STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	
	)	
	)	

DIRECT TESTIMONY

OF

JEREMY KALIN

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL ("NRDC"),

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

09 APRIL 2026

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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: I was asked by the Natural Resources Defense Council ("NRDC"), Sierra Club and Southern Alliance for Clean Energy ("SACE") to testify in this proceeding.

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

A: I am an advisor, 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 on energy project finance, energy policy and related business issues. I have attached a copy of my CV to my testimony (JK-Exhibit 1). I am also an author of the 2023 paper published by Rocky Mountain Institute ("RMI"), "Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators" 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. 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. From 2010 to 2017, I served as CEO of Eutectics Consulting LLC, a mission-driven

company focused on financing energy projects in underserved and untapped markets. While in public office, I served as state legislative liaison for the White House energy policy team, and later advised the U.S. Department of Energy Jobs Strategy Council under Democratic and Republican Secretaries of Energy. Among other projects, in 2013, I led the modernization of Minnesota's nationally-recognized Energy Assurance Plan, and have continued to be deeply engaged in emergency preparedness and response since then.

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.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A: Yes. I previously testified before the Georgia Public Service Commission in Docket 44902, in re: Georgia Power Company's 2023 Fuel Cost Recovery (FCR-26) Application.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: In my testimony, I provide the following:

1. A history of fuel-cost-passthrough policies, including Georgia's Fuel Cost Recovery mechanism;
2. An explanation of the "moral hazard" presented by Georgia's Fuel Cost Recovery mechanism, and why the Georgia Power request and the FCR itself continue to pose a threat to Georgia ratepayers' economic wellbeing and electricity reliability;
3. Other states' actions to reduce the moral hazard of fuel pass through policies, protect ratepayers and strengthen reliability;
4. Factors the Commission should consider in evaluating whether Georgia Power's significant rate increases are prudent and justifiable, in light of:
    a. The Commission's invalidation of only 0.05% of all fuel expenses dating from FCR-21 to today;

b. Georgia Power's implied admission that the utility has not taken any meaningful steps to reduce ratepayers' exposure to Georgia Power's fuel costs;

5. The reliability vulnerabilities to which Georgia Power's overreliance on natural gas as an electric generation source and the FCR-27 request exposes Georgia's entire electric sector;

6. Context for evaluating Georgia Power's proposed 200% increase in natural gas hedging authority to $3.32 billion;

7. 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%.

8. A recommendation to the Commission to:

a. Amend the FCR procedures under which the Commission evaluates the prudence, economic value and reliability impacts of FCR applications;

b. Amend the FCR testing period procedures to establish more reliable and accurate forecasts and benchmarks for FCR tariffs;

c. Reject most of the FCR-27 application and require that Georgia Power submit a revised FCR-27 application with:

i. updated natural gas price forecasts in light of the global natural gas volatility caused by the war in Iran and the Straits of Hormuz transit access challenges;

ii. greater clarity on the impact of increased oil prices and oil price volatility on the delivered coal forecast and the coal transportation services agreements entered into the Company since FCR-26;

iii. a natural gas hedging plan restricted to the current authority provided in FCR-26;

iv. an IFR threshold increase to $300 million, but only if tied to a symmetrical fuel-risk-sharing and fuel-cost-sharing mechanisms

wherein Georgia Power is responsible for ten percent (10%) of the total cost of all fuel expense risk.

d. Adopt the proposed FCR-27 tariff rate as an Interim Fuel Rider tariff, in order to provide timely relief to ratepayers until Georgia Power submits a revised FCR application and the Commission approves such revised application.

e. Regardless of action on Georgia Power's FCR-27 application, the Commission should initiate a full Fuel Cost Recovery modernization docket, including requiring the utility to be responsible for some portion of fuel purchase risks and fuel purchase costs for all future FCR tariffs.

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, Official Code of Georgia Annotated ("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 ("PSC"). 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.

I. HISTORY OF FUEL COST PASSTHROUGH MECHANISMS

Q: HOW DOES GEORGIA'S FUEL COST RECOVERY MECHANISM COMPARE WITH THE OTHER STATES, INCLUDING THE HISTORY OF FUEL PASS THROUGH CLAUSES?

A: During most of the first 100 years of the electric power industry, fuel costs were the complete responsibility of utilities. The National Electric Light Association ("NELA") argued in 1907 for what we know today as the electric utility regulatory compact, recognizing that financially

sustainable electric utility business models depended on access to capital to expand utility service; accepting state regulation and public oversight of capital investments would provide these utilities 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."[1]

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.

When World War I disrupted oil, coal and gas supply, fuel prices increased significantly with significant month-to-month volatility. In one of many war-time measures, electric utilities asked regulators for insulation against these fuel-price swings and the resulting major financial risk. Commissions and other regulators responded by authorizing temporary fuel-pass-through policies, which were terminated soon after the end of World War I.

World War II sparked a similar global disruption of energy supply, amidst extensive economy-wide rationing. Regulations again adopted 100% fuel pass-through-policies, provided utilities relief from unprecedented price volatility and supply challenges. Amidst victory gardens and ration books, utility customers likely understood that the higher cost of electricity – including the complete passthrough to ratepayers of electric generation fuel costs – as their war effort contributions. The end of the war brought with it the end of the fuel pass through regimes, and for nearly three more decades, electric utilities bore full responsibility for all of their fuel costs.[2]

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[1] Vol. 1, National Electric Light Association, *Thirtieth Convention, Papers, Reports, and Discussions*, p. 642 (1907), *available at* https://play.google.com/books/reader?id=hXtNAAAAYAAJ&pg=GBS.RA2-PA28&hl=en.

[2] Electric Consumers Resource Council, *Fuel Adjustment Clauses & Other Cost Trackers* (Sept. 5, 2023), *available at* https://perma.cc/PP42-GDKT.

The 1970s rise of Organization of the Petroleum Exporting Countries ("OPEC") and the associated oil scarcity led to renewed demands from utilities the full fuel-pass-through tariff of the wartime eras. State legislators and utility commissions adopted 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.

Unlike the world wars, the OPEC crisis did not end with any formal treaty or declaration. Neither the Georgia Legislature nor the PSC have revisited this 100% fuel-pass-through policy; many states have similarly let this temporary policy persist without sufficient scrutiny.

Q: DO ALL STATES REQUIRE THAT UTILITIES PASS THROUGH 100% OF FUEL COSTS AND FUEL RISKS TO RATEPAYERS?

A: No. Some states have enacted statutes that specifically require 100% pass-through of fuel costs and fuel risks to ratepayers. Many states, like Georgia, have fuel cost recovery statutes that provide the Commission with flexibility as to the amount of utility fuel costs to be passed to ratepayers. Some states do not have any specific fuel cost pass through statutes but rely on Commission orders.

Q: DOES GEORGIA'S FUEL COST RECOVERY STATUTE, O.C.G.A. § 46-2-26, REQUIRE 100% OF FUEL COSTS TO BE PASSED THROUGH TO RATEPAYERS?

A: No.

Q: CAN YOU EXPLAIN?

A: While I am a lawyer, I am not licensed to practice law in Georgia. My observations are based on several years of work inventorying and reviewing state fuel pass through policies.

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, and the statute does not require the Commission to adopt a rate tariff authorizing a utility to recover **all** of its fuel costs. Further, I have not found any Commission rule or other administrative guidance that requires the Commission must approve a utility's fuel rate tariff such

that the utility recovers 100% of its fuel costs; Georgia's fuel cost recovery regime appears only to require that the Commission may approve a fuel cost recovery tariff. O.C.G.A. § 46-2-26(e) requires the Commission to "issue an order stating the base rates to be used by the utility" going forward, providing the Commission with significant flexibility on the amount of the base rates to be charged and collected from ratepayers.

Consistent with other sections of the Georgia Code and under Commission rules and policies, the Commission can modify the proposed fuel tariff from the utility's application. The Commission has done exactly that in other FCR dockets. In 2005 the Commission reduced Georgia Power's FCR tariff proposed by Georgia Power,[3] and in 2000 the Commission made multiple changes to the proposed FCR tariff alongside consideration of other pending rate-related matters by the utility.[4] The Commission has also rejected the proposed FCR tariff in favor of alternative FCR tariffs, including in dockets 19142-U and 21229-U in 2005, when the Commission required extended amortization periods.

Q: GIVEN THIS HISTORY, HOW DOES GEORGIA POWER'S PROPOSED FCR-27 TARIFF FIT IN WITH RECENT FCR RATES FOR THE COMPANY?

A: This following table accounts for all June through December Secondary Distribution customer FCR tariff rates from FCR-24 through the proposed FCR-27:

FCR-24	3.1718 cents per kWh
FCR-25	3.5484 cents per kWh
FCR-26	4.5876 cents per kWh
FCR-27	3.7214 cents per kWh

[3] *Order* (May 19, 2005), Ga. Pub. Serv. Comm'n, Dkt. No. 19142, *available at* https://psc.ga.gov/search/facts-document/?documentId=82630.
[4] *Final Order* (Mar. 30, 2000), Ga Pub. Serv. Comm'n, Dkt. No. 11884, *available at* https://psc.ga.gov/search/facts-document/?documentId=37553.

Georgia Power's proposed FCR-27 tariff represents a per kWh increase of 17.33% from FCR-24, adopted in 2015, recognizing that the utility's FCR-27 proposal fails to address the looming risks that could very well cause the FCR-27 fuel cost forecast to fall significantly short of actual costs, for reasons I will discuss shortly.

Q: CAN THE COMMISSION BE CERTAIN THAT THE PROPOSED FCR-27 TARIFF WILL NOT TRIGGER FURTHER FCR INCREASES?

A: No, I do not believe so, for reasons I will discuss further, as well as those disclosed by Messrs. Houston and Berrigan in their Direct Testimony. First, Georgia Power's under-recovery of fuel expenses is projected to grow $88 million just in the five-month period of December 2025 through May 31, 2026.[5] The company also admits to increasing fuel expense in the FCR-27 forecasted period, which I believe is likely understated significantly.[6] The Energy Information Administration's ("EIA's") natural gas price update for January 2026, released in March 2026 after the Houston and Berrigan testimony was filed but before the commencement of the war in Iran, shows a 69% increase in natural gas prices to electric generation consumers from January 2025, from $6.21 to $10.20, and a 107% increase from January 2024, from $5.08 to $10.20. In their testimony, Messrs. Houston and Berrigan recognize the significant uncertainty inherent in their FCR-27 proposal, when they state "Taken together, these factors suggest a tighter supply-demand balance and the potential for continued natural gas price volatility."[7]

Second, the company relies on a large-load revenue forecast that must be realized in order to achieve the presumed downward pressure on rates in the company's next base rate case. Messrs. Houston and Berrigan claim that these large load customers "will bear the appropriate cost responsibility in each hour for the fuel cost" and that these large load customers will "reduce rate

[5] *Direct Testimony of Adam D. Houston and Matthew S. Berrigan on Behalf of Georgia Power Company in Support of Georgia Power's Fuel Cost Recovery (FCR-27)*, 4 (Feb. 17, 2026), Ga. Pub. Serv. Comm'n, Dkt. No. 225466, *available at* https://psc.ga.gov/search/facts-document/?documentId=225466 [hereinafter "Testimony"].
[6] *Id*. at 5.
[7] *Id*. at 15.

pressures for all Georgia Power customers."[8] The company properly recognizes in this FCR-27 application that the Fuel Cost Rate tariff reviews must be considered in the context of rate case dockets.[9] Georgia Power is not alone in forecasting the significant growth of data centers, but like any large project – whether a new load or a new generation facility – interconnection capacity, financing, local permitting and any number of other issues are likely to mitigate or slow the pace of such growth. The Company's FCR-27 application appears to require that a significant amount of new data centers be built in order to achieve the claimed benefits or general ratepayer protections.

Third, the company's Projected Fuel Costs, as summarized in Table 3 of the Houston Berrigan testimony, relies heavily on increased coal generation across the company's fleet.[10] The Company claims a 33% reduction in the marginal coal cost assumptions for the FCR-27 test period compared with the FCR-26 historical period, stating such reductions are due in part to "significant lower transportation prices" achieved via newly-negotiated service agreements entered into by the company since FCR-26.[11] The Company's claim requires serious scrutiny, since transportation costs generally account for 41% of all coal purchases for electric power plants,[12] and all or nearly all of the coal delivered to generating plants in Georgia are transported from out of the state.[13] Coal is typically transported by diesel-powered trains, and the Strait of Hormuz closures and access challenges have spurred an immediate four-fold increase in crude oil tanker shipping rates in the Middle East; a backup of vessels confined in the Persian Gulf with already-loaded crude oil has reduced the availability of global tanker capacity and increased tanker rates.[14] This sustained global supply of crude oil has quickly increased domestic rates of petroleum products, including diesel.

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[8] *Id*. at 18.
[9] *Id*. at 17.
[10] Testimony at 16.
[11] *Id*. at 18.
[12] EIA, *Coal Explained*, *available at* https://www.eia.gov/energyexplained/coal/prices-and-outlook.php (last updated Apr. 17, 2024).
[13] EIA, *Georgia, Analysis*, *available at* https://www.eia.gov/states/GA/analysis (last updated Mar. 20, 2025).
[14] EIA, *Middle East Crude Oil Tanker Rates Reached a Multi-Decade High in March* (Mar. 26, 2026), *available at* https://www.eia.gov/todayinenergy/detail.php?id=67386.

Fourth, it is hard to overstate the impact of the war in Iran on fuel cost volatility and the potential impact on Georgia ratepayers. The 2022 Russian invasion of Ukraine was a major cause of the $2.2 billion under-recovery that led to the FCR-26 rate increase. In evaluating the impact of the first 14 trading days after the onset of the Iran hostilities, the Purdue University Center for Agriculture found that the Brent Crude Oil spot price increase in March 2026 is significantly greater than the same period following the first hostilities in Ukraine; the total Brent Crude Oil spot price is higher in real dollars already than the same point in 2022.[15]

The war in Iran also bears significant price volatility risks for natural gas markets. While the Henry Hub spot price for natural gas has remained fairly stable for the first weeks of hostilities along the Persian Gulf, the global natural gas supply has tightened. As the price of natural gas exports from the United State rises, domestic suppliers will continually face temptation to shift from local demand to the more lucrative export market, particularly in the Southeast United States with access to methane export infrastructure.[16]

Q: HOW SIGNIFICANT IS THE FUEL COST RECOVERY TARIFF IN TERMS OF OVERALL ECONOMIC COST?

A: The company incurred $8.409 billion in fuel costs during the three years of the FCR-26 historical period,[17] an average of $2.803 billion per year.

[15] Ken Foster & Bernhard Dalheimer, *The Iran Conflict, Energy Prices, and U.S. Farm Profitability: A Balanced Assessment*, Purdue University Center for Commercial Agriculture (Mar. 31, 2026), *available at* https://ag.purdue.edu/commercialag/home/paer-article/the-iran-conflict-energy-prices-and-u-s-farm-profitability-a-balanced-assessment.

[16] Jamison Cocklin, *Europe's Storage Deficit Expected to Continue Pulling U.S. LNG During Strong Restocking Season*, Natural Gas Intelligence (Feb. 19, 2026), *available at* https://naturalgasintel.com/news/europes-storage-deficit-expected-to-continue-pulling-us-lng-during-strong-restocking-season/.

[17] Testimony at 9 (citing a 2.2% increase of $185 million above budgeted costs, reflecting a total cost of $8.409 billion).

The company's projected fuel cost for the FCR-27 two-year test period is $7.073 billion,[18] an average of $3.536 billion per year. If realized, Georgia Power will incur a 26% increase in fuel costs from FCR-27.

The Company states that large load customers will pay for their required fuel costs, as noted. However, the Company has not clearly stated the extent to which additional fuel costs will be incurred regardless of whether large loads are realized (in other words, whether large data centers are actually built and begin operating), or if some fuel costs will be incurred by the company and cannot be curtailed or avoided should the large load growth not be realized, or fall short of the forecasted load growth. As discussed later, the Company's FCR-27 proposal would position the Company to have committed significant sunk costs into serving these large loads, including but not limited to the hedging premiums incurred months or years in advance of new loads coming online. All of the Company's ratepayers will face these increased hedging premiums if any project large load is not realized within the FCR-27 period, or at all.

Q: WHAT DO YOU ESTIMATE IS THE TOTAL FUEL SPEND BY GEORGIA POWER FROM THE FCR-21 APPLCIATION DATE THROUGH THE FCR-26 HISTORICAL PERIOD?

A: Because I have not accessed any trade secret data, I have relied on the Company's statements in their public filings in FCR proceedings, Annual Reports and annual 10-K disclosure filings to the Securities and Exchange Commission. In doing so, I conservatively estimate, that Georgia Power has incurred between $29 billion and $40 billion dollars on fuel purchases for the generation of electric power, from 2010 through May 31, 2026.

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

[18] *Id*. at 16.

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."[19]

Q: HOW OFTEN HAS THE COMMISSION DETERMINED THAT ANY OF GEORGIA POWER'S PROPOSED FUEL COSTS WERE IMPRUDENT?

A: From FCR-21 through this current docket, the Commission has not ever disallowed any Georgia Power proposed fuel costs for fuel cost recovery from ratepayers for imprudent conduct, nor for illegal conduct.

Q: HAS GEORGIA POWER EVER BEEN REQUIRED BY THE COMMISSION TO REDUCE THE FUEL COSTS RECOVERED FROM RATEPAYERS THROUGH THE FCR TARIFF?

A: From FCR-21 through this current docket, no. Since 2010, the only circumstances under which the company has reduced its total fuel costs recovered from ratepayers has been through voluntary stipulation.

Q: WHAT IS THE TOTAL AMOUNT THAT THE COMPANY HAS AGREED TO REMOVE FROM FUEL COST RECOVERY TARIFFS?

A: Since 2010, from FCR-21 through this current docket, the company has voluntarily agreed to remove from the fuel cost balance a total of just $14.5 million.[20] Working from the most conservative estimate of $29 billion dollars spent by Georgia Power on fuel costs during the same period, this accounts for just 0.05% of all fuel costs incurred by Georgia Power. A more precise calculation of all FCR-claimed fuel cost balance expenses over the period will likely result in an even smaller percentage of voluntarily removed costs. In other words, the Commission has permitted the Company to collect from ratepayers at least 99.95% of all claimed fuel costs.

[19] Ga. Code Ann. § 46-2-26(h) (2024) (emphasis added).
[20] $6 million in the FCR-24 stipulation agreement; $1.5 million in the FCR-25 stipulation agreement, and $7 million in the FCR-26 stipulation agreement.

Q: AS AN EXPERIENCED BUSINESS LAWYER AND ADVISOR, HOW WOULD YOU CHARACTERIZE THIS SMALL AMOUNT OF VOLUNTARY REMOVAL BY THE COMPANY?

A: I think a reasonable reading is that the company views this periodic, de minimis voluntary removal of 0.05% of all fuel costs as just a cost of running the business. Any similar enterprise would almost certainly internalize these small recovery reductions in their general business projections.

II. THE "MORAL HAZARD" INHERENT IN THE FUEL COST RECOVERY TARIFF

Q: WHAT IS A "MORAL HAZARD?"

A: A moral hazard occurs when one party is incentivized to take more risk than they normally would because that party is insulated against such risk.[21] If the decisionmaker is so insulated from the consequences of a decision, such decisionmaker is likely to take a bigger risk. The extent of the moral hazard – and such insulation – determines the scope of risk the decisionmaker is willing to take on.

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

A: While O.G.C.A. 46-2-26 does not require the utility to collect **all** of its fuel costs from ratepayers, the statute permits the utility to set fuel recovery rates that pass along 100% of the fuel costs to ratepayers.[22] As discussed previously, the 1970's energy crisis spurred action to address global fuel volatility, not just in electric utility fuel procurement but across all fuel-consuming industries. Every state traded complete utility insulation from fuel cost volatility – at the cost of consumer exposure to such wild price swings.

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

[22] Georgia PSC, *Fuel Cost Recovery*, p. 2, *available at* http://www.psc.state.ga.us/electric/regulation/Fuel_Cost_Recovery.pdf (last visited Apr. 6, 2026).

Q: IS THE COMMISSION REQUIRED TO IMPLEMENT FUEL COST RECOVERY IN A MANNER THAT CONTINUES AND EXACERBATES THE MORAL HAZARD?

A: I think the statute does provide plenty of flexibility to better allocate risk between the utility and the ratepayers, particularly through fuel-cost-risk-sharing.

III. FUEL RISK SHARING IN OTHER STATES

Q: WHAT IS FUEL-RISK-SHARING?

A: Under a fuel-risk-sharing policy, the utility sets a total fuel budget at the beginning of the rate-setting period based on expected fuel costs. At the end of each portion of the rate-setting period – typically on an annual basis – if actual costs increase from the approved benchmark, the utility pays a percentage of the difference, passing along such savings to ratepayers by otherwise reducing fuel costs that such customers would have paid. If actual costs decrease, the utility retains a portion of those cost savings as an incentive, with the balance of savings passed along to ratepayers.

Note that the terms "fuel-risk-sharing" and "fuel-cost-sharing" are sometimes used interchangeably, or are shortened to "fuel sharing."

Q: IS TARIFF SETTING IN FUEL-RISK-SHARING MUCH DIFFERENT IN 100% FUEL PASS THROUGH POLICIES, SUCH AS GEORGIA'S FCR?

A: While the fuel cost forecasting and other elements of Georgia's current fuel cost recovery tariff continue to face accuracy challenges, many of the components of fuel-risk-sharing policies are in place in Georgia. I will discuss the key questions to consider when reviewing fuel-risk-sharing proposals, but the basic foundations of the policy architecture are already in place.

Q: WHAT IS THE STATUS OF FUEL-RISK-SHARING TODAY IN OTHER STATES?

A: As of the date of this testimony, at least 9 states require some form of fuel-risk-sharing by their investor-owned-utilities: Hawaii; Idaho; Missouri; Montana; Oregon; Vermont; Washington;

Wisconsin, and Wyoming.[23] In the last three years, at least three states have advanced fuel-risk-sharing policies: Colorado, Nevada and Virginia very recently.

Q: IN THE LAST FORTY YEARS, HAS ANY STATE REQUIRED 100% UTILITY RESPONSIBILITY FOR FUEL COSTS?

No state has determined it necessary to completely eliminate the utility's ability to pass through the vast majority of fuel expenses to ratepayers without any utility exposure. In other words, no state has returned to 100% utility responsibility for fuel costs and fuel risks.

In the 8 states with existing fuel-risk-sharing policies, the current levels of fuel-risk-sharing range from 20% utility responsibility to single-digit utility responsibility. Some states that require smaller amounts of utility fuel-risk responsibility provide additional, overlapping incentives for utilities to further reduce their exposure to fuel price volatility.

Q: HAVE ANY STATE COMMISSIONS RECENTLY REVIEWED FUEL-RISK-SHARING POLICIES AT ANY DEPTH?

A: Each of the 9 states with fuel-sharing requirements have rejected attempts to eliminate the utility's responsibility for a portion of fuel risk. Wyoming recently reviewed extensive testimony and data in evaluating the effectiveness of their Energy Cost Adjustment Mechanism and the related Net Power Cost policy. In January 2024, the Wyoming PSC affirmed their current 20% utility fuel-sharing policy applied to Rocky Mountain Power to be in the public interest.[24] The Wyoming Commission came within one vote of increasing utility responsibility to 30%, as originally required in the 2003 initial fuel-sharing order.[25]

Even in the rare cases where a state no longer requires fuel-sharing, these Commissions are again discussing fuel-sharing regimes. As recently as March 2025, in their March 2025 order

[23] Xavier Zheng et al., *How Fuel Cost-Sharing Can Deliver Savings for Utility Customers*, RMI (Feb. 26, 2026), *available at* https://rmi.org/how-fuel-cost-sharing-can-deliver-savings-for-utility-customers/.
[24] *Memorandum Opinion, Findings, and Order*, 50 (Jan. 2, 2024), Wyo. Pub. Serv. Comm'n, Dkt. No. 20000-633-ER-23, Rec. No. 17252.
[25] *Id*.

addressing Arizona Public Service's fuel cost recovery tariff request, the Arizona Corporation Commission made it a specific point to explain the history of Arizona's prior 90/10 fuel sharing and its removal as part of a settlement agreement, explaining: "The [2011] Decision did not find that the 90/10 provision was ineffective, just that Staff believed its elimination would benefit customers when fuel prices were lower, as they apparently were at that time (as evidenced by the lower base fuel rate). (*See* Ex. RUCO-13 at 25.)"[26] The Arizona Commission demurred on the question of reinstating this 90/10 fuel-sharing provision, calling it a "more difficult issue, in light of conflicting evidence."[27]

Q: IS THERE AN OPTIMAL AMOUNT OF UTILITY FUEL-RISK AND FUEL-COST RESPONSIBILITY IN ANY SUCH SHARING POLICY?

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 requirements in those states with sharing suggest that allocating a small percentage of fuel risk and fuel costs to 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, fuel-sharing policies provide utilities with more upside opportunity than downside risk.

I believe that the most effective fuel-risk-sharing policies are "symmetrical" and are not punitive. 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-

[26] *Decision No. 79293*, 193, FN 376 (Mar. 5, 2024), Ariz. Pub. Serv. Comm'n, Dkt. No. E-01345A-22-0144, *available at* https://docket.images.azcc.gov/0000210704.pdf?i=1775600725806.
[27] *Id*.

utility, of course. But designed well, a modernized Fuel Cost Recovery mechanism in Georgia will provide consistent benefits to the utility and to ratepayers.

IV. FACTORS THE COMMISSION SHOULD CONSIDER IN EVALUATING THE FCR-27 PROPOSAL

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

A: No, I do not think so. And apparently neither does Georgia Power.

Fuel Cost Recovery dockets implicated Integrated Resource Plans, rate cases and specific plant Certificate of Need applications. I believe the Commission would be wise to consider the multiple factors and broader economic forces through a specific Fuel Cost Recovery modernization docket.

In their testimony, Messrs. Houston and Berrigan indicate that any evaluation of the economic impact of the FCR-27 tariff must be considered within the context of their next base rate case.[28] Messrs. Houston and Berrigan also explicitly reference the company's Storm Damage Recovery Application filing.[29] The Commission has frequently referenced rate cases and other dockets during considerations of FCR tariffs.

The inverse is also true. For instance, much of the FCR-26 rate hike and the FCR-27 vulnerabilities were discussed when the Commission took up the company's integrated resource plan ("IRP") and demand-side management ("DSM") Stipulation of 2022. Intervenors SACE and Southface Energy Institute specifically recommended that Georgia Power not proceed with planned expansion of natural gas generation and procurement, and that the Commission consider an order "setting an upper limit on the recovery of fuel costs for [the] PPAs to adequately protect ratepayers

[28] Testimony at 17.
[29] *Id*. at 4.

from market volatility and unprecedented price spikes."[30] In his Direct Testimony in the 2022 IRP and DSM dockets, witness Ron Binz, former Chair of the Colorado Public Utility Commission, repeatedly highlight the risks associated with natural gas spikes.[31]

With the company's total fuel costs rising now reaching $3.3 billion a year as forecasted in FCR-27,[32] and with natural gas and oil price volatility remaining high, the Commission would be wise to revisit whether to integrate Fuel Cost Recovery tariffs with general rate cases or specific Integrated Resource Plan dockets.

Q: YOU HAVE USED THE TERM "VOLATILITY" A FEW TIMES. WHAT IS VOLATILITY IN THE CONTEXT OF A FUEL COST RECOVERY TARIFF?

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: NATURAL GAS PRICE VOLATILITY IS OFTEN DESCRIBED AS OUT OF THE UTILITY'S CONTROL AND "UNPRECEDENTED." DO YOU AGREE?

A: No. Georgia Power has repeatedly been warned of the volatility and risk of relying on fuel-based power generation, as recently as the 2023 IRP Update and 2025 IRP.[33] As intervenors SACE and Southface stated, by only focusing on natural gas and coal as supply options, Georgia Power

[30] *SACE and Southface Energy Institute Post-Hearing Brief*, 18 (July 7, 2022), Ga. Pub. Serv. Comm'n, Dkt. Nos. 44160 & 44161, *available at* https://psc.ga.gov/search/facts-document/?documentId=190679 [hereinafter "SACE/Southface Post-Hearing Brief"].
[31] *Id*.
[32] Testimony at 15.
[33] *Direct Testimony of Lucy Metz on Behalf of the Sierra Club and the Southern Alliance for Clean Energy*, 35 (Nov. 12, 2025), Ga. Pub. Serv. Comm'n, Dkt. Nos. 56298 & 56310, *available at* https://psc.ga.gov/search/facts-document/?documentId=224479.

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."[34]

The relationship between fuel price volatility, resource planning and rate cases are interconnected to the extent that the Commission should not consider fuel cost recovery without also addressing resource planning and overall rate setting; and the Commission should not consider rate setting and resource planning without simultaneously considering the impact of fuel cost recovery rates.

V. FUEL COST RECOVERY IMPLICATIONS FOR RELIABILITY

Q: DOES GEORGIA'S 100% PASSTHROUGH FUEL COST RECOVERY MECHANISM HAVE RELIABILITY AND HOMELAND SECURITY IMPLICATIONS?

A: Yes.

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

[34] SACE/Southface Post-Hearing Brief at 17.

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."[35]

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.[36]

The 2024 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 20 of 45 disasters.[37] 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 ("ESF-12") 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.[38]

Specifically, ESF-12 requires that the PSC ensures "equitable provision and restoration of services to the public" during response and recovery phases of a disaster or emergency.[39] Good

[35] GEMA/HS, *Georgia Emergency Operations Plan*, p. 6 (Oct. 28, 2024), *available at* https://gema.georgia.gov/what-we-do/planning [hereinafter "GEOP"].
[36] *Id*.
[37] *Id*. at 7.
[38] GEMA/HS, *Emergency Support Function 12 (Energy) Annex to Georgia Emergency Operations Plan*, p. 4 (July 6, 2023), *available at* https://gema.georgia.gov/what-we-do/planning.
[39] *Id*. at 3.

emergency preparedness relies on redundancy of resources and supply options that can meet the emergent needs in case of a primary failure or disruption. In the simple statement of the EIS Council, a nonprofit organization focused on global disaster preparedness, "Redundancy is essential for ensuring the continuous operation of critical infrastructure."[40]

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 power generation source, leaving a significant portion of the state's electricity supply vulnerable to a disruption from a number of hazards, such severe weather or domestic terrorism.

Q: HOW MUCH DOES HAS GEORGIA'S RELIABILITY ON NATURAL GAS INCREASED OVER THE LAST FEW DECADES?

A: Since 1997, Georgia's natural gas delivery to electric consumers has increased from 17,034 MMcf to 401,348 MMcf.[41]

Q: WHAT PERCENTAGE OF TOTAL CAPACITY DOES NATURAL GAS SUPPLY FOR THE COMPANY?

A: In the 2025 IRP, Georgia Power reported that natural gas consists of 44% of their 2025 summary capacity mix, and that coal consists of another 16%.

Q: CAN YOU RESTATE THE CONNECTION BETWEEN 100% FUEL PASS THROUGH POLICIES AND OVERRELIANCE ON FOSSIL FUEL?

A: Because utilities do not bear any financial cost or risk responsibilities for fuel, any increased in the cost or the volatility of purchased fuel is not born by the utility. The Fuel Cost Recovery mechanism provides a utility with a blank check of sorts to increase the throughput of fuel-based generation, even if non-fuel alternatives would provide greater value to ratepayers and greater resource diversity. Once a plant has been granted a certificate of public necessity the

[40] EIS Council, *The Role of Redundancy in Critical Infrastructure Protection*, *available at* https://eiscouncil.org/redundancy-critical-infrastructure/ (last visited Apr. 8, 2026).
[41] *See* EIA, *Natural Gas*, *available at* https://www.eia.gov/dnav/ng/hist/n3045ga2a.htm (data through Mar. 31, 2026).

equivalent, and absent any disallowance of costs for imprudence or illegally activity, the utility can be assured that all or nearly all of its fossil fuel expenses will be collected from ratepayers, even where the total operating costs of those power plants are now outside of the original economic cost-effectiveness calculation.

Q: DOES GEORGIA'S CURRENT FUEL COST RECOVERY MECHANISM ALSO HAVE LARGER NATIONAL SECURITY IMPLICATIONS?

A: Yes. Repeatedly, a significant number of retired three- and four-star Admirals and Generals have examined critical national security, energy and climate change issues as members of the Military Advisory Board convened by strategic think tank Center for Naval Analysis ("CNA").[42] These national security leaders declared as the first finding in their report "Ensuring America's Freedom of Movement: A National Security Imperative to Reduce U.S. Oil Dependence:"

> America's dependence on oil constitutes a significant national security threat. Our overreliance on oil is a national vulnerability.

While focused on oil's impact on the transportation sector of the U.S. economy, these Admirals' and Generals' collective caution should also be applied to Georgia's heavy reliance on natural gas as well. In the same report, these Admirals and Generals followed with a second key finding, which has become too real in light of the Iran war:

> We chose our reduction target [of a 30 percent reduction in petroleum use] based on a specific military challenge. CNA analysis shows that if America used 30 percent less oil, our economy would have enough resilience to sustain the effects of a complete shutdown of the Strait of Hormuz (the narrow passage for international shipping between the Sultanate of Oman and Iran), or any other major shipping choke point, with little effect. That image is a satisfying one (particularly to those of us who have spent much of our careers focused on Persian Gulf threats), and offers as good a definition as any of oil independence and increased security.[43]

[42] CNA Military Advisory Board, *Ensuring America's Freedom of Movement: A National Security Imperative to Reduce U.S. Oil Dependence*, CNA (Oct. 2011), *available at* https://www.cna.org/analyses/2011/ensuring-americas-freedom-of-movement.
[43] *Id*.

Q: IN LIGHT OF GLOBAL SUPPLY VULNERABILITIES, DOES GEORGIA POWER'S FCR-27 PROPOSAL HELP PROTECT AGAINST THE SUCH IDENTIFIED AND LONG-STANDING THREATS?

A: No. While each federal administration might emphasize one set of national security priorities over another, the general threat analysis and domestic preparedness requirements change very little. The utility's proposed expanded reliance on natural gas and coal generation and on diesel-powered coal transportation resources will exacerbate Georgia's vulnerabilities to global disruptions and to domestic hazards.

Q: WHY SHOULD THE COMMISSION CONSIDER OVERRELIANCE ON FUEL-BASED RESOURCES IN THIS FCR-27 APPLICATION AND NOT IN A RATE CASE OR AN INTEGRATED RESOURCE PLAN?

A: The IRP is, by rule, a "planning process" and does not provide a venue for evaluating the real-time, operational decisions that determine whether ratepayers are exposed to excessive costs.[44] The Company's own summary of the 2025 IRP includes cautionary notes that highlight the "risks and uncertainties" including "projected economic growth and load growth" and that "actual results [could] differ materially from management expectations [including] variations in demand for electricity, available sources and costs of natural gas and other fuels and commodities, the ability to control costs…. [and] impacts from geopolitical conflicts…."[45] The Company cannot dismiss this disclosure of risks as required boilerplate language under securities laws, as such disclosures must address all material risks to their operations and any potential return on investment. The roadmap provided by the 2025 IRP requires that the Commission ensure that the resource plan is implemented with proper care and diligence, including this FCR docket.

[44] Ga. Comp. R. & Regs. 515-3-4-.02(25) (Mar. 24, 2026).
[45] Georgia Power, *2025 Integrated Resource Plan, Georgia Power's Plan to Reliably, Economically Meet the Energy Needs of a Growing Georgia*, *available at* https://www.georgiapower.com/content/dam/georgia-power/pdfs/about/2025-irp-one-page-summary.pdf.

VI. HEDGING

Q: CAN YOU SUMMARIZE THE COMPANY'S PROPOSAL TO INCREASE THEIR USE OF NATURAL GAS HEDGING IN FCR-27?

A: Georgia Power has asked the Commission for authority to increase their use of natural gas hedging to 267% of FCR-26 levels.[46]

Q: THE COMPANY STATES THEY ARE JUST INCREASING HEDGING FROM 40% TO 60%. WHY WOULD THAT SO DRAMATICALLY INCREASE THEIR HEDGING AUTHORITY?

A: The Company is currently allowed to hedge 40% of its budgeted natural gas burn up to 36 months. Table 3 of Messrs. Houston and Berrigan testimony states that the two-year FCR-26 test period total natural gas budget amounted to $2.132 billion, for a total $1.066 billion each year.[47] Over three years this amounts to $3.198 billion. Forty percent (40%) of this total equals $1.279 billion in hedging authority.

The Company is requesting authority to hedge up to 60% of its budgeted natural gas burn for up to 48 months. Table 3 of Messrs. Houston and Berrigan testimony forecasts a two year FCR-test period total natural gas budget of $2.848 billion, for a total of $1.424 billion each year. Over four years this amounts to $5.696 billion. Sixty percent (60%) of this total equals $3.147 billion in requested hedging authority.

$3.147 billion authority is 267.2% greater than $1.279 billion authority.

Q: WHAT IS THE EASIEST WAY TO UNDERSTAND HEDGING IN THIS CONTEXT?

A: Fuel supply hedging general takes two forms: Physical hedging and financial hedging.

Physical hedging involves the advance purchase, delivery and storage of the commodity, relying on the purchaser's calculated gamble that the price is lower at the date of purchase than it

[46] Testimony at 21.
[47] *Id*. at 16.

will be when the purchaser needs to use the commodity – or in the case of an electric utility, to burn the commodity to generate electricity.

Financial hedging involves a similar calculation, but binds the selling party (or commonly the brokering party) to deliver the commodity in the future for a price agreed upon at the time of the hedging contract. Instead of paying for the storage of the commodity in the case of physical hedging, the purchaser pays for the future delivery obligation of the seller (or the broker).

Q: HOW SHOULD THE COMMISSION EVALUATE GEORGIA POWER'S DRAMATIC EXPANSION IN HEDGING AUTHORITY?

A: The Missouri PSC conducted two workshops to assess the cost-effectiveness of investor-owned electric utility and local natural gas distribution company use of financial natural gas hedging.[48] The Missouri Commission staff report provides an effective summary of the considerations the Georgia Commission could use to evaluate Georgia Power's 267.2% increase in natural gas hedging.

The Missouri report advises, "Hedging should be viewed as the cost of mitigating risk, and the gas market is not without risk."[49]

The Missouri report further advises, "Appropriate use of hedging instruments can take advantage of the [then-]current relatively low price of natural gas." Noting that as of the date of this testimony, the Iranian hostilities have already increased the price of natural gas and the overall volatility of natural gas prices going forward, the Georgia Commission should recognize that the FCR-27 proposal is not being made during a time of low natural gas prices.

Energy sector advisory and consulting firm ICF International more deeply investigated the use of hedging, via long term contracts, in a paper published in 2011, authored by Vice President

[48] *Staff Report*, 1 (Apr. 8, 2013), Mo. Pub. Serv. Comm'n, File No. EW-2013-0101, *available at* https://www.efis.psc.mo.gov/Document/Display/73082.
[49] *Id*. at 6.

Bruce Henning.[50] Mr. Henning found that such long-term contracts can be a tool to manage and mitigate adverse impacts from short-term price movements "as part of a diversified portfolio."

Mr. Henning warned that after-the-fact review of hedging effectiveness can be extremely difficult:

> For regulated entities, the standard of review is whether the utility acted prudently given the information available at the time of the decision. As such, a comparison between the contract price and the *ex post* market prices is generally thought to be an inappropriate factual basis for a disallowance. Nevertheless, in most proceedings, exhibits are presented that make just such comparisons.

Instead, Mr. Henning states that regulators must take seriously their obligations in advance of hedging activity, particularly in a pre-approval authorization docket such as FCR-27:

> Pre-approval can create risks for regulators (and the customers they represent) because they are in the position of approving management decisions without having access to all the information available to the utilities. It is this balancing of risks and opportunities that forms the basis for evaluating the benefits of a portfolio that includes an element of contracts (and other forms of hedges) that can provide increased price stability for gas market participants.

Mr. Henning's concludes:

> [T]here are issues and market disruptions that can occur in either extreme. A portfolio approach to contracting offers a possibility to mitigate the risks of either extreme… [T]here are legitimate reasons for the general move to short-term and indexed contracts. Even so, there are reasons to consider long-term contracts for a **minority portion** of a gas portfolio. (emphasis added)

Q: DOES GEORGIA POWER'S HEDGING EXPANSION REQUEST CONSTITUTE A "MINORITY PORTION" OF ITS NATURAL GAS PORTFOLIO?

A: No. Georgia Power's requested 267.2% expansions of natural gas hedging authority would allow the utility to take significant risks relating to 60% of its total natural gas purchases. This is hardly a "minority portion" of a mixed portfolio of risk mitigation tools.

[50] Long-term Contracting for Natural Gas: Examination of the Issues that Affect the Potential for the Increased Use of Contracting to Stabilize Consumer Prices.

Q: DOES GEORGIA POWER'S HEDGING EXPANSION REQUEST CONSTITUTE A "MINORITY PORTION" OF ITS OVERALL GENERATION PORTFOLIO?

A: No. As explained previously, Georgia Power already relies too heavily on natural gas in terms of reliability and resource diversity. Further, Georgia Power is proposing to increase its reliance on coal generation during FCR-27, for which the company relies on hedging as well, including physical hedging.[51]

Q: GIVEN MR. HENNING'S CAUTION IN HIS PAPER, DOES THE COMMISSION HAVE ENOUGH INFORMATION TO TAKE THE RISKY STEP TO PROVIDE PRE-AUTHORIZATION FOR THE HEDGING EXPANSION AS REQUESTED?

A: No. For the reasons provided earlier, I do not believe approval of the hedging request is responsible.

VII. INCREASING THE INTERIM FUEL RIDER CAP

Q: WHAT IS THE HISTORY OF GEORGIA POWER'S INTERIM FUEL RIDER ("IFR") CAP?

A: The Commission initially approved the Interim Fuel Rider IFR mechanism in FCR-21 in 2005. Over the years, Georgia Power's IFR threshold has been increased as follows:

FCR-21	$75 million
FCR-22	Unchanged from CFR-21 (Commission rejected staff recommendation of $40 million)
FCR-23	$200 million, up to 115% of FCR-23 rates

[51] Ga. Pub. Serv. Comm'n, Dkt. No. 39638, Georgia Power Company Fuel Recovery No. 4, *available at* https://psc.ga.gov/search/facts-docket/?docketId=39638.

FCR-24 (IFR-2)	Unchanged from FCR-23
FCR-25	Unchanged from FCR-23
FCR-26	$200 million, with authority to reach 140% of FCR-26 rates[52]
FCR-27	$300 million

Q: THE COMPANY CLAIMS THAT THE IFR MECHANISM BENEFITS CUSTOMERS. DO YOU AGREE?

A: Like much of their FCR-27 application, Georgia Power improperly describes the IFR as a consumer protection mechanism. The IFR does not actually mitigate costs to ratepayers in any way. Instead, the IFR mechanism allows the utility to further shift risk to ratepayers, particularly during times of significant price volatility. As fuel costs increase and reach the IFR threshold, the Company merely passes along the utility's increased fuel costs to ratepayers. The utility is thus allowed to keep collecting more via the higher FCR tariff, effectively providing further disincentive to reduce fuel costs. The IFR accelerates the moral hazard of 100% fuel pass through costs.

Q: COULD THE COMMISSION RESPONSIBILY APPROVE EXPANDING THE IFR AUTHORITY?

A: If the Commission required Georgia Power to integrate expanded IFR authority with a fuel-risk-sharing mechanism, the moral hazard risk is likely to be greatly reduced, and ratepayers would likely benefit.

Q: ON WHAT GROUNDS OR PRECEDENT DO YOU BASE YOUR BELIEF THAT FUEL-RISK-SHARING WILL BENEFIT GEORGIA POWER AND RATEPAYERS?

[52] The FCR-26 IFR approval was split between the under-collected revenue during FCR-25 and the forward-looking FCR-26. Only the FCR-26 change is reflected here.

A: In the nine states with fuel-risk-sharing today, their Commissions have found such policies to be in ratepayers' interest.

Further, RMI recently published a fuel-risk-sharing analysis in another southeastern state, North Carolina.[53] RMI modeled the likely impact on ratepayers and on utility shareholders over a five year period from 2020 through 2024. RMI found that fuel sharing could have saved ratepayers $89 million during this high price volatility period, and shareholders would have earned an additional $10.9 million. While North Carolina and Georgia are different states with distinct differences, the two states share some key factors: population; industry; electrical load and projected load growth; the majority of utility service provided by a multi-state investor-owned-utility, and a current policy of 100% fuel-pass-through rates. Where reasonable difference can be found between Georgia and North Carolina, the Commission would be wise to pursue a similar state-specific analysis from RMI to determine the scope of potential benefits if fuel-risk-sharing were in place in Georgia.

As described earlier, Commissions in Colorado and Nevada have actively engaged in developing fuel-risk-sharing policies after legislative action; in March 2026, the Virginia legislature has required that the Commission formally study fuel-risk-sharing as a tool to protect ratepayers.

Fortunately, Georgia's fuel-cost-recovery statute provides the Commission sufficient flexibility to approve fuel-risk-sharing within the overall fuel-cost-recovery tariff.

Q: WHAT SHOULD THE COMMISSION REQUIRE THE COMPANY TO INCLUDE IN A FUEL-RISK-SHARING PROPOSAL?

A: As laid out in JK-Exhibit 2 "Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators Fuel-Cost Pass-Through Reform," the Commission should ensure the Georgia Power proposal properly balances these factors:

[53] Zheng, *supra* note 22.

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. However, a utility responsibility of ten percent (10%) is often sufficient to incent utilities to more aggressively manage fuel risk exposure.
2. **Symmetrical or asymetrical 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. While both symmetrical and asymmetrical sharing policies can be structured to provide both rewards and penalties to the utility, I believe that a symmetrical sharing structure can be more easily understood by utility analysts, and still substantially benefit ratepayers.
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. Some sharing policies utilize a "deadband" approach that provides a preestablished margin of fuel cost changes in which a utility can pass through all of the fuel costs to ratepayers as they do today.
4. **Reliance on forecasts versus actual historic pricing**. Forecasting natural gas pricing can feel like an exercise in futility. Some states have adjusted the timing of fuel cost reviews to ensure greater reliability of actual pricing and costs, given the challenge of reliable forecasting.
5. **Retaining Hedging at Reasonable Levels.** As discussed above, while hedging permits the utility to purchase stability and price predictability in exchange for a premium payment for such future fuel supply, the company proposes to expand its use of hedging 267% to become its primary means of fuel cost management. Hedging can

be a useful tool, if primarily applied to a small portion of a utility's fuel purchases, and ratepayers are sufficiently protected from the impact of excessive hedging premiums.

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 Georgia Power attempt to sidestep the fuel risk requirements strictly through Power Purchase Agreements rather than utility-owned assets.

VIII. SUMMARY

Q: CAN YOU SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS TO THE COMMISSION?

A: 1. I recommend that the Commission provide for more extensive reviews of Fuel Cost Recovery expenditures, tariff changes, forecasting, hedging authority and Interim Fuel Rider requests.

2. I recommend that the Commission more closely coordinate Fuel Cost Recovery dockets with rate cases and/or Integrated Resource Plan dockets to ensure consistent analysis and methodologies between all dockets, and to ensure that the interrelated issues are considered particularly with respect to reliability and ratepayer impact.

3. I recommend that the Commission reject Georgia Power's requests in the FCR-27 application, with the exception noted below with respect to the FCR-tariff rate as an Interim Fuel Rider tariff, and required that Georgia Power submit a revised FCR application with the following updates:

i. Updated natural gas price forecasts in light of the global oil and natural gas volatility caused by the war in Iran;

ii. Updated coal price forecasts in light of increased oil prices and the impact on the company's coal transportation services agreements;

iii. A natural gas hedging plan restricted to the current authority provided in FCR-26.

iv. An IFR threshold increase to $300 million, but only in the condition that Georgia Power submit a proposal for fuel-risk-sharing and fuel-cost-sharing mechanisms wherein the company is responsible for ten percent (10%) of the total cost of all fuel expenses, with the opportunity to be rewarded for reducing overall fuel costs against an established benchmark so long as ratepayers realize at least ninety percent (90%) of the savings from such reduction.

4. I recommend that the Commission adopt the proposed FCR-27 tariff rate as an Interim Fuel Rider tariff, in order to provide timely relief to ratepayers until Georgia Power submits a revised FCR application and the Commission approves such revised application.

5. Regardless of action on Georgia Power's FCR-27 application, the Commission should initiate a full Fuel Cost Recovery modernization docket, including requiring the utility to be responsible for some portion of fuel purchase risks and fuel purchase costs for all future FCR tariffs.

Q: DOES THIS COMPLETE YOUR TESTIMONY?

A: Yes. Thank you.

JK-Exhibit 1: Curriculum Vitae of Jeremy Kalin

JEREMY KALIN

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EDUCATION

J.D. **William Mitchell College of Law**, St. Paul, MN.

University of New Mexico, School of Architecture and Planning, Albuquerque, NM.

B.F.A. **University of Minnesota**, Minneapolis, MN.

PROFESSIONAL EXPERIENCE

Attorney and Shareholder, Avisen Legal P.A. 2019 - present

- Impact Counsel practice focused on low-carbon project finance and early-stage investment. Practice areas include energy policy; climate finance and related impact investment; solar electricity and energy efficiency; greenhouse gas reduction and related projects.
- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
- General Counsel for venture capital funds investing in technology companies.
- Admissions: Minnesota and the District of Columbia.

Kalin LLC, Principal 2017 - 2023

- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
- Built and launched multiple award-winning low- and moderate-income solar finance platforms for U.S. Department of Energy.
- Built and launched Credit Unions' CU Green® clean energy investment platform.

Senior Advisor, National Caucus of Environmental Legislators (NCEL) 2016 - 2022

- National, bipartisan non-profit organization supporting state lawmakers advancing clean energy and resilient communities policies across all 50 states.

Senior Advisor, GOVERNING Institute 2014 - 2020

- Advisor and Speaker on Infrastructure, Workforce and Clean Energy Economy

Eutectics®, CEO 2010 – 2018

- Nationally-recognized, mission-driven clean energy finance consulting firm with over $273 Million in projects in progress or completed nationwide.
- Clients include: U.S. Department of Energy; City of Morris (MN); Baltimore City (MD); Chisago County HRA-EDA; Philadelphia (PA) Energy Authority; St. Paul PHA; The Nature Conservancy; University of Minnesota; etc.

State Representative, Minnesota House of Representatives District 17B (Chisago County) 2007 - 2011

- **Coalition of Legislators for Energy Action Now (CLEAN), Chair*;*** Obama White House bipartisan task force of legislative leaders on clean energy and climate policy.
- **Minnesota Green Jobs Task Force, Co-Chair.**
- **Legislative Chief Author:** 2010 Property Assessed Clean Energy (PACE) Act; 2009 Green Jobs Act / ARRA Energy Appropriation; 2008 Military and Overseas Voter Act; 2007 Demand Efficiency Act (*selected legislation).*

Vice-Chair, East Central (MN) Regional Development Commission 2004 - 2006

- Vice-Chair and Chisago County Representative on regional economic development authority serving Pine, Isanti, Chisago, Kanabec and Mille Lacs Counties.

SELECTED COMMUNITY SERVICE

Mississippi Headwaters Fund Advisory Board, The Nature Conservancy	2016 – 2018
The Violence Project Research Center, Board Member	2020 - 2024
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
FBI Citizens Academy, Minneapolis Division	2018
Minnesota Chamber of Commerce, Energy Policy Committee	2014 - 2016
State Innovation Exchange (SiX), Founding Advisory Board	2012 – present
Overseas Vote Foundation, Advisory Board	2009 - 2012
James J. Hill Business Reference Library, Board Member	2010 – 2012
Chisago County (MN) Land Use Coalition	2004 - 2006
East Central (MN) Arts Council	2004 – 2006

SELECTED AWARDS AND RECOGNITION

Royal Society of the Arts, Fellow	2018 - 2022
British American Project, Fellow	2014 - present
Progress Minnesota 2017 Honoree (Eutectics)	2017
Midwest Energy Efficiency Alliance, Inspiring Leadership Award	2008
Legislator of Distinction, League of Minnesota Cities	2008
Legislative All-Star, Fresh Energy Minnesota	2007
Graduate Teacher of the Year, University of New Mexico, School of Architecture and Planning	2003

TEACHING EXPERIENCE

University of Minnesota, College of Design, "Design Thinking for Public Policy"

University of New Mexico, Graduate Teaching Assistant, School of Architecture and Planning

Massachusetts College of Art, Visiting Faculty

University of Minnesota College of Liberal Arts, Art Department, Teaching Assistant

SELECTED RECENT SPEAKING APPEARANCES

IMPACT, United States Green Building Council, Minnesota

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

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RMI

Strategies for Encouraging Good Fuel-Cost Management

A Handbook for Utility Regulators

Report / July 2023

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About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

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Executive Summary

Ensuring that rates are affordable and fair to customers is central to the mission of the regulatory commissions that oversee public utilities in the United States. Regulators operationalize this charge in many ways, from conducting detailed analyses of utility investment plans to carefully tailoring programs to the needs of low-income customers. However, in many jurisdictions little attention is paid to controlling fuel costs, which are a major factor driving recent increases in electricity bills.

Fuel costs represent a sizable portion of electric utility customers' bills, and fuel-price volatility can drive further bill increases with little notice. For example, in the wake of winter storm Uri in 2021, natural gas shortages caused prices to spike. Months later, regulators across the country were asked to approve utilities' requests to recover billions of dollars from customers to cover unexpected fuel costs.[1] Russia's 2022 invasion of Ukraine also caused coal and gas prices to increase dramatically.

The sustained high natural gas prices of 2022 drove the single largest year-on-year increase in electric bills.[2] The high energy bills are undoubtedly connected to the $16 billion in unpaid energy bills and massive increases in utility shutoffs in that time frame.[3] Those utility disconnections can have severe impacts, including potential eviction, loss of child custody, and even death.[4] Fortunately, utility regulators can do something to help avoid future harms to captive customers.

In most jurisdictions, fuel costs are handled through a regulatory mechanism known as a fuel adjustment clause (FAC).[i] Unlike most components of utility rates, a FAC enables the utility to recover exactly what it spent on fuel — so if the company manages to reduce its fuel costs, it retains none of the savings, and if it spends more than budgeted, its customers pick up the bill. This gives utilities that operate under FACs little incentive to manage their fuel costs carefully, and it gives regulators limited visibility into whether the utility spent more than was necessary.

However, FACs were not always the norm. Until the latter part of the 20th century, regulators typically handled fuel costs in the same fashion as most other components of utility rates. An estimate of expected fuel costs was built into the basic rates utilities charged for service (i.e., "base rates"), and the utility was expected to fund its fuel purchases with whatever amount it collected in this fashion. Unlike under a FAC, no ex-post true-up to the utility's actual expenditures was performed.

The status quo is already unaffordable for many people who struggle to pay their electric bills, and FAC policies that give utilities little incentive to manage fuel costs carefully are exacerbating this problem. Fortunately, FACs are ripe for revision due to technological advances and evolving markets. Vertically integrated electric utilities have more options than ever before to reduce their reliance on expensive and price-volatile fuels.[ii] These opportunities include switching to fuel-free generating resources, negotiating more favorable supply contracts, and taking steps to reduce the amount of fuel needed to meet customer

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i In this handbook, the term FAC refers to all policies that enable utilities to collect what they actually spent on fuel from customers through an ex-post true-up. However, the names used to refer to these policies vary by state (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

ii Electric distribution companies in restructured states may also have opportunities to negotiate supply contracts and support demand-side management, but this handbook focuses on vertically integrated utilities.

needs (e.g., by working to conserve energy and shift demand). In contrast, customers have few strategies available to reduce fuel costs, so requiring them to continue bearing all fuel-price risk under FAC policies is increasingly unreasonable.

Fortunately, multiple regulatory strategies are available to reduce utility fuel costs. This handbook presents six reform options that regulators can use to encourage utilities to carefully manage their fuel costs and adopt cost-effective fuel-free resources. We also examine key questions related to each option and, where relevant, highlight examples of states that have already implemented these policies. The six reform options we discuss are:

- **Fuel-cost sharing.** This policy creates a financial incentive for the utility to carefully manage its fuel costs by requiring it to bear part of the risk of fuel-cost volatility. Under a typical fuel-cost sharing policy, the utility captures a share of the savings if it can reduce fuel costs below expected levels, and it also bears a share of any cost overruns. Fuel-cost sharing has already been implemented by a number of states, though the design details of these policies vary. For states adopting this option, we recommend the use of historical values or externally derived forward price indexes from public sources to avoid potential gaming risks. Regulators could elect to apply fuel-cost sharing to proposed new power plants, and they could have the utility lock in the price forecast used during plant approval as the amount utilities are allowed to recover from customers for fuel to run the plant over its lifetime.

- **Fuel-cost true-up removal.** This reform represents a return to the ratemaking approach that was standard before FACs became the norm. As under a FAC, an estimate of expected fuel costs is built into base rates — but unlike a FAC, no ex-post true-up is performed to match the funds recovered from customers to the utility's actual expenditures. Although no state has implemented this policy to replace a FAC, many precedents exist from the years before states adopted their FACs. This policy would shift the risk of fuel price volatility back onto utilities.

- **Fuel-risk reduction tariffs.** This strategy consists of implementing new retail tariffs that both create an incentive for the utility to reduce fuel costs and reduce participating customers' exposure to fuel-cost volatility. Such tariffs could be structured in various ways, such as by fixing the per-kilowatt-hour (kWh) rate used to recover fuel costs (and not truing it up afterward) or by offering customers a subscription-style tariff with a flat monthly charge. A number of states have implemented tariffs with this basic structure, though their motivation for doing so has not focused specifically on fuel costs.

- **Planning and procurement.** Many opportunities exist to reform resource planning and procurement in ways that encourage better fuel-cost management. These include updates to long-term planning processes, closer scrutiny of fuel-price projections, locking in forecasts for new generation, requiring all-source solicitation and procurement, the use of fuel management plans, and refinements to how utilities utilize hedging. Some states have implemented one or more of these policies to update planning and procurement.

- **Strategies to increase access to information.** It can be difficult for regulators to determine whether the fuel costs a utility presents for recovery through a FAC are unnecessarily high, so strategies that increase regulators' and stakeholders' access to information can encourage utilities to contain their fuel costs. These include making fuel-supply contract terms more transparent, utilizing enhanced prudence reviews, requiring regular audits, and facilitating broader and deeper stakeholder engagement in regulatory processes.

- **Efficiency ratio.** This is an emerging concept that regulators can consider, though it does not currently have a track record comparable to the other policy options. An efficiency ratio consists of a financial incentive tied to a production-cost-efficiency metric. In other words, it is a type of performance incentive mechanism (PIM) that encourages the utility to reduce the average cost of producing a megawatt-hour (MWh) of power.

These six policy options offer regulators a variety of possible strategies to reform existing FAC policies. Both utilities and the jurisdictions they operate in vary, so there is not likely to be a single "best" policy for every circumstance. The key questions we discuss in relation to each policy highlight some of the important design choices regulatory commissions are likely to face, and regulators may identify additional opportunities to tailor policies to local needs as reform discussions proceed. We encourage commissions to also consider the benefits of adopting more than one reform. For example, particularly strong synergies are likely to exist between strategies that increase access to information and the other policy options we discuss.

Given the impact that fuel has on both customer bills and the carbon emissions of electric utilities, we urge commissions to consider changing the way that utilities recover fuel costs from customers. Recent years have brought a raft of affordability challenges to states around the country, and we expect these trends to continue due to uncertain and volatile gas prices, the need to upgrade the grid to ensure resilience and replace aging distribution infrastructure, and required capacity expansions to accommodate the move toward electrification.

Because FAC policies give electric utilities little incentive to carefully manage their fuel costs, regulatory commissions should investigate and take action to reform these policies. This handbook is intended as a resource to support these important regulatory discussions.

Introduction

Fuel costs represent a sizable share of the total cost of producing electricity from power plants. These costs can also fluctuate substantially from month to month as fuel prices and quantities change. The magnitude and volatility of fuel costs make it imperative that utilities manage them carefully, but under typical ratemaking practices they have no financial incentive to do so. This is because of the widespread use of a policy known as the fuel adjustment clause (FAC).[iii]

FACs are rate riders that automatically true up the revenues collected from customers to match the utility's actual fuel expenditures.[iv] Although a utility's fuel costs are generally subject to a prudence review by its regulatory commission before they can be recovered, in practice the effectiveness of these reviews tends to be limited due to the information asymmetry between the utility and the regulator and the structure of the dockets wherein the prudence review occurs. Regulators often find it difficult to determine whether the receipts submitted by the utility were in fact the best use of customers' money. This is because regulators may not have good visibility into the effort the utility put into negotiating lower fuel prices, what fuel-free alternatives were available to the utility, and other factors. This often results in near-automatic approvals of requests for cost recovery and, as a consequence, little incentive for the utility to carefully manage its fuel costs.

This is problematic because the utility is the party best positioned to manage fuel-cost risk. Although fuel prices are not entirely under the utility's control, the company generally can negotiate more favorable fuel-supply contracts and take steps to reduce the amount of fuel needed to meet demand (e.g., by working to conserve energy, shift demand, or procure nonfuel alternatives). In contrast, customers have little ability to manage fuel-cost risk — yet FACs unfairly shift this risk entirely onto their shoulders. Vertically integrated utilities, which generate their own power to supply customers, are particularly able to manage fuel-cost risk by shifting their generation portfolios to fuel-free alternatives.[v] As a result, these utilities are the focus of this handbook, although some of the policy options we discuss may be relevant for other energy utilities as well.

FACs create a situation that economists refer to as "moral hazard," which exists when one party makes the decisions while another bears the risk of those decisions. By insulating the utility from the risks of poor fuel-cost management decisions — and also not rewarding the utility for making good decisions — a FAC gives it little incentive to work hard to reduce fuel costs. By transforming fuel costs from a major business expense to a side consideration, FACs enable poor fuel-cost management decisions that undermine affordability and perpetuate utility reliance on carbon-intensive fuel-based generation resources.

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iii In this handbook, the term FAC refers to all such policies, but in some states they have different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

iv FACs are an example of what is known in regulatory parlance as a cost tracker. FACs are not the only type of cost tracker, but they (along with purchased-power cost trackers) are the most ubiquitous.

v Vertically integrated utilities are those that own generation, transmission, and distribution capacity, though most also purchase some power from other generators to meet customer demand. Electric distribution companies do not own generation yet they may also have opportunities to reduce fuel costs, such as by negotiating better supply contracts and supporting demand-side management. Though this handbook focuses on vertically integrated utilities, some of the policies discussed could be appropriate for electric distribution companies as well.

A FAC is typically implemented in several steps. First, the utility develops a forecast of future fuel costs, including estimates of both prices (e.g., $/million British thermal units) and quantities (e.g., the share of total demand that will be met by gas- or coal-fired generation). This forecast is then built into the rates that the utility can charge its customers for electric service — specifically, as part of the volumetric component (i.e., the per-kWh rate customers pay). After the rates take effect, the revenues collected through this rate component are compared with the utility's actual expenditures on fuel, and the cumulative difference is tracked over time via a balancing account.[vi] Periodically, the utility applies for the balance to be trued up by adjusting the FAC rider; the regulator considers the utility's application and approves the expenditures for recovery if they are deemed prudent (this usually happens in a dedicated fuel-cost recovery proceeding). Once the fuel costs are approved for recovery, the value of the FAC rider is adjusted to collect the additional revenue from customers (or to refund money if the utility collected more than it spent on fuel). The FAC rider typically appears as a separate line item on customer bills.

FACs are the norm today, but this was not always the case. Until the latter part of the 20th century, fuel costs were generally not given special treatment. Instead, they were handled in the same fashion as most other components of utility rates. Namely, the commission would approve a utility estimate of future fuel costs, which were then built into rates, and the utility could apply to raise its rates if the gap between the expected and actual fuel costs became too great. This approach established predictable per-kWh rates for customers and also rewarded the utility for limiting its actual fuel costs.

This changed in response to the fuel-price volatility caused by major geopolitical events during the previous century. In the wake of the two world wars, some utilities sought relief from exposure to fuel-price risk from their regulatory commissions and were granted temporary FACs. Then following the 1970s oil embargo, utilities across the country persuaded regulators to institute FACs with no sunset dates, and in some cases they even convinced legislators to write FAC policies into state statutes. As a result, FACs became the status quo nationwide.

However, the time has come to end the use of FACs for fuel-cost recovery. Due to an array of technological advances, utilities have more control than ever before over the amount they spend on fuel. Today, cost-effective solar and wind generation, battery storage, virtual power plants, and the managed charging of electric vehicles all provide new avenues to reduce reliance on fuels like natural gas and coal.

Retiring FAC policies could help motivate utilities to take full advantage of these new opportunities, which could reduce both customer costs and carbon emissions. This handbook presents six policy options that regulators can consider as alternatives to traditional FAC policies. We explore key questions regulators might consider in policy design, and, where relevant, we offer examples from US states with such policies.

vi In regulatory accounting terms, this variance is tracked over time through a regulatory asset (or regulatory liability).

Fuel-Cost Sharing

Fuel-cost sharing creates a financial incentive for the utility to carefully manage its fuel costs. Under a typical fuel-cost sharing mechanism, the utility can earn more if it reduces fuel costs and must bear a share of the burden if those costs rise. In other words, this reform exposes the utility to a portion of the fuel-cost volatility risk, so it is no longer fully insulated from fuel-cost changes as it is under a traditional FAC. Instead, under fuel-cost sharing the utility has some "skin in the game."

In fuel-cost sharing, an estimate of expected fuel costs is first built into rates, and then just part of the difference between the revenues collected and the utility's actual fuel expenditures is trued up. As is the case for a traditional FAC, this true-up is performed through a rider that applies an additional charge or credit to customer bills. The key difference between a traditional FAC and this policy option is that fuel-cost sharing trues up only part of the difference between the utility's *expected* and *actual* fuel costs.[vii]

Key Questions

Fuel-cost sharing can be implemented in a variety of ways. The most important questions that policymakers are likely to face include the following:[viii]

How should the expected value be set? Because fuel-cost sharing functions by truing up only part of the difference between the expected and actual fuel costs, an "expected" level of fuel costs must be determined by the regulator. This expected value can be based on either *forecasted* or *historical* values. Although forecasts are the most common approach used today by states that have adopted fuel-cost sharing, they can open the door to gaming. Specifically, if a forecast is used to set the expected value of fuel costs, the utility can benefit financially either by reducing fuel costs relative to the forecast or by inflating the forecast.

To avoid creating an incentive to inflate the forecast, regulators can instead base the expected value on historical fuel expenditures (e.g., a five-year rolling average of past fuel costs). If a forecast is used, regulators should consider using forward price indexes (e.g., NYMEX futures for natural gas are publicly available) rather than relying on the utility's bespoke modeling.[ix] Additional design decisions around the expected value will also need to be made. These include whether the forecast (or historical values) should be based on just the individual utility or a relevant peer group, whether a third party should be responsible for any tasks (e.g., developing the forecast), and what (if any) historical period of fuel expenditures should be considered.

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vii Performing a true-up that brings the revenues collected in line with the actual costs incurred is often referred to as passing through these actual costs to customers. For example, a traditional FAC passes through 100% of the utility's actual fuel costs, whereas a fuel-cost sharing mechanism may pass through 90% of these costs. In this handbook, we do not use the term pass-through in this way, but readers may encounter it in other contexts.

viii For additional discussion of some of these questions, see Albert Lin, Jeremy Kalin, and Kaja Rebane, *Learning to Share: A Primer on Fuel-Cost Pass-Through Reform*, Pearl Street Station Finance Lab, 2023, **https://www.pssfinancelab.com/post/can-we-share-the-cost-of-fuel**.

ix Regulators should also ensure that any data source they use has sufficiently liquid trading to populate a credible sample, and that it includes buyers that are not rate-regulated utilities subject to this kind of cost-of-service regulation (e.g., industrial customers, merchant shippers). Where regulators face a choice between a less liquid trading point near the load the utility serves and a more liquid hub farther away, they may want to consider using the latter, subject to adding or subtracting a basis differential associated with observed pipeline rates or other clearly measurable factors.

How often should the expected value be updated? Although it may make sense to update the expected value at the time of a general rate case, a regulator could choose to reset it more frequently. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, and that amount could then be recovered through a separate rider. However, updating the expected value too frequently could reduce the strength of the incentive created by the fuel-cost sharing mechanism. For instance, if the expected value is updated monthly, it may end up tracking actual fuel costs too closely, with the result that the mechanism functions similarly to a typical FAC.

How much sharing should occur? The amount of sharing should be high enough to motivate the utility to manage its fuel costs carefully, but low enough to avoid exposing the utility to unreasonable risk. Because utilities vary, there is not one universally "best" sharing amount. For example, sharing 5% of fuel costs (i.e., truing up 95% of the difference between expected and actual fuel costs) may be appropriate for a utility that is highly dependent on natural gas, whereas sharing 30% of fuel costs may be feasible for a utility with a less price-volatile resource mix (e.g., one that is high in coal or renewables).[x]

Should deadbands or other thresholds be used? The simplest approach to fuel-cost sharing is to apply the same sharing percentage regardless of how close or far actual fuel costs end up being from the expected value. This approach, which is sometimes called straight sharing, is most common among existing fuel-cost sharing policies. However, another option is to change the amount of sharing when this difference crosses a specific threshold. For example, a mechanism could feature no sharing if actual fuel costs are within a certain percentage of expected fuel costs — a design called a deadband. Alternatively, a mechanism could feature several bands with different sharing percentages (e.g., 20% sharing if actual fuel costs are within 5% of the expected value, 10% sharing if actual fuel costs are between 5% and 10% of that value, and 5% sharing if the difference is greater than 10%).

Deadbands and other thresholds have both potential benefits and drawbacks, which regulators should consider carefully during the design process. One potential benefit of a deadband, specifically, is that it can simplify policy administration. Outcomes that fall within the deadband do not require any adjustment to the fuel-cost rider that appears on customer bills, which reduces the need for prudence reviews and associated litigation. One drawback is that deadbands and other thresholds can create an uneven incentive structure for the utility. For instance, if the utility's share of fuel costs drops dramatically when a particular threshold is crossed (e.g., from 20% to 5%), the company may have little financial incentive to manage its fuel costs when it expects them to deviate from the expected value by more than that amount (such as during a period of high gas prices). Another drawback of complex banded structures is that they can be hard for customers to understand.

Should the mechanism be symmetrical or not? Another design question is whether the mechanism should operate differently depending on whether actual fuel costs end up being higher or lower than expected. Under a symmetrical mechanism, the financial rewards to the utility when fuel costs are lower than expected are a mirror image of the penalties to the utility when fuel costs are higher than expected. Under an asymmetrical mechanism, the rewards and penalties are structured differently. For example, a regulator could design an asymmetrical mechanism that trues up 95% of the deviation between expected and actual fuel costs when costs are lower than expected but just 85% when costs are higher than expected. In general, symmetrical mechanisms are viewed as more fair to the utility, create more consistent incentives for utility performance, and are easier for customers to understand than asymmetrical mechanisms. When the risk is asymmetrical, however, an asymmetrical sharing adjustment may be appropriate.

x Percentages presented here are for illustration purposes only. Regulators should conduct quantitative analysis looking at their utility's specific fuel mix to determine fuel-sharing percentages, as even two utilities in the same state might have different fuel mixes and therefore require different sharing percentages.

How should the true-up be conducted? The timing and duration of the true-up of expected to actual costs is another design consideration. As is the case with the true-up under a FAC, the true-up under fuel-cost sharing can be operationalized in different ways. For example, because positive and negative fluctuations in fuel costs tend to cancel each other out over time, performing true-ups every month or quarter will tend to result in more variable customer bills than performing them annually.[xi] Regulators concerned about rate shock may wish to perform less frequent true-ups, or to spread the cost recovery (or refund) needed to implement the true-up over a longer time period.

Should purchased power costs be included? Most vertically integrated utilities purchase some power from other parties, and they typically recover 100% of these purchased-power costs from customers via a true-up that operates much like a traditional FAC. Because generated and purchased power are substitutes, applying a sharing mechanism to one and not to the other may encourage gaming. For instance, the utility may purchase more power when fuel prices rise even if this is more costly for customers. Incorporating purchased power in the fuel-cost sharing mechanism can avoid this type of perverse outcome.[xii] Most fuel-cost sharing mechanisms today include purchased power or exist alongside mechanisms that track it.

Should sharing apply equally to all plants? Though fuel-cost sharing is typically implemented in the same fashion for all of a utility's fuel costs, this need not be the case. For example, a regulator that wants to focus the utility's attention on making better investment decisions going forward could apply a higher sharing percentage to new generating plants than to existing plants. If a commission were to apply fuel-cost sharing only to new plants, it could also lock in the fuel-price forecast used at the time of approval.

Should the amount of sharing increase over time? Once fuel-cost sharing is implemented, a utility can be expected to find ways to reduce its reliance on price-volatile fuels — and over time, the utility may be capable of managing a greater share of the remaining fuel-cost volatility risk. Recognizing this, a regulator may wish to ratchet up the sharing percentage over time to continue to create a strong incentive for the utility to improve further. Doing so on a forward-looking basis would give the utility better visibility into the timing and magnitude of future changes than would an ad-hoc approach.

Could fuel-cost sharing undermine electrification? The electrification of home heating, transportation, and other end uses will result in increased electric demand on the grid. Unless the new demand is met entirely by fuel-free generation, this will result in higher total fuel costs. Therefore, a fuel-cost sharing mechanism that penalizes the utility for higher-than-expected total fuel costs would tend to discourage it from supporting electrification. However, if used in concert with policies supportive of electrification, fuel-cost sharing instead could help create an incentive to meet the increased demand with new fuel-free resources (e.g., wind, solar) and to proactively manage new loads (e.g., electric vehicle charging) to shift usage away from high-cost hours.

Regulators could also address the potential impact of fuel-cost sharing on electrification more directly. One way could be to design the fuel-cost sharing mechanism with a carve-out for beneficial electrification. A second way could be to create a separate performance incentive mechanism (PIM) for beneficial

xi Performing true-ups annually also enables any normal seasonal variations in fuel costs to be netted out.

xii Exposing the utility to a share of fuel-cost risk could encourage it to shift its generation portfolio toward renewable resources, as these do not require fuel purchases. In this way, fuel-cost sharing could support state decarbonization goals. However, purchased power includes electricity generated from both fuel-fired and fuel-free resources, so purchased-power cost sharing would not be expected to drive decarbonization in the same way. Where reducing carbon emissions is an important policy goal, regulators could tailor the purchased-power sharing mechanism to support it. 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 sharing percentage to fossil-fuel-fired resources than to renewables).

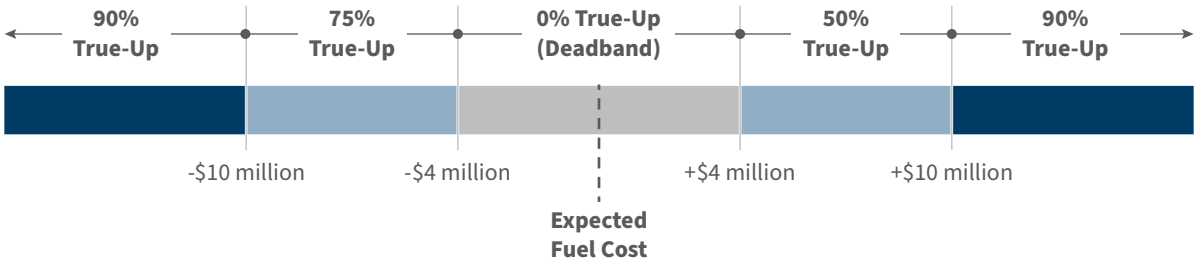
electrification that offsets the negative impact of the fuel-cost sharing mechanism.[xiii] A third possibility could be to structure the fuel-cost sharing mechanism to operate on a per-MWh basis rather than a total-cost basis, though this has the downside of creating an incentive to sell more electricity (i.e., a throughput incentive) whenever fuel prices dip below expected levels. We refer to such a mechanism as a type of "efficiency ratio"; for further discussion, see **page 27**.

State Examples

Wyoming is one state that has implemented fuel-cost sharing. Rocky Mountain Power's Energy Cost Adjustment Mechanism (ECAM) trues up the utility's actual net power costs (which include purchased power) to its forecasted costs in a symmetrical fashion.[5] The ECAM utilizes a straight-sharing approach. The mechanism previously shared 30% of fuel costs (i.e., the mechanism trued up 70% of the difference between expected and actual costs), but regulators subsequently updated the policy to share just 20% today.[xiv]

Washington has a fuel-cost sharing policy called the Power Cost Adjustment Mechanism (PCAM) for Pacific Power. The PCAM includes purchased power, relies on forecasts, and employs an asymmetrical banded design. The design features a deadband of $4 million on either side of the forecast within which no true-up is made. If actual costs exceed this amount, there are two sharing bands: within the first (up to $10 million), 50% of the difference is trued up; and within the second (over $10 million), 90% is trued up. If actual costs are less than expected, there are also two sharing bands: within the first (down to -$10 million), 75% of the difference is trued up; and within the second (less than -$10 million), 90% is trued up. This banded structure is illustrated in **Exhibit 1**. Under the current PCAM, the difference for a single year is recovered from customers over two years to reduce rate shock.[6]

Exhibit 1 Banded Design of Pacific Power's Fuel-Cost Sharing Mechanism



RMI Graphic. Source: RMI

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xiii For example, if the utility's average fuel cost per kWh is $0.02 and the sharing percentage is 10%, the fuel-cost sharing mechanism would create a $0.002 penalty for every kWh of new load. A PIM that rewards the utility $0.002 per kWh of beneficial electrification would offset this penalty, and a PIM that offered more than this could create a financial incentive for the utility to pursue electrification.

xiv These sharing percentages can be found on Rocky Mountain Power's tariff sheets. For the present 80% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, Original Sheet No. 95-6, P.S.C. Wyoming No. 17, issued June 25, 2021. For the previous 70% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, First Revision of Amended Original Sheet No. 95-6, P.S.C. Wyoming No. 16, issued October 27, 2017. The utility's 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**.

Oregon employs fuel-cost sharing subject to an earnings test. For example, Portland General Electric has an Annual Power Cost Variance Mechanism, which shares 10% of the difference between expected and actual costs (i.e., 90% of the difference is trued up) outside of a deadband. However, this occurs only if sharing does not cause the utility's earnings to deviate by more than 100 basis points from its commission-approved return on equity. The deadband is asymmetrical (no sharing occurs if actual costs are between $15 million less than forecast and $30 million more than forecast) and the mechanism includes purchased power.[7]

Missouri also has fuel-cost sharing mechanisms in place for Ameren, Evergy, and Liberty utilities. These mechanisms are all symmetrical, feature a straight-sharing design with a 5% sharing percentage (i.e., 95% of the difference between expected and actual costs is trued up), rely on forecasts, and include purchased power.[8] In a naming convention that may be confusing for those working in other states, these mechanisms are referred to as fuel adjustment clauses.[xv]

Hawaii uses a fuel-cost sharing mechanism for the Hawaiian Electric Companies (HECO).[9] The Energy Cost Recovery Clause (ECRC) takes a straight-sharing approach and employs forecasts to set the expected value that is built into rates. Under the mechanism, HECO trues up 98% of the difference between expected and actual fuel costs in a symmetrical fashion. The utility's annual financial exposure under the ECRC is capped at $2.5 million.

xv This differs from how we use this term in this handbook, in which we define a FAC as a mechanism that trues up 100% of the difference between expected and actual fuel costs.

Fuel-Cost True-Up Removal

Rather than reducing the extent to which expected fuel costs are trued up to actual fuel expenditures (as in fuel-cost sharing), the true-up can be eliminated entirely. This would mean that fuel costs would not receive special ratemaking treatment — they would simply be recovered in the same fashion as most utility costs.

Expecting utilities to fund their fuel expenditures without a rider may seem like a radical idea today, but this was standard practice until the mid-20th century. Removing the true-up would shift fuel-price volatility risk back to the utility, which is in a much better position to manage that risk than its customers. In other words, this policy option would restore the balance between utilities and customers that traditional ratemaking achieved. It would also give the utility a very strong incentive to seek ways to reduce its reliance on price-volatile fuels.

However, suddenly removing the true-up could create financial difficulties for a utility that has structured its current business model on the assumption that customers will bear all fuel-cost volatility risk. For example, if natural gas prices increase sharply and the utility relies heavily on gas generation, the impact on the utilities' financials could be drastic. Regulators interested in this reform should therefore proceed carefully and consider appropriate steps to protect the utility's financial health (e.g., by phasing out the true-up over time).

Implementing this reform can be mechanically simple — it only requires removal of the true-up step in a typical FAC. In other words, an estimate of expected fuel costs would be built into rates, but no ex-post true-up to actual expenditures would be made. The expected value to be included in rates would be determined as part of a regular rate case in the same fashion as other rate components, and it would not be updated further until rates are reset.[xvi] If fuel costs subsequently rise, the utility could cut costs elsewhere or come in for another rate case, and if fuel costs fall, the utility could enjoy additional profits.

Alternatively, a regulator could determine the expected value of fuel costs outside of a full rate case. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, which could then be recovered as a separate rider. This approach could be particularly useful in jurisdictions that employ multiyear rate plans, where typically utilities are expected to stay out of rate cases for three to five years at a time.

xvi If a regulator expects fuel costs to vary seasonally, it could set a seasonal structure for the expected value rather than a single annual number. Automatic escalation based on an external index (e.g., inflation) could also be applied. We are not talking about such automatic adjustments when we refer to rates being "reset" here, but instead to the process of updating the estimate itself.

Key Questions

Some of the key questions that pertain to fuel-cost true-up removal include the following:

How should the expected value be set? As is true under a typical FAC, this policy option requires determining an "expected" level of fuel costs, which is then built into the volumetric component of rates. An important question is how this expected value will be determined and, in particular, whether it will be based on forecasted or historical values. The key drawback to relying on a forecast is that it can open the door to gaming because the utility would benefit financially if it can inflate the forecast. Setting the expected value based on historical data can help avoid this problem.[xvii] Another way to address this concern would be to use a publicly available commodity forecast (e.g., NYMEX for gas prices).

How often should the expected value be updated? Because this policy option removes the true-up of expected to actual fuel costs, it is important to update the expected value periodically to reflect changing conditions. If the expected value is set as part of a traditional rate case, it could be updated every one to two years along with other rate components. If the regulator opts to set the expected value in an alternative venue (e.g., a special fuel-cost docket), it could update the value as often as desired. Updates that are too frequent are likely to undermine the strength of the cost-containment incentive created by the mechanism, whereas updates that are too far apart could result in unacceptable windfall profits or losses to the utility. The regulator should carefully balance these factors when determining the cadence of updates.

How can the risk of extreme outcomes be reduced? Because actual fuel costs may sometimes be substantially higher or lower than expected when rates are set, a utility operating without a true-up may at times collect substantially more or less than what it spends on fuel. High windfall profits could undermine affordability for customers, whereas substantial losses could threaten the utility's financial health. To avoid this, the regulator could adopt strategies to protect customers and the utility from extreme outcomes. For example, the regulator could specify particular conditions (e.g., utility profits that rise above a particular threshold) that would automatically trigger a review of the expected fuel-cost value.[xviii]

Would the utility cut key services if fuel prices spike? If the true-up is removed and fuel costs surge, a utility may cut costs elsewhere in an effort to hit its earnings targets. Although this concern is not unique to fuel costs, a large fuel-price spike could put substantial pressure on the utility to look for savings opportunities. This could lead to spending cuts in important but flexible spending categories like vegetation management, which could cause reliability problems down the road. Regulators could guard against such reactions by taking measures to reduce the risk of extreme outcomes, as discussed previously. They could also consider tracking or incentivizing utility performance in key dimensions that may be affected by spending reductions (e.g., reliability, customer service).

State Examples

At present, no state has removed the fuel-cost true-up. However, this policy was standard practice in every state before FACs became the norm.

xvii This gaming concern is also relevant to fuel-cost sharing, and we examined it in more depth in the section about that policy option. We encourage interested readers to review the more detailed discussion in that section.

xviii This is similar to the "reopener" provisions that are often included in multiyear rate plans.

Fuel-Risk Reduction Tariffs

Utilities could offer new retail tariff options that create an incentive for the utility to reduce fuel costs while simultaneously insulating customers from fuel-cost fluctuations. Such "fuel-risk reduction" tariffs would enable individual customers to avoid some of the risk of fuel-cost volatility. The strength of this incentive would depend on how many customers take service under the new tariffs, which would in turn depend on how many customer classes have access to it and whether it is implemented on an opt-in or opt-out basis.

Fuel-risk reduction tariffs would offer customers the opportunity to lock in a predetermined rate for the fuel-cost component of their bills. If the utility's actual fuel-cost expenditures differ from the revenues collected through these tariffs, the difference would not be trued up. In other words, if the utility paid more for fuel than it recovered from customers on the tariff, it would not recover that additional amount, and if it paid less, it would not refund the difference to customers.

Providing a fuel-risk reduction tariff as an option could increase customer choice. For example, such tariffs might appeal to customers who are concerned about volatility and willing to pay a potential premium for increased bill predictability.

Key Questions

The key questions for policymakers interested in developing a fuel-risk reduction tariff include the following:

How should the fuel-risk reduction tariff be structured? Tariffs that shift fuel-cost risk away from retail customers could be structured in different ways. One option is a *fixed-rate* tariff that features a set per-kWh rate for fuel costs. Because the revenues collected via this rate would not be subsequently adjusted to reflect the utility's actual fuel costs, such a tariff would expose the utility to more fuel-price risk than a traditional FAC. The set per-kWh rate could be time differentiated (e.g., it could differ by time of day or by season), but it would not be adjusted during the period when it is in effect. A fixed-rate tariff would operate similarly to the fuel-cost true-up removal policy option but on an individual customer basis.

Another option is a *flat-charge* tariff that features a monthly charge for fuel costs. Such a tariff could be implemented on a stand-alone basis, or it could be part of a broader subscription rate in which the customer's entire bill remains the same month to month. A flat-charge tariff could apply the same charge to all customers in a class, or the size of the charge could be based on past consumption levels (e.g., the average number of kWh consumed over the previous year). The second of these options is preferable.

Although applying the same flat charge to all customers would offer maximum predictability to the customer, this approach has some major downsides. Because customers would always pay the same amount regardless of how much electricity they use, they would have no financial incentive to conserve energy, install distributed generation, or shift demand in ways that benefit the grid. Because all of these actions can reduce total system costs, such a tariff could drive up costs for other customers in the short and long term (e.g., higher congestion charges during peak hours, more transmission and distribution system upgrades) and undermine state energy efficiency and emissions-reduction goals. Applying the same flat

charge to all customers would also disproportionately benefit high-usage customers, who on average have higher incomes than low-usage customers. For all of these reasons, applying the same flat charge to all customers is not recommended.

A flat-charge tariff that is instead based on past consumption levels could partly address these issues. For example, if the average number of kWh consumed over the previous year is used to determine the size of the monthly charge, a customer who expects to remain on the tariff will have some incentive to conserve and to install distributed generation.[xix] Basing the size of the fixed charge on past consumption could also help avoid the subsidization of high-income customers by low-income customers.

Both the fixed-rate and flat-charge options would increase predictability for customers participating in the tariff, which means someone else must bear additional fuel-cost risk. This risk should not be placed on nonparticipating customers (e.g., by increasing the size of the FAC true-up on those customers' bills) because this could raise subsidization concerns and it would also undermine the utility's incentive to contain fuel costs. Instead, the utility should manage the additional risk. The customers participating in the tariff could also be asked to pay a risk premium; this would be incorporated into the tariff and would represent the price the customer must pay for increased predictability.

Should the tariff be opt-in or opt-out? Customer participation in opt-in tariffs tends to be much lower than in opt-out tariffs. Implementing a fuel-risk reduction tariff on an opt-in basis would enable individual customers to reduce their exposure to fuel-cost volatility, while likely keeping the overall financial risk to the utility low. In contrast, implementing the tariff on an opt-out basis would have much broader impacts on both customers and the utility.

How often should customers be allowed to opt in and out of the tariff? Whether the tariff is opt-in or opt-out, it could enable customers to bet on fuel-cost trends, opting in if they think prices will increase and opting out if they think prices will decrease. The risk of such behavior is likely to be greatest among large commercial and industrial customers, but this strategy could be used by any savvy customer. To reduce this risk, regulators could limit how often customers can opt in and out of the tariff.

Which customer classes should be included? The fuel-risk reduction tariff could be offered to a small subset of customers or more broadly. Such tariffs may be of particular interest to those who value stability (e.g., commercial customers), though if customers must pay a premium for that stability, they may be less appropriate for some customer segments (e.g., low-income residential customers). Regulators should also consider whether some customers will need help understanding whether the new tariff makes sense for them, making customer outreach and education necessary.

How should the preset rate or charge for fuel be determined? The per-kWh rate or flat charge for fuel costs can be based on either a forecast or historical values. As with fuel-cost sharing and fuel-cost true-up removal, relying on forecasts could open the door to gaming because if a utility is able to inflate the forecast, the rate and thus collected revenues will increase. Relying on historical values instead (e.g., a five-year rolling average of past fuel costs) can help avoid this problem.

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xix The incentive to conserve would be somewhat less under this tariff design than under a fixed-rate tariff because the financial benefit to the customer of saving a kWh would be delayed by up to a year. The incentive to install customer-owned distributed generation would also be somewhat less because customers would still need to pay the upfront cost of the system but would not realize any savings on their bill for some time. Such a tariff could, however, encourage customers who are planning to electrify their home to adopt energy efficiency retrofits the year before, as this would lock in a lower flat charge for their first year of increased consumption due to electrification.

How often should the rate or charge be updated? As fuel costs change over time, the per-kWh rate or flat charge should be changed periodically to reflect updated expectations. These updates could be conducted only through a general rate case (and thus occur on the same schedule as the updates to most other rate components) or they could be performed more frequently through a dedicated proceeding. Less frequent updates could give more certainty to customers enrolled in the tariff about the size of future bills. However, if updates are too infrequent, the tariff could collect more or less revenue than necessary over an extended period, resulting in large windfall gains to the utility (which could undermine affordability) or large losses (which could negatively impact the utility's cash flow). The best schedule for updating the tariff will depend on local factors, such as the utility's fuel mix, the share of customers enrolled in the tariff, and the existing rate-case schedule. Regulators could also put guardrails in place that trigger a review if actual fuel costs deviate sharply enough from expected values.

Would a fuel-risk reduction tariff affect electrification? A fuel-risk reduction tariff would not penalize the utility for greater total fuel usage (as some other policy options discussed in this handbook would), so it would not create a financial incentive for the utility to oppose electrification. On the customer side, a tariff that applies the same flat charge to all customers regardless of usage could even encourage electrification, but there are more efficient, equitable, and direct ways to accomplish this policy goal.[xx]

State Examples

A number of utilities offer flat-charge-style tariffs. While these may include other cost components besides fuel expenses, they can offer models to regulators interested in designing fuel-risk reduction tariffs.

Oklahoma Gas & Electric (OG&E) is one example. It offers a "guaranteed flat bill" to its residential and small general service customers that features a fixed monthly charge over the course of a year. The level of the charge is based on the individual customer's weather normalized historical usage over 12 to 24 months, as well as an adjustment for expected usage changes over the period. The formula used to calculate the level of the charge includes a risk premium, the impact of which is capped at 10%. If actual usage exceeds expected usage by at least 30% over three months, the utility has the ability to move the customer off the tariff and charge them an early departure fee.[10] In 2021, OG&E experienced a loss from its guaranteed flat bill tariff when winter storm Uri drove up natural gas prices.[11]

Florida Power & Light (FP&L) also offers a flat-charge tariff to residential and small general service customers. Its FLAT-1 tariff consists of a fixed monthly charge for a period of one year, the size of which is based on the customer's historical consumption normalized for weather and adjusted for changes in customer behavior. The calculation includes a risk premium capped at 5%. FP&L can require a deposit up to twice the estimated average monthly bill to move a customer onto the tariff, and the utility can move the customer off the tariff and charge a removal fee if their consumption exceeds expectations by 30% for three months.[12]

xx As discussed previously, applying the same fixed charge to all customers would diminish customers' financial incentive to conserve electricity. This would encourage customers to electrify but not in an efficient manner, which could unnecessarily drive up overall system costs. Also, not all customers would be equally positioned to act on a tariff-based electrification incentive. For instance, renters may not have the power to make upgrades to their residences, and low-income customers may not have the ability to purchase electric vehicles. Other types of programs (e.g., rebates for building owners, electrification of public transit) may be more effective electrification strategies than retail tariffs for these customers.

Duke Energy Indiana offers a flat-charge tariff to a limited number of residential customers with load profiles that "can be modeled with reasonable predictability." The size of the monthly charge under the Your FixedBill tariff is calculated based on 12 or more months of past usage data, normalized for weather, and subject to a usage adjustment (this adder is capped at 3.6% for the first year the customer is on the tariff and 0.8% after that). The formula used to calculate the charge can include a risk premium (called a program fee) of up to 9%. Duke can send letters warning the customer of excess usage, and if after two such letters the customer's usage is 15% greater than expected for any month, the utility can reprice the monthly charge based on updated usage information. If the customer does not accept the new amount they are removed from the Your FixedBill tariff and charged a $50 administration fee.[13]

In states that have opened the electricity market to retail competition, various fixed-rate plans are available to customers. These could also serve as examples for fuel-risk reduction tariffs adopted for regulated utilities that feature a fixed-rate design.

Planning and Procurement

A variety of updates to planning and procurement processes could help reduce utilities' reliance on costly and price-volatile fuels. Updating long-term planning and procurement methods can reduce utility reliance on fuels over time (and thus the need to recover fuel costs from customers). Shorter-term strategies, meanwhile, can focus utility attention on careful fuel-cost management and limit the impact of fuel-price volatility on customer bills. A number of key reforms that regulators could consider are explored below.

Long-term planning. Changes to long-term resource planning requirements can play a large role in shifting the utility's portfolio away from price-volatile fuels over time. Such reforms can take a variety of shapes. Many, but not all, states conduct resource planning, though there is plenty of room for improvement in how those resource plans are conducted, reviewed, and approved.[14]

Regulators could direct the utility to fully consider cost-effective demand-side resources (e.g., energy efficiency, demand flexibility) during portfolio creation and to treat them as supply-side resources rather than as reductions in demand during modeling. Regulators could also mandate the inclusion of specific portfolio types (e.g., fuel-free portfolios) in the utility's analysis, and they could require more robust analysis of fuel-price volatility in the utility's resource plans. Regulators could also empower stakeholders to scrutinize the utility's modeling choices and propose their own portfolios, such as by requiring the utility to run new models based on stakeholder-provided inputs or requiring the company to make its modeling data, assumptions, and software available to stakeholders.[xxi]

Scrutiny of fuel-price projections. Regulators should also change how price-volatile fuels like natural gas are considered during the planning process. This could be accomplished through increased scrutiny of gas-price forecasts and their underlying assumptions and by requiring the utility to run high gas-price sensitivities for all portfolios. Commissions should also direct utilities to conduct more sophisticated analyses (e.g., stochastic analyses) to reveal potential cost impacts under a variety of converging conditions (e.g., fuel-price spikes, heat waves, supply disruptions).

Regulators should also ensure that the fuel-price forecasts used across proceedings are consistent. A utility should not be permitted to use a low gas-price forecast when planning new generation resources and a higher forecast to set the expected value for a fuel-cost sharing mechanism. As another example of how the fuel-cost assumptions used in planning could be improved, regulators could require that new fuel-related infrastructure proposals (e.g., gas-fired plants and pipelines) be presented with realistic service lives that are in line with state climate goals. For example, regulators could choose not to permit a utility to propose a 30-year lifetime for a new gas plant in a state with a zero-by-2050 policy goal.

xxi For example, one expert recommends that the utility provide: (1) the entire modeling database in a format readable without a model license; (2) a well-documented manual detailing the logic of the model, defining the inputs and outputs, and providing guidance on its use; and (3) the ability to license the model at a reasonable cost if a license is not otherwise provided by the utility. See William Driscoll, "States Could Save Consumers Billions with Solar, by Requiring Transparent Utility Modeling," *PV Magazine*, September 9, 2019, **https://pv-magazine-usa.com/2019/09/09/states-could-save-consumers-billions-with-solar-by-requiring-transparent-utility-modeling/**.

Locking in forecasts for new generation. If a utility expects to bear some of the financial risk of fuel-cost volatility, it will be inclined to do the most robust possible planning to account for the price volatility of fuels. Regulators can build a reasonable level of risk exposure into the planning process by requiring that all new generation be subject to fuel-cost sharing. Commissions could also consider locking in the price forecast used at the time of approval as the baseline (i.e., the expected value) used by the fuel-cost sharing mechanism.[xxii]

All-source solicitation and procurement. Long-term planning is often based on resource-specific assumptions, and then the resources selected are procured as a separate step later. The resource-selection process is highly sensitive to the input assumptions, so if those assumptions are unrealistic (e.g., fuel prices that are too low) or limited (e.g., distributed resources are not considered), this can create a bias toward selecting traditional, fuel-based resources.[15] Procurement processes can also favor traditional solutions when they invite bids for specific resources rather than system needs. Updating these processes can result in increased selection of fuel-free generation and demand-side resources.

Regulators should mandate the use of all-source solicitation and procurement as a means of removing the bias against fuel-free resources. All-source solicitation and procurement involves defining the utility's needs (e.g., energy, capacity, flexibility services) and then inviting bids for any technologies that can meet those needs. The submitted bids can be used to represent the options available during the planning process, and they can also serve as the basis for subsequent procurement decisions.[16] To ensure all proposals can compete fairly, the fuel-price risk associated with different resources should be carefully considered when selecting between them.[17]

Fuel management plans. Fuel management plans encourage utilities to focus more on fuel-cost management, and they also better position regulators to determine whether the fuel costs that utilities later present for recovery were prudently incurred. These plans can require the utility to articulate its fuel procurement plans, predict fuel-cost outcomes under different possible scenarios (e.g., severe weather events, supply-chain disruptions), and explain its risk management strategies. To ensure that plans are of high quality, they should be subject to regulatory review and approval. Moreover, plan sponsors should be subject to discovery and cross-examination, and stakeholders should have opportunities to review and provide input on plans through filed comments, public hearings, and responsive testimony.

Hedging. Hedging refers to the use of financial instruments to mitigate risk. Used by utilities to reduce the impact of fuel-price volatility on customer bills, hedging can be thought of like insurance where premiums are paid to prevent high-price outcomes. When done correctly, hedging can provide stability and savings, but if done improperly, it can result in unnecessary costs. Some hedging arrangements require a monthly or annual fee in exchange for a cap on prices. Others lock in a predetermined price and amount of fuel to be purchased at a future date, which insulates the off-taker from market price volatility. Many utilities use hedging to some extent, but in many jurisdictions it is subject to little or no review.

Regulators interested in reforming hedging should review current practices and consider whether any changes are needed to better serve customer interests. However, many commissions do not have staff with sufficient experience or expertise in hedging to fully examine the risks and benefits of particular hedging agreements. In those cases, oversight of hedging practices could be folded into the fuel management plans described above.

xxii This idea was also discussed in relation to the fuel-cost sharing policy option, on **page 12**.

Key Questions

Given the variety of possible updates to planning and procurement processes, the questions regulators face will depend on the reforms they are considering. However, they may include the following:

How should utility bids be treated during all-source solicitation and procurement? To obtain the best outcomes, all-source solicitation and procurement processes should create a level playing field for all proposals. However, if the utility is responsible for choosing between bids, it may favor its own submissions (or those of its affiliates) over the bids of third parties. Regulators can prevent this by not allowing the utility (or its affiliates) to submit bids, or if they do allow the utility to submit proposals, they can take steps to ensure that all proposals are fairly evaluated.[18] One way to accomplish that would be to require the use of both an independent consultant to draft the request for proposals (with no input from any utility division that could submit a bid) and an independent evaluator to assess the proposals received.

Is hedging worth the additional cost? Like any insurance, hedging needs to be used carefully to cost-effectively protect against volatile fuel prices. Hedging is not guaranteed to be cost-effective, and it could be imprudently procured. Evaluating fuel hedging through independent audits and regularly reviewing the performance of hedging instruments are key.

Should resource and system planning processes be coordinated? Because long-term resource planning focuses on the resources that will be needed to meet demand, reforming these processes represents a key opportunity to reduce utility reliance on costly and price-volatile fuels. However, the physical configuration of the transmission and distribution system also matters because this determines which fuel-free resources can actually be used and how much flexibility there is to substitute between them. Closer coordination between resource planning and system planning processes can enable better optimization of the overall system to enable demand to be reliably and affordably met with less fuel.

State Examples

Various states have planning and procurement policies in place that can serve as examples for other regulators. For example, **Indiana** requires utilities to evaluate demand-side resources "on a consistent and comparable basis" with supply-side resources during the planning process, including consideration of the resources' risk and cost-effectiveness.[19] In **New Mexico**, when regulators granted stakeholders access to utility modeling, they enabled stakeholders to propose alternative resource portfolios to replace a retiring coal plant. The result was that the commission adopted an entirely fuel-free portfolio identified by stakeholders, rather than the option preferred by Public Service Company of New Mexico (which had included new natural gas-fired generation).[20] Meanwhile, the use of all-source solicitation and procurement in **Colorado** produced third-party bids with what Public Service Company of Colorado described as "shockingly" low wind and solar prices.[21]

Strategies to Increase Access to Information

A central reason why traditional FACs create suboptimal outcomes concerns access to information. Utilities generally have better access to information than their regulators do, and because of this "information asymmetry," it can be difficult for regulators to determine whether the fuel costs presented for recovery through a FAC are unnecessarily high. For example, the regulator may not be able to tell if a utility is using its better contracts to supply competitive markets and dumping its inferior ones on customers.

Strategies to improve information access can support sound fuel-cost management in multiple ways. Where another fuel-cost reform has been implemented, greater access to information can help the regulator understand how well that policy is working and whether additional changes are merited. Strategies that improve information access can also be beneficial on their own because they can help regulators better administer the FAC policies that remain in place in most of the United States.

A variety of strategies could enhance regulators' and stakeholders' access to information. Four of the most promising in relation to fuel costs are discussed below.

More transparent fuel-supply contract terms. In many states today, utilities are allowed to treat their fuel-supply contracts as trade secrets, which prevents customers and other stakeholders from evaluating whether they are reasonable. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudence issues and flag them for the commission to consider. Regulators could increase transparency by requiring utilities to publicly disclose the key terms of these contracts (e.g., minimum delivery amounts, automatic pricing adjustments, changes in the scope of utility and vendor responsibilities).

Enhanced prudence reviews. In many states, fuel-cost recovery proceedings are limited in scope and subject to tight timelines. As a result, fuel costs are often approved for recovery after only a superficial prudence review. Regulators could reform these proceedings to enable enhanced scrutiny. Regulators can strengthen the minimum filing requirements to shift the burden of proof onto the utility requesting cost recovery, while simultaneously demonstrating a willingness to disallow recovery if the utility cannot convincingly demonstrate prudence. For this strategy to be effective, it must be be clear to the utility that disallowance is a real and substantive risk. Simply applying a slightly higher level of review to an existing, cursory process is unlikely to be successful.

Regular audits. Audits by an independent third party can give regulators, customers, and stakeholders better visibility into a utility's performance, including its fuel-cost management, fuel procurement practices, and risk-reduction strategies. Requiring both a management audit and a financial audit on an annual basis would be beneficial.

The financial audit provides insight into how the utility has been spending money. This audit would enable both the regulator and stakeholders to better judge whether its fuel purchases have been prudent.

The management audit may be a substantially longer document. It could include detailed information across multiple dimensions (e.g., how much natural gas is purchased through short-term versus long-

term contracts, the origins of purchased coal, contract terms and conditions). It can also include auditor recommendations (e.g., that the utility take specific steps to ensure gas plants remain operational during cold weather, that the utility purchase more power through power-purchase agreements to reduce uneconomic fuel purchases). The management audit can enable stakeholders to access important information without the need for lengthy discovery processes, and the auditor's recommendations can shape regulatory decisions.

Regulators should require the sponsors of audits to be subject to discovery and cross-examination in relevant dockets. Audit parameters should also be clearly defined to provide clarity in priority areas of performance and to enable comparison with industry peers.

Broader and deeper stakeholder engagement. Robust stakeholder engagement in proceedings where fuel-cost recovery is considered can help regulators access and analyze the information they need to make sound decisions. Where commission staff have limited capacity to dig into utility fuel-cost filings, stakeholders can help identify inconsistencies and potential prudence concerns. Enabling stakeholders to offer their own proposals for changes (rather than being limited to reacting to utility proposals) can also help surface new solutions. Finally, stakeholder responses in dockets that point out issues related to fuel-cost recovery can help build a library of information that other stakeholders and regulators (both within and outside the state) can later use to improve policies.

Strategies to enhance stakeholder engagement include restructuring proceedings to allow more time for stakeholders to provide input, ensuring ample opportunities for discovery and cross-examination, and equipping stakeholders with the resources they need to engage meaningfully (e.g., automatic access to key information such as via management audits, intervenor compensation to enable less well-resourced stakeholders to participate). Regulators could also solicit input from previously underrepresented constituencies and increase the participatory nature of commission processes (e.g., informal solution-finding workshops in addition to formal litigated processes).

Key Questions

The key questions regulators will face depend on which strategies they choose to pursue to increase information access. However, such questions will likely include the following:

Will additional effort be required from regulators and stakeholders? As with any reform, the amount of effort that a reform will demand is important to consider. Enhanced prudence reviews are likely to increase the demands on regulators and their staff, who may already be heavily burdened by existing work. In addition, strengthening stakeholder engagement could require devoting regulatory resources to educating parties who are not familiar with existing policies or processes. However, there are often multiple ways to accomplish the same goal, and regulators can consider whether there are alternatives that reduce the needed effort. The time that commission staff and stakeholders must devote to discovery requests can be reduced by using regular financial and management audits, as well as by requiring the utility to automatically disclose key data, models, and documents during enhanced prudence reviews.

Will additional time be needed to reach decisions? Some strategies to increase access to information may require additional time. Enhanced prudence reviews may take longer than current prudence reviews, and establishing robust stakeholder engagement in a fuel-cost recovery proceeding may require comment periods to be lengthened, public hearings to be added, or outreach to be conducted to specific

constituencies. If additional time is needed, regulators should consider how processes can be changed to accommodate this. For example, conducting fuel-cost recovery proceedings less frequently could offset the increased time it takes for an enhanced prudence review during each proceeding.

How should sensitive information be handled? Though greater disclosure of utility fuel-supply contract terms, data, models, and other information could be beneficial, some information is sensitive and should be disclosed selectively. Regulators should consider whether any part of a fuel-supply contract should remain confidential, and if so, a nondisclosure agreement should be required for stakeholders to access it. Utilities may wish to keep certain data as a trade secret so it cannot be accessed by competitors, but regulators should consider whether this is appropriate for a utility that functions as a regulated monopoly (and which therefore does not face direct competition).

What will be the cost to customers? Some strategies to increase information access involve costs that are ultimately born by customers. Audits require substantial time and effort from both the third parties conducting them and the utilities subject to them, while achieving robust stakeholder engagement may require that intervenor compensation be provided to less well-resourced parties. As with any reform, it is the regulator's responsibility to determine whether the incremental costs of a reform outweigh the benefits the reform is likely to provide.

State Examples

A number of states have policies that support increased access to information. One is **Kentucky**, which requires utilities to file copies of all fuel-supply contracts (including any modifications and related documents) promptly, to justify in writing any purchases from utility-controlled sources, and to also justify any price-escalation clauses. Kentucky then makes all these documents available for public inspection.[22]

Ohio regulators recently required independent performance audits of extra customer charges that were collected by three utilities buying power from coal-fired power plants (often at above-market prices), and regulators then solicited stakeholder comments on the auditors' findings.[23]

Minnesota also requires utilities to submit an independent auditor's report every year evaluating the previous year's automatic fuel-cost adjustments, though regulators' ability to choose not to approve the auditor's report is limited.[24]

States also have taken steps to broaden and deepen stakeholder engagement.[xxiii] In a recent distribution system planning proceeding, **Oregon** conducted stakeholder education, structured the proceeding in ways that facilitated stakeholder input, and provided less formal venues (e.g., workshops) for engagement. In **Michigan**, the MI Power Grid initiative has engaged hundreds of diverse stakeholders through more than 50 meetings, including representatives of local communities, environmental justice organizations, and consumer advocates. Also, **at least 16 states** offer intervenor compensation to support stakeholders' ability to engage in regulatory proceedings.[xxiv]

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xxiii For more information about all the state examples discussed in this paragraph, see Cory Felder, Jessie Ciulla, Rachel Gold, and Jacob Becker, *Regulatory Process Design for Decarbonization, Equity, and Innovation*, RMI, 2022, **https://rmi.org/insight/puc-modernization-issue-briefs/**.

xxiv These 16 states are Alaska, California, Colorado, Hawaii, Idaho, Illinois, Kansas, Maine, Michigan, Minnesota, New Hampshire, Oregon, Tennessee, Washington, West Virginia, and Wisconsin.

Efficiency Ratio

As detailed previously, reforms designed to share fuel-cost risk between utilities and their customers is an emerging policy space in which most US states have limited experience. We anticipate that decision makers will develop a range of new policy proposals in the coming years as fuel-cost volatility, advances in fuel-free technologies and demand management strategies, and continued social inequities push them to reevaluate the wisdom of existing FAC policies.

One such emerging idea is implementing a PIM to encourage the utility to reduce the cost of producing a MWh of power. A PIM is a regulatory tool that ties a portion of a utility's earnings to a desired outcome, which is measured by a specific metric. In this case, the metric is the utility's production cost efficiency measured in $/MWh, so we refer to this type of PIM as an "efficiency ratio." The $/MWh metric could focus narrowly on the utility's own fuel expenditures, or it could include purchased power and represent the utility's net power costs.

To be effective, an efficiency ratio PIM must not only measure the utility's production cost efficiency today but also indicate whether the metric has improved or declined over time. To accomplish this, the historical value of the metric (e.g., the utility's historical per-MWh fuel costs) is compared with the metric's current value. If the utility's $/MWh has decreased, its production cost efficiency has improved and the company would be eligible for a financial incentive under the mechanism. Conversely, if the $/MWh has increased, its production cost efficiency has declined and the company may be subject to a penalty.

The financial reward or penalty under a PIM can be structured in various ways. An efficiency ratio is no exception; while by definition an efficiency ratio must employ a $/MWh metric, regulators have the flexibility to select from a range of possible incentive structures. These possibilities include a constant marginal incentive (e.g., the utility earns the same reward for each incremental improvement in the metric), a lump sum (e.g., the utility earns a fixed reward if its performance exceeds a specific threshold), and more complex designs (e.g., a banded design in which the marginal or lump-sum incentive changes multiple times as the utility's performance crosses different thresholds).

Another possibility is to use the $/MWh metric to implement a usage-normalized version of fuel-cost sharing. In this approach, the improvement (or decline) in the value of the $/MWh metric would be multiplied by the total MWh from a reference period. For example, using the MWh expected under "normal" weather conditions as the multiplier would result in a weather normalization. Under this PIM, if the actual weather conditions were "normal" over the time period, the financial impact on the utility would be the same as a fuel-cost sharing policy — but if a heat wave caused usage to skyrocket, the utility would not be penalized for the resulting increase in fuel costs.

In addition to the structure of the financial incentive, regulators must also consider its magnitude. Ideally the incentive should be large enough to motivate the utility to achieve the policy goal, but no larger since excessive rewards unnecessarily burden customers and excessive penalties could negatively impact the utility's financial health. If both financial incentives and penalties are used, the commission must also consider whether these should be symmetrical or asymmetrical.

Regulators could design the efficiency ratio to apply to all power generated by the utility (i.e., a single $/MWh metric could be used) or separately to different categories of power (e.g., the $/MWh could be tracked and incentivized separately by fuel type). Regulators may also wish to apply the efficiency ratio to purchased power to avoid encouraging the utility to make uneconomic substitutions between purchases and its own generation (e.g., generating more electricity when fuel prices fall even if power could be purchased from third parties more cheaply).

Regulators should also consider how different factors may impact the $/MWh metric. For instance, although an improvement in the metric may reflect improvements in the utility's fuel-cost management, such improvement could also be due to factors outside the utility's control (e.g., general market conditions) or utility actions that run counter to policy goals (e.g., running an aging coal plant more to decrease the heat rate, reduce the $/MWh, and earn a larger reward under a coal-specific efficiency ratio). Commissions may therefore wish to apply additional tests that require the utility to show that any $/MWh reductions were the result of its own appropriate actions before allowing it to receive an incentive payment. Regulators could also consider adjusting penalties if the utility can convincingly demonstrate that a deterioration in the metric was due to no fault of its own.

Potential Benefits and Drawbacks

As a new policy option, the key benefits and drawbacks associated with the efficiency ratio are still emerging. However, the following considerations may be relevant.

One benefit is that if the $/MWh metric is restricted to the utility's own fuel costs, it is straightforward to calculate. Since all vertically integrated, investor-owned utilities report historical data on fuel costs and generation to federal agencies (e.g., the Energy Information Administration, the Environmental Protection Agency), there is no need for fuel-cost forecasting. However, if additional costs are included in the metric (e.g., the fuel costs in purchased power, other variable operating expenses deemed part of the net power cost), these data may not be as readily available, and in some cases they may require estimation.

Furthermore, utilities may be more supportive of the idea of an efficiency ratio PIM than other policy options. Thus far, the efficiency metric concept has sparked greater engagement from utilities in states considering action by commissions or legislatures.[xxv]

xxv This is based on informal conversations that some of the authors have had about fuel-cost management options with state legislators, commissioners, consumer advocates, and utility representatives.

However, the efficiency ratio concept also has certain drawbacks. One is that focusing on $/MWh may not advance other policy objectives. A utility could reduce the $/MWh ratio by either reducing the numerator (cost) or increasing the denominator (electricity production). However, tactics to increase the total electricity production may not be in the public interest.[xxvi] For instance, a utility could "improve" the $/MWh metric by declining to pursue opportunities to conserve energy during hours when costs are below average.[xxvii] The effects of this drawback are limited somewhat by the fact that in the next period the lower $/MWh value becomes the new benchmark.

An efficiency ratio applied separately to different categories of power (e.g., one that tracks the $/MWh by fuel type) could create additional challenges. For instance, if the PIM rewards the utility for reducing its per-MWh cost of generating power from natural gas, a drop in natural gas prices could enable the utility to earn a reward for each additional MWh it can generate from that fuel — even if this means curtailing more cost-effective resources (e.g., wind, solar). This could result in both higher costs to customers and higher carbon emissions. An efficiency ratio applied separately to different categories of power could also create an incentive to run coal units at higher capacity factors to increase plant efficiency (i.e., to decrease the heat rate), something entirely within the utilities' control.

Further Development

As the efficiency ratio is an emerging idea, its benefits and drawbacks have not been fully explored. As with any novel policy, regulators interested in this concept should investigate its potential impacts carefully. The design and implementation of any efficiency ratio should also include robust engagement with utilities, consumer advocates, trade associations, and other relevant stakeholders.

xxvi A financial incentive to sell more electricity is called a throughput incentive. Since a throughput incentive tends to undermine utility support for energy efficiency programs, many states have taken steps to combat the throughput incentive created by traditional ratemaking. Such policy actions include revenue decoupling and PIMs focused on energy efficiency programs. Regulators in states that have energy efficiency as a policy goal may wish to consider whether additional actions are merited to address any throughput incentive created by an efficiency ratio.

xxvii If a utility's per-MWh costs are substantially higher in a few hours of the day or year, most hours of the year may in fact fall into the "below-average cost" category. For example, in the late afternoon a certain utility may need to bring more costly gas plants online to meet its daily peak — and its per-MWh cost may rise further during a few hot summer afternoons when air conditioning usage is peaking, wholesale electricity prices are spiking, and the utility must purchase additional power to meet its customers' needs. A few very costly hours can push the average $/MWh well above the median, with the result that the majority of hours have costs that are below average.

Conclusion

The traditional FAC policies that are common across the United States give electric utilities little incentive to carefully manage their fuel costs. Under a FAC, customers, rather than the utility, pay for excessive fuel expenditures, and if the utility reduces its fuel costs, it does not benefit. Given the impact that fuel has on both customer bills and carbon emissions, it is worth considering alternatives to the traditional FAC.

When the wisdom of FACs is called into question, utilities often defend these policies by arguing that they have no control over fuel costs. However, this was never entirely the case, and it is even less true today. Thanks to technological advances, utilities are in a better position to manage their fuel costs now than ever before. This is true on both the supply side (e.g., cost-effective renewables, battery storage) and on the demand side (e.g., time-of-use rates, virtual power plants).

Because of these developments, considering alternatives to traditional FACs is particularly timely — and we encourage regulators to explore the options available to them. This handbook is intended as a resource to support these discussions.

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BEFORE

THE GEORGIA PUBLIC SERVICE COMMISSION OF

DOCKET NO. 56765

In re:

Georgia Power Company's Fuel Cost Recovery (FCR-27)

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the Direct Testimony of Jeremy Kaldin on behalf of Sierra Club, NRDC, and SACE has been furnished by electronic mail on this 9th day of April, to the following:

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