Date: April 3, 2024

To: The Public Utilities Commission

From: Marc Vatter, Director of Economics and Finance, Office of the Consumer Advocate

Subject: The cost structure of provision of retail electric commodity

At a hearing March 20, 2024 in Docket No. DE 23-044, the Commission invited input from participants in written form by April 3 on the general question of the future of default energy service. This document is that input from the OCA. It speaks to the general topic of default service procurement and rate design, and to a specific question regarding the expected risk premium associated with procurement through a futures market, relative to the ISO-New England spot market. As an alternate proposal at the hearing, Liberty suggested a purchase of call options, and the Commission posed this specific question.

Summary

The OCA conducted an investigation of the cost structure for retail electric commodity in New Hampshire that drew on nationwide data. An implicit premise underlying the 1996 Electric Utility Restructuring Act, RSA 374-F ("the Act") was that minimum average cost for a retailer occurred at a level of sales that was small relative to demand in an electric distribution utility's service territory, a cost structure that would lead to participation of a large number of retailers in each local market, which would compete rates down to levels close to marginal cost, the gold standard for competitive efficiency. We found, rather, that long run supply price for a firm selling retail commodity, including the four distribution utilities in New Hampshire, generally declines as sales increase. For default service providers, rates are subject to regulation or oversight so as to equal average cost, so providers of default service have declining average costs in general, a cost structure that does not create the conditions for participation by a large number of small firms. Large retailers can undersell small competitive retailers, economically, if not legally, precluding participation by a large number of small firms in any local market and an overall transition from default to competitive supply.

Twenty-eight years since passage of the Act, most residential customers have still eschewed independent suppliers. But, five years since passage of the community power law,

> -- Member towns in the year-old Community Power Coalition of New Hampshire are reaping the benefits of banding together to buy electricity on their own.
>
> -- As of Feb. 1, residential and small commercial customers in the coalition's 16 active member communities will pay a base electricity rate of 8.1 cents per kilowatt-hour, a 26 percent reduction from their already-competitive rate of 10.9 cents per kWh.
>
> -- Another 29 communities are planning to enjoy the lower rate after they launch their own programs this spring, effectively making the statewide coalition the second-largest

> electrical supplier in the state…-- The coalition uses the collective buying power of all of their residents and businesses to secure competitive rates in the wholesale market.[1]

Community power aggregation, which Section 374-F:2 I-a of the Act defines as default service, is reaping the benefits of the economies of scale we quantify here, benefits that utility default service providers have not been allowed to reap for their customers.

> 'We don't have to purchase power at a given time period,' [Brian Callnan, the coalition's first chief executive officer] said. In contrast, 'the investor-owned utilities don't have that flexibility' in their regulated procurement process.[2]

Section 374-F:1 II of the Act quotes part II, article 83 of the New Hampshire Constitution: "Free and fair competition in the trades and industries is an inherent and essential right of the people." Section 374-F:3 VII says: "The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market." At the outset, Section 374-F:1, I of the Act states its purpose as follows: "The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets."

Given the economies of scale in retail sales that we have quantified, rates cannot be "reduced" through competition among small independent suppliers, but they can be reduced by allowing utility default service providers the same flexibility allowed to community aggregators, who are also default service providers.[3] Not, of course, the flexibility to exercise market power, but to make utility default service as attractive as possible to customers. The OCA, then, recommends that the Commission discontinue exercising its discretion to "discourage . . . long-term use" of default service as provided for in Section 374-F:3 V(c). In so recommending, the OCA is in broad agreement with the Department of Energy, whose recent report "focuses on potential improvements to default electric service available to New Hampshire's electric utility customers who do not participate in the competitive retail electricity market."[4]

The Act also does not preclude the Commission from designating a single default service provider in any given location, and we think it unlikely that multiple default service providers in any given location were contemplated. We, therefore, recommend that the Commission investigate the possibility of designating municipalities participating in community aggregation as the sole providers of default service within their borders. This should afford customers in those communities the maximum benefits of the economies of scale. At least in the medium term, competition between utility and community default service would apply downward pressure on rates, though, in the long run, in which both municipalization and privatization are

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[1] Prevost, L. (2024). Five years later, New Hampshire's community power law is reshaping the electricity market, *Energy News Network*, February 5, 2024. Available at https://newhampshirebulletin.com/2024/02/05/five-years-later-new-hampshires-community-power-law-is-reshaping-the-electricity-market/, accessed April 1, 2024.

[2] *Ibid*, Prevost (2024).

[3] Also see https://www.oca.nh.gov/news-and-media/dithering-about-default-energy-service, accessed April 1, 2024.

[4] Exeter Associates, Inc. (2024), "Solicitation and procurement of default electric service in New Hampshire," prepared for the New Hampshire Department of Energy in response to INV 2023-001, p. 1.

on the table[5], economies of scale could drive one or the other out. So long as utilities are well regulated, and aggregators receive effective oversight from municipal governments, the latter scenario would minimize rates.

We do not see these recommendations as a jettisoning of restructuring, but an adjustment thereto. For example, according to DOE's report, at page 12,

> In the Restructuring Plan, the PUC stated that default service would be procured competitively through either competitive bids or spot market purchases that would provide customers an opportunity to realize the benefits of competition even if they did not directly participate in the market.

That is to say, competition does work in other segments of the industry; in this example, among the wholesale sellers from whom retailers buy. Wherever it does, it should be policy.

The estimated risk premium associated with futures purchases relative to spot is discussed in an appendix.

Monopsony power in electric commodity?

We began this investigation by asking whether retailers had monopsony power as buyers in wholesale markets; i.e., whether they faced upward-sloping supply curves for commodity. The "collective buying power" referred to above could be taken to mean that. Firms that buy little in a particular market do not have monopsony power; they are "price takers;" they face horizontal supply curves. According to an article[6] from the *Electricity Journal*: "Notably, monopoly utilities that procure capacity in an organized market alongside other monopoly utilities would have significantly less monopsony power. For this reason, we are not considering buyer-side market power in an organized market to be properly within the definition of a monopsony." Having "buyer-side market power" is not the same as being the only buyer in a market; it just means the supply curve slopes up. We adopted the working hypothesis, though, that no one has monopsony power in the regional market.

We then asked whether retailers might have monopsony power locally. For energy, the regional price in ISO New England is the Locational Marginal Price ("LMP") at the reference node, which, by definition, has LMPs with no congestion or loss components. Congestion and loss components of LMPs separate the nodes where they obtain from the reference node economically; they distinguish local markets from the regional market. Thinking that congestion and loss components would be highest at peak times, we downloaded LMPs for the first half of September last year; the ISO New England peak day was September 7. We found that they were non-trivial near the peak hour that day in remote areas like Berlin, Hinsdale, Drewsville, and New Hampton. See lmp_rt_final_20230907_20240307 v2.xlsb. Overall, though, this is scant evidence that monopsony power plays an important role even in local markets.

[5] By "municipalization", we mean a municipality commencing participation in community aggregation. By "privatization", we mean a municipality ending its participation in community aggregation and turning to default service from an investor own utility.

[6] Wilson, J.D., O'Boyle, M., Lehr, R. (2020). Monopsony behavior in the power generation market, *The Electricity Journal* 33, p. 3. https://doi.org/10.1016/j.tej.2020.106804

Economies of scale in electric commodity?

We then investigated whether the opposite was the case. Rather than monopsony power, whether big sellers charge and, assuming effective regulation or oversight, pay lower prices; that supply curves for retail commodity slope down, not up. If this is the case over a large range of sales, then the sale of commodity retail is a natural monopoly, and retail supply is not workably competitive, at least without regulation or oversight of rates. To be clear, independent suppliers must compete with default service providers, but, if large sellers sell for less, it will be their prices that the independents will have to match, not the other way around.

We estimated the relationship between average retail price and the volume of retail sales across all customer classes using EIA data[7] on electric retailers nationwide from 2001 to 2022 (44,107 observations on 3,263 retailers).[8] We found that greater sales volume is associated with lower prices nationally, and that this is also true for the four electric utilities in New Hampshire. Eversource showed stronger economies of scale than any other retailer in New Hampshire. The New Hampshire retailer with the weakest economies of scale in the EIA dataset was New Hampton Village Precinct, whom we mentioned above as a conceivable monopsonist based on sometimes high congestion and loss barriers with respect to the regional spot market.

Given the estimates, using 2022 loads and rates, a 1% increase in sales is associated with a 0.13% decrease in rates for Liberty, a 0.15% decrease for Eversource, Unitil, and the New Hampshire Electric Cooperative, and a 0.16% decrease nationally. Average rates in 2022 were about $250/MWh for the large utilities in New Hampshire except Unitil, who charged about $237/MWh. The national average rate was $119/MWh. That long run supply is a little more elastic in New Hampshire is caused by the much higher prices here; the base value on which the *percentage* fall in price is calculated is much higher here. However, the *absolute* fall in price corresponding to an increase in sales in New Hampshire is near the top compared to the absolute fall in price in the various states.

This told us two things: (1) There is no optimal (minimum cost) scale for a retailer that is small relative to demand, so retail competition cannot be expected to provide commodity more cheaply than well-regulated default service; small retailers can only compete by differentiating their products in the minds of customers; and (2) if community power has a cost advantage over utility default service, it is not mainly because of wholesale negotiating power associated with large volumes purchased; utility default service providers also have that, even if they lack the flexibility to take full advantage of it.

Policy implications

A crucial premise underlying the Act was that retail competition would minimize retail rates. Small retailers would be able to underprice large ones, so competition among a large number of small retailers would impose mutual discipline on retail rates. The evidence we present here obviates that premise; this evidence had not accrued at the time the Act was originally passed. Rather, a large retailer can underprice small retailers, potentially making it rational for them to exit the market. In fact, independent retailers have been unable to take much market share from utility and community default service providers for this reason.

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[7] https://www.eia.gov/electricity/data/eia861/, accessed March 15, 2024.

[8] We used a fixed (retailer) effect model, and the residuals were not autocorrelated, which indicates that Equation (1) was well-specified.

The main policy implication is that customers should not be discouraged from using default service, and utilities should not be prevented from making default service attractive. The definition of "default service" in the Act includes both utilities and community aggregators:

> I-a. "Default service" means electricity supply that is available to retail customers who are otherwise without an electricity supplier and are ineligible for transition service and is provided by electric distribution utilities under RSA 374-F:3, V or as an alternative, by municipal or county aggregators under RSA 53-E.

Community aggregators are also not subject to some of the requirements of competitive electric suppliers imposed in Section 374-F:7 of the Act or any of the provisions in the section on ratepayer protection from competitive suppliers, RSA 374-F:4-b. Therefore, at a minimum, utilities should be free to do anything that community aggregators are allowed to do to make their sales of commodity attractive to customers, including securing benefits of economies of scale for those customers. Section 374-F:3, paragraph VII says:

> Choice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market.

The existence of economies of scale in the provision of electric commodity precludes minimizing rates with "a range of viable suppliers," but disadvantaging utility default service is not in conformance with the second sentence of paragraph VII. The Act does not *require* that default service offerings be mediocre. Section 374-F:3, paragraph V ("Universal Service"), subparagraph c says:

> Default service should be designed to provide a safety net and to assure universal access and system integrity… If the commission determines it to be in the public interest, the commission *may* implement measures to discourage misuse, or long-term use, of default service.

(Emphasis added.)

That something is a safety net does not imply that it must be inferior, and the Commission is *not required* to exercise its authority to discourage long-term use of default service. The culture and practice of regulation, however, has been to push customers toward independent suppliers by constraining the appeal of utility default service and the options for procuring it.

The more commodity utilities provide, the less they will charge, and this is in the interest of residential customers. Given that utilities are not allowed any markup on default commodity, they are prevented from abusing their market power, but they do have incentive to minimize the cost for commodity that they pass through in rates because, by lowering rates, they sell more commodity, which allows them to build larger distribution systems, on which they earn a competitive return on investment. According to Burke and Abayasekara (2018), although "electricity demand is very price inelastic in the short run, with a same-year elasticity of -0.1…The long-run elasticity is near -1, larger than often believed."[9] Thus, through default service, utilities have incentive to capture the economies of scale in commodity on behalf of their customers. The Commission should let them do this.

[9] Burke, P.J., Abayasekara, A. (2018). The price elasticity of electricity demand in the United States, *The Energy Journal* 39(2), 123-146, https://www.jstor.org/stable/10.2307/26534427.

The second policy implication is that community power should also be allowed to do this, as it currently is; no change in this policy is needed. Community power is public power without the wires or generators. The two long-established models, regulated IOUs and public power, can be expected to capture the economies of scale in provision of electric commodity, thus minimizing rates. Accordingly, two forms of default service need not and should not be provided. In aggregating communities, regulated private utility default service may need to be eliminated because the local government is providing the default service. Economically, this would help, and likely be necessary to, capture the benefits of economies of scale for residential and other customers.

Free competitive entry in retail commodity, though, is a subtler policy issue, given the econometric evidence of economies of scale. According to Section 374-F:1 of the Act,

I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.

II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it."

In distribution, retail competition is not allowed. Wires are owned monopolistically either by regulated IOUs or governments because they are subject to extensive economies of scale, which imply that a well-regulated monopoly will “reduce costs for all consumers” compared to competitive markets for distribution; that such a well-regulated monopoly does not “tend to hinder or destroy” “fair competition”. Given the evidence that provision of retail electric commodity also exhibits economies of scale at least as large as Eversource’s load, should the OCA, then, ask the Commission to end retail choice in commodity?

The economies of scale in provision of commodity are not as great as those in distribution, and the OCA does not, at least at this time, seek an end to retail choice in New Hampshire. Retailers with small market shares cannot underprice default service if default service providers are freed to make default commodity as appealing as possible to customers. Independent retailers may be unable to compete and exit the market of their own accord. If they generally do, the benefits of economies of scale will be secured for customers without running afoul of letter of the Act, if not of its mistaken premise regarding the cost structure of the industry (which is that there is a cost-minimizing level of sales for the firm that is small relative to demand).

Any independents who remained would be doing so because they would be able to differentiate their offerings in the minds of customers. The differentiation could be innovative or deceptive. This is true for any monopolistically competitive market. As in other such markets, private (https://www.powersetter.com/g/?utm_source=yahoo_ads) and public (https://www.energy.nh.gov/engyapps/ceps/shop.aspx) information is available to help customers find innovators and avoid deceivers. Section 374-F:3, II of the Act says: “Customers should expect to be responsible for the consequences of their choices.” There are also laws against deceptive claims. Among such laws, Section 374-F:7 of the Act says in relevant part:

> III. The department [of energy] may investigate and petition the commission to assess fines against, revoke the registration of, order the rescission of contracts with residential customers of, order restitution to the residential customers of, and prohibit from doing business in the state any competitive electricity supplier, including any aggregator or broker, which is found to have . . . [e]ngaged in any unfair or deceptive acts or practices in the marketing, sale, or solicitation of electricity supply or related services.

There may be a trade-off between the benefits of economies of scale and those of innovation (net of deception). The OCA asks the Commission to allow utilities to make default service attractive, and re-examine the market after a few years to see what role retail choice still plays. If independent retailers’ market share is small, then little will be lost in the way of economies of scale, and ongoing efforts to differentiate products and the threat of entry could help discipline default service providers if retail choice is maintained. In turn, default service providers may discipline independent retailers to continue innovating by mimicking their innovations. This competitive process drives innovation in monopolistically competitive markets in general.

The downside risk is deception. If that becomes the prevalent form of product differentiation, it could be wise to mandatorily eliminate retail choice, especially if doing so would not require legislation, though it probably would. If independent retailers’ market share becomes small, because of their inability to compete on price, elimination of retail choice should not be very painful.

<u>The evidence: a technical discussion</u>

The economies of scale in retail electric commodity are statistically significant. We estimated this equation:

$$\frac{\Delta P_{Rt}}{\Delta Q_{Rt}} = \beta_0 \beta_R S_{Rt-1}^{\beta_{S_{t-1}}} S_{Rt-2}^{\beta_{S_{t-2}}} \beta_Q Q_{Rt}^{\beta_Q - 1} \tag{1}$$

where ΔP_{Rt} is a hypothetical change in price for Retailer R in Year t, ΔQ_{Rt} is a hypothetical change in MWhs sold, $\beta_0 = \underset{57.13}{682.17}$ is common to all retailers nationwide (and the number below is its standard error) β_R is a fixed effect unique to each retailer, S_{Rt-x} is summer peak load in MWs lagged x years, a proxy for transmission and distribution costs, whose presence serves to hold those constant while Q_{Rt} changes, $\beta_{S_{t-1}} = \underset{0.01}{0.03}$, $\beta_{S_{t-2}} = \underset{0.01}{0.04}$, and $\beta_Q = -\underset{0.05}{0.16}$ are also common to retailers nationally. The estimated values for β_R for the four large utilities in New Hampshire are

Table I: Fixed retailer effects, β_R, for large utilities in New Hampshire

Utility	Retailer effect
Eversource	2.40
Coop	2.11
Unitil	1.91
Liberty	1.68
USA	1.00

The higher the value of β_R, the more rapidly price declines with sales volume. At any given price, price declines more rapidly in New Hampshire than nationally, where $\beta_R = 1$, but at 2022 prices, price declines a little less rapidly in percentage terms in New Hampshire because price is over twice as high here as it is nationally; the base value on which the percentage change in price is calculated is much higher here.

The regression was done using Equation (1) in log form, and includes a lagged dependent variable.

$$p_{Rt} = b_0 + b_R + b_{s_{t-1}} s_{t-1} + b_{s_{t-2}} s_{t-2} + b_q q_{Rt} + b_p p_{Rt-1} \qquad (2)$$

where lower case indicates logs. Long run estimates of the Greek capitals in Equation (1) are given by assuming that price is at its long run equilibrium value at both $t-1$ and t in Equation (2); so, for example, $\beta_0 = \exp\left(b_o / \left(1 - b_p\right)\right)$ and $\beta_Q = \exp\left(b_q / \left(1 - b_p\right)\right)$.

There was zero first-order autocorrelation in the residuals, indicating that the model is well-specified; the number of lags of summer peak was chosen to minimize absolute first-order autocorrelation in the residuals. Table II compares the selected ("Base") model to alternative specifications in terms of the reciprocal of elasticity of national long run supply, the *p*-value attached to a null of a horizontal supply curve, first order (AR(1)) autocorrelation in the residuals, and the magnitude of the coefficients relative to their variability, $b'\left[vv'\right]^{-1} b$ (divided by one million), where b is the $Kx1$ vector of estimated coefficients, v is the KxK estimated variance-covariance matrix of the coefficients, and K is the number of regressors.

Table II: Comparing specifications of the regression model

Model	National inverse elasticity of LR supply	*p*-value	AR(1)	$b'[vv']^{-1}b$
i. Base	-0.16	0.001	-0.0009	11,650
ii. No control for T&D costs	0.06	0.100	-0.0325	4,814
iii. 1-year longer lags of summer peak load; $s_{t-x} \rightarrow s_{t-x-1}$	-0.36	0.000	0.0387	7,501
iv. Variation of HDD with solar and wind removed	-0.11	0.016	-0.0213	5,999
v. Both iii and iv	-0.24	0.000	0.0061	3,963

All five specifications show economies of scale, except for Specification ii, in which lagged summer peak load, s_{t-x}, a proxy for transmission and distribution costs included in rates, is omitted from the equation. The base model was selected as such because AR(1) is minimized, and because data on solar and wind output by state for 2022 were not yet available from EIA, causing a large loss in observations in Models iv and v. By the AR(1) criterion, though, Alternative v is second best, and exhibits greater economies of scale than the base model. Autocorrelation is often used to test the specification of regression models because its absence indicates that errors in prediction do not persist over time. Such systematic variation in errors means that some systematic variation in the dependent variable is not explained by the model.

The final metric, $b'\left[vv'\right]^{-1}b$, incorporates variation over space and time, and own-variance and covariance of the estimated coefficients; a multidimensional analogue of the reciprocal of the coefficient of variation (a mouthful, but an accurate and descriptive one). By this measure, the base model stands out: Despite the absolutely greater inverse elasticities of supply, the coefficients on sales, coming out of Specifications iii and v, which, by themselves, raise the value of $b'\left[vv'\right]^{-1}b$, the base model exhibits much less variability relative to the coefficients as a group. The optional text box below describes v; therein, the expression for s^2 shows the use of variation over both space and time.

$v = s^2[Z'M_dZ]^{-1}$, where Z is the $NTxK$ matrix of observations of the regressors, N is the number of retailers, T is the number of years in the sample,

$$M_d = \begin{bmatrix} M^0 & 0 & \dots & 0 \\ 0 & M^0 & \vdots & 0 \\ \vdots & \dots & \ddots & \vdots \\ 0 & 0 & \dots & M^0 \end{bmatrix}, M^0 = I_T - \frac{1}{T}ii' \qquad (3)$$

I_T is a TxT identity matrix, i is a $1xT$ vector of ones, and

$$s^2 = \frac{\sum_{R=1}^{N}\sum_{t=1}^{T}\left(q_{Rt} - b_R - z'_{Rt}b\right)}{NT - N - K} \qquad (4)$$

where z'_{Rt} is a $1xK$ row vector of observations of the regressors for Retailer R in Year t, and b is the $Kx1$ vector of estimated coefficients.

We instrumented for q_{Rt} using gross state product[10] and heating degree days by census region[11] in order to identify a supply curve using Equation (2). The supply curve of a seller with market power does not exist, but IOUs, public power, and cooperatives, through regulation or oversight, sell at cost, and independent retailers have small market shares, so their firm supply curves do exist, and may, theoretically, slope either up or down, though this empirical investigation indicates that they slope down. Though energy prices affect the macroeconomy, we expect that the price charged for one form of energy (electricity) by one seller will have a negligible contemporaneous, within-year effect on statewide economic activity. We observe that weather in general, and, in this instance, heating degree days, is exogenously determined.

[10] https://apps.bea.gov/regional/histdata/releases/0616gsp/index.cfm, accessed March 18, 2024.

[11] https://www.eia.gov/outlooks/steo/data/browser/#/?v=28&f=A&s=&start=1997&end=2024&id=&map=&ctype=linechart&maptype=0&linechart=ZWCDPUS~ZWHDPUS, accessed March 18, 2024.

(2) is the equation for the second stage regression. The equation for the first stage is

$$q_{Rt} = a_0 + a_R + a_g g_{Rt} + a_h h_{Rt} + a_{s_{t-1}} s_{t-1} + a_{s_{t-2}} s_{t-2} + a_p p_{Rt-1} \qquad (5)$$

where g_{Rt} is gross state product in the state where Retailer R is selling, and h_{Rt} is heating degree days in the census region where Retailer R is selling. All of the instruments are highly significant in the first stage; they are not weak. The correlation matrix for the variables and observations used in the first and second stage regressions is

Table III: Correlation matrix of regression variables

	p_{Rt}	s_{Rt-1}	s_{Rt-2}	q_{Rt}	p_{Rt-1}	g_{Rt}	h_{Rt}
p_{Rt}	1						
s_{Rt-1}	-0.1102	1					
s_{Rt-2}	-0.1083	0.9880	1				
q_{Rt}	-0.1592	0.9646	0.9596	1			
p_{Rt-1}	0.9665	-0.1017	-0.1000	-0.1480	1		
g_{Rt}	0.0004	0.2418	0.2408	0.2461	0.0063	1	
h_{Rt}	-0.0354	-0.2934	-0.2908	-0.2928	-0.0456	-0.2775	1

The dependent variable p_{Rt} is virtually uncorrelated with the excluded instruments g_{Rt} and h_{Rt}. By construction, the (second stage) regressors are uncorrelated with the (second stage) residuals, but if we regress the second stage residuals on the excluded instruments, with fixed effects, only heating degree days, which are exogenously determined, and only affect price through demand,[12] is a significant regressor: In that regression, the p-value on a null of insignificance of the coefficient on g_{Rt} is 0.62, while that on the coefficient on h_{Rt} is zero.

Calculations and data are shown in Scale regressions v6.xlsb. A regression log is available on request.

[12] Heating degree days are uncorrelated with solar and wind production, available here: https://www.eia.gov/state/seds/seds-data-complete.php?sid=US, accessed March 25, 2024. When heating degree days are regressed on solar, wind, and hydroelectric production, with fixed effects, none of them is a statistically significant predictor of heating degree days, and hydro is the most insignificant, with a p-value of 0.975. That regression is not done to estimate causality, but association, none of which is statistically significant.

Appendix: The risk premium associated with futures purchases relative to spot

Assuming that natural gas was "on the margin" in generation of electricity, we estimated a long cycle in spot prices at Henry Hub, and surmised that it was three years in length. Henry_Hub_Natural_Gas_Spot_Price EIA.xlsb shows the result in months in Cell H333. Entries in Column H above that cell are the length of time between the date in the given row and the next time that prices, rounded to the nearest 25 cents, were the same, but moving in the opposite direction. Cell H333 shows the average for Column H: 36 months. Hedging this far in advance would protect customers from global fuel price volatility like that observed after Russia's invasion of Ukraine.

Assuming that there is no arbitrage opportunity between futures markets for physical delivery and call options, we compared monthly average futures prices on the NYMEX at the ISO-NE internal hub settled about[13] three years before delivery to spot prices at the same delivery dates from December 2013 to February 2024. Inflation was 2.90% during that time. Assuming a 10.00% nominal, and, therefore, 7.10% real compounding rate, a stylized long run return on stock market equity, a risky investment like electric commodity futures, we levelized both futures and spot prices to the present time. Weighting peak and off peak prices by the number of hours used by the ISO, we found that real futures prices were $0.44/MWh, in 2024$, lower than spot, a slightly negative risk premium. This is shown in Cell G130 of the Real prices tab in Futures market risk premium v2.xlsm. When the calculation is done in nominal terms, the risk premium, shown in Cell G130 of the Prices tab, is $-1.62/MWh.

Possible reasons for the negativity are: (1) that futures markets simply do not anticipate global fuel price shocks, and (2) that futures prices are negatively correlated with personal consumption in the U.S. macroeconomy, far more so than spot prices. Correlations of prices with personal consumption are shown in Row 131 of both tabs. Widely used financial models like the Consumption Capital Asset Price Model (CCAPM) predict this: If a stream of payments is high when personal consumption is low, then that stream can be used to smooth consumption. The ultimate purpose of all economic activity is consumption, so this is what people try to smooth over time, more so than returns to financial assets. One might suggest that the inflation post-Covid was not expected, so the actual inflation of 2.90% was higher than that which was expected when futures markets were settled. Replacing this with the Fed's 2.00% target rate of inflation results in a real risk premium of $-0.61/MWh, also slightly negative.

Figure I graphs the futures and spot price data used to calculate the risk premium, along with the ISO-NE forward capacity auction (FCA) price for the commitment period coinciding with the dates of delivery on the horizontal axis. The FCA is a futures market, too, and, notably, its participants foresaw the tightness in the spot market in late 2017 just as the participants trading energy futures did.[14]

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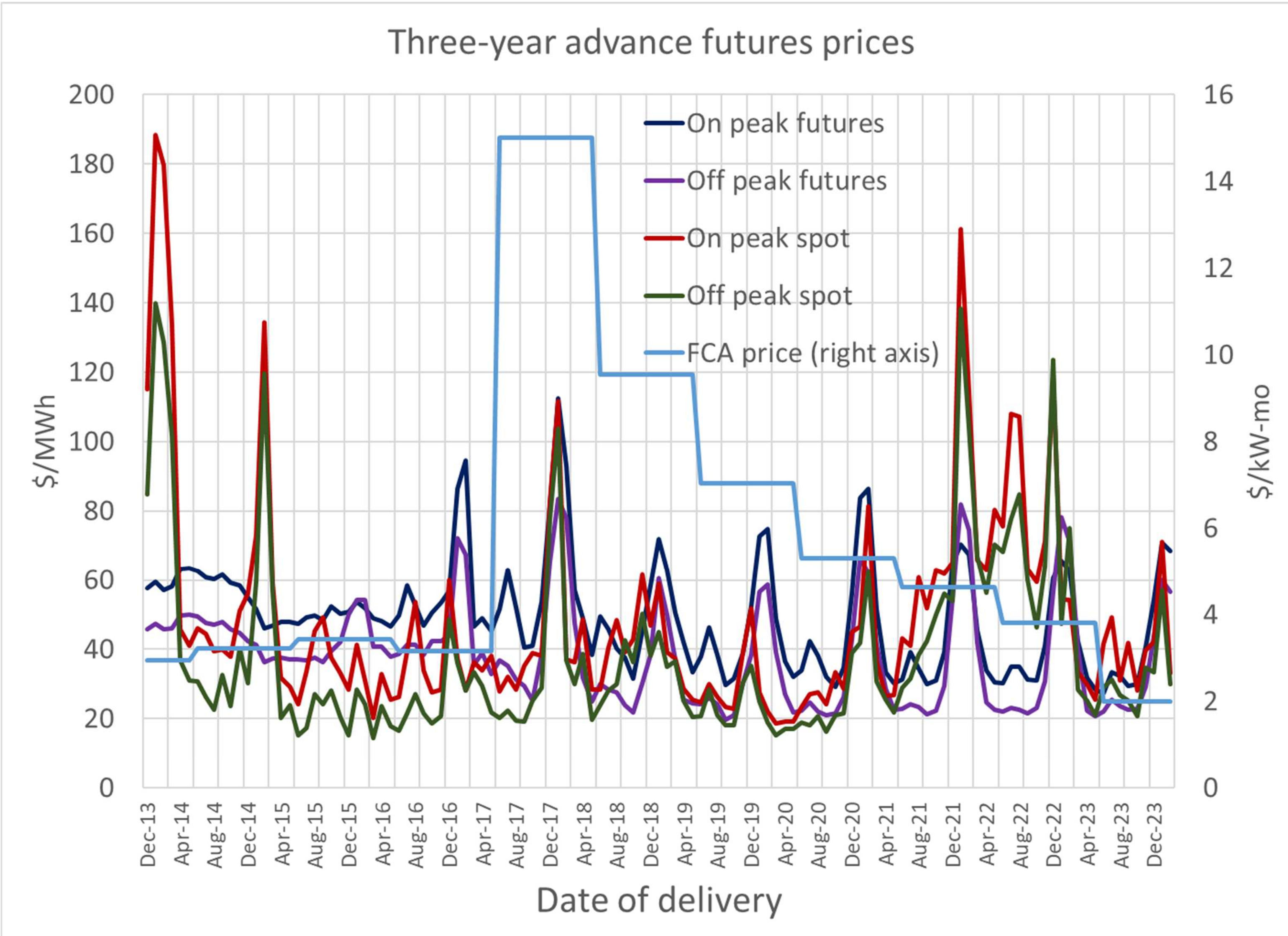
[13] Missing observations were filled in with reference to earlier futures prices.

[14] As an aside, both our estimate of the 36 month length of the long cycle in natural gas prices and the FCA's price signal incenting capacity additions when spot markets became tight point to the usefulness of the current structure of the FCA, apart from prompt and seasonal capacity markets. It is also reasonable to think that recently high spot prices, associated with constrained import capacity for both natural gas and electricity into New England, have caused capacity prices to fall. Generators can cover capex with high spot prices, and do not need high capacity revenues, or even CSOs, so they can bid low in the FCA.

On the other hand, neither the FCA nor the energy futures prices reflect any expectation of the fuel price shock during 2021-23. It is for this reason that purchasing futures, or call options, would protect customers from similar shocks going forward.

Figure I



Three-year advance futures prices
On peak futures
Off peak futures
On peak spot
Off peak spot
FCA price (right axis)
$/MWh
$/kW-mo
200
180
160
140
120
100
80
60
40
20
0
16
14
12
10
8
6
4
2
0
Dec-13
Apr-14
Aug-14
Dec-14
Apr-15
Aug-15
Dec-15
Apr-16
Aug-16
Dec-16
Apr-17
Aug-17
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Apr-19
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Dec-19
Apr-20
Aug-20
Dec-20
Apr-21
Aug-21
Dec-21
Apr-22
Aug-22
Dec-22
Apr-23
Aug-23
Dec-23
Date of delivery