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April 9, 2026

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light and Southface Institute; Docket No. 56765

Dear Ms. Tanner:

Please find enclosed an electronic version of the following Direct Testimony **of Albert Lin on behalf of Georgia Interfaith Power & Light and Southface Institute** to be filed in Docket No. 56765.

Respectfully submitted,



_____

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Counsel for GIPL and Southface

STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION

In Re:	**)**	
	)	
Georgia Power Company's Fuel Cost Recovery (FCR-27)	**)**	**Docket No. 56765**
	)	

DIRECT TESTIMONY OF ALBERT LIN
ON BEHALF OF
GEORGIA INTERFAITH POWER & LIGHT
AND SOUTHFACE INSTITUTE

April 9, 2026

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SECTION I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A: My name is Albert Lin. I am a consultant with the OG Finance Lab located on the 20000 block of Via La Jolla in San Juan Capistrano, California 92675.

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A: I have worked in financial analysis and capital markets since 1989. Directly after graduating from the University of Texas at Austin with a Bachelor of Science in Finance, Bachelor of Arts in International Business, and an Honors Business Master's degree, I worked for a regulated utility called General Telephone and Electric ("GTE," now called Verizon). GTE conducted business in over 20 different states in the United States with most of the company's revenue derived from regulated activities approved by Public Utility Commissions ("PUCs") or a similar governmental body in each State GTE conducted business in. My roles were in the finance and audit departments where I analyzed and supported optimal financial outcomes for shareholders within the policies and orders of each respective State's PUC. I focused on the financial and accounting activities that would likely achieve the highest financial returns possible with the least operating risk and variability of outcomes for GTE's equity shareholders. These roles included satisfying credit rating agencies that could impact the cost of debt for GTE, which would likely also affect how shareholders perceived the equity value.

After a series of legislative changes culminating in the Telecommunications Act of 1996, the primary activities for GTE were fully de-regulated across the country. Just prior to the

passing of the Telecommunications Act of 1996, my work focus shifted to the equity valuation of wireless communications assets, pricing the cost of capital and equity value of wireless communication assets for various Wall Street capital markets firms plus being a founder and partner for a FINRA (Financial Industry Regulatory Authority) registered broker-dealer that focused on equity valuation and forecasts in high-growth industries such as the technology industry sector.

Starting in 2012, I served as CEO and Chairperson of the Board of EmberClear Corporation, during which the company developed, permitted, and sold to Ares Capital and ITOCHU Power & Environmental Services three natural gas combined-cycle plants and a zero-emissions integrated gasification combined-cycle with carbon dioxide sequestration and/or re-use plants of 300 to 450 Megawatts of nameplate capacity.

From 2020 to the present, I have been focused on economic and financial analysis supporting the energy industry. This includes the regulated utility sector of the United States. More specifically, I have published on matters related to the Return on Equity (ROE) and the Fuel Adjustment Clause (FAC) since 2021. Publications have taken the form of presentation slides, handbooks, whitepapers, and blogs.

A copy of my professional resume, which includes my employment history, education, and history of commission and similar hearings, is attached as Exhibit AL-1 to this testimony.

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

A. Yes. I have testified in general rate cases and fuel rider dockets before this commission. The specific hearings are listed in my CV attached.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: Georgia Interfaith Power and Light (GIPL) and Southface Institute.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to provide the Commission with data and supporting analysis for my recommendations for increased regulatory oversight and transparency of fuel costs. The present trend for the cost of fuel to continue rising with increasing volatility has created a condition where management of the financial exposure and management practices has never been more important since the 1979 "Energy Crisis." With the cost of fuel accounting for over a quarter of each residential bill, increased attention to rising fuel costs is an urgent matter for affordability and economic prosperity.

Q: WHAT DO YOU HOPE THE COMMISSION WILL TAKE AWAY FROM YOUR TESTIMONY?

A: My hope is that my testimony reminds the Commission of the significant risks to customer bills posed by Georgia Power's deepening reliance on natural gas, and that armed with this knowledge, the Commission will take steps to increase its oversight of fuel costs. In this testimony, I have limited my recommendations to procedural steps to increase oversight in the context of Georgia Power's recommendations to the contrary. However, the Commission has broad authority to regulate how Georgia Power spends customers' money. The Commission also has the ability to ensure fair competition between technologies to promote economic efficiency between all technologies available. My recommendations here are merely the first step in that process. I encourage the Commission to think creatively about how to study fuel costs and its impacts on customers; to continue to prioritize diversification of fueled and non-fuel choices; and to carefully consider how the long-held

regulatory status quo should be updated to match the changes in the industry to minimize the growing financial risks from increasingly volatile fuel costs.

SECTION II. FINDINGS AND RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR FINDINGS.

A: My findings are as follows:

1. Natural gas price volatility is hard to manage and places upward pressure on fuel costs.
    a. Georgia Power Company (GPC or the Company) is investing in more generation using natural gas technologies. Natural gas exhibits more volatile prices than any other major fuel source, and the price volatility of natural gas is increasing. The Company intends to increase future exposure to natural gas generation technologies at a time when many major contributing causes to the price volatility of natural gas continue or have even increased.
    b. Declines in fuel costs on customer bills in 2026 are the result of paying off the large "financing plan" for the extremely high fuel costs of FCR-26.
    c. GPC residential customers spend over a quarter (27%) of their total electric bill on fuel costs currently, and as GPC increases exposure to the most price-volatile technologies, customers should expect to see continued pressure from rising fuel costs.
2. Financial transparency for fuel costs is lacking.
    a. Hedging price volatility puts upward pressure on total costs over time. It also obscures the financial risks of GPC's heavy reliance on natural gas.

b. Transparency into the Company's fuel cost data and management processes improves efficiency and decreases the risk of future fuel cost price shocks or surprises. The Company's proposed Interim Fuel Rider (IFR) threshold increase to $300 million and the request for a flexible next filing date for FCR-28 are examples of changes which obscure or delay any party aside from the Company from knowing about the fuel cost amount and volatility over time.

c. GPC customers do not see fuel cost details on monthly bills by default. The omission of a fuel cost line item for monthly billing lowers visibility into one of the largest portions of a customer's bill.

d. The Commission's fuel structure—which allows GPC to pass 100% of fuel costs to its customers—erodes GPC's incentive to limit natural gas or use low- and no-fuel energy options.

e. Additionally, the ability to automatically adjust fuel costs affecting customer bills by 40% above or below the approved rate after the IFR is triggered is extremely high relative to the rate of inflation and further encourages the use of price-volatile fuels.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: Given the findings listed above, the Commission should increase oversight and transparency for fuel cost recovery. Specifically, I recommend that the Commission:

a. Deny the Company's request to increase the IFR limit, so the Commission and public can better monitor fuel cost changes in a timely manner;

b. Set a date for when GPC must propose its next Fuel Cost Rider hearing;

c. Reduce the maximum amount by which fuel rates can be adjusted during an FCR cycle (i.e., the period between fuel cases) from 40% above or below the approved FCR-27 rates to 15%; and

d. Order GPC to add a fuel cost line item on monthly bills to all customers.

SECTION III. FUEL COSTS RISING DUE TO NATURAL GAS DEPENDENCY

Q: HOW DOES THE COST OF FUEL IMPACT THE TYPICAL GEORGIA POWER RESIDENTIAL CUSTOMER?

A: For residential customers, the fuel cost over the period of January 2023 - December 2025 averaged 27% of their total bill:

Figure 1: GPC's Historical Period Average Monthly Bill[1]

Historical Period (January 2023 - December 2025)

Type of Customer	Historical Period Average Monthly Bill	Percent of Monthly Bill Attributable to Fuel Costs
Municipal-Residential	$ 160.61	27.11%
County-Residential	$ 157.67	27.11%
Municipal-Residential, Eligible for Income Qualified Discount	$ 126.58	27.05%
County-Residential, Eligible for Income Qualified Discount	$ 124.27	27.05%

Notes:
Bills based on typical residential customer averaging 1,000 kWh per month
"Percent of Monthly Bill Attributable to Fuel Costs" includes FCR charges, Municipal Franchise Fee on FCR charges, and Income Qualified Discount on FCR, if applicable.

Q: YOU CONCLUDE FUEL COSTS ARE RISING. PLEASE EXPLAIN WHAT YOU MEAN.

A: Both Georgia Power's total fuel costs and its customer rate to recover day-to-day fuel costs are increasing. Georgia Power's total fuel expenditures are increasing substantially, due to both the rising cost of fuel and the expected growth in customers' demand for energy.

[1] FCR-27, MFRH-1.1 (PD).

Georgia Power's projected customer rate to cover its fuel costs for each unit of energy delivered (Part A of the FCR Rate) is also increasing substantially. The FCR-27 test period shows a 25% increase versus the FCR-26 test period resulting in Part A costs of 3.645-3.6953 cents per kWh.[2]

Q: **WHAT IS CAUSING GEORGIA POWER'S TOTAL FUEL COSTS TO RISE?**

A: GPC testifies that its fuel costs for FCR-27's Test Period are $7.1 billion, a $1.4 billion (25%) increase over FCR-26.[3] Natural gas is the largest portion of fuel costs and energy generation, representing 40.3% of fuel costs and 33.7% of generation.[4] The Company states that, "compared to the FCR-26 test period, fuel cost for natural gas, including PPAs, is projected to increase by 21% from $30.91/MWh to $37.38/MWh."[5] While the system is growing, the data in the table below shows the Company anticipates fuel costs to rise faster than generation growth and the cost per MWh of electricity. These cost increases come at a time when the Company is planning to use more natural gas than ever before: "On an annual basis, the MMBtu of natural gas burn projected in the test period in FCR-27 is 522 million MMBtu compared to the 461 million MMBtu that were projected in the test period in FCR-26 Budget."[6]

[2] FCR-27, Direct Testimony of Adam H. Houston and Matthew S. Berrigan, page 6 Table 2 and page 15, lines 13–23 (Feb. 17, 2026) ("FCR-27 Houston & Berrigan Testimony").

[3] *Id.* at page 15, lines 13–19.

[4] *Id.* at page 16, Table 3.

[5] *Id.* at page 16, lines 9–11.

[6] *Id*. at page 21, lines 14–16.

Figure 2: GPC's Comparison of Projected Fuel Costs[7]

Comparison of Projected Fuel Costs
FCR-27 vs FCR-26

	FCR-27 Test Period (June 2026 - May 2028)			FCR-26 Test Period (June 2023 - May 2025)			FCR-27 vs FCR-26 % Change		
	($ Millions)	(GWh)	($/MWH)	($ Millions)	(GWh)	($/MWH)			
Natural Gas*	$ 2,848	76,187	$ 37.38	$ 2,132	65,992	$ 32.31	34%	15%	16%
Coal	1,258	35,487	35.44	499	9,746	51.15	152%	264%	-31%
Nuclear	427	48,871	8.74	448	46,376	9.66	-5%	5%	-9%
Solar & Hydro	-	4,187	-	-	4,004	-	-	5%	-
Renewable PPAs**	1,218	24,915	48.89	949	18,633	50.93	28%	34%	-4%
Purchases	1,322	36,395	36.34	1,633	39,838	40.98	-19%	-9%	-11%
Total	$ 7,073	226,041	$ 31.29	$ 5,660	184,589	$ 30.66	25%	22%	2%

*Includes PPA's for which GPC is responsible for purchasing fuel; includes hedge gains/losses
**Includes Solar, Biomass, Wind, and Battery PPA resources

The Company's FCR-27 test period projection in Figure 2 shows just how reliant on natural gas GPC has become. No other fuel cost category is even half as large as natural gas in projected cost, and projected energy generation from natural gas is over 50% greater than the next-highest source of generation (nuclear).

Q: HOW DOES GPC PRESENT ITS FUEL RATE?

A: Georgia Power has a two-part fuel rate, which it then applies to customer bills. "Part A" estimates the rate needed to cover projected fuel costs. "Part B" estimates the rate needed to repay fuel costs that Georgia Power has incurred that it did not anticipate when setting its fuel rates. In other words, "Part A" covers the forecasted day-to-day projected costs of fuel, and "Part B" is a under-recovery mechanism to service the financing plan representing past increases in fuel costs that Georgia Power incurred beyond the projected day-to-day rate.[8]

[7] MFRP-1, Attachment A PD.

[8] FCR-27 Houston & Berrigan Testimony, at page 7, lines 1–6.

Q: HAS THE INCREASE IN PROJECTED FUEL COSTS TRANSLATED TO AN INCREASE IN THE FUEL RATE CHARGED TO CUSTOMERS?

A: Yes. I used the PD versions of Georgia Power's historic and test-year rate calculators (MFRH-1.1 and MFRP-1.1), the Part A and Part B fuel rates from Georgia Power Exhibit 6, and the Line Loss Allocators from Georgia Power Exhibits 5A and 5B to calculate the average monthly fuel cost for the average Georgia Power customer paid in the past versus what he/she will pay in the future, broken out by FCR part.[9] Georgia Power has proposed increasing Part A of its customer fuel charge by approximately 13% to cover increasing projected costs.

Q: IF THE FUEL COSTS ARE RISING SO RAPIDLY AND THE FUEL RATE IS INCREASING, HOW IS IT POSSIBLE THAT GPC EXPECTS CUSTOMER BILLS TO DECLINE BY $5.74/MONTH[10]?

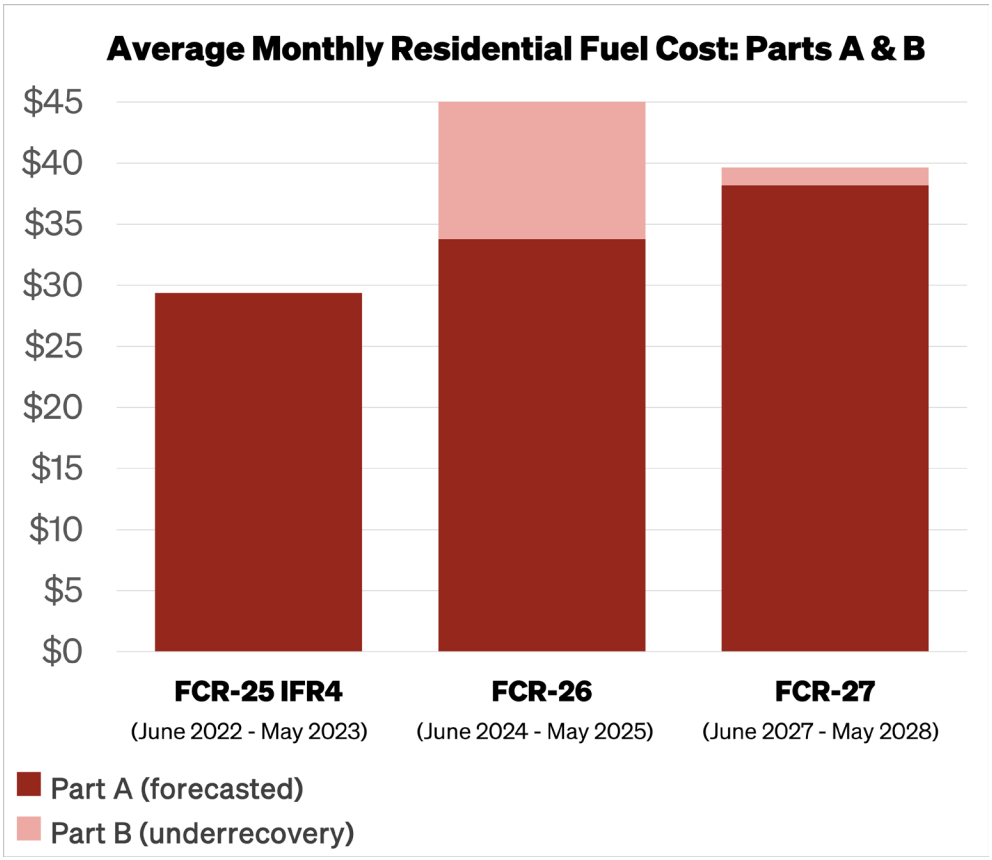
A: Customers see a smaller bill in 2026 only because they finally finished paying off a three-year "installment plan" from the fuel cost spike of 2022.

I used the same analysis described in my previous answer to produce the chart below, which demonstrates how customers' bills will go down with the adoption of FCR-27 while fuel costs are on the rise. The average Georgia Power customer will pay $4.38 more per month for current fuel costs than during the FCR-26 period.

[9] The analysis also accounts for the municipal franchise fee (MFF).

[10] *Id.* at page 6, lines 5–7.

Figure 3: Comparison of FCR-25, FCR-26, and FCR-27[11]



FCR-27 Part A costs are higher than the FCR-26 Part A costs, which were higher than the FCR-25 costs with the IFR in effect.

Instead, the decrease in overall fuel cost from FCR-26 to FCR-27 is driven by changes in Part B costs. Consider what happened in FCR-26. In that docket, the Commission raised the average customer bill by approximately $15.94 per month.[12] Over two-thirds of that increase were "Part B" costs designed to pay off a past under-recovery of over $2 billion,[13]

[11] Note that FCR-25 did not split costs into Parts A and B and included no under-recovery of past costs. *See* FCR-25, Dkt. 43011, Direct Testimony of Sarah P. Adams, page 5 (March 9, 2020).

[12] Georgia Power, 2023 Fuel Cost Recovery, https://www.georgiapower.com/about/company/filings/fuel-cost.html (last accessed Apr. 6, 2026) ($15.94); FCR-26, Dkt. 44902, Rebuttal Testimony of Sarah P. Adams and Adam D. Houston, page 7, line 25 to page 8, line 1 (Apr. 24, 2023) ("approximately $15.90").

[13] FCR-27 Houston & Berrigan Testimony, at page 4, lines 18–20.

which was the result of gas prices spiking upward in 2022. (The rest of the increase reflected the rising Part A, forecasted increase in costs of fuel at that time.) Since then, customers have paid over $10/month to pay off the under-recovery that accrued in 2022. Those billions in under-recovery will finally be paid off on May 31, 2026.[14] So those costs of over $10/month are removed from the bill.

However, as detailed above, the forecasted costs of fuel (Part A) continue to rise, pushing projected day-to-day costs up by over $4 per month. And even a $15.94 increase in 2023 was not sufficient to cover Georgia Power's fuel costs, so a new (though much smaller) under-recovery has formed (Part B).[15] So in total, though the $10+ monthly bill for past under-recovery from 2022 will finally expire, bills will only go down by approximately $5.74/month because the day-to-day cost of fuel continues to rise.

Consider the following analogy: Imagine that your air conditioner breaks on a hot August day, forcing you to purchase a replacement using a credit card. Once the credit card balance is finally paid down to zero after 36 months, your monthly household budget breathes a sigh of relief. However, your actual daily living expenses—like groceries, insurance, and property taxes—have actually gotten more expensive in the meantime. Georgia Power is proposing a bill reduction for residential customers of $5.74 a month, but what really happened is the massive emergency credit card bill from 2023 is finally paid off. [16] So even

[14] *Id.* at page 4, lines 21–23.

[15] *Id.* at page 4, lines 24–26.

[16] Although the decrease in Part B costs is responsible for nearly all of the decrease in customer bills, two additional accounting changes also contribute to reducing customer bills for FCR-27. One results from a legal settlement amounting to $55.2 million and the other from a change in Georgia' state income tax rate that saved $13.2 million. *See* FCR-27 Houston & Berrigan Testimony, at page 14, lines 3–14. These two items are indeed savings but are tiny compared to the $2,200 million of under-recovered fuel costs from FCR-26.

though daily living (fuel) expenses are going up, the total monthly charge is going down as a result of the installment plan charges ending. In other words, any messaging about a proposed decrease in customer bills misses the fact that fuel costs are going up.

SECTION IV. NATURAL GAS VOLATILITY

Q: WHAT IS THE PRIMARY REASON GEORGIA POWER CONTINUES TO EXPERIENCE UNDER-RECOVERY OF ITS PROJECTED FUEL COST BALANCE, REQUIRING RELIANCE UPON MULTI-YEAR PAYMENT PLANS FOR CUSTOMERS?

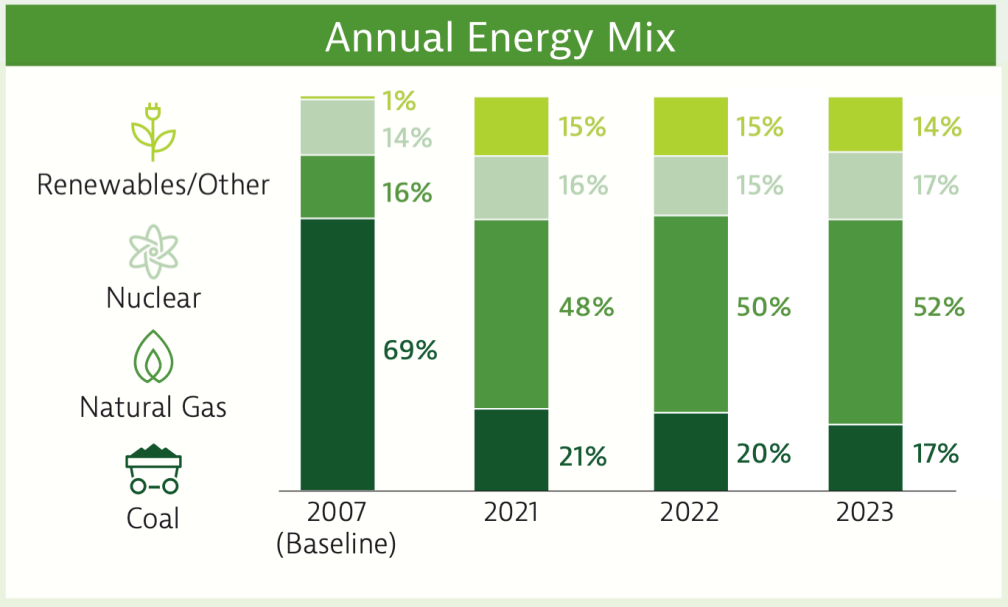
A: The primary reason for cost increases is the growing reliance on natural gas as a generation technology. Natural gas prices are very difficult to predict and highly volatile.

Q: **TO WHAT EXTENT DOES THE COMPANY RELY ON NATURAL GAS FOR POWER GENERATION?**

A: As discussed above, natural gas is by far GPC's largest source of power generation. GPC's reliance on natural gas has increased over time.

GPC is the largest operating entity of its holding company, Southern Company. Figure 4 highlights the company-wide portfolio transition from a 2007 baseline where natural gas was 16% of energy generation to a 2023 energy mix made up of 52% natural gas:

Figure 4: Southern Company Energy Transition[17]



I anticipate natural gas fired generation will remain the largest energy source for Georgia Power for many years to come. Company witnesses Houston and Berrigan testified that "[n]atural gas fired generation is projected to be the largest energy source for Georgia Power during the FCR-27 test period, with approximately 40% of the total projected fuel costs coming from natural gas."[18] Just last year, this Commission approved a nearly-10 gigawatt capacity expansion of the Georgia Power system to be in service by 2031, and approximately 60% of those new resources are fueled by natural gas.[19]

Q: WHY ARE NATURAL GAS PRICES SO VOLATILE?

A: Natural gas prices are far more sensitive than other fuels to supply and demand dynamics; any imbalance creates extremely large price changes. This is in part because natural gas

[17] Southern Company, Energy Portfolio Transition & Scenario Planning Presentation (Sept. 2024), https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/net-zero-transition/energy-portfolio-transition-scenario-planning-fact-sheet.pdf.

[18] FCR-27 Houston & Berrigan Testimony, at page 19, line 27 to page 20, line 2.

[19] *See generally* Dkt. Nos. 56298 & 56310; *see also* Dkt. No. 55378.

has unique physical characteristics, such as the need to use modest-to-high pressure to transport and store the fuel. Moreover, the Company has increased its reliance on natural gas at the same time many other utilities are doing the same.

Figure 5: U.S. Electricity Generation from Natural Gas[20]

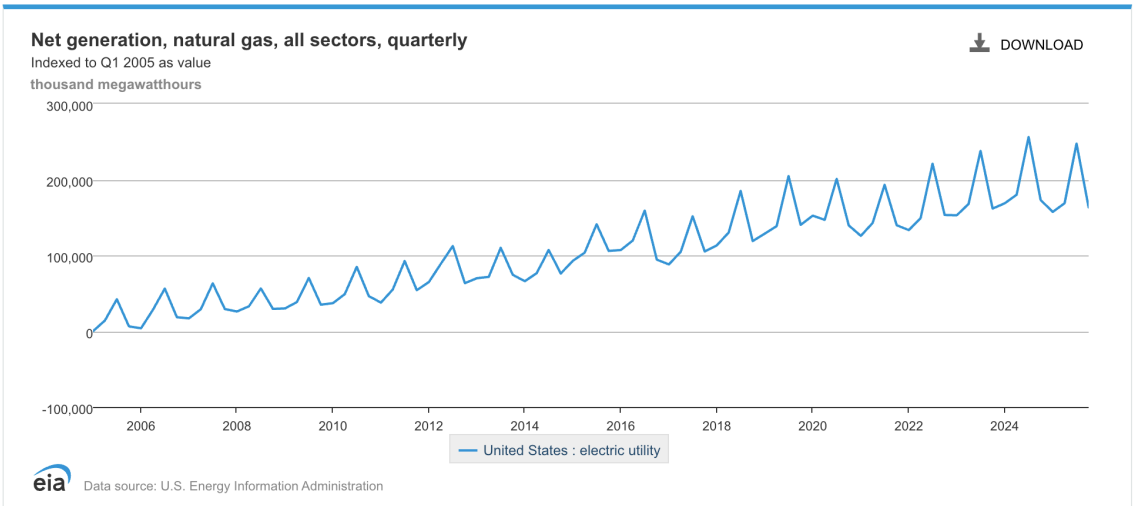
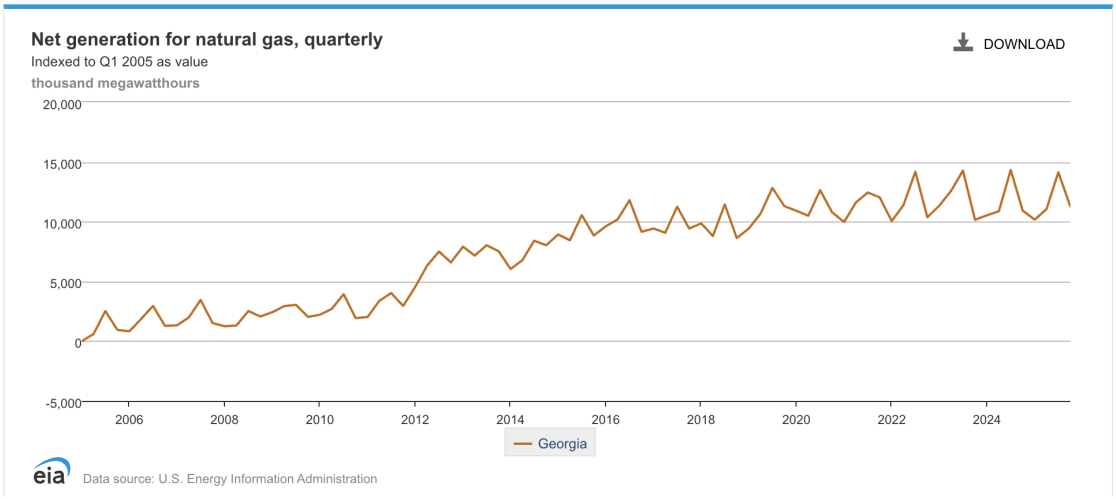


Figure 6: Georgia Electricity Generation from Natural Gas[21]



[20] U.S. Energy Info. Admin., Electricity Data Browser, https://www.eia.gov/electricity/data/ (last accessed Apr. 9, 2026) (filters set for 2005 thru 2025 Nat Gas used for Electricity Generation).

[21] *Id.* (filters set for 2005 thru 2025 Nat Gas used for Electricity Generation in Georgia).

As more utilities concurrently expand their use of natural gas, the common infrastructure required to produce, transport, and store the fuel is placed under increasing demand. This utility-dominated demand reacts to typical utility load cycles, including seasonal spikes during both winter and summer. Such patterns can create periods when supply struggles to keep pace with demand, especially during extreme weather events. When growing demand is combined with lagging transportation and storage infrastructure,[22] the result is more frequent instances where the price of natural gas becomes highly volatile and unpredictable. These conditions expose ratepayers to more frequent significant price swings, as supply shortages or bottlenecks lead to sudden and sometimes dramatic increases in cost.

Physics and increased U.S. demand for power generation are not the only factors driving natural gas price volatility. The EIA's *Today in Energy* publication listed several factors that contributed to natural gas prices hitting record high volatility in the first quarter of 2022.[23] The report stated:

> U.S. natural gas prices are typically more volatile during the first quarter of a year because of the fluctuating demand for natural gas for space heating as weather changes. Factors that contributed to heightened volatility in the first three months of this year [2022] include:
>
> - Weather-driven fluctuations in natural gas demand
> - Declining natural gas production in January and February
> - Declines in Lower 48 states' working natural gas levels

[22] *See* Andrew Baker, *East Coast Manufacturers Left in Cold Amid Scarce Natural Gas Pipeline Capacity*, Nat. Gas Intelligence (Feb. 10, 2025), https://naturalgasintel.com/news/east-coast-manufacturers-left-in-cold-amid-scarce-natural-gas-pipeline-capacity/; U.S. Energy Info Admin., Weekly Natural Gas Storage Report for Week Ending in March 27, 2026 (Apr. 2, 2026), https://ir.eia.gov/secure/ngs/ngs.html (showing relatively flat trend for gas in underground storage over the past five years).

[23] U.S. Energy Info. Admin., *U.S. natural gas price saw record volatility in the first quarter of 2022* (Aug. 24, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53579.

- Record U.S. [liquified natural gas ("LNG")] exports to Europe to help offset reduced natural gas supplies from Russia

In the years since that 2022 report, geopolitical events have further emerged as a material risk factor for natural gas price spikes. Large governments such as the United States, Germany, and France have also entered the market as competitors to domestic users of natural gas. The recent EU-USA energy purchase agreement announced on July 28, 2025 is designed to have the U.S. Government enter the natural gas market to export $750 billion of energy to Europe over the next three years, comprised mostly of LNG, petroleum, and nuclear.[24] Although I am skeptical that the U.S. will have the physical infrastructure to deliver $750 billion worth of energy in three years, there is good reason to think that substantial increases in LNG exports to Europe will continue.[25] Germany, the largest economy in the EU, has provided state-backed credit to "balance" natural gas supplies whenever necessary at the current market price via an organization called "Trading Hub Europe."[26] France, the second largest economy in the EU, has given citizens a subsidy for energy in the form of "energy checks" after the natural gas price spike in 2022, which enables France to continue obtaining and paying for natural gas even after price spikes.[27] These are just two examples of European actions driving demand for LNG. These trends

[24] U.S. White House Fact Sheet, *The United States and European Union Reach Massive Trade Deal* (July 28, 2025), https://www.whitehouse.gov/fact-sheets/2025/07/fact-sheet-the-united-states-and-european-union-reach-massive-trade-deal/.

[25] Nour Eltigani, *US energy stocks surge on $750 billion EU purchase pledge*, Energy Connects (July 29, 2025), https://www.energyconnects.com/opinion/features/2025/july/us-energy-stocks-surge-on-750-billion-eu-purchase-pledge/.

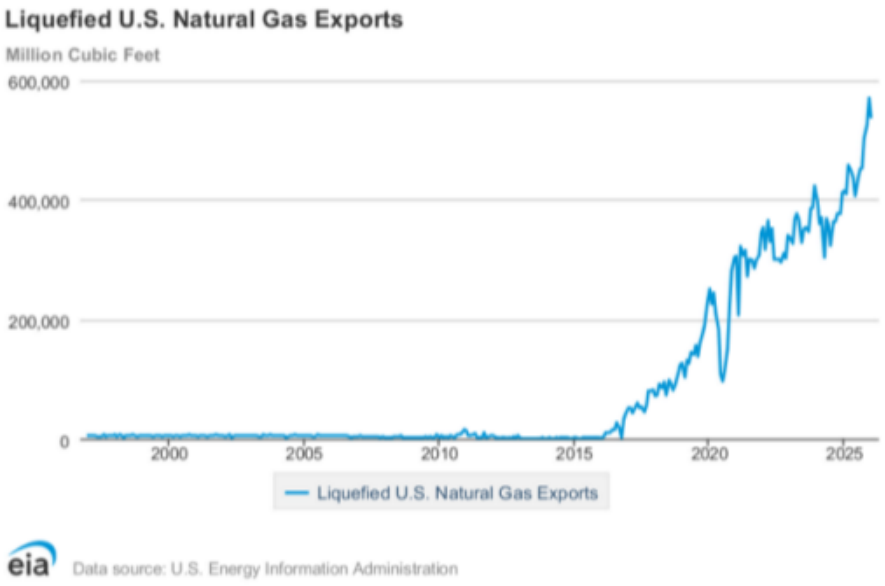
[26] Trading Hub Europe, *Information and services for providers of balancing gas and/or services*, https://www.tradinghub.eu/en-gb/Services/Balancing-gas-supplier/Information (last accessed Apr. 9, 2026).

[27] Service Public, *How to benefit from the energy check in 2026?* (Apr. 1, 2026), https://www.service-public.gouv.fr/particuliers/actualites/A17885?lang=en.

suggest that the U.S. natural gas industry will shift from domestic investment to LNG sales to Europe and Asia. It is logical to assume that demand from these foreign governments—price-insensitive buyers that are much larger than the entire utility industry—will only stiffen competition for natural gas and place additional upward pressure on gas prices.

If extreme price increases in short periods of time occur with greater frequency and if the largest governments in the world agree to buy U.S.-produced natural gas, it is logical to assume that U.S. LNG exporters will take advantage of the high prices and the meteoric rise of LNG exports will continue:

Figure 7: Natural Gas Export Volumes from the United States[28]

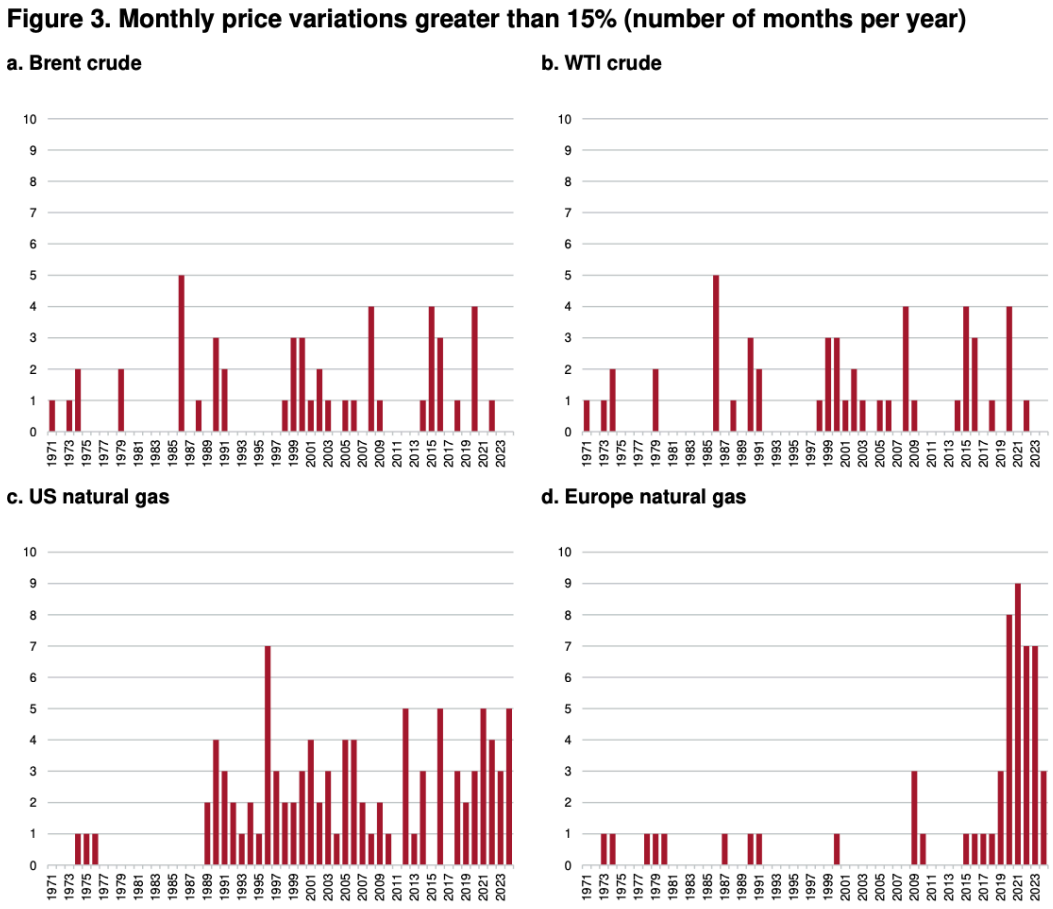


Q: JUST HOW VOLATILE ARE NATURAL GAS PRICES?

[28] U.S. Energy Info. Admin., Liquified Natural Gas Exports (March 31, 2026), https://www.eia.gov/dnav/ng/hist/n9133us2m.htm

A: Natural gas price volatility has overtaken the price volatility of crude oil, which used to be the benchmark for a high volatility large commodity. This trend has become more pronounced in recent years. A recent study from the Elcano Royal Institute analyzed historical trading data and measured the number of months where price variations for natural gas exceeded 15 percent, an indicator of volatility.[29] The report illustrated the findings as "Figure 3" which I have reproduced here in Lin Figure 8.

Figure 8: Natural Gas Price Volatility Surpasses Oil Price Volatility



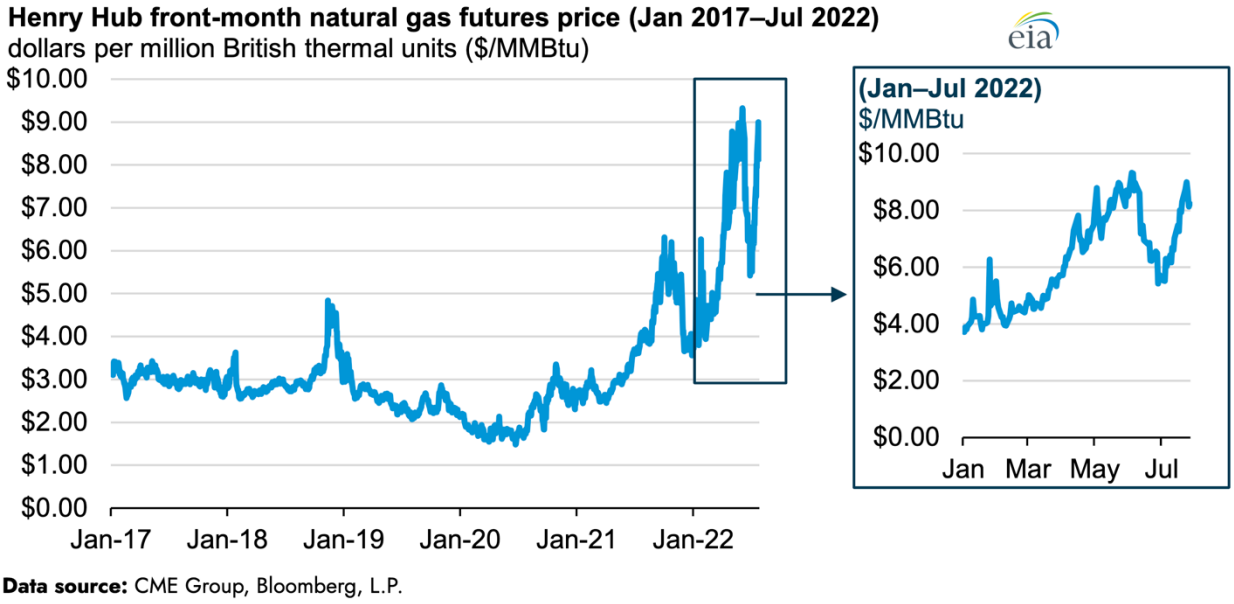
Source: the authors based on World Bank data.

[29] Enrique Feás & Isidoro Tapia, *The Volatility of Energy Prices and its Effect on Industry*, Elcano Royal Inst. (Mar. 20, 2025), https://www.realinstitutoelcano.org/en/analyses/the-volatility-of-energy-prices-and-its-effect-on-industry/.

The findings show that price volatility for natural gas in the United States has far exceeded price volatility of crude oil for the past 35 years. The graphic also reflects the fact that volatility may compound for many months or longer.

In addition to the Elcano study, studies from the U.S. Department of Energy examining historical prices point to a growing trend in natural gas price volatility in the United States. In 2022, the U.S. Energy Information Administration ("EIA") published a chart depicting the volatility of natural gas prices, which is presented here as Figure 9.

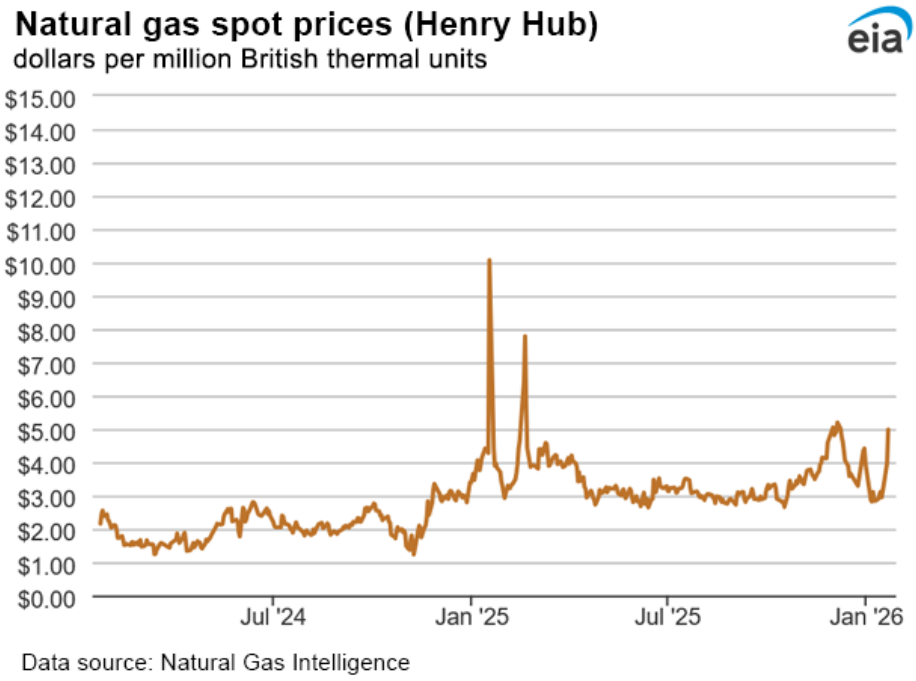
Figure 9: Natural Gas Price Volatility Trend 2017–2022[30]



As Figure 9 illustrates, natural gas prices were highly volatile in the 2017–2022 period, with all-time price volatility records set in 2022. That extremely high volatility has continued, as seen in the EIA's January 2026 publication reproduced here as Figure 10.

[30] U.S. Energy Info. Admin., *U.S. natural gas price saw record volatility in the first quarter of 2022* (Aug. 24, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53579.

Figure 10: Natural Gas Price Volatility Trend 2023–2026[31]



Q: HAS NATURAL GAS PRICE VOLATILITY BEEN A LONG-STANDING ISSUE?

A: Yes. However, the electricity industry's exposure to natural gas and its price volatility is a recent phenomenon which was not a material concern when natural gas generation was largely used for peaking load demand. In 2004, the Massachusetts Institute of Technology ("MIT") conducted one of the earliest studies to quantify the volatility of natural gas prices in the United States.[32] Although the MIT study was published over 20 years ago, it used historical trading data to demonstrate that natural gas price volatility was greater than crude

[31] U.S. Energy Info. Admin., Natural Gas Weekly Update (Jan. 22, 2026), https://www.eia.gov/naturalgas/weekly/?utm_medium=email.

[32] Robert S. Pyndick, *Volatility in Natural Gas and Oil Markets*, JOURNAL OF ENERGY & DEV. Vol. 30 No.1 (2004), https://web.mit.edu/rpindyck/www/Papers/Vol_NG.pdf.

oil price volatility even prior to 2004.[33] For much of the last 70 years, crude oil was seen as the larger and more important fuel compared to natural gas. Crude oil prices were considered extremely hard to predict despite the size of the market and financial motivation to make accurate predictions.[34] Today, the same can be said about natural gas.

Q: IF NATURAL GAS EXPOSURE IS VERY LARGE AND PRICES ARE VERY VOLATILE, CAN THE PRICE BE PREDICTED TO AVOID LARGE CHANGES IN THE LEVELIZED COST OF FUEL?

A: No. Natural gas prices cannot be reliably predicted—and not for lack of effort. Given the large amount of money involved in the energy commodities industry, there is enormous financial motivation to accurately predict future prices.[35] Company Witnesses Houston and Berrigan agree with the experts; they testify that, "Taken together, these factors suggest a tighter supply-demand balance and the potential for continued natural gas price volatility."[36]

Q: HAS THE COMPANY EXPERIENCED HIGH NATURAL GAS PRICE VOLATILITY?

A: Yes. As the Company observes, "Natural gas prices remain subject to significant volatility. . . . [T]his volatility can be seen in the wide range of spot prices at Henry Hub, which

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[33] *Id.* at 7–8.

[34] *See generally* James D. Hamilton, *Understanding Crude Oil Prices,* NAT'L BUREAU OF ECON. RSCH. (Nov. 2008), https://www.nber.org/system/files/working_papers/w14492/w14492.pdf.

[35] *See* Bagher Modjtahedi & Nahid Movassagh, *Natural-gas futures: Bias, predictive performance, and the theory of storage,* 27 ELSEVIER ENERGY ECON. 617 (2005) https://www.sciencedirect.com/science/article/abs/pii/S0140988305000538; *see also* Mark Bolinger et al., *Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation,* ERNEST ORLANDO LAWRENCE BERKELEY NAT'L LAB'Y (2003), https://eta-publications.lbl.gov/sites/default/files/report-lbnl-53587.pdf.

[36] FCR-27 Houston & Berrigan Testimony, at page 15, lines 8–10.

ranged from $1.23 to $12.97 per MMBtu in 2023 through 2025."[37] Wide-ranging fluctuations have continued this year: the Company testified that "as recently as late January 2026, Henry Hub natural gas prices rose above $30 per MMBtu during Winter Storm Fern, illustrating the ongoing potential for volatility in natural gas markets."[38] I urge the Commission to consider the significant cost risks that accompany Georgia Power's deepening reliance on natural gas, which has fluctuated in price tenfold in just the past three years.

SECTION V. SHORTCOMINGS OF THE COMPANY'S PROPOSALS

Q: DO YOU AGREE WITH GPC THAT ADDITIONAL HEDGING OF THE NATURAL GAS FUEL COST WOULD HELP MITIGATE THE INCREASING PRICE PRESSURES FROM NATURAL GAS?

A: Not necessarily. Georgia Power testifies that hedging is critical. Specifically, the Company states: "For a Company like Georgia Power that anticipates consuming more than 250 million MMBtu of natural gas per year, a robust hedging program serves as a critical tool to mitigate upward price volatility for customers."[39] The Company describes the following benefits of hedging:

1. Mitigate upward price volatility of natural gas.[40]
2. Fix and cap costs for a portion of the natural gas purchased.[41]

[37] *Id.* at page 20, lines 9–11.

[38] *Id.* at page 21, lines 1–3.

[39] *Id.* at page 20, lines 13–15.

[40] *Id*. at page 19, lines 26–27.

[41] *Id.* at page 20, lines 3–6.

3. Provide rate stability for customers.[42]

But although hedging blunts the impacts of extreme price spikes for natural gas, overall, it can also put upward pressure on natural gas prices for customers.

Hedging behaves just like insurance. The utility is the buyer of the insurance. If the Company wants to have a known maximum price for the natural gas it purchases, the price volatility risk must be taken by a counterparty who agrees to absorb the risk for a cost—essentially, an insurance premium. These counterparties understand the risk and know the price volatility of natural gas as well as Georgia Power does. They will accordingly charge a rate for the insurance that allows them to profit over time. So, increased hedging may keep costs for customers steadier in the long run, but it will keep them steadily high.

Q: HAS THE COMPANY IDENTIFIED THE AMOUNT OF HEDGING OPTIMAL FOR ITS CUSTOMERS?

A: I cannot answer that question based on this record. Under the current regulatory framework, the Company can pass through 100% of hedging costs to (most) customers. In a competitive marketplace, a rational actor would only buy as much hedging as needed to offset the risk that a catastrophic event would impair its financial security. But because Georgia Power bears none of the hedging costs, it has minimal incentive to evaluate the optimal amount of hedging for its customers.

For the same reason, GPC has limited incentive to investigate whether the problems it seeks to solve through increased hedging are in fact symptoms of overreliance on a highly volatile resource. Rather than continuing to hedge a higher and higher percentage of its

[42] *Id.* at page 4, lines 13–15.

natural gas purchases and thus lock in a higher and higher floor for fuel costs, the Company might—if it had incentive to—reconsider its fuel mix or the expected costs for hedging over time.

I recognize that Georgia has a long-standing practice of passing 100% of fuel costs to customers. As such, Georgia will likely see greater risks for fuel cost increases unless the practices are updated in a manner where the incentives align with the risks. In the meantime, I urge the Commission to approach Georgia Power's assessment of financial benefits concerning fuel cost management with the knowledge that the financial risks are rising and being borne by the customer.

Q: IF HEDGING CANNOT SOLVE FOR VOLATILE AND RISING NATURAL GAS COSTS, COULD A HIGHER IFR THRESHOLD BE USEFUL?

A: No. The IFR is the threshold that triggers both the Company's reporting requirements to the Commission and the public and its ability to adjust its fuel rate. The Company "proposes to increase the IFR threshold from the current amount of $200 million approved by the Commission to $300 million."[43]

The IFR is a tool to help the Commission respond to fuel cost volatility. To be sure, the current level of natural gas price volatility appears to have surpassed what Georgia Power predicted when fuel rates and the IFR levels were set. And because Georgia Power is deepening its reliance on natural gas, the most volatile and hard to predict fuel, the odds of the current IFR threshold being exceeded are indeed rising.

[43] *Id.* at page 22, lines 5–6.

But higher-than-expected price volatility is not sufficient reason to allow an increase in the IFR threshold. Raising the IFR threshold from $200 million to $300 million essentially hides significant cost increases from public view for a longer period. That undermines a primary benefit of the IFR: for the Commission and the public to obtain information about unexpected fuel costs accruing on customers' balance before it becomes a much larger surprise. Further, the IFR notification period alerts the Commission and customers of fuel volatility and to the fact that Georgia Power is carrying an unexpected fuel balance, which is compounded by carrying costs, which are also passed to customers. This information allows the Commission to consider corrective action.

I recommend keeping the current level even if the $200 million level results in more frequent reporting of the data.

Q: DO YOU HAVE ANY ADDITIONAL OBSERVATIONS ABOUT THE IFR?

A: Yes. If the IFR is triggered, GPC may adjust customer fuel rates by a certain percentage above the rate approved in the fuel cost proceeding. Before FCR-26, GPC could adjust rates by up to 15% above the approved rate if the IFR were triggered.[44] In the FCR-26 order, the Commission updated that percentage to 40%.[45] 40% is extremely high relative to the rate of inflation and further encourages the use of price volatile fuels. I recommend that percentage should be lowered back to 15%.

Q: THE COMPANY IS NOT PROPOSING A SPECIFIC DATE FOR ITS NEXT FUEL CASE. DO YOU AGREE WITH THIS APPROACH?

[44] FCR-26, Direct Testimony of Sarah P. Adams and Adam D. Houston, page 21, lines 18–19 (Feb. 28, 2023).

[45] FCR-26, Order Adopting Stipulation, Dkt. No. 44902, at 4 (May 25, 2023).

A: No. Given GPC's rising fuel costs and increased exposure to the most price-volatile of fuels, the fuel cases are more important than ever. The Company highlights this growing issue and risk when it states that its "recommended change to the IFR mechanism will also enable the Company and the Commission to respond in a more timely and effective manner to fuel price volatility, thereby further mitigating the need to establish a fixed date for the next fuel case at this time."[46] The Commission should question the logic and prudence of how increasing the IFR threshold and thereby lowering the frequency of the fuel case—the one regularly occurring docket that provides oversight and transparency for the over $3 billion dollars of annual fuel costs—better addresses the rising risks identified by the Company than simply scheduling another fuel case. I recommend the Commission ask the Company to set a fuel case date just as it has done in the past.

Q: HAVE YOU IDENTIFIED ANY OTHER OPPORTUNTIES TO INCREASE TRANSPARENCY IN CUSTOMERS' FUEL COSTS?

A: Yes. All parties, including consumers, should understand fuel costs represent a very large portion of the total bill. As such, the fuel cost is a stand-alone item worthy of disclosure. Customer bills do not currently display this information, so most customers are likely unaware of the size of fuel costs and the extent of fuel price volatility over time. I therefore recommend that the Commission order GPC to provide a fuel cost line item on all customer bills.

SECTION VI. CONCLUSIONS

Q: WHAT ARE YOUR RECOMMENDATIONS FOR THE COMMISSION?

[46] FCR-27 Houston & Berrigan Testimony, at page 25, lines 15–18.

A: I recommend that the Commission:

- Deny the Company's request to increase the IFR limit, so the Commission and public can better monitor fuel cost changes in a timely manner;
- Set a date for when GPC must propose its next Fuel Cost Rider hearing;
- Reduce the maximum amount by which fuel rates can be adjusted during an FCR cycle (i.e., the period between fuel cases) from 40% above or below the approved FCR-27 rates to 15%; and
- Order GPC to add a fuel cost line item on monthly bills to all customers.

Q: ARE THERE OTHER RESOURCES OR PERSPECTIVES WHICH MAY BE HELPFUL FOR THE COMMISSION?

A: Yes. There has been information and testimony given to the Commission in the prior FCR-26 hearing which may add to the understanding of the issues being addressed in FCR-27. Witnesses Jeremy Kalin and Brent Alderfer both address relevant fuel cost topics applicable to the current FCR-27:

- The misaligned interest of having 100% of the fuel cost paid by a party which does not possess the information or ability to impact the cost.
- The structural and persistent price volatility of natural gas should be expected.
- Other states have started to address fuel cost price shocks and annual increases beyond forecasts.

Their testimonies are attached as Exhibits AL-2 and AL-3, respectively.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	**Docket No. 56765**
Fuel Cost Recovery (FCR-27)	)	

EXHIBIT AL-1

ALBERT LIN

SKILLS

- **Financial Consulting on ROE and Regulatory Policy**
- **Equity Investment and Valuation (Broker-Dealer Operations)**
- **Energy Generation Development (IGCC/CCGT)**
- **Board of Directors (Governance) of publicly traded and private companies**

SUMMARY

Finance executive and entrepreneur in capital markets focused on consulting to the energy industry in recent years. Providing perspective and analysis of impacts of energy policy when new technology and practices are present constitute most consulting engagements.

EXPERIENCEHIGHLIGHTS

Consultant | Gizmo Global | 2015-Present

Financial Consulting focused on the energy industry with emphasis on the electricity system of the USA. Acted in capacity of executive, manager, and consultant to The Finance Lab as well as other electricity dense users such as data centers

Energy Policy Analysis | OG Finance Lab | 2020-Present

Directing the OG Finance Lab to assist energy policy stakeholders on financial incentives and implications. Providing key features of legislation governing fuel clause adjustment (CO Bill 2022/2023) and analyzing the impact of ROE rate setting for regulated utilities in the United States

CEO and Chairperson of the Board | EmberClear | 2008-2015

Electricity Generation Asset Developer. Permitted, developed, sold IGCC and CCGT power plants to PE Funds and Large International Power Plant Operators ranging in sizes from 330 – 450 Megawatts

alin@soonercap.com **(415) 409-9150**

https://www.linkedin.com/in/linalbert/

Managing Director | AmTech| 2002-2007

Co-Founder for a Technology Focused broker dealer. Acted as Director of Research for 24 equity analysts. Sold to a publicly traded competitor after annual revenue per employee exceeded $1MM in 2007

Equities Analyst | Various| 1992-2002

Sell-side equities analyst in wireless communications for SG Cowen & Co, Soundview Financial, and Rauscher Pierce.

Buy-side technology portfolio manager for

The Abernathy Group, Meerkat Capital, and Ivory Capital. Managed portfolio of high growth technology equities in a long-short strategy.

Finance Manager | Verizon| 1989-1992

Various finance and audit positions at regulated telecommunications company General Telephone & Electric which became Verizon Communications. Prepared financial analysis used for regulatory and shareholder meetings

EDUCATION & OTHER

University of Texas @ Austin (1989)

BS: Finance

BA: International Business

Honors Masters Business Degree

Guest Lecturer at Boston College Graduate School of Business 2020-2023 "Blockchain & Crypto Currencies"

FINRA Series 7,24,63,65 (licenses granted, but no longer sponsored)

Electricity Industry Details

Regulatory Engagements:

Public Service Commission of South Carolina Duke Energy Carolinas, LLC General Rate Case Docket 2025-172-E (December 2025)

Public Service Commission of South Carolina Duke Energy Progress, LLC General Rate Case Docket 2025-154-E (November 2025)

North Carolina Utilities Commission Duke Energy Progress, LLC Fuel and Fuel-Related Charge Adjustments Docket E-7 Sub 1358 (November 2025)

Virginia State Corporation Commission Virginia Electric & Power Company Fuel Factor Hearing PUR 2025-00059 (July 2025)

North Carolina Utilities Commission Duke Energy Carolinas, LLC Fuel and Fuel-Related Charge Adjustments Docket E-7 Sub 1313 (June 2025)

Montana Public Services Commission educational ROE discussions and analysis of Northwestern Energy General Rate Case (2024.05.053) and Montana-Dakota Utilities General Rate Case (2024.04.061) with Northern Plains Resource Council (Jan 2025)

PacifiCorp Rocky Mountain Power General Rate Case ROE expert witness in Utah for Western Resource Advocates (Dec 2024)

ROE workshop for RE-AMP serving Midwest USA (Aug 2024)

Dominion Energy South Carolina General Rate Case (24-035-04) ROE expert witness in South Carolina (June 2024)

Electricity Industry Details

Regulatory Engagements (Continued):

Georgia Power Yates Certification Hearing (No. 55378) expert witness in Georgia for Sierra Club and Southern Alliance for Clean Energy (May 2024)

Testified and attended drafting sessions for Colorado SB291 to legislate fuel cost sharing for Colorado Public Utilities Commission (April 2023)

Natural gas price risk discussion with South Carolina Legislators (12 total) for Southern Alliance for Clean Energy (Feb 2023)

Ex-Parte discussion of natural gas price risk to Public Services Commission and Office of Regulatory Staff in South Carolina (Jan 2023)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	**Docket No. 56765**
Fuel Cost Recovery (FCR-27)	)	

EXHIBIT AL-2

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's	)	
2023 Fuel Cost Recovery (FCR)	)	Docket No. 44902
Application	)	

DIRECT TESTIMONY

OF

JEREMY KALIN

ON BEHALF OF SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

("SACE")

14 April 2023

Q: PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.

A: My name is Jeremy Kalin. My business address is c/o Avisen Legal, P.A., 901 Marquette Avenue South, Suite 1675, Minneapolis MN 55402.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: Sierra Club and Southern Alliance for Clean Energy ("SACE").

Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE, AND EDUCATIONAL BACKGROUND.

A: I am an advisor, consultant, attorney and shareholder at Avisen Legal., P.A. in Minneapolis, Minnesota. I am licensed to practice law in the State of Minnesota and the District of Columbia, first admitted to the Minnesota Bar in 2010. I serve as legal counsel to energy developers, investors, advocates, project hosts and state and local governments across the United States in my areas of expertise. I also serve as consultant and advisor in a number of capacities and organizations, including the Pearl Street Station Finance Lab; to the non-partisan nonprofit energy thought leadership organization RMI, the bipartisan National Caucus of Environmental Legislators, and the Novogradac Renewable Energy Tax Credit Working Group. I have attached a copy of my CV to my testimony (JK-Exhibit 1). I am an author of the recent paper published by Pearl Street Station Finance Lab, "Learning To Share: A Primer On Fuel-Cost Pass-Through Reform" which I have provided as an Exhibit to this testimony (JK-Exhibit 2).

I was elected to the Minnesota House of Representatives for two terms, where I served on the Energy Policy and Finance Committee, authoring numerous energy bills that became law including the Demand Efficiency Act, the Next Generation Energy Act, the Public Building Enhanced Energy Efficiency Program and the Commercial Property Assessed Clean Energy Act. Building on my research while a law student, I also authored the 2010 Ratepayer Protection Act calling for Commission action to better align utility financial incentives with macroeconomic factors and public policy goals at the state and federal level; while that bill did not become law, it was one of earlier calls across the country to modernize electric utility incentive structures, including the calls to update the Fuel Cost Recovery mechanism in Georgia and in dozens of other states.

From 2010 to 2017, I was CEO of Eutectics Consulting LLC, a mission-driven company focused on financing energy projects in underserved and untapped markets. Among other projects, in 2013, I led my company's work updating the nationally-recognized Energy Assurance Plan for the State of Minnesota. While in public office, I served as state legislative liaison for the White House climate and clean energy policy team, and later advised the U.S. Department of Energy Jobs Strategy Council under Democratic and Republican Secretaries.

My undergraduate degree is from the University of Minnesota. I pursued graduate studies in the University of New Mexico School of Architecture and Planning for two years and have a Juris Doctorate from William Mitchell College of Law in St. Paul, Minnesota. Like so many lawyers and former elected officials, my undergraduate degree is a Bachelor of Fine Arts in ceramics, and I spent several years as a working potter and teacher.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA COMMISSION?

A: No. This is my first time testifying before the Georgia Public Service Commission.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: In my testimony, I provide the following:

1. An overview of the relevant history of fuel-cost pass-through policies in place across the United States, including Georgia's Fuel Cost Recovery mechanism, to provide context for Georgia Power's FCR-25 and FCR-26 rate increases;

2. A specific discussion of the "moral hazard" presented by Georgia's Fuel Cost Recovery mechanism, and why the Georgia Power request poses a significant threat to Georgia ratepayers' economic wellbeing;

3. Factors the Commission should consider in evaluating whether Georgia Power's significant rate increases are prudent and justifiable, given Georgia Power's implied admission that the utility has not taken any meaningful steps to reduce ratepayers' exposure to Georgia Power's fuel costs;

4. The potential negative impact on reliability of continuing the current Fuel Cost Recovery mechanism, including an overreliance on natural gas as an electric generation source, wherein 100% of fuel costs are passed through to ratepayers, as proposed by Georgia Power in this docket;
5. A brief discussion of Georgia Power's proposal to essentially eliminate the need for future Fuel Cost Recovery dockets by increasing the Interim Fuel Rider cap to 40%.
6. A brief response to the proposed April 12, 2023 Stipulation between Georgia Power and the Georgia Public Service Commission Public Interest Advocacy Staff.
7. A recommendation to the Commission to establish a specific docket to more deeply evaluate the benefits of requiring some amount of risk and cost-sharing by Georgia Power in managing its fuel supply, including the benefits to ratepayers; to overall system reliability; to emissions and to national security. A modernized Fuel Cost Recovery mechanism could allow Georgia Power to secure earnings for its shareholders, while better protecting its customers from fuel price spikes and fuel price volatility.

Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A: I have reviewed Georgia Power's Direct Testimony; other Georgia Power filings as part of the docket; many of the Minimum Filing Requirement documents, and Georgia's Fuel Cost Recovery statute, O.C.G.A. 46-2-26. I have briefly reviewed other relevant sections of O.C.G.A. 46-2-20 through 46-2-33, as well as Department 515 Rules of Georgia, Public Service Commission. Further, I have reviewed the April 12, 2023 Stipulation between Georgia Power and Georgia Public Service Commission Public Interest Advocacy Staff as a proposed resolution to the Company's request in this docket, as well as the proposed revised Interim Fuel Rider provision attached to the Stipulation as Attachment A.

I have also briefly reviewed previous Fuel Cost Recovery dockets and other Commission materials to which I refer in this testimony. All of the material I reviewed is public data; I did not receive any trade secret or otherwise confidential information.

Q: PLEASE SUMMARIZE YOUR TESTIMONY

A: In my testimony I provide the following:

- In the matter of the FCR-25 tariff under-recovered fuel balance, the Commission should rigorously review the prudency of Georgia Power's actions. While Georgia Power could not have predicted the specific events that contributed to the under-recovered fuel balance, multiple experts warned of the risks of excessive reliance on natural gas and the ongoing price volatility of natural gas even without winter storm Uri and Russia's invasion of Ukraine. Georgia Power could have taken any number of prudent steps to minimize its exposure to natural gas price volatility.
- The Commission should not approve the forward-looking FCR-26 fuel rate adjustment. The Commission should instead initiate a Fuel Cost Recovery modernization docket to include some amount of fuel-cost-sharing and fuel-risk-sharing by the utility, to mitigate the moral hazard under the current policy of passing through 100% of fuel costs to ratepayers. The Commission has the authority under the Fuel Cost Recovery statute -- because of Georgia Power's failure to take sufficient prudent steps -- to make amendments that would better allocate risk and costs between utilities and ratepayers. A modernization docket is the best means to evaluate all the policy options, relevant factors and potential impacts.
- Georgia Power's proposal to increase the Interim Fuel Rider maximum adjustment to 40% without Commission review risks violating the Commission's statutory responsibility to conduct a prudency review of Georgia Power's fuel costs. The Commission should reject this proposal.
- Georgia Power's proposals also risk the utility's strong prior record on reliability. Addressing Fuel Cost Recovery tariffs without considering the impact of other ratemaking dockets has led to unintended consequences, including an outsized reliability on natural gas. Other non-fuel alternatives could have mitigated the multi-billion-dollar impact to ratepayers.

I. HISTORY OF FUEL COST RECOVERY POLICIES

Q: WHAT IS THE HISTORY OF FUEL PASS THROUGH CLAUSES, INCLUDING GEORGIA'S FUEL COST RECOVERY MECHANISM?

A: During most of the first 100 years of the electric power industry, fuel costs were the complete responsibility of utilities.

The Chicago Gas Trust was incorporated in 1887 with an authorized $25,000,000 in capital shares, and soon acquired controlling interests in the four gas companies operating in Chicago for just $300,000. Immediately after the merger, gas prices rose 25%, which the Chicago Tribune blasted as "gas extortion." While it took 20 more years for states to adopt the first Public Utility Commissions, the outcry over the Chicago Gas Trust consolidation helped cement the public's interest in affordable, stable and reliable utility service, overseen by a utility commission. [1]

Ultimately, the National Electric Light Association (NELA) argued in 1907 for what we know today as the electric utility regulatory compact. Sustainable business models for electric utilities in 1907 depended on access to capital to expand utility service and accepting state regulation with public oversight of capital investments would provide stable access to capital. NELA's Subcommittee on Public Regulation and Control wrote, "[I]t should be impressed upon the officials controlling public-utility corporations that the public will is that these companies shall exist, not primarily to make dividends upon certain investments of capital, but as the most efficient means of supplying the public's needs."[2]In the interest of consumer protection and incentivizing efficient production of electricity, the newly created public utility commissions included fuel costs as just one of the utility's many costs of doing business. These "inputs" were not a unique cost category requiring special ratemaking treatment.

[1] Harold Platt, The Electric City: Energy and the Growth of the Chicago Area, 1880-1930 (University of Chicago Press 1991) provides a good history of the early days of market development, competition, consolidation and predatory behavior that led to the National Electric Light Association's call for regulation in exchange for a guaranteed utility service territory, the foundation of the electrical regulatory compact we know today, including in Georgia.

[2] National Electric Light Association, Proceedings 1907, p 649.

When World War I disrupted oil, coal, and gas supply globally and in the United States, causing fuel prices to soar, utilities lobbied commissions for relief from fuel-price volatility and the associated risk of significant financial loss. Public utility commissions responded by implementing the first temporary fuel-pass-through policies, and then discontinued the practice shortly after World War I's end.

World War II again disrupted global oil, coal and gas supply across the world, and again public utility commissions responded. The fuel pass-through-policy protected utilities from the severe supply challenges and price volatility. With domestic purchasing constrained by rationing and a national call for energy conservation, increased electricity bills – including the new fuel pass through costs - were likely understood as a citizen's contribution to the war effort. When peacetime returned to the United States, commissions again reverted to the prior policy, and for nearly 30 years, utilities were responsible for 100% of the fuel costs for power generation.[3]

The oil shocks of the 1970s sparked new utility demands to be insulated from global geopolitics and supply constraints. This time, state legislators joined utility commissions in adopting fuel pass through policies, ultimately enacting statutes such as Georgia's Fuel Cost Recovery Statute, O.C.G.A. 46-2-26, adopted by the Georgia Legislature in 1979.

The gasoline lines have disappeared, and the United States is substantially more energy secure than it was during the first days of OPEC. But while the wide lapels and bad disco dancing of the 1970s have been relegated to the history pages, the 100% pass-through-policies of fuel costs are still the law of the land in Georgia and nearly all other states.[4]

[3] Electric Consumers Resource Council, "Fuel Adjustment Clauses and other Cost Trackers," https://elcon.org/fuel-adjustment-clauses-cost-trackers/, accessed April 10, 2023.

[4] S&P Global Market Intelligence, *RRA Regulatory Focus: Adjustment Clauses, a state by state overview* 2 (2017), https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf.

Q: HOW IS THIS HISTORY RELEVANT TO THIS DOCKET AND GEORGIA POWER'S REQUEST TO RECOVER UNDER-COLLECTED COSTS UNDER FCR-25 RATES AND TO INCREASE RATES IN THE FCR-26 TARIFF GOING FORWARD?

A: While the Fuel Cost Recovery has been in statute for 44 years, it is important to remember that utilities have been responsible for managing fuel costs and fuel price risks for most of the 116 years of utility regulation in the United States. The Fuel Cost Recovery pass-through policy is not a required element of the regulatory compact but is instead a regulatory creation.

The following two charts show the correlation between: (1) increased consumption of natural gas for power generation in Georgia, as shown in Chart 1, from 2008 to 2023, and (2) increased per-kilowatt-hour (per-kWh) retail rates for all ratepayers in Georgia, as show in Chart 2, from 2000 to 2023.

Chart 1

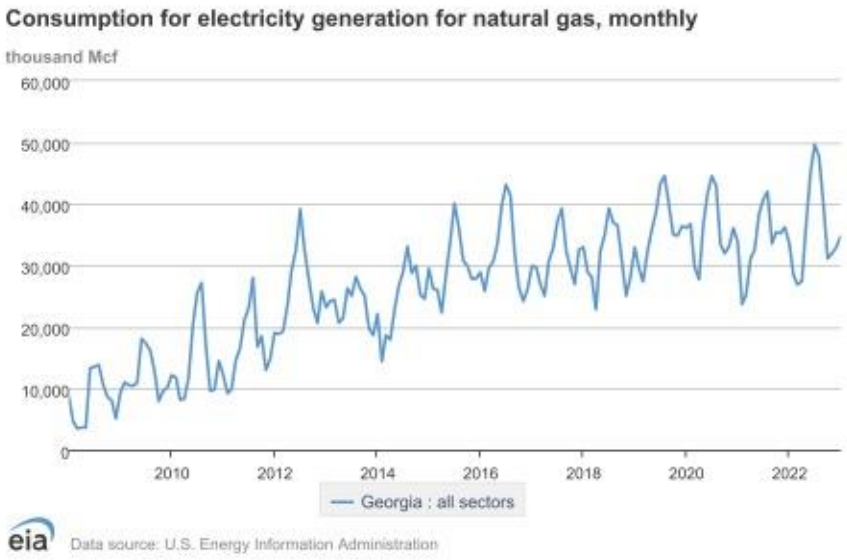
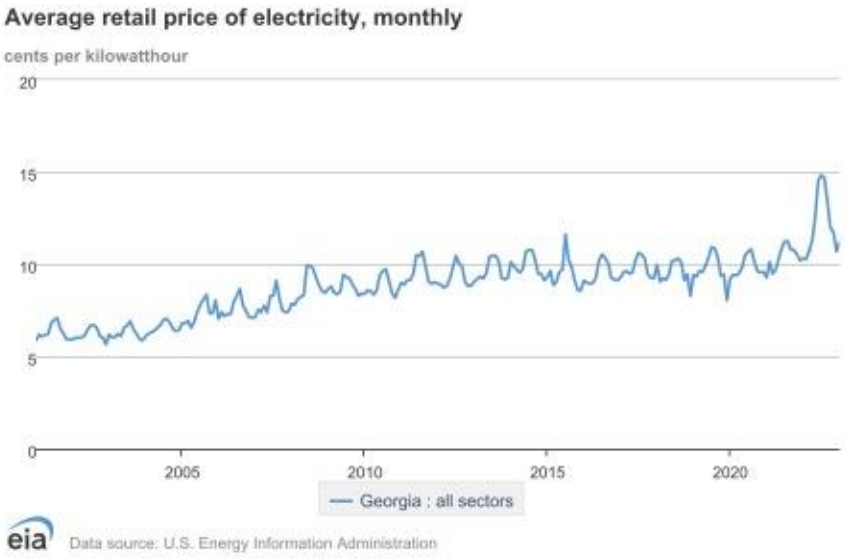


Chart 2



During this period, utilities have borne 0% of responsibility for fuel costs and managing fuel risk in Georgia and have passed 100% of both fuel costs and fuel risks to ratepayers.

II. FUEL COST RECOVERY'S MORAL HAZARD

Q: WHAT IS A "MORAL HAZARD?"

A: In general terms, a moral hazard occurs when one party is incentivized to take more risk than they normally would because that party is insulated against that risk.[5] In other words, a moral hazard exists when the consequences of a decision are so disconnected from the decisionmaker that that party takes a bigger risk as a result.

Q: HOW IS THE MORAL HAZARD EMBODIED IN GEORGIA'S FUEL COST RECOVERY STATUTE, O.C.G.A. 46-2-26?

A: Georgia's Fuel Cost Recovery statute permits Commission-regulated utilities to charge its ratepayers a rate sufficient to recover the cost of fuel, through a proposed formula based on "an estimate of

[5] *See generally* Mark Thoma, *Explainer: What is Moral Hazard*, CBS News (Nov. 22, 2013), https://www.cbsnews.com/news/explainer-moral-hazard/.

[the utility's] fuel costs and retail sales for the next three conservative months and proposed base rates to recover those costs" (paragraph c) and an amendment which "shall include an adjustment based on actual expense to date in order that the accumulated retail costs of the utility shall equal, as nearly as possible, the revenues recovered pursuant to the fuel recovery allowance…" (paragraph g).

While the statute does not require the utility to collect **all** of its fuel costs from ratepayers, O.C.G.A. 46-2-26 does permit the utility to set fuel recovery rates that pass along 100% of the fuel costs to ratepayers.[6] Georgia's fuel pass through policy is consistent with the pass-through statutes and Commission rules in nearly every other state. Like so often happens in policymaking, the 1970's energy crisis merited a response of some sort to address the global volatility at the time, not just in thermoelectric generation fuel procurement but across the oil, gas and coal industries. The trade-offs of the 1970s and early 1980s – exchanging consumer exposure to fuel costs in exchange for complete insulation of utility risk – may have made sense then. Though I understand some consumer advocates cited the potential moral hazard at the time, the 44-year history of the Georgia's Fuel Cost Recovery – and this current request from Georgia Power – shine a harsh light on the perils of continuing this policy of 100% pass-through to ratepayers, and 0% responsibility for the costs and risks by shareholders.

Q: DO YOU READ THE STATUTE TO REQUIRE THE COMMISSION TO IMPLEMENT FUEL COST RECOVERY IN A MANNER THAT EXACERBATES THE MORAL HAZARD?

A: No, I do not.

I have seen enough similar fuel-cost pass-through statutes to support my belief that O.C.G.A. 46-2-26 provides enough flexibility for the Commission to adjust the risk- and cost-sharing ratios of the Fuel Cost Recovery mechanism in Georgia.

In O.C.G.A. 46-2-26(c), the statute requires the utility to propose "base rate tariffs to recover those (fuel) costs." The statute does not require the utility to propose a rate tariff to recover **all** of its fuel costs. I have read several sections of related Georgia statute and Commission rules, and have not yet seen any

[6] Georgia Public Service Commission background on Fuel Cost Recovery, undated, http://www.psc.state.ga.us/electric/regulation/Fuel_Cost_Recovery.pdf, accessed April 10, 2023.

requirement that the Commission must approve a utility's fuel rate tariff such that the utility recovers 100% of its fuel costs – only that the Commission may approve such a tariff.

I see several areas where the Commission may establish a fuel rate tariff requiring the utility to accept some amount of responsibility for fuel costs and fuel risks. In particular, 46-2-26(e) requires the Commission to "issue an order stating the base rates to be used by the utility" going forward. This language suggests that the Commission has wide latitude, consistent with other sections of the Georgia Code and under Commission rules and policies, to modify the proposed fuel tariff, as the Commission has done specifically in prior Fuel Cost Recovery (FCR) dockets. For instance, in docket 19142-U, decided May 17, 2005, the Commission reduced the FCR tariff proposed by Georgia Power, recognizing excess costs due to replacement energy expenses during unscheduled outages, and in docket 11884-U, decided March 30, 2000, the Commission made multiple changes to the proposed FCR tariff, in consideration of other pending rate-related matters by the filing utility, Savannah Electric and Power Company. In multiple Fuel Cost Recovery tariff dockets, the Commission has reduced the proposed FCR tariff by requiring extended amortization periods, including in dockets 19142-U and 21229-U, presumably during periods of lesser natural gas price volatility than these past three years.

Q: DID YOU REVIEW THE DIRECT TESTIMONY OF MS. SARAH ADAMS AND MR. HOUSTON ON BEHALF OF GEORGIA POWER?

A: Yes.

Q: WHERE IN THE UTILITY'S TESTIMONY AND MINIMUM FILING REQUIREMENT DOCUMENTS DO YOU SEE THIS MORAL HAZARD IMPACTING GEORGIA POWER RATEPAYERS?

A: Georgia Power's own supporting documents show a 78.4% increase from the current FCR-25 IFR-4 rates to the proposed FCR-26 rates, and an 87.4% summer rate increase.[7]

[7] MFRP-1C.

I am hard pressed to find any better example of how ratepayers are bearing the cost of this moral hazard. It is not an academic question for many families, particularly those living on tight budgets. As a business owner, I also know the stress that such severe rate increases have on businesses doing everything they can to control costs and remain competitive in a global business environment.

Q: HOW WOULD YOU DESCRIBE THE SCALE OF GEORGIA POWER'S FUEL COST RECOVERY RATE INCREASE PROPOSALS?

A: Georgia Power's proposed rate increase is shocking, and the numbers speak for themselves.

I also believe that the Company may be muddying the waters as to the full scope of the Fuel Cost Recovery impact on ratepayers. Georgia Power has proposed amortizing the under-recovered fuel balance over 36 months rather than 24 months. It is unclear, if the FCR would be higher -- a 117.6% increase rather than the stated 78.4% increase -- if the shorter amortization period were applied. If so, "shocking" would no longer properly capture the scale of this rate increase.

In addition to the massive impact on individuals with limited means, the utility's proposed Fuel Cost Recovery rate increase has implications for broader regional competitiveness. Georgia businesses are no different from others across the country, facing significant challenges in attracting and retaining qualified employees. While the state of Georgia certainly has much to offer in terms of quality of life, the cost of living is a significant factor when workers decide where to make their home, and where to ply their trades – including the cost of rent and home ownership, as well as the cost of energy during hot Georgia summers.

I understand that Georgia Power's per-kilowatt rates are just below the national average, overall. However, when it comes to overall electric bills, Georgia ratepayers pay the 8th highest average monthly electric bills in the country. Only South Carolinians pay a higher average monthly electric bill in the region.[8] Georgia Power's Fuel Cost Recovery rate increase request is substantially higher than the impact of Duke Energy Carolina's pending fuel cost pass through rate increase request in South Carolina, by approximately

[8] EIA 2021 Average Monthly Bill – Residential.

$1.24 to $7.24 per month more.[9] Depending on the final amortization period selected, Georgia Power's Fuel Cost Recovery rate request would likely make Georgians' electric bills the highest in the Southeast.

III. FACTORS FOR "PRUDENT" REVIEW BY THE COMMISSION

Q: COMPARING GEORGIA POWER'S REQUEST WITH OTHER FUEL COST RECOVERY REQUESTS NATIONALLY, DO YOU SEE SOME POSITIVES?

A: Yes, very much so.

First, the best measurement of the efficiency of fuel costs to electric output is the ratio of fuel dollars spent for each Megawatt hour (MWh). Consistent with the stated challenges of the Company's request, Georgia Power states that the dollar per megawatt hour ($/MWh) fuel cost for coal, natural gas and nuclear generation resources, and the costs of purchased power, are projected to increase 97%, 92%, 17% and 28% respectively. While I believe the utility could have prudently mitigated these increases through procurement of non-fuel technologies such as solar and energy storage, I am very pleased to see the utility use the $/MWh metric for measuring economic efficiency.[10]

Second, Georgia Power recognizes that generation from renewable resources lowers the utility's overall cost of fuel.[11] It may be self-evident, but worth stating explicitly, that the use of non-fuel generation technologies adds MWhs to the utility's generation mix without any fuel costs that need to be first paid by the utility and then passed along to ratepayers. With the Inflation Reduction Act's increased tax credits for many non-fuel generation options, including solar, energy storage, wind and clean hydrogen, among others, these non-fuel resources will continue to be even more cost-competitive and even cost-advantageous to the utility's ratepayers. While ratemaking should never be conducted in a vacuum or from a single-issue perspective, the advantages of $0 fuel costs for such resources warrant diversifying the utility's generation mix.

[9] Docket 2022-3-E, South Carolina.
[10] Direct Testimony of Ms. Adams and Mr. Houston on behalf of Georgia Power Company, Docket No. 44902, p. 15.
[11] Ibid.

Third, Georgia Power recognizes that the Commission has substantial flexibility under the Fuel Cost Recovery statute, O.C.G.A. 46-2-26, to modify the specific mechanisms of Fuel Cost Recovery and the specific amounts that the utility can collect. I disagree with Georgia Power's proposal to authorize the utility to effectively remove the need for Fuel Cost Recovery dockets. But I do agree with Georgia Power that the Commission has sufficient latitude and authority to protect ratepayers by reforming the Fuel Cost Recovery itself.

Q: ARE THERE ELEMENTS OF GEORGIA POWER'S REQUEST THAT REQUIRE FURTHER CLARIFICATION?

A: Yes.

The Company's Direct Testimony includes in its list of other "primary drivers" to the increased fuel costs "energy purchased from a variety of renewable resources such as solar, wind, and biomass."[12] While biomass may have input costs, solar and wind generation technologies do not include fuel costs.

Further, the Company states that the FCR-26 upward rate adjustment will increase a typical residential customer's bills approximately $17 to $23. I believe that this $204 to $276 annual cost to a typical Georgia Power residential customer is understated by a factor of 50%, as the utility has proposed extending the recovery period out from the conventional two years to a total of three years. The Commission would be wise to secure utility clarification on this cost impact where the under-recovered balance from FCR-25 rates amortized over just the two years.

Q: IS THE COMMISSION REQUIRED TO ACCEPT GEORGIA POWER'S POSITION THAT THE UTILITY COLLECT ALL OF ITS FUEL COSTS?

A: No. Georgia's Fuel Cost Recovery statute states that the utility bears the burden of proof to show that the costs are prudent, as previously discussed. Ken Costello stated it best when he described these utility cost recovery claims:

[12] Direct Testimony, p. 17.

Utilities sometimes convey the false assertion that they have a right to recover any costs they incurred, even before the regulator has assessed their reasonableness. Their position seems to be that "we expend money to satisfy mandates or serve our customers, so regulators should allow us recovery of this money in rates with little scrutiny." It presumes that regulators should trust that utilities will always act in the public interest. Good regulation would question the prudence and legitimacy of any costs; it owes that much to utility customers.[13]

Q: IN REVIEWING GEORGIA POWER'S FUEL COST RECOVERY RATE REQUEST, WHAT STANDARD SHOULD THE COMMISSION APPLY?

A: The Fuel Cost Recovery statute states that the Commission shall "make appropriate adjustment for any reported fuel cost that is the result of illegal or **clearly imprudent conduct** on the part of the utility" (emphasis added).

Q: DID YOU SEE EVIDENCE THAT GEORGIA POWER HAS TAKEN PRUDENT STEPS TO REDUCE THE UTILITY'S FUEL COSTS DURING THE FCR-25 RATE PERIOD?

A: I do not see much evidence that the Company has taken sufficient prudent steps to protect ratepayers during the prior FCR-25 rate period.

Q: PLEASE EXPLAIN.

A: Sometimes, common sense can be as useful as precedent. Merriam-Webster defines the term "imprudent" as "lacking discretion, wisdom, or good judgment." Collins defines the term as "without thought of consequences; lacking in judgment or caution; rash; indiscreet."

As recently as last year, Georgia Power was warned that a continued reliance on highly volatile natural gas pricing, combined with the elevated coal market pricing and high volatility, would lead to this exact scenario of excessive fuel costs.[14] In the midst of the worst effects of the Russian invasion of Ukraine and global concerns about inflation dominating the news every day, Georgia Power submitted and

[13] Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives," National Regulatory Research Institute, April 2014, p. 23.
[14] Post-hearing brief of Southern Alliance for Clean Energy (SACE) and Southface Energy Institute (Southface), dockets 44160 and 44161, July 7, 2022, pp. 17-18.

advocated for the Company's triennial Integrated Resource Plan (IRP) and a Stipulation between the Company and the PSC Public Interest Advocacy Staff to procure Power Purchase Agreements from six natural gas plants.

On October 12, 2021, the Company had already recognized the substantial under-recovered fuel balance in the wake of winter storm Uri's natural gas price spikes in Georgia and nationally and filed the Interim Fuel Rider Notification and Plan with the Commission, increasing the FCR-25 Fuel Cost Recovery rates by the maximum 15%. As the Company testified in this current docket, "despite implementing the maximum allowed 15% increase… (which took effect in January 2022), the Company's [] under-recovered fuel balance increased dramatically in 2022."[15]

Yet, even as the Company was monitoring this "dramatic" increase in natural gas costs, Georgia Power persisted with their pursuit of even more costly and risky natural gas resources in the IRP and DSM Stipulation of 2022. Intervenors Southern Alliance for Clean Energy and Southface Energy Institute specifically recommended that Georgia Power not proceed with such plans, and that the Commission consider an order "setting an upper limit on the recovery of fuel costs for (the) PPAs to adequately protect ratepayers from market volatility and unprecedented price spikes."[16] In his Direct Testimony in these IRP and DSM Stipulation 2022 dockets, witness Ron Binz, former Chair of the Colorado Public Utility Commission, repeatedly highlighted the risks associated with natural gas spikes.[17]

Q: DID YOU SEE ANY EVIDENCE THAT GEORGIA POWER PLANS TO TAKE SUFFICIENT PRUDENT STEPS TO REDUCE THE UTILITY'S FUEL COSTS GOING FORWARD, AS PROPOSED BY THE INCREASED FCR-26 RATE?

A: No, at least not enough evidence that the Company is prudently trying to reduce its fuel costs looking forward.

Q: PLEASE EXPLAIN.

[15] Direct Testimony, p. 13
[16] Post-hearing brief of SACE and Southface, dockets 44160 and 44161, p. 18.
[17] Ibid.

A: In discussing steps the Company is taking to mitigate the impact of FCR-26 rates on its customers, Ms. Adams and Mr. Houston point to only one Company action to reduce the actual fuel costs for Georgia Power operations;[18] this additional procurement of fuel-free solar generation resources amounts to only 0.006%[19] of the total GWH's projected total power generation according to the Company's own filings in their Direct Testimony.[20]

When specifically describing the Company's efforts to mitigate the impact of fuel costs on ratepayers, Georgia Power boasts of implementing the maximum Interim Fuel Rider (IFR) increase on ratepayers of approximately 15% effective January 1, 2022.[21] Implementing an IFR increase is not actually a cost mitigation method, but instead is a risk mitigation method for the utility, at the literal expense of ratepayers. Rather than reducing actual fuel costs paid by the Company to generate electricity at coal- and natural-gas-fired power plants, increasing the IFR merely passes along the utility's increased fuel costs to its customers. The utility is thus allowed to collect more via the higher FCR tariff, effectively providing a further disincentive to the utility to aggressively reduce the fuel costs themselves. The IFR mechanism worsens the moral hazard, rather than mitigates it.

Further, the utility cites as a positive cost-mitigation method its proposed amortization of the $2.6 billion under-recovered fuel balance under FCR-25 over 36 months instead of the more conventional 24 months. Again, this is not actually a fuel cost mitigation measure. Instead, Georgia Power is effectively double-charging customers by increasing the forward-looking FCR-26 rates starting June 1, 2023, and adding on top of it the 36 months of amortized costs for prior fuel costs. This proposal is akin to a family charging its monthly grocery bills on the credit card, and spending the next three months paying off that month's grocery bills. That same family will need to buy groceries each subsequent month, but will be

[18] Direct Testimony, p. 9 and p. 15.
[19] 1,150 GWh of the total 184,589 GWh projected on Table 2 of the Direct Testimony of Ms. Adams and Mr. Houston, p. 16.
[20] Ibid, p. 16.
[21] Ibid, p. 14.

paying principal and interest on the prior three month's groceries, making it harder and harder to make the family budget balance.

In Georgia Power's case, they are proposing a similar painful negative-feedback-loop of increased costs, with very minimal stated efforts to reduce actual fuel costs. And the impact on a typical residential customer in Georgia is profound. Over each of the three years of FCR-25 under-recovered collections, that typical residential customer will pay between $204 and $276 more on their Georgia Power bills.[22] If the Commission instead uses the conventional 24-month amortization period for the FCR under-recovered fuel cost collection, I infer that the typical residential customer will pay 50% more than stated in the three year test case, between $306 and $414 more each year – a shocking impact, made even more difficult to accept given Georgia Power's *de minimis* steps to mitigate and reduce the actual fuel costs during the period.

Ironically, it may be in ratepayers' interests for the Commission to approve Georgia Power's proposal to spread out this painful impact for ratepayers across multiple years. But it is imperative that the Commission take additional steps to prevent increased pain through the higher forward-looking FCR-26 rate, and to take a proactive look at modernizing the Fuel Cost Recovery mechanism itself.

Q: COMPARED TO OTHER UTILITIES, HOW DO YOU VIEW GEORGIA POWER'S ACTIONS TO PROTECT RATEPAYERS FROM NATURAL GAS PRICE HIKES AND OVERALL NATURAL GAS PRICE VOLATILITY?

A: Over the last 30 months, advising the Pearl Street Station Finance Lab, I have participated in a broad review of fuel pass through clauses across the United States. I have also closely monitored utility actions during the COVID-19 pandemic period, starting in March 2020, and in response to multiple severe weather events such as winter storms Uri and Elliot as well as to the geopolitical chaos in Russia and Ukraine. I find Georgia Power's actions to be consistent with some of the less proactive utilities, slow to respond to the ratepayer risks and reliability impacts of overreliance on natural gas. The Company's Direct Testimony frequently mistakes accounting mechanisms for actual steps to reduce their fuel expenditures.[23]

[22] Ibid. p. 4
[23] Direct Testimony, pp. 8-9, among others.

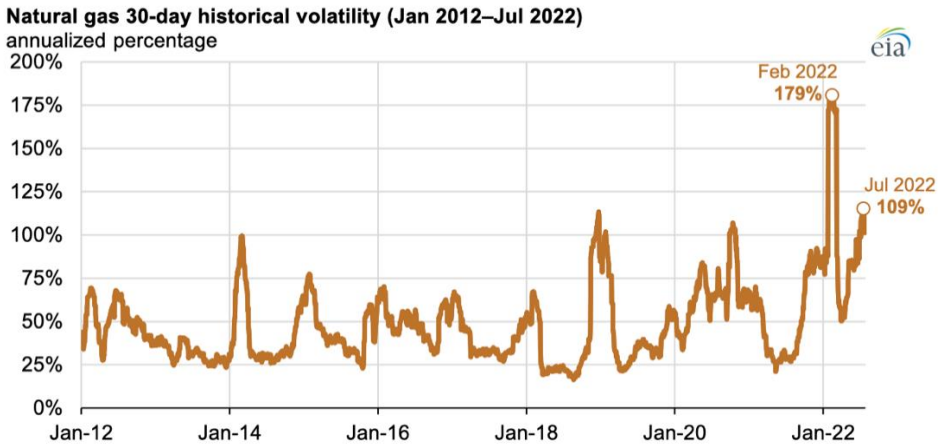
Q: WHAT IS "VOLATILITY"?

A: For commodities like gas or coal, "volatility" describes how quickly the price of a commodity changes over time. In economic and financial terms, volatility refers to the standard deviation of changes in a price variable over time. "Price volatility" does not necessarily mean that prices are increasing, or that prices are decreasing. Instead, price volatility means that prices are changing rapidly over a short period of time.

Q: CAN VOLATILITY ACTUALLY BE "UNEXPECTED?"

A: No, not anymore. Natural gas 30-day historical price volatility approached summer 2022's price volatility index at least three times during the last decade, not including the late winter 2022 volatility spike in the wake of Russia's invasion of Ukraine.

Chart 3



Q: HOW WOULD YOU CHARACTERIZE GEORGIA POWER'S DESCRIPTION OF THE DRIVERS TO THE UTILITY'S FUEL COST INCREASES?

A: I have a lot of sympathy for their circumstances. Georgia Power does not have any meaningful influence on geopolitical affairs, such as the Russian invasion of Ukraine in early 2022. Georgia Power is also not directly responsible for individual severe weather events, even as we must all recognize the impact of carbon emissions in driving a changed climate, including increased frequency and scale of severe weather events such as hurricanes and major winter storms.

Q: DO YOU AGREE THAT DEMAND AND PRICE INCREASES ARE "HIGHER THAN EXPECTED" AND "UNPRECEDENTED?"

A: Not really. I already discussed how natural gas price volatility cannot be reasonably described as "unexpected." The number and severity of significant weather events is also not "unexpected," as the effects of climate change accelerate globally, nationally, and in the Southeastern United States.

In June 2020, Investor advocacy organization Ceres released its updated report, "Addressing Climate as a Systemic Risk: a call to action for U.S. financial regulators," yet another in a series of reports detailing the quantifiable and known risks of climate-related severe events, which Ceres has released since at least 2012. In its June 2020 report, Ceres stated:

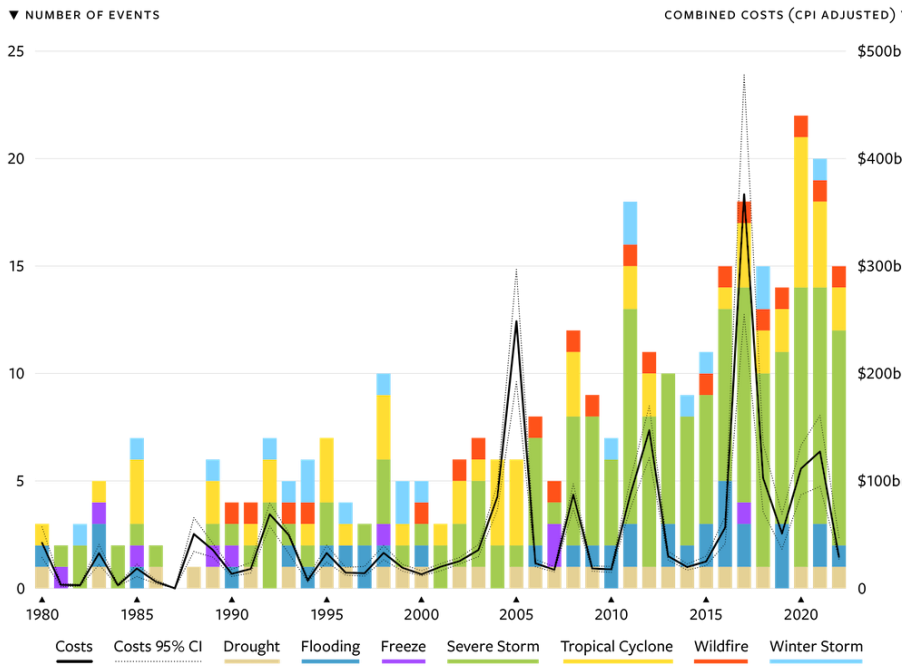
> Systemic risks have the potential to destabilize capital markets and lead to serious negative consequences for financial institutions and the broader economy. Under this definition, climate change, like the current COVID-19 crisis, is indisputably a systemic risk. Its wide-ranging physical impacts… are likely to manifest in both cumulative and unexpected ways and present clear systemic risks to U.S. financial markets -- and the broader economy. Left unmanaged, these risks could have

significant, disruptive consequences on asset valuations, global financial markets and global economic stability.[24]

The National Oceanographic Institute's National Centers for Environmental Information monitors the number and cause of CPI-adjusted billion-dollar weather and climate-related disaster events. Since 1980, the United States has sustained 348 such billion-dollar disasters, including 20 winter storms and freezes. Chart 4 shows the significant increase in the number, scale and scope of such major disaster events in the last decade.[25]

Chart 4 – Billion-dollar climate and severe-weather events by type since 1980

[24] Ceres, "Addressing Climate as a System Risk: a call to action for U.S. financial regulators", June 2020, https://www.ceres.org/resources/reports/addressing-climate-systemic-risk.
[25] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023), https://www.ncei.noaa.gov/access/billions/.



Georgia Power has repeatedly been warned of the volatility and risk of relying on fuel-based power generation, as recently as the 2022 IRP and PPA dockets. As intervenors SACE and Southface stated, by only focusing on natural gas and coal as supply options, Georgia Power left the Commission, and thus, the utility's ratepayers, "a choice between two volatile, risky fossil fuels, at the expense of innovative, cost controlled and less risky renewables projects."[26]

Q: THE COMPANY STATES THAT IT DOES NOT EARN A RETURN ON FUEL COSTS. DO YOU AGREE?

A: Georgia Power is not alone in making this statement related to fuel pass through policies such as the Fuel Cost Recovery here in Georgia. That said, these statements are misleading, and do not tell the whole story.

Like nearly every Investor-Owned Utility, it is true that Georgia Power does simply pass along all of the fuel costs to ratepayers through the Fuel Cost Recovery mechanism. However, the Fuel Cost

[26] SACE and Southface Post-hearing brief, dockets 44160 and 44161, 2022, p. 17.

Recovery policy of passing along 100% of all fuel costs to ratepayers, and requiring no assumption of risk or cost by the utility, results in an extraordinary situation of ratepayer risk and utility profit.

While Georgia Power does not make a profit or generate any return on investment for the fuel purchased, they do make a profit on the power plants that burn this fuel. In Georgia, as in most cost-of-service regulated states, Georgia Power's profit margin is calculated as a rate-of-return, multiplied by the value of the rate-based capital assets owned by the utility. When Georgia Power owns and operates a power plant, regardless of the generation technology, the utility can increase its earnings. I believe it is a general axiom of electric utility economics that earning a return on the capital rate base is the principal driver of Investor-Owned Utilities' shareholder earnings.

As a fiscally conservative former lawmaker, I have always found it useful to think about how public officials – and the general public – might view a state or local government procurement process for purchasing vehicles in its fleet. The government might have to choose between Option One and Option Two, where Option One is a lower-initial-price truck but with lower fuel economy on a mileage-per-gallon (or equivalent kWh-per-mile) basis, and Option Two is a higher-initial-price truck but with higher fuel economy. Option One will be more cost-effective initially, but would ultimately cost more in taxpayer funds over long-term operation. Option Two will be more expensive initially, but will save taxpayer funds over long-term operation. The government procurement team will then have to determine how quickly it will realize the financial benefit of Option Two, as well as whether capital expenditure fund levels are sufficient to support Option Two's higher upfront cost. Further, as public stewards of both taxpayer funds and of overall public health and other public goods, the government needs to determine whether other public goods would be served by the higher initial cost of Option Two's greater fuel economy, including fleet reliability, reduced emissions and related increased public health, and other factors. Any competitive business faces similar decisions of upfront cost and long-term operational expenses, though the private-sector intangible factors typically replace public goods for the business's brand improvement and reputational benefits.

The Fuel Cost Recovery severely distorts this budgeting and planning consideration for Georgia Power and other Investor-Owned Utilities. Building and operating natural gas plants has grown Georgia

Power's rate base, with no risk to the utility. The Fuel Cost Recovery mechanism ensures that the utility will collect all fuel costs from ratepayers, no matter the price volatility, so long as the Commission determines these costs are prudently incurred. Over the years, Georgia Power has grown its capital rate base of power plants, completely insulated from the risk of price volatility, particularly for the purchase of natural gas and coal. This moral hazard, explained above, is not just theoretical. The consequence of the moral hazard inherent in a 100% Fuel Cost Recovery mechanism within the capital-rate-based financial model is that Georgia Power is able to increase its earnings base, in spite of the narrow claim that the "Company does *not* earn a return on these fuel costs."[27]

Not only are the costs "directly passed through to customers,"[28] by taking a "single-issue" ratemaking approach through Fuel Cost Recovery dockets, the larger earnings base for the utility creates additional inflationary pressure on ratepayers.

Q: IS IT APPROPRIATE TO VIEW FUEL COST RECOVERY DOCKETS IN ISOLATION?

A: No, I do not believe it is appropriate to review these Fuel Cost Recovery dockets without understanding the interplay with other ratemaking dockets, as well as Integrated Resource Plans and specific-plant Certificate of Need applications, for the reasons cited above. I believe the Commission would be wise to consider the multiple factors and broader economic forces through a specific Fuel Cost Recovery modernization docket. The Commission may determine that the interests of fairness require the Commission to evaluate at least the FCR-25 rate recovery request under the existing Fuel Cost Recovery mechanism. However, given other active dockets and Georgia Power requests in front of the Commission, I believe the Commission would be wise to reassess the overall Fuel Cost Recovery approach in tandem with the other dockets, and to defer decisions on the forward-looking FCR-26 upward rate adjustment.

Q: TO PROTECT RATEPAYERS, DO YOU BELIEVE THE COMMISSION SHOULD APPROVE GEORGIA POWER'S FCR-25 RATE RECOVERY REQUEST?

A: No.

[27] Direct Testimony, p. 3.
[28] Ibid.

Q: TO PROTECT RATEPAYERS, DO YOU BELIEVE THE COMMISSION SHOULD APPROVE GEORGIA POWER'S FCR-26 TARIFF INCREASE?

A: No.

Q: IF THE COMMISSION DOES APPROVE GEORGIA POWER'S INCREASED RATE REQUESTS NOW, WHAT SHOULD THE COMMISSION DO TO PROTECT RATEPAYERS IN FUTURE YEARS?

A: At the very least, I believe the Commission should initiate a docket to review all of the varied policy goals and conduct a robust financial analysis of changes to the Commission's Fuel Cost Recovery process.

Q: IN YOUR REVIEW OF GEORGIA'S FUEL COST RECOVERY AND SIMILAR MECHANISMS, WILL THE CURRENT UPWARD RATE REQUEST IMPACT GEORGIA POWER'S ABILITY TO PROVIDE AFFORDABLE AND RELIABLE SERVICE?

A: Yes. Very much so.

IV. FUEL COST RECOVERY IMPLICATIONS FOR RELIABILITY

Q: TO PRESERVE RELIABILITY, DO YOU BELIEVE THE COMMISSION SHOULD APPROVE GEORGIA POWER'S FCR-25 RATE RECOVERY REQUEST?

A: From a reliability standpoint, the under-recovered fuel balance is essentially water over the dam, or more accurately, money burned up the smokestack. It is not useful to assess the FCR-25 rate recovery request from the paradigm of reliability.

Q: TO PRESERVE RELIABILITY, DO YOU BELIEVE THE COMMISSION SHOULD APPROVE GEORGIA POWER'S FCR-26 TARIFF INCREASE?

A: No. More critically, approving the Georgia Power FCR-26 rate increase is likely to exacerbate Georgia Power's concentrated risk as a large consumer of natural gas, and heavily reliant on natural gas generation. Ms. Adams and Mr. Houston state that the coal and natural gas supply constraints of 2020 to

2022 "resulted in natural gas customers across the country paying higher prices for gas due to high demand and limited availability for alternative fuel sources."[29]

Continuing the Fuel Cost Recovery mechanism status quo would spur Georgia Power to continue to rely on natural gas generation as a primary resource, as the utility could count on recouping 100% of its fuel supply costs, even in the case of renewed supply constraints, global geopolitical disruptions, and ongoing price volatility.

Q: EARLIER YOU STATED THAT THE CURRENT FUEL COST RECOVERY MECHANISM HAS RELIABILITY AND HOMELAND SECURITY IMPLICATIONS. CAN YOU EXPLAIN FURTHER?

A: As required by the federal Department of Homeland Security's Federal Emergency Management Agency (FEMA), the Georgia Emergency Management and Homeland Security Agency (GEMA/HS) maintains Georgia's Emergency Operations Plan (GEOP). The GEOP is developed by GEMA/HS in coordination with other state agencies, non-governmental organizations and private sector partners and is aligned with the National Incident Management System, National Response Framework and the National Disaster Recovery Framework. Every four years, GEMA/HS updates the GEOP itself and all of the GEOP annexes, including Annex 12 – the Energy Annex.

Like all statewide Emergency Operations Plans, the GEOP takes the approach of "All Hazard Planning" including identification of past and potential future emergencies in the state. The GEOP then conducts a vulnerability analysis, a function of the built environment, local economy, demographics and environmental uses of a region. The GEOP states very clearly that damage and/or destruction to any of Georgia's six critical lifeline sectors, including Energy, "represents enormous economic, social, and general functional costs to a community, while also impeding emergency response and recovery activities."[30]

[29] Direct Testimony, p. 11.
[30] Georgia's Emergency Operations Plan (GEOP), 2017 with 2019 updates, p. 6.

The GEOP does not mince words in describing the public health, safety and lifeline support implications of events that would damage or destroy parts of the state's Energy infrastructure, particularly for electrical power.[31]

The 2019 GEOP identified several specific "Hazards of Concern" based on past emergencies as well as current and future vulnerabilities. During the period included by GEMA/HS for the GEOP, Severe Weather was the most common cause of declared disaster events in Georgia, accounting for 29 of 42 disasters. Of these severe weather events through 2019, 4 were severe winter weather events – a Hazard of Concern identified three years before winter storm Elliott wreaked havoc in Georgia, and two years before Superstorm Uri created substantial natural gas price increases and subsequent price volatility for months, including substantial impacts in Georgia.

Emergency Support Function 12 – Energy Annex supports the GEOP and provides guidance to prepare for, respond to, recover from and mitigate the effects of a disaster or emergency on Georgia's Energy System, and is the principal conduit by which the critical energy infrastructure is protected and restored. The Commission assumes primary oversight of emergency and disaster operations pertaining to electrical infrastructure, including planning and coordinating preparedness and mitigation activities pertaining to electrical and natural gas infrastructures.

I had the honor of escorting recently retired general and flag officers, Navy SEALs, and other veterans of the United States Special Forces. I recall frequent references to the need for multiple tools in case of the loss or failure of one tool. One Navy SEAL officer stated often: "You have to assume that if you have three tools for the job, one will break, and you will lose another one. So, what's three is really two. If you have two, it's really one. And if you have just one, you're sure as done."

The Fuel Cost Recovery mechanism and policy of 100% pass through to ratepayers has incented Georgia Power to rely far too heavily on a single source of new electrical generation: natural gas-fueled power plants.

[31] Ibid.

V. PROPOSAL TO CHANGE INTERIM FUEL RIDER MECHANISM

Q: HOW SHOULD THE COMMISSION VIEW GEORGIA POWER'S REQUEST TO RAISE THE INTERIM FUEL RIDER INCREASE MAXIMUM FROM 15% to 40%?

A: With respectful skepticism. I believe the Company's proposal would negate any future need for a Fuel Cost Recovery docket whatsoever. Georgia Power could rely entirely on the Interim Fuel Rider notice requirements under Commission rules, thus circumventing the spirit and the letter of O.C.G.A. 46-2-26. The Commission does indeed have the authority to adjust the Fuel Cost Recovery mechanism under the statute, but the Commission may not actually have the authority to permit any utility to avoid the public scrutiny and oversight that a Fuel Cost Recovery docket provides.

Q: WHAT DO YOU MEAN BY AVOIDING PUBLIC SCRUTINY, IF THE INTERIM FUEL RIDER CAP IS INCREASED TO 40%?

A: Fuel Cost Recovery dockets include an opportunity for the Commission to determine whether utility fuel expenses are the result of "illegal or clearly imprudent conduct on the part of the utility," in which case the Commission is obligated to disallow such fuel cost recovery by the utility.[32] I do not see how the Commission could exercise its obligation if the Interim Fuel Rider maximum adjustment is higher than the current 15%, permitting the utility to avoid any needed Fuel Cost Recovery docket going forward.

VI. APRIL 12, 2023, STIPULATION

Q: DID YOU REVIEW THE STIPULATION AGREEMENT BETWEEN GEORGIA POWER AND THE COMMISSION'S PUBLIC INTEREST ADVOCACY STAFF?

A: Yes, as well as the Attachment A related to the Interim Fuel Rider mechanics.

Q: DOES THE STIPULATION AGREEMENT SOLVE THE ISSUES RAISED IN YOUR TESTIMONY?

[32] O.C.G.A 46-2-26(h).

A: No, it does not. The Stipulation would only reduce the Company's approximate $2,520,000,000 under-recovered fuel balance by $7,000,000, retaining 99.72% of Georgia Power's original request under this docket. Further, the Stipulation does not address the significant negative consequences of increasing the Interim Fuel Rider cap to 40%.

I do not see any reason to modify my description of the docket, amended by the Stipulation, as "shocking."

Q: SHOULD THE COMMISSION APPROVE THE DOCKET AS AMENDED BY THE PROPOSED STIPULATION AGREEMENT?

A: No. My overall recommendation has not changed after my review of the Stipulation documents.

VII. COMMISSION DOCKET ON MODERNIZING FUEL COST RECOVERY

Q: WHAT SHOULD THE COMMISSION CONSIDER IN A FUEL COST RECOVERY MODERNIZATION DOCKET?

A: I believe the Commission should follow other states, such as Missouri and Idaho, among others, in pursuing a modernized sharing of fuel costs and fuel risk between the utility and its ratepayers. Such Fuel Cost Recovery reforms require balancing utility shareholder concerns against ratepayer protection; ensuring reliability and mitigation of emissions, and achieving transparency alongside reasonable business considerations.

I believe the Commission can best consider these issues in a holistic fashion through a specific docket focused on modernizing the Commission's Fuel Cost Recovery mechanism, including a reasonable amount of risk to be assumed by utilities.

As laid out in the Primer on Fuel-Cost Pass-Through Reform, such a docket should address these factors:

1. **The proper amount of fuel cost sharing and fuel risk sharing to be assigned to the utility.** There is not one "best" sharing amount that should be applied to all utilities because utilities vary in multiple ways. Each utility relies on different mixes of fuel-

and non-fuel generation sources, and each utility faces different risk profiles in their jurisdictions.

2. **Symmetrical or asymmetrical incentives and penalties.** A symmetrical fuel-cost sharing assigns the same percentage of fuel risk and fuel cost responsibility to the utility regardless of whether the actual fuel costs are higher or lower than expected. An asymmetrical mechanism shares a different amount in each case. Both symmetrical and asymmetrical sharing can be structured to provide both rewards and penalties.
3. **Straight sharing of fuel costs and risks, or the use of "deadbands**." The simplest structure for a fuel-cost sharing mechanism is to always require the same level of utility fuel cost responsibility (e.g., 10 percent) regardless of how much the utility's actual costs deviate from expectations or forecasts. A "deadband" approach can ensure that risk-sharing and cost-sharing changes the greater utility's actual costs have deviated from expectation or forecast. For instance, with respect to natural gas price volatility, the deviation from forecasted gas prices was significant enough over the past three years to merit some adjustment to a risk-sharing formula; the Commission would be able to evaluate different scenarios through modeling in a modernization docket.
4. **Reliance on forecasts versus actual historic pricing**. Forecasting natural gas pricing can feel like an exercise in futility. Some states, such as my home state of Minnesota, have adjusted the timing of fuel cost reviews to ensure greater reliability of actual pricing and costs, given the challenge of reliable forecasting.
5. **Transparency of key contract terms.** Georgia's current Fuel Cost Recovery rules require some disclosure of fuel supply agreement terms. But I believe that some critical contract terms can still be treated as confidential trade secret information, such as minimum delivery amounts ("take or pay" provisions), automatic price increases and others.

6. **Review for Prudency.** The Commission may find that it has ample authorization under the current FCR mechanism to properly review utility acts to ensure they address known or foreseeable risks that can result in shocking rate impacts as proposed in this docket. Any modernization effort should ensure that this prudency review continues.
7. **Hedging.** As the Company implies in the current docket, a utility can purchase stability and price predictability in exchange for a premium payment for such future fuel supply. Hedging is currently a permitted strategy by Georgia Power to address price risk – at an initial cost to its ratepayers. The Commission should evaluate the use of hedging as a cost-effective strategy over decades, and not just in times of geopolitical turmoil and a global pandemic.
8. **Purchased Power.** Georgia's Fuel Cost Recovery mechanism currently ensures that the fuel costs of purchased power are included in the utility's fuel rate calculations. Any risk-sharing and cost-sharing proposal should consider continuing this policy component, lest a utility attempt to sidestep the fuel risk requirements strictly through Power Purchase Agreements rather than utility-owned assets.
9. **Integrating Fuel Sharing in Other Ratemaking.** Fuel cost recovery has become a form of single-issue ratemaking that even Georgia Power admits could become more than 36% of the total revenue collected via ratepayers' bills.[33] Fuel costs and fuel risk continue to be critical factors in utility Integrated Resource Plans. Modernizing Fuel Cost Recovery in Georgia will make for a more efficient and consistent resource review across multiple dockets and multiple factors.

Q: IS THERE AN OPTIMAL AMOUNT OF UTILITY RESPONSIBILITY THAT THE COMMISSION SHOULD CONSIDER?

[33] MFRP 1-1.

A: I do not believe it is worthwhile to even consider returning to the pre-OPEC days of assigning to the utility 100% of fuel cost and fuel risk responsibility. Fuel risk sharing efforts in Hawaii, Idaho and other states suggest that sharing even 10% of fuel risk and fuel costs with the utility can have a dramatic benefit for reliability, resource diversity, ratepayer protection and utility performance.

Q: DOES THE UTILITY HAVE ANYTHING TO GAIN BY ACCEPTING FUEL RISK-SHARING AND FUEL COST-SHARING?

A: Absolutely. When designed well, a modernized fuel-sharing policy will provide utilities with a form of a performance incentive mechanism. If the utility can actively reduce fuel risks and fuel costs, as determined in a Fuel Cost Recovery docket, the utility should be rewarded for such efforts. The total fuel risk and fuel cost savings to the ratepayer should exceed any additional earnings awarded to the investor-owned-utility, of course. But designed well, a modernized Fuel Cost Recovery mechanism in Georgia will provide consistent benefits to the utility and to ratepayers.

CONCLUSION

Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A: 1. In the matter of the FCR-25 tariff under-recovered fuel balance, the Commission should rigorously review the prudency of Georgia Power's actions. While Georgia Power could not have predicted the specific events that contributed to the under-recovered fuel balance, multiple experts warned of the risks of excessive reliance on natural gas and the ongoing price volatility of natural gas even without winter storm Uri and Russia's invasion of Ukraine. Georgia Power could have taken any number of prudent steps to minimize its exposure to natural gas price volatility.

2. The Commission should not approve the forward-looking FCR-26 fuel rate adjustment. The Commission should instead initiate a Fuel Cost Recovery modernization docket to include some amount of fuel-cost-sharing and fuel-risk-sharing by the utility, to mitigate the moral hazard under the current policy of passing through 100% of fuel costs to ratepayers. The Commission has the authority under the Fuel Cost

Recovery statute -- because of Georgia Power's failure to take sufficient prudent steps -- to make amendments that would better allocate risk and costs between utilities and ratepayers. A modernization docket is the best means to evaluate all the policy options, relevant factors and potential impacts.

3. Georgia Power's proposal to increase the Interim Fuel Rider maximum adjustment to 40% without Commission review risks violating the Commission's statutory responsibility to conduct a prudency review of Georgia Power's fuel costs. The Commission should reject this proposal.

4. Georgia Power's proposals also risk the utility's strong prior record on reliability. Addressing Fuel Cost Recovery tariffs without considering the impact of other ratemaking dockets has led to unintended consequences, including an outsized reliability on natural gas. Other non-fuel alternatives could have mitigated the multi-billion-dollar impact to ratepayers.

5. The Commission should not accept the proposed April 12, 2023, Stipulation between Georgia Power and the Georgia Public Service Commission Public Interest Advocacy Staff, as it does not materially address the issues raised in this testimony.

Q: DOES THIS COMPLETE YOUR TESTIMONY?

A: Yes. Thank you.

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- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
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- Admissions: Minnesota and the District of Columbia.

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- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
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Safety and Security Committee Chair, Shir Tikvah Synagogue 2018 - present

Jewish Family and Children's Service of Minneapolis, Director 2013 - 2021

Capital Expansion Working Group, Innovative Housing Network, Chair 2016 - 2017

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Minnesota Chamber of Commerce, Energy Policy Committee 2014 - 2016

State Innovation Exchange (SiX), Founding Advisory Board 2012 – present

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Royal Society of the Arts, Fellow 2018 - present

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American Institute of Architects, National Conference

Minnesota Real Estate Journal, Energy Summit

National Press Club, GOVERNING Outlook

United States Senate, Climate and Energy Security briefing

Center for Climate Strategies Forum on State and Subnational Leadership, United Nations Conference of Partners (COP15), Copenhagen, Denmark

University of Minnesota, College of Design, Commencement Speaker

National Press Club, United States Green Building Council Green Schools Caucus national launch

The White House, State Leadership on Clean Energy

Energy Efficiency Finance Forum, American Council for an Energy Efficient Economy

Georgetown University Climate Center, State Leadership on Climate and Energy

Good Jobs, Green Jobs Conference, Blue-Green Alliance Conference

Midwest Energy Solutions Conference, Midwest Energy Efficiency Alliance

SELECTED RECENT ARTICLES

Learning to Share: A Primer on Fuel-Cost Pass-Through Reform, Pearl Street Station Finance Lab, April 2023

Commentary: Clean Energy Still Trumps Partisan Politics, Midwest Energy News, November 2016

Sustainable: The Business Case for Going Green, Finance & Commerce, June 2016

Minnesota Community's Energy Focus Gives It Edge in National Competition, Midwest Energy News, June 2016

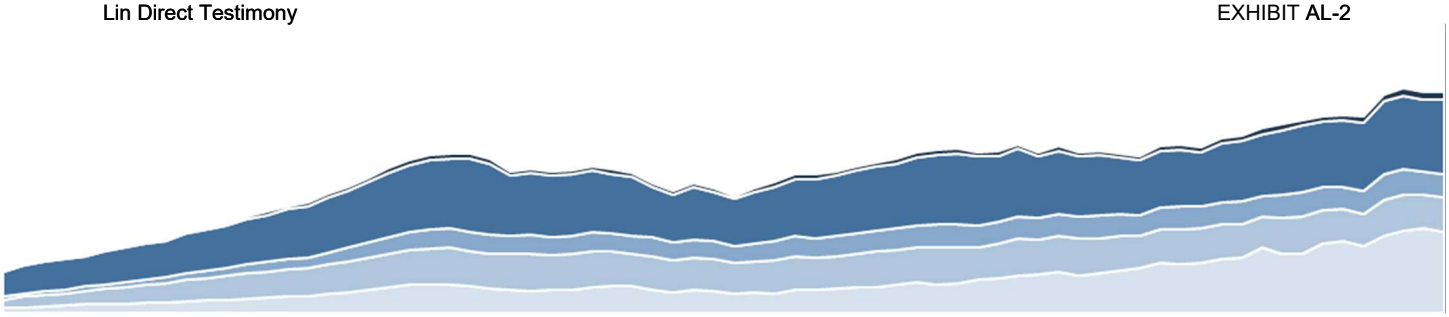
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'SolarNote' Aims to Reduce Complexity in Financing, Finance & Commerce, February 2014

From Commodity to Service: Why the Capitalization Model for Electric Regulation is Failing Minnesota, J.D. thesis paper, June 2010



LEARNING TO SHARE: A PRIMER ON FUEL-COST PASS-THROUGH REFORM

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Acknowledgements:

This report was made possible by the generous support of Energy Foundation.

We would like to thank Rachel Gold (RMI) and Joe Daniel (RMI) for their thoughtful review of this work and Liza Martin (Independent Contractor) for editing expertise.

Organizational affiliations are listed for identification purposes only. The opinions expressed herein do not necessarily reflect those of the organizations that funded the work or the individuals who reviewed it. Pearl Street Station Finance Lab bears sole responsibility for the report's content.

April 5, 2023

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Executive Summary

Electric utilities in the United States spend billions of dollars annually buying fuel to generate electricity. These costs often make up a sizable share of customer bills, and unlike other bill components, they can vary substantially from month to month. This makes it imperative that utilities manage their spending on fuels carefully—but most utilities have no financial incentive to do so. This is because in most states today, utilities are allowed to pass on 100 percent of their actual spending to customers through policies called "fuel adjustment clauses" (FACs).

FACs create a problem that economists call "moral hazard." Moral hazard exists when one party does not suffer the consequences of making bad decisions, so it takes bigger risks as a result. Current 100 percent pass-through policies create moral hazard because if utilities manage to reduce fuel costs (for example, by negotiating better prices or reducing their fleet's reliance on fuel) their customers receive all of the benefits, and if utilities manage their costs poorly, their customers pick up the bill.

Ever since FACs were implemented, they have created this moral hazard problem. However, in recent decades its real-world consequences have grown more acute due to a series of developments. These include several trends which have magnified the risks of heavily relying on price-volatile fuels for electricity generation, and others which have decreased the cost of fuel-free alternatives. In addition to the heavy cost burden that FACs impose on today's customers, they also fail to incent utilities to properly consider low- and no-fuel options that could help lower carbon emissions.

Though FACs are the norm today, these policies are ripe for revision by legislators and public utility commissioners interested in addressing these growing challenges. However, not all policy makers understand the downsides of current FAC policies, and not all those who do are motivated to take proactive actions to address them. Advocates can play important roles in educating key policymakers, encouraging them to act, and enlisting the support of other parties when needed to advance reforms in their state.

Eliminating FACs altogether may seem like the simplest policy fix, but moving from a 100 percent pass-through to a zero-percent pass-through overnight could create financial difficulties for utility companies. Fortunately, such an abrupt change is not necessary. Updating the FAC to pass through a lower share of the utility's actual spending to customers can successfully address the moral hazard problem while limiting the total risk the utility is exposed to. This type of reform is called "fuel-cost sharing."

Fuel-cost sharing can be implemented in different ways. The basic fuel-cost sharing policy that has been adopted by most states to date represents only a modest departure from the status quo. It entails first building a forecast of fuel costs into the utility's base rates (as is true of FAC policies), and then truing up less than 100 percent of the difference between the forecasted and actual spending. However, this is not necessarily the optimal design, since relying on forecasts makes this approach vulnerable to gaming by the utility. FAC reforms can also be designed in other ways that may better serve local policy priorities.

A range of design considerations are relevant. These include the extent of fuel-cost sharing, whether the sharing is symmetrical, and which costs are included in the mechanism. Other policies can also

be used to complement the fuel-cost sharing mechanism or serve as alternatives to it, including reforms that increase transparency, encourage hedging, and increase the scrutiny of utility spending decisions.

While FAC policies remain the norm across the United States today, a few states have adopted fuel-cost sharing policies or other reforms. These include Hawaii, Idaho, Oregon, Wyoming, Montana, Washington, Wisconsin, Vermont, and others.

Reforming FAC policies could enhance affordability by motivating utilities to manage their fuel costs more carefully. It could also reduce carbon emissions by encouraging utilities to switch more quickly to fuel-free technologies. It is time for these outdated policies to change, and both commissions and advocates can play important roles in advancing reforms.

Introduction

Every year in the United States, electric utilities spend billions of dollars purchasing fuel to generate electricity. During the COVID-19 pandemic, between 2020 and 2021, vertically integrated utility companies alone spent $70 billion in fuel costs.[1] This represents a sizable share of the total cost of producing electricity.

However, thanks to an obscure policy commonly known as the "fuel adjustment clause" (FAC), most US utilities lack any financial incentive to reduce how much money they pay for fuel.[2] Instead, these utilities are allowed to "pass through" 100 percent of these costs to their customers via a bill rider. Customers then have little choice but to pay for these costs—since the alternative would be to lose their access to electricity. In many states, the FAC is a specific line item on electric utility bills, as illustrated in Figure 1.

Figure 1. Sample Electric Bill from Xcel Energy

ELECTRICITY CHARGES		RATE: Net Energy Billing Svc		
DESCRIPTION	USAGE UNITS		RATE	CHARGE
Basic Service Chg				$8.00
Basic Service Chg				$1.90
Energy Charge Winter	946 kWh		$0.088030	$83.28
Energy Charge Winter	0 kWh		- $0.121590	$0.00
Fuel Cost Charge	946 kWh		$0.035507	$33.59
Sales True Up	946 kWh		- $0.007360	- $6.96 CR
Affordability Chrg				$0.98
Resource Adjustment				$14.23
Interim Rate Adj				$8.14
Subtotal				**$143.16**
City Fees			5.00%	$7.06
Transit Improvement Tax			0.50%	$0.74
City Tax			0.50%	$0.74
County Tax			0.15%	$0.23
State Tax			6.875%	$10.20
Total				**$162.13**
Premises Total				**$162.13**

A FAC often appears as a separate line item on customer electricity bills. It is highlighted on this residential bill from Minnesota.

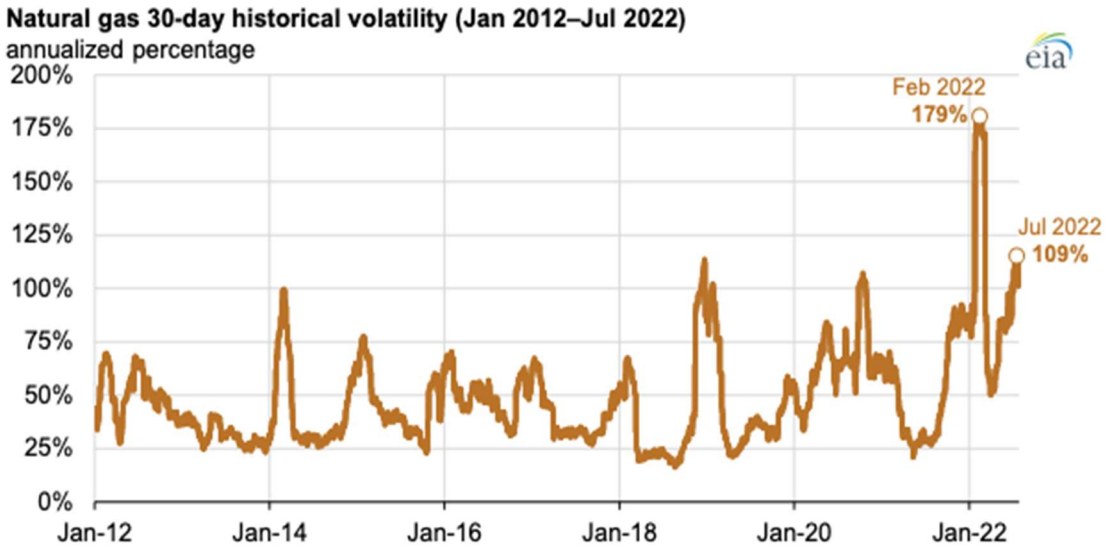
The burden on customers is further increased by the variability of fuel costs. Unlike most components of utility bills, the size of the fuel charge fluctuates substantially over time. This is largely due to the volatility of natural gas prices (and to a lesser extent, coal prices) coupled with changing weather. For example, in January 2022, fuel-cost volatility combined with Kentucky

[1] Albert Lin and Joe Daniel, Electricity Customers are Getting Burnt by Soaring Fossil Fuel Prices, RMI, June 23, 2023, www.rmi.org/electricity-customers-are-getting-burnt-by-soaring-fossil-fuel-prices

[2] Fuel costs are passed through to customers via FACs by both electric utilities and natural gas utilities. While this primer focuses specifically on electric utilities, many of the same arguments for FAC reform apply to gas utilities as well. We refer to policies that pass 100 percent of fuel costs through to customers via a bill rider as "fuel adjustment clauses" (FACs), but in some states these policies go by different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

Power's FAC resulted in "roller coaster" rates that made it difficult for some customers to make ends meet.[3] Figure 2 illustrates the volatile nature of natural gas prices over the last decade.

Figure 2. Historical Price Volatility of Natural Gas



Natural gas prices are highly volatile. Though the price spike in early 2022 was particularly severe, gas prices continually rise and fall in unpredictable ways.[4]

Though FACs pass through 100 percent of actual costs to customers, most components of utility rates do not work this way. The basic rates utilities charge customers for electric service (known as base rates) are set in advance according to the projected costs of power generation and delivery over a set period of time. These base rates establish a predictable per-kWh rate, even if utilities spend more or less than was expected when the rates were set.

In contrast, a FAC allows a utility to charge customers for the exact amount spent on fuel. As a result, fuel does not represent a business cost or profit center for utility companies. This means utilities are able to ignore the cost and volatility of fossil fuels in their decisions, even though customers end up paying more as a result.

Allowing utilities to ignore the consequences of relying on fuels distorts decision-making about what types of resources to invest in, which can disadvantage fuel-free resources in utility planning and investment decisions. Since earnings are not affected if fuel prices rise, the utility can ignore the risk of volatile and elevated costs when making investment decisions. Ignoring the volatility of fossil fuels tips the scales towards them—and away from more cost-effective fuel-free alternatives like wind, solar, and energy efficiency. FACs also give utilities no incentive to find shorter-term strategies to lower fuel costs, such as negotiating better fuel-supply contracts.

This phenomenon differs from what happens in a competitive market, where a company that succeeds in reducing its costs will gain an advantage over its competitors. A regulated utility with a

[3] Emily Bennett, WSAZ Investigates: Kentucky Power bill spike, January 28, 2022, https://www.wsaz.com/2022/01/28/wsaz-investigates-kentucky-power-bill-spike

[4] Figure from EIA, U.S. natural gas price saw record volatility in the first quarter of 2022, August 24, 2022, https://www.eia.gov/todayinenergy/detail.php?id=53579

FAC gains nothing if it succeeds in reducing its fuel costs. Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill.

"Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill."

History of Fuel-Cost Pass-Through Policies

Fuel costs were not always treated as a 100 percent pass-through to utility customers. For almost the whole first century of US utility regulation, utilities were expected to manage their fuel costs in the same fashion as other business expenses.

The first power plants were built in the last few decades of the 19th century. To prevent privately owned utilities from overcharging customers, local and state governments stepped in to regulate the rates they could charge. The newly created public utility commissions treated fuel costs as just one aspect of the costs of doing business, rather than as a unique cost category requiring special ratemaking treatment.[5]

When World War I caused fuel prices to soar, utilities lobbied commissions for relief from fuel-price volatility and the associated risk of significant financial loss. Public utility commissions responded by implementing the first temporary FACs, which they discontinued shortly after the war. When World War II also created global fossil-fuel supply challenges, commissions reinstituted temporary FACs—which were likewise curtailed once peacetime resumed.

The oil shocks of the 1970s again sparked utility demands for insulation from global supply disruptions, and this time both state legislators and public utility commissions responded. Though the gasoline lines of the 1970s soon disappeared, in most states the statutes and commission decisions that established FACs have never been meaningfully revisited.

Today, these policies are the norm across the country. In most states, the process through which costs are approved for recovery through FACs is opaque to customers and their advocates, since investor-owned utilities are allowed to treat their fuel-supply agreements as trade secrets. This means that despite being saddled with 100 percent of the costs, ratepayers cannot generally evaluate whether the fuel-supply agreement terms are reasonable.

It is reasonable to wonder why legislators and public utility commissions have left these policies in place for so long. FACs are typically justified based on the idea that utilities cannot control the cost of fuel. However, this assertion was never entirely true, and it is even less true today. For example, utilities make decisions about how much natural gas capacity to build, and they negotiate the fuel-supply contracts that determine the prices they pay for natural gas. In addition, due to technological

[5] We refer to all such regulatory bodies as "public utility commissions." In many states the body has a similar name (e.g., the Nevada Public Utilities Commission), but this is not always the case (e.g., the Maryland Public Service Commission, the Kansas Corporation Commission, the Washington Utilities and Transportation Commission).

advances, utilities can now displace fuel-based generation with a range of cost-competitive alternatives that use little to no fuel (e.g., solar, wind, batteries, energy efficiency). Yet, because FACs insulate utilities from the financial consequences of relying on fuel, the companies have little incentive to change.

The Problem: Moral Hazard and Inefficient Investment Decisions

FACs create a problem that economists call "moral hazard." Moral hazard exists when one party does not suffer the consequences of making bad decisions, so they may take bigger risks as a result. The moral hazard problem crops up in many spheres, including insurance, investing—and utility regulation.[6]

In the regulatory sphere, 100 percent fuel-cost pass-through policies provide a particularly stark example of moral hazard. When a FAC is in place, the utility decides how much fuel to buy and at what price—but it is the utility's customers who pay the cost if the utility spends more money than necessary. In other words, the utility (and its shareholders) are held harmless from the consequences of poor fuel-management decisions.

"The moral hazard problem has existed since the first FACs were implemented; however, in recent decades the real-world consequences of this have grown more acute."

The moral hazard problem has existed since the first FACs were implemented; however, in recent decades, the real-world consequences of this have grown more acute. This is due to two types of recent trends. First, a series of developments have magnified the risks of relying heavily on fuels. Second, the costs of fuel-free alternatives have decreased.

Trends that Have Magnified the Risks of Relying Heavily on Fuels

The first category is developments that have increased the risks associated with relying on fuels. These include the following:

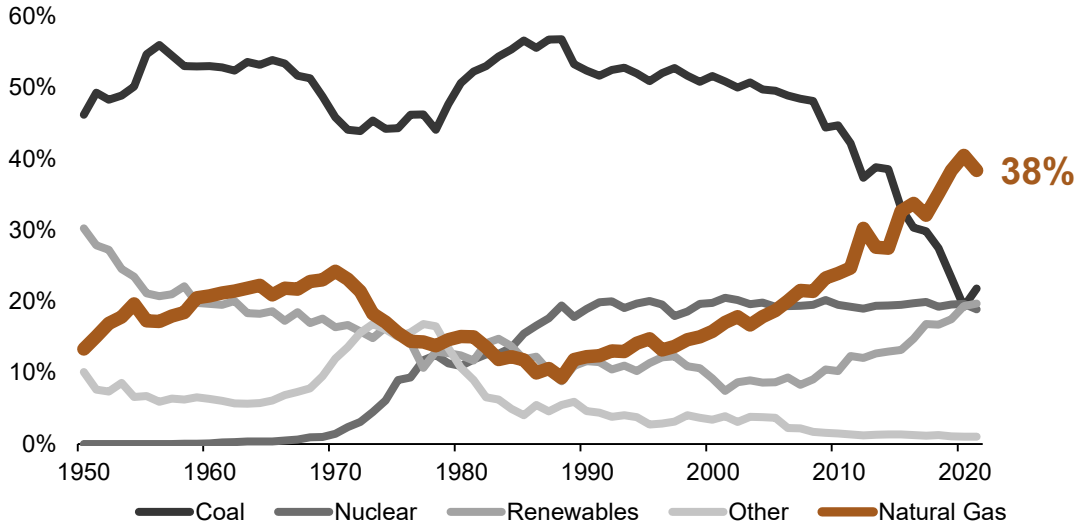
> **Greater utility dependence on natural gas.** Over the last two decades, utilities have been building gas-fired power plants at a rapid pace. Because of this construction spree, the share of electricity generated from gas has risen dramatically (Figure 3), and electric utilities have grown from being small, niche buyers of natural gas to being the gas industry's biggest buyers (Figure 4). This has created a situation in which customers are much more exposed to the effects of gas-price volatility than they used to be. Natural gas prices are by their nature volatile, and now a much higher share of electricity generation depends on gas purchases.[7] In addition, the electric sector's demand tends to rise and fall in a pattern driven by seasonal

[6] The classic insurance example is that an insured party may take more risks than they would otherwise, since the insurer will pay for any loss that may occur. An example from the world of investing is that a money manager may take excessive risks with other people's wealth.

[7] Jamison Cocklin, U.S. Natural Gas Price Volatility at All-Time High in 2022, Natural Gas Intelligence, August 16, 2022, https://www.naturalgasintel.com/u-s-natural-gas-price-volatility-at-all-time-high-in-2022

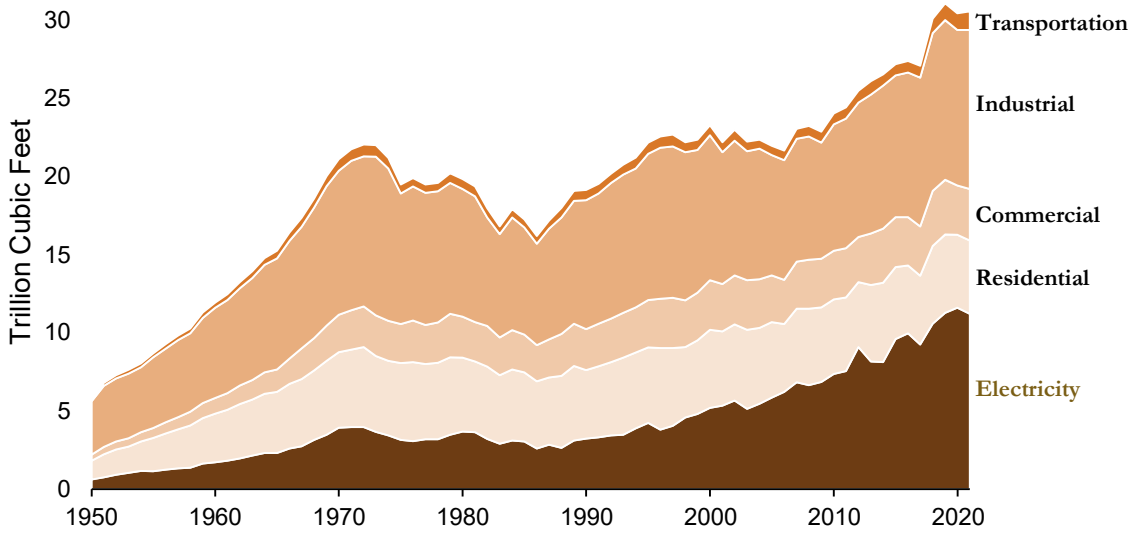
changes and regional weather events—which can cause supply constraints. For example, if a major heat wave hits the eastern United States, the electric utilities in all impacted states will consume more natural gas than usual to meet the increased need for air conditioning, resulting in rapid price increases as regional gas inventories are depleted.

Figure 3. US Electricity Generation by Resource



Between 1950 and 2022, the share of electricity generated from natural gas roughly tripled, from 13 percent to 38 percent.[8]

Figure 4. US Natural Gas Consumption by Sector



In recent years, the electric power sector has become the largest customer of the natural gas industry.[9]

[8] Data from EIA, February 2023 Monthly Energy Review, Table 7.2a, https://www.eia.gov/totalenergy/data/monthly
[9] Data from EIA, February 2023 Monthly Energy Review, Table 4.3, https://www.eia.gov/totalenergy/data/monthly

More severe weather. Another recent trend is that weather is becoming more severe due to climate change. The growing intensity of both summer heat waves and winter cold snaps increases the odds of large fuel-price spikes as gas demand outstrips available supply. For example, in 2021, Winter Storm Uri led to a steep drop in natural gas production, leading to supply constraints and record-setting prices.[10] Forest fires, hurricanes, and even seasonal weather events can also trigger fuel-supply disruptions that translate into price volatility.

Increasing exposure to geopolitical risks. Globalization has made the international economy increasingly interconnected. With heightened natural gas prices in Asia and Europe, US producers ship a sizable share of domestically produced gas abroad as liquified natural gas (LNG)—and the United States recently became the world's largest LNG exporter.[11] This heavy involvement in international trade makes the US natural gas sector vulnerable to conflict-induced supply disruptions, which can translate into increased fuel-price volatility. For example, when Russia invaded Ukraine in February of 2022, the combination of sanctions against Russian gas and increased exports to Europe caused global prices for natural gas to soar.[12]

Trends that Have Made Fuel-Free Alternatives More Attractive

In addition to the trends magnifying the risks of relying heavily on fuels for electricity generation, a series of developments have made fuel-free alternatives more reliable and cost-effective. These include the following:

Cheaper fuel-free alternatives. Through the end of the twentieth century, most commercially viable generation technologies (e.g., coal, natural gas, nuclear) required fuel. Today, fuel-free energy resources like energy efficiency, solar, and wind are often the lowest-cost sources of power,[13] while new technologies like advanced metering infrastructure (AMI) and distributed energy resource management systems (DERMS) can enable storage, energy efficiency, and demand response to be deployed in ways that allow a much higher share of demand to be met by these resources.[14] Utilities today can choose to reduce fuel dependence in ways that were not possible even a few years ago.

Supportive federal policies. The Inflation Reduction Act (IRA), passed in 2022, featured a range of provisions that increased the economic attractiveness of fuel-free alternatives. These include the extension of the production tax credit (PTC) and investment tax credit (ITC) that are available to renewable and storage facilities, changes that better position

[10] American Public Power Association, Winter Storm Uri, Extreme Winter Events, And Natural Gas Reforms, Issue Brief, January 2022, https://www.publicpower.org/system/files/documents/January%202022%20-%20Winter%20Storm%20Uri.pdf

[11] EIA, The United States became the world's largest LNG exporter in the first half of 2022, July 25, 2022,

[12] IEA, Russia's War on Ukraine: Analysing the impacts of Russia's invasion of Ukraine on global energy markets and international energy security, https://www.iea.org/topics/russias-war-on-ukraine

[13] Zachary Shahan, Wind & Solar Are Cheaper Than Everything, Lazard Reports, CleanTechnica, November 15, 2020, https://cleantechnica.com/2020/11/15/wind-solar-are-cheaper-than-everything-lazard-reports

[14] Lauren Schwisberg, The Business Case for New Gas Is Shrinking, RMI, December 8, 2022, https://rmi.org/business-case-for-new-gas-is-shrinking

regulated utilities to take advantage of these tax credits, and access to low-cost debt to help retire existing fossil-fired power plants.[15]

The Consequences of Moral Hazard Have Grown More Acute

Taken together, these recent trends have fundamentally changed the US energy landscape. The risks of overreliance on fuel-based generation have increased while fuel-free alternatives have become more reliable and cost effective. In the present world, it literally pays to reduce utilities' reliance on fuel, but it is the customer not the utility that benefits from those cost reductions.

While a utility doesn't profit from using more fuel, it doesn't profit from decreasing fuel usage either. It's also important to realize that managing fuel costs carefully isn't free. It takes managerial effort and investment in expertise, and utility managers are incentivized to focus on other areas of operations and investment. Because of this, utilities are not taking full advantage of current opportunities to reduce fuel costs. Fortunately, a practical solution to this moral hazard problem is available. We turn to this next.

A Promising Solution: Fuel-Cost Sharing

FACs are the norm today, but this can be changed. These outdated policies are ripe for revision by legislators and public utility commissioners who care about making utility services more affordable, protecting customers from unnecessary risks, and/or reducing carbon emissions. The moral hazard created by 100 percent pass-through policies undermines all of these goals. Updating these policies can yield multiple benefits by motivating the party that is best positioned to reduce fuel costs to use its information, abilities, and skills to do so.

Since FACs have only been the norm for a few decades, it may seem like the best solution would be to eliminate them altogether. However, such a marked departure from current practice could pose significant risks. Today's utilities would be more sensitive to unexpected fuel-cost fluctuations than their early 20th-century counterparts, since current business models have developed based on the expectation that utilities will be sheltered from this source of volatility.[16] For this reason, suddenly moving from a 100 percent passthrough to a zero-percent pass-through policy could undermine a utility's financial stability, driving up its cost of capital and eventually necessitating rate hikes.[17]

Fortunately, states do not need to shift 100 percent of the fuel-cost risk back onto the utility. The goal of reforming the FAC is simply to motivate the utility to keep its fuel costs in check—and this can be done while limiting the total risk the utility is exposed to.

This reform can be accomplished by updating the FAC to only pass through part of the fuel costs to customers. This does not mean that customers wouldn't pay anything for the rest—just that they

[15] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service, RMI, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira

[16] The relevant features of current utility business models include but are not limited to their capital structure, organizational structure, and risk profile.

[17] A utility's cost of capital is the minimum amount the utility would need to pay debt and equity investors to secure the funds it needs to run its business. This is sometimes referred to the utility's "true" cost of capital to distinguish it from the estimated cost of capital regulators use when setting rates, which is generally higher than the true cost of capital.

would reimburse the utility for the rest of the fuel in the same way they pay for most utility expenditures. In other words, these costs would be recovered in rates that are set in advance and not trued up afterwards to match actual expenditures. This reform is called "fuel-cost sharing," though in reality what it does is share the risk that fuel costs will deviate from expectations between the utility and its customers.

Fuel-cost sharing can be implemented in different ways—and we discuss key design options later. However, at this point it would be helpful to understand the basic mechanics of the form that has been most often adopted by states thus far.

This form of fuel-cost sharing requires only a modest departure from the way most FACs are implemented today. Under the typical 100 percent pass-through policy, a forecast of fuel costs is first built into base rates and the FAC then trues up the forecast once the actual expenditure has been made. The FAC does this by charging or crediting customers for the difference between the forecasted and actual fuel costs via a rider; this usually appears as a separate line item on customer bills. The only change to this status-quo policy that is made to implement the reform is to true up less than 100 percent of this difference.

For example, a fuel-cost sharing policy of this type could true up just 90 percent of the gap between the forecasted and actual fuel costs. This would mean that if fuel costs are less than forecast the utility will get to keep 10 percent of the underspend, and if fuel costs exceed the forecast it will bear 10 percent of the excess amount. In other words, the utility will now have a financial incentive to seek ways to reduce fuel costs—and customers will receive 90 percent of any savings.

While this is the variant of fuel-cost sharing that has been most widely adopted to date by the states addressing the FAC, it is not necessarily the optimal one. One of its biggest drawbacks is that if the utility is able to inflate the fuel-cost forecast that is built into base rates, it will be able to retain a share of that inflated amount (e.g., 10 percent in our example). In other words, anchoring the fuel-cost sharing mechanism to a forecast can invite the utility to game the forecast.

Fortunately, there are ways to avoid this problem, and there are also alternative structures that can allow regulators to tailor their fuel-cost sharing policy to local circumstances. We will discuss some of these policy design options later.

Avenues for Reform

It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility.

To identify appropriate reforms, it is important to first understand how fuel costs are currently regulated. The biggest question is whether 100 percent of fuel costs are passed through to customers or if there is some form of fuel-cost sharing already in place. Keep in mind that 100 percent fuel-pass-through mechanisms are sometimes called different names, even though we refer to them all as FACs here.

The next step is to determine which decision makers have the ability to reform the existing policy. Public utility commissions are responsible for overseeing regulated utilities and setting the prices

they can charge, so achieving FAC reform will likely require engaging with the commission. However, some state legislatures have passed laws that mandate 100 percent pass-through policies, so, in these states, reform will require revising these statutes. In addition, interested legislatures can motivate reform at the commission by encouraging or requiring it to revisit these policies.

How to Engage a Public Utility Commission on Fuel Adjustment Clause Reform

To engage a public utility commission on the topic of FAC reform, advocates first need to identify the best formal venue.

Commissions make decisions through individual proceedings (aka "dockets") that focus on particular regulatory issues. Each proceeding is assigned a specific identifying number (often called a "docket number"), and the documents associated with the proceeding can generally be obtained through a commission's online docket search.[18] Participating in a proceeding typically requires applying for intervenor status, but sometimes the commission will issue a notice inviting comments from the general public.[19] The types of proceedings that may be good venues for FAC reform include the following:

Dedicated FAC dockets. Commissions typically periodically review and approve fuel costs for recovery in specific FAC-related dockets, so engaging in these proceedings can be one way to push for changes. However, in some states, these proceedings offer little opportunity to scrutinize utility requests for fuel-cost recovery—for example, where stakeholders lack access to key data, face rapid turn-around times for comment submission, are constrained by a narrow definition of the issues in scope for the proceeding, or face other barriers that prevent them from advocating effectively for reform. In these cases, pushing for changes to the way the commission conducts these dockets may be a prerequisite to reforming a FAC through them.

> "It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility."

Rate cases. General rate cases may also provide a venue for stakeholders to raise concerns about fuel-cost treatment and offer solutions. The basic function of rate cases is to set the utility's base rates going forward, and to do this the commission examines a wide array of different topics that pertain to utility expenditures. Rate cases are typically conducted over a longer time frame than dedicated FAC dockets and in a way that invites more input from stakeholders.

[18] The structure of online docket searches varies greatly—some are relatively intuitive while others can be very difficult to navigate. If you have trouble with the docket search (or more general questions about what to look for), commission staff are often willing assist if asked.

[19] To become an intervenor, a party must typically submit a request to the commission that justifies why they should be granted intervenor status. Generally, this means showing that they have a compelling interest in the outcome and that they will make some kind of unique/valuable contribution because they represent a particular group/perspective. The commission will then either grant or deny them intervenor status.

Performance-based regulation proceedings. Proceedings that focus on investigating or implementing performance-based regulation (PBR) are another potential venue for FAC reform. The purpose of fuel-cost sharing is to better align the utility's incentives with the interests of customers and society, which is precisely the definition of PBR. In other words, fuel-cost sharing can be considered a PBR mechanism, and it is therefore appropriate to discuss in PBR proceedings.

Special dockets. Commission rules vary on the authorized scope and process for dockets on special topics. However, in nearly every state, a commission could open a special docket to review current fuel-cost recovery policies, consider the implications of updating these policies, and solicit public input. In some cases, a legislative hearing can spur a commission to open a special docket, and in other cases customers or other stakeholders can petition it to do so.

Public utility commissions vary greatly across states. Some may quickly recognize the problems created by 100 percent pass-through policies and act decisively to change them. In many cases, this type of response is driven by a particularly proactive commission member, so it is worthwhile for advocates to consider which commissioners may be inclined to act as champions for reform. Other commissions may not be receptive to the idea of addressing FAC reform without outside pressure.

How to Enlist Other Actors to Encourage a Commission to Act

Where a public utility commission is not inclined to take up the issue of FAC reform or is prohibited from doing so, advocates should consider enlisting the help of other parties. These include the following:

State Legislators. Though setting utility rates is the commission's responsibility, state legislators may be able to direct or encourage the commission to take action. For example, lawmakers could hold a hearing on the FAC, introduce legislation directing the commission to align its mission and operations with state policy goals, distribute sign-on letters for colleagues to join them in encouraging commission attention to fuel-cost pass-through policies, or hold stakeholder meetings on the topic.

Governors. Governors may also be able to encourage FAC updates. For example, a governor may be able to issue an executive order requiring the commission to consider or recommend reforms that align its activities with affordability or climate goals, or one that provides guidance about key design criteria (e.g., what constitutes "the public interest" for the purpose of regulatory decision-making). Also, in many states the governor is responsible for appointing commission members. In these cases, the governor could prioritize FAC reform as a significant consumer protection agenda item when appointing (or reappointing) individuals to serve on the commission.

Attorneys general. In some states, the attorney general can petition the public utility commission to open a proceeding to consider a particular issue—which could include FAC reform. Also, in most states, an attorney general can initiate a review of confidential information in fuel-supply agreements to determine whether alleged trade secret information

meets the legal standard for being withheld from public view. Such a review could examine key contract terms, such as guaranteed delivery volumes regardless of need, as well as cost or price escalators that are above consumer price index averages. Some attorneys general also serve as the consumer advocate, which may give them the power to request commission dockets and take other actions to support FAC reform.

> "Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful the most important thing is to get started."

Utilities. Since the idea of FAC reform is to expose utilities to a share of the fuel-cost risk, they may not be in favor of updating the policy. However, in some cases a utility may be receptive to the idea if it expects to be able to profit by reducing fuel costs. Utility proposals often carry substantial weight with both public utility commissions and legislators, so utility support of reform can help move the process forward.

Though the recommendations discussed are broadly applicable, every public utility commission is unique. FAC reform advocates can tailor their approach to their particular commission by researching its processes, mission, and relevant recent decisions, as well as the attitudes and policy positions its members demonstrate through their statements and actions.

How to Achieve Reform Through Legislative Action

In all states, a public utility commission can only operate within the constraints of state statutes, which are established by state legislatures.

In some states, the legislature has enshrined the FAC into statute. In these states, the public utility commission alone will not be able to update the policy since the legislature must first amend the statute. Where this is the case, would-be changemakers should develop a legislative strategy prior to—or at least in parallel with—their efforts to engage the commission.

In other states, the legislature has provided the public utility commission with the statutory authority necessary to revise the fuel-cost pass-through policy. In these states, advocates may wish to focus their efforts solely on the commission. However, even in these states, a legislative route to change is possible. For example, state lawmakers could introduce legislation to reform the FAC, even if the existing policy was implemented by the commission.

When drafting a bill, state legislators often meet with other lawmakers and affected parties to inform policy design and secure buy-in. Advocates should be aware that this may occur, and they may even wish to encourage their legislative champions to meet with utility representatives, consumer

advocates, and other stakeholders. These parties may be more open to policy reforms when consulted early and away from the media attention that can occur once a bill is introduced or a hearing is in progress, and meeting with them may also result in better policies. However, utilities or other stakeholders may also use this opportunity to urge lawmakers to weaken or abandon the proposed reforms. To guard against this possibility, advocates can educate their legislative champions ahead of time about the arguments against reform that they are likely to hear and whether those arguments are reasonable.

Depending on the state's policies governing communication between lawmakers and commissioners, legislators may also wish to engage commissioners directly in crafting statutory reforms to fuel-cost pass-through policies. Some commissioners may choose to be deeply involved in such discussions, and they may even be willing to endorse specific legislative changes or testify at public hearings. Other commissioners may be reluctant to step outside of their quasi-judicial role in this way, even if they agree that a legislative update would be beneficial.

Advocates interested in legislative reform can increase the chances for success by providing their legislative champions with specific policy recommendations and examples to follow. In particular, advocates would be wise to point to precedents for FAC reform from other states, as lawmakers may be reluctant to act if they believe they will be the first state to implement such a change.[20]

How to Get Started on Reforms in Your State

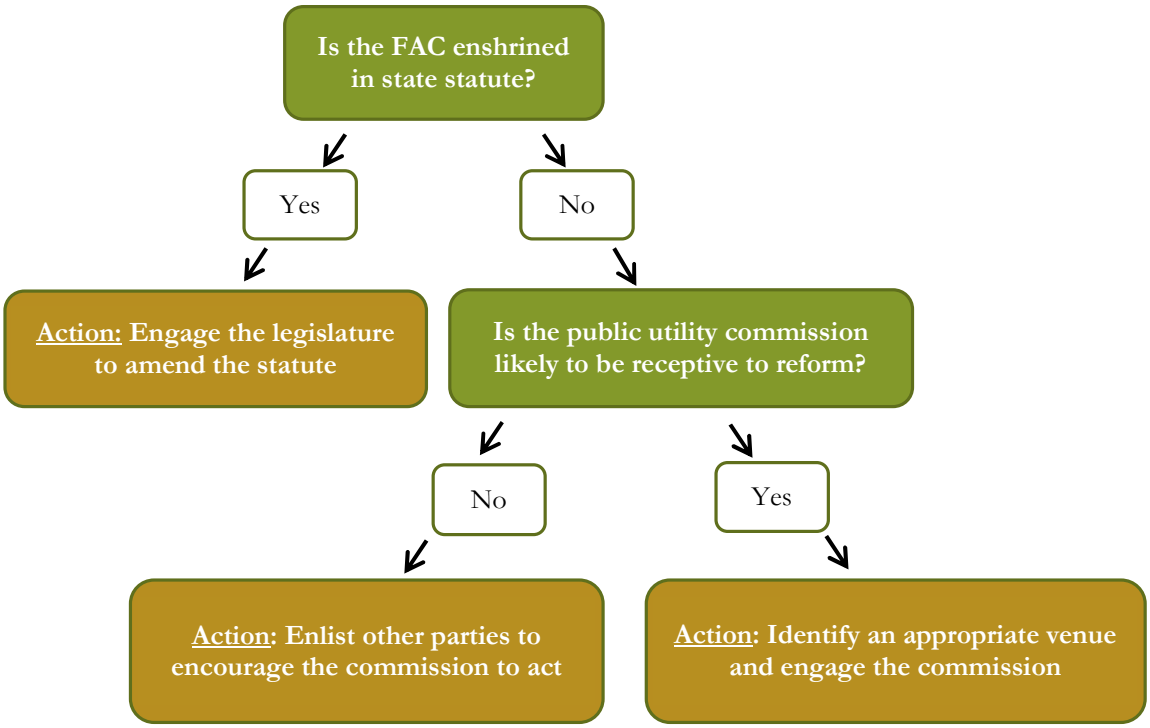
Achieving fuel-cost pass-through reform in a state may be a complex process, as advocates may need to intervene in arcane regulatory proceedings, navigate legislative policymaking, and/or enlist the support of other parties. The process may be relatively quick, but it could also take years to update a FAC policy.

Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful, the most important thing is to get started.

Once advocates have decided they want to reform the policy in their state, they are ready to start crafting a strategy. Figure 5 illustrates the key questions that advocates embarking on this process will face.

[20] We provide some examples of states that have implemented FAC reforms later in this primer, and national nonpartisan organizations like the National Conference of State Legislators may be able to provide additional information.

Figure 5. Key Steps for Achieving Fuel Adjustment Clause Reform



Key Policy Considerations

Though the concept of fuel-cost sharing is simple, this reform can be implemented in a variety of ways. In addition, there are other reforms that could also help address related problems. When considering ways to reform an existing FAC, the following topics are worthy of consideration.

Amount of Fuel-Cost Sharing

When designing a fuel-cost sharing policy, advocates should consider the degree of sharing between the utility and its customers. For example, a utility could be responsible for just 5 percent of fuel costs (i.e., passing through 95 percent to customers) or for 20 percent (i.e., passing through 80 percent to customers). The ideal sharing percentage is a level that is high enough to motivate the utility to keep its fuel costs in check, but low enough that the utility is not exposed to unreasonable levels of risk.[21]

There is not one "best" sharing amount that should be applied to all utilities because utilities vary in multiple ways. For example, utilities rely on different mixes of fuel- and non-fuel generation sources, and they face different risk profiles in their jurisdictions.

[21] If the utility is exposed to a level of risk that is excessive, it could make it harder for the company to access low-cost capital. This could drive up its cost of capital (and by extension, the rates it must charge customers to remain financially whole), and at the extreme it could even create cash-flow problems severe enough to prevent it from serving its customers. While moderate sharing percentage would be unlikely to cause such problems, there may be an upper limit to how much sharing is in customers' best interest.

Symmetry

Another design question is whether a fuel-cost sharing mechanism should be symmetrical or asymmetrical. A symmetrical mechanism shares the same percentage regardless of whether the actual fuel costs are higher or lower than expected. An asymmetrical mechanism shares a different amount in each case. Both symmetrical and asymmetrical sharing can be structured to provide both rewards and penalties.

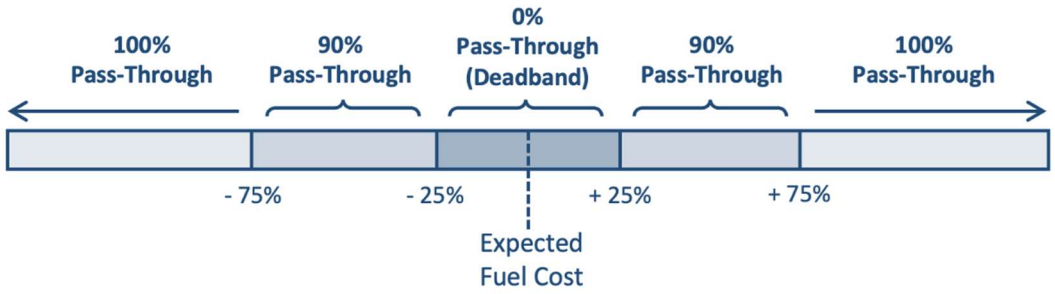
For example, a commission may design a mechanism with a higher pass-through percentage when fuel costs are lower than expected (thus passing more of the savings on to customers) than when fuel costs are higher than expected. Such a mechanism can direct more of the benefits of fuel-cost savings to customers—but it also weakens the utility's incentive to pursue opportunities to reduce fuel costs below a certain level. Symmetrical mechanisms also tend to be easier for customers to understand than asymmetrical mechanisms. These tradeoffs should be carefully considered when deciding between symmetrical and asymmetrical designs.

Straight Sharing Versus Sharing Bands

The simplest structure for a fuel-cost sharing mechanism is to always require the same level of utility fuel cost responsibility (e.g., 10 percent) regardless of how much the utility's actual costs deviate from expectations. This approach, which is sometimes call "straight sharing," is the most common among existing fuel-cost sharing policies.

Another option is to use bands (also sometimes called thresholds). For example, a regulator could adopt a mechanism that performs no true-up if actual fuel costs fall within 25 percent of the expected value (this is called a "deadband"), a 90 percent true-up if actual costs are 25-75 percent greater than or less than that value, and a 100 percent true-up if they deviate by more than 75 percent. Figure 6 illustrates this hypothetical banded design.

Figure 6. Example of a Policy Design with Sharing Bands



In this example, the pass-through amount increases as the size of the deviation from the expected fuel cost becomes larger. Such a design can reduce the risk to the utility posed by large fuel-cost spikes, as well as the risk to customers of paying for large windfall profits if fuel costs dip very low. Alternatively, sharing bands could be used to increase (rather than decrease) the utility's risk exposure as fuel costs deviate more from the expected level; this could greatly increase the utility's incentive to reduce its reliance on fuel. Sharing bands could also be deployed in an asymmetrical fashion.

While banded designs can reduce the risk of extreme outcomes to the utility or its customers, they can also create uneven incentives. For example, a banded design that passes through 100 percent of fuel costs beyond a certain threshold dissolves the utility's financial incentive to reduce costs beyond that threshold. In addition, banded designs can be harder for customers to understand and more complex to administer than straight sharing.

Forecast Versus Historical Prices

Fuel-cost sharing mechanisms in place today share the difference between the actual fuel costs a utility incurs and the costs it was expected to incur. These "expected" costs can be based on either a forecast (i.e., a forward-looking estimate) or historical values. Forecasts are the most common approach used today, but that does not necessarily mean they are the best choice.

Traditional 100 percent pass-through policies typically utilize forecasts to set the base rates that the FAC then trues up, and most states that have adopted fuel-cost sharing have continued to rely on them. Forecasts may also be preferred because they can be tailored to reflect changing conditions—but, in reality, the accuracy of fuel-cost forecasts may be low. This is particularly true for forecasted natural gas costs, as this fuel is subject to substantial price volatility that is hard to predict.[22, 23]

However, forecasts have another drawback in the context of fuel-cost sharing: they open the door to possible gaming. Specifically, if the utility is able to inflate the forecast, it will be rewarded with a greater amount of "savings" relative to it (and also be less likely to have to bear a share of any "overspends"). It is important to note that any such gaming will not reduce the utility's financial incentive to seek savings once the forecast is adopted—so the fuel-cost sharing mechanism will still encourage the utility to reduce fuel costs. However, if the utility manages to game the forecast this will increase the costs of the policy to customers.[24]

The alternative is to use historical spending to set the expected fuel-cost baseline. Relying on historical actuals rather than forecasts avoids the gaming problem just described, and it is also more straightforward to calculate.

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[22] The price volatility of natural gas is driven by multiple factors. These include domestic transportation and storage constraints, shifting levels of international demand, and global supply-chain disruptions (e.g., due to extreme weather events and geopolitical events).

[23] For example, the price forecasts shown on pg. 11 of the following report are typical: Deloitte, Energy, oil, and gas price forecast: Energy costs are stretching price elasticity and energy affordability, December 31, 2022. https://www2.deloitte.com/ca/en/pages/resource-evaluation-and-advisory/topics/deloitte-canadian-price-forecast.html

[24] The company will have the same financial incentive to reduce fuel costs because the utility's marginal incentive (i.e., the reward it can earn for reducing fuel costs by the next increment) is not changed by the level of the forecast. For example, imagine a utility that is subject to a 90 percent pass-through policy and that is expected to use 100 units of fuel at $5/unit. If this utility can find a way to spend $4/unit on fuel instead of $5/unit, it will earn a $10 reward for doing so (i.e., 100 units x $1/unit * 10 percent). If these are real savings that would not have occurred without the utility's effort, everyone wins: the utility gets its $10 reward and customers receive $90 of savings. However, if the utility can convince its regulator that the price of fuel is likely to be $6/unit instead of $5/unit, it will earn a $10 reward for doing nothing (i.e., for spending $5/unit) and then another $10 for reducing its spending to $4/unit. Either way, the utility earns the same incentive ($10) for reducing its fuel costs from $5/unit to $4/unit, so its marginal incentive to pursue this savings opportunity is the same. However, if the utility is able to inflate its forecast to $6/unit, its customers will pay an extra $10 incentive and receive nothing in return.

However, relying on historical spending could itself create an incentive problem under certain policy designs. When the utility's historical spending is used to set the baseline, reducing fuel costs in one year will reduce the expected-cost baseline in future years. This means that if the utility's reward for reducing fuel costs now is not large enough to offset the burden of operating under a lower baseline in the future, the utility will not be motivated to reduce its fuel costs. This situation is most likely to occur where an asymmetrical design is used that requires a utility to bear most of the cost when actual fuel prices are higher than expected, but which passes on most of the savings to customers when they are lower than expected.

Transparency

In many states today, the moral hazard problem created by FACs is compounded by a lack of visibility into fuel-supply contracts. While commission staff often have access to otherwise undisclosed contracts and key terms, they may not have the time or expertise to complete a thorough review on their own. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudency issues and flag them for the commission and its staff to consider. The end result is less regulatory scrutiny of utility fuel expenditures.

Though fuel-cost sharing addresses the moral hazard problem created by traditional 100 percent pass-through policies, transparency is still important. State lawmakers and utility regulatory commissions can take steps to ensure that the key terms of utility fuel-supply contracts are transparent to customers and other stakeholders, while protecting necessary trade secrets as appropriate. Such terms include (but are not limited to) pricing, annual escalators or other pre-determined price increases, minimum delivery amounts, and contract length.

Disallowance on Prudency Grounds

The purpose of fuel-cost sharing is to motivate the utility to seek ways to reduce its fuel costs. However, it is not the only policy tool available to accomplish this objective. Another option is to identify fuel-cost savings opportunities that are available to the utility and to disallow cost recovery if the utility fails to take advantage of these opportunities.

For example, a regulator might determine that a certain utility could reduce its reliance on natural gas for power generation by 5 percent a year if it aggressively pursues a demand-side portfolio of energy efficiency, demand response, and load-shifting measures. The regulator could then allow the utility to pass through all natural gas costs up to this level via the existing FAC, while disallowing any recovery of costs beyond this level on the grounds that they were imprudently incurred.[25]

As another example, a regulator could demonstrate a willingness to scrutinize all fuel costs presented for recovery and disallow any for which the utility cannot convincingly demonstrate prudency. This more rigorous prudency review could encourage the utility to pursue opportunities to reduce fuel costs, to be more transparent as a strategy to show the regulator that it has been making an effort, and to reduce its reliance on fuel-fired generation over time. For this strategy to be effective, however, it must be clear to the utility that disallowance is a real and substantive risk—simply

[25] The allowed level of natural gas usage could also be adjusted to reflect actual weather conditions. Such a normalization could reduce the risk of windfall losses or gains due to usage fluctuations driven by weather events, which are not under the control of the utility.

applying a slightly higher level of review to an existing FAC docket that currently functions as a rubber stamp is unlikely to be effective.

Hedging

Fuel-cost sharing can reduce the risk posed by fuel-price spikes by encouraging the utility to secure more favorable fuel-supply contracts and reduce its reliance on fuel-based generation sources. However, another way to reduce the risk of price volatility is hedging. Hedging refers to the use of financial instruments to mitigate the risk of unexpected negative investment outcomes. Requiring that utilities hedge can reduce the risk of fuel-price spikes to customers, but hedging also means incurring an additional cost that is then passed on to customers. Whether to encourage or require hedging (or particular kinds of hedging) is a question that should be considered whether or not fuel-cost sharing is in place.

Purchased Power

Fuel-cost sharing is only relevant for vertically integrated utilities that purchase fuel to generate power and then sell that power to customers. However, some regulated utilities do not own generation (these "wires only" utilities are the norm in restructured states), and even vertically integrated utilities may buy substantial amounts of power from other parties to serve their customers. These parties may include independent power producers, other regulated utilities, and unregulated affiliate companies of the purchasing utility.

Typically, the cost of purchased power is recouped in the same fashion that fuel costs are: as a 100 percent pass-through to customers. A sharing mechanism can be implemented for purchased power in the same way as for fuel costs, but whether this makes sense will depend on local circumstances.

In cases where a regulator is implementing fuel-cost sharing for a vertically integrated utility, applying an equivalent sharing policy to purchased power should be seriously considered—because without this, gaming may occur. For example, during a natural-gas price spike a utility that is subject to fuel-cost sharing but not purchased-power cost sharing could substitute spot-market purchases for its own generation. Such a move would likely raise rather than lower costs to customers, contrary to the goal of the fuel-cost sharing policy. Applying sharing to both fuel and purchased power could avoid this type of behavior.[26]

However, in cases where the utility does not own generation, the case for applying a sharing policy to purchased power is less clear. For a utility that has substantive opportunities to lower these costs through its own actions, a purchased-power sharing policy could make sense. For instance, a wires-only utility may be able to lower the cost of the power it purchases by aggressively promoting energy efficiency programs to its customers. It could also lower costs by negotiating better contracts, switching to different suppliers, or helping customers shift demand to lower-cost hours (e.g., via demand-response programs, managed EV charging, and time-varying rates). However, if a wires-only utility has limited control over purchased-power prices (e.g., because it purchases most of its power through wholesale markets where it acts as a price-taker rather than as a price-setter) and

[26] If a purchased-power sharing policy is adopted alongside a fuel-cost sharing policy, they should be equivalent—but this does not mean identical. Since fuel costs only make up a portion of purchased-power costs, the sharing factor for purchased power could be lower than the one applied to the utility's own fuel costs.

limited ability to influence customer behavior (e.g., because a separate state entity is responsible for administering demand-side management programs), it may make little sense to apply a sharing mechanism to its purchased power costs.

Stakeholders should also note that purchased power includes electricity generated from both fuel- and non-fuel resources. This means that purchased-power cost sharing will not necessarily drive decarbonization in the same way as fuel-cost sharing would be expected to. Where reducing carbon emissions is an important policy goal, additional strategies to accomplish this aim could be considered. For example, the sharing mechanism could be designed in a way that distinguishes between different types of generation resources (e.g., it could apply a higher pass-through percentage to renewables than to fossil fuel-fired generation).

Examples of State Fuel-Cost Sharing Policies

A few states have adopted fuel-cost sharing mechanisms to varying degrees, and interest in this neglected aspect of utility regulation has been growing in recent years. However, advocates should keep in mind that just because a particular design feature is common does not necessarily mean it is a good idea. Being familiar with existing forms of fuel-cost sharing policies but also willing to advocate for improvements to them is likely to result in the best outcome. States that have implemented fuel-cost sharing include Hawaii, Idaho, Oregon, Wyoming, Montana, Washington, Wisconsin, Vermont, and others. Below we discuss how a few of those states have adopted such policies.

Hawaii

The Hawaii Public Utilities Commission adopted fuel-cost sharing for the Hawaiian Electric Companies (HECO) in 2018.[27] The Energy Cost Recovery Clause (ECRC) utilizes a straight-sharing approach anchored to a forecast of fuel costs, in which the utility passes through 98 percent of fuel costs to customers regardless of whether its actual costs are above or below the forecast. HECO's annual financial exposure under the policy is capped at $2.5 million. In 2022, the Commission invited intervenors to consider proposals to modify the risk sharing component of the ECRC, signaling an openness to increase the sharing factor—though no decision to adjust it has yet been made.[28]

Idaho

The Idaho Public Utilities Commission adopted the Power Cost Adjustment (PCA) mechanism for Idaho Power in 1992 to share power supply costs between the utility and its customers. The mechanism features a straight sharing design, relies on forecasts, is symmetrical, and includes purchased power. The PCA initially passed through 90 percent of power supply costs, but in 2009 the commission increased this to 95 percent. In approving this change, it explained that "power supply cost volatility has increased significantly since the PCA was implemented, and that with increased volatility, a sharing percentage of 5% still provides strong incentive for the Company to

[27] Hawaii Public Utilities Commission, Final Decision and Order No. 35545, Docket No. 2016-0328, June 22, 2018, https://puc.hawaii.gov/wp-content/uploads/2018/06/DO-No.-35545.pdf

[28] Hawaii Public Utilities Commission, Decision and Order No. 38429, Docket No. 2018-0088, June 17, 2022, pg. 56.

make prudent power purchases."[29] In 2009, the commission also adopted a mechanism called the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM features straight sharing with a 95 percent pass-through, has a symmetrical design, employs forecasts, and includes purchased power.[30]

Wyoming

In 2011, the Wyoming Public Service Commission adopted the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM was a modification of a prior sharing policy called the Power Cost Adjustment Mechanism (PCAM), which was created based on a statute that allowed the commission to use non-traditional rate tools to optimize outcomes.[31] The ECAM trues up the utility's actual net power costs (which include fuel, purchased power, and certain other costs) to its forecasted costs in a symmetrical fashion. The ECAM previously featured a 70 percent pass-through and it employs an 80 percent pass-through today.[32]

Missouri

In 2005, the Missouri legislature enacted Senate Bill 179, which was subsequently codified as Section 386.266 of the Revised Missouri Statutes (RSMo). The legislation authorized the utilities to pass fuel and purchased power costs through to customers if approved by the Missouri Public Service Commission, and it also granted authority to the commission to include an incentive for efficiency and cost-effectiveness as part of the mechanism. The commission implemented the first mechanism in 2007 (and the last one in 2015). In Missouri, these mechanisms are referred to as "fuel adjustment clauses" (FACs) even if they feature fuel-cost sharing.[33] The mechanisms in place for Ameren, Evergy, and Liberty Utilities all feature straight sharing with a 95 percent pass-through.[34]

Wisconsin

The Wisconsin Public Service Commission was authorized by Wisconsin Statute § 196.20(4) to establish automatic adjustment clauses for regulated utilities, and the commission codified the rules

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[29] Idaho Public Utilities Commission, Order No. 30715, Case No. IPPC-E-08-19, January 9, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE0819/OrdNotc/20090109final_order_no_30715.pdf

[30] Idaho Public Utilities Commission, Order No. 30904, Case No. PAC-E-08-08, September 29, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE0808/OrdNotc/20090929final_order_no_30904.pdf; Idaho Public Utilities Commission, Order No. 35419, Case No. PAC-E-22-05, May 26, 2022, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2205/OrdNotc/20220526Final_Order_No_35419.pdf

[31] Wyoming Public Service Commission, Memorandum Opinion, Findings, and Order, Docket No. 20000-368-EA-10, February 4, 2011, https://pscdocs.utah.gov/electric/09docs/0903515/71051ExhibitA2-9-11.pdf

[32] For the present 80 percent pass-through policy, see the current version of Sheet No 95-6 (P.S.C. Wyoming No. 17, Original Sheet No. 95-6). For the previous 70 percent pass-through policy, see P.S.C. Wyoming No. 16, First Revision of Amended Original Sheet No. 95-6 Canceling Amended Original Sheet No. 95-6. Source: Rocky Mountain Power, Energy Cost Adjustment Mechanism, Schedule 95. The current tariff can be downloaded at: https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf

[33] This is different from how we use this term in this primer, where we define a FAC as a 100 percent fuel-cost pass-through mechanism.

[34] Lena M. Mantle, Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper; Office of the Public Counsel, Revised January 14, 2022, https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=939661980

for doing so as Wisconsin Administrative Code § PSC 116.03.[35,36] Under these rules, each of the state's five major investor owned electric utilities (Wisconsin Electric Power Company, Wisconsin Public Service Corporation, Madison Gas & Electric, Wisconsin Power and Light, and Northern States Power – Wisconsin) are required to file fuel cost plans.[37] Each plan includes a forecast of the utility's expected costs for fuel, purchased power, and related expenditure categories to be collected from customers. Once the utility's actual fuel (and related) costs are known, the commission can approve a true-up to collect or refund any difference that represents 2 percent of the forecasted amount. In other words, there is a 2 percent deadband where no sharing occurs and a 100 percent pass-through outside this deadband. The commission has the authority to rule on whether or not the utility's actions were prudent when determining the extent of cost recovery to be allowed. The true-up occurs through a fuel adjustment which appears on customers' bills.[38]

Conclusion

Many Americans today struggle to pay their electric bills. Fuel costs often represent a large share of customer bills, and unlike most rate components these charges can vary substantially from month to month. Reducing fuel costs—as well as fuel-cost volatility—is imperative to ensuring that electricity is affordable and accessible to all.

Fortunately, electric utilities have more ways to reduce fuel costs today than ever before. These opportunities exist on both the supply and demand side (e.g., increasingly cheap solar and wind generation, distributed energy resources that shift load to lower-cost hours), and they are enhanced by supportive federal policies like the Inflation Reduction Act (IRA). However, these opportunities have not spurred a utility rush to decrease fuel costs. Why?

The answer is that most states pass 100 percent of fuel costs through to customers, which gives utilities no financial incentive to reduce these costs. If a utility finds any savings, customers reap all the benefits—and if it spends more than necessary, customers pick up the bill.

It is time for these outdated policies to change, and advocates can play important roles in this process. This primer has described the problems created by existing 100 percent pass-through policies, explained how fuel-cost sharing reforms can produce better outcomes, and provided tools that advocates can leverage to encourage reforms in their states. If these reforms are well designed, they will result in lasting benefits for customers, utilities, and the environment.

[35] Wisconsin Statutes, https://docs.legis.wisconsin.gov/statutes/statutes/196/20

[36] Wisconsin Public Service Commission, Chapter PSC 116, March 15, 2023, https://docs.legis.wisconsin.gov/code/admin_code/psc/116.pdf

[37] Wisconsin Public Service Commission, Final Decision, Docket 6680-ER-103, December 13, 2022,

[38] Alliant Energy, RE: Wisconsin Power and Light Company Electric Tariff for Fuel Adjustment, Docket No. 6680-ER-103, December 21, 2022, https://apps.psc.wi.gov/pages/viewdoc.htm?docid=455114

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
	)	
Georgia Power Company's	**)**	**Docket No. 56765**
Fuel Cost Recovery (FCR-27)	**)**	

EXHIBIT AL-3

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's	)	
2023 Fuel Cost Recovery (FCR)	)	Docket No. 44902
Application	)	

DIRECT TESTIMONY
OF
BRENT ALDERFER

ON BEHALF OF SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY ("SACE")

April 14, 2023

Q: PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.

A: My name is Brent Alderfer. I am a former public service Commissioner, an energy project developer and policy advisor. My address is Meetinghouse Rd, New Hope, Pennsylvania.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: Sierra Club and Southern Alliance for Clean Energy ("SACE").

Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE, AND EDUCATIONAL BACKGROUND.

A: I have a law degree from Georgetown University and an electrical engineering degree from Northeastern University.

I am cofounder and CEO of a company that developed utility-scale solar generation starting in 2010. We developed several gigawatts of utility-scale solar early in the commercialization of solar for utilities across the country, bringing the price down to compete in competitive bidding with other technologies. We developed the Butler Solar project here in Georgia, which was selected by Georgia Power through a competitive bid process and included in its 2015 energy portfolio. The project was purchased in 2015 by Southern Power, a subsidiary of Southern Company. By 2021 we had developed several gigawatts of solar projects and built a pipeline of about 10 gigawatts of solar projects under development. At the end of 2021 we sold the solar development company to AES Corporation, a global diversified energy company rapidly expanding renewable energy assets. I have no financial interest in AES or in solar project development.

In the decade prior to 2010 we developed utility-scale wind farms. We originated early wind projects with utility green pricing programs in partnership with 15 different utilities as the economics of wind generation in moderate wind regimes improved. As the economics of wind technology continued to improve at scale, we developed larger wind projects and by 2005 had originated about two gigawatts of projects. We sold the wind development company in 2006 to Iberdrola, a Spanish utility and largest owner of renewable energy at the time. I worked for Iberdrola for several years as they entered the U.S. market and built out the pipeline of wind projects in the U.S. They now own eight utilities in the U.S. serving about

3 million customers under the name Avangrid. I have no financial interest in Iberdrola, Avangrid or wind development. Prior to wind and solar development, I was a utility Commissioner on the Colorado Public Utility Commission. Prior to that I practiced law in corporate and commercial practice in Denver and Philadelphia. I have attached a copy of my CV to my testimony (BA-Exhibit 1).

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: No.

Q: WHAT IS THE FOCUS OF YOUR CURRENT WORK?

A: Currently, I am working and advising on projects delivering favorable economics in the transition to reliable, clean energy portfolios. I serve on the board of New Energy Economics, a 501(c)(3) organization offering non-partisan data-driven analysis on energy policy options that result in clean-energy paths to lower utility rates, maintain reliability, and foster economic development for communities and states.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: In my testimony, I provide the following:

- A review of the drivers of Georgia Power's proposed fuel cost increase, including increasing fuel prices, greater fuel price volatility, and increased reliance on natural gas generation in Georgia Power's portfolio;
- Forward planning assumptions based on rising fuel prices and fuel price volatility and their impact on rates and on Georgia Power's ability to make prudent necessary investments in the future;
- Tools for the Commission to mitigate and hedge fuel-cost risks;
- A summary of the shared economics of adding renewable generation including additional solar generation to the utility portfolio;
- Considerations in applying the "just and reasonable" statutory standard to the sudden and extreme fuel-cost increases underlying this and future fuel cases.

Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A: I reviewed:

(i) The direct testimony of Sarah P. Adams and Adam D. Houston on behalf of Georgia Power Company, and

(ii) Section 46-2-26 of the Georgia Code: Restriction as to Utilization of Fuel-Adjustment Tariffs; Procedure for Rate Change by Utility Based Solely on Change in Fuel Costs; Extent of Commission's Power Over Rate Changes; Disclosure Requirements for Utilities Seeking Rate Change

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

- Planning assumptions going forward need to assume, prepare for and reduce exposure to higher and more volatile natural gas prices;
- High concentrations of natural gas generation in the portfolio multiply the rate shock from increases and swings in fuel prices;
- Renewable generation as a fuel-free resource lowers electricity costs and provides an effective long-term hedge against high and volatile fuel prices;
- Economics of utility-scale solar allow fuel savings to utility customers on the order of the fuel cost shocks at issue in this case, while at the same time offering investment earning potential for the utility;
- Rapid and irreversible structural changes in and exposure to global markets require an update of low fuel-price assumptions and resulting resource decisions as a fundamental underlying element of just and reasonable allocation of fuel costs.

Q: IN GEORGIA, HOW ARE UTILITY FUEL COSTS INCLUDED IN CUSTOMER UTILITY BILLS?

A: As part of the "Jurisdiction, Powers and Duties Generally" of the Public Service Commission, the Georgia Code provides a procedure for the utility to change customer rates "based solely on change in fuel costs". O.C.G.A. 46-2-26. The statute requires Commission review under a just and reasonable standard with the burden of proof on the utility to show that an "increased rate, based on fluctuations in fuel costs, is just and reasonable" O.C.G.A. § 46-2-26(d).

Q: IS THIS A COMMON WAY FOR COMMISSIONS TO APPROVE FUEL COST RECOVERY?

A: Yes, since the late 1970s when swings in fuel prices tied to global oil embargos and global oil demand first appeared many states adopted fuel cost recovery mechanisms to "pass through" fuel price increases directly to customers outside of full utility rate cases that otherwise establish just and reasonable customer rates and utility earnings. Georgia Power recently completed a rate case with new rates taking effect January 1st of this year. This fuel cost recovery case filed so closely upon the recent rate case illustrates the separation of fuel costs from other elements of utility cost of service and the direct impact of fuel costs on customer utility bills.

Q: IN GEORGIA POWER'S STATEMENT ON THE PROPOSED FUEL COST INCREASE, THE COMPANY EMPHASIZED THAT IT DOES NOT EARN A PROFIT ON THE FUEL COSTS. HOW SHOULD THAT AFFECT THE COMMISSION'S CONSIDERATION IN THIS PROCEEDING?

A: The utility earns a profit from investments in fuel-burning generation but does not earn profits on fuel purchased for that generation. No party in this case profits from higher fuel costs. The issue of course is who bears the losses.

There have been objections over the years from consumer advocates and others to one-hundred percent allocation of fuel risk to customers on grounds of fairness and one-sided risk. Separation of control and risk removes incentives to control fuel costs and mitigate fuel risks. As long as fuel prices stay low, the risk is low and the cost burden less significant and so fuel-cost pass-through mechanisms have received little attention in the recent past. The question for the Commission is what is "just and reasonable" in the allocation of fuel costs when low fuel prices are no longer the norm.

Two underlying factors have altered the bargain under fuel-adjustment provisions. First, fuel led by natural gas has entered a period of rapid and extreme price volatility. On its face it is not reasonable to assume that either customers or the utility can absorb fuel-cost changes of this magnitude in their household

or business operating budgets, respectively. Unrestrained fuel costs create a no-win situation for the Commission to allocate unreasonably large and unpredictable costs from which no one benefits.

The second change in the landscape in the last decade is greatly reduced costs (up to 80 percent reductions) for fuel-free alternatives, including solar, wind, storage and efficiency. Because these resources use no fuel they hedge fuel prices, lowering the fuel-cost burden on customers and the utility. Georgia Power has experience with and referenced those fuel-cost hedging benefits in their testimony. Those benefits are limited currently by the comparatively small levels of renewable energy in the portfolio.

A greater share of renewables in the generation portfolio, in addition to lowering and stabilizing rates for customers offers an increased investment opportunity. With no fuel costs, virtually all of the levelized energy cost is capitalized up front, which means a very secure and stable capital investment with commensurate investment opportunities. Under well-established competitive procedures for securing those needed resources at the best price, the utility could potentially capitalize on those investments and earn a profit on them, which as it noted it does not earn on purchasing fuel for the current portfolio.

Q: WITH REGARD TO THE INCREASING BURDEN POSED BY FUEL PRICES, HOW SHOULD THE COMMISSION ASSESS THE MAGNITUDE OF CURRENT FUEL GAS PRICE SWINGS?

A: Fuel prices have risen in multiples above the low-price assumptions used by Georgia Power in previous planning and resource decisions. Georgia Power described the cost increases as "unprecedented":

> For electric utilities, like Georgia Power, the impact of elevated fuel prices – particularly the price of natural gas, which more than tripled between 2020 and 2022 – was especially acute, given their reliance on natural gas as a critical fuel resource to generate electricity. In addition to natural gas, commodity prices for coal – another critical fuel resource for electric utilities – reached unprecedented levels, increasing nearly five-fold from 2020 to 2022. (Direct Testimony of Sarah P. Adams and Adam D. Houston On Behalf of Georgia Power Company Docket No. 44902 Page 5 of 23.)

The utility has under-recovered fuel costs of $2 billion over 2 ½ years and projected the bill could reach $2.6 billion, due to low fuel-cost assumptions. As I will describe later, these cost increases are actually *not* unprecedented.

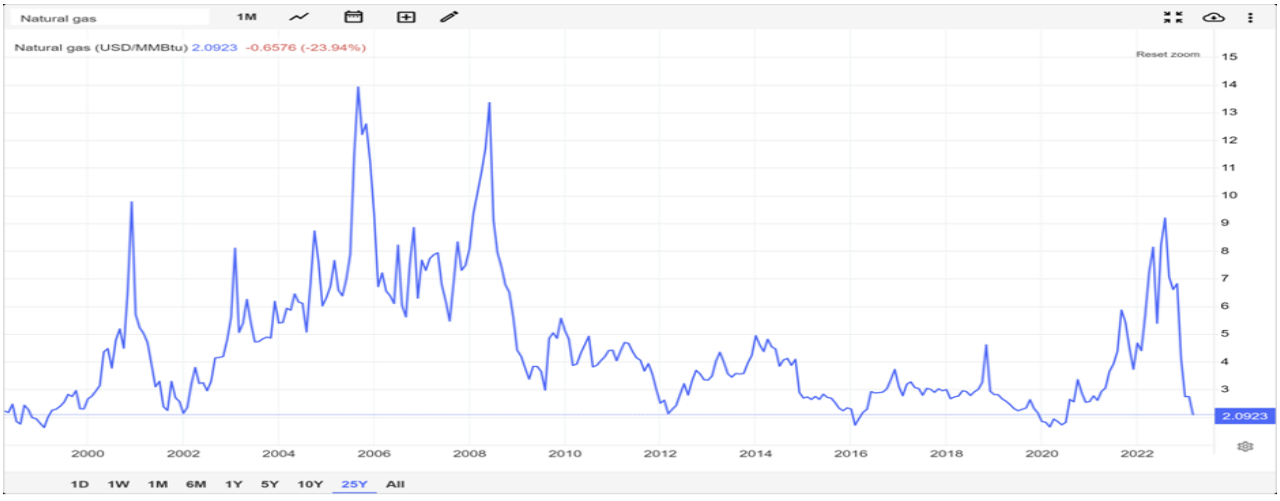
Q: WHAT ARE THE IMPACTS OF THESE MUCH HIGHER FUEL COSTS ON CUSTOMERS AND THE UTILITY?

The impact on the utility customers is an electric bill increase as sudden and extreme as the increase in fuel costs. There are few options to mitigate the $2.6 billion of excess cost. The utility has proposed spreading recovery of the shortfall over the next three years and increasing by $2 per month relief for seniors to ease the burden. Reducing the immediate customer burden at any level is of course desirable and necessary in the current circumstances, but it doesn't solve the underlying problem. Without a plan to address heavy dependency on natural gas fuel cost overruns will continue to burden customers and crowd out headroom for necessary improvements and investments by the utility going forward.

Q: WITH NATURAL GAS PRICES HAVING COME DOWN CAN THE COMMISSION AND RATEPAYERS ASSUME THESE LARGE FUEL COST SPIKES WON'T HAPPEN AGAIN?

A: No. The risk of increased fuel prices and volatility rises over the next decade. Recent price swings are not the result of short-term supply and demand issues. As Georgia Power accurately summarized in its pre-filed testimony, the price increases and volatility are the result of structural changes in global markets for natural gas, the exposure to which is expanding here in the U.S. We have entered a market where global forces dominate natural gas prices. Here is the curve of natural gas prices over the last 25 years:

Figure 1



It is easy to see on this chart that while recent price increases are unprecedented in the last decade, they are not unprecedented overall. The recent swings are actually smaller and just beginning in comparison to the size of price swings and duration of price volatility experienced in the prior decade. The current drivers of natural gas markets are global with larger and less predictable forces. As Georgia Power confirmed in its testimony, geopolitical unrest and increasing absorption of domestic production for global demand with proliferation of Liquid Natural Gas (LNG) terminals in the U.S. now drive natural gas prices. More LNG export terminals are scheduled to come on-line on the East and Gulf Coasts in 2024. Some have described these export terminals as potentially "starved" for natural gas supply. At a minimum each terminal brings competing demand and opens further exposure to global market forces.

Continued high price volatility assumed by Georgia Power is consistent with current industry prognoses. A recent article in the commodity trade press summarized prospects of continued natural gas volatility as follows:

> "I think volatility is here to stay for the foreseeable future," Citi analyst Paul Diamond told *Argus*. "The underlying issues causing that step change in the last 24 months are not going away." If one measures volatility by the number of days an asset moves by more than 7 percent in value, 2022 was the most volatile year for natural gas prices since at least the beginning of the shale era. In 2022, the price for day-ahead delivery at the US benchmark Henry Hub in Louisiana rose or fell by more than 7 percent on 65 occasions, the most of any year since at least 2009, according to an *Argus* analysis. So far, the Henry Hub has done so 21 times this year. At that rate, 2023 will be more volatile than 2022.[1]

The dangers posed by future price swings is multiplied by the asymmetric risk of fuel price changes. Given the low fuel-price assumptions in the past, potential savings from downswings in fuel prices are extremely limited, maybe $1/MMBtu at most since prices stay above zero, whereas there is no cap on increasing prices that rise by several hundred percent to $14/MMBtu or more as shown on the historical price chart.

Q: WHAT ASSUMPTIONS SHOULD THE COMMISSION USE FOR FORECASTING NATURAL GAS PRICES AND PRICE VOLATILITY GOING FORWARD?

[1] Argus Media. "US Gas Price Volatility Likely To Continue." Published on 28 March 2023.

A: The Commission should use the planning assumptions presented by Georgia Power in this case, which are higher natural gas prices and greater volatility. Georgia Power properly recognized the need going forward "to respond to the type of sudden and extreme fuel price volatility that impacted global fuel markets during the FCR-25 period." (Direct Testimony at page 4 of 21). The response proposed in this case is a 267% increase (from 15% to 40%) in the amount of future fuel cost increases that would automatically pass through to customers under the Interim Fuel Recovery Mechanism, without advance review by the Commission (Direct Testimony at page 4 and 21).

Q: WHAT DOES THAT MEAN FOR UTILITY CUSTOMERS AND THE UTILITY?

A: What it means is more, not less, customer exposure to fuel price increases. It may mean fewer cases like this to review bill increases but expanding the Interim Fuel Recovery Mechanism will allow multiple bill adjustments like this as routine rather than extraordinary events. Planning for more frequent and larger price pass-throughs is consistent with Georgia Power's assessment of the structural changes to natural gas markets that now determine prices. This is not a one-off event. Georgia Power also pointed out that fuel-price exposure has increased because it has increased natural gas fired generation in its portfolio, which multiplies any given fuel price increase into higher total dollar fuel costs passed on to customers. Whether less Commission review of future fuel-cost pass-throughs is the right response is the underlying issue in this case.

Q: ARE THERE WAYS TO MITIGATE FUEL COSTS AND FUEL COST VOLATILITY TO AVOID RATE-SHOCK IN THE FUTURE?

A: Yes, Georgia Power referenced it in the direct testimony of Ms. Adams and Mr. Houston. After noting that the dollar per megawatt-hour costs for coal, natural gas, and nuclear generation resources are projected to increase 97%, 82%, and 17%, respectively, the testimony stated that renewable generation lowers the cost of fuel, adding a planned increase in renewable resources:

> "Generation from renewable resources – which lowers the cost of fuel – is estimated to increase almost 1,150 gigawatt hours ("GWh") or 41%." (Direct Testimony of Ms. Adams and Mr. Houston at 15).

That current planned increase in renewables amounts to about 1.4% of total load.

At the average price of $5.14 per mmbtu projected for FCR-26 test period (Direct Testimony of Ms. Adams and Mr. Houston at 15) the increase in renewable resources proposed by Georgia Power saves about $140 million over the three-year period proposed for recovery of the fuel cost excess. By comparison, under the same assumptions, adding solar generation equal 10% of total load would save about $1 billion in fuel costs over three years and additionally thereafter.

Q: THAT LEVEL OF FUEL SAVINGS WOULD CERTAINLY BE WELCOMED BY CUSTOMERS. HOW WOULD IT WORK FOR THE UTILITY?

A: The economics of solar and other renewables at utility scale are competitive with natural gas and coal fired generation on a levelized-cost-of-energy basis. That means, simply by buying renewable energy under long-term contracts, the utility can lock in energy savings and hedge against future fuel price swings.

As mentioned, capital investment in renewable energy generation offers additional benefits for the utility if the Commission allows such investments. With no fuel costs, virtually all of the levelized cost of renewable energy is upfront capital expense, with very low ongoing-operating costs. Twenty-five-year product warranties are standard for solar projects, which now have decades of proven operating history and rock-solid results with no volatility and no surprises. That is a gold standard for capital investment. With no fuel cost, dollars formerly expended on fuel are invested as upfront capital.

As an example, based on the numbers in this case, adding another 10% solar would mean about 3.5 gigawatts of new solar capacity, which after accounting for tax credits would mean a total capital expenditure approximately the same as the amount sought in recovery in this one fuel case. In addition to bill savings for customers, utility investment in some part of that portfolio would increase utility earnings, strengthening the financial health of the utility, which is always a consideration of the Commission. This has been described as a “steel for fuel” strategy and brings the win-win benefits of renewable energy home to the broadest range of Georgia beneficiaries.

There are additional economic development benefits available from investing in renewable energy. Under last year’s Federal amendments, there are significant adders to the applicable tax credits for domestic

content and for preferred redevelopment sites in the state. In addition, in the state-on-state competition for U.S. based manufacturing, which has experienced a surge of proposals, sites that cannot offer clean renewable electricity have lost out to competing sites that can. Given that the fundamental economics are favorable, there is no reason not to capitalize on the economic development benefits that come with it.

Competitive procurement of renewable generation allows the Commission to assure the most savings for customers and establishes market investment returns should the Commission choose to allow utility investment and profit on additional investment. Other states have effectively used competitive procurement to lower the capital expenditures and in some instances divided a portfolio of projects between utility and independent ownership. Competitive procurement to assure the best price for renewable resources has resulted in favorable and unexpectedly low costs for adding renewable resources to utility portfolios. Georgia Power used competitive bidding to procure solar power in the past and would undoubtedly get vigorous bid competition in further procurement. Competitive procurement and potential utility project ownership are two of the most effective tools the Commission has to secure the new energy economics available to counter increases like the ones faced in this proceeding. Both of those proven approaches should be adopted by the Commission.

Q: YOU MENTIONED THAT FUEL CASES HAVE TRADITIONALLY SIMPLY PASSED FUEL COSTS DIRECTLY THROUGH TO CUSTOMERS IN INCREASED RATES. WHAT ELSE SHOULD THE COMMISSION DO?

A: In fuel cases like this, the Commission is looking to review, manage and allocate fuel price risk. Given the consensus that economic and market circumstances elevate the risk of continued fuel price hikes, determining what is "just and reasonable" will require the Commission to investigate and address the sudden and extreme price increases to date.

Georgia Power accurately explained that the current elevated fuel risk derives from the combination of (i) changing global markets, which are accelerating and here to stay, and (ii) increased share of natural gas generation in its portfolio. The market changes are reasonably clear and outside of the control of Georgia Power and the Commission. The concentration of natural gas generation is under the control of Georgia

Power and the Commission and arises from multiple decisions in multiple dockets, including IRPs, rate cases, avoided cost dockets and energy efficiency proceedings. A quick review of the economics of renewable energy as a cost-effective hedge to natural gas market changes in this case shows the need for the Commission to update the resource portfolio economic assumptions as part of a just and reasonable determination.

Q: HOW SHOULD THE COMMISSION DO THAT?

A: The first step is updated fuel price assumptions across all resources and planned resource additions to assure that the Commission has an updated assessment of fuel price impacts. That is a clear first step to assure customers that the Commission is on top of fuel price risks and taking the necessary steps to mitigate fuel risk on their behalf.

The economics compel an update of fuel price assumptions across the generation portfolio (whether previously included in the 2022 IRP or other dockets). The goal is to avoid spending short-term dollars on fuel when those same dollars could deliver greater short- and long-term savings and returns. The rapid market changes leading to this case demonstrate the urgency of getting updated assumptions in place now before next round of fuel price swings.

The second step is to align utility and customer interests in decisions on fuel costs and capital investment. As a starting point the utility might bear a percentage of the fuel-price risks of the current portfolio in return for expanded investment opportunity in a more price-stable future portfolio.

Since there are alternatives that are win-wins for both Georgia Power and its customers, detailing those alternatives is the Commission's next step. The Commission deserves to have the options identified and quantified with current data to avoid more surprises.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A: In summary, I recommend that the Commission in this proceeding or in a proceeding opened for this purpose:

- Make a finding based on the facts presented in this case and to protect customers from unreasonable fuel-cost increases, that a high-case projection of fuel prices, volatility and

risk needs to be included as the base-case assumption in resource decisions and planning going forward;

- Update fuel-cost assumptions and quantify potential cost savings and investment returns as well as other future and long-term benefits from adding fuel-*free* renewable generation to the utility portfolio above the levels currently proposed; and
- Establish a just and reasonable percentage of fuel-price risk in the current portfolio to be borne by the utility in return for expanded investment opportunity in a more price-stable future portfolio.

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

R Brent Alderfer

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Professional Summary

Brent Alderfer is a seasoned entrepreneur and renewable energy expert with extensive experience in the development of utility-scale wind and solar energy projects. With a background in electrical engineering and law, he founded Community Energy, Inc., a leading renewable energy firm. Under his leadership, the company became a major player in the renewable energy industry, providing renewable projects and related market services to utilities and businesses across the country. The Company sold its wind energy development business to Iberdrola in 2006 and sold its solar energy development business to AES in 2021.

Education

- Bachelor of Science in Electrical Engineering, Northeastern University
- Law Degree, Georgetown University

Work Experience

- Founder and CEO, Community Energy, Inc.
    - Led the company's growth and expansion into a major player in the renewable energy industry
    - Developed wind and solar projects across the United States
    - Provided renewable energy products and services to utilities and businesses
- Commissioner, Colorado Public Utility Commission (1996-1999)
- Commercial Lawyer, various law firms (1980s-1990s)
    - Represented commercial clients on corporate, finance and regulatory matters

Skills

- Renewable energy project development
- Finance, renewable energy projects
- Policy, regulatory compliance
- Leadership and team management
- Strategic planning and business development

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Accomplishments

- Ernst & Young Entrepreneur of the Year Award
- Sustainable Energy Fund, Pennsylvania, Lifetime Achievement Award
- Member of various industry and environmental organizations

Interests, Organizations

- New Energy Economics
- MEDA, International Development
- Philanthropy and community involvement
- Farming
- Outdoor, skiing, running, hiking

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Albert Lin on behalf of Georgia Interfaith Power & Light and Southface Institute** was filed with the Public Service Commission in Docket No. 56765 by electronic delivery on the 9th of April, 2026. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



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