STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1282

In the Matter of Application of Duke Energy Carolinas, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	CUCA'S POST-HEARING BRIEF

Carolina Utility Customers Association, Inc. ("CUCA"), through counsel, hereby respectfully submits this Post-Hearing Brief regarding the Application to adjust the fuel and fuel-related cost components of electric rates filed by Duke Energy Carolinas, LLC in the above-captioned proceeding (the "Company," "Duke," or "DEC").[1]

INTRODUCTION

DEC is requesting a proposed Experience Modification Factor ("EMF") adjustment (excluding regulatory fee) for industrial customers of 1.726 cents per kWh to recover the difference between fuel revenues realized and fuel costs incurred during the test period.[2] The test year under-recovery sought to be recovered by DEC totals $998 million.[3] This nearly billion dollar under-recovery vastly exceeds any prior under-recovery sought to be recovered by DEC[4] and is roughly equivalent to DEC's entire projected annual spend on gas to fuel its gas generation units for the billing year beginning September 2023.[5] In fact,

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[1] This brief does not address all issues arising in this proceeding. CUCA's silence on any issue should not be construed as acquiescence to any particular position.

[2] Tr. vol. 2, 155 (Clark Supp. at 2); Tr. vol. 2, 141 (Clark Dir. at 6).

[3] Tr. vol. 2 Exhibits, at Clark Supp. Exh. 3, p. 1.

[4] *See* Tr. vol. 2 Exhibits, at CUCA Public Staff Panel Cross Exh. 1.

[5] Clark Dir. Exh. 2, Sch. 1, at 1; Tr. vol. 2, 197 (Clark cross-examination).

it is 125% more than the total of all under-recoveries reported by DEC over the past 17 years (since 2006) and is 300% more than the previous largest single year under-recovery—which was last year.[6]

By any measure, DEC's request in this proceeding is extraordinary and unprecedented. And, if granted, its impact on rates will be dramatic and "shocking". As proposed, the rider adjustment will—by itself, without consideration of any other impact on retail rates—cause an average 17.98% increase on customer's bills.[7] And its impact on industrial customers, who, by definition, utilize energy-intensive processes, will be much greater.

The Agreement and Stipulation of Partial Settlement entered into between DEC and the Public Staff—and not endorsed by any other intervenor—would extend the payment period from twelve to sixteen months, reducing the average rate increase from 17.98% to 13.31%[8] and would allow DEC to recover an additional 4% interest (rather than zero) from North Carolina retail customers on the difference between the 12-month recovery period and the 16-month agreed upon recovery period.[9] While this proposal is an improvement over Duke's application, the proposed rate increase resulting from the settlement remains "shocking" and would be incurred at precisely the same time DEC is seeking a 9.5% total Year-1 increase in its MYRP Rate Case application pending in Docket No. E-7, Sub 1276.[10]

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[6] *See* Table 2 *infra.*

[7] Tr. vol. 2, 156 (Clark Supp. at 4).

[8] Duke Energy Carolinas, LLC and the Public Staff's Agreement and Stipulation of Partial Settlement, filed in Docket No. E-7, Sub 1282 on May 31, 2023 (the "Settlement Stipulation"), at 4.

[9] Settlement Stipulation, at 4.

[10] *See* Tr. vol. 2, 278 (Lawrence Dir. at 19).

Accordingly, under the settlement DEC customers could, on average, see a 22.8% increase in their bills by December 2023—an increase that would constitute "rate shock."[11]

As discussed below, the Commission should protect ratepayers by adopting a longer recovery period for this extraordinary under-collection and/or utilize EDIT refunds to offset the fuel under-recovery—as suggested by DEC in its rebuttal testimony.[12] CUCA recognizes that fuel costs are generally recovered on a "pass-through" basis and absent a demonstration of imprudent operations DEC is entitled to recover its fuel costs. However, the Commission has authority to determine the method of recovery in a pro-consumer fashion to help soften the blow of one-time, sudden rate increases beyond the proposed stipulated settlement terms. CUCA makes several specific recommendations for improvement to DEC's and the Public Staff's fuel cost adjustment proposals.

ARGUMENT

I. THE IMPORTANCE OF NORTH CAROLINA MANUFACTURERS.

Notwithstanding the decline in manufacturing in some sectors in the last several decades,[13] North Carolina manufacturers remain a backbone of the state economy and critically important in many local communities. Manufacturing (1) creates wealth for local communities; (2) is a significant contributor to employment; (3) pays premium compensation to its employees; (4) plays a disproportionate and important role in the economies of the state's smaller communities and local areas; and (5) produces positive

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[11] *See* Tr. vol. 2, 277 (Lawrence Dir. at 18) (opining that "a one-time increase of *16.5% does* constitute rate shock") (emphasis added).

[12] Clark and Bauer Rebuttal Testimony, at 18-21 (Tr. vol. 2, 175-178).

[13] *See, e.g.,* Dir. Testimony of Kevin W. O'Donnell, Docket No. E-2, Sub 1300 (Mar. 27, 2023), at 87-92.

multiplier or "spillover" effects that support related industries and other sectors of the economy.[14] According to the most recent data available from the National Association of Manufacturers, manufacturing output in North Carolina, measured in dollars, has risen from approximately $86 billion in 2010 to $102 billion in 2021 and manufacturing accounts for 17% of the total output in the state, employing 10.4% of the workforce with an average annual compensation of over $79,000 in 2021.[15]

The Commission and Duke have long played a critical and constructive role in ensuring that manufacturing is attracted and retained in North Carolina in the face of interstate and international competition. Energy, of course, is one of the most significant costs for manufacturers—an input cost that is absolutely critical in most instances to the creation of manufactured products for sale. Increases in energy costs often cannot be simply passed along to consumers—certainly not as a pass-through as Duke is permitted to do.[16]

The current economy presents a number of challenges for North Carolina manufacturers. Historic workforce challenges, persistent inflation and logistics and transportation impediments are but a few of those challenges. Rising energy costs are another challenge, as this Commission is well aware. CUCA urges the Commission to fashion relief in this proceeding that is appropriate to the needs of North Carolina

[14] *See, e.g.,* Tr. vol. 2, 344-345 (Collins Dir.); Dir. Testimony of David Lyons, Docket No. E-7, Sub 1276 (Jul. 19, 2023), at 3-4; Dir. Testimony of Charles Heilig, Docket No. E-2, Sub 1300 (Mar. 27, 2023), at 4-5; Dir. Testimony Kevin W. O'Donnell, Docket No. E-2, Sub 1219 (Apr. 13, 2020), at 12-13 (Tr. vol. 14, 139-140); Dir. Testimony Kevin W. O'Donnell, Docket No. E-22, Sub 532 (Sept. 8, 2016), at 45-46 (Tr. vol. 8, 208-209).

[15] Available at https://www.nam.org/state-manufacturing-data/2022-north-carolina-manufacturing-facts/.

[16] *See* Dir. Testimony of Charles Heilig, Docket No. E-2, Sub 1300 (Mar. 27, 2023), at 5-6.

consumers, including those in the industrial class, taking into consideration the unprecedented nature of DEC's request. DEC will receive full recovery for its incurred fuel costs under any scenario proposed in this proceeding, so the Commission should adopt an approach that helps manage the rising costs and the adverse impacts of the proposed fuel rider charges coupled with the pending request for a general rate increase.

II. THE PROPOSED SETTLEMENT STIPULATION TERMS FAIL TO APPROPRIATELY PROTECT DEC CUSTOMERS FROM RATE SHOCK.

In its Settlement Stipulation, Duke is seeking one-time, sudden average rate increases across all customer classes of 13.3%. The request comes in parallel with DEC's request in the pending MYRP general rate case proceeding for an additional 9.5% average rate increase in rate year one. Considered singularly, or collectively, the increase will cause detrimental rate shock for customers, particularly high load factor and energy-intensive industrial customers

A. DEC has failed to demonstrate that its actions to address well-established risks associated were appropriate and effective.

Following on heels of Winter Storm Elliott and DEC's first ever load shedding event,[17] DEC now seeks to impose an unprecedented price hike on its customers.

Yet, the intervenors have repeatedly identified the risk to consumers from Duke's increasing reliance on natural gas resources in prior fuel rider proceedings—urging Duke to implement enhanced measures to protect against these risks. For example, in 2019, Public Staff witness Jay Lucas warned:

> … DEC, like other utilities, has increased its reliance on natural gas to produce electricity and serve load. As utilities have significantly increased their reliance on a fuel with greater price variances (compared to nuclear and coal) in

[17] *See generally* Docket No. M-100, Sub 163.

> order to more economically serve their customers, these same customers are exposed to greater risk of fuel cost under- and over-recoveries despite the overall decreasing cost of natural gas. Increased natural gas consumption, coupled with recent winter weather events of the last few years, have caused exposure to higher than anticipated short-term natural gas prices. Given the increased risk of under-recoveries if natural gas prices, are not forecasted as accurately as possible, the Public Staff believes that the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs.[18]

Witness Lucas' warning followed prior, and similar, observations by the North Carolina Sustainable Energy Association ("NCSEA"). In connection with the 2015 fuel rider proceeding, NCSEA warned that:

> DEC's consumption of natural gas is steadily increasing and this trend is expected to continue during the billing period. As DEC's consumption of natural gas increases, it becomes increasingly prudent and reasonable to try to protect customers from the price volatility that has historically been associated with natural gas. Natural gas hedges are one means of providing DEC's customers with insulation from or insurance against price volatility. Another means of providing such protection is diversification of the generation fleet that serves DEC's customers so that the fleet includes more generating facilities that do not consumer fuel . . . ."[19]

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[18] Affidavit of Jay B. Lucas, DEC 2019 Fuel Rider Proceeding, Docket No. E-7, Sub 1190 (May 20, 2019) , at 2–3 (internal citations omitted).

[19] NCSEA's Post-Hearing Brief, *DEC 2015 Fuel Rider Proceeding*, Docket No. E-7, Sub 1072 (Jul. 2, 2015), at 3. *See also* NCSEA's Post-Hearing Brief, *DEC 2016 Fuel Rider Proceeding*, Docket No. E-7, Sub 1104 (Jul. 7, 2016), at 3 (citing the testimony of DEC witness Daji) ("As DEC's consumption of natural gas increases, it becomes prudent and reasonable to try to protect customers from the price volatility that has historically been associated with natural gas.").

To this point, DEC had consumed 42 Bcf of natural gas during its 2012 test period corresponding to the 2015 rider proceeding,[20] while, in its current test period, DEC reports consuming 253.5 million MBtu—an increase compared to the prior test year gas burn of 189.6 million MBtu.[21] In other words, DEC's use of natural gas has only escalated since the 2015 filing by NCSEA and, as evidenced by Duke's Carbon Plan, may increase substantially in the near future.[22]

Surprisingly, given the extent to which actual fuel costs deviated from forecasts, DEC's testimony provides very little insight into its hedging practices applicable here. Witness Swez avers that Duke "continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach" and that it "monitors and make[s] adjustments as necessary to its natural gas hedging program to ensure it remains appropriate based on market conditions and the Company's fuel procurement strategy."[23] But witness Swez does not describe those policies in detail, nor does he explain how Duke's policies successfully were utilized in this instance to mitigate the impact of the escalating fuel costs during the test year, nor does he offer an explanation of how Duke's procurement practices could be improved to prevent a recurrence of a billion dollar under-collection. To this point, witness Swez was not familiar with Duke's Fuel Procurement Practices Report required by Rule R8-52(b) as filed

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[20] *Id.*

[21] *See* Tr. vol. 2, 22 (Swez Dir. at 8).

[22] *See* Tr. vol. 2, 53-55) (cross-examination of DEC witness Swez); Order Adopting Initial Carbon Plan, Docket No. E-100, Sub 179 (Dec. 30, 2022), at 77-79 (approving, for planning purposes and subject to future evidentiary showings, 800 MW of CTs and a CC of up to 1,200 MW).

[23] Tr. vol. 2, 27.

in Docket No. E-100, Sub 47A[24] Finally, the brief one-sentence reference to hedging methodology in Exhibit 1 to Mr. Swez's testimony ("A targeted percentage of the natural gas fuel price exposure is managed via a rolling 60-month structured financial natural gas hedging program.") is not consistent with the methodology with the most recent Natural Gas Hedging Report filed in 2014 in Docket No. E-100, Sub 47A.[25]

The gas market disruptions that occurred in 2022 highlight the need for an examination of strategies to minimize these risks for customers. In DEP's pending general rate case proceeding, CUCA recommended adoption of a fuel PIM to incent aggressive planning on the part of the utility and create a financial incentive to reduce fuel costs.[26] Attached as Exhibit 1 is a recently-issued "Handbook for Regulators" which describes other regulatory strategies to encourage fuel-cost management best practices. *See* RMI, Strategies for Encouraging Good Fuel-Cost Management, July 2023 (attached as Exhibit 1).[27]

Given the recognized risks of price fluctuations which have been accentuated by Duke's increasing reliance on natural gas, coupled with the extraordinary nature of Duke under-collection in the test year under consideration in this proceeding, DEC's evidentiary showing as regards (1) the reasons for its under-collection, (2) the reasonableness of its

[24] Tr. vol. 2, 56-57.

[25] *See* Natural Gas Hedging Report for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 47A (Jan. 31, 2014).

[26] *See* Docket No. E-2, Sub 1300 at Tr. vol. 21, 672.

[27] CUCA is bringing this resource to the attention of the Commission as a contribution to the discussion of these issues, including examples from other states.

hedging and other impact mitigation practices, and (3) the benefits derived from its existing risk mitigation practices is deficient.

B. DEC's request is historically high and will harm manufacturers and other ratepayers.

The Settlement Stipulation entered into between DEC and the Public Staff would result in an immediate 13.31% rate increase to total bills for all customers[28] at precisely the same time DEC is seeking a 9.5% total year-one increase in its MYRP Rate Case proceeding in Docket No. E-7, Sub 1276.[29] Accordingly, DEC customers could see, on average, a 22.8% increase in their bills by December 2023.

For industrial customers in particular, this is a potentially devastating rate shock. DEC did not offer a projection of the rate impact on industrial customers in its Settlement Stipulation, but on cross-examination witness Clark estimated a $30,000 impact on industrial customers based on a "typical" energy use of 5 million kWh per year[30]—which is roughly equivalent to a 1 MW customer with a 58% load factor.[31] Of course, this energy usage profile (1 MW; 58% load factor) is not representative of large industrial users who are a bedrock of the North Carolina economy. Rate impact for these customers which will be much higher.

Shown below on Table 1 is a calculation of projected rate impacts <u>of the fuel rider alone</u> based on DEC's original proposal for larger industrial customers (40 MW, 20 MW and 10 MW) with a 75% load factor. For example, a 40 MW 75% load factor customer

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[28] Settlement Agreement, at 4.
[29] *See* Tr. vol. 2, 278 (Lawrence Dir. at 19).
[30] Tr. vol. 2, 199.
[31] (1,000 K) * (58%) * (8,760 hours per year) = 5,080,800 kWh/year.

will pay $2.7 million per year more under DEC's original proposal—again, solely due to the EMF fuel factor (and EMF interest) increase.

Table 1 Estimates of Rate Impact of Proposed Rider (per DEC's Corrected Application) on Industrial Customers				
	40 MW	**20 MW**	**10 MW**	**1 MW**
Existing Rider (before reg fee) ($ per kWh)	0.024122	0.024122	0.024122	0.024122
Proposed Rider ($ per kWh)	0.034394	0.034394	0.034394	0.034394
Percentage Increase	43%	43%	43%	43%
Existing fuel rider payment (monthly)	$ 528,272	$ 264,136	$ 132,068	$ 13,207
Proposed fuel rider payment (monthly)	$ 753,229	$ 376,614	$ 188,307	$ 18,831
Increase per month	$ 224,957	$ 112,478	$ 56,239	$ 5,624
Proposed rate impact per year	**$ 2,699,482**	**$ 1,349,741**	**$ 674,870**	**$ 67,487**

Shown below on Table 2 is a calculation of projected rate impacts of the fuel rider alone for larger industrial customers (40 MW, 20 MW and 10 MW) with a 75% load factor, based on DEC and the Public Staff's Agreement and Stipulation of Partial Settlement. proposal. Even under the stipulation, a 40 MW 75% load factor customer will pay nearly $2.2 million per year more.

Table 2 Estimates of Rate Impact of Proposed Rider (per DEC and Public Staff Stipulation) on Industrial Customers				
	40 MW	**20 MW**	**10 MW**	**1 MW**
Existing Rider (before reg fee) ($ per kWh)	0.024122	0.024122	0.024122	0.024122
Proposed Rider ($ per kWh)	0.032422	0.032422	0.032422	0.032422
Percentage Increase	34%	34%	34%	34%
Existing fuel rider payment (monthly)	$ 528,272	$ 264,136	$ 132,068	$ 13,207
Proposed fuel rider payment (monthly)	$ 710,042	$ 355,021	$ 177,510	$ 17,751
Increase per month	$ 181,770	$ 90,885	$ 45,443	$ 4,544
Proposed rate impact per year	**$ 2,181,240**	**$ 1,090,620**	**$ 545,310**	**$ 54,531**

Unlike DEC, manufacturers and other industrial consumers of electricity typically do not have the ability to pass through to their customers price increases they incur for their costs of doing business.[32] Indeed, it is often the case that industrial customers enter into forward contracts for the sale of their products with fixes prices or they compete in national and international markets where the price for the product is set by the market. For DEC's largest customers—customers who are some of the most significant contributors to cost recovery for DEC's baseload generating facilities—these sort of unbudgeted price increases can make the difference between keeping a plant open and closing it.[33]

"It is a well-established principle of ratemaking that a sudden, severe increase in rates — 'rate shock' — should be avoided." *In Re Hedging Commodity Costs by Natural Gas Local Distribution Companies*, Docket No. G-100, Sub 84, 215 P.U.R.4th 349 (Feb. 26, 2002) (quoting Comment of the Attorney General). As the Commission has expressly noted in the context of "extreme volatility in natural gas commodity costs":

> to the ratepayer paying a monthly bill, it makes little difference whether the bill has soared because of a re-allocation of fixed costs in a general rate case or because rapidly increasing commodity gas costs are being passed through in a purchased gas adjustment proceeding.

Id. Given the Public Staff's testimony that "a one-time increase of 16.5% does constitute rate shock,"[34] it is clear that the "compromise" one-time increase of 22.8% also would constitute rate shock.

CUCA is not unsympathetic to the disruption in the commodity market which occurred during the test year at issue here, but DEC should not be insensitive to the strain that spiking rates puts on customers. Duke is in the business of proactively managing these risks. Customers are not.

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[32] *See, e.g.,* Dir. Testimony of Charles Heilig, Docket No. E-2, Sub 1300 (Mar. 27, 2023), at 5-6.

[33] *Id.*

[34] *See* Tr. vol. 2, 277 (Lawrence Dir. at 18).

C. The magnitude of the EMF under-collection is unprecedented in recent years.

DEC's requested fuel cost adjustment is largely driven by its EMF under-collection of $999 million.[35] Table 3 below summarizes the various EMF over- and under-collections in DEC fuel rider proceedings over the past 17 years.[36]

Table 3				
Summary of EMF Adjustments in Prior Fuel Rider Proceedings				
Year	**Docket**	**Description**	**EMF Overcollection (millions)**	**EMF Undercollection (millions)**
1	E-7, Sub 805	DEC Fuel Rider (2006)	$ 3.7	
2	E-7, Sub 825	DEC Fuel Rider (2007)		$ 56.2
3	E-7, Sub 847	DEC Fuel Rider (2008)		$ 32.0
4	E-7, Sub 875	DEC Fuel Rider (2009)		$ 124.7
5	E-7, Sub 934	DEC Fuel Rider (2010)	$ 151.1	
6	E-7, Sub 982	DEC Fuel Rider (2011)	$ 10.3	
7	E-7, Sub 1002	DEC Fuel Rider (2012)		$ 18.5
8	E-7, Sub 1033	DEC Fuel Rider (2013)	$ 47.3	
9	E-7, Sub 1051	DEC Fuel Rider (2014)	$ 5.3	
10	E-7, Sub 1072	DEC Fuel Rider (2015)		$ 10.0
11	E-7, Sub 1104	DEC Fuel Rider (2016)	$ 41.0	
12	E-7, Sub 1129	DEC Fuel Rider (2017)	$ 44.0	
13	E-7, Sub 1163	DEC Fuel Rider (2018)		$ 73.3
14	E-7, Sub 1190	DEC Fuel Rider (2019)		$ 78.2
15	E-7, Sub 1228	DEC Fuel Rider (2020)		$ 57.1
16	E-7, Sub 1250	DEC Fuel Rider (2021)		$ 20.5
17	E-7, Sub 1263	DEC Fuel Rider (2022)		$ 327.0
	TOTAL		$ 302.7	$ 797.5
	E-7, Sub 1283	DEC Fuel Rider (2023)		$ 999.0

As shown by Table 3, the under-collection at issue here is 125% greater than all DEC EMF under-collections over the past fifteen years *combined* (since 2006). And it is 300% more the largest single year EMF under-recovery—which was just last year. As

[35] *See* Tr. vol. 2, 141 (Clark Dir. at 6).
[36] CUCA Public Staff Panel Cross Exhibit 1 (Tr. vol. 2 Exhibits).

discussed below in Section III, treating a nearly $1 billion under-collection as 'business as usual' is not in the best interest of DEC's ratepayers.

III. THE COMMISSION SHOULD REQUIRE A LONGER RECOVERY PERIOD TO PROTECT CUSTOMERS FROM RATE SHOCK.

The proposed stipulation terms would allow DEC to recover this unprecedented under-collection over a 16-month period, in exchange for an additional 4% interest (a total of $6.656 million) to be paid by North Carolina retail customers.[37]

The Commission has previously approved recovery of EMF under-collections over a 24-month period with no interest. Here, the proposed recovery of under-collections over 16-months has not been adequately justified by DEC or the Public Staff. Nor is there justification from further raising DEC customer rates through the recovery of 4% interest on the unprecedented EMF under-collection amount.

The Commission has the authority to establish a recovery rate which is appropriate to the circumstances presented. Duke points to language in G.S. § 62-133.2(d) prescribing that any increment or decrement be reflected in rates for 12 months, implying an argument that the Commission is limited to a 12-month recovery period. *See* G.S. § 62-133.2(d) ("The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."). However, this provision does not anywhere state that the Commission's general powers to avoid rate shock and set rates in

[37] Duke Energy Carolinas, LLC and the Public Staff's Agreement and Stipulation of Partial Settlement, filed in Docket No. E-7, Sub 1282 on May 31, 2023 (the "Settlement Stipulation"), at 4.

the public interest are overridden by reference to this 12-month period. Instead, viewed in context, the language merely prescribes a minimum recovery period that coincides with the 12-month test year. If the General Assembly has intended to limit the Commission's plenary authority over rate setting it would have said so.

Moreover, here Duke has agreed in the Settlement Stipulation to extend the recovery period beyond 12 months to 16 months—so there is no disagreement among the parties as regards the Commission's authority, rather it is just an issue of what the appropriate recovery period should be.

The Commission, of course, has approved longer periods before to avoid rate shock.

In Dominion Energy North Carolina's ("DENC") 2014 fuel proceeding in Docket No. E-22, Sub 15 after the "polar vortex" weather event of January 2014, the Commission approved the amortization of an under-collection over two years without interest in order to mitigate rate shock to DENC's customers and resulted in his resulted a decrease in the overall impact on rates from 8.3% to 5.1%.[38]

Similarly, in Duke Progress's fuel proceeding from 2008 in Docket No. E-2, Sub 929 the Commission approved a 3-year recovery period with interest based on the 5-year

[38] *See* Tr. vol. 2, 348 (Collins Dir. at 7); Order Approving Fuel Charge Adjustment, *DENC 2014 Fuel Rider Proceeding*, Docket No. E-22, Sub 515 (Dec. 18, 2014), at 26; Rebuttal Testimony of Edward J. Anderson, Docket No. E-22, Sub 515 (Nov. 5, 2014), at 5 (noting rate impact of 8.3% under original proposal).

Treasury rate.[39] This resulted in a decrease of the overall impact on rates from 13.61% to 9.05%.[40]

Other state regulatory commissions have been faced with similar requests based on the fuel cost disruptions in 2022 and have generally acted to provide for extended recovery periods.[41]

Here, the proposed 16-month recovery at 4% interest of an unprecedented $1 billion under-collection would result in an average rate increases of 13.31%, which exceeds any prior permitted recovery, and does not appropriately protect DEC customers from rate shock.

Resisting a further extension of the recovery period, Duke expresses concern about potential impairment of its credit metrics as recognized by the various credit agencies. But here there is no evidence that an extension of the recovery period would in any way impair DEC's access to the credit market and, by contrast, the very credit reports cited by Duke recognize that state commissions are likely to extend fuel cost recovery periods in light of the magnitude of the costs a5 issue. As noted by Public Staff witness Lawrence, Moody's Investors Service expressly noted its expectation that: "More regulators are likely to extend fuel cost recovery periods to between 18 and 36 months, up from the typical 12 months, to ease the impact on customer electricity rates."[42]

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[39] Order Approving Fuel Charge Adjustment, *Carolina Power & Light d/b/a Progress Energy Carolinas 2008 Fuel Rider Proceeding*, Docket No. E-2, Sub 929 (Nov. 14, 2008), at 17-18, 21.

[40] *Id.*

[41] *See* Tr. vol. 2, 279-281 (Lawrence Dir.) (citing decisions from Florida, Virginia, and South Carolina).

[42] *See* Tr. vol. 2, 281 (Lawrence Dir.).

As is well-recognized, "the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the" constitution. *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974). Therefore, although the Commission must enable DEC to "compete in the market for capital," the Commission's "ultimate objective of rate making" is to set rates "which will enable the utility to do [this], and no more." *State ex rel. Utils. Comm'n v. Gen. Tel. Co. of Se*., 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972); *see* N.C. Gen. Stat. § 62-133.

In other words, the Commission must set rates no higher than what is necessary for DEC to secure adequate debt; to raise rates further so that DEC can obtain cheaper debt would violate the General Assembly's overriding directives as regards rate setting. As DEC's CFO conceded in a prior general rate case, the Commission has no duty to "set rates and make decisions so that a company has one of the highest credit ratings" and can secure the best interest rates.[43] DEC's argument that the Commission should permit rate shock to protect its credit ratings is constructed from speculation that is of little evidentiary value here.

In order to reduce rate shock to customers, CUCA recommends that EMF under-collection recovery be spread over 24- or 36-months with no interest[44] (as in the DENC

[43] Docket No. E-7, Sub 1214 (cross-examination of DEC witness Young; Tr. vol.3, 42).

[44] On cross-examination in the recent DEP rate proceeding, DEP's witness Laura Bateman emphasized that Duke had never, to her knowledge, sought to recovery financing costs in connection with the flow through of un-recovered fuel costs. *See* Tr. vol. 23, 226 (Bateman cross-examination ("Q. …to be clear, if fuel costs go up $100 million over the course of the year, Duke passes that entire expense on to ratepayers, correct? A. Well, I think it's yes ... at least as far back as I can remember, we have not requested any financing costs. So I do think there is a sharing of pain if there is underrecovery.").

proceeding) rather than the stipulated 16-month recovery with an additional 4% interest proposed in the Settlement Stipulation. Alternatively, or additionally, the Commission may wish to apply EDIT which is ratepayer monies subject to refund to the under-collection, as proposed by DEP in its rebuttal testimony.[45] On cross-examination, Duke's witness acknowledged that, although the Public Staff was not willing to agree to return of EDIT as a component of the Settlement Stipulation, from DEP's perspective that option remained viable for the Commission.[46]

CONCLUSION

DEC's unprecedented $1 billion under-collection should not be treated as business as usual. CUCA acknowledges the extreme volatility in fuel commodity pricing over the past year. However, DEC has failed to demonstrate that its actions to address these well-established risks associated were appropriate and effective, and the Settlement Stipulation entered into between DEC and the Public Staff would result in a potentially devastating rate shock to DEC's industrial customers.

Instead, in order to protect DEC customers from rate shock, the Commission should take steps to mitigate rate increases, including by (1) requiring a recovery period of 24-36 months of DEC's EMF under-collection in order to mitigate rate increases, (2) disallowing EMF interest recovery, and/or (3) applying EDIT refunds to offset EMF under-recovery.

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[45] Tr. vol. 2, 175-178 (Clark and Bauer Rebuttal Testimony, at 18-21).
[46] Tr. vol. 2, 201 (Clark cross-examination).

Respectfully submitted, this 24th day of July, 2023.

Marcus W. Trathen
Christopher B. Dodd
BROOKS, PIERCE, McLENDON,
HUMPHREY & LEONARD, LLP
Suite 1700, Wells Fargo Capitol Center
150 Fayetteville Street
P.O. Box 1800 (zip 27602)
Raleigh, NC 27601
(919) 839-0300
mtrathen@brookspierce.com
cdodd@brookspierce.com

Counsel for CUCA

Certificate of Service

I hereby certify that a copy of the foregoing CUCA'S POST-HEARING BRIEF has been served this day upon all parties of record in this proceeding, or their legal counsel, by electronic mail.

This the 24th day of July, 2023.

BROOKS, PIERCE, MCLENDON,
HUMPHREY & LEONARD, LLP

/s/ Chris Dodd

EXHIBIT 1

RMI, Strategies for Encouraging Good Fuel-Cost Management, July 2023

Strategies for Encouraging Good Fuel-Cost Management

A Handbook for Utility Regulators

Report / July 2023

Authors and Acknowledgments

Authors

Joe Daniel
Rachel Gold
Jeremy Kalin, Avisen Legal
Albert Lin, Pearl Street Station Finance Lab
Kaja Rebane

Authors listed alphabetically. All authors are from RMI unless otherwise noted.

Contacts

Joe Daniel, jdaniel@rmi.org
Rachel Gold, rgold@rmi.org

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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

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.

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.

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).

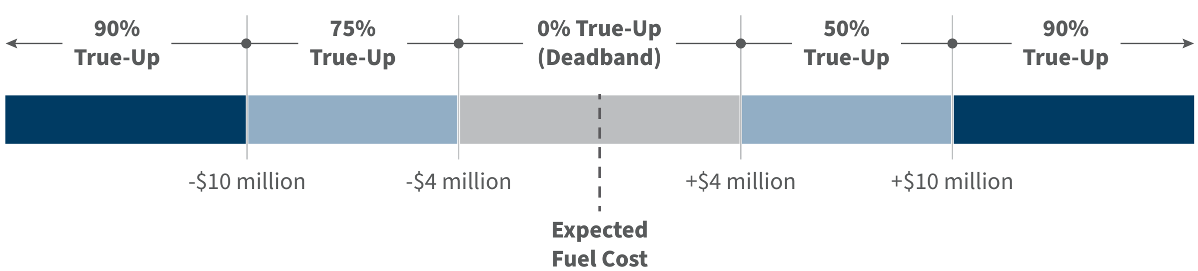
electrification that offsets the negative impact of the fuel-cost sharing mechanism.[xiii] A third possibility could be to structure the fuel-cost sharing mechanism to operate on a per-MWh basis rather than a total-cost basis, though this has the downside of creating an incentive to sell more electricity (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

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.

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]

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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RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org