. Our testimony is provided on behalf of SEIA, the Georgia Solar Energy Industries Association ("GASEIA"), and Vote Solar, as joint intervenors in this proceeding (collectively "Joint Intervenors").

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. The purpose of our testimony is to review and comment on the Georgia Power Company's ("GPC" or "the Company") application in this rate case. The bulk of the testimony focuses on topics that directly and indirectly impact the solar industry, including the proposed interconnection fee modification, the Company's request to recover $1.4 million in revenue deficiency due to RNR customers, and its decision to close several tariffs while directing customers onto the "Smart Usage" tariff. We also discuss several other issues related to transparency and fairness in this case and make recommendations on how the Commission can ensure that the Company is not abusing its monopoly position.

[1] *In Re: Georgia Power Company's 2022 Integrated Resource Plan*, Docket No. 44160; *In Re: Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan*, Docket No. 44161.
[2] Exhibit KL-1, Kevin M Lucas CV.

Q7. WHAT IS YOUR ANALYSIS OF THIS CASE?

A7. This is a critical juncture for the Company and its customers. GPC, along with the rest of the electric industry, is in the middle of a massive transformation towards cleaner resources. To their credit, GPC and the Commission have shown leadership to advance this transition through renewable energy procurements. But the Company cannot request – and the Commission cannot approve – a blank check to fund its transition without first proving that its investments and expenses are reasonable and prudent.

GPC comes to the Commission requesting permission to increase its rates by nearly $3 billion over the next three years. It supports this massive request with sparse testimony and limited supporting evidence while being protected by a regulatory process that denies non-Staff intervenors discovery rights to push back on the Company's claims. If the Company's proposals are granted, customers will be subjected to massive rate hikes that have not been robustly supported or even well documented by the Company.

Unfortunately, the Company's case is full of questionable investments and tactics that do little to contain costs in the transition. For example, the Company proposes to spend nearly $100 million on a distributed energy resource management system ("DERMS") despite having a tiny fraction of distributed energy resources of more advanced states that manage without a DERMS. At the same time, the Company maintains a "tool" that purports to inform customers about onsite solar generation, but is instead designed to discourage customers who are seeking to actively manage their (soon-to-be-increasing) bills through solar.

Absent robust oversight by the Commission, the Company will continue its decade-long tradition of increasing profits well above its approved ROE. Since the Annual Surveillance Report ("ASR") process was implemented in 2011 alongside the multi-year Alternative Rate Plan ("ARP") structure, GPC has collected than $1.87 billion in revenue above its approved ROE. Further, because of the overly generous ROE dead band approved

by the Commission, the Company has been able to keep more than $1.57 billion of this amount, with more than $460 million coming during the COVID years of 2020 and 2021.

Actions proposed by the Company in this case could enable this trend to continue. The Company requests permission to close several residential tariffs to new premises while shifting more customers to its demand-based default rate and actively obfuscating eligibility requirements on the remaining time of use tariff. If approved, this would drive more and more customers onto a poorly designed demand-based tariff that will charge them much more than the costs they incur on the system. Exacerbating this issue, the Company completely ignores core functionality of its multi-million-dollar advanced metering infrastructure ("AMI") deployment to provide data for its rate design and cost of service study ("COSS"). Instead, it relies on statistical load studies that appear to result in a massive over-collection of revenue from residential customers.

From top to bottom, the Company's application advances its profits at the (literal) expense of its customers. Yes, more investment will be needed to transition to clean energy resources, but GPC should not be allowed to exercise outsized market power. The magnitude of the potential cost increases in this and future cases will have material impacts on residential and business customers in the state. The Commission must remain steadfast and carefully scrutinize the Company's proposals, paring back those that are unnecessary or unsupported while providing sufficient but not excessive financial security to the Company.

Q8. WHAT ARE YOUR RECOMMENDATIONS ON THE COMPANY'S PROPOSALS?

A8. Our recommendations on the specific points of the Company's proposal that we discuss follow:

- The Company's proposed $200 interconnection fee should be rejected and its current $5/kW fee for systems under 250 kW maintained. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW.
- The Commission should deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a

result, has overallocated costs to customer classes with RNR projects that is not considered in this figure.

- The Commission should strongly reconsider the width and asymmetry of the currently-approved ROE dead band. Ideally, it would be reduced to +/- 50 basis points, but at a minimum should be returned to the +/- 100 basis points in place prior to 2020.
- The Smart Usage tariff should not be the default rate and should be substantially redesigned with either a peak TOU demand charge collecting a fraction of production and transmission costs or a non-coincident peak charge collecting only low-voltage distribution assets. The Commission should require the Company to validate that the Smart Usage tariff is revenue neutral with respect to the traditional Residential tariff.
- The Commission should require the Company to continue offering the Residential and Nights and Weekends tariffs to new premises. The default rate should be changed to the Nights and Weekends tariff.
- The Commission should require the Company to develop a rate comparison tool that would automatically calculate a residential customer's bill based on historic usage on the various tariff options. It should also be required to collect billing demand data for each customer.
- The Solar Advisor Tool should be scrapped as it is actively biased against onsite solar.
- The Company should explain why its AMI data is insufficiently precise to use in its rate design and COSS. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible.
- The Commission should adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities.
- The Commission should direct the Company to provide funding for Staff and/or independent consultants to perform additional transmission studies related to North Georgia Reliability and Resilience Action Plan and transmission planning generally.

II. THE COMMISSION AND THE PUBLIC ARE HARMED BY THE INABILITY OF INTERVENORS TO PROPOUND DISCOVERY ON THE COMPANY

Q9. WHAT ARE THE TOP LINE REQUESTS AND RECOMMENDATIONS FROM GPC IN THIS RATE CASE?

A9. At a high level, GPC is asking the Commission to approve the recovery of billions of dollars of existing and planned assets, increase its return on equity ("ROE") to 11%, and authorize a proposed rate adjustment that will collect roughly $2.8 billion in additional revenues between 2023 and 2025.[3] If these revenues are approved, rates will collect $1 billion more annually in 2025 than in 2022, leading to an increase of roughly $16.29 to a residential customer using 1,000 kWh per month.[4]

The Company proposes to change its interconnection fee structure for systems connecting to the distribution grid, implementing a flat $200 for all projects regardless of size. It also makes an upward revenue adjustment of $1.4 million to collect what it claims is a cost shift associated with the implementation of the RNR Monthly pilot program.

The Company also proposes to close two residential tariffs, including the traditional flat rate tariff ("R tariff") and the Nights and Weekends TOU tariff ("TOU-REO tariff"), to new premises. With the three-part Smart Usage ("TOU-RD"), which includes a sizable non-coincident demand component, now acting as the default tariff, and the Company's refusal to eliminate confusion regarding its inappropriately-named Plug-in EV rate ("TOU-PEV tariff"), new customers are increasingly put on a rate that is poorly suited for their usage patterns.

Q10. WHAT IS YOUR OVERALL IMPRESSION OF GPC'S RATE CASE FILING?

A10. On balance, we found the GPC written testimony quite minimal given the magnitude of the financial and policy changes that the Company is requesting. The Company presented

[3] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company at 7, 9 ("Panel Direct").
[4] Panel Direct at 11.

testimony from three individual GPC witnesses, one panel of GPC witnesses, and two consultants, discussing the following topics:

- GPC Company or Affiliate Witnesses
  - Christopher C. Womack: overview of rate case filing[5]
  - Larry T. Legg: rate design[6]
  - Lee Evans: cost of service study[7]
  - Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson panel: revenue requirement[8]
- Consultants
  - James M. Coyne: ROE and capital structure calculation[9]
  - Steven M. Fetter: role of credit ratings and utility regulation on utility financials[10]

Discounting the introductory section of the testimony, all three of the individual Company witnesses' testimonies providing the overview of the case, the discussion of rate design, and the cost of service model were roughly 20 pages each. The panel supporting the revenue requirement produced roughly 50 pages of testimony. The two consultants, who supported the ROE and capital structure recommendations, produced testimony of 45 and 20 pages. GPC is requesting to increase customer rates by billions of dollars while making impactful policy changes, all supported with fewer than 200 pages of written testimony.

Q11. HOW DOES THIS COMPARE TO SOME OF THE OTHER CASES IN WHICH YOU HAVE PARTICIPATED?

A11. [Mr. Lucas] It is notable in its brevity. For example, in Consumers Energy's 2022 rate case, the primary utility witness sponsored over 250 pages of written testimony himself in a filing that contained more than 1,800 pages of written testimony from 35 witnesses.[11] This does not include additional thousands of pages of witness exhibits. While I am not suggesting that

[5] Direct Testimony of Christopher C. Womack On Behalf of Georgia Power Company. ("Womack Direct").
[6] Direct Testimony of Larry T. Legg On Behalf of Georgia Power Company ("Legg Direct").
[7] Direct Testimony of Lee Evans On Behalf of Georgia Power Company ("Evans Direct").
[8] Panel Direct.
[9] Direct Testimony of James M. Coyne On behalf of Georgia Power Company ("Coyne Direct").
[10] Direct Testimony of Steven M. Fetter On behalf of Georgia Power Company ("Fetter Direct").
[11] *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission Case No. U-21224.

maximizing page count should be the goal of a utility filing, there are some topics that simply require more attention than can be afforded in a sub-20 page document.

Q12. CAN YOU PROVIDE SOME EXAMPLES OF THIS IN GPC'S FILING?

A12. [Mr. Lucas] Yes. GPC mentions that the Commission authorized $1.3 billion in spending from 2020 through 2022 on its Grid Investment Plan project in the 2019 rate case.[12] However, the Company spent $1.5 billion over this time,[13] and requests to spend an additional $2.2 billion in the next three-year phase.[14] There is no specific mention in testimony of the roughly $200 million of incremental spending beyond the original approved cost; in fact, the figure needed to be calculated from two different pieces of testimony.

Further, the Company declined to discuss the preliminary results from the 2020-2022 investment round at all, claiming that revisiting the benefit estimates was "not warranted at this time" as too few projects had been in service through a full year.[15] While a full reckoning of the benefits may be premature, some discussion of the preliminary results is certainly appropriate given the Company's request for an additional $2.2 billion in spending on this program.

Another example is the proposed flat $200 interconnection fee for customer-generators seeking to interconnect to the Company's system. This new fee is a notable change from the current process and would apply equally to all systems regardless of their size and complexity of the interconnection process, a departure from both current practices and industry standards. Despite the many questions that this new fee raises, the totality of the Company's justification is one sentence long: "This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer-generator to the system and helps ensure that such costs are not borne by all other customers."[16]

[12] Panel Direct at 49.
[13] Direct Testimony of Christopher C. Womack On Behalf of Georgia Power Company at 6 ("Womack Direct").
[14] Panel Direct at 49.
[15] Panel Direct at 50.
[16] Legg Direct at 14.

One other example comes from a seemingly innocuous mention: "The Company is modifying its payment and service policies in section F to help make those policies more transparent to customers. These additions are meant to help protect all customers from higher costs that could result from legal claims against the Company."[17] There is no mention in testimony of what section F is, much less what the changes are. One has to seek out section F in the Company's exhibits, where one would find a rather startling change of policy:

> 9. 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.[18]

This entirely new section 9 would dramatically limit the ability for customers to seek damages from the Company arising from issues with the customer's electricity service, including issues that are "reasonably foreseeable, contemplated, or avoidable" by GPC. While I will leave it to other parties to argue about the policy merits of this proposal, it is a striking change to have been buried in written testimony as it was.

Q13. BUT SURELY THESE OBFUSCATION TACTICS ARE NOT UNIQUE TO GPC?

A13. [Mr. Lucas] No, they are not. In my experience participating in cases in various jurisdictions, the utility rarely discloses more than is necessary to make its case. Excel workbooks are stripped of all formulas, or sometimes presented only as PDFs. Even when available as interactive files, key figures are often hardcoded and summary data presented without supporting backup data. Declarative statements in written testimony often lack references, making it challenging to trace their origin and validate their claims. While GPC's tactics in

[17] Legg Direct at 13.
[18] 1.60_R&R Sec F - Contract and Enforcement Regulations Tracked.doc

this case are at times frustrating, they are not unique. But at the same time, the burden is on the Company to demonstrate that its request is just and reasonable, and the Commission should scrutinize how robustly such a thin application makes this case.

Q14. WHAT IS THE TYPICAL WAY THAT INTERVENORS PUSH BACK ON THESE TACTICS?

A14. [Mr. Lucas] The typical approach is for intervenors to ask discovery. This vital process allows participants in the case to fill in the many missing gaps. Working Excel models are requested, supporting documentation must be furnished, original sources can be vetted. The less that is provided by a utility in its original filing, the more that needs to be uncovered through discovery.

Q15. DOES THIS CRITICAL PROCESS EXIST IN GEORGIA?

A15. For intervenors other than Staff, no, it does not. Intervenors are not authorized to ask discovery in proceedings such as this rate case.[19] We are grateful that Staff is robustly exercising its discovery rights in this proceeding, and we have cited to its discovery in our testimony. However, there are certain analyses that we were unable to perform due to the inability to ask our own questions.

Q16. WHAT ARE SOME OF THESE ANALYSES?

A16. One relates to the aforementioned interconnection fee. After the Company initially provided zero analytical support for its proposal, Staff requested and received additional data on the calculation – in an Excel file with only hardcoded numbers and no formulas.[20] However, the responses provided by the Company simply invite more questions. For example:

- Why do the number of feasibility studies or standard impact studies not match the number of projects?
- What triggers a Network Underground or Reliability Study?
- Why does the Company use a different inflation assumption in this worksheet than in the rest of its case?
- Why is it appropriate to spread costs for impact and feasibility studies that appear to only apply to larger projects to all projects regardless of size?

[19] See O.C.G.A. § 46-2-57; Procedural and Scheduling Order issued April 7, 2022 in Docket No. 44280 ("The Commission authorizes PIA Staff to issue discovery pursuant to O.C.G.A. § 46-2-57(a). PIA Staff may conduct depositions and use any other methods of formal and informal discovery in this docket.")

[20] STF-TAI-1-40 and STF-TAI-1-40 Attachment.

- What is actually done in the "Project Review and Generate Agreement" step, and why does it cost $105 for a small system and $2,096 for a large system? Given this disparity, why does the Company charge every project a $59 fee for this step regardless of the project size or whether that project required that step?
- Why does the number of sub-10 kW projects that undergo the "Project Review and Generate Agreement" and "Witness Test and Meter Re-Programming" steps fall over time?
- What specific steps are needed for the "Project Billing and Tariff Rider Added" step and why does it cost $88 to perform these tasks? Why does this step only apply to 3,555 projects, which does not match any of the other project numbers?

To perform a robust analysis of the Company's interconnection proposal, these questions need answers. Some may have straight forward answers, some may uncover errors in GPC's analysis, while other may reveal arbitrary decision making. In response to our request for clarification of these questions above, the Company arranged a meeting with members of the Company's renewables team to answer our specific questions about the interconnection workpaper. That meeting was useful in answering many of our questions. However, because we were unable to ask the required follow ups through formal discovery, and the Company's witness sponsoring this testimony was unable to provide the needed details, these issues very well could have remained unresolved when this testimony was due.

Q17. DOES GEORGIA'S MULTI-PHASE HEARING PROCESS OFFER INTERVENORS AN OPPORTUNITY TO ADDRESS THESE TYPES OF ISSUES?

A17. In theory, it does. However, live cross-examination is necessarily less robust than a deliberate written discovery process. For instance, Joint Intervenors' counsel sought answers to questions such as those above from Company witnesses during the first round of hearings. Unfortunately, the Company witness who discussed the interconnection agreements during the hearings in some answers directly contradicted the documents that the Company provided in discovery while in other answered claimed to be unable to answer as his group did not prepare the studies, as discussed in Section III below. With no ability to ask follow-up discovery questions, and Company witnesses failing to have knowledge of the topics they sponsored in testimony, the record on the matter is muddied to the detriment of the Commission and the public.

Q18. WERE YOU ABLE TO PARTIALLY RESOLVE YOUR QUESTIONS ON THIS ONE PARTICULAR ISSUE?

A18. We were. At the request of our counsel, the Company arranged a meeting after its initial testimony to discuss our questions regarding the interconnection fee. We are very appreciative that the Company made their staff available for our questions, and while they were able to answer some of those questions, several of their responses simply identified more issues that would have benefitted from additional follow up.

Further, the interconnection fee analysis was only one of many lines of questioning that we had on the Company's testimony and responses to Staff's discovery questions. We had many other questions on many other topics that would have required multiple meetings with multiple business groups. Obtaining answers to all these questions through an informal, off-the-record process does not feel like a long-term sustainable process.

The function of a formal discovery process is to ensure that questions are clearly asked, clearly answered, and available to enter into the record on which the Commission makes its decision. We are pleased that we are able to submit this testimony without having to guess about the Company's interconnection fee workpaper, but we had to make educated guesses and assumptions about several other topics discussed here.

Q19. WHAT IS THE IMPACT OF INTERVENORS NOT BEING ABLE TO ASK DISCOVERY?

A19. On the whole, it does a disservice for both the Commission and the public as a whole. The Commission is being asked to make very hard decisions in this and other proceedings that directly impact the livelihood of Georgia residents and businesses. In this case, among other things, the Company is asking permission to raise residential bills by hundreds of dollars per year, and some business bills by thousands of dollars per year. To do so without the most robust record possible means that some important information may be missed.

Q20. DOES THIS HAVE A PARTICULARLY PROBLEMATIC IMPACT FOR THE SECOND PHASE OF THIS DOCKET?

A20. Yes. The second phase of this docket will address cost of service issues associated with RNR customers. The Company will file its testimony on October 20th. Responses from other intervenors are due 21 business days later on November 18th. However, the Company has 15 business days to respond to discovery.[21] This means that even if Staff reads the Company's testimony and submits discovery the next day, and they will have less than a week to analyze and incorporate the response in its own testimony. It also means that there is no opportunity to ask a second round of discovery on the first set of answers, something that Staff frequently did in the initial phase of the hearing. This timeline is simply not compatible with producing a robust record on what will certainly be a complex issue.

Q21. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?

A21. [Mr. Lucas] Ideally, all intervenors would be able to ask discovery. In the various jurisdictions I have worked, only one commission put a restriction on discovery, and that was only to limit the number of questions that could be asked in one day.[22] All other jurisdictions allowed unlimited intervenor discovery by parties to other parties in formal proceedings, while the respective utilities and intervenors maintained the right to object to questions asked.

If the Commission feels that unlimited discovery is too large of an initial step to take, it could offer non-Staff parties limited discovery rights. These could include a cap on the number of questions asked per day or in total. That said, if the Commission were to expand discovery rights, I would caution against strong restrictions given the purpose of discovery is to produce a more robust record on which the Commission can base its decisions.

The burden to prove that its requests in this case are just and reasonable is on the Company. It must do so under scrutiny of the Commission, Staff, and other intervenors. Discovery is a critical element of this examination and preventing all non-Staff intervenors discovery rights necessarily results in a weaker record on which the Commission must make its decisions.

[21] Second Amended Procedural And Scheduling Order issued August 5, 2022 in Docket No. 44280.
[22] The Public Utility Commission of Texas limited intervenors to 50 questions and/or subparts per day, but there was no limit on the total number of interrogatories.

III. GEORGIA POWER'S PROPOSED $200 FLAT INTERCONNECTION FEE SHOULD BE REJECTED

Q22. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A22. We discuss the Company's proposal to institute a flat $200 interconnection fee for projects seeking to connect to the Company's system. This approach replaces the current protocol of $5/kWAC for systems under 250 kWAC in the RNR or Energy Offset Only program, and $3,900 (weekdays) or $4,400 (weekends) for systems over 250 kWAC in the Energy Offset Only or Qualifying Facility program.[23]

Q23. PLEASE SUMMARIZE YOUR FINDINGS.

A23. The Company's proposal is vague, lacks support, and should be rejected. It provides no evidence for its claim that the current fee structure causes non-participants to pay for the interconnection studies needed to install distributed generation ("DG") systems on its grid. The one piece of analysis that the Company provided raises more questions than it answers. GPC has not demonstrated that this change is reasonable and prudent, and as such, the existing structure should be left in place.

Q24. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S INTERCONNECTION FEE PROPOSAL?

A24. We recommend the Commission reject the proposal and maintain its current fees of $5/kW for systems under 250 kW. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW. The interconnection fees of neighboring utilities discussed below provide the Commission with a range of reasonable options.

[23] Georgia Power "Behind the meter solar workshop Q&A", question 23. ("BTM Solar FAQ"). Available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/residential-pdfs/residential-rate-plans/georgia-power-btm-solar-faq-document-august-2021.pdf

The Company's Proposal is Overly Vague

Q25. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INTERCONNECTION PROCESS AND FEE?

A25. The Company proposes to change its testing requirements and shift from a per kW fee for smaller systems and a high flat fee for larger systems to one that has a $200 flat fee for all customers.[24] The entirety of GPC's discussion of this change follows:

> Q. PLEASE EXPLAIN THE CHANGES TO THE CUSTOMER GENERATION SECTION OF THE RULES AND REGULATIONS.
>
> A. The Company has proposed new language to clarify when a customer-owned generator is required to undergo witness testing and would be responsible for the appropriate fees associated with this testing. The anticipated impact of this change is to reduce the number of instances that require witness testing going forward. The Company is also proposing to introduce a one-time $200 interconnection fee that will be required for all customers proposing to interconnect a customer generating facility to the Georgia Power system. This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer-generator to the system and helps ensure that such costs are not borne by all other customers.[25]

Q26. DO THE CHANGES IN THE CUSTOMER GENERATOR SECTION OF THE RULES AND REGULATIONS CLARIFY WHEN A CUSTOMER-GENERATOR IS REQUIRED TO UNDERGO WITNESS TESTING?

A26. No, it does not. Currently, the Company performs "witness testing" for all systems – regardless of size – connecting to its distribution system that is intended to validate the protection protocols of systems; in essence, GPC employees make sure that the system trips offline when it is supposed to do so. The Company does not propose witness test modifications for systems over 250 kW but adds the sentence "Customer-owned generators less than 250 kilowatts may also be required to undergo witness testing if the Company deems that the generator poses a safety or reliability risk."[26]

Q27. DOES THE COMPANY PROVIDE ANY EXPLANATION FOR HOW IT WOULD DEEM THAT A GENERATOR POSES A SAFETY OR RELIABILITY RISK?

[24] Legg Direct at 14.
[25] Legg Direct at 14.
[26] 1.70_R&R Sec G - Customer Generation Tracked.doc

A27. No. There is no further explanation in the Rules and Regulations for how the Company would determine this. Although the Company claims this will reduce witness testing in the future, it provides no support in its documentation for this assertion as it does not explain what would trigger a "safety or reliability risk" that would still necessitate a witness test.

The Company's Interconnection Fee Analysis Contains Inconsistent, Unsupported, and Erroneous Data

Q28. DID THE COMPANY PROVIDE ANY ADDITIONAL INFORMATION ABOUT THIS PROPOSAL?

A28. Yes. In response to a discovery request from Staff, the Company provided additional details on its proposal and a single page, hardcoded Excel file with some analytical support for the costs underlying its $200 fee. According to GPC, this fee "collects the known costs directly attributed to process project applications for interconnection."[27]

Q29. HOW MUCH REVENUE DOES THE COMPANY PROJECT TO COLLECT THROUGH THIS NEW FEE?

A29. It projects collections of $3.05 million between January 2023 and December 2025, or roughly $1.0 million per year.[28]

Q30. DOES THE COMPANY OFFER ANY TESTIMONY OR EVIDENCE THAT THE CURRENT INTERCONNECTION FEE UNDER-COLLECTS REVENUE ASSOCIATED WITH INTERCONNECTION APPLICATIONS?

A30. No, it does not. We were not able to locate any information in the Company's testimony or exhibits that details interconnection application fee revenues under the current process, nor any discussion supporting the claim that these are insufficient compared to costs.

Q31. PLEASE DISCUSS THE WORKPAPER THAT THE COMPANY PROVIDED IN RESPONSE TO STAFF'S DISCOVERY REQUEST.

A31. The Company provided a one-page Excel file breaking down the interconnection cost schedule for 2023, 2024, and 2025. All formulas were removed, leaving only hardcoded values. There is no reason for the Company to do this; it protects no information and just

[27] STF-TAI-1-40.
[28] Id.

makes subsequent analysis by intervenors more complex. While this particular analysis was relatively easy to reverse-engineer, GPC's practice of removing formulas in Excel files is an unnecessary obstruction tactic and should be strongly discouraged.

The file broke down the fee into five components, listed below in Table 1 along with the average cost for each category for each year.[29] The overall average cost is $190, to which the Company adds $10 per application for "costs not easily quantifiable or attributable on an average per project basis."[30] The figures assume a 3% annual inflation rate and a 15% year-over-year increase in the number of interconnections and breaks down projects into three size categories: less than 10 kW, 10-250 kW, and greater than 250 kW.[31]

Average Cost Per Application	2023	2024	2025	Average
Impact & Feasibility Study	$9	$9	$10	$9
PowerClerk Costs	$34	$34	$34	$34
Project Review and Generate Agreement	$59	$35	$36	$43
Project Billing and Tariff Rider Added	$67	$60	$53	$60
Witness Test and Meter Re-Programming	$63	$33	$34	$44
Total	**$231**	**$171**	**$167**	**$190**

Table 1 - GPC Interconnection Costs

Q32. CAN YOU EXPLAIN WHY THE COST OF SEVERAL LINE ITEMS DECREASE OVER TIME?

A32. Three of the five items fall in cost over time. Of these, the Project Review and Generate Agreement and the Witness Test and Meter Re-Programming steps fall because the Company assumed the number of sub-10 kW projects going through these steps falls from 50% in 2023 to 25% in 2024 and 2025. The Project Billing and Tariff Rider Added cost falls because the Company assumed this step applies to constant 3,555 projects each year, a figure which does not match the number of projects used elsewhere on the schedule and does not increase over time.

[29] STF-TAI-1-40 Attachment. Customer counts, study costs, and other costs referenced in this section are sourced from this attachment.
[30] STF-TAI-1-40.
[31] All system capacity sizes are in kW_{AC} unless otherwise denoted.

Q33. WHY DID THE COMPANY ASSUME THAT SMALL PROJECTS WOULD MOVE FROM 50% TO 25% IN SOME OF THE STEPS?

A33. As the Company did not provide any information about its assumptions, it was unclear to what the 50% and 25% applies. Does this mean that only 25% of projects are reviewed, have contracts generated, undergo witness testing, or have the meter reprogrammed? Are project review and generate agreement different steps? Do all projects that undergo witness testing also have their meter reprogrammed, or do some projects require meter reprogramming but not witness testing? None of this is clear in the Company's analysis.

While we were unable to ask discovery to find out these answers, we were able to ask these questions during an informal Q&A session with the Company. The Company clarified it is able to increasingly automate simple "cookie-cutter" projects under 10 kW, avoiding the need of a manual review of basic project information (e.g., the account number matching the address, system components are UL listed, etc.) and witness testing, and are able to have semi-automated interconnection agreements created. The Company also clarified that all meters undergo field reprogramming, and all projects must have a contract generated, despite only listing that 50% to 25% of systems under 10 kW incur these costs.

Q34. WHY DID THE COMPANY ASSUME THAT A CONSTANT 3,555 PROJECTS UNDERGO THE PROJECT BILLING AND TARIFF RIDER ADDED STEP?

A34. This was confirmed during our conversation to be an error. The 3,555 projects represented the total number of systems that were brought online in 2021, the baseline year for the analysis. This value was inadvertently applied to 2023-2025 installations rather than using the projected number of projects for those years.

Q35. WHY DID THE COMPANY FAIL TO INCLUDE A WITNESS TESTING COST PER APP FOR SYSTEMS OVER 250 KW?

A35. [Mr. Lucas] I initially assumed this to be an error, as it is directly contradicted by the Company's proposed changes to the Rules and Regulations, which clearly states: "3. All customer generation sized 250 kilowatts and above, whether installed behind-the-meter or

stand alone, must undergo a system impact study and **the witness testing process** as required by the Company and will be responsible for all associated fees."[32]

However, the Company confirmed during our conversation that not only do all systems over 250 kW undergo witness testing, but also that this witness testing was sufficiently complex and expensive that the Company decided to exclude these costs from the common interconnection fee calculation.

Q36. **IS THIS DECISION IN ANYWAY CONSISTENT WITH ITS APPROACH FOR THE REST OF THE COSTS?**

A36. No, it is not, and it shows the arbitrary nature of the Company's proposal. The Company is perfectly content to require systems under 10 kW to subsidize $2,000-$2,500 studies and $2,100 project reviews for systems over 250 kW, but it drew a line at the witness testing fee and required large projects to directly pay this fee. Why is it ok to exclude an expensive witness test from common cost recovery, but ok to include expensive study and project review costs in common cost recovery? Further, this confirmation directly undermines its statement that the $200 fee "collects the known costs directly attributed to process project applications for interconnection" as the mandatory witness testing fee for systems over 250 kW is specifically excluded from the calculation.

Q37. ARE THERE OTHER UNEXPLAINED VARIATIONS IN THE WORKPAPER?

A37. [Mr. Lucas] Yes. The number of projects that go through the various study process is inconsistent with the number of projects listed. Table 2 below shows the total count of projects by size, along with the number of studies conducted.

[32] 1.70_R&R Sec G - Customer Generation Tracked.doc (emphasis added)

	2023	2024	2025
Less Than 10 kW-AC	4,610	5,302	6,097
10-250 kW-AC	85	97	112
Greater Than 250 kW-AC	12	13	15
Total Projects	**4,706**	**5,412**	**6,224**
Feasibility Study	92	106	122
Standard Impact Study	12	14	17
Network Underground	5	6	7
Reliability Study	4	5	6

Table 2 - Interconnection and Study Counts

It appears from these figures that most but not all projects over 10 kW are required to have a Feasibility Study, but there is no explanation for why 5, 4, and 5 of the projects over 10 kW in 2023, 2024, and 2025, respectively would not require a Feasibility Study. Likewise, it seems that the Standard Impact Study applies to projects over 250 kW but appears that some projects between 10 and 250 kW also require this study. Only a handful of projects require a Network Underground or Reliability Study; again, no context was provided for these assumptions.

I was able to get some answers regarding this step during my conversation with the Company. GPC explained that all projects, including projects under 10 kW, undergo a basic screening process that checks to make sure the account information is correct, and that the system size does not exceed the local transformer size. Projects that pass this initial screen – which includes an increasing number of small projects – do not need further studies. At the same time, the Company performs a Feasibility Study on 100% of the projects over 10 kW and a handful of projects under 10 kW that fail the initial screen. Likewise, the Impact Study is mandatory for 100% of systems over 250 kW and the few projects that do not pass the initial Feasibility Study process.

The Network Underground is only done on systems that intend to connect to an urban mesh grid and require additional operational analysis, such as ensuring the system does not export to the grid. The Reliability Study is triggered for the few projects that use new

equipment that has not been encountered by the Company before, even if the equipment is UL listed and conforms with IEEE standards. According to the Company, this is primarily solar plus storage projects.

The Company's Hearing Witness Directly Contradicted GPC's Testimony and Discovery Answers and Was Unable to Provide Additional Details

Q38. WHICH COMPANY WITNESS SPONSORED THE $200 INTERCONNECTION FEE TESTIMONY AND SUPPORTED IT DURING THE HEARING?

A38. Witness Legg sponsored the Company's testimony on the $200 interconnection fee and answered questions under cross examination during the hearing.

Q39. DID MR. LEGG CONTRADICT PORTIONS OF THE COMPANY'S TESTIMONY AND DISCOVERY RESPONSES DURING HIS HEARING CROSS EXAMINATION?

A39. Yes, he did in several instances. Mr. Legg stated: "And again, repeating a little bit of what I said yesterday, I don't run the renewables department, but I'm familiar with generally the cost being outlined here. From the standpoint of witness testing, that is something that for under 250 kW customers, my understanding is that they may not all be witness tested in the future. The company will decide if there is a need to witness test those, so it's -- so even though the fee was being paid by everyone, every single commercial [project] may not be witness tested."[33]

Q40. WHAT DO THE COMPANY'S PROPOSED CHANGES TO THE CUSTOMER GENERATION SECTION OF THE RULES AND REGULATIONS SAY REGARDING WITNESS TESTING?

A40. [Mr. Lucas] The Company's proposed language follows: "3. All customer generation sized 250 kilowatts and above, whether installed behind-the-meter or stand alone, must undergo a system impact study and the witness testing process as required by the Company and will be responsible for all associated fees… Customer-owned generators less than 250 kilowatts

[33] Hearing transcript page 1088 lines 15-24.

may also be required to undergo witness testing if the Company deems that the generator poses a safety or reliability risk."[34]

In its workpaper, the Company assumed that 100% of projects between 10 and 250 kW would undergo the Witness Testing and Meter Re-Programming. While it is accurate that a declining fraction of systems under 10 kW will undergo the Witness Testing and Meter Re-Programming step, these are dominated by residential systems. By contrast, 100% of projects over 10 kW, which will encompass nearly all if not all commercial projects, will in fact require witness testing. It was my understanding from the meeting with the Company that functionally all of the commercial projects do require witness testing, along with a declining share of residential projects as more evolve into the "cookie cutter" category.

Q41. IS THERE ANOTHER EXAMPLE WHERE MR. LEGG CONTRADICTS THE COMPANY'S DISCOVERY RESPONSES?

A41. Yes. When asked about the discovery workpaper, Mr. Legg stated:

> If you think about what those -- what those things all -- those costs entail, they're not based on the size of the customer. So setting up, in your example, a 7 kW customer versus a 200 kW customer in the billing system, or taking their application, or looking at a feasibility study, doing project review, all of those types of things are just based on the fact that they are interconnecting with the system. They're not necessarily driven by the size of the customer. So that's where we're proposing -- that's why we're proposing to spread those costs evenly across everyone who applies.[35]

Q42. WHAT DOES THE WORKPAPER BEING DISCUSSED SAY ABOUT THESE STEPS?

A42. [Mr. Lucas] While the workpapers were ambiguous on this matter, I confirmed through my conversation that all systems over 10 kW require a Feasibility Study and all projects over 250 kW require a full Impact Study. Systems under 10 kW do not require a Feasibility Study unless they fail the initial screening process, which based on the figures in the workpaper almost never happens. Further, only a few systems under 250 kW were required to undergo a full Impact Study.

[34] 1.70_R&R Sec G - Customer Generation Tracked.doc
[35] Hearing transcript p 1090 lines 5-12

Further, the Project Review and Generation Agreement cost is strongly differentiated by system size; projects under 10 kW cost $105, while projects over 250 kW cost $2,096. Despite Mr. Legg's testimony, there are clear instances that these costs are not only differentiated by project size, but that small projects are subsidizing large projects.

Q43. WERE THERE INSTANCES IN WHICH MR. LEGG WAS UNABLE TO ANSWER QUESTIONS BECAUSE OF HIS LACK OF KNOWLEDGE OF THE SUBJECT MATTER?

A43. Yes, there were several instances. When asked about whether larger systems are going to require more witness testing than smaller systems, Mr. Legg responded "I don't know that larger or smaller systems would require more or less witness testing. I'm not familiar with the procedures for who needs a witness test or not. That's really determined by our renewables department."[36]

When asked whether other utilities, including neighboring utilities in the South, waive similar fees for smaller systems, Mr. Legg responded "I'm not aware."[37]

When asked whether larger systems may require more studies and costs associated with interconnection than smaller systems, Mr. Legg again responded "That's possible, but I just -- I don't know because my group does not prepare those studies."[38]

When asked whether smaller systems would be subsidizing larger systems under the Company's proposal, Mr. Legg responded, "Well, as I look down through the data request -- and again, I'm limited in knowledge, that my department, like I said, doesn't run these different types of tests or take the applications."[39]

When asked about what is involved in the various steps such as Project Review and Generate Agreement and Project Billing and Tariff Rider Added, Mr. Legg again struggled to provide clarity to the Company's data:

> Yeah, we're reaching -- again, we're reaching the limits of my understanding of this, but, you know, reviewing projects and generating an agreement for the customer to

[36] Hearing transcript page 1090 lines 19-23
[37] Hearing transcript page 1091 line 5
[38] Hearing transcript page 1092 line 4-6
[39] Hearing transcript page 1092 line 24 to page 1093 line 2

sign. I would assume project billing and tariff rider, these have to be set up in our billing system and billed through -- through -- you know, it's more complex billing than standard residential billing because you have the pushback aspect. You have the netting aspect. So there's more handling in the billing setup for these customers as well.[40]

Q44. WERE YOU ABLE TO GET MORE INFORMATION ABOUT THE BILLING MODIFICATION PROCESS IN YOUR INFORMAL CONVERSATION?

A44. [Mr. Lucas] Yes, I was, and the answers were very surprising. Based on my understanding of the conversation, the steps need to process billing system changes is extremely inefficient, requiring multiple "touches" of the customer's account throughout the interconnection process. As I recall, the Company said that billing personnel had to make account adjustments to the billing system three different times in the process. This is followed by manual review of every single RNR account to ensure that the billing system, meter reads, and netting calculations are performed correctly.

Q45. DOES GPC PROVIDE ANY SUPPORT FOR THE COST OF EACH STUDY OR STEP IN THE INTERCONNECTION REVIEW PROCESS?

A45. [Mr. Lucas] No, it did not. The studies range from $53 for the Feasibility Study to $2,472 for the Network Underground study. Similarly, the Project Review and Generate Agreement costs vary substantially; $105 for systems under 10 kW, $157 for systems between 10 and 250 kW, and $2,096 for systems over 250 kW. No data, such as the number of labor hours required to perform the study, is provided to support these figures.

The Company assumes a cost of $105 for systems under 10 kW to complete the project review and generate the interconnection agreement. Given the Company's use of PowerClerk, which standardizes the intake of project information, it should be trivial to automatically generate a standard form interconnection agreement. However, I learned during my meeting that PowerClerk cannot directly create the interconnection agreement despite having all the relevant information. Instead, a GPC employee must enter the

[40] Hearing transcript page 1094 lines 5-14

information into another form, which can then be used to generate an interconnection agreement. It is unclear why this functionality is not fully automated.

The Company also assumes a total cost of $88 for the Project Billing and Tariff Rider Added step. Given that GPC has not indicated anywhere in its testimony that it manually bills these customers, I expected RNR bills to be generated automatically by the billing system software and that enabling an RNR tariff would involve little more than updating a few account flags in the Company's billing system. But after my conversation with the Company, it appears that these steps are much less efficient than they should be.

Q46. PLEASE EXPAND ON THIS POINT.

A46. [Mr. Lucas] I am particularly concerned about the revelation that billing analysts have to manually verify every account to ensure the billing system is working properly. The details were a bit unclear, but it was suggested that this step was needed to validate that the tariff was eligible for the RNR program, that meter reads were properly pulled into the system, that solar generation was properly read, that the netting calculation was done correctly.

It is concerning how a billing system that surely cost millions of dollars and an AMI infrastructure that cost tens or hundreds of millions of dollars needs to be manually checked for such basic billing functionality. Before I switched to clean energy policy, I worked for Accenture for six years implementing enterprise resource software at Fortune 500 companies. When I worked on these systems 20 years ago, I would never have designed a process that needed this level of manual intervention, nor would any client ever accept such a solution as it would be notoriously inefficient and fail to achieve adequate cost savings.

Under the Company's Proposal, Customers with Small Systems Would Subsidize Customers with Larger Systems

Q47. DOES THE COMPANY PROPOSE TO CHARGE INDIVIDUAL PROJECTS BASED ON THE STUDIES AND PROCESS STEPS THEY ARE REQUIRED TO PERFORM?

A47. No, it does not. Rather, it proposes to charge every project a pro rata share of the total cost of all the studies for all projects. For example, the Feasibility Study (at a cost of $53 per study in 2023) is generally constrained to projects over 10 kW, and the Standard Impact ($1,988), Network Underground ($2,472), and Reliability ($227) studies are applicable to just a handful of projects over 250 kWAC. Rather than charge these costs to the size category, the Company proposes to have every system pay $9 in 2023 for these studies.

Similarly, the Company assumes that 50% of projects under 10 kW will undergo the Project Review and Generate Agreement step (at $105 per application in 2023), while all projects between 10 and 250 kW ($157 per application) and over 250 kW ($2,096) will require this step. As with the interconnection study, rather than charge the costs on a per-size basis, the Company lumps all costs into one average $59 fee for this step. This means that a large project saves more than $2,000 by having smaller projects subsidize its project review.

Q48. WHAT WAS THE COMPANY'S JUSTIFICATION FOR THIS APPROACH?

A48. Mr. Legg discussed the Company's approach during cross-examination "So I think the thought was, yeah, it's the -- these costs are spread across all of these different customers. There may be some that vary by size of customer, but generally these are costs that are being caused across, regardless of size, across this group of customers and they should be responsible for paying those costs."

Q49. IS THIS STATEMENT SUPPORTED BY THE EVIDENCE PRESENTED IN THE DISCOVERY RESPONSE?

A49. [Mr. Lucas] No, it is not. I was able to produce an analysis that broke out the various costs from the Company's workpaper on a per application basis. This required making assumptions about the cost of the excluded witness test fee for systems over 250 kW and to correct the error related to the 3,555 projects in the Project Billing and Tariff Rider Added step. I assumed the Witness Test for systems over 250 kW cost $2,500 in 2023 as this was just slightly higher than the highest cost that the Company deemed appropriate to socialize among all projects.

Q50. WHAT IS THE RESULT OF THIS ANALYSIS?

A50. [Mr. Lucas] The results are shown below in Table 3 below using the Company's assumed costs. As discussed above, the Company did not provide support for its Project Review and Generate Agreement and Project Billing and Tariff Rider Added steps. Even given the incredible inefficiencies in these steps uncovered during my conversation with the Company, these costs may be overstated, and I was not able to obtain the details needed about the labor rate and hours required to perform each step. The Company also provided no support for the specific fraction of sub-10 kW systems that it deemed to not be "cookie cutter" that would be able to bypass several of the manual steps.

Despite this, it is clear as day that there is a substantial variation in interconnection costs. Systems under 10 kW – using the Company's unverified cost figures for its billing steps – average $203 over the three years. Systems between 10 and 250 kW average $469. By contrast, systems over 250 kW incur an average cost of $8,294, which may be understated given the additional complexity of the mandatory witness test for large systems.

	2023	2024	2025	Avg
Less Than 10 kW-AC	**$236**	**$184**	**$188**	**$203**
Impact & Feasibility Study	$0	$0	$0	$0
PowerClerk Costs	$34	$34	$34	$34
Project Review and Generate Agreement	$52	$27	$28	$36
Project Billing and Tariff Rider Added	$88	$91	$93	$91
Witness Test and Meter Re-Programming	$62	$32	$33	$42
10-250 kW-AC	**$456**	**$469**	**$482**	**$469**
Impact & Feasibility Study	$53	$55	$57	$55
PowerClerk Costs	$34	$34	$34	$34
Project Review and Generate Agreement	$157	$162	$167	$162
Project Billing and Tariff Rider Added	$88	$91	$93	$91
Witness Test and Meter Re-Programming	$124	$127	$131	$127
Greater Than 250 kW-AC	**$7,947**	**$8,271**	**$8,665**	**$8,294**
Impact & Feasibility Study	$3,228	$3,412	$3,662	$3,434
PowerClerk Costs	$34	$34	$34	$34
Project Review and Generate Agreement	$2,096	$2,159	$2,224	$2,160
Project Billing and Tariff Rider Added	$88	$91	$93	$91
Witness Test and Meter Re-Programming	$2,500	$2,575	$2,652	$2,576

Table 3 - Interconnection Fees by Project Size

Q51. IN YOUR VIEW, IS IT APPROPRIATE FOR SMALL CUSTOMERS TO SUBSIDIZE LARGE CUSTOMERS IN THIS WAY?

A51. No, and given the rhetoric the Company uses in other contexts about not charging customers for costs they don't create, it is surprising to see the opposite proposed here.

There is Precedent for Tiered Fees and Reducing or Eliminating Interconnection Fees for Small Customers

Q52. DID THE COMPANY PROVIDE ANY EVIDENCE REGARDING THE PREVALENCE OF FLAT INTERCONNECTION FEES REGARDLESS OF SYSTEM SIZE?

A52. No, it did not. Further, when asked whether utilities, including neighboring utilities in the south, waive interconnection fees for smaller systems, Mr. Legg responded "I'm not aware."[41]

Q53. DID YOU REVIEW THE INTERCONNECTION FEES FOR UTILITIES IN NEARBY STATES?

A53. Yes. Two themes appeared from this review, neither of which are found in the Company's proposal. First, utilities charged differential fees based on system size. Second, small systems often pay no interconnection fees.

The state of Florida issued regulations guiding the interconnection process. [42] These rules establish three tiers: under 10 kW, between 10 and 100 kW and between 100 kW and 2 MW. For the smallest tier, utilities are prohibited from charging any interconnection fees, and for the two larger tiers, the utility can petition the Florida commission to implement cost-based fees. Florida Power and Light charges a flat $400 fee for projects between 10 and 100 kW.[43] For projects between 100 kW and 2 MW, FPL charges an application fee of $1,000 and, if necessary, and interconnection study fee of $2,000.[44]

[41] Hearing transcript page 1091 line 5
[42] https://www.flrules.org/gateway/readFile.asp?sid=0&tid=5455200&type=1&File=25-6.065.doc
[43] https://www.fpl.com/content/dam/fplgp/us/en/clean-energy/net-metering/pdfs/net-metering-tier2.pdf
[44] https://www.fpl.com/content/dam/fplgp/us/en/clean-energy/net-metering/pdfs/net-metering-tier3.pdf

Dominion Energy in Virginia does not charge a fee for systems under 10 kW, but does charge a witness test fee of $50 for systems between 10 and 25 kW.[45] Systems up to 500 kW pay a $100 processing fee, and systems over 500 kW pay a $1,000 processing fee.[46] In South Carolina, Dominion charges $100 for systems up to 20 kW, $250 for systems between 20 and 100 kW, and $500 for systems between 100 kW and 2 MW.[47]

Duke Energy has a similar structure as the other utilities. In North Carolina, it charges a $100 application fee for residential systems up to 20 kW, $750 for non-residential projects between 20 and 100 kW, and $1,000 for projects between 100 kW and 2 MW.[48,49]

Q54. WHERE DOES THIS LEAVE THE RECORD ON THE COMPANY'S INTERCONNECTION FEE PROPOSAL?

A54. [Mr. Lucas] The Company has offered no evidence in its testimony or exhibits that the current fees fail to collect the costs for reviewing interconnection applications. The Company's witness at the hearing was unable to explain what each step consisted of, much less whether the values in the Company's workpaper were supportable. He also contradicted key elements of the Company's own documentation, which clearly shows that interconnection fees are highly dependent on system size. And despite this, GPC proposes to dramatically increase fees for small systems. Under the current regime, a customer with a 7-kW system would pay $35. This would increase to $200 under its proposal.

The Company's only support for its proposal contained seemingly inconsistent data, unsupported assumptions, and at least one calculation error. The number of projects is inconsistently handled within the workpaper, and no justification for these discrepancies was provided. Some of the steps are performed less frequently in future years, reducing costs, but

[45] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/terms-and-conditions/vatc25ra.pdf?la=en&rev=23280dd2f29e4b5c91ca2f163976a50e
[46] https://law.lis.virginia.gov/admincode/title20/agency5/chapter314/section170/
[47] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/south-carolina/renewable-energy-developers/sc-generator-interconnection-procedures.pdf?la=en&rev=c0dc6f7905574d5d80fce185c8352ad4
[48] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own/interconnection-up-to-20kw#:~:text=A%20nonrefundable%20%24300%20fee%20is,the%20Interconnection%20Request%20Online%20Application.
[49] https://www.duke-energy.com/business/products/renewables/generate-your-own/interconnection-more-than-20kw

no explanation was offered for why these values fall over time. The cost for steps such as making billing system modifications are not supported by any data in the record or in discovery responses. Steps that appear to be quite basic – such as flagging an account as a RNR customer in the billing system – have costs that imply unreasonably high levels of effort. Although I was able to clarify some of these issues – including the surprisingly inefficient billing process – during my meeting with the Company, it has offered no evidence into the record on these points that support its cost structure.

Even if the Company was able to demonstrate that it is under-collecting interconnection review costs, its proposal is unfair to small customers. Customers installing larger systems require impact and feasibility studies that are simply not performed for small systems. In total, the cost of the interconnection review for a project over 250 kW is more than 40 times more expensive than for a project under 10 kW, and yet the Company proposes charging every customer the same fee.

Further, the Company arbitrarily decided to socialize high study costs for large systems while selectively choosing to exclude witness testing fees for those same projects. This approach is completely inconsistent with its stated claim that all projects should bear interconnection costs proportionately.

Q55. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A55. We recommend the Commission reject the proposal and maintain its current fees of $5/kW for systems under 250 kW. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW. The interconnection fees of neighboring utilities discussed above provide the Commission with a range of reasonable options.

IV. GEORGIA POWER'S NET METERING REVENUE ADJUSTMENT IS FLAWED AND LACKS CONTEXT

Q56. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A56. We discuss the Company's proposed $1.4 million revenue adjustment related to "base revenue erosion associated with the monthly netting cost shift."[50] Given the Company plans to provide RNR-related testimony in the second phase of this proceeding, we limit our discussion to the specific $1.4 million figure and its incorporation into the Company's cost of service study. We anticipate the Company will produce more than the one paragraph of testimony it submitted in this round – half of which was directly copied from its IRP filing – in the second phase of this case, and we will discuss its broader RNR testimony at the appropriate time.

Q57. PLEASE SUMMARIZE YOUR FINDINGS.

A57. The $1.4 million adjustment is based solely on lost revenue and not supported by any cost of service analysis. The Company did not incorporate any demand or energy reductions from exported energy from RNR customers in its cost of service study ("COSS") model. This results in the Company using billing determinants that are too high for classes with either RNR Monthly or RNR Instantaneous customers, which in turn results in too many costs being allocated to these classes. These steps are necessary to determine whether the $1.4 million in revenue erosion is offset in full or in part by cost reductions from exported energy.

Even if one were to take the $1.4 million base revenue erosion figure at face value, it pales in comparison to the astounding amount of excess revenue that the Company has collected from its customers over the past decade. While the Company touts that the "embedded sharing mechanism" associated with the Alternate Rate Plan structure "has enabled the Company to provide approximately $297 million in benefits back to its customers since 2013", this is a spectacularly misleading statement. In reality, the Company

[50] Legg Direct at 11.

has collected more than $1.8 billion above its approved ROE from customers in the past eleven years, with only a small fraction of that returned to customers through the sharing mechanism.

Q58. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE PURPORTED COST SHIFT?

A58. We recommend the Commission deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a result, has overallocated costs to customer classes with RNR projects that is not considered in this figure. This hits the residential class most directly given its higher proportion of exported energy.

We also recommend the Commission strongly reconsider the width and asymmetry of the currently-approved ROE dead band. The Company has consistently managed its operations to increase its profits well beyond the central approved ROE value. Expanding the delta between the ROE and the upper end of the dead band has resulted in the Company collecting $114 million in 2020 and 2021 that would have otherwise been returned to customers.

The Company Does Not Incorporate Demand or Energy Reductions from Exported RNR Generation in its COSS Model

Q59. HOW DOES THE COMPANY CALCULATE THE $1.4 MILLION COST SHIFT FIGURE?

A59. The Company's original filing did not contain details on the calculation, so Staff asked for the workpapers in discovery.[51] In response, the Company provided a nearly-identical analysis that it presented in its 2022 Integrated Resource Plan proceeding.[52] This analysis takes the following steps to calculate the figure:

[51] STF-TAI-1-27.
[52] STF-TAI-1-27 Attachment A.

1. Calculate the bill a customer would have had on the RNR Instantaneous rate, specific to the customer's tariff and inclusive of all rider revenues.
2. Calculate the bill a customer received on the RNR Monthly rate, which first nets inflow from the Company and exported energy on a monthly basis.
3. Add up the difference between these two values for all months for all customers on a given tariff.
4. Scale each tariffs' results to 5,000 customers based on the composition of the RNR active, pending, and wait list customers.

Q60. IS THIS ARGUMENT BASED ON COST OF SERVICE OR BASED ON REVENUE DEFICIENCY?

A60. This analysis is based entirely on revenue deficiency and does not factor cost of service at all. The Company simply calculated the difference in customer bills on the two netting schemes (instantaneous vs. monthly) and added up the total difference. There is no consideration of how the exported energy impacts the Company's cost of service.

Q61. DID YOU IDENTIFY AN ISSUE WITH THE AVOIDED SOLAR COST RATE THE COMPANY USED IN ITS ANALYSIS?

A61. Yes. In its workpapers, GPC uses the incorrect solar avoided cost rate. It is using the 2022 value of $0.02676/kWh from the 2021 Avoided Cost and Solar Avoided Cost Projection filing in Docket 16573.[53] Nine of the twelve months of data in the Company's analysis was from 2021, not 2022. GPC should have used the appropriate rate for the appropriate month, or if simplifying the analysis, used an avoided cost figure more weighted towards the 2021 value ($0.02884/kWh) than then 2022 value ($0.02676/kWh). Using a lower value for the avoided cost credit rate increases the apparent difference between the monthly and instantaneous RNR netting, making the total "cost shift" appear larger than it would otherwise. While this does not directly impact the base rate calculation as the RNR credit is accounted for separately, it does make the program seem more expensive in total than it should.

We also find it problematic that the Company assumed the solar avoided cost rate will remain constant through the three years of the ARP. This calculation is a function of the Company's avoided cost of generation, which is itself heavily influenced by the price of

[53] 2021 Avoided Cost and Solar Avoided Cost Projections, Docket 16573, July 30, 2021. https://psc.ga.gov/search/facts-document/?documentId=186573

natural gas. In fact, when the Company updated its filing this summer, the 2022 BTM solar avoided cost rate increased from $0.02676/kWh to $0.03400/kWh, a 27% jump.[54] Natural gas prices have remained high through all of 2022 and are projected to remain elevated through 2023 as well.[55] This suggests that the solar avoided cost rate will remain higher in the future than in the past, further inflating the Company's estimate of the "cost shift" associated with this program.

Q62. HOW DOES THE COMPANY TREAT CUSTOMER-GENERATOR ENERGY THAT IS DELIVERED TO ITS GRID FROM BEHIND-THE-METER ("BTM") SYSTEMS IN ITS COSS AND ASSOCIATED WORKPAPERS?

A62. GPC ignores it. The billing determinants that are used in the COSS are not adjusted for excess generation that is exported to the Company's system.

Q63. HOW DID YOU DETERMINE THIS?

A63. [Mr. Lucas] It was through a combination of discovery responses and an analysis of the Company's workpapers. GPC provided two data sets in response to Staff discovery requests; one that contained hourly loads during 2021 for the entire Georgia Power system,[56] and one that contained hourly loads during 2021 for each rate schedule.[57] Staff asked subsequent discovery on whether the data file with hourly loads for each rate schedule included exported energy from the RNR tariffs.[58] The Company responded that the original data "does not include customer generated energy (delivered to the Georgia Power Grid) under Rate RNR-10."[59]

I was able to reconcile the data between the schedule-specific hourly load file (which was confirmed to exclude exported energy), the total Georgia Power hourly load file, and the

[54] 2022 Avoided Cost and Solar Avoided Cost Projections, Docket 16573, July 29, 2022. https://psc.ga.gov/search/facts-document/?documentId=191003
[55] https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html
[56] STF-TAI-1-10.
[57] STF-TAI-1-12.
[58] STF-TAI-4-2.
[59] Id.

Company's COSS model using the historic 2021 test year.[60] In particular, I was able to confirm that the tariff-specific and total jurisdictional demand figures matched between the files, meaning they were developed from the same original data source. Given the tariff-level hourly load file did not contain any excess energy, it follows that the COSS does not either.

Q64. WHY DOES THIS MATTER?

A64. Exported energy from a customer's BTM system flows to meet the nearest demand. In almost every case for small RNR systems, this will mean the excess energy flows out through the customer-generators meter to the nearest transformer, and from there flows to the nearest neighbor's load. The energy flows through the neighbor's meter, causing the neighbor to be billed the full retail rate for this energy, including embedded costs for the Company's entire generation, transmission, and distribution system, as well as rider charges related to fuel expense, nuclear prepayments, and coal ash pond mitigation costs. This is despite the fact that the Company did not generate the energy, does not own the BTM asset, and only a tiny fraction of its distribution system was used to facilitate the energy delivery.

From a COSS perspective, failing to decrement the class's energy and demand allocators for exported energy means that the Company is overstating the allocators for classes with RNR systems. While the residential class only consumes 36% of electricity purchased from the Company by customers on an RNR tariff, it accounts for nearly 60% of exported energy.[61] These customers invested capital in generators that provide benefits to the Company's system through peak demand reduction and avoided fuel costs, among other benefits. Further, because residential customers export a relatively higher proportion of generation compared to non-residential customers, they are disproportionately harmed by the Company's omission of exported generation in the COSS. The Commission should require GPC to incorporate exported energy through the COSS model and flow the resulting class allocator reductions to the appropriate customer class.

[60] STF-TAI-1-1.
[61] STF-TAI-4-1.

The $1.4 million NEM Adjustment Pales in Comparison to the Company's Pending Revenue Requests and Billions of Dollars of Excess Revenue Collection

Q65. HOW DOES THE $1.4 MILLION NEM ADJUSTMENT COMPARE TO SOME OTHER FIGURES FROM THIS CASE?

A65. It is literally a rounding error. The $1.4 million NEM adjustment, if approved, would amount to less than twenty cents a year.[62] By contrast, the Company is requesting a total rate increase of roughly $2.8 billion in additional revenues between 2023 and 2025.[63] If these revenues are approved, rates will collect $1 billion more annually in 2025 than in 2022, leading to an annual increase of roughly $195.48 to a residential customer using 1,000 kWh per month.[64] In other words, the rate increase requested by the Company is about 1,000 times larger than the NEM adjustment.

On top of this, the Company is not seeking to add all its investments in Plant Vogtle to the rate base in this rate case, resulting in an anticipated $8.2 billion exclusion in rate base in 2024.[65] When asked how an on time delivery of Plant Vogtle will impact rates, the Company answered that it will increase rates by another 10.1% in 2024, on top of the request being made in this docket, and excluding costs over the already-approved $7.3 billion level.[66] Based on current rates, this adjustment may create an additional increase of $166 per year for a typical residential customer using 1,000 kWh per year, not including any future approved costs over $7.3 billion.[67]

Between the Company's rate case request in this docket and the potential approval of partial costs of Plant Vogtle, residential customers may see an increase in base rates of more

[62] $1,383,445 / 84,459,603 MWh = $0.0164/MWh. $0.0164/MWh * 12 MWh/year = $0.197/year. STF-TAI-1-27 Attachment A, Evans Exhibit LPE-1 and LPE-2.
[63] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company at 7, 9 ("Panel Direct").
[64] Panel Direct at 11.
[65] APA-SPA-ADH-MBR-6, Schedule 3.
[66] STF-NEC-1-14.
[67] 10.1% / 11.9% * $16.29 *12 = $165.91

than $350 per year in a few years. Compared to this, the two dimes per year for the NEM adjustment is literal pocket change.

Q66. IS THERE ANOTHER MECHANISM IN THE RATE CASE THAT ALSO EXPOSES CUSTOMERS TO SIGNIFICANT COST INCREASES?

A66. Yes. Each rate case, the Commission approves a specific ROE and capital structure. Currently, the Company enjoys a 10.5% ROE and a ~~54%~~ 56% equity / ~~46%~~ 44% debt capital structure.[68] These values feed into the COSS to calculate the total revenue requirement based on forecasted net plant in service, operating expenses, and taxes. From this revenue requirement, rates are designed based on forecasted usage to exactly collect the revenue requirement. Of course, the assumptions embedded in the COSS, load forecast, and cost projections will have errors, and the actual revenues collected and costs incurred will not exactly match those in the COSS models. The result is an ROE that differs from the Commission-approved 10.5%.

This is addressed in Georgia through the use of an ROE earning band mechanism. While rates are calculated based on assumptions to produce an ROE of 10.5%, if the Company collects revenue or manages costs to produce an ROE above or below this figure within a certain range (the "dead band"), no additional action is required. Currently, the Company's Commission-approved ROE is 10.5%, but the Company's multi-year rate plan is authorized to operate within an ROE dead band of 9.5% to 12%.[69]

Q67. WHAT WAS THE ORIGIN OF THE ROE DEAD BAND MECHANISM?

A67. The ROE dead band concept has been in place since at least the 2010 rate case settlement. In that case, the ROE dead band of 10.25% to 12.25% was established, with a central approved ROE of 11.15%.[70] In the 2013 rate case settlement, which remained in force from 2013 through 2018, the Commission approved an ROE dead band of 10% to 12% while dropping

[68] Order Adopting Settlement Agreement at 6, December 17, 2019, Docket 45216. ("2019 Rate Case Order")
[69] 2019 Rate Case Order at 9.
[70] Final Order at 10, December 29, 2010, Docket No. 31958.

the ROE to 10.95%.[71] Two-thirds of earnings in excess of 12% were returned to customers, and the Company could petition for an interim cost recovery mechanism should the ROE drop below 10%.[72] In the 2019 rate case settlement, the ROE was reduced to 10.5% and the ROE dead was adjusted to its current 9.5% to 12.0% with 80% of excess earnings being returned to customers.[73] GPC agreed to a one-time foregoing of its share of the earnings above the dead band in 2019 as part of a settlement agreement.[74]

Under this structure, if the ROE obtained from actual adjusted revenues and costs in a year is between 9.5% and the authorized ROE of 10.5%, the Company would be required to absorb the lower revenues. Conversely, if actual adjusted revenues and costs produce an ROE between 10.5% and 12%, the Company is entitled to keep all of the excess revenue. If the effective ROE falls below the lower end of the dead band (currently 9.5%), the Company may petition the Commission for an increase in base rates. If the effective ROE rises above the top of the dead ban (currently 12%), the Company must return to customers 80% of earnings above the top ROE threshold.

Q68. ARE APPROVED ROE DEAD BANDS A REASONABLE CONCEPT IN THEORY?

A68. Yes. When implemented properly within a multi-year rate plan construct, an ROE dead band can provide useful flexibility to a utility. Locking in rates for several years increases rate certainty for both the utility and customers and reduces the time and expenses involved in rate cases. Pairing this with an earnings dead band provides flexibility when actual results invariably diverge from forecasts.

However, there must be correspondingly robust controls over the ROE dead band and earnings mechanisms that mitigates extreme outcomes. For example, if rates were calculated based on certain assumptions that were reasonable at the time but turned out to be meaningfully short of what a utility needed to cover its costs and earn a reasonable rate of

[71] Order Adoption Settlement Agreement, December 23, 2013, Docket 36989.
[72] Id.
[73] 2019 Rate Case Order at 5-6.
[74] Id at 11.

return, there would be policy benefits to allowing the Company to request a rate increase prior to the end of the multi-year plan to help maintain its financial security. On the flip side, if the embedded assumptions in costs and rates result in the Company earning an outsized profit, mechanisms should kick in to protect consumers.

As with all things in utility regulation, there is debate over the "right" answer. This was an issue in the prior rate case, with Staff recommending an earnings band of 9.2% to 10.5% against an ROE of 9.2%, and DOD/FEA recommending narrowing the dead band to +/- 0.5% around the authorized ROE of 9.1%.[75] Instead, the Commission found reasonable and approved the Company-proposed 9.5% to 12.0% ROE band.[76] This resulted in an ROE dead band of -1% / +1.5% around the approved ROE, which was an expansion from the prior -0.95% / +1.05% band that had been in place from 2014 to 2019. As discussed shortly, this decision had material consequences for customers.

Q69. HOW HAS THE COMPANY PERFORMED RELATIVE TO ITS AUTHORIZED ROE?

A69. GPC has consistently over-performed relative to its authorized ROE, although the exact amount was not produced because the Company dodged answering a discovery question on this issue. When asked by Staff to "identify the incremental profit (in dollars) retained by Georgia Power above *the ROE* set by the Commission for each year from 2013 through 2021", the Company responded with a workpaper that identified earnings over the *ROE dead band* approved by the Commission.[77] This subtle deflection obscures a critical data point that Staff appeared to be seeking by asking for the incremental revenue and profit above "the ROE" (singular, implying the central, approved ROE) set by the Commission, not the "REO band" as answered by the Company.

Despite its attempt to obscure the question asked, GPC's response is revealing. In the nine years between 2013 and 2022, the Company collected excess revenue in six years totally

[75] 2019 Rate Case Order at 5-6.
[76] Id.
[77] STF-PIA-3-2 (emphasis added).

$380 million *above* the top of the ROE dead band.[78] This response does not include excess revenue above the approved, central ROE value and below the top of the ROE band. Given the Company has not requested a special rate case in these years to address earnings below the bottom of the ROE threshold, it stands to reason that it has not under-earned below the ROE band.

Q70. HOW DID THE COMPANY DISCUSS THESE RESULTS?

A70. In testimony, the Company touted the results as a "benefit" of the multi-year plan: "Not only have the three-year rate plans helped to keep rates stable and predictable, but the embedded sharing mechanism has also enabled the Company to provide approximately $297 million in benefits back to customers since 2013."[79]

This characterization is staggering in its bravado. To frame as a "benefit" to customers the return of a portion of the nearly $400 million collected above and beyond a generous ROE earnings dead band is Orwellian doublespeak. To accept this framing is to accept the notion that the Company is entitled to unlimited upside profits from its operations and that any limits on its earnings is a "benefit" for customers. This is simply not how a monopoly's earnings should work under the regulatory compact.

Q71. HOW MUCH HAS THE COMPANY COLLECTED ABOVE ITS CENTRAL APPROVED ROE BUT BELOW THE TOP OF THE ROE EARNINGS BAND?

A71. [Mr. Lucas] This is an excellent question, and in fact was directly asked by Staff in discovery. However, as mentioned above, the Company did not answer the question posed. As I am unable to ask discovery, I was not able to ask a follow up question requesting this information directly from the Company.

That said, I was able to produce a reasonable estimate based on the Annual Retail Surveillance reports ("ARS") that have been filed since 2011. Based on my analysis, between 2011 and 2021 the Company has collected a total of $1.49 billion in revenue above

[78] STF-PIA-3-2 Attachment.
[79] Womack Direct at 4.

its approved ROE but below the upper limit of the ROE dead band. This revenue is not impacted by the sharing mechanism, and the Company is authorized to keep every dollar. Further, the Company has retained an additional $83 million from earnings above the top of the ROE dead band, pushing its total excess collection to $1.57 billion.

Q72. HOW DID YOU CALCULATE THIS FIGURE?

A72. [Mr. Lucas] I used the workpapers that were filed with each of the Company's ASRs.[80] These workpapers included a summary of the Company's adjusted earnings and adjusted rate base; its cost of equity, debt, and capital structure; and a calculation of its actual ROE based on those values. Workpapers for years in which the Company reported excess earnings above the ROE dead band had a "Sharing" tab that calculated the excess revenue and cost share between customers and the Company.

Using these files, I was able to simply update the ROE to the central approved value and have the model calculate the excess revenue requirement collected. For years in which the Company did not report an ROE above the top of the ROE band, I recreated the "Sharing" tab to perform this calculation. I also reviewed the annual Staff filings and Commission orders on the ASRs, some of which made adjustments to the ROE or reported revenue collections found in the Company's original filing.

Q73. WHAT ARE THE RESULTS OF THIS ANALYSIS?

A73. [Mr. Lucas] My results are below in Table 4. Over the past 11 years, the Company has collected a staggering $1.87 billion above its approved ROE. "Only" $380 million of this is above the upper ROE dead band limit and subject to partial refund to customers; this is the source of the $297 million "benefit" that the Company references in testimony.

[80] See e.g. Georgia Power Company 2021 Annual Surveillance Report, Docket 42516, workpaper "2021 DI21.xlsx"

	Approved ROE	Upper Band	Actual ROE	Above ROE & Below Upper Band	Above Upper Band	Total Excess Revenue Collection
2011	11.15%	12.25%	11.72%	$67,795,000	$0	$67,795,000
2012	11.15%	12.25%	12.14%	$122,525,000	$0	$122,525,000
2013	11.15%	12.25%	11.56%	$52,200,000	$0	$52,200,000
2014	10.95%	12.00%	12.14%	$132,184,000	$16,962,000	$149,146,000
2015	10.95%	12.00%	11.55%	$74,961,000	$0	$74,961,000
2016	10.95%	12.00%	12.49%	$142,500,000	$65,325,000	$207,825,000
2017	10.95%	12.00%	12.04%	$153,033,000	$5,784,000	$158,817,000
2018	10.95%	12.00%	13.18%	$136,196,000	$154,400,000	$290,596,000
2019	10.95%	12.00%	12.88%	$147,463,000	$123,480,000	$270,943,000
2020	10.50%	12.00%	11.89%	$216,976,000	$0	$216,976,000
2021	10.50%	12.00%	12.09%	$243,860,000	$14,167,000	$258,027,000
Total				$1,489,693,000	$380,118,000	$1,869,811,000
Average	10.92%	12.07%	12.15%	$135,427,000	$34,556,000	$169,983,000

Table 4 - GPC Excess Revenue Collection

Q74. WHAT ARE YOUR OBSERVATIONS ON THIS RESULT?

A74. [Mr. Lucas] I have several. First, despite the revenue sharing mechanism, the Company has been able to retain hundreds of millions of dollars per year of excess revenue above its central, approved ROE value before it has to return a single dollar to customers. While the ROE earnings dead band can be a useful policy construct when paired with multiyear rate plans, it is currently set too wide and too strongly favors the Company over customers. I urge the Commission to revisit the appropriateness of the current band, particularly the recent approval of the upside potential to 1.5% over ROE.

Second, the Commission's approved ROE is not functioning as a practical limit on the Company's earnings. If the Company had experienced years in which it earned less than its ROE and years in which it earned more than its ROE, one could argue that its rates were set correctly. But the persistent one-way prejudice towards overearning strongly suggests that the Company rates are consistently set too high relative to the costs it actually incurs. GPC has collected excess revenue in every single year since 2011, with an average of $135 million collected above the central ROE and below the top of the ROE dead band. The smallest annual increment was an excess ROE of 0.41% worth $52 million; the largest was 2.23% worth $291 million. The Company's actual ROE has averaged 12.15% over the past 12 years, 223 basis points higher than the average approved ROE of 10.92%.

Third, the changes over time in GPC's rate base and capital structure have exacerbated this issue. In 2011, the Company's adjusted net rate base was $14.3 billion and its equity share set to 51.4%.[81] In 2021, its adjusted net rate base had grown 51% to $21.6 billion and its equity share nearly 5% to 56.1%.[82] The combination of a larger rate base on which it earns a return, a higher share of equity in its capital stack, and the approval of a 1.5% upside prior to any refunds to customers has resulted in huge increase in revenue collections above the ROE but below the upper ROE band. The Company had an ROE of 12.14% in 2012 and collected $123 million above its ROE but below the upper ROE dead band. GPC's 2021 ROE was lower at 12.09%, but it collected $244 million above its ROE and below the upper ROE dead band.

Q75. HOW DO THESE FIGURES TRANSLATE INTO A COST PER TYPICAL RESIDENTIAL CUSTOMER?

A75. [Mr. Lucas] It is difficult to calculate this figure precisely as customers on different tariffs may be contributing relatively more or less to the over-collection depending on how their rate was designed. However, I reviewed the total revenue collected per class from 2011 to 2021 using Energy Information Administration ("EIA") data and applied the overcollection in proportion to total revenue share.[83] These figures were divided by the number of residential customers in each year to produce an average impact shown below in Table 5.

[81] GPC 2011 Annual Retail Surveillance Report.
[82] GPC 2021 Annual Retail Surveillance Report.
[83] Energy Information Administration Form 861. Available at https://www.eia.gov/electricity/data/eia861/

	Above ROE & Below Upper Band	Residential Share	Annual Per Customer
2011	$67,795,000	$27,129,274	$13.24
2012	$122,525,000	$49,700,126	$24.15
2013	$52,200,000	$20,948,286	$10.11
2014	$132,184,000	$53,751,705	$25.69
2015	$74,961,000	$31,429,969	$14.84
2016	$142,500,000	$60,861,550	$28.38
2017	$153,033,000	$63,995,058	$29.44
2018	$136,196,000	$57,899,108	$26.26
2019	$147,463,000	$62,998,967	$28.15
2020	$216,976,000	$98,263,733	$43.15
2021	$243,860,000	$105,947,061	$45.75
Total	$1,489,693,000	$632,924,839	$289.16
Average	$135,426,636	$57,538,622	$26.29

Table 5 - Residential Impact of Revenue Above ROE & Below Upper ROE Band

Over the past 11 years, the Company's revenue collection above its approved ROE but below the upper ROE band has cost residential customers $633 million in total. The average customer's annual impact is around $26, but due to the factors discussed above, in 2020 and 2021 has jumped to around $45 per year.

Q76. TURNING FULL CIRCLE, HOW DO THESE FIGURES COMPARE TO THE PURPORTED NEM COST SHIFT?

A76. They are also orders of magnitude larger. In 2021, the Company claims the total base rate revenue erosion from NEM is $1.4 million, or less than $0.20 per year for a customer using 1,000 kWh a month. In the past two years, the Company has collected more than 200 times as much from residential customers from revenue above its approved ROE and below the upper ROE band.

Q77. PUTTING EVERYTHING TOGETHER, HOW DO THE VARIOUS REQUESTED AND PENDING COST INCREASES AND EXCESS REVENUE COLLECTION COMPARE TO THE PURPORTED NEM COST SHIFT?

A77. There simply is no comparison. The NEM revenue erosion, even if taken at face value, amounts to about $0.20 a year for a typical residential customer. Between the requests made in this case, the projections of the currently-authorized Plant Vogtle costs, and the excess

revenue collected above the approved ROE but below the upper ROE dead band under the current structure, the annual bill for a typical residential customer will increase by about $34 per month or more than $400 a year. This is more than 2,000 times as large of an impact and is the very definition of a red herring.

Cost Impact for Residential Customer	Monthly Amount	Annual Amount
GPC Requests in This Case	$16.29	$195.48
GPC Projection of Vogtle Costs	$13.83	$166.00
2021 Revenue Above ROE but Below Upper ROE Band	$3.81	$45.75
Subtotal	$33.91	$407.03
NEM Revenue Erosion	$0.02	$0.20
Total	**$33.93**	**$407.23**

Table 6 - Summary of Rate Impacts for Residential Customer

Q78. AS A PRACTICAL MATTER, GIVEN THE COMPANY HAS EXCEEDED ITS APPROVED ROE EVERY YEAR SINCE 2011, WHERE WOULD THE $1.4 MILLION IN REVENUE ADJUSTMENT GO?

A78. It would either go entirely to the Company (if its earnings are above the approved ROE and below the upper ROE band) or be refunded 80% to customers (if its earnings are above the top of the ROE band). For example, if the revenue adjustment had been in place in 2020, then the Company would have collected an additional $1.4 million in revenue below the top of the ROE dead band. This would have been added to the $217 million that it already collected and kept that year. If the adjustment had been in place in 2021, then 80% of the adjustment would have been returned to customers since the Company's ROE exceeded 12%.

The only way that the $1.4 million in revenue erosion could represent a revenue deficit as opposed to just more money collected by the Company is if GPC earned below its approved ROE. And considering this is something that has never happened since the ASR process was implemented, the overwhelming likelihood is all or part of the $1.4 million adjustment would simply be added to the annual revenue overcollection.

Q79. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?

A79. [Mr. Lucas] I strongly recommend the Commission revisit the ROE dead band that governs the ARP. The decision to lower the central ROE to 10.5% in the last case while leaving the

top of the ROE band at 12% instead of lowering it to 11.5% resulted in GPC collecting and keeping $142 million more in 2020 and 2021 above the ROE but under the 12% upper dead band.[84] If the upper band had instead been set at 11.5%, $114 million (80% of the total) would have been returned to customers to help reduce current and future bills. Instead, GPC kept 100% of the excess.

Given the increase in rate base and equity share, I would recommend the Commission set the ROE band to +/- 50 basis points. The Company has clearly demonstrated that it is able to manage costs to maximize profitability, having never failed to exceed its approved ROE in the past 11 years, while exceeding a 12% ROE in 7 of the last 11. If the Commission were to set the upper ROE band at 11% in 2021, the Company would have still kept $81 million before hitting the upper ROE band and having the shared savings mechanism kick in. Combined with 20% of all revenue beyond 11%, there should be ample incentive for the Company to continue to effectively maximize its profits while providing more protection to customers against higher bills.

[84] 2020 and 2021 ASR Reports.

V. GEORGIA POWER'S DEMAND-BASED "SMART USAGE" TARIFF IS FLAWED AND SHOULD NOT BE THE DEFAULT RATE FOR NEW PREMISES

Q80. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A80. In this section, we discuss the Company's "Smart Usage" TOU-RD tariff. This is a three-part tariff consisting of a fixed customer charge, a peak/off peak energy charge, and a demand charge. We discuss the design of this tariff and how its use of a non-coincident peak ("NCP") demand charge to collect a significant portion of a customer's bill is fatally flawed. We also analyze the usage patterns of new customers added to this tariff since it became the default rate choice for new premises.

Q81. PLEASE SUMMARIZE YOUR FINDINGS.

A81. The TOU-RD tariff is not reflective of cost-causation and should not be the default residential tariff. Its NCP billing demand is a faulty measure that does not consider the timing of an individual customer's peak demand. Further, it produces higher bills for most customers on the tariff compared to the R, TOU-REO, or TOU-PEV options, particularly for lower-than-average use customers. This exacerbates the problem of having the TOU-RD rate as the default rate for new customers; those added to this tariff in the past two years are disproportionally lower-than-average use customers and are experiencing significantly higher bills than they would have on the R tariff.

Q82. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE TOU-RD RATE?

A82. The Commission should require substantial modifications to the TOU-RD tariff. First, it should no longer be the default tariff due to the all the reasons discussed below. Second, it should be redesigned in one of two ways: with a TOU billing demand charge that recovers a smaller portion of the fixed production, transmission, and distribution costs, or as an NCP billing demand charge that only recovers low voltage distribution equipment close to the customer. Third, the Commission should require the Company to update its billing determinants to ensure that the rate is revenue neutral with respect to the R tariff. We discuss each of these recommendations below.

The Smart Usage Tariff is Improperly Designed and Should be Modified

Q83. PLEASE DESCRIBE THE TOU-RD TARIFF.

A83. The TOU-RD tariff is a three-part tariff, with a fixed customer charge, a volumetric energy charge based on total peak and off-peak kWh consumption, and an NCP demand charge based on the highest 60-minute billing demand in a month. Currently, customers pay about $14 per month for the customer charge, $0.096/kWh and $0.0103/kWh for peak and off-peak energy, respectively, and $8.21 per kW of peak demand for base rates.[85] Peak periods for energy consumption are between 2 and 7 PM weekdays from June to September, with all other hours (and summer holidays) being off-peak; there is no time constraints on the maximum demand.

Q84. IS THE CONCEPT OF "BILLING DEMAND" EASILY UNDERSTOOD OR EASILY CONTROLLED BY TYPICAL CUSTOMERS?

A84. No, we do not believe it is. While the Company's literature suggests that customer can simply stagger appliance use (such as the laundry, cooking dinner, or running the air conditioner) at the same time to avoid high charges on the TOU-RD tariff, this concept is not as easily done as it is made out to seem.[86]

Customers generally do not know how much power their appliances consume. Laundry can have substantially different impacts on one's energy use. Old dryers consume substantially more energy than new ones, and gas dryers use much less electricity than electric dryers. Further, the power demand depends on the temperature setting and duration of the cycle. Likewise, cooking loads vary substantially based on equipment and preparation. Modern induction cooktops can pull upwards of 10 kW of power, while oven power consumption varies greatly depending on whether it is on a low bake or high broil setting. Air condition is certainly a major contributor to power usage, but the types of air condition

[85] TOU-RD-6 tariff. Customers separately pay for the various fuel, ECCR, and NCCR riders. Available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/electric-service-tariff-pdfs/TOU-RD-6.pdf

[86] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/smart-usage.html

units can vary dramatically from small, window units in apartments to multiple 5+ ton units in detached single family homes.

On top of this, many appliances pull different amounts of power at different times in their usage cycle. Even if set to a constant temperature, air conditioners kick on and off depending on the ambient temperature, heating load from the sun, air circulation, insulation level, and many other factors. Similarly, running hot water in the sink for a few minutes may cause the electric water heater to kick in, pulling many kW of power without the customer's knowledge or control. It is simply unrealistic to expect a customer to manually manage all the appliances in her house during every single hour of the month lest a single unfortunate event conspire to set a customer's peak demand for a month.

Even worse, customers with electric vehicle chargers or electric space heaters with high power draws that cannot be avoided indefinitely have no means of reducing their bills under a certain level, even if they never used other appliances at the same time. This effectively converts the demand-based tariff into an unavoidable fixed charge, which is neither cost-reflective nor just and reasonable.

Q85. DID THE COMPANY PROVIDE WORKPAPERS THAT DETAILED HOW THIS RATE WAS DESIGNED OR WHAT COSTS THE ENERGY AND DEMAND CHARGES WERE DESIGNED TO RECOVER?

A85. No, it did not. Staff asked in discovery "Please provide executable copies of all workpapers and analyses utilized to develop the proposed rate schedule revenue increases and specific rate designs for all aspects of this case."[87] The workpapers that the Company provided did not detail the composition of the various rate design components, but instead generally scaled up each existing rate component (i.e., the base, energy, and demand rates) to collect the targeted revenue increase. As such, there is no evidence in the record or Staff discovery on how the rate is intended to recovery various costs from the COSS model.

[87] STF-TAI-1-16.

Q86. WERE YOU ABLE TO DETERMINE HOW MUCH REVENUE IS COLLECTED THROUGH EACH COMPONENT OF THE TARIFF?

A86. [Mr. Lucas] Yes. GPC provided confidential workpapers that have the specific values used for its rate increase calculations,[88] but also provided a public data set of customer usage from which one can perform a similar calculation.[89] I present both figures below including fuel costs and recovery riders in Table 7 as I believe it is important to provide as much information to the public as possible. The slight differences in the figures are due in part to the use of only customers with 12 months of billing data from the public customer database workpaper. These customers have been on the tariff longer, and as discussed below, are higher-use customers who tend to have more energy use relative to peak demand compared to newly added customers.

TOU-RD Revenue	Customer	Energy	Demand
GPC Rate Design	[redacted]	[redacted]	[redacted]
Customer Database	11.8%	40.7%	47.5%

Table 7 - TOU-RD Revenue Split

Based on the public customer database, 59% of customer's annual bills are either fixed customer charges or based on a single hour of demand in each month. The share is even [redacted] at [redacted]% for the GPC rate design workpaper. In other words, only [redacted]% to 41% of customer's annual bill can be controlled by how much energy they use in a month; the rest is either fully fixed or locked in from load in only 12 hours a year.

Q87. WERE YOU ABLE TO DETERMINE HOW THE COMPANY'S COSTS BREAK DOWN BETWEEN CUSTOMER, ENERGY, AND DEMAND CLASSIFICATION?

A87. [Mr. Lucas] I was not able to exactly duplicate the classification structure found in the rate design, but using data from public version of the Company's COSS model, I was able to summarize operating expenses and depreciation and amortization costs by function for the

[88] STF-TAI-1-16 Attachment AJ TRADE SECRET.xlsx
[89] STF-TAI-1-12. ("Customer Database")

residential customer class.[90] These functions map fairly directly to the customer, energy, and demand components of the rate. The results are presented below in Table 8.

Function	Residential Share
Production - Variable	30.3%
Production - Fixed	34.8%
Transmission	6.2%
Distribution	18.7%
Customer	10.1%
Total	**100.0%**

Table 8 - GPC Expense Breakdown

Q88. WOULD YOU EXPECT THE MAPPING OF COSS EXPENSES TO TRANSLATE DIRECTLY TO THE RATE DESIGN?

A88. [Mr. Lucas] No, I would not. It is neither necessary nor appropriate to exactly map the COSS results into a rate design. Rate design should be reflective of the COSS results, but other considerations such as gradualism and customer understanding, acceptance, and actionability must also be factored in. For example, it is entirely appropriate to recover demand-based costs through a volumetric energy charge (as all of the residential tariffs except TOU-RD do) despite some of these costs being driven by customer demand.

Q89. THAT SAID, HOW DO THE COST PROPORTIONS FROM THE COSS COMPARE TO THE TOU-RD RATE REVENUE COLLECTION?

A89. [Mr. Lucas] They are directionally similar. The Production – Variable cost category contains fuel and variable O&M expenses that are a function of energy generated. The COSS places about 30% of residential expenses into this category, while the rate collects about 40% and [redacted]% of revenue based on the energy usage of the Customer Database and GPC rate design workpapers, respectively.

The Production – Fixed, Transmission, and Distribution costs are typically allocated based on various measures of peak demand (e.g., 4CP, 12CP, Class NCP). These functions

[90] Exhibits LPE-1 and LPE-2

contain about 52% of the COSS expenses, while the rate collects about 48% and [redacted]% of revenue through the demand charge for the Customer Database and GPC rate design workpapers, respectively.

Finally, the Customer costs are independent of energy or demand and pertain to the costs of connecting customers to the system and back-office functions such as billing. The COSS assigns about 10% of residential expenses to this category, while the rates collect about 12% and [redacted]% of revenues through the Customer Database and GPC Rate Design workpapers, respectively.

Q90. WHAT DOES THIS MEAN?

A90. [Mr. Lucas] It means that nearly all demand-based costs related to production, transmission, and distribution are collected through the demand charge. While this may appear appropriate given both are demand-based measures, a customer's individual NCP demand level has nothing to do with the coincident peak demand measures that drive costs in the COSS. This is a fatal flaw in the rate design, and the Commission should direct GPC to redesign the rate to correct this shortcoming.

Q91. PLEASE EXPAND ON THIS POINT.

A91. [Mr. Lucas] The core premise of the COSS is that customers are assigned costs in proportion to their usage during hours that drive those costs. The system is sized to meet the peak demands of its customer base; as such, costs are allocated based on each customer group's load during peak hours. In the Company's COSS, production capacity costs are generally allocated to customer classes based on a 12CP method, while transmission costs are generally allocated based on a 4CP method. Distribution costs are allocated based on either the 4CP (voltage levels C-E) or Class NCP (voltage levels F-G) demand levels.[91] Precisely zero costs are allocated based on the independent peak demand of individual customers, even though

[91] The Company allocates demand-based production costs and step-up substation costs on a 12CP basis, and high-voltage transmission costs on an 80% 4CP/ 20% 12CP basis. Lower-voltage transmission assets are allocated on a 4CP or NCP basis depending on voltage level. Evans Direct at 17.

there is a commonly used COSS allocator (sum of individual max demand) that captures this value.

A key consideration is rate design is that rates should be reflective of cost-causation; that is, if costs are driven by usage during peak hours, then the rate should reflect this and charge more for usage during peak hours. By designing the TOU-RD rate to capture most of the demand-based costs through an individual NCP demand charge, the Company is breaking the rule of cost-reflective rates.

From a COSS perspective, any customer who sets their individual peak usage during an hour that is not the Class NCP or one of the 12CP hours is necessarily not adding to the peak demand on the system. Put another way, if the individual's peak occurs in the any of the 719 hours a month that are not the 12CP peak hour, or any of the 8,759 hours of the year that are not the Class NCP hour, there is spare capacity on the system.[92] Only in the instance that a customer sets their individual peak demand in the same hour as the Class NCP or one of the 12CP hours could they potentially be adding marginal cost or changing the COSS allocation values.

But even in this case, the theoretical costs that a customer could impose are limited by the physical reality of the system. If a customer's individual maximum demand in April coincides with the 12CP hour for April, even though the COSS allocates some costs based on this hour, there is no incremental cost imposed on the physical system as the total load being served in April is much lower than the total load served during the summer peaks. The stress on all pieces of equipment during the highest load in April is still substantially lower than the stress on all pieces of equipment during peak summer hours. If an asset can handle peak loads in the summer, it necessarily can handle peak loads in April.

Q92. WHAT DOES THIS MEAN FOR CUSTOMERS ON THE TOU-RD?

[92] By definition, the peak hour is the one where the aggregate load of a class or tariff is highest, including the demand of the individual customer. All hours other than this hour necessarily have lower total demand, otherwise that hour would become the peak hour.

A92. The combination of these factors means that billing a customer for most of the demand-based production, transmission, and distribution costs based on their individual monthly peak demand does not follow the protocols of cost-reflective rates. The rate is unable to send price signals to reduce system costs because the measure of demand being used – the individual's peak demand – is not a driver of system costs.

Further, the rate is not actionable. A customer is unaware of their billing demand level until after they receive their bill, and even then, they are not provided with any useful information about when or why they set their peak demand. The Company's billing system does not retain the time and date of when the customer's peak demand is set, so not even this basic information can be passed onto a customer's bill.[93] With no knowledge of when they set their peak or what occurred to make this happen, there is no ability for customers to manage their peak demand.

Q93. DO YOU HAVE AN EXAMPLE OF HOW THESE MISMATCHES CAN RESULT IN CUSTOMERS BEING OVERCHARGED FOR THEIR USAGE?

A93. A perfect example is a customer with an electric vehicle ("EV") who always charges during overnight hours, and whose EV charger is the largest power draw in their house. Residential EV charges commonly draw 9.6 kW, and some more powerful units can pull 19.2 kW. A customer who routinely charges overnight when there is spare capacity on the distribution, transmission, and generation system is not driving any cost increases as the capacity of system is capable of handling much more load.

However, on the TOU-RD rate, this customer would lock in monthly charges of nearly $80 for the 9.6 kW charger and over $150 for the 19.6 kW charger despite the fact that these loads do not cause any demand-based costs on the system. Worse, because the customer's demand-based bill would be locked in every month from charger her car, there is no incentive for the customer to manager her other loads (e.g., air conditioning, washing

[93] STF-TAI-2-2.

machine, etc.) during the actual high stress hours. This perverse incentive could cause her to increase her peak demand during hot summer afternoons which could contribute to higher costs while avoiding any cost responsibility for her usage.

Q94. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?

A94. We are not proponents of demand charges for residential customers, particularly those offered without any supporting technology to help customers enable their demand. But given the TOU-RD rate is a voluntary rate and customers are not required to take service on it, there are a few ways the rate design could be improved.

The first would be redesigning the demand charge as a TOU demand charge. In this structure, the demand rate would only be based on peak hours of the day, much like the volumetric rate is higher during peak hours. These peak summer afternoons from 2 to 7 contain the hours in which the grid is under stress and where load reduction from customers is most useful. Sending a price signal to manage demand during these hours is more actionable than requiring customer to be hypervigilant over every hour of the month.

The second would be to maintain the NCP demand charge but use it to only collect low-voltage distribution costs near the customer's premise (i.e., voltage levels G). While these assets are still often shared among multiple customers, they have lower load diversification than higher voltage assets. Using an individual's NCP demand to collect this small set of costs would be more reflective of cost-causation. In this structure, the production, transmission, and higher-level distribution costs would be collected through volumetric TOU rates.

Q95. DO YOU HAVE THE DATA NEEDED TO DETERMINE WHAT THE RATES WOULD LOOK LIKE UNDER YOUR PROPOSED STRUCTURE?

A95. No, we do not. If the TOU demand charge was designed to collect most demand-based production, transmission, and distribution costs during the four summer hours, it would likely be set at a very high level (perhaps more than $20/kW). This may not be desirable as it could lead to wide swings in bills based on an inadvertently high hour of usage and very high

summer bills. Instead, we recommend that a sizeable portion of the demand-based costs be recovered through a volumetric TOU rate to produce a demand charge in the $10-12 range. This would still send a robust price signal to reduce demand during summer peak hours but would prevent surges in summer bills.

If the NCP billing demand was kept but the collected costs reduced to low-voltage assets such as line transformers, based on the plant in service ratios from the COSS, we would expect the demand rate to fall to around $1/kW. While this is much lower than the demand charge in the current TOU-RD design, it is all that should reasonably be collected through an NCP-based billing demand given the inherent lack of cost-reflection in this metric.

Low Use Customers are Substantially Overcharged on the Smart Use Tariff

Q96. DID YOU ANALYZE HOW CUSTOMERS WITH DIFFERENT USAGE LEVELS FARED ON THE VARIOUS RESIDENTIAL RATES?

A96. [Mr. Lucas] Yes, I did. Staff asked for monthly usage data from each residential customer in 2021.[94] Using this data set, I was able to perform several analyses on how customers taking service on the TOU-RD tariff would have fared on the TOU-PEV, TOU-REO, and R rates. I began by trimming the data to only include customers with a full 12 months of recorded data. Given the TOU-RD rate experienced substantial customer growth during 2021 due to the decision to make it the default rate at the beginning of this year, this reduced the data set from about 61,000 customers with partial months of data to about 11,000 customers with 12 months of data. While this does represent a sizable reduction to the data set, these are also customers who self-selected into this tariff prior to it become the default. In other words, they affirmatively chose to be on this tariff.

After trimming the data, I recreated each TOU-RD customer's bill under the other tariffs, including fuel cost and the various adder tariffs. Because the data set did not

[94] STF-TAI-2-2.

specifically break down peak, off-peak, and super off-peak usage for these customers, and I was unable to ask for the data myself, I calculated the tariff average peak, off-peak, and super off-peak values from another data set the Company provided to Staff.[95] Given that an individual's bill may contain relatively more or less peak or super off-peak energy than the tariff average, I also ran sensitivities around these figures.

Q97. WHAT DID YOUR ANALYSIS SHOW?

A97. [Mr. Lucas] In theory, since this is a voluntary rate, and all customers who were taking service under it as of January 2021 self-selected into the rate, one might have expected the group of customers to have lower bills compared to other tariffs. However, as is clearly evident, this is not the case. My analysis showed that even for these self-selecting customers, most experienced higher annual bills on the TOU-RD tariff than they would have had on the R (61%), TOU-REO (63%), and TOU-PEV (72%) tariff. Moreover, for customers below the median usage, nearly all customers experienced higher bills on the TOU-RD rate than the R (90%), TOU-REO (89%), or TOU-PEV (94%) tariffs.

Figure 1 is a summary of the results comparing the TOU-RD tariff to the R tariff. In this chart, the blue dots represent the bill increase (above the 0% line) or bill decrease (below the 0% line) shown on the left y axis against the average monthly usage on the x axis. The orange line shows on the right y axis the cumulative percentage of customers up to that usage level that have higher bills on the TOU-RD rate than the R rate shown. The vertical purple line represents the median usage of this customer set, equal to 971 kWh per month.

[95] STF-TAI-1-12.

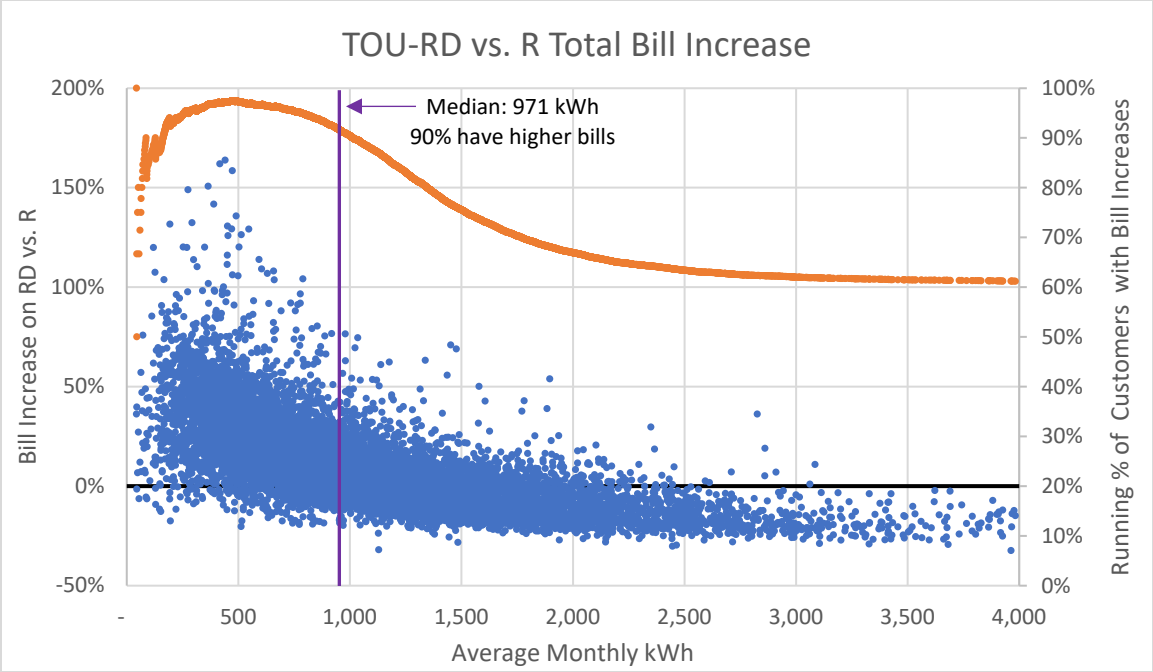


Figure 1 - TOU-RD vs. R Total Bill Increase

The chart shows a clear relationship between bills on these two tariffs. Small customers, shown on the left side of the chart, almost exclusively pay more on the TOU-RD tariff. For customers that average less than 500 kWh per month, 97% pay more on the TOU-RD rate than they would have on the R rate. By the time the median usage of 971 kWh is reached, this has fallen slightly to 90%. In other words, 90% of the bottom half of customers by usage level pay more on the TOU-RD rate than on the R rate. In fact, the *average* bill increase of the lower half of customers by usage is a whopping 23.4%. Some unlucky low-use customers see bill increases over 50% or even 100% on this tariff, despite their demand peaks not causing cost increases on the system.

Customers only begin to consistently see savings on this tariff as the usage levels grow. Not until usage has increased to around 1,300 kWh (33% above the median usage) do about half of the customers experience lower bills. By the time usage reaches 2,000 kWh a month (roughly double the median usage) do customers consistently save on the TOU-RD tariff. All told, 61% of all customers in the data set – regardless of usage – had higher bills on the TOU-RD tariff than they would have had on the R tariff.

Q98. DID YOU ALSO COMPARE BILLS WITH THE OTHER TOU RATES AS WELL?

A98. [Mr. Lucas] Yes, I did. I preformed the same analysis on the TOU-REO and TOU-PEV rates, and found very similar results. Figure 2 and Figure 3 below show these analyses.

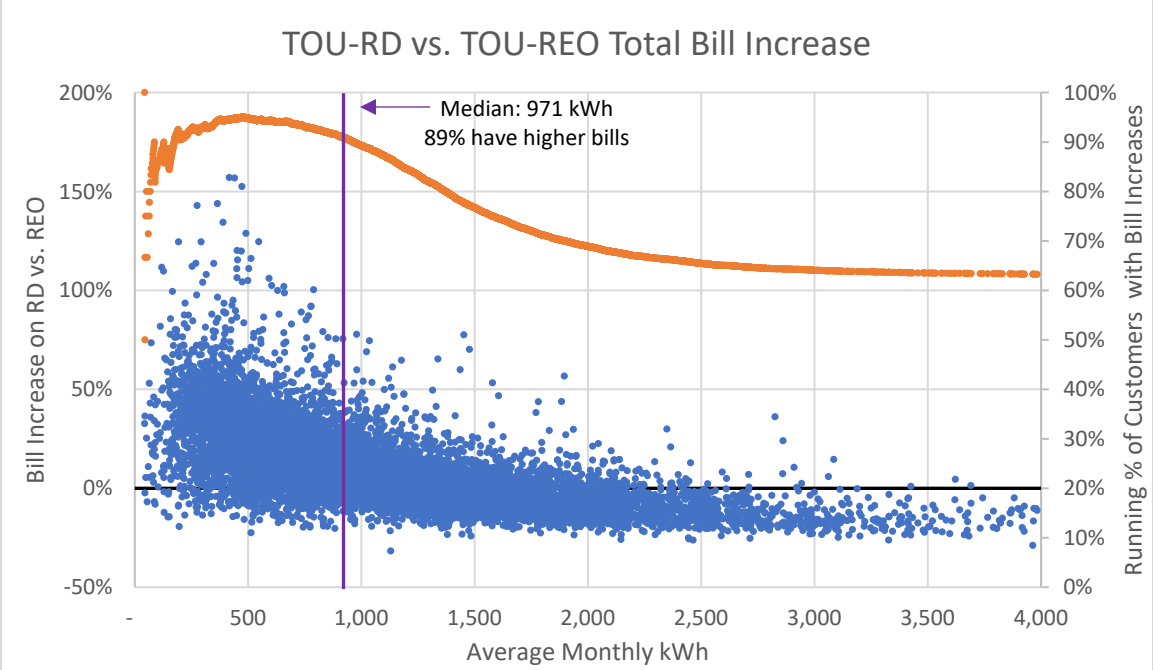


Figure 2 - TOU-RD vs. TOU-REO Total Bill Increase

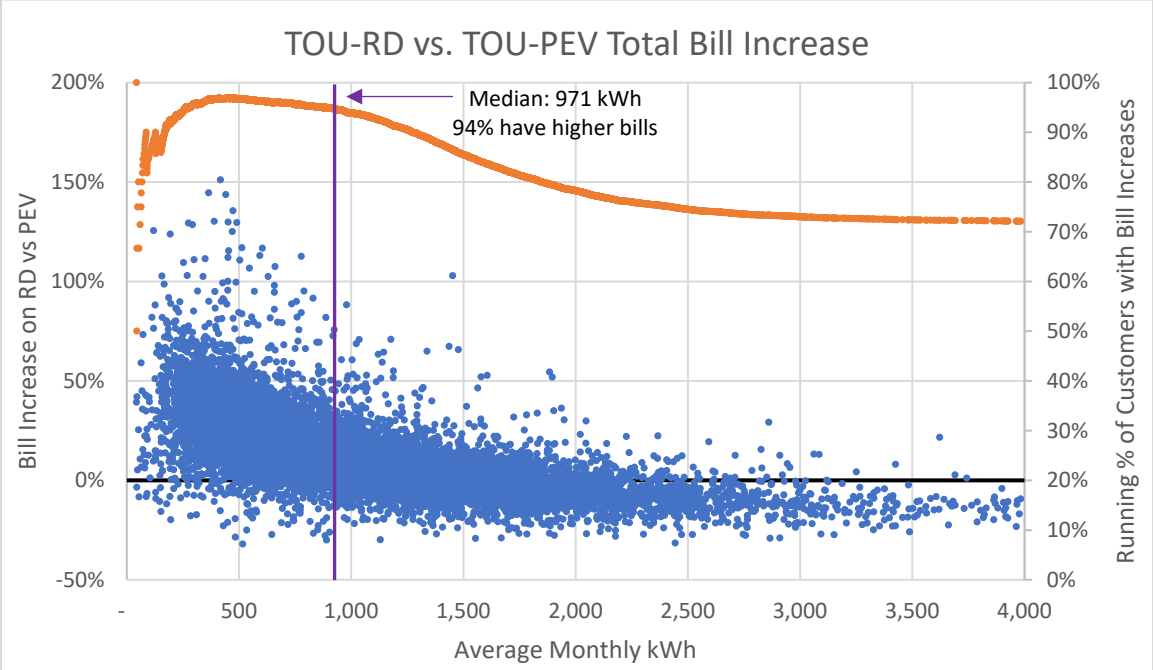


Figure 3 - TOU-RD vs. TOU-PEV Total Bill Increase

The shapes are nearly identical, with low-use customers faring equally as poorly on the TOU-REO rate as the R rate and even worse than if they had been on the TOU-PEV rate.

Q99. WHAT WAS THE IMPACT ON THE RESULTS OF CHANGING THE PEAK USAGE PERCENTAGES?

A99. [Mr. Lucas] About 20% of the TOU-RD tariff energy usage during summer months was during peak hours. Table 9 below shows the results when I changed the peak usage to 10% and 30% of summer usage, respectively. The changes were minor; the vast majority of sub-median usage customers continued to pay more on the TOU-RD tariff, and the average bill increase for these customers stayed within 7% across the spread of peak usage levels.

Peak Summer Usage	10%	20% (Baseline)	30%
% of All Customers with Higher Bills vs:			
R	53%	61%	69%
REO	69%	63%	56%
PEV	70%	72%	72%
% of Sub-Median Use Customers with Higher Bills vs:			
R	83%	90%	95%
REO	93%	89%	84%
PEV	94%	94%	93%
Average Bill Increase for Sub-Median Use Customers vs:			
R	20.0%	23.4%	26.8%
REO	24.0%	20.5%	17.4%
PEV	24.1%	24.2%	24.5%

Table 9 - Rate Comparison Peak Usage Sensitivity

Q100. DO THESE RESULTS SURPRISE YOU?

A100. [Mr. Lucas] While the magnitude of the impact on low-use customers is surprising, it is not surprising that low-use customers fare poorly on this tariff. Customers with low monthly usage tend to have lower load factors.[96] And customers with low load factors are penalized by rate designs with NCP demand charges that collect a substantial portion of the overall tariff revenue. I calculated the load factor in the data set, and unsurprisingly, low-use customers had low load factors as seen in Figure 4 below.

[96] A load factor is a fraction that represents the total usage in a period divided by the maximum demand in the period times the number of hours. A load factor of 1.0 represents constant usage at a set level, while a low value such as 0.1 represents occasional high peak demands but low overall usage.

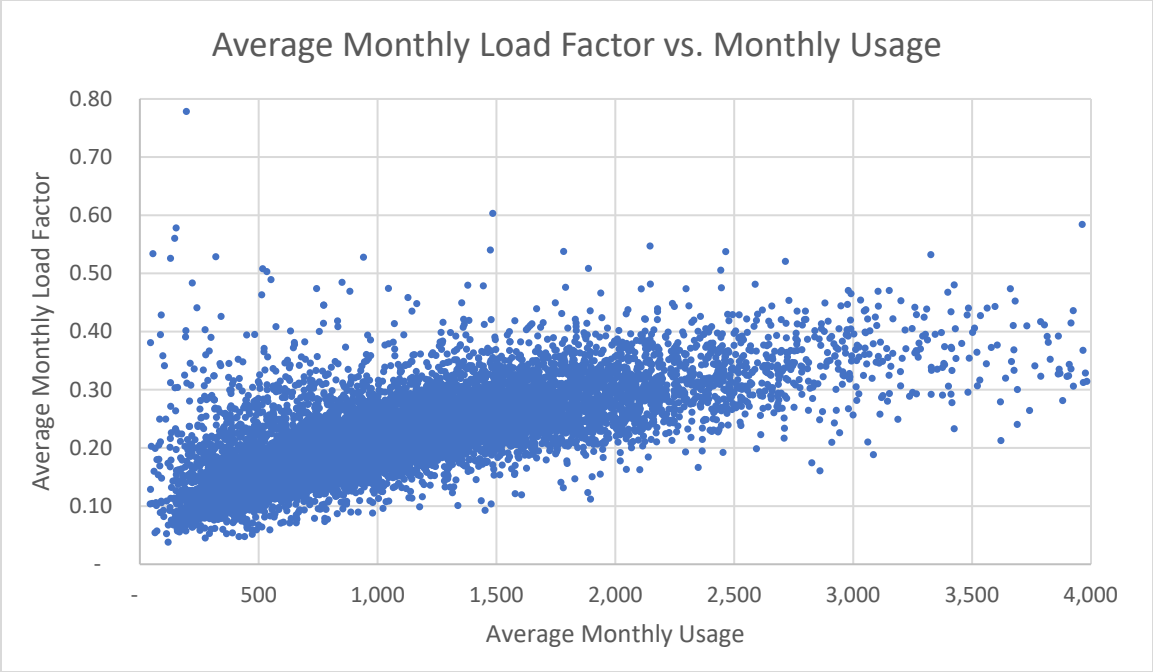


Figure 4 - TOU-RD Customer Average Monthly Load Factor

Even worse, customers with low NCP load factors have low coincident factors. This means their individual peak demand is not aligned with system peak hours when high loads actually drive costs. This relationship, dubbed the Bary Curve, has been known for decades and was discussed by the Edison Electric Institute in its 1984 publication "The Art of Rate Design."[97] In summary, high NCP demand from low-use customers is not putting stress on the system because the demand spikes tend to fall outside peak hours.

Q101. WERE YOU ABLE TO ANALYZE THE GPC CUSTOMER SET TO EXPLICITLY DEMONSTRATE THIS?

A101. [Mr. Lucas] No, I was not because I was not able to ask for hourly data for a sample of customers. However, in another case in which I was able to ask discovery, I did obtain this information and performed this analysis. DTE Energy in Michigan produced a workpaper that showed the three highest load hours in each month in 2018 and 2020 for 10,000 random residential customers. I analyzed the data to determine how many of those hours corresponding with the 4CP, 12CP, and Class NCP hours.

[97] The Art of Rate Design, Chapter 5, Frank S. Walters, Edison Electric Institute, 1984.

On average, only 1% of the 10,000 customers had their individual peak demand in a month fall during one of the 4CP hours. Even fewer experienced alignment with the 12CP hours. The Class NCP metric was the "highest" of the three, with a mere 1.33% of customers experiencing their monthly peak at the same time as the class peak.

	Individual Customer Monthly Highest Load		
COSS Hour	1st Highest	2nd Highest	3rd Highest
4CP	1.03%	0.91%	0.81%
12CP	0.78%	0.59%	0.51%
Class NCP	1.33%	1.08%	1.02%

Table 10 - DTE Energy Individual Peak Hour Coincidence Analysis

Further, these customers were not limited to low-use, low-load factor customers, whose overlap between individual peak demand and system peak demand was even lower. I performed the same analysis on customers with rooftop PV who, due to self-consumption, had lower load factors than a non-PV customer. There were only 4 instances over the 1,348 4CP customer-hours – 0.3% – when the customer's highest load hour of the month corresponded to the 4CP hours. Similarly, only 0.5% of peak hours occurred during the 12CP hours. And there was only one single instance where a DPV customer's peak hour fell during the Class NCP peak. These results reinforce the futility of attempting to send a price signal with an NCP billing demand structure; individual customers simply do not peak during the same hours that drive system costs.

Q102. PLEASE SUMMARIZE YOUR ANALYSIS ON THE TOU-RD TARIFF THUS FAR.

A102. [Mr. Lucas] I began by analyzing data from a set of 11,000 TOU-RD customers who had been on the tariff for all twelve months of 2021. I found that nearly all low-use customers on this tariff paid substantially more than they would have on the R, TOU-REO, or TOU-PEV rates. I showed that the low-use customers also had low load factors, which strongly contributed to their higher bills on an NCP tariff. I also showed that residential customers from another utility had extremely low levels of correlation between individual peak demand hours and system peak demand hours.

This analysis shows that the TOU-RD rate is poorly designed and is actually harming many of customers that self-selected into the tariff. It also provides quantitative support for my assertion that the NCP billing demand structure does not send meaningful price signals. I now turn to implications of making this rate the default rate for residential customers.

New Customers are Disproportionately Low Use Customers and are Being Harmed by the Default Rate

Q103. WHAT IS A DEFAULT RATE?

A103. A default rate is the rate that a new customer is placed on at the commencement of their electric service. Customers have the option to choose other rates for which they qualify, but absent an affirmative choice, they are placed on the default rate.

Q104. WHAT IS THE CURRENT DEFAULT RATE FOR RESIDENTIAL CUSTOMERS?

A104. The TOU-RD rate was set as the default rate beginning in January 2021 as part of the 2019 Rate Case settlement agreement.[98] The Company was required to "report back to the Commission at the time of its next base rate case regarding the adoption of TOU-RD and its use as the default rate for newly constructed residential premises."

Q105. WHAT DID THE COMPANY REPORT IN ITS FILING REGARDING THE ADOPTION OF THE TOU-RD AS THE DEFAULT RATE?

A105. There was only one reference to the word "TOU-RD" in the Company's entire application, and it was in response to its proposal to close the R tariff to new customers:

> Since the beginning of 2020, Georgia Power has proactively promoted its wide variety of residential rate options to help and encourage customers to choose the rate that best meets their needs when establishing service. As a result, customer adoption of alternative residential rate options such as Smart Usage ("TOU-RD"), Plug-in Electric Vehicle ("TOU-PEV"), Pay by Day ("PBD") and FlatBill has increased significantly. Indeed, the number of residential customers who have chosen to participate in a time-of-use rate has increased by more than 250%. Many customers have demonstrated both a demand and preference for these rate plans. By closing the R tariff to new premises, the Company will continue to transition new residential accounts onto other rates within the Domestic Group that better align with the cost to serve customers. Again, the R tariff will remain available to existing residential premises on Georgia Power's system that established service prior to January 2023.

[98] 2019 Rate Case Order at 14.

Q106. IN YOUR VIEW, DOES THIS MENTION SATISFY THE COMMISSION'S DIRECTIVE TO "REPORT BACK" ABOUT THE TOU-RD RATE AS A DEFAULT OPTION?

A106. No. The Company has no discussion about the TOU-RD as the default rate and provided no analysis on its adoption. The only mention, cited above, is in passing. Staff needed to ask discovery questions to extract any additional details from the Company.

Q107. WHAT DID THOSE DISCOVERY RESPONSE SHOW?

A107. It showed that customers who have been placed on the TOU-RD rate since January 2021 have experienced higher bills than they would have on the R tariff. Further, many customers that were placed on the tariff in 2021 left after a few months. And in contrast with the Company's statement above about the increases in the number of customers on the various TOU rates, the only rate that has been appreciable growth is the TOU-RD rate after becoming the default rate.

Q108. WHAT DATA DID GPC PROVIDE REGARDING THE RATE CHOICES OF NEW CUSTOMERS?

A108. In response to a discovery request by Staff, GPC provided the number of new customers who signed up on the various residential rates from January 2021 through May 2022.[99] This data is summarized in Figure 5 below. Between January 2021 and May 2022, about 50,000 and 22,000 customers had been enrolled on the TOU-RD and R tariff, respectively. However, only 17 and 13 new customers had been enrolled on the TOU-REO and TOU-PEV tariffs, respectively. This moribund adoption rate is not distinguishable from zero.

[99] STF-PIA-2.

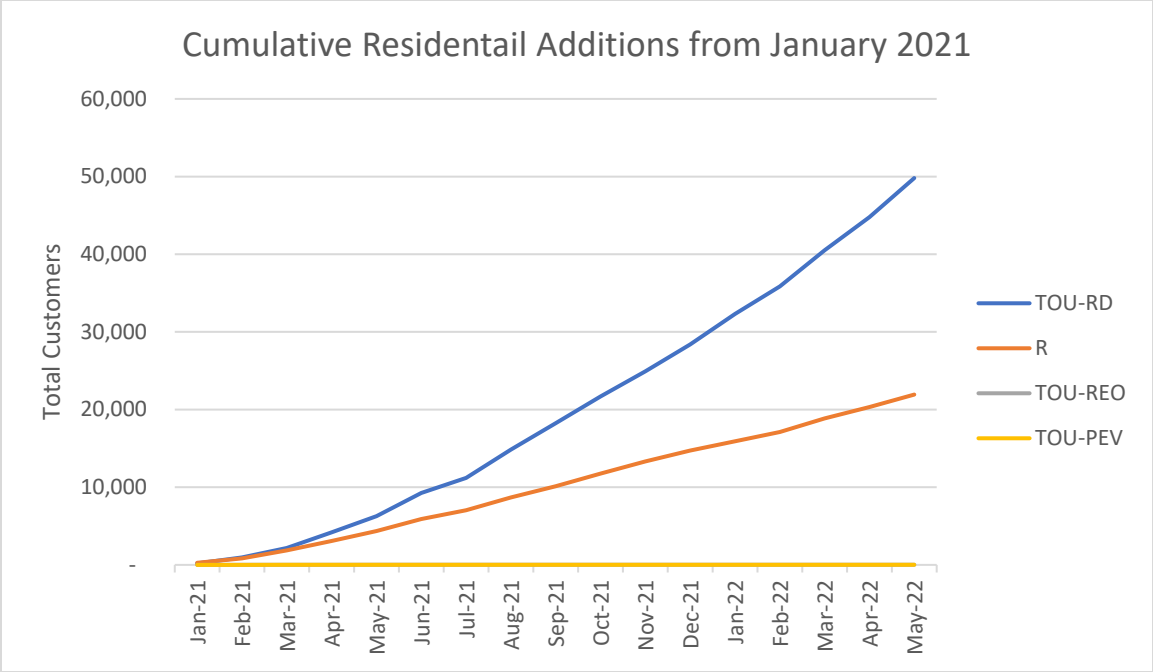


Figure 5 - Cumulative Residential Customer Additions from January 2021

Q109. DO YOU HAVE SIMILAR DATA FOR CUSTOMERS GOING BACK TO 2020, WHEN THE COMPANY SUPPOSEDLY STARTED PROACTIVELY PROMOTING ITS RATES?

A109. [Mr. Lucas] I have public data for the TOU-REO and TOU-PEV tariffs,[100] but only confidential data for the TOU-RD tariff which I needed to extrapolate from annual customer data. As is seen below in Table 11, the participation increase in the TOU-PEV tariff was relatively small and partially offset by decreases in the number of TOU-REO customers. The only meaningful change occurred in the TOU-RD tariff, as shown above, was driven by the new customers added through the default tariff.

	TOU-REO	TOU-PEV	TOU-RD (Est)	Total
Jan 2020	7,416	4,640	[redacted]	[redacted]
Jan 2021	6,935	5,208	[redacted]	[redacted]
Jan 2022	6,467	6,674	[redacted]	[redacted]
May 2022	6,320	7,547	[redacted]	[redacted]
Delta 1/20-5/22	**(1,096)**	**2,740**	[redacted]	[redacted]

Table 11 - Customer Changes on the TOU Rates

[100] STF-TAI-1-32

Based on this data, customers are defecting from the TOU-REO rate, slowly signing up for the TOU-PEV rate (which, as discussed below is likely impacted by intentional confusion created by the Company), and being defaulted into the TOU-RD rate. In fact, in the years before the TOU-RD became the default rate, growth was [redacted], with [redacted] between 2017 and 2019 and only [redacted] second half of 2020.[101]

Q110. DID THE COMPANY PROVIDE DATA ON HOW MANY CUSTOMERS DEFECTED FROM THE TOU-RD RATE?

A110. [Mr. Lucas] They did, although it strongly conflicts with other data provided by the Company. In response to Staff discovery, the Company stated that only 259 customers unenrolled from the TOU-RD tariff in 2021, 95 of which were from a single properly manager in a single month.[102]

However, data provided in another Staff request tells a very different story. I analyzed 2021 data from the Customer Database discussed above looking for new customers that signed up on the rate (indicated by billing data in a month where none was present before) and then left to go to another rate (indicated by billing activity on a different tariff in a later month). Rather than 259 customers defecting from the rate for the whole year, I found that roughly 1,300 customers who were not on the tariff as of January 2021 left the tariff at some point in 2021, and roughly 1,850 who were on the tariff as of January 2021 left the tariff at some point in 2021. These do not include customers who disconnected their service during the year, as indicated in the data set as a customer whose last bill was prior to December.

Q111. RETURNING TO THE CUSTOMERS THAT WERE ADDED TO THE TARIFF, HOW DID THEIR USAGE LEVELS COMPARE TO AVERAGE CUSTOMERS?

A111. [Mr. Lucas] They were lower-use customers. Staff asked for the average monthly peak demand of new TOU-RD customers and the residential class as a whole along. It also

[101] STF-TAI-1-16 Attachment AJ TRADE SECRET
[102] STF-PIA-2-1 Attachment

requested the average usage of the new TOU-RD customers, which I was able to compare to the residential class as a whole from another data set. As seen in below in Figure 6, the new TOU-RD customers have significantly lower usage (solid line) and lower peak demand (dotted line) than existing residential customers. This gap persisted even after some early irregularities in the data set.[103]

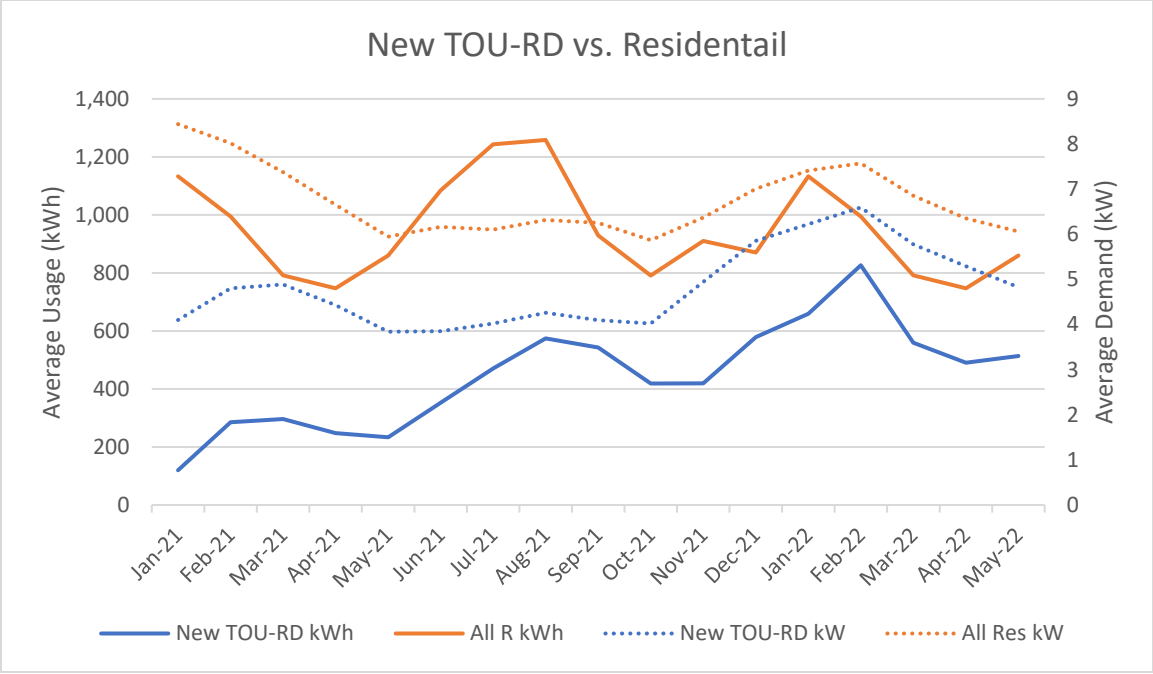


Figure 6 - New TOU-RD vs. Residential Usage

Q112. IS THERE ANOTHER DATA SET THAT SHOWS A SIMILAR IMPACT OVER TIME?

A112. Yes. The Company provided hourly usage by tariff. As seen in F below, the TOU-RD and R customers usage was nearly identical in the early months of 2021. But as more new customers were added to the tariff as a result of it becoming the default choice, the average usage on the TOU-RD fell. By the end of 2021, the full customer set had usage that was 16% lower than the R tariff. If one were to scale that to the full year, TOU-RD customers would average 815 kWh per month compared to the average R customer of 968 kWh per month.

[103] Early 2021 data for new TOU-RD customers was significantly lower than early 2022 data. One potential explanation is apartment buildings that were hooked up for electric service but not yet occupied.

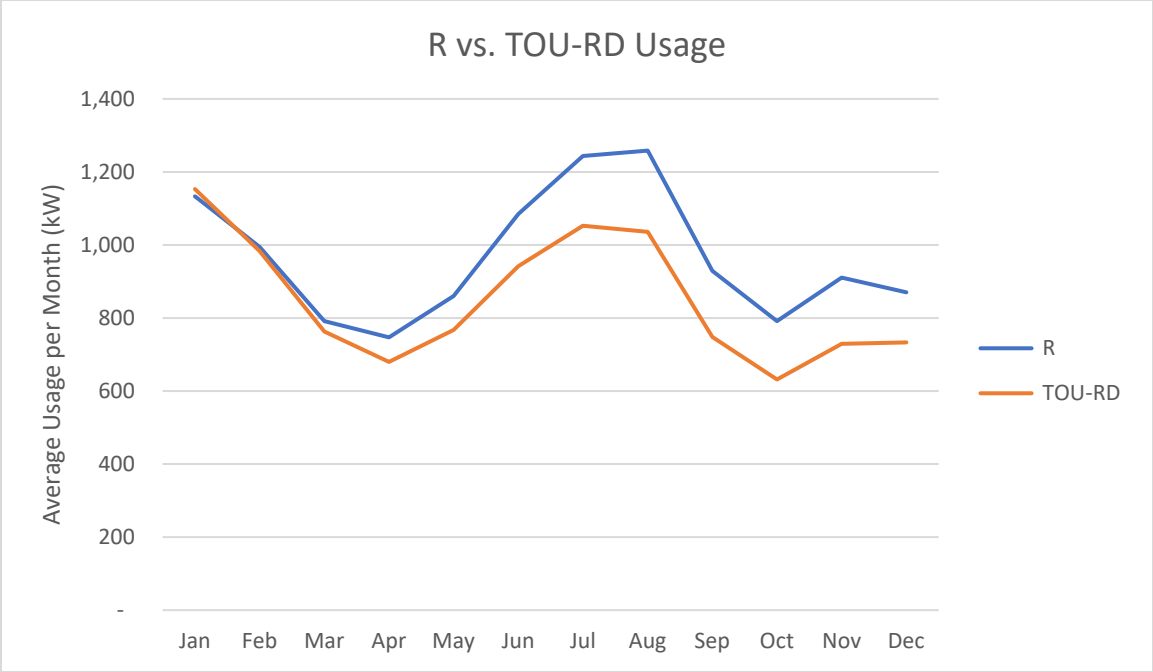


Table 12 - TOU-RD vs. R 2021 Monthly Average Usage

This trend also appears in the Customer Database data. Figure 7 below shows a normalized histogram and cumulative distribution function of peak billing demand for customers from January 2021 (blue) and December 2021 (orange). The increase in the number of small customers in December is apparent by the notable "hump" on the left side of the top graph showing many more customers with billing demands under 3 kW and by the higher position of the December line in the bottom chart indicating a larger cumulative percentage of customers at each level of billing demand.

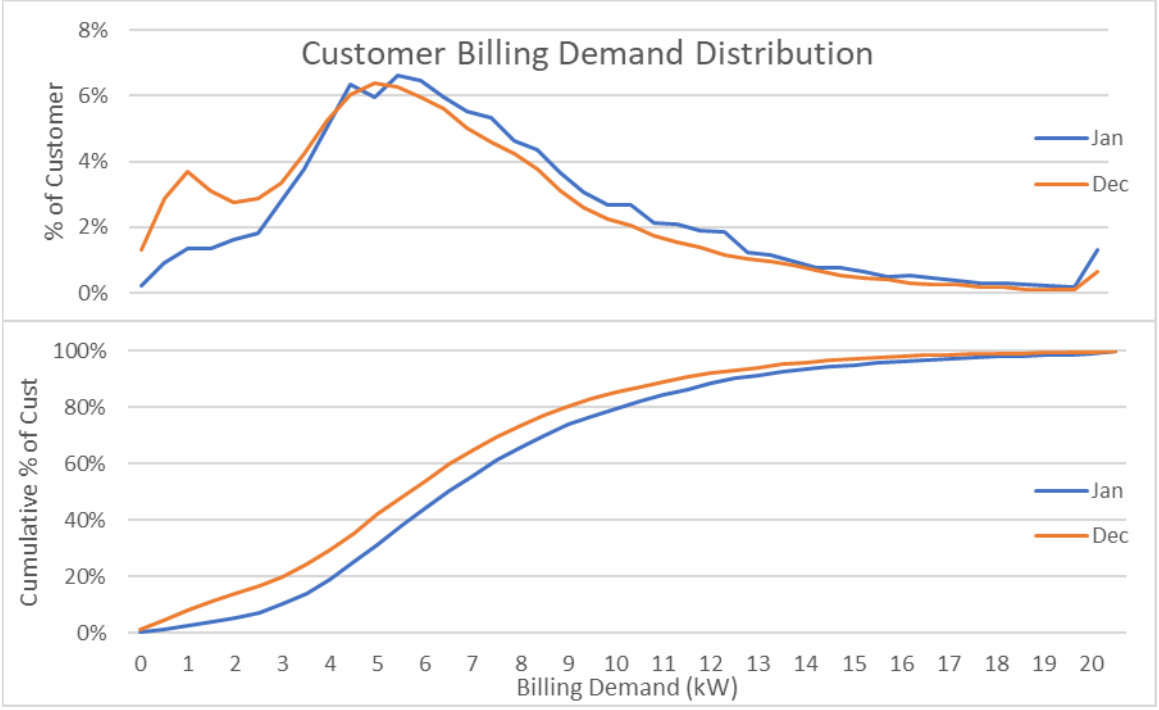


Figure 7 - January and December Billing Demand Distribution

Q113. DID GPC'S DATA SUPPORT YOUR EARLIER ANALYSIS ABOUT LOWER USE CUSTOMERS GETTING HIGHER BILLS ON THE TOU-RD TARIFF?

A113. [Mr. Lucas] Yes. The Company provided the average bill that new TOU-RD customers received along with what they would have received on the R tariff. As with my analysis, the Company's data shows a substantial premium on the TOU-RD tariff. Over the span of 17 months of data provided by the Company, customers were charged an average total of $1,250 on the TOU-RD tariff, while they would have only been charged $984 on the R tariff. The cost of the "default" choice was a 27% premium on their bills.

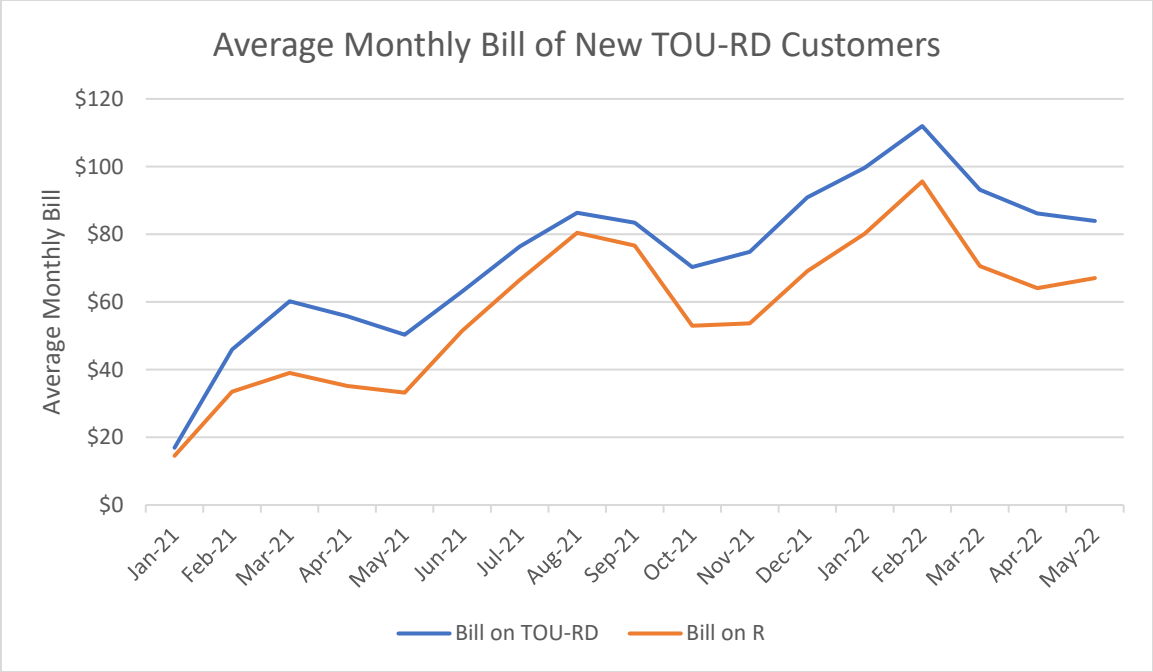


Figure 8 - Average Monthly Bill of New TOU-RD Customers

Q114. DID CUSTOMERS THAT WERE SIGNED UP BY DEFAULT ON THE TOU-RD TARIFF RECEIVE INFORMATION ABOUT OTHER RATES THAT WERE AVAILABLE TO THEM?

A114. Not directly. When asked by Staff what information customers newly added to the TOU-RD rate receive,[104] the Company responded, "New customers to the Smart Usage rate (TOU-RD) receive a welcome letter that confirms their enrollment and provides helpful information to educate them on how to take advantage of the rate's design." It included a copy of a letter that is mailed to the new customer.[105] Nowhere in this letter is the customer provided with information about other rate options, including those that may save the customer more money than the TOU-RD rate.

Q115. WHAT IS YOUR CONCLUSION BASED ON THIS AND YOUR PRIOR ANALYSES?

A115. It is entirely inappropriate for the TOU-RD rate as currently designed to be the default rate. The rate is not cost-aligned given the use of individual customer NCP billing demand to collect shared costs for production, transmission, and distribution. It causes higher bills for

[104] STF-PIA-2-3.
[105] STF-PIA-2-3 Attachment A.

more than 90% of customers that use less than the median amount of energy compared to alternative rates. It appears not to be revenue neutral with respect to the other tariffs.

The TOU-RD rate is the only rate that has seen substantial growth in the past two years, largely due to the decision to make it the default rate in January 2021. But the new customers being added to the tariff are disproportionately low use customers. As a result, they are being penalized through bills that are 27% higher on average than if they had been on the R tariff.

These facts are presumably all known to the Company. It knows that new customers are paying more on the TOU-RD rate than they would on the R rate because it produced data that confirmed this fact. And despite a direct requirement from the Commission in the prior rate case to report on these matters, the Company was conspicuously silent on the issue. The Company now requests to close the R tariff and the TOU-REO tariffs to new premises, which would close all but one conventional post-pay option (TOU-PEV) for new customers. At the same time, it actively sows confusion about the TOU-PEV rate to muddy the waters on eligibility. The net result of these actions is to make customers pay more for their electricity service despite them not causing a corresponding increase in cost.

Q116. WHAT DO YOU RECOMMEND WITH RESPECT TO THE TOU-RD TARIFF?

A116. The Commission should require substantial modifications to the TOU-RD tariff. First, it should no longer be the default tariff due to the all the reasons discussed above. Second, it should be redesigned in one of two ways: with a TOU billing demand charge that recovers a smaller portion of the fixed production, transmission, and distribution costs, or as an NCP billing demand charge that only recovers low voltage distribution equipment close to the customer. Third, the Commission should require the Company to update its billing determinants to ensure that the rate is revenue neutral with respect to the R tariff.

VI. THE COMMISSION SHOULD STRIVE TO INCREASE FAIRNESS AND TRANSPARENCY IN RATE CASES AND OPTIONALITY IN RATE DESIGN

Q117. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A117. In this section, we discuss various components of the Company's filing regarding availability of certain tariffs, technology tools that can aid or hinder customer education, and technical issues that impact the Company's COSS. While these changes are not as individually impactful as those discussed above, they have an overall effect of reducing transparency and fairness and customer optionality.

Q118. PLEASE SUMMARIZE YOUR FINDINGS.

A118. The Company's proposal to close the R and TOU-REO customers to new customers should be denied. There is little policy support for this step, and the Company produced no evidence supporting its claim that customers would be "confused" if the TOU-REO remained active. Worse, the Company is actively sowing confusion among its customers with its public facing materials on the TOU-PEV rate and its "Solar Advisor Tool". Finally, the Company's position on two technical issues related to the COSS are confusing at best, particularly related to the supposed inaccuracy of its AMI data.

Q119. WHAT ARE YOUR RECOMMENDATIONS FROM THIS SECTION?

A119. The Commission should require the R and TOU-REO tariffs to remain open to all customers and set the TOU-REO tariff as the default rate for new residential premises. It should direct GPC to rename and rebrand its TOU-PEV tariff to undo the blatantly misleading information regarding the purpose and eligibility requirements of this tariff. The Solar Advisor Tool should be scrapped as it is beyond salvage. Finally, the Commission should direct the Company to use the 4CP allocator for production costs and use actual AMI data instead of statistical load research data for its COSS and rate design workpapers.

The Residential and Nights and Weekends Tariffs Should Remain Available

Q120. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE R AND TOU-REO TARIFFS?

A120. The Company proposes to close both tariffs to new premises as of January 1, 2023.[106]

Q121. WHAT IS THE JUSTIFICATION GIVEN FOR CLOSING THE R TARIFF TO NEW PREMISES?

A121. The Company claims that its proposal "is the logical next step in the Company's ongoing efforts to encourage residential customer to move towards more modern rate structures… Many customers have demonstrated both a demand and preference for these rate plans. By closing the R tariff to new premises, the Company will continue to transition new residential accounts onto other rates within the Domestic Group that better align with the cost to serve customers."[107]

Q122. DID THE COMPANY PERFORM ANY ANALYSIS ON OTHER UTILITIES THAT ARE PROPOSING TO ELIMINATE OR REDUCING STANDARD VOLUMETRIC RATE OPTIONS FOR RESIDENTIAL CUSTOMERS?

A122. No. When asked this question, the Company responded, "The Company has not performed a specific analysis of which utilities or jurisdictions are eliminating standard volumetric rate options for residential customers."[108] The Company notes that utilities are increasingly exploring additional rate options that are more reflective of cost of service, but offered no evidence of utilities actively eliminating rates.

Q123. DID THE COMPANY PROVIDE ANY SUPPORT FOR ITS CLAIM THAT "MANY CUSTOMERS HAVE DEMONSTRATED BOTH A DEMAND AND PREFERENCE FOR THESE RATE PLANS."

A123. In what should be clearly noticed as a trend in this docket, the Company provided no details in its filing about these preferences. Instead, Staff was required to ask two rounds of discovery to get any documentation to support this statement. In the end, the Company provided a report summarizing its 2022 survey on residential rates. All of the results of the report were redacted as trade secret, despite the fact that there is no competitor to GPC's monopoly control over residential customers.

Q124. WHAT WAS YOUR IMPRESSION OF THE SURVEY?

[106] Legg Direct at 15.
[107] Legg Direct at 8.
[108] STF-TIA-1-29.

A124. [Mr. Lucas] We have no ability to dispute what individual customers think of the service that GPC is providing to them. That said, surveys are carefully constructed, between the choice of who to call, when to call, and how to phrase the questions. The survey was crafted with very carefully worded questions such as "[redacted]" and "[redacted]" rather than the more direct "I understand how to use electricity on the rate to save money." These subtle differences are intentional. The only direct comments about saving money or not on a given rate came from free-form comments to the generic "[redacted]" However, absent an actual rate comparison tool (which is discussed in more detail below), customers are not able to tell if they are on the best rate for their usage patterns even if they believe they are saving money on the rate.

Given this, it is telling that many of the free-form comments that the report referenced on the TOU-RD were [redacted]. These comments are quoted below and closely mirror our critiques of the rate design:

[redacted][109]

We also noticed that the selection criteria for the survey excluded many of customers [redacted] rate and did not even [redacted] tariff. In fact, [redacted]% of customers that remember whether or not they [redacted]

[redacted] said [redacted], with only [redacted]% of those saying [redacted].[110] Customers who were added to the rate after it became the default had much higher bills on the TOU-RD tariff than on other rates, but these customers appear to have been largely [redacted].

Q125. WHAT IS THE JUSTIFICATION FOR THE CHANGE TO THE TOU-REO TARIFF?

A125. The Company claims that closing this rate, which has been around since 1994, to customers at new premises "will avoid the confusion that could arise from having three competing time of use tariff options."[111]

Q126. DOES THE COMPANY PROVIDE ANY SUPPORT WHATSOEVER THAT THE "CONFUSION" IT SEEKS TO AVOID EXISTS?

A126. No, it does not. There is no supporting documents or studies that demonstrate any confusion exists. Further, given this rate has been available to customers for nearly 30 years, it is difficult to see how confusion would suddenly emerge now.

Q127. ARE THERE DIFFERENCES BETWEEN THE TOU-REO AND TOU-PEV TARIFFS THAT MERIT KEEPING BOTH RATES AVAILABLE?

A127. Yes. These two tariffs are similar in that they both contain a volumetric TOU rate component, but the off-peak rates are quite different. The TOU-REO tariff contains two TOU periods, while the TOU-PEV adds a super off-peak. The details of the rates are in Table 13 below, showing the current base rate plus fuel rider.

Characteristic	TOU-REO	TOU-PEV
Peak Hours	2-7 PM Weekdays June – Sept	
Peak Rate	$0.240219	
Super Off Peak Hours	N/A	11 PM to 7 AM
Super Off-Peak Rate	N/A	$0.039512
Off Peak Rate	$0.079467	$0.099043

Table 13 - TOU-REO and TOU-PEV Rate Comparison

[110] [redacted]% of total respondents indicated they [redacted] said they [redacted], while [redacted]% said they [redacted]

[111] Id.

Both rates share the peak TOU periods and rate. The TOU-PEV adds a low-cost overnight component, which necessarily pushes up the off-peak component. In fact, the off-peak rate on the TOU-PEV tariff is 25% higher than the off-peak rate on the TOU-REO tariff. For customers with higher overnight usage, the TOU-PEV rate might be a good choice. But for customers who do not use much energy overnight, the TOU-PEV rate would be more expensive given the increase in the off-peak rate when most of their consumption occurs.

Q128. DID THE COMPANY PERFORM AN ANALYSIS THAT SUPPORTS THIS CLAIM?

A128. Yes. In 2020, the Company performed a rate impact analysis for customers on the TOU-REO and TOU-PEV tariffs.[112] It found that fully 76% of customers on both rates would pay more on the TOU-PEV rate than they would on the TOU-REO rate. As seen below in Figure 9, most of these customers would see bill increases on the TOU-REO tariff of between 2% and 4% ($10-$100 in this data set), with about 20% (those with sufficient overnight usage) saving more than 1% on the TOU-PEV rate.

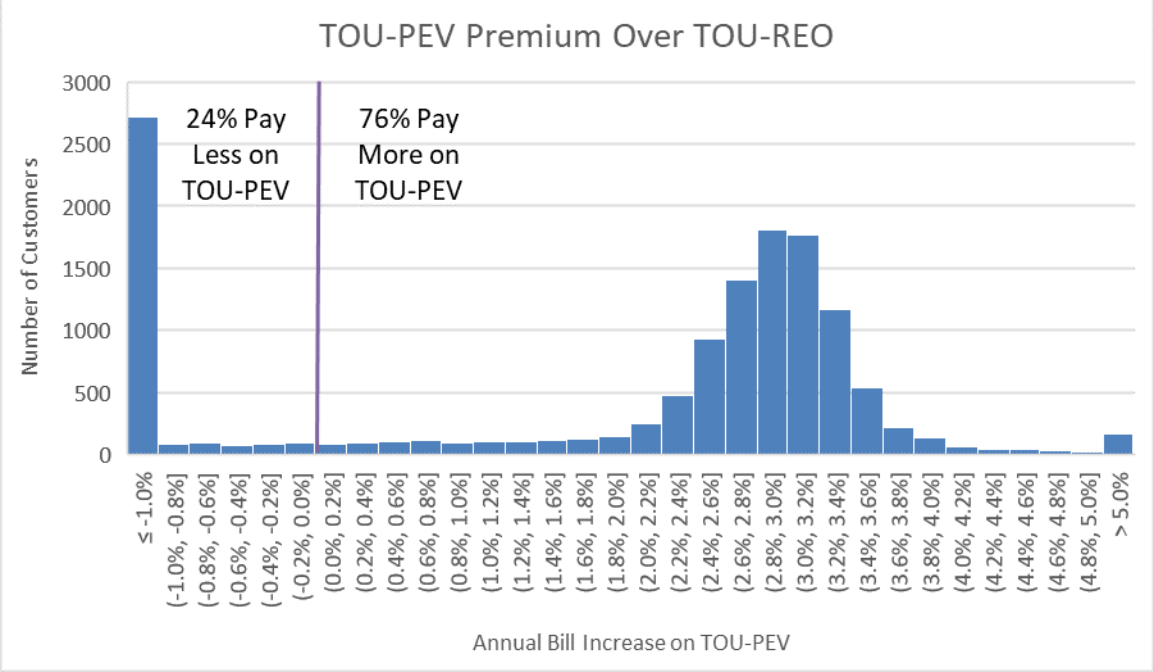


Figure 9 - TOU-PEV Premium Over TOU-REO

[112] STF-TAI-1-32 Attachment B.

Q129. IF THE COMPANY'S PROPOSALS ARE APPROVED, WHAT WOULD HAPPEN TO CUSTOMERS FROM NEW PREMISES SIGNING UP FOR SERVICE?

A129. New customers are not eligible for the Flat Bill tariff (which is effectively the R tariff with a risk premium adder) as they do not have a year of historical usage on which to base the charge. Thus, they would only have two traditional post-paid options: TOU-RD and TOU-PEV. The TOU-RD rate has serious deficiencies as discussed earlier in my testimony, while the TOU-PEV would result in a bill increases over the R tariff for low-use customers and over the TOU-REO for most new customers.

Q130. WHAT DO YOU RECOMMEND WITH RESPECT TO THESE RATES?

A130. We respectfully recommend the Commission require GPC to continue offering both tariffs for new residential premises. While the R tariff does not have a time of use component, the summer inclining block structure appropriately charges low-use customers less based on their lower contribution to summer system peak demands that drives production and transmission costs.[113] Although there is merit in moving more new customers to TOU-based rates, the Company has not provided justification for closing the R tariff or evidence of other utilities taking the same extreme step.

Further, if the TOU-REO tariff was also closed, customers would either need to move onto the TOU-RD rate (which as analyzed earlier charges a substantial premium to low-use customers) or to the TOU-PEV rate (with its much higher off-peak rate that causes bill increases for most customers). The TOU-REO rate continues to serve a purpose for customers without substantial enough overnight usage to save money. It maintains a lower off-peak rate more consistent with the Block 1 rate from the R tariff while still sending a price signal to reduce usage during peak hours that drive system costs.

[113] As discussed in Section V, low use customers tend to have low load factors, and customers with low load factors tend to have low coincidence factors.

Georgia Power is Misleading Customers about the Plug-In EV Rate and Should be Stopped

Q131. DOES THE PLUG-IN EV RATE REQUIRE A CUSTOMER TO OWN AN EV TO QUALIFY FOR THE RATE?

A131. No, it does not.

Q132. WOULD THE AVERAGE CUSTOMER BE ABLE TO DETERMINE THIS FROM THE COMPANY'S WEBPAGE?

A132. [Mr. Lucas] No, I do not believe they would. The Company's public-facing content regarding the Plug-In EV rate (discussed here as the TOU-PEV rate) consistently and strongly implies that EV ownership is a necessary prerequisite for qualifying for this tariff. In fact, when I first reviewed the Company's website content on this rate, I was surprised to learn that an EV was not required.

Q133. DO YOU HAVE ANY EVIDENCE TO SUPPORT THE IDEA THAT MANY IF NOT MOST CUSTOMERS ON THE EV RATE DO IN FACT OWN EVS?

A133. [Mr. Lucas] Yes. I analyzed hourly data from the TOU-PEV, TOU-REO, and R tariffs provided by the Company.[114] The load profile between 7 AM and 11 PM is very similar across the tariffs, with both of the TOU rates showing a drop in peak usage between 2 PM and 7 PM compared to the R tariff. I created a "Scaled TOU-PEV" load profile by taking the average ratio of the TOU-PEV and R usage in off-peak and peak hours and applying it to the R usage during the super off-peak hours. There was a dramatic increase in usage on the TOU-PEV rate starting at 11 PM that gradually narrowed as the super off-peak period concluded at 7 AM, as evidenced by the difference between the actual and scaled TOU-PEV usage (solid and dashed blue line, respectively, in Figure 10 below).

[114] STF-TAI-1.12 Attachment.

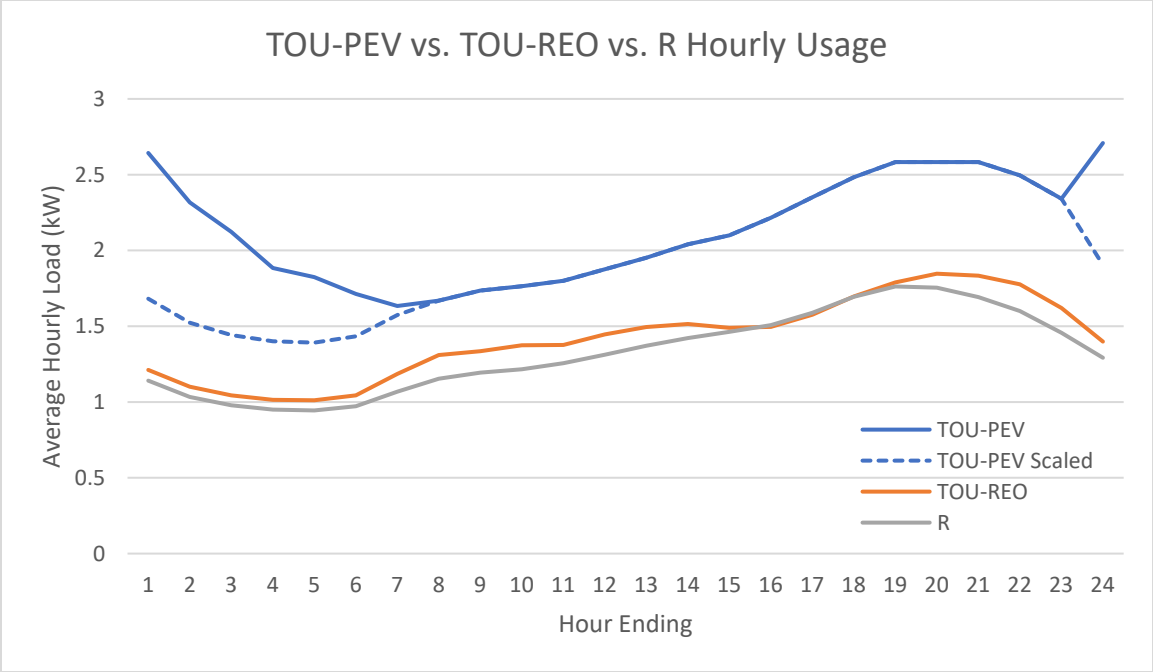


Figure 10 - TOU-PEV vs. TOU-REO vs. R Hourly Usage

Q134. WHAT DOES THIS CHART SHOW?

A134. [Mr. Lucas] It shows that customers on the TOU-PEV tariff consistently – across all months, seasons, and days of the week – add an average of about 1.5 kW of demand at the strike of 11 PM when the super off-peak rate starts. This increase falls over the next few hours until it largely vanishes by 7 PM. Programmable thermostats cannot explain the data as the leap occurred in winter (electric heating but no cooling or gas heating loads), summer (cooling but no heating loads), and shoulder months (neither much heating nor cooling load).

There are few loads that can consistently add that much demand at the same time or that would show the gradual decay over the super off-peak period as charging an EV. As mentioned, home chargers commonly pull 8-10 kW of power. Not every EV user charges every night, so the fact the step increase is an average of 1.5 kW instead of 8 kW is not surprising. Further, not every EV is charged from a fully depleted state, meaning that all charged cars will charge at the beginning of the super off-peak period, some will charge for half of the super off-peak period, and a few will charge for whole super off-peak period. This perfectly explains the decay shown above.

Q135. DO YOU HAVE OTHER QUALITATIVE SUPPORT ABOUT THE PREVALENCE OF EVS ON THIS RATE?

A135. [Mr. Lucas] Yes. In the residential rate survey discussed in the prior section, respondents offered comments on the TOU-PEV rate. Many of these specifically referred to [redacted][115]

Q136. IS IN FACT NECESSARY FOR CUSTOMERS TO OWN AN EV TO QUALIFY FOR THIS RATE?'

A136. No, it is not. But one would hardly know that from the Company's webpage. The Company could take any number of simple steps to clarify that this rate is broadly available to all customers, but it has actively decided to perpetuate confusion over the rate.

The Company was directly asked by Staff: "Does the Company have any plans to rename the Time-of-Use Electric Vehicle (TOU-PEV) rate to avoid customer confusion over their eligibility to select this tariff?" The Company responded flatly "There are currently no plans to rename the Time-of Use Plug-in Electric Vehicle rate."[116]

Q137. WHAT ARE SOME EXAMPLES OF HOW THE COMPANY PERPETUATES THIS CONFUSION?

A137. It starts with the tariff name. There is no reason to name the tariff the "Time-of Use Plug-in Electric Vehicle" rate. The Company could name it something description like "Overnight Savings" or "Super Off-Peak Savings." The rate provides a reduced rate to all overnight usage, not just for customers charging an EV.

[115] STF-PIA-6-54 Attachment TRADE SECRET at 26.
[116] STF-TAI-1-34.

Every prominent instance of the Company's webpage directly ties the TOU-PEV rate to EVs and EV charging. On the main Residential page,[117] there is an "Explore more" section on "Electric Transportation" that leads to a page on electric vehicles entitled "Discover the Benefits of Electric Vehicles".[118] This page has links to several pages, including the Electric Vehicle Resources page.[119] In the FAQ of this page, there are two Q&As that explicitly and unambiguously imply that the EV rate is offered to EV drivers rather than being generally available.

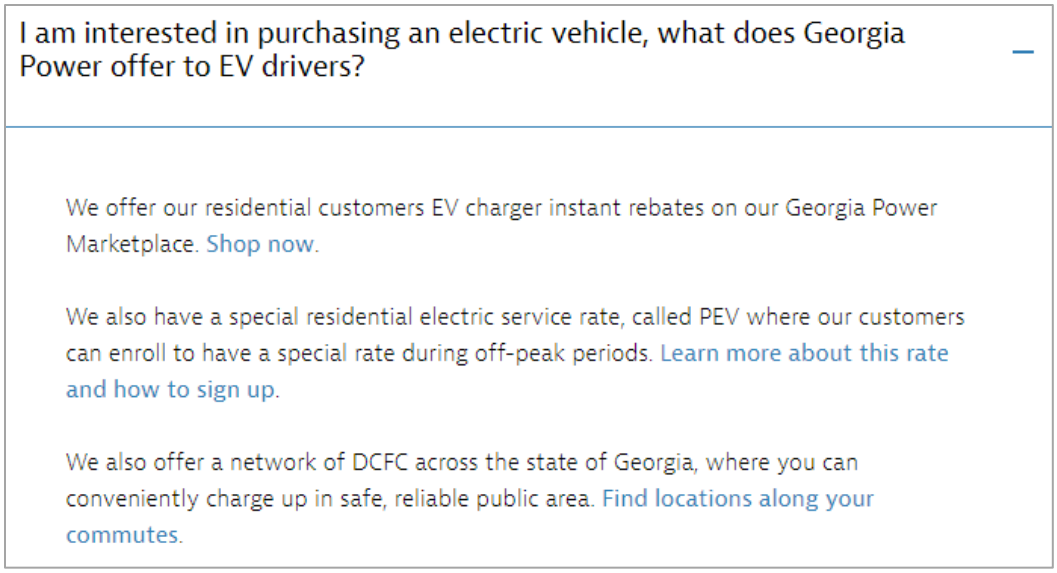


Figure 11 - GPC EV Resources Webpage

[117] https://www.georgiapower.com/residential.html
[118] https://www.georgiapower.com/residential/save-money-and-energy/products-programs/electric-vehicles.html
[119] https://www.georgiapower.com/residential/save-money-and-energy/products-programs/electric-vehicles/ev-resources.html

If one clicks on the links in the FAQ, they are directed to the main TOU-PEV tariff page entitled "Plug-In Electric Vehicle"[120] Excerpts from this and other pages discussing the TOU-PEV rate are shown below.[121] There is also a video discussing the different available rate options. The narration for the TOU-PEV rate follows: "Drive an electric vehicle? If so, the Plug in Electric Vehicle rate could be a great option for you. This rate has cheaper prices from 11 PM to 7 AM to encourage nighttime EV charging."

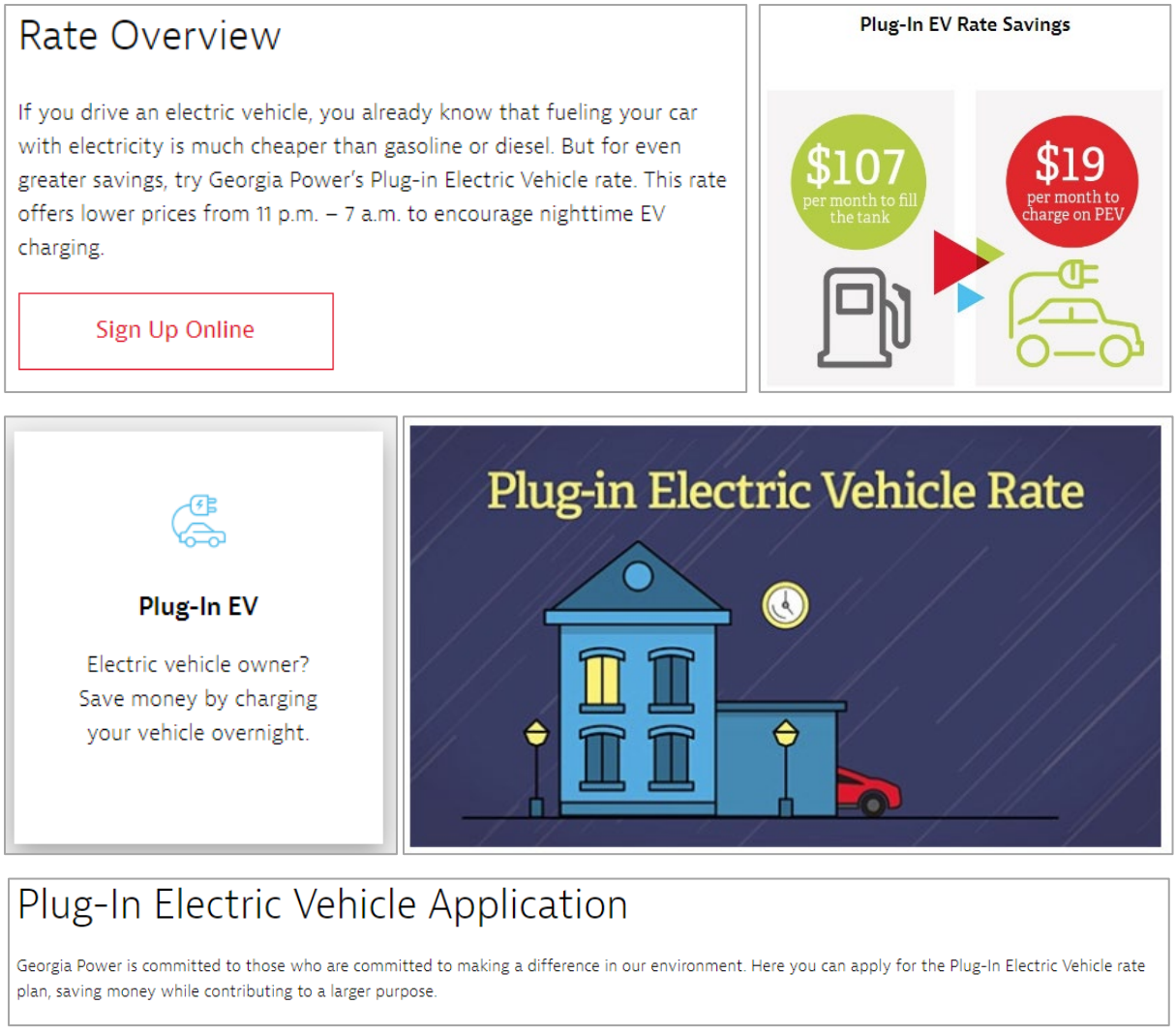


Figure 12 - GPC TOU-PEV and Related Webpages

[120] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/plug-in-ev.html
[121] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans.html

Time and time again on GPC's website, the Company conflates eligibility of the TOU-PEV tariff with driving an EV: "If you drive an electric vehicle", "Electric vehicle owner?", "Drive an electric vehicle?", "$19 to month to charge on PEV". These are not isolated incidents; all these mentions of the rate on its webpage includes a discussion of EVs.

Q138. DO YOU BELIEVE THE TOU-PEV RATE IS A WELL-DESIGN AND USEFUL RATE?

A138. [Mr. Lucas] Yes, I do. While I was not able to scrutinize the source data behind the rate design, the TOU-PEV tariff appears to be well-designed. It has a relatively high on-peak energy rate that is constrained to summer weekdays when the system is under stress and sends a robust price signal for customers to reduce or shift usage from this period. It offers a very low overnight super off-peak rate that appears to be intended to only collect fuel and variable O&M costs and not to collect capacity costs which are not driven by usage during this time period.

These are hallmarks of good rate design, but as with any single rate design, the rate is not a perfect match for all customers. Lower use customers with normal overnight usage will not fare well on this tariff. The TOU-PEV off-peak rate – where most of a lower-use customer's consumption will fall – is 13% higher than the Block 1 rate on the R tariff and 25% higher than the TOU-REO off-peak rate. For these customers, other rate options will provide better experiences. On the other hand, customers who use electric space heating or heat pumps may benefit from the lower overnight costs on this tariff compared to the R or TOU-REO rate.

Q139. IF THIS RATE IS WELL-DESIGNED AND COULD HELP NON-EV OWNERS, WHY WOULD THE COMPANY ALLOW CUSTOMER TO BE CONFUSED ABOUT THEIR ELIGIBILITY ON THIS RATE?

A139. [Mr. Lucas] It is a good question, and one that I would have liked to ask additional discovery about. Absent that, I can only turn to the numbers. And the numbers confirm that, quite simply, GPC makes more money if customers are on the TOU-RD tariff than if they were on the TOU-PEV tariff. In the Customer Database data set discussed above in Section V, 72% of customers with 12 months of usage experienced higher bills on the TOU-PEV tariff than

on the TOU-TOU-RD tariff, with an average increase in annual bills of 23%. In total, just for this set of 11,000 customers, the Company collected nearly $1 million or 5% more revenue than it would have if they were on the TOU-PEV rate.

If one ramps this up to all new premises, GPC's additional revenue would scale proportionately. In fact, when I reanalyzed the complete Customer Database for all customers on the TOU-RD rate, the figures were even worse. With the complete sample of 61,000 customers with at least one month of service on the TOU-RD rate, 90% of all customers had higher bills in 2021 on the TOU-RD rate than they would have had on the TOU-PEV rate. The Company earned an extra $6.8 million on these customers in 2021, a staggering 19.7% increase over what they would have collected if these customers were on the TOU-PEV tariff.

The large difference between the 12-month customers and the full data set is due to the addition of lower-use customers in 2021 onto a tariff which is particularly poorly suited for them. I would expect if this analysis were repeated next year with more customers with 12 months of usage that the revenue collection difference between the TOU-RD and TOU-PEV rate would increase substantially from the 5% mentioned above.

Q140. HOW DO THESE FIGURES COMPLEMENT YOUR ANALYSES ON THE INTENTIONAL CONFUSION OF THE TOU-PEV RATE?

A140. The throughline is evident when looked at holistically. First, the Company petitioned for and received permission to make the TOU-RD rate the default for new residential premises. Then, the Company proposes to close the TOU-REO and R tariffs, which would force new premises onto the TOU-RD or TOU-PEV rate. At the same time, it obscures the eligibility of customers without an EV to take service on the TOU-PEV. This increases the number of new customers who stay on the TOU-RD tariff – most of whom pay more – and decreases new premise additions and existing customer switching to the TOU-PEV rate. The end result is GPC makes more money.

Q141. WHAT DO YOU RECOMMEND ON THIS ISSUE?

A141. The Commission should require GPC to rename the TOU-PEV rate, modify its webpage materials, and update its customer service protocols to clarify that all customers can sign up for the rate independent of their ownership or operation of an EV. It should also highlight the potential benefits of customers who use electric space heating, who may receive lower bills relative to other rates from overnight heating use.

The Default Rate Should be Changed to the Nights and Weekends Tariff

Q142. BASED ON THE TOTALITY OF YOUR TESTIMONY IN THIS CASE, WHAT DO YOU BELIEVE IS THE CORRECTION DEFAULT OPTION FOR RESIDENTIAL CUSTOMERS?

A142. We believe the "Nights and Weekends" TOU-REO rate should be set as the default tariff. Customers should still have the option to opt out of this rate onto any other available rate, including the R rate. The Company has failed to present information required by the Commission in the 2019 Rate Case order to report on the TOU-RD tariff as the default rate. While not a substitute for the Company's obligation, we believe our testimony has provided some useful details. In summary,

- The TOU-RD rate is poorly designed and not reflective of cost-causation principles
- The TOU-RD rate substantially overcharges low-use customers relative to the costs they incur on the system
- New remises added to the TOU-RD rate in 2021 experienced much higher bills than they would have on the R, TOU-REO, or TOU-PEV rate

These are simply not good characteristics for a default rate. By contrast, the TOU-REO rate has been around for nearly 30 years, is simple to understand, and can provide bill savings for customers who are able to shift usage out of the peak 2 PM to 7 PM summer weekday window while reducing systems costs incurred from aggregate demands during those same hours.

The Commission Should Direct Georgia Power to Create a Robust Bill Comparison Tool

Q143. WHAT STEPS WERE INVOLVED IN YOUR BILL IMPACT ANALYSES PERFORMED IN THIS CASE?

A143. [Mr. Lucas] I had to perform a series of analyses that pulled information from multiple sources, including Company exhibits, discovery questions, GPC's webpage, and multiple tariffs. To calculate the bills of customers on different rates, I created a complex spreadsheet that calculated bills based on on-peak, off-peak, and super off-peak usage; peak demand values; fixed customer charges; and ECCR/NCCR/DSM adders, taking care to align different rates for different TOU periods and months as needed.

Q144. WOULD YOU EXPECT MOST GPC CUSTOMERS TO BE ABLE TO PERFORM A SIMILAR ANALYSIS ON THEIR OWN USAGE?

A144. [Mr. Lucas] No. While this is par for the course for a rate design analyst, it is far beyond what could be expected from a typical GPC customer trying to understand their bill. To duplicate these steps, the customer must first set up an account and log in to GPC's webpage. From there, they must download their hourly usage for at least the past twelve months. They would have to look up the tariff information for each rate they want to analyze, while pulling the appropriate fuel cost recovery rate (of which there are three, plus an Interim Fuel Rider), properly calculating the various adder tariffs (of which there are also three), and then correctly factor in the Municipal Franchise Fee and Local Tax Adjustment.[122]

Q145. IS IT REASONABLE TO EXPECT CUSTOMERS TO DO THIS?

A145. No, it is simply not reasonable to expect customers to be able to perform this analysis even if they were technically able to do so. GPC's website only has generic information comparing the rates that is not personalized to an individual customers' usage patterns; just because two customers use 1,000 kWh per month does not mean they will have the same bill on the various TOU rates.

[122] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans.html#tariffs

Q146. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE?

A146. We recommend the Commission require the Company to develop a rate comparison tool that would automatically perform the analysis above and present a customer with their bill on each tariff based on their historic usage. The tool could also analyze the customers usage patterns and suggest more targeted recommendations. For example, if the tool notices that the customer uses a lot of energy during peak summer hours, it could recommend ways to save on their bill like using a programmable thermostat to pre-cool their house before 2 PM.

The Company should also begin collecting peak demand information for customers who are not on the TOU-RD rate. Although this is not current practice, given the Company has completed its deployment of AMI and has the ability to store this information, it could be an easy enhancement to implement. By collecting this data, the Company would be able to also inform customers how they would fare on the TOU-RD tariff in the bill comparison tool.

The Solar Adviser Tool is Biased and Should Be Overhauled

Q147. WHAT IS THE SOLAR ADVISER TOOL?

A147. The Solar Adviser Tool ("SAT") is an online "tool" that is prominently placed on the Company's Solar Programs webpage.[123] The tool's copy states: "Is a Solar Installation Right For You? Use our residential solar adviser tool to explore considerations and estimated costs for a solar panel installation on your home. Get real life figures to help you determine the best solar program for you and your goals."[124]

When one clicks on the SAT, the customer is presented with the following image:

[123] https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/solar.html
[124] Id.

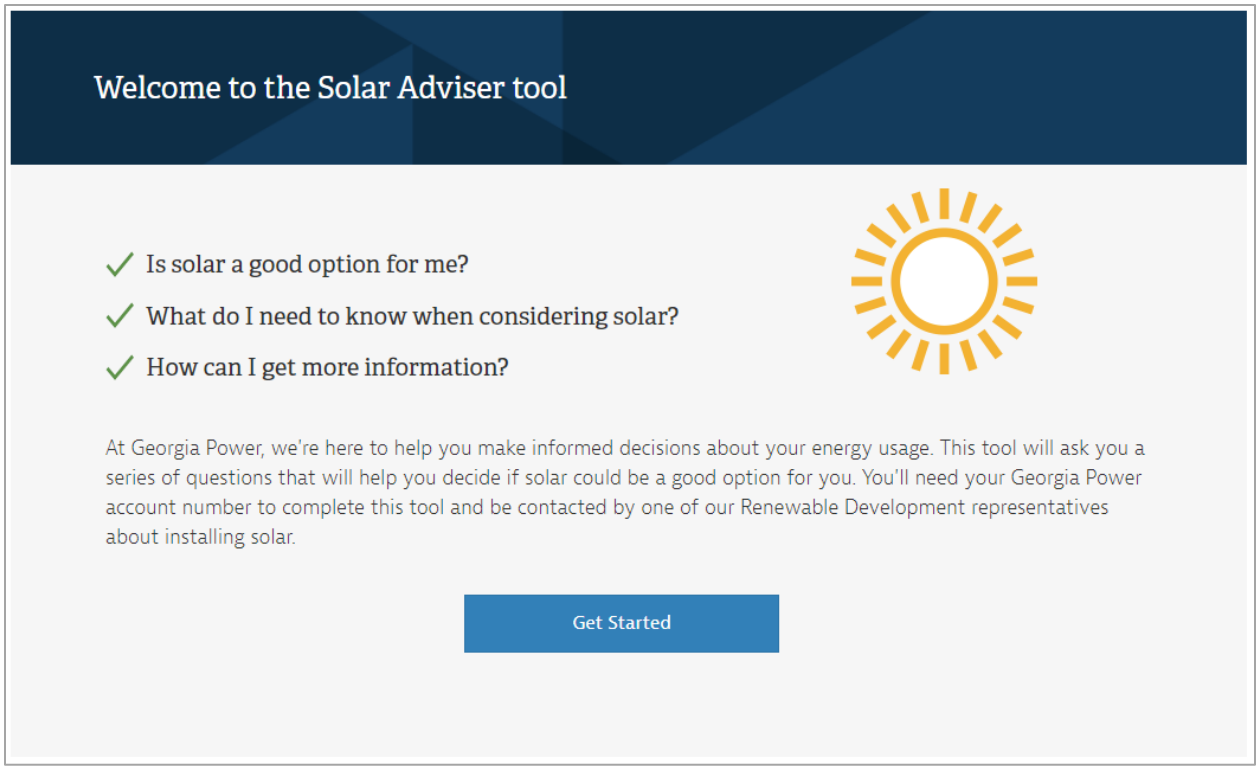


Figure 13 - Solar Adviser Tool Launch Page

Clicking on "Get Started" launches the tool into a series of questions. These follow in the order in which they are presented, followed by the text that accompanies the question. The available response options are also shown.

1. Do you own your home?* Solar installation involves drilling to secure solar panels to your roof. For example, if you live in a condominium, you must have ownership of your roof space and it be clearly defined.
    - Yes/No
2. How much sun shines on your roof?* The performance of PV panels may be reduced by the shading effect due to trees, passing of clouds, neighboring buildings and any other means.
    - Full Sun / Shaded / Not Sure
3. Is your roof less than 5 years old?* Consider replacing a damaged or failing roof prior to a solar installation. There are costs involved with un-installing and re-installing a solar installation.
    - Yes / No
4. Does your home have at least 200 sq. ft. of uninterrupted roof space?* Uninterrupted roof space is most efficient for a solar installation (100 square feet of roof space for every 1kW of solar). More complex rooftops can increase the installation cost and time.

- Yes / No / Not Sure

5. Are you planning to live in your home at least 5 more years?* The typical payback period, or breakeven – can exceed 10 or more years. There are costs involved with removing and re-installing a solar installation.
   - Yes / No
6. Select the size of your home. For an estimate of how much you can save by installing solar, pick the home that best matches your own.
   - Small / Below 1,600 sq ft / 4 kW / $10,080
   - Medium / 1,600 – 3,499 sq ft / 6 kW / $15,120
   - Large / 3,500 sq ft & up / 10 kW / $25,200
7. Select the city closest to your home. Solar panel performance varies by your location due to sunlight and weather. Calculations assume a relatively open, southern-facing roof surface.
   - Athens / Atlanta / Augusta / Columbus / Macon / Savannah / Valdosta
8. Select your electric rate. If you are unsure, or on a different rate plan, the standard service figures are used and therefore final results may very [sic] slightly
   - Standard Residential / Nights and Weekends / Not Sure / Other

Q148. WHAT HAPPENS AFTER ONE ANSWERS ALL OF THE QUESTIONS?

A148. The SAT produces a "results page" that is based only on the final three questions. A sample of the page is shown below in Figure 14 for a medium-sized system located near Athens on the Standard Residential rate.

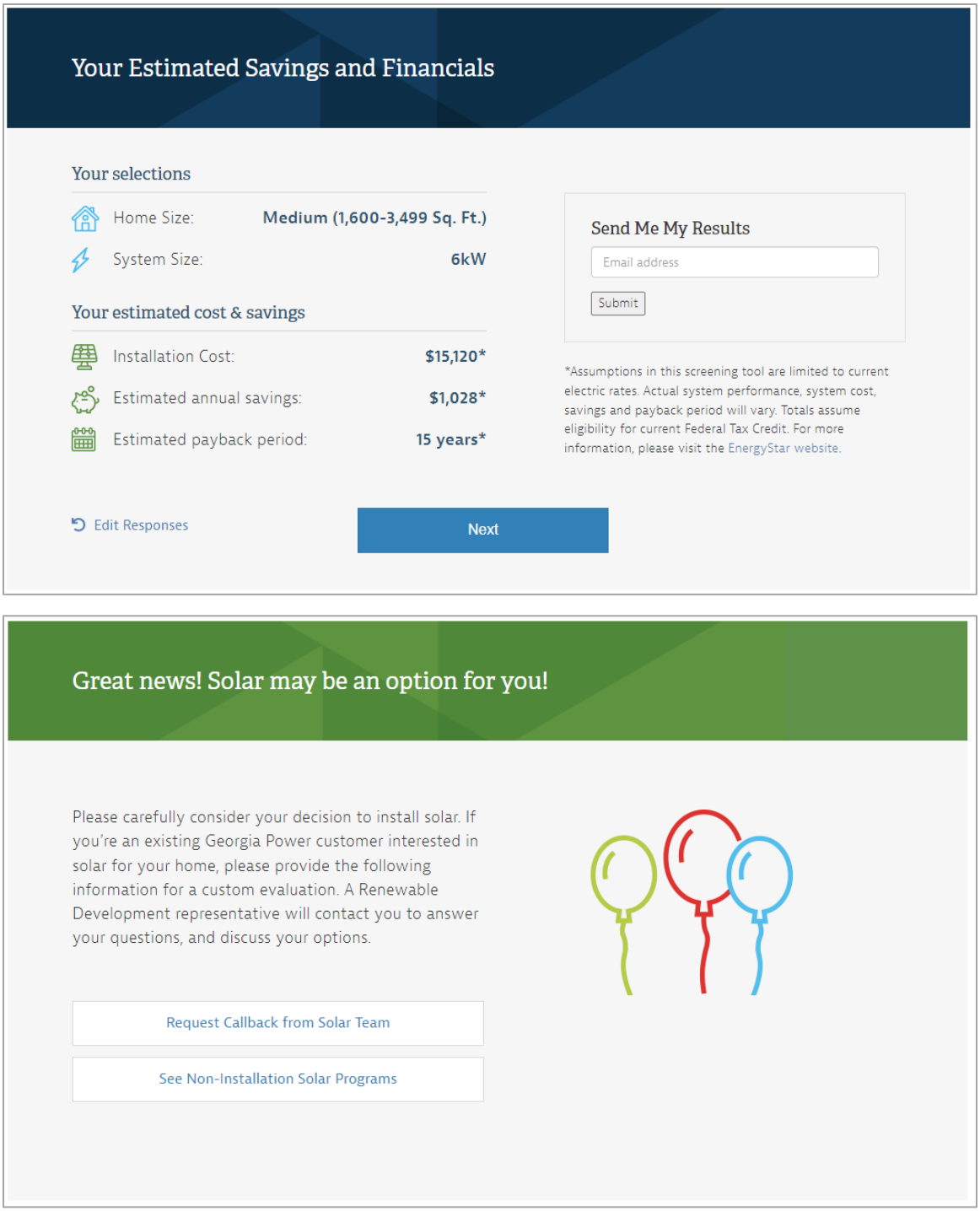


Figure 14 - SAT Analysis Results

When one clicks the "Next" button, one is presented with one final page, shown above. If one clicks on the Request Callback button, the user is prompted to enter her name, phone, email, and GPC account number. If one clicks the "See Non-Installation Solar

Programs," the user is taken to one final page with links to the Company's Community Solar and Simple Solar pages, with the following note: "We are dedicated to providing more ways for customers to support the growth of solar energy through our non-installation solar programs. These programs are perfect for residential customers who are unable or do not wish to install their own solar panels."

Q149. WHAT DO THE ASTERISKS IN THE FIRST 5 QUESTIONS INDICATE?

A149. These indicate that the question is "for informational purposes only."

Q150. ARE THESE QUESTIONS REALLY JUST "INFORMATIONAL"?

A150. No. The only result of asking these is to create FUD – fear, uncertainty, and doubt – in the mind of the customer. The answers do not impact the SAT's results at all. In fact, one can answer anything for the first five questions, including how much sun the roof receives, and not change the results of the analysis.

Many questions and accompanying text are designed to make onsite solar appear less attractive. For example, the third question asks whether your roof is less than 5 years old and suggests "replacing a damaged or failing roof prior to a solar installation." The clear implication is that roofs over 5 years old are suspect and may not be compatible with a new solar installation. This is simply not true.

Likewise, the questions asking whether the roof has at least 200 square feet of uninterrupted roof space or is shaded have no impact on the results. Most customers would be unaware how much uninterrupted roof space they have or how much shade falls on their house, and they should certainly not climb on their roof to take measurements. Not all roof "interruptions" are the same; normal interruptions such as an exhaust pipe has effectively no impact on pricing, but a customer may be confused into thinking that routine roof installs are "more complex rooftops" that can increase the price. And the only choices on shading are Full Sun / Shaded / Not Sure. The year-round level of shading cannot easily be discerned from any single observation, and shade in the morning may have different impacts on the

performance of the system than shade in the afternoon. None of these nuances are captured in the SAT.

Similarly, the question asking whether you plan to live in your house for more than 5 years introduces unneeded doubt and uncertainty. The value of the asset does not vanish if the original owner moves out of the house, but GPC conspicuously notes that payback periods may exceed 10 years and that there are costs of removing and re-installing a solar installation. Modern residential solar systems last for 25 or more years and continue to produce value for all current and future homeowners. In fact, the solar installation adds value to the house and can attract a higher selling price, with a recent report noting "We find clear evidence that solar systems are correlated with higher selling prices if those systems are owned by the homeowner."[125]

Q151. TURNING TO THE ACTUAL RESULTS OF THE SAT, WHAT DID YOU FIND?

A151. The results from a system near Athens appear below in Table 14. To make these figures, the Company was required to make assumptions about the usage patterns of customers installing different system sizes, although this is not disclosed anywhere in the tool's workflow.

Savings ($) / Payback	R Tariff	TOU-REO
Annual Savings ($)		
Small	$592	$594
Medium	$1,028	$961
Large	$1,930	$1,773
Savings per kW ($)		
Small	$148	$148
Medium	$171	$160
Large	$191	$177
Payback (years)		
Small	17	17
Medium	15	16
Large	13	14

Table 14 - SAT Results by Size and Tariff

[125] Begley, Jaclene and Hoen, Ben, Solar at High Noon: Solar Home Premiums in a Rapidly Maturing Market (July 2, 2021). Available at SSRN: https://ssrn.com/abstract=3894549

For example, the savings per kW vary depending on the system size and tariff, meaning that the percentage of Block 3 usage (on the R tariff) and Peak usage (on the TEO-REO) tariffs are a function of system size. This would only happen if the Company assumed that customers installing larger systems had higher total usage on the R tariff or a higher on-peak percentage of usage on the TOU-REO tariff. Although it is not unreasonable to assume a customer installing a larger system has higher overall usage, there is nothing that prevents a high-use customer from installing a smaller PV system, particularly given the incentives embedded in the RNR Instantaneous tariff. Further, there is substantial diversity in on-peak usage for customers with similar total load levels; using a generic average assumption could have major impacts on the results of this analysis.

Q152. WHAT FINANCIAL METRICS ARE ASSUMED IN THE SAT?

A152. The SAT assumes that all systems cost $3,600/kW assuming a 30% federal ITC eligibility, although it is unclear and undocumented whether the tool reflects the old 22% ITC or new 30% ITC rate.[126] It is also unclear whether the system size and cost is indicative of kW_{AC} or kW_{DC}. The former is used in the Company's interconnection process, but the latter is often used in conversations between customers and solar installers. The difference in prices between the two assumptions can be roughly 20%, a non-trivial amount. There is also no sourcing for the $3,600/kW figure in the tool.

Q153. IS THE "PAYBACK PERIOD" METRIC ALWAYS RELEVANT TO A CUSTOMER?

A153. No. The payback period is only relevant to systems purchased with cash. In this case, bill savings gradually offsets the initial net purchase price to produce a time when the purchase price has been fully offset and the "payback period" has been met. But if a customer finances a system, she could realize net positive cash flow on day one. For example, if a customer's monthly loan fee was a flat $100, and the bill savings from the PV system was $110, she

[126] Each system cost divided by its capacity divided by 0.7 = $3,600 / kW.

would save $10 immediately. There is no payback period as this metric simply does not apply to financed purchases.

Q154. WHAT DO YOU RECOMMEND WITH REGARD TO THE SAT?

A154. We recommend it be scrapped. The SAT is clearly biased against customer-owned, customer-sited solar. It requires customers to answer questions that are irrelevant to its results. The embedded assumptions assume usage patterns and financing methods that are unvetted and non-universal. And even if a customer pushes through all the FUD, the end result is a callback from GPC's own solar team, not a recommendation to use one of the many qualified installers in the state. Georgia Power customers would be better served if this tool did not exist.

The Company Should Explain Why its AMI Data is "Not Precise Enough" for Universal Use

Q155. ACCORDING TO COMPANY FILINGS, HOW MANY SMART METERS DOES THE COMPANY HAVE?

A155. The Company reported 2.3 million residential and 325,000 non-residential smart meters.[127] This represents 100% of residential and industrial customers and 95% of non-residential meters, although interestingly the Company reports 100% of its energy that year being served through AMI meters.[128] The Company appears to have largely completed its AMI rollout by 2011.[129]

Q156. GIVEN THE UNIVERSAL AVAILABILITY OF AMI DATA FROM ITS RESIDENTIAL AND INDUSTRIAL CUSTOMERS, AND NEAR UNIVERSAL AVAILABILITY FROM ITS COMMERCIAL CUSTOMERS, DOES GPC USE ONLY AMI DATA IN ITS COSS AND RATE DESIGN?

A156. [Mr. Lucas] Astonishingly, no. Staff noted this discrepancy and asked how it was possible that the Company could not provide peak demand values for individual customers not already

[127] EIA Form 860, Advanced Meters, 2021 data.
[128] The number of reported residential customers exactly matches the number of residential AMI meters. The Company reported about 15,000 non-AMI meters for commercial customers (out of 331,000 customers) and only 7 non-AMI meters for industrial customers (out of about 10,700). Total sales are reported as 82,944,041 MWh, while total sales from AMI meters are slightly higher at 83,039,174.
[129] EIA Form 860, Advanced Meters, 2011 data.

on the TOU-RD tariff but be able to provide hourly data for all customers on other tariffs.[130] Staff appears to be reasonably expecting that the Company's hourly AMI data was aggregated to produce the hourly load profile data for each tariff. I suspect they were as surprised as I was by the Company's response:

> The rate schedule hourly demands provided in STF-TAI-1-12 are developed from the Company's load research studies as discussed in IRP Technical Appendix Section 9.5 and in accordance with industry standard practices. The Company's standard AMI meter readings, while programed for the accurate determination of billing determinants for rendering bills, are not precise enough to develop individual load profiles that can be summed to represent a rate schedule's load nor total system load...
>
> These studies are designed to deliver representative load profiles at the rate level; they cannot determine load profiles for each individual customer. Therefore, the AMI meters and readings are appropriately used for billing individual customers and the Company's long-standing load research process is appropriately used for developing the hourly demands for rates.[131]

In other words, despite having AMI meters on functionally all of its residential and industrial customers, and on more than 95% of its commercial customers, the Company does not use the AMI data in its COSS or rate design workpapers. Instead, it uses load sampling methods necessary before universal AMI that statistically recreates hourly usage for tariffs and COSS classes from a sample of customers.

Q157. WHY IS THIS SO SURPRISING?

A157. [Mr. Lucas] Because the only reason to do load research using a sample of load meters is if access to population-level AMI data was not available. There is no sub-hourly data in COSS; everything is aggregated to a full hour. Residential AMI meters provide hourly readings. Certain commercial rate designs bill based on sub-hourly durations, but these can be easily summed to produce hourly values. Tariff groups that use the roughly 5% or 15,000 non-AMI meters in the commercial class may need to use load research, but that represents a tiny fraction of the Company's total customers and energy usage. If the Company has hourly or

[130] STF-TAI-4-5.
[131] Id.

sub-hourly usage from every customer in a tariff or customer group, it can and should just add those values up.

Load research, no matter how good, can only introduce errors when compared to counting an entire population. The Company states in IRP Technical Appendix Section 9.5 that about 2,000 customers have had load research meters installed on their property, or less than 0.1% of total customers. While this number of meters almost certainly provides a statistically robust sample, it necessarily will have uncertainty with respect to directly counting the population.

Q158. WHAT IS YOUR RESPONSE TO THE COMPANY'S OBSERVATION THAT AMI METERS ARE ACCURATE ENOUGH FOR BILLING BUT NOT FOR LOAD RESEARCH?

A158. It is confusing at best. First, the Company did not provide any context for what it means by "not precise enough", but precision is typically related to overall accuracy of the meters. For example, there are multiple ANSI standards on meters. Specifically, ANSI standard C.12-2022 defines various accuracy levels of metering equipment, such as Class 0.5 (+/- 0.5% of actual) and Class 0.2 (+/- 0.2% of actual).[132]

While certain meters are more accurate than others, and it is possible that the Company installed less accurate meters (e.g., Class 0.5 instead of Class 0.2) in its customer base, the measurement errors found in a population should be randomly distributed and non-correlated. This means that even if individual meters have errors up to 0.5% under or over the actual reading, these errors should cancel each other out as more meters are included in the total. The result of adding up all the values from thousands or millions of meters would be a total that is functionally indistinguishable from the real value.[133]

The only way in which this would not hold true is if the errors of the individual meters are not randomly distributed and/or are correlated. For instance, if the meters the Company installed all tended to read higher values than actual, then the results from adding

[132] The previous ANSI standard for meters when GPC was rolling out AMI was C12.20. This has since been merged into a newer standard and updated. https://blog.ansi.org/ansi-c12-1-2022-code-electricity-metering/

[133] Statistically speaking, the more samples in a data set, the lower the margin of error around the actual value.

up all of the meters in the population to produce a total could be skewed. Of course, this also would mean that the Company is systematically over-billing customers, which is its own problem.

Q159. DO YOU HAVE ANY DATA THAT COMPARES THE BILLING KWH TO THE LOAD RESEARCH KWH?

A159. [Mr. Lucas] Yes. The Company provided annual billing kWh data in its confidential rate design workpapers.[134] It also included load research kWh in its hourly load by customer file.[135] I compared these for several residential tariffs to see how they differed. The results are below in Table 15.

Tariff	AMI Billing Data kWh	Load Research kWh	Delta (%)
R / Flat	[redacted]	25,962,520,817	[redacted]
TOU-REO	[redacted]	84,061,880	[redacted]
TOU-PEV	[redacted]	109,255,935	[redacted]
TOU-RD	[redacted]	280,327,637	[redacted]
Prepay	[redacted]	1,076,455,414	[redacted]

Table 15 - AMI vs. Load Research kWh Totals

Q160. WHAT DOES THIS DATA SUGGEST?

A160. [Mr. Lucas] Absent compelling evidence that the AMI meters are systematically biased in one direction (which is contraindicated by the presence of positive and negative variations above), it suggests that the errors in the load research data are small but non-zero.

The result from the R / Flat customer group is particularly problematic. Because there are [redacted] kWh in the Load Research group that were used to set rates, the rates for this class are slightly [redacted] than they would otherwise be in order to collect the desired revenue requirement for this tariff. These [redacted] rates are then applied to [redacted] billing kWh from the AMI meter reads, resulting in [redacted] revenue than should have been collected from the rate.

[134] STF-TAI-1-16 Attachments.
[135] STF-TAI-1-12 Attachment.

Essentially, the tariff collects roughly [redacted] revenue than it should, resulting in [redacted] revenue collection of $[redacted] in 2021.[136]

Q161. WHAT DO YOU RECOMMEND ON THIS ISSUE?

A161. [Mr. Lucas] I recommend the Company explain in detail why it is not using its AMI data in its COSS and rate design for customer classes or tariffs that have universal or near-universal AMI deployment. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible. Customers paid for AMI and expect to get benefits from that investment such as cost savings from load research. Instead, it appears the Company is installing and maintaining duplicative load research meters while also charging customers for Company resources to analyze the data.

The Commission should also request an investigation as to whether the discrepancies between the load research values and the AMI billing values are resulting in the over-collection or under-collection of revenue from certain tariffs.

The Commission Should Approve the 4CP Production Cost Allocator

Q162. HOW DOES THE COMPANY ALLOCATE COSTS IN ITS COSS?

A162. In the Company's COSS, production capacity costs are generally allocated to customer classes based on a 12CP method, while transmission costs are generally allocated based on a 4CP method. Distribution costs are allocated based on either the 4CP (voltage levels C-E) or Class NCP (voltage levels F-G) demand levels.[137]

Q163. IS THIS APPROACH TYPICAL IN YOUR EXPERIENCE?

A163. [Mr. Lucas] It is somewhat unusual in my experience, particularly for a summer-peaking utility such as the Company. I have usually seen production costs allocated based on a 4CP

[136] STF-TAI-1-16 Attachment A TRADE SECRET. Value represents the excess collections of base, fuel, and adder rider revenue for the R and FlatBill service based on an [redacted] of billed kWh.

[137] The Company allocates demand-based production costs and step-up substation costs on a 12CP basis, and high-voltage transmission costs on an 80% 4CP/ 20% 12CP basis. Lower-voltage transmission assets are allocated on a 4CP or NCP basis depending on voltage level. Evans Direct at 17.

method or a combination 4CP and energy method and transmission costs allocated on a 12CP method. Higher voltage, shared distribution assets are typically allocated based on a Class NCP basis, while lower voltage assets are sometimes allocated based on Class NCP and sometimes on the Sum of Individual Maximum Demand ("SIMD") allocator.[138]

It is clear from the Company's testimony that other parties have noted that production costs are often allocated based on 4CP demand. In fact, the Company produced alternative versions of the COSS that included a 4CP production cost allocator, although it does not recommend their adoption.[139]

Q164. HOW DO THE COMPANY'S LOADS CHANGE THROUGHOUT THE YEAR?

A164. [Mr. Lucas] The Company's peak loads are concentrated during the summer months. Figure 15 below shows the average, maximum, and minimum 12CP peak in each month from 2017 through 2021.[140] While there are some years in which the winter months had high peaks, the average and minimum winter peaks remain considerably lower than summer months. In fact, January 2018, the most extreme winter month in the past 5 years, still had lower demand than every summer month in 2018 and would have been no higher than the 3rd highest month peak in any year between 2017 and 2021.

[138] The SIMD is calculated by summing each individual customer's maximum demand regardless of when it occurs. I do not believe that the SIMD is an appropriate allocator for any distribution costs, but when it is used, it is typically used for assets very close to the customer such as line transformers.
[139] Evans Direct at 4.
[140] STF-PIA-8-2 Attachment.

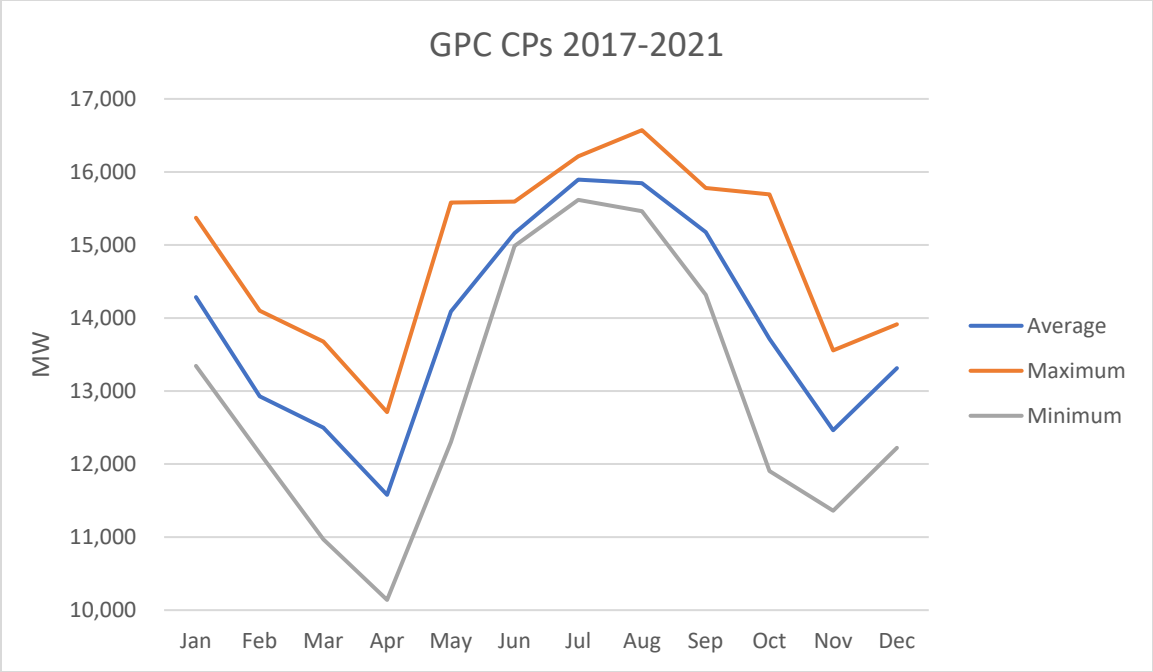


Figure 15 - GPC CPs 2017-2021

Q165. WHY DOES THE COMPANY RECOMMEND CONTINUING THE USE OF THE 12CP ALLOCATOR FOR PRODUCTION COSTS AND NOT RECOMMEND ADOPTING THE 4CP PRODUCTION COST ALLOCATOR?

A165. [Mr. Lucas] The Company's testimony is a bit confusing on this point. It indicates that the 12CP allocator has been used by the Company since 1989, is often used in FERC filings for wholesale jurisdictional purposes, and has been used by many utilities across the country.[141] While these all may be true, this text applies to the 12CP allocator generically, and not the 12CP allocator as applied to production costs.

The Company does offer some testimony on the value of 12CP to "summer and winter reliability planning", which may refer to production capacity. But even if one were to consider winter and summer peak demands as equally important to reliability (which, based on history, they are not), there is no justification for including the shoulder months in production capacity planning given their substantially lower peak demand levels.

[141] Evans Direct at 14.

Q166. DOES THE COMPANY TREAT THE IMPORTANCE OF WINTER LOADS CONSISTENTLY ACROSS ITS APPLICATION?

A166. No. The Company's testimony on the importance of winter load in planning is contradicted by one of its discovery responses. When asked by Staff whether it considered adding a winter TOU rate to its rates to reflect winter peaks on the system, the Company responded "At this time, Georgia Power has not identified a need for a winter peak time of use residential rate. This is due to the fact that the Company continues to forecast its peak loads to occur within the summer months. These summer peaks occur during predictable afternoon hours between the months of June through September, which correspond to existing residential time of use offerings."[142] The Company continued by noting that winter peaks are less predictable, less frequent, and shorter in duration than summer peaks.

Q167. WHY IS THIS AN IMPORTANT CONSIDERATION FOR SOLAR CUSTOMERS?

A167. Any discussion of the benefits that solar brings should consider how it performs during peak load hours, and for the Company, peak load hours tend to fall on hot, sunny summer afternoons when solar is generating well. The solar generation is both used onsite to meet load and exported to the grid to meet the neighbor's load. If production costs are not allocated to customers based on these summer months, then solar generation will appear less valuable than it actually is.

Q168. WHAT DO YOU RECOMMEND WITH REGARD TO THE PRODUCTION COST ALLOCATOR?

A168. [Mr. Lucas] I recommend the Commission adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities. Further, the 12CP allocator brings in too many low-demand shoulder months that do not contribute to production costs due to spare capacity on the system.

[142] STF-TAI-1-31.

Q169. ARE ANY OF THE TRANSMISSION PROJECTS REQUESTED BY THE COMPANY IN THIS RATE CASE ASSOCIATED WITH THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A169. No. The Company's response to a Staff discovery request noted that none of the projects in this rate case are associated with the North Georgia Reliability and Resilience Action Plan and that Plan is "currently under study and development in conjunction with the Integrated Transmission System Participants."[143]

Q170. IS THAT A PROBLEM?

A170. Yes. There is no clear indication in this rate case that the Company has allocated additional costs to pay for the North Georgia Reliability and Resilience Action Plan over the next three years. As Georgia faces retirement limitations in the north, and generation interconnection restrictions in the south, it is extremely important that multiple transmission scenarios be evaluated simultaneously, expeditiously. The proposed rate case does not do an adequate job explaining how the Company intends to plan for the future.

Q171. DOES STAFF HAVE DEDICATED FUNDING TO CONDUCT TRANSMISSION PLANNING OVERSIGHT?

A171. It does not appear that the Company has allocated any additional funding for Staff to assist with development, review, or oversight of the North Georgia Reliability and Resilience Action Plan, or transmission planning oversight more broadly.

Q172. HOW COULD ADDITIONAL FUNDING FOR TRANSMISSION PLANNING FOR THE COMPANY AND/OR STAFF BE HELPFUL?

A172. Additional funding for the Company could be used to upgrade software programs that evaluate multiple types of economic congestion, as is done in many other regions of the country. It could also be used to allow Staff to issue a request for proposals to hire an

[143] STF-PIA-4-23.

independent transmission consultant firm to run scenario-based analyses, evaluate various benefit metrics, and provide advice and recommendations to the Commission regarding future transmission plans. An independent transmission consultant firm could look beyond the current 10-year transmission planning horizon and could have a broader scope of work developed and led directly by the Commission. This sort of independent analysis is already done to evaluate RFP bids and was used by the Commission Staff in the IRP evaluating generation expansion but has not yet been done with transmission planning.

Q173. WOULD STAFF'S INDEPENDENT TRANSMISSION CONSULTANT REPORT REPLACE THE COMPANY'S NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A173. No. It would provide the Commission alternative recommendations to compare against the Company's recommendations that may even confirm the Company's plan as the preferred plan. Because transmission development can result in assets that last 40 to 60 years, it would be prudent to get a robust second opinion.

VII. CONCLUSION

Q174. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A174. Our recommendations in this case follow:

- The Company's proposed $200 interconnection fee should be rejected and its current $5/kW fee for systems under 250 kW maintained. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW.
- The Commission should deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a result, has overallocated costs to customer classes with RNR projects that is not considered in this figure.
- The Commission should strongly reconsider the width and asymmetry of the currently-approved ROE dead band. Ideally, it would be reduced to +/- 50 basis points, but at a minimum should be returned to the +/- 100 basis points in place prior to 2020.
- The Smart Usage tariff should not be the default rate and should be substantially redesigned with either a peak TOU demand charge collecting a fraction of production and transmission costs or a non-coincident peak charge collecting only low-voltage distribution assets. The Commission should require the Company to validate that the Smart Usage tariff is revenue neutral with respect to the traditional Residential tariff.
- The Commission should require the Company to continue offering the Residential and Nights and Weekends tariffs to new premises. The default rate should be changed to the Nights and Weekends tariff.
- The Commission should require the Company to develop a rate comparison tool that would automatically calculate a residential customer's bill based on historic usage on the various tariff options. It should also be required to collect billing demand data for each customer.
- The Solar Advisor Tool should be scrapped as it is actively biased against onsite solar.
- The Company should explain why its AMI data is insufficiently precise to use in its rate design and COSS. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible.
- The Commission should adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities.
- The Commission should direct the Company to provide funding for Staff and/or independent consultants to perform additional transmission studies related to North Georgia Reliability and Resilience Action Plan and transmission planning generally.

Q175. DOES THIS CONCLUDE YOUR TESTIMONY?

A175. Yes, it does.