BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Authority to Establish A Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 23-301-EL-SSO

Direct Testimony of Travis Kavulla

On Behalf of
Direct Energy Business LLC,
Direct Energy Services LLC,
Reliant Energy Northeast LLC dba NRG Home and NRG Business,
Stream Ohio Gas & Electric LLC,
And
XOOM Energy Ohio LLC

Dated: October 23, 2023

BACKGROUND

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Travis Kavulla and I am Vice President, Regulatory Affairs for NRG Energy, Inc. ("NRG"). My business address is 1825 K St. NW, Suite 1203, Washington, D.C. 20006.

Q2. HOW LONG HAVE YOU BEEN IN THIS POSITION?

A. I have been in this position since September 2019.

Q3. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES.

A. Together with my team, I lead the company's engagement on regulatory policy concerning both retail markets and wholesale markets. My professional experience and educational background are fully described in my curriculum vitae attached as **Exhibit A**.

Q4. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Direct Energy Business LLC, Direct Energy Services LLC, Reliant Energy Northeast LLC dba NRG Home and NRG Business, Stream Ohio Gas & Electric LLC, and XOOM Energy Ohio LLC (collectively, the "NRG Retail Companies"), each of which are affiliates of NRG.

Q5. WHAT IS THE NATURE OF THE NRG RETAIL COMPANIES' BUSINESS?

A. The NRG Retail Companies are active Competitive Retail Electric Service ("CRES") providers in the FirstEnergy service territory that have been offering electricity products of varying durations. The NRG Retail Companies have served residential and commercial customers in the FirstEnergy service territories since the early 2000s. Some of the NRG Retail Companies are also active Competitive Retail Natural Gas Service providers throughout Ohio and operate in numerous other jurisdictions throughout the Eastern U.S., California, and Canada. Collectively, the NRG Retail Companies serve millions of electricity and natural customers across 24 U.S. states, the District of Columbia, and eight provinces in Canada. In 2022, companies affiliated with NRG supplied approximately 155 TWH of electricity and 1,918 MMDth of natural gas.

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to propose that the FirstEnergy utilities move all SSO customers to a retail rate design that bills them on-peak and off-peak rates. Specifically, I propose that FirstEnergy's Time-of-Day Option rates approved by the Commission in Case No. 20-50-EL-ATA be continued but instead implemented as the default rates for all SSO customers with an advanced meter. Without this change, Ohio customers are likely to continue spending a very substantial amount of money in support of FirstEnergy's metering rate base, without realizing the full benefits of a smart grid, an argument I explore more comprehensively in a recent paper I was invited to write by the Energy Systems Integration Group, entitled *Why is the Smart Grid So Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector*, which is attached as **Exhibit B.**

Q7. YOU DRAW A CONNECTION BETWEEN SMART METER DEPLOYMENT AND THE USE OF TIME-VARYING RATES. HAS THAT CONNECTION BEEN DRAWN IN PREVIOUS PROCEEDINGS BEFORE THIS COMMISSION?

A. Yes, it has. As a result of FirstEnergy's last ESP, FirstEnergy was required to undertake grid modernization initiatives that promote customer choice in Ohio and to file a grid modernization business plan.[1] Thereafter, FirstEnergy filed its grid modernization plan in Case No. 16-481-EL-UNC "Grid Mod I"). Part of that plan included a cost-benefits

[1] ESP IV Case, Opinion and Order at 22, 95-96.

analysis justifying the substantial costs associated with the accelerated depreciation of its existing rate base in metering and the intended supplemental investment in the deployment of advanced metering infrastructure ("AMI" or "smart meters") to approximately 2 million customers. The cost-benefit analysis filed by FirstEnergy included benefits associated with the introduction of innovative rate designs that would result in lower costs to supply and deliver power to customers.[2] While this was not the only benefit offered to justify the substantial utility spending at the heart of the Grid Mod I effort in Ohio, it was the only real benefit that was designed to transform the experience of the customer. As part of the Stipulation and ultimately the Commission Order resolving the Grid Mod I case, FirstEnergy committed to propose a time-variable rate ("TVR") offering for non-shopping customers which would be designed to achieve energy and capacity savings and to leverage the capabilities of enabling devices. Further, FirstEnergy was required to create and facilitate a grid modernization collaborative working group to update stakeholders on the status of the Companies' grid modernization efforts and to provide for customer input and advice.[3] The TVR proposed by FirstEnergy included optional time-of-day rates for both residential and non-residential SSO customers.

Q8. DID THE COMMISSION RELY UPON THE AVAILABILITY OF A TVR FOR NON-SHOPPING CUSTOMERS AS PART OF ITS ORDER APPROVING FIRSTENERGY'S GRID MODERNIZATION APPLICATION, AS REVISED BY THE STIPULATION?

[2] Grid Mod I, Grid Modernization Business Plan (Feb. 29, 2016) at 22-27.
[3] Grid Mod I, Opinion and Order (July 17, 2019) at ¶¶ 35, 38-39, 109-110; Grid Mod I, Stipulation and Recommendation at 17-18.

A. Yes. The Commission approved a Stipulation that included this requirement, finding that the rate offering "will be designed to achieve the energy and capacity savings detailed in the cost-benefit analysis and should leverage enabling devices, e.g., smart thermostats."[4]

Q9. WHAT ARE FIRSTENERGY'S CURRENT TIME-OF-DAY RATE OFFERINGS FOR SSO CUSTOMERS?

A. FirstEnergy offers an optional time-of-day rate to both residential and non-residential SSO customers who have an advanced meter installed by FirstEnergy. In the FirstEnergy tariffs, the options are referred to as Time-of-Day Option (Residential) and Time-of-Day Option (Non-Residential), both of which are within the Generation Service Rider (Rider GEN) tariff sheet.

Q10. HOW MANY CUSTOMERS ARE TAKING SERVICE UNDER FIRSTENERGY'S TIME-OF-DAY OPTIONAL RATES?

A. As of July 31, 2023, there were 144 residential customers taking service under the Rider GEN Time-of-Day Option (Residential) rate. At the same time, no commercial or industrial customers were taking service under FirstEnergy's Rider GEN Time-of-Day (Non-Residential) rate**.**[5]

Q11. IN TERMS OF THE RATE OF ENROLLMENT, HOW MANY CUSTOMERS ARE TAKING SERVICE UNDER THESE INNOVATIVE RATES THAT WERE PART OF THE BENEFITS PACKAGE IN THE GRID MOD I CASE?

A. Approximately seven thousandths of one percent, or 0.0072%, again assuming a customer base of 2 million people who are or ultimately will be eligible for the rate.

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[4] *Id.* at ¶ 38.
[5] NRG Set 01-INT-002.

Q12. ARE YOU PARTICULARLY SURPRISED BY THIS LOW LEVEL OF ENROLLMENT?

A. Not especially. A growing body of literature in behavioral economics suggests that when faced with low salience decisions, like the purchase of an ethereal though important service like electricity, that the default option is the presumed safe or proper choice even if it is the not the best one.[6] For the SSO TVR rate, this phenomenon is amplified by two other factors. First, the rate design of TVR is naturally somewhat more complex than a flat rate, and this complexity reinforces the tendency of customers to view it as exotic and not worthy or too risky to select, even though this dimension also does right by one of the key goals of utility regulation, which is to set prices in a manner that is reflective of costs. Secondly, the rate itself is marketed to *non-shopping* customers to begin with, the very people who are least likely to make an affirmative choice of any kind and instead remain served under the default option. More specifically, essentially the only jurisdictions with significant levels of TVR subscribership are those places where utility regulators have adopted TVR as the default, opt-out model, which I describe in my paper.[7] Although I believe this SSO TVR rate is superior to the opt-out SSO rate in a number of ways, I do not believe it will ever gain significant subscribership unless it is the default option.

Q13. REGARDING THE TIME-OF-DAY OPTION (RESIDENTIAL), WHAT ARE FIRSTENERGY'S CURRENT RATES?

A. As of the time of filing this Direct Testimony, the Time-of-Day Option (Residential) energy rates, in cents per kWh, are as follows:

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[6] Exhibit B at 19-20.
[7] *Id* at 9-11.

	Summer	Winter
Midday Peak (2:00 pm to 6:00 pm EPT) (Weekdays except Holidays)	18.7334	15.5234
Shoulder Peak (6:00 am to 2:00 pm EPT and 6:00 pm to 8:00 pm EPT) (Weekdays except Holidays)	12.6610	11.8718
Off-Peak (all other hours)	9.3667	7.7622

For residential customers, the capacity charges are the same as the standard capacity charges under Rider GEN. These retail prices for capacity are not time-varying, even in the SSO TVR rate design, even though these prices are related to costs that do vary based on the peak demand of consumers' usage.

Q14. HOW WAS THE RATE DESIGN ESTABLISHED?

A. For the rate design, "the historical real-time LMP rates in the ATSI zone were used to establish seasonal, midday-peak and shoulder-peak factors, based on the ratio of the average LMP price during midday-peak and shoulder-peak hours to the average LMP price for all hours."[8] Following feedback from stakeholders, FirstEnergy modified these factors to achieve a midday-peak to off-peak price ratio of approximately 2:1. These factors were applied to the standard Rider GEN rate to develop the seasonal rates for each time block. PUCO Staff explained these details in its Staff Review and Recommendation when FirstEnergy proposed these time-of-day rates.[9] Additionally, in the Staff Review and Recommendation, Staff provided comparison charts comparing peak demand and LMP rates for summer and winter. These are attached to my testimony as **Exhibit C**. These rates were designed to be revenue-neutral to FirstEnergy and customers as a whole.

[8] *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co. for Approval of New Tariff Language*, Case No. 20-50-EL-ATA, Staff's Review and Recommendation (Feb. 21, 2020) at 4-5.
[9] *Id.*

Q15. WHAT IMPACTS DO YOU ANTICIPATE RESULTING FROM THIS RATE DESIGN?

A. As FirstEnergy explained, reductions in costs resulting from a demand side acting in efficient economic relation to the prices "result[s] in a benefit to all non-shopping customers in the form of a decreased amount to be reconciled through Rider GCR."[10] Ultimately, the rates will reduce purchased power expense and peak demand, which results in lower capacity and transmission costs in the short term, and fewer necessary capital expenditures in the long term. The retail TVR rate design does not impact the competitive bidding process to obtain wholesale full-requirements service. However, while my proposal would not impact the process, it would again place downward pressure on SSO rates and overall costs by reducing the expected energy and capacity that an SSO supplier would need to procure.

Q16. WHAT IS YOUR PROPOSAL FOR RESIDENTIAL SSO CUSTOMERS?

A. My proposal is for FirstEnergy to continue the Time-of-Day Option (Residential) but as the default option used to bill all residential SSO customers with an advanced meter under the existing rate design. To this end, all customers with an existing advanced meter would be billed a Time-of-Day rate, and customers without an advanced meter would be switched to this rate when an advanced meter is installed. Accordingly, instead of an optional opt-in rate, it would be the opt-out retail rate for SSO customers. My proposal would keep the existing rate structure of FirstEnergy's current Time-of-Day Option for residential customers, so there would be a Midday-Peak Rate, a Shoulder-Peak Rate, and an Off-Peak Rate. The Midday-Peak time would be 2pm to 6pm EPT, Monday through Friday, except

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[10] *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co. for Approval of New Tariff Language*, Case No. 20-50-EL-ATA, Finding and Order (Jan. 27, 2021) at ¶ 20.

holidays; the Shoulder-Peak time would be 6am to 2pm and 6pm to 8pm EPT, Monday through Friday, excluding holidays; and all other hours would be Off-Peak.[11]

Q17. REGARDING THE TIME-OF-DAY OPTION (NON-RESIDENTIAL), WHAT ARE FIRSTENERGY'S CURRENT RATES?

A. Regarding the Time-of-Day Option (Non-Residential), the energy charges again depend upon the rate schedule.

		Summer			Winter	
	Midday Peak	Shoulder Peak	Off-Peak	Midday Peak	Shoulder Peak	Off-Peak
GS	18.8604	11.6625	9.4637	11.5775	11.7948	8.7079
GP	18.2061	11.2580	9.1355	11.1759	11.3857	8.4058
GSU	17.6945	10.9416	8.8787	10.8618	11.0657	8.1696
GT	17.6767	10.9306	8.8698	10.8509	11.0546	8.1614

For non-residential customers, the capacity charges are not time-variable but are different for each rate schedule. Further, the peak times for the non-residential TVR offer is different than for the residential TVR offering. For non-residential customers, Midday peak time is noon to 6pm EST, Monday through Friday, except holidays; while Shoulder-peak time is 6am to noon and 6pm to 10pm EST, Monday through Friday, except holidays.

Q18. WHAT IS YOUR PROPOSAL FOR NON-RESIDENTIAL SSO CUSTOMERS?

A. Similar to my proposal for residential SSO customers, I propose that FirstEnergy continue the Time-of-Day Option (Non-Residential) but as the default option used to bill all non-residential SSO customers with an advanced meter under the existing time-of-day rate

[11] Holidays would be New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

design. My proposal would keep the existing rate structure of FirstEnergy's current Time-of-Day Option for non-residential customers, so there would be a Midday-Peak Rate, a Shoulder-Peak Rate, and an Off-Peak Rate. The Midday-Peak time would be noon to 6pm EST, Monday through Friday, except holidays; the Shoulder-Peak time would be 6am to noon and 6pm to 10pm EST, Monday through Friday, except holidays; and all other hours would be Off-Peak. [12]

Q19. CAN YOU DESCRIBE THE BENEFITS OF YOUR PROPOSAL?

A. Yes. Regarding FirstEnergy's existing time-of-day options, the Commission explicitly found that FirstEnergy's "commitment to offer a time-varying rate" would be "[o]f significant benefit."[13] As I noted above, the efficacy of Grid Mod I depends, at least in part, on changes in customer behavior that are the result of time-varying rate designs, including those offered in the first instance through SSO. As to the proposal to make the SSO default rate the currently tariffed Time-of-Day Option rates, the major benefit from my perspective is that it better aligns retail prices with costs, which is to say it more closely meets the bedrock regulatory principle of cost causation. My **Exhibit B** provides a more extensive basis for support for the need for a more active demand side in this time of industry transition, and that demand-side activation likely must originate in rate design when it comes to price-regulated products like those in the SSO. My proposal would empower and incentivize non-shopping customers to control their energy usage with the added benefit of better utilizing FirstEnergy's advanced metering infrastructure.

[12] Holidays would be New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

[13] *Grid Mod I*, Opinion and Order at ¶¶ 110-111; *TVR Case*, Opinion and Order (Jan. 27, 2021) at ¶ 19.

Q20. DO YOU BELIEVE THAT THIS RATE IS JUST AND REASONABLE?

A. Like FirstEnergy, the Commission Staff, and other parties when they stipulated to the rate design and the Commission itself when it approved it two years ago, I believe it is just and reasonable. I am not proposing any changes to this rate other than to its applicability provision. While there is an argument to be made to price capacity and other demand-related costs into the peak period of this TVR rate, the fact that it has a 2:1 differential between on- and off-peak intervals based on energy costs will nevertheless redound to the advantage of lower costs for other elements of the cost of service that are demand-related, including capacity and transmission, and not just energy. Meanwhile, the differential between on-/shoulder-/and off-peak itself is well-founded and largely based on multi-year trends in wholesale market pricing, and that differential is substantial enough to produce demand elasticity based on the literature I reviewed in my **Exhibit B**. Moreover, beyond being a just and reasonable rate on its own terms, it is superior to the flat rates that the vast majority of SSO customers take service under for a couple of reasons. First, as described above, it is more reflective of the costs to serve customers than the alternative, flat rate. Second, the TVR rate correctly hands down the incentives for an active demand side to the end user because, in the SSO supply arrangement, it cannot be imagined that the two other parties involved can or would work positively around those incentives. That is because SSO wholesale suppliers—unlike retail suppliers—have no ability to reach through their supply agreement to activate demand. The utility, meanwhile, has no apparent financial incentive to do so itself, and may in fact have a disincentive to do so, since some of the short- and long-term costs that an active demand side would obviate ultimately produce profit to the utility and its affiliates. I explore this point in more detail in my paper.[14]

Q21. DO YOU HAVE ANY OTHER OBSERVATIONS ABOUT WHETHER THE TVR RATE DESIGN COULD LEVERAGE OTHER DEVICES?

A. As noted above, the Commission in approving Grid Mod I said that the TVR that would become effective "will be designed to achieve the energy and capacity savings detailed in the cost-benefit analysis *and should leverage enabling devices, e.g., smart thermostats*."[15] (emphasis added). To the extent this has occurred for the 144 residential customers now on this rate, it is purely through actions those customers may have taken, which are not visible to any other entity. While I do not believe it needs to be adopted as part of the TVR tariff, the Commission could in this proceeding establish a smart-thermostat program and use the rate design here contemplated as an opportunity to "leverage" these devices.[16] This would simultaneously produce greater value to these devices while also automating the demand that would be activated in response to TVR rates, whether offered through the SSO or through CRES.

Q22. DO YOU BELIEVE THAT THE SSO TVR RATE, IF ADOPTED AS THE DEFAULT, SHOULD SUNSET AT SOME POINT AND RETURN TO A FLAT RATE DESIGN?

A. The Commission has ordered FirstEnergy to continue to make available a SSO TVR rate "until such time that a sufficient market offering comparable rates is established, which

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[14] Exhibit B at 14.
[15] Grid Mod I, Opinion and Order at ¶ 38.
[16] The Commission elected not to include a smart thermostat program in Grid Mod I because, among other things, FirstEnergy had an existing smart thermostat program in its EE/PDR Portfolio Plan. Grid Mod I, Opinion and Order at ¶ 109. That program has ended.

was defined in the *Grid Modernization Case* as a market having either (a) at least three suppliers offering products utilizing AMI data or (b) at least three different types of time-varying products utilizing AMI data."[17] I would consequently defer any judgment to that future proceeding, but I would also urge the Commission to take this opportunity not to make that judgment necessarily automatic, since an opt-out SSO TVR rate should be treated as the normal default rate for regulated rates for all the reasons I describe in **Exhibit B**.

Q23. ARE THERE STEPS THAT FIRSTENERGY WOULD HAVE TO TAKE TO MAKE IT POSSIBLE FOR CRES TO WIDELY MARKET THEIR OWN TVR OR FLEXIBLE-DEMAND PRODUCTS?

A. Yes, and by and large those steps are spelled out in the Grid Mod I order. However, the benefits have not yet been completely achieved because of the slow deployment of AMI. I think the introduction of the Time-of-Day Option rate as the default SSO TVR rate would help break the ice on the market, making customers broadly familiar that such products are normal, cost-reflective, and have the potential to offer savings to customers who flex their demand. The role of the utility and utility regulators in helping to create and shape the competitive retail market is well acknowledged throughout Ohio's history of restructuring. The market enhancements in the Grid-Mod I Order include:

- Providing a map of AMI deployment and an AMI tag on the Customer Information List provided to CRES providers.
- Using a scalable MDMS with AMI to allow for implementation of a Home Area Network (HAN) to connect qualified devices.

[17] *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co. for Approval of New Tariff Language*, Case No. 20-50-EL-ATA, Finding and Order (Jan. 27, 2021) at ¶ 31.

- Implementing data access enhancements, including necessary upgrades to systems and processes for wholesale market settlements. This means calculating and settling individual total hourly energy obligation, peak load contribution, and network service peak load values for each customer, instead of relying on generic load profiles. Access to this data was to be provided to suppliers through API without fees charges.

The Commission directed FirstEnergy to implement these market enhancements to improve the amount and diversity of supplier offerings for customers.[18] In my opinion, FirstEnergy should continue to implement these market enhancements and also make the Time-of-Day Option rate the default SSO TVR rate.

Q24. DO YOU HAVE ANY OTHER PROPOSALS REGARDING TVR RATES?

A. Yes. I propose that the Grid Mod I Collaborative continue to meet to evaluate the benefits of moving all SSO customers to time-of-day rates. Additionally, I recommend that existing marketing and education funding be used exclusively for education, and that funding be increased to educate customers on the SSO's new TVR rate design. FirstEnergy estimates that the annual cost for marketing and education of its current TVR rate offerings to be approximately $50,000 for Q3 2023 through Q1 2024.[19] Because I do not propose any changes to the rate other than its applicability (opt-out, rather than opt-in) the materials that FirstEnergy already has formulated are still useful in the event my proposal is adopted. I recommend that the existing funding be increased, allocated to SSO customers, and used exclusively for educational purposes.

[18] Grid Mod I, Opinion and Order at ¶ 36-39.
[19] NRG Set 01-INT-009.

CONCLUSION

Q25. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. For the reasons set forth above, I propose that FirstEnergy continue its Time-of-Day optional rates but instead make them the default rate designs for residential and non-residential SSO customers with an advanced meter.

CERTIFICATE OF SERVICE

In accordance with Rule 4901-1-05, Ohio Administrative Code, the PUCO's e-filing system will electronically serve notice of the filing of this document upon the following parties. In addition, I hereby certify that a courtesy copy of the foregoing was sent by, or on behalf of, the undersigned counsel to the following parties of record on October 23, 2023, via email.

/s/ *James F. Lang*

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4891-9100-0714, v. 4

Exhibit A

TRAVIS KAVULLA

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VICE PRESIDENT, REGULATORY AFFAIRS **Sept. 2019 – Present**

NRG Energy, Inc. *Princeton, New Jersey*

Leader of the department responsible for the company's engagement with state and federal regulatory agencies, working to develop policy and ensure compliance with applicable laws and regulations.

DIRECTOR, ENERGY & ENVIRONMENTAL POLICY **JAN. 2019 – Sept. 2019**

R Street Institute *Washington, DC*

Led the energy program of a 501(c)(3) "think tank" dedicated to promoting free markets and effective government. Focused principally on the power sector, R Street's energy program supported three overarching policy goals: exposing power plants to competition, providing consumers a choice in energy provider, and efficiently networking markets together to ensure the robustness of competition. R Street led opposition to state and federal subsidies to specific generators or types of generation, and has promoted a transparent price on carbon emissions as a vehicle for environmental regulation. R Street also has promoted reforms that make it easier to construct energy infrastructure and license new technologies.

In furtherance of its policy goals, R Street publishes white papers and op- eds, files regulatory comments, and provides legislative testimony.

GOVERNING BODY MEMBER **JULY 2018 – AUG. 2019**

Western Energy Imbalance Market (EIM) *Folsom, CA*

One of five independent board members of the Western Interconnection's first regional, real-time electricity market, which is operated by CAISO. Nominated by market participants in 2018 and elected by the other governing body members to a term of three years. The governing body actively engages with market participants and works to build upon the economic efficiency of the market. In the last year, significant reforms to EIM have included revisions to local market power mitigation (increasing the default energy bid for hydroelectric resources) and a revision to how greenhouse gas emissions are accounted for in the marketplace. Market-design discussions for a day-ahead market are just beginning, which will including considerations of energy price formation, transmission costs, and governance.

CHAIRMAN, NORTH AMERICAN NUMBERING COUNCIL **NOV. 2017 – Sept. 2019**

Appointed by FCC Chairman Ajit Pai to lead the stakeholder council responsible for providing the FCC comprehensive recommendations on several emerging topics associated with next-generation communications technologies. Topics on which the council engaged included measures to combat robo-calling through the creation of a call authentication trust anchor that certifies legitimate telephone calls, the creation of a nationwide number portability framework that allows 10-digit numbers to be ported freely throughout the United States and across different types of devices, and the modernization of toll-free number distribution through the establishment of an auction mechanism. While appointed as a utility commissioner, continued to serve in this role until Fall 2019 at the request of Chairman Pai. Online at http://nanc-chair.org

COMMISSIONER, CHAIRMAN (2011-13) & VICE-CHAIRMAN (2015-19) **JAN. 2011 – JAN. 2019**

Montana Public Service Commission *Helena, MT*

One of five commissioners of the State of Montana's utility commission, serving in leadership roles at the state, regional, and national level at various times. Responsible for regulating energy and water monopolies, as well as certain telecommunications companies and motor carriers in the

State of Montana. Nominated in contested Republican primary and elected to office in 2010, and re-elected without opposition in 2014 to a term expiring in 2018. Made decisions on hundreds of matters, with a focus on rate reviews of monopoly utilities, and the reform of ratemaking, interconnection, and reporting requirements for firms in markets transitioning to competition.

Testified before U.S. Congressional committees and in administrative proceedings and technical conferences of the Federal Energy Regulatory Commission (FERC) and the Environmental Protection Agency (EPA). Frequent speaker to organizations and conferences in the field of energy and telecommunications. Named by S&P Global Market Intelligence on its list of "The 10 most influential people in energy in 2016." Advised on the intersection of technological development and regulation as a member of the advisory council of the Electric Power Research Institute. Active participant in the Harvard Electricity Policy Group.

Other professional involvement includes leadership related to national and regional energy and telecommunications policy (detailed below).

AFFILIATED ROLES TO SERVICE ON THE MONTANA PUBLIC SERVICE COMMISSION

PRESIDENT, NAT'L ASSN. OF REGULATORY UTILITY COMMISSIONERS — NOV. 2015 – NOV. 2016
MEMBER, EXECUTIVE COMMITTEE, NARUC — NOV. 2014 – NOV. 2018

As NARUC President, supervised a newly hired executive director and established strategic direction of the organization, with 40 staff devoted to improving the practice of utility regulation. Afterwards, continued to serve as a board director and a member of NARUC's Executive Committee.

Focus as President at NARUC included several major initiatives involving energy and telecommunications, including:

- Engagement with FERC and others on the design and regulation of the wholesale electricity markets, including the interaction between Regional Transmission Organizations (RTOs) and states, and on the reform of Public Utility Regulatory Policies Act of 1978 (PURPA).
- Improved training for new utility commissioners, focused on basic issues of ratemaking.
- Supervised the advocacy before the FCC and federal courts on issues including the Universal Service Fund/Connect America Fund, municipal broadband pre-emption, inmate calling, and net neutrality.
- Writing and publication of a "Compensation and Pricing Manual for Distributed Energy Resources," such as a roof-top photovoltaic solar, in order to address controversies about cost-shifts in current net-metering policy.
- Analysis and critical response to the EPA's Clean Power Plan.

On operations, approved plans and supported new NARUC executive director to tighten criteria for staff performance review and eliminate excessive fringe benefits and pay raises. Led a retreat of executive committee to ensure that NARUC's international program and a NARUC-affiliated organization had wind-down or contingency plans in the eventuality that program revenue became unavailable. Online at http://www.naruc.org

CO-CHAIR, NORTHERN TIER TRANSMISSION GROUP **JAN. 2013 – JULY 2018**

Co-chair of the Steering Committee of NTTG, which undertakes regional transmission planning for a collection of utilities including PacifiCorp, Portland General Electric, Idaho Power, NorthWestern Energy, the Utah Associated Municipal Power Systems, and Deseret Generation & Transmission Cooperative. NTTG's Steering Committee approves regional transmission plans, provides policy guidance, and directs FERC filings on behalf of the group.

The Steering Committee's work in the past several years has included debating and approving the region's filings in response to FERC's Order 1000, requiring interstate transmission planning processes, as well as revisiting and improving the group's use of production cost modeling for the purposes of estimate the economic benefits of transmission expansion. Online at http://www.nttg.biz

CHAIRMAN, CMTE. ON REGIONAL ELECTRIC POWER COOPERATION **OCT. 2016 – OCT. 2018**

Co-chair, along with John Chatburn of the Idaho Governor's Energy Office, of CREPC, which twice per year brings together governor's offices, utility commissioners, and consumer advocates in order to improve relationships between states, utilities, and other stakeholders in the western United States and Canada.

MEMBER, EIM TRANSITIONAL COMMITTEE **APR. 2015 – JULY 2016**

CHAIRMAN, PUC ENERGY IMBALANCE MARKET WORKING GROUP **JAN. 2012 – JULY 2015**

Headed a successful effort by state regulators to evaluate the costs and benefits of forming a real-time energy market across the dozens of balancing authorities in the Western United States. The Public Utility Commissioners Energy Imbalance Market (PUC EIM) Working Group included a member from each of the Western Interconnection's utility commissions, and was a project of CREPC. Also served on the California Independent System Operator (CAISO) EIM Transitional Committee, which designed a regional governance model to oversee the largest real-time energy market in the Western United States.

DIRECTOR, WESTERN ELECTRICITY COORDINATING COUNCIL (WECC) **FEB. 2013 – FEB. 2014**

MEMBER, MEMBER ADVISORY COMMITTEE **JAN. 2014 – NOV. 2015**

Appointed to the WECC Board of Directors at a time when WECC, the regional reliability regulator for the Western Interconnection under the North American Electric Reliability Corp. (NERC), was undergoing a governance overhaul, bifurcating its reliability coordinator function from its standards, compliance auditing, and transmission planning functions. Acted as a strong advocate for bifurcation and the installation of an independent board of directors.

Served on the seven-member selection committee for WECC's CEO. Elected by WECC Members to the Nominating Committee, responsible for selecting independent board directors. Online at http://www.wecc.biz/

EARLIER WORK EXPERIENCE

FREELANCE JOURNALIST **JULY 2008 – DECEMBER 2010**
Contributed full-length pieces and reporting to a variety of sources, including *National Review*, the *Wall Street Journal*, the *Dallas Morning News*, Fox News, the *Times* of London, *Standpoint* magazine (UK), *The New Atlantis*, *Catholic World Report*, *The Claremont Review of Books* and other outlets. Based in England and Kenya in 2008 and 2009 and traveled widely in Africa, Europe, and South Asia. Special projects editor for National Review Online, supervising five journalists.

ASSOCIATE EDITOR **JAN. 2007 – OCT. 2007**
National Review and *National Review Online* *New York, NY*
Member of the editorial staff of biweekly magazine of politics and culture, leaving to become a Gates Scholar at Cambridge. Continues to contribute periodically.

EDUCATION

M.PHIL., HISTORY FALL 2007 – SUMMER 2008
University of Cambridge *Cambridge, England*
Gates Scholar, competitively awarded through the Gates Trust at Cambridge, funded by the Bill & Melinda Gates Foundation. Considerable field research conducted in pursuit of thesis, a critical history of government-led economic planning and the beginnings of development aid in the British colonial world of the 1950s.

B.A., HISTORY SEPT. 2002 – JAN. 2007
Harvard University *Cambridge, Mass.*
History, graduated *cum laude*. Columnist for campus daily, *The Crimson*, and editor of *The Salient*.

PROFESSIONAL AFFILIATIONS & HONORS

Chairman, North American Numbering Council, Nov. 2017 – Sept. 2019

President & Director, National Association of Regulatory Utility Commissioners; President (Nov. 2015 – Nov. 2016); Director (Jan. 2011 – Jan. 2019).

Co-Chairman, Northern Tier Transmission Group Steering Committee; Jan. 2013 – July 2018.

Member, Advisory Council, Electric Power Research Institute; Nov. 2014 – Aug. 2018.

Member, Federal Communications Commission's Federal-State Joint Board on Jurisdictional Separations; Dec. 2013 – Jan. 2019.

Chairman, Public Utility Commissioners Energy Imbalance Market Group, Dec. 2011 – 2015 (Chairman as of Dec. 2012).

Director, Board of Directors, Western Electricity Coordinating Council; Feb. 2013 – Feb. 2014

Director & Treasurer, Board of Directors, National Regulatory Research Institute; May 2012 – Nov. 2014.

Member, Advisory Council for Center for Public Utilities, New Mexico State University, Nov. 2011 – Jan. 2019.

Journalism Fellow; Phillips Foundation; July 2008 – July 2009 (currently known as the Robert Novak Fellow).

Gates Cambridge Scholar; Gates Trust, Bill & Melinda Gates Foundation, Cambridge, England.; 2007-08.

COMMENTS AND TESTIMONY

Federal Energy Regulatory Commission. Comments of Travis Kavulla, J. Arnold Quinn, on behalf of NRG and Vistra. Regarding: Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, AD23-3-000, May 15, 2023.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, Sharon Segner, on behalf of NRG and LS Power. Regarding: Transmission Planning and Cost Management; Joint Federal-State Task Force on Electric Transmission; Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, AD22-8-000; AD21-15-000; RM21-17-000, March 23, 2023.

Maine Public Utilities Commission. Comments of Travis Kavulla, Marc Hanks, on behalf of NRG. Regarding: Rate Structure For Standard Offer Service, 2023-00019, February 21, 2023.

Massachusetts Department Of Public Utilities. Comments of Travis Kavulla, Marc Hanks, on behalf of NRG. Regarding: Investigation By The Department Of Public Utilities On Its Own Motion Into The Provision Of Basic Service, D.P.U. 23-50, February 08, 2023.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, AD23-3-000, December 06, 2022.

Massachusetts Department Of Public Utilities. Comments of Travis Kavulla, Marc Hanks, on behalf of NRG. Regarding: Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid. Basic Service Filing, D.P.U 22-BSF-D3, September 26, 2022.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation Interconnection, Docket No. RM21-17, August 16, 2022.

Oklahoma Corporation Commission. Comments of Travis Kavulla, Sam Gafford, on behalf of NRG. Regarding: In The Matter Of The Application Of Oklahoma Gas And Electric Company For A Financing Order Pursuant To The February 2021 Regulated Utility Consumer Protection Act Approving Securitization Of Costs Arising From The Winter Weather Event Of February 2021, PUD 2021-000072, August 16, 2022.

New York Public Service Commission. Comments of Travis Kavulla, Jennifer Hsia, on behalf of NRG. Regarding: Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, Case 22-M-0149, August 10, 2022.

Pennsylvania Public Utility Commission. Testimony of Travis Kavulla, on behalf of NRG and RESA. Regarding: Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027, P-2021-3030012; P-2021-3030013; P-2021-3030014; P-2021-3030021, April 07, 2022.

Arizona Corporation Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: TEP PPFAC Adjuster, E-01933A-19-0028, April 07, 2022.

Pennsylvania Public Utility Commission. Testimony of Travis Kavulla, on behalf of NRG and RESA. Regarding: Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027, P-2021-3030012; P-2021-3030013; P-2021-3030014; P-2021-3030021, March 24, 2022.

Department of Energy. Comments of Travis Kavulla, on behalf of NRG. Regarding: Request for Information Regarding Establishment of a Civil Nuclear Credit Program, DOE-HQ-2022-0006, March 17, 2022.

Pennsylvania Public Utility Commission. Testimony of Travis Kavulla, on behalf of NRG and RESA. Regarding: Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027, P-2021-3030012; P-2021-3030013; P-2021-3030014; P-2021-3030021, February 25, 2022.

Arizona Senate Committee of Natural Resources, Energy and Water. Testimony of Travis Kavulla, on behalf of NRG. Regarding: Senate Bill 1631, February 16, 2022.

Federal Highway Administration. Comments of Travis Kavulla, Sam Gafford, on behalf of NRG. Regarding: Request for Information: Development of Guidance for Electric Vehicle Charging Infrastructure Deployment, 2021-25868, January 26, 2022.

Committee of Natural Resources, Energy and Water, Arizona House of Representatives. Comments of Travis Kavulla, on behalf of NRG. Regarding: Senate Bill 1631, January 18, 2022.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Modernizing Electricity Market Design, AD21-10-000, July 19, 2021.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, Neal Fitch, on behalf of NRG. Regarding: Modernizing Electricity Market Design, AD21-10-000, April 26, 2021.

US House of Representatives. Comments of Travis Kavulla, on behalf of NRG. Regarding: CLEAN Future Act, April 12, 2021.

New Jersey Board of Public Utilities. Comments of Travis Kavulla, on behalf of NRG. Regarding: Investigation of Resource Adequacy Alternatives, EO20030203, March 05, 2021.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Carbon Pricing in Organized Wholesale Electricity Markets, AD20-14-000, December 01, 2020.

California Public Utility Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021, Rulemaking 20-11-003, November 30, 2020.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Carbon Pricing in Organized Wholesale Electricity Markets, AD20-14-000, November 16, 2020.

California Public Utility Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access, Rulemaking 19-03-009, October 15, 2020.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Carbon Pricing in Organized Wholesale Electricity Markets, AD20-14-000, September 11, 2020.

Maryland Public Service Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Impacts Of Covid-19 Pandemic On Maryland'S Gas And Electric Utility Operations And Customer Experiences, PC53, August 21, 2020.

Pennsylvania Public Utility Commission. Testimony of Travis Kavulla, on behalf of NRG. Regarding: Petition of PECO Energy Company for Approval of Its Default Service Program for the Period From June 1, 2021 Through May 31, 2025, P-2020-3019290, July 23, 2020.

New York Public Service Commission. Comments of Travis Kavulla, Angela Schorr, on behalf of NRG. Regarding: Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, 20-M-0266, July 13, 2020.

New Jersey Board of Public Utilities. Comments of Travis Kavulla, on behalf of NRG. Regarding: Investigation of Resource Adequacy Alternatives, EO20030203, June 24, 2020.

Pennsylvania Public Utility Commission. Testimony of Travis Kavulla, on behalf of NRG. Regarding: Petition of PECO Energy Company for Approval of Its Default Service

Program for the Period From June 1, 2021 Through May 31, 2025, P-2020-3019290, June 16, 2020.

US House of Representatives. Comments of Travis Kavulla, on behalf of NRG. Regarding: CLEAN Future Act, June 16, 2020.

New Jersey Board of Public Utilities. Comments of Travis Kavulla, on behalf of NRG. Regarding: Investigation of Resource Adequacy Alternatives, EO20030203, May 20, 2020.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NRG. Regarding: Carbon Pricing in FERC-Jurisdictional Organized Regional Wholesale Electric Energy Markets, AD20-14-000, May 14, 2020.

US House of Representatives. Comments of Travis Kavulla, on behalf of NRG. Regarding: CLEAN Future Act, September 13, 2019.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, John Jimison, Jeffery Dennis, Anne Reynolds, Todd Foley, Gabe Tabak, Kerinia Cusick, Charles Hernick, William White, Betsy Beck, Katie Guerry, Nina Plaushin, Carl Zichella, Philip Squair, Fred Heutte, John Moore, Micahel Jacobs, and Rob Gramlich, on behalf of R Street. Regarding: Inquiry Regarding the Commission's Electric Transmission Incentives Policy, PL19-3-000, August 26, 2019.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of R Street. Regarding: Inquiry Regarding the Commission's Electric Transmission Incentives Policy, PL19-3-000, June 18, 2019.

Minnesota Public Utilities Commission. Comments of Travis Kavulla, William Murray, on behalf of R Street. Regarding: In the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, E-002/CI-17-401, June 10, 2019.

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Rhode Island Public Utilities Commission. Comments of Travis Kavulla, on behalf of R Street. Regarding: Guidance Document Regarding Principles To Guide The Development And Review Of Performance Incentive Mechanisms, 4943, May 16, 2019.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of R Street. Regarding: PJM Interconnection, L.L.C.; Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., ER19-1486-000; EL19-58-000, May 14, 2019.

Ohio House of Representatives, Subcommittee on Energy Generation. Testimony of Travis Kavulla, Alan Smith, on behalf of R Street. Regarding: HB 6, April 24, 2019.

US Senate Committee on Energy & Natural Resources. Testimony of Travis Kavulla, on behalf of R Street. Regarding: Outlook for Energy and Minerals Markets in the 116th Congress, February 05, 2019.

House Committee on Energy & Commerce. Testimony of Travis Kavulla, on behalf of NARUC. Regarding: H.R. 4476, the “PURPA Modernization Act of 2017”, January 19, 2018.

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Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NARUC. Regarding: Technical Conference on Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, AD16-16-000, June 29, 2016.

House Committee on Energy & Commerce. Testimony of Travis Kavulla, on behalf of NARUC. Regarding: The Nuclear Waste Fund: Budgetary, Funding, And Scoring Issues, December 03, 2015.

Federal Energy Regulatory Commission. Comments of Travis Kavulla, on behalf of NARUC. Regarding: Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, AD15-4-000, February 25, 2015.

House Committee on Energy & Commerce. Testimony of Travis Kavulla, on behalf of NARUC. Regarding: State Perspectives: Questions Concerning EPA’s Proposed Clean Power Plan, September 09, 2014.

PUBLICATIONS, ARTICLES, AND OTHER WRITINGS

Kavulla, Travis. "Why Is the Smart Grid So Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector." (2023).

Kavulla, Travis. "Utility Player: California's Disastrous Electricity Policy." American Affairs Volume VII, Number 1 (Spring 2023): 46–49.

Kavulla, Travis. "Lubbock, Texas Empowers Citizens with Energy Choice." NRG Insights, March 25, 2022.

Kavulla, Travis. "Supplier-consolidated billing: A tool for innovation and accountability in retail energy markets." Utility Dive, March 7, 2022.

Kavulla, Travis. "Empower Customers to Shop and Let Industry Bear the Risk of Energy Price Volatility." NRG Insights, October 20, 2021.

Kavulla, Travis, and N. R. G. Energy. "Moving forward: Approaches for state-federal cooperation in a decarbonizing electricity sector." (2021).

Kavulla, Travis. "Reflections on elections: What the 2020 election could mean for electricity policy in 2021." NRG Insights, December 21, 2020.

Kavulla, Travis. "A tale of two markets: incentivizing long-term clean energy investments." NRG Insights, December 15, 2020.

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Kavulla, Travis. 'Government helped make shopping around for energy unpleasant—and can help fix it.' (Oct 2020).

Kavulla, Travis. "Will regulators allow utilities to reap a windfall because of COVID-19?" Utility Dive, June 23, 2020.

Kavulla, Travis. 'Problems in Electricity Governance: An Assessment.' R Street Policy Study No. 180 (Aug 2019).

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Kavulla, Travis. 'Reviewed Work: “The Billion-Dollar Coal Bailout Nobody is Talking About: Self-Committing in Power Markets”.' R Street (Jun 2019).

Kavulla, Travis. 'Bailout Bill Not the Right Approach.' Montana Standard (May 2019).

Kavulla, Travis. "How nuclear plants are gaming climate-change rules." Politico, The Agenda, April 23, 2019.

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Kavulla, Travis. "Colstrip bill puts corporation before consumers." Bozeman Daily Chronicle, March 20, 2019.

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Kavulla, Travis. "Opinion: Customers deserve accurate energy pricing." The Detroit News, February 7, 2019.

Kavulla, Travis. 'Carbon Capture and Sequestration.' R Street R Sheet (Feb 2019).

Kavulla, Travis. "Problems in electricity market governance: an assessment." R Str. Policy Study 180 (2019): 1-16.

Kavulla, Travis, and Frank Lacey. "Financial and Governance Protections for Electric Cooperatives." (2019).

Kavulla, Travis, and Gürcan Gülen, "‘Missing Money’ and an off-ramp to the capacity debate." The Electricity Journal, Volume 32, Issue 7, 2019.

Kavulla, Travis. "Efficient Solutions for Issues in Electricity Seams." (2019).

Kavulla, Travis. "The Pretext Problem: Our politics is broken when it doesn’t allow participants to state their ends plainly." PERC, December 6, 2018.

Kavulla, Travis. 'The Economics—and Politics—of Broadband.' American Affairs (Nov 2018).

Kavulla, Travis. "Energy West customers will see their bill increase 3.73 percent. Here is why." Great Falls Tribune, October 8, 2018.

Kavulla, Travis. "A new, worse approach to pipeline regulation for FERC." Utility Dive, August 31, 2017.

Kavulla, Travis. "FERC tries to thread the needle in debate over markets versus mandates." Utility Dive, March 13, 2018.

Kavulla, Travis, and Laura Farkas. "Streamlining the production of clean energy: Proposals to reform the hydroelectricity licensing process." Pub. Land & Resources L. Rev. 39 (2018): 123.

Kavulla, Travis, and Jennifer M. Murphy. "Aligning PURPA with the Modern Energy Landscape: A Proposal to FERC." National Association of Regulatory Utility Commissioners white paper. https://pubs. naruc. org/pub. cfm (2018).

Kavulla, Travis. "NorthWestern’s bad bets have cost consumers hundreds of millions." Missoulian, August 8, 2017.

Kavulla, Travis. "Hitting the Refresh Button on Net Neutrality." National Review, July 13, 2017.

Kavulla, Travis. 'Indian Country.' National Review (Jan 2017).

Kavulla, Travis. "There Is No Free Market for Electricity: Can There Ever Be?" American Affairs, Summer 2017, Volume I, Number 2.

Kavulla, Travis and Steve Daines. "Time for court to define limit of EPA's power." Missoulian, October 11, 2016.

Kavulla, Travis. "How Utilities Team Up With Greens Against Consumers." WSJ, February 26, 2016.

Kavulla, Travis. 'Making History.' American Gas (Feb 2016).

Kavulla, Travis. "Utility Regulation, Old and New." Power 160, no. 12 (2016): 108-108.

Kavulla, Travis. "Problem for the Climate Warriors: China Needs More Coal Plants to Reduce Its Smog." National Review, December 11, 2015.

Kavulla, Travis. 'Efficient Markets, Effective Regulation: Installation Remarks of NARUC President Travis Kavulla.' NARUC (Nov 2015).

Kavulla, Travis. 'Realpolitik and CO2: Mitigation in the U.S. and China.' Clearing Up No. 1718 (Oct 2015).

Kavulla, Travis. 'For Water Rights in Montana, It's Still the Wild West.' Wall Street Journal (Jun 2015).

Kavulla, Travis. 'Public-Land Colonialism of Cliven Bundy and the Bureau of Land Management.' National Review (May 2014).

Kavulla, Travis. 'Are Competitive Solicitations Actually Competitive?.' Public Utilities Fortnightly (Nov 2013).

Kavulla, Travis. 'Timing is Everything: Aligning States' Wind Integration Tariffs with Capacity Costs.' Rutgers Conference CRRI (Sep 2013).

SPEECHES, PANELS, AND PRESENTATIONS

Mitchell Foundation. Remarks of Travis Kavulla, on behalf of NRG. Regarding: VPP, Jun 2023.

California Public Utility Commission. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Why Is the Smart Grid So Dumb?, May 2023.

Electricity Camp in the Rockies. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Why Is the Smart Grid So Dumb?, May 2023.

Restructuring Roundtable. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Why Is the Smart Grid So Dumb?, Mar 2023.

CERAWeek. Remarks of Travis Kavulla, on behalf of NRG. Regarding: transmission permitting, Mar 2023.

Princeton University. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Introduction to Electricity Regulation, Mar 2023.

PowerGen. Remarks of Travis Kavulla, on behalf of NRG. Regarding: weatherization, gas, renewables, markets, Feb 2023.

NARUC Winter Meeting. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Making the Smart Grid Smarter Through Intelligent Rate Design, Feb 2023.

Connecticut Department of Energy & Environmental Protection. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Four Reforms for a More Active Demand Side in Connecticut, Nov 2022.

ESIG Fall Technical Workshop . Remarks of Travis Kavulla, on behalf of NRG. Regarding: Why is the Smart Grid so Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side of the Electricity Sector, Oct 2022.

21st Century Energy Policy Development Task Force. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Performance-Based Ratemaking, Sep 2022.

. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Missing Incentives in Regulatory Policy for Mass-Market Demand Response, Jul 2022.

MACRUC. Remarks of Travis Kavulla, on behalf of NRG. Regarding: retail, Jun 2022.

ESIG. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Task Force for Aligning Retail Pricing with Grid Needs, Jun 2022.

Future Power Markets Forum. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Competitive Generation Procurement?, May 2022.

GTI Public Interest Advisory Committee. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Gas Costs: Who Paid During Winter Storm Uri?, Apr 2022.

EPSA Competitive Power Forum. Remarks of Travis Kavulla, on behalf of NRG. Regarding: tension of state and federal policy, Mar 2022.

Stanford University. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Rethinking the Risk/Reward Paradigm: A Perspective on Utility Regulation, Mar 2022.

NARUC. Remarks of Travis Kavulla, on behalf of NRG. Regarding: gas price spikes and winter storm Uri, Feb 2022.

NEPGA New England Energy Summit. Remarks of Travis Kavulla, on behalf of NRG. Regarding: innovation, retail, procurement, DR, TOU, Dec 2021.

NECPUC. Remarks of Travis Kavulla, on behalf of NRG. Regarding: TOU and DER, Oct 2021.

S&P Platts. Remarks of Travis Kavulla, on behalf of NRG. Regarding: electric-gas interdependency in ERCOT, May 2021.

NARUC Winter Meeting. Remarks of Travis Kavulla, on behalf of NRG. Regarding: electric vehicles, Feb 2021.

Northwestern University Electricity Dialogue . Remarks of Travis Kavulla, on behalf of NRG. Regarding: price spikes, Jan 2021.

NARUC Annual Meeting. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Clean Energy and the Markets, Nov 2020.

EUCI. Remarks of Travis Kavulla, on behalf of NRG. Regarding: Accelerating Grid Modernization: Retail & Clean Energy, Sep 2020.

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Open Meeting of the Federal Energy Regulatory Commission. Remarks of Travis Kavulla, on behalf of R Street. Regarding: A Tribute to FERC Commissioner Cheryl LaFleur, Jul 2019.

Advanced Rate Design Workshop. Remarks of Travis Kavulla, on behalf of R Street. Regarding: Rate Design in a 100% Clean-Energy Transition, Jul 2019.

Legislative Branch Capacity Working Group. Remarks of Travis Kavulla, on behalf of R Street. Regarding: Losing its Charge? Can Congress Keep Up with the Pace of FERC’s Regulation in Energy Policy?, Jul 2019.

NEPOOL Summer Meeting. Remarks of Travis Kavulla, on behalf of R Street. Regarding: Opening Remarks: Evolving Markets and Public Policy in New England, Jun 2019.

9th Annual Breakthrough Dialogue 2019. Remarks of Travis Kavulla, on behalf of R Street. Regarding: Whole Earth Discipline, Jun 2019.

34th Annual Western Energy Conference. Remarks of Travis Kavulla, on behalf of R Street. Regarding: Monopoly and Regulation in Context, May 2019.

California Public Utilities Commission Forums on Governance, Management, and Safety Culture. Remarks of Travis Kavulla, on behalf of R Street. Regarding: regulating California utilities in the face of wildfire risk, Apr 2019.

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Scalia Law School, George Mason University. Remarks of Travis Kavulla, on behalf of Montana PSC. Regarding: Powering Forward: Current Issues in the Permitting of Energy Infrastructure, Oct 2018.

Hoover Institution. Remarks of Travis Kavulla, on behalf of Montana PSC. Regarding: future of markets in electricity, Sep 2018.

National Regulatory Research Institute Webinar. Remarks of Travis Kavulla, on behalf of Montana PSC. Regarding: Tracking Net Neutrality: State Actions, Jun 2018.

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37th Public Land Law Conference, AB3 School of Law, University of Montana. Remarks of Travis Kavulla, on behalf of Montana PSC. Regarding: A Regulatory Perspective on Alternative Energy Development in the West, Oct 2017.

AWEA Regional Meeting. Remarks of Travis Kavulla, on behalf of Montana PSC. Regarding: Accessing New Wind Projects in the Northwest: Working with the New Administration on Transmission, Jul 2017.

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Exhibit B

WHITE PAPER

Why Is the Smart Grid So Dumb?

MISSING INCENTIVES IN REGULATORY POLICY FOR AN ACTIVE DEMAND SIDE IN THE ELECTRICITY SECTOR

By Travis Kavulla, NRG Energy

Advanced metering infrastructure was supposed to transform the retail customer experience, empowering demand to participate in a genuinely two-sided market across from supply. But as smart meters become ubiquitous, few retail customers see time-of-use prices related to the cost elements of electricity service that vary over time. Someone, somewhere must face clear incentives to actively manage demand in order for it to happen. Yet even the companies that serve retail customers too often lack meaningful exposure to these costs.

This paper examines the incentives facing two different types of retailers: utility monopolies and competitive retailers. It finds incomplete incentives to activate demand flexibility throughout their business models. Regulated utilities under modern amendments to traditional cost-of-service regulation are usually deadened to incentives altogether, or even perversely incentivized. Competitive retailers typically are faced with incentives around supply costs, but too often have no role billing for and intermediating other network charges. Reforms are proposed: time-of-use rates as the default retail product for regulated-utility customers, all retailers exposed to and responsible for billing all relevant grid costs, and public investment and standards for automated devices. Absent these reforms, transformation of electric grids—increasingly subject to intermittent supply, volatilely priced fuels, and rising demand—will be costlier and slower.

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

January 2023

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About the Author

Travis Kavulla is vice president of regulatory affairs for NRG Energy and a lecturer at the University of Chicago's Harris School of Public Policy. He has served previously as chairman of the Montana Public Service Commission and as president of the National Association of Regulatory Utility Commissioners. The views expressed here are his own.

About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ESIG Publications Available Online

This white paper is available at https://www.esig.energy/aligning-retail-pricing-with-grid-needs. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

Get in Touch

To learn more about the topics discussed in this white paper or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

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Contents

The Smart Grid's Unfulfilled Promises

It was 2009, President Barack Obama had just taken office, a huge federal stimulus to jolt the electricity sector into the 21st century had been passed, and utilities had their eyes fixed on a transformational opportunity: the smart grid.

"Change is in the air," wrote Commissioner Rick Morgan of the District of Columbia's Public Service Commission. "The smart grid that's beginning to emerge in North America will rely on hardware like 'smart' meters, 'smart' appliances and thermostats, remote sensors, and sophisticated communications systems. These devices, when linked together, will enable utilities and their customers to respond in real time to conditions on the power grid, thereby creating new opportunities to reduce costs and increase customer value" (Morgan, 2009).

In the succeeding years, billions of dollars were spent in advanced metering infrastructure (AMI)—automated meters that precisely measure consumption or production at more granular intervals than the past's monthly meter reads, relaying those data instantaneously between customers, substations, and utility back offices with high fidelity. If the transmission grid is the physical network on which the wholesale electricity market is founded, these smart meters are the physical basis for retail customer empowerment. They unlock the opportunity to make the sector into a genuinely two-sided market where sources of flexible demand and distributed energy resources actively participate in response to prices driven by grid needs that are transmitted through the smart meter.

Smart meters unlock the opportunity to make the electricity sector into a genuinely two-sided market where sources of flexible demand and distributed energy resources actively participate in response to prices driven by grid needs.

Yet those ambitions have largely failed to materialize. To take but one concrete example, Pennsylvania's FirstEnergy electric utilities commenced their AMI roll-out in 2014 and by mid-2019 had achieved a nearly universal, 98.5 percent deployment across all customers, spending $920 million to deploy just over 2 million smart meters.[1] As part of the Pennsylvania statute that laid the groundwork for these investments, the FirstEnergy Companies were required to create at least one rate offering that made use of the technology by having a time-varying component—a reasonable requirement given the soaring rhetoric about the transformed customer experience foretold by the smart grid.[2] Echoing Commissioner Morgan's comments, Pennsylvania utility commissioner Rob Powelson, later appointed to the Federal Energy Regulatory Commission, wrote a separate opinion concurring in the AMI spending, but noting, "To be frank, it is pointless to have smart meters if you are still going to have 'dumb' rates."[3]

1 These utilities are Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company (collectively, "the FirstEnergy Companies"). See "Smart Meter Technology Procurement and Installation Plan Annual Progress Reports" for the years 2019 and 2021, both filed at the Pennsylvania Public Utilities Commission Docket No. M-2013-2341990.

2 Act 129 (2008), with the time-varying rate offering requirement codified at 66 Pa. C.S.A. §2807(f)(2)(iii). https://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66&div=0&chpt=28&sctn=7&subsctn=0.

3 Statement of Commissioner R. Powelson, *Smart Meter Procurement and Installation*, PA PUC Docket No. M-2009-2092655, June 18, 2009.

The FirstEnergy Companies did introduce a time-of-use rate. Between June 2019 and December 2021, the number of residential customers enrolled in it ranged from 44 to 97.[4] Those numbers are not missing digits. Taking the figure at the upper range, that is approximately one residential customer for every 20,000 smart meters installed or an enrollment rate of five-thousandths of one percent (0.005%).

This sorry outcome is hardly out of the ordinary. The Brattle Group estimated in a 2019 survey that only 1.7 percent of all residential customers in the United States were enrolled in time-of-use rates (Faruqui, Hledik, and Sergici, 2019). Only a handful of state and provincial regulatory commissions in North America have determined to make time-of-use rates the default option for residential and small commercial customers. Everywhere else, utilities charge flat rates—the same per-kilowatt-hour price in all hours.[5] Thus have "smart meters" perpetuated "dumb rates." While smart meters might convey more information to consumers about their energy usage, this on its own has been found to have no significant effect whatsoever on a household's use of energy (List, Metcalfe, and Price, 2018). Again, whatever else smart meters achieve, if they are paired with "dumb rates," they do not achieve outcomes around the shape and volume of demand. Prices matter.

On the opposite pole, there exists a mostly hypothetical landscape where utilities and other businesses that serve retail electricity customers use smart meters to completely absent themselves of an intermediary function, letting the wholesale market and the retail market converge. We have one recent but catastrophic example of this in the United States: Griddy, the only American business exclusively dedicated to the use of the smart grid to pass through real-time wholesale price signals directly to residential customers.

Only a handful of state and provincial regulatory commissions in North America have made time-of-use rates the default option for residential and small commercial customers. Everywhere else, utilities charge flat rates. Thus have "smart meters" perpetuated "dumb rates."

Griddy imploded in the aftermath of Winter Storm Uri in 2021 as supply fell from outages at power plants and wellheads, demand rose in the face of extreme cold, and wholesale prices in the face of these supply shortages settled at Texas regulators' pre-established "value of lost load" that also functioned as the wholesale market's price cap (then, $9,000 per megawatt-hour). Passing through those prices as promised, Griddy customers received bills for thousands of dollars for mere days of electricity service—if they were lucky enough (or perhaps unlucky enough) to have it at all.[6] Griddy constituted less than one-half of one percent of all customers in Texas, though their experience came to characterize a free-wheeling and inadequately regulated marketplace. Ironically, the state's competitive retail market otherwise caused retailers to bear the costs of unhedged wholesale positions, protecting their customers, since customers themselves generally were served by contracts with fixed prices.[7] Texas lawmakers outlawed the Griddy business model shortly thereafter.[8] In Griddy's bankruptcy proceedings, all its erstwhile customers were forgiven any obligation they had to pay outstanding charges to the company (Moritz, 2021).

These are the two extremes in how an electricity retailer might use the smart grid to transform the customer

4 FirstEnergy Response to Office of Consumer Advocate to Interrogatory Set 1, No. 34, Joint Petition of Metropolitan Edison Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs, Docket Nos. P-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021. Available in the Direct Testimony of Travis Kavulla, Exhibit TK-8, https://www.nrg.com/assets/documents/energy-policy/_2022/nrg-resa-direct-testimony-in-the-first-energy-default-service-plan-proceeding.pdf.

5 The only minor permutation observed to this flat rate is that certain jurisdictions' rates change after a consumer uses a certain quantity of kilowatt-hours in a billing period, called inclining (or declining) block rates.

6 See, for example, Oxner (2021).

7 As described in greater detail below, in the 15 jurisdictions affected by the storm, the rule was to pass-through fuel and purchased power costs to consumers, while many Texas retailers experienced substantial losses or even went bankrupt. Exceptions in Texas's ERCOT market were Griddy as well as the municipal and cooperative utilities that remain monopolies (Sharfman and Merola, 2022).

8 H.B. 16, 87th Leg., Reg. Sess. (Tex. 2021), https://capitol.texas.gov/tlodocs/87R/billtext/pdf/HB00016F.pdf.

experience: not at all, signaling to customers that each and every kilowatt-hour they use has the same value as any other kilowatt-hour, or, on the other extreme, by making retail prices a mirror of wholesale prices, issuing customers a new price as often as every five minutes without any protection from extreme price spikes. Live in the cave or on the roller coaster, as it were. An appropriate outcome almost certainly lies somewhere in the middle.

Someone, somewhere must face the clear price incentive to actively manage demand in order for it to happen.

The unfulfilled promises of the smart grid in mind, the main purpose of this paper is to understand the intersection between an energy transition that is badly in need of a more active demand side and the regulatory policies that have restrained that from happening. In an attempt to get back on track toward fulfilling the smart grid's promise, I will also propose some solutions.

This paper is organized in three parts:

- A survey of the growing importance of activating mass-market (which is to say residential and small commercial customers') demand in the modern electricity economy, the AMI and smart-device landscape that makes this possible, and what utility regulatory commissions are doing (or, as the case may be, not doing) to activate this demand through their rate-design and retail-market-structure decisions.
- An examination of how this landscape fits into the incentives that face two very different business models of energy supply service: cost-of-service-regulated utilities that typically lack any genuine financial exposure to marginal energy costs and thus lack an incentive to activate demand, and competitive retailers that do face some positive version of this incentive, though it is diffuse and sometimes incomplete.
- A reform agenda which can be summarized simply: Every electricity customer in the United States should either take service under a time-varying rate as a default option or should be supplied by a provider that does have the financial incentive and ability to activate the customer's demand in relation to the dynamic wholesale market on the customer's behalf. Someone, somewhere must face the clear price incentive to actively manage demand in order for it to happen.

Ratemaking and Technology, Supply and Demand, and the Imperative for Time-Varying Prices

Smart meters themselves have done us no wrong, of course. Their broken promises are only a reflection of a failure by both regulators and industry to keep pace with technological change. More to the point, smart-grid technologies now exist and are widely deployed. It is imperative to use them in ways that assist utility regulation in living up to its most visible and in some ways only purpose: setting prices that face demand in a manner that fairly reflects costs. It is ironic that utility regulation has not done this so far, because its traditions are finely calibrated to nuanced considerations throughout the ratemaking process—indeed, in everything but this final step of pricing, which again has been restrained until recently by the absence of smart meters.

In utility accounting, regulators separate the utility system into relevant *functions* (everything from boilers at power plants to flag poles at the utility office building) and then allocate the costs of those functions to the attributes of consumer demand *causing* those costs.[9] These attributes may include kilowatt-hours of energy needed in aggregate, kilowatts of coincident or non-coincident peak demand needing to be accommodated on each segment of the system, or simply the number of customers taking service from the system.

Figure 1 (p. 5) illustrates how, in arriving at their ratemaking decisions, regulators must classify the relationship between certain costs and how customers use energy, which is to say when customers use energy and how much energy—the load shape and its duration curve. Then, in the next step of utility regulation, these allocated costs are sieved through the process of rate design. This step is where the inherent contradictions of utility regulation emerge. That's because those costs that had been allocated to groups of customers, based on when and how much energy is used by the class as a whole, are in this step rendered into prices that, for individual residential and small commercial customers, reflect none of those fine-tuned attributes. Typically, these customers will pay a rate that is two parts: a dollars-per-customer-per-month fee and then the round-the-clock price per kilowatt-hour that applies regardless of when and how much energy is used.[10] Thus does a system of regulation that begins with such precision that it measures the cost and function of a flag pole end up yielding prices that are not very precise at all.

It is imperative to use smart-grid technologies in ways that assist utility regulation in living up to its most visible and in some ways only purpose: setting prices that face demand in a manner that fairly reflects costs.

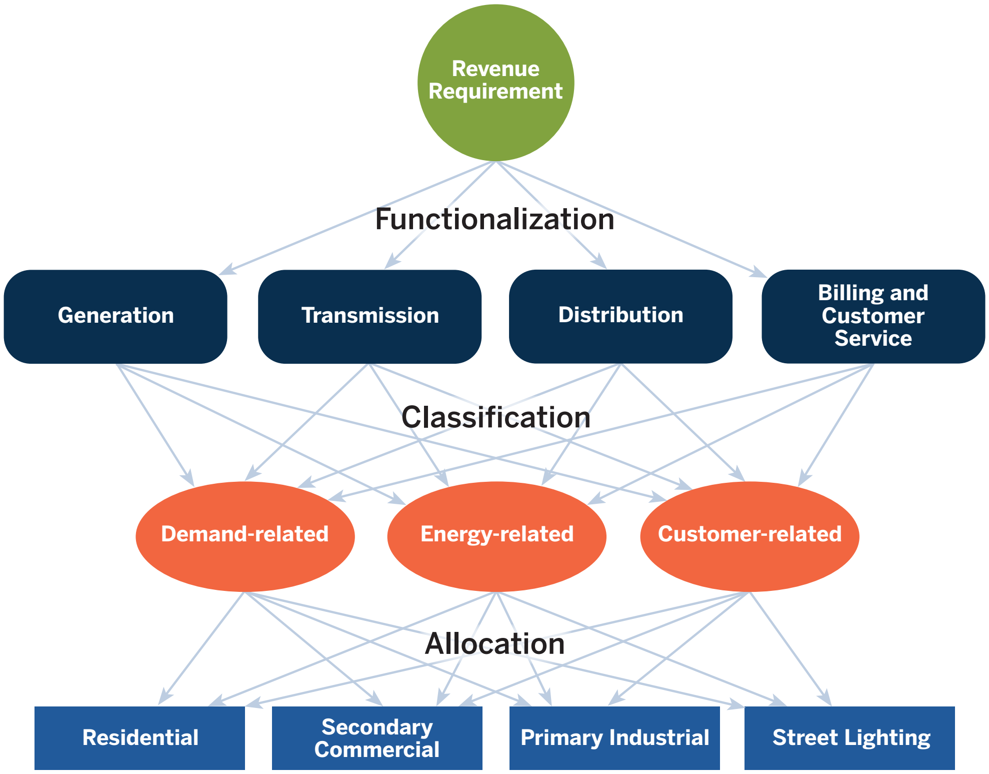
Through its processes ascertaining the appropriate function, classification, and allocation of costs, traditional utility ratemaking is often called cost-of-service regulation. And yet because cost-of-service regulation's ultimate prices tend not to be time-varying, their cost basis is

9 18 C.F.R. Part 101, "Uniform System of Accounts," https://www.govinfo.gov/content/pkg/CFR-2021-title18-vol1/pdf/CFR-2021-title18-vol1-part101.pdf. See "Electric Plant Instructions—Structures and Improvements" for reference to flag poles.

10 For larger customer classes, for whom demand is often measured and billed as a third part to rate design, there is more theoretical consistency between the "cost allocation" and "rate design" steps of the ratemaking process. A time-of-use rate should be a generally acceptable substitute for demand charges that will tend to bewilder mass-market customers.

FIGURE 1

Traditional Embedded Cost-of-Service Study Flowchart



Source: Lazar et al. (2020).

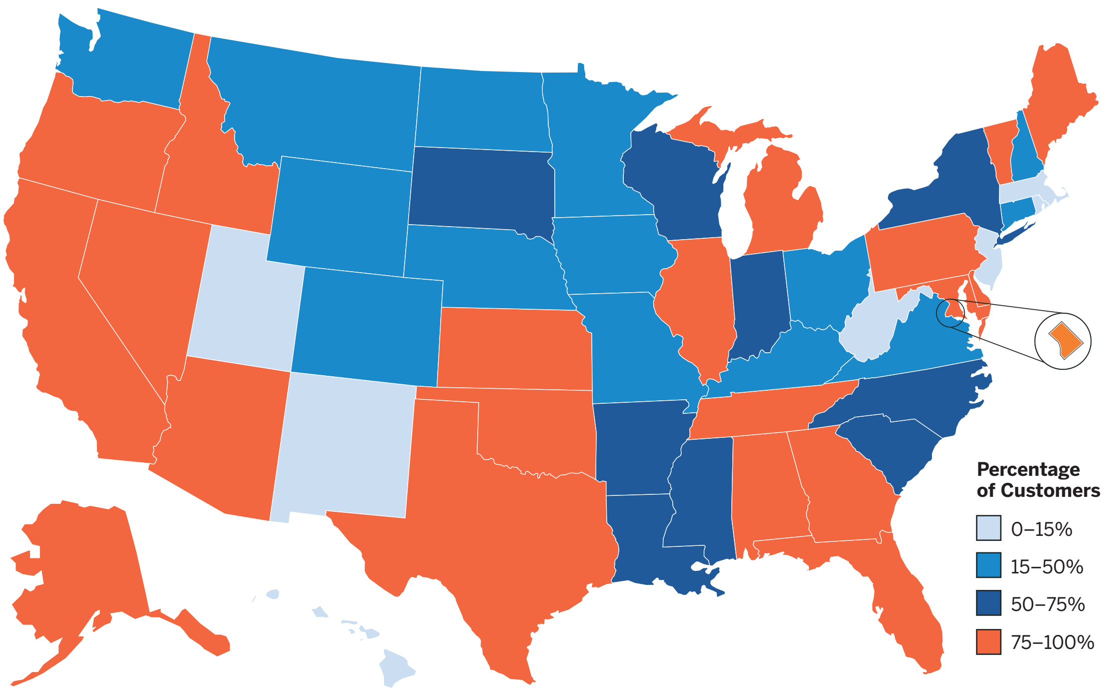
attenuated from the realities of any element of service whose costs vary with time (which they all do, some quickly, some over the *longue durée*). In effect, without time-varying rates, utility ratemaking reverts to being a crude tool to pay to utilities the money that regulators believe them to be owed, with nearly all other priorities subjugated to this imperative—which just so happens to be the pre-eminent goal of the most well-resourced entity to appear before these utility commissions. There were, perhaps, defenses of this crude approach in the past, either because a lack of AMI necessitated these flat rates or because a relatively uniform cost structure upstream justified them. Neither of those things is true now.

Smart Meters, Smart Devices

Smart meters are well on their way to ubiquitous deployment, with 75 percent of U.S. households estimated to have a smart meter, and 115 million of them deployed in 2021, growing to 124 million in 2022 (Cooper, Shuster, and Lash, 2021, 3) (Figure 2). A 93 percent deployment rate is projected by the end of this decade (Wolak and Hardman, 2021, 55-56). In places with AMI, there is no hardware technology barrier to time-varying retail rates.

Deployment of smart meters does not break along the familiar dividing lines of energy policy. It is not aligned to "blue" versus "red" states, those with aggressive clean energy targets and those without, and so forth. California has ubiquitous smart meters, but New York lags and Massachusetts has practically none, even though all of them are climate leaders, and New York famously staged a lengthy (and, given the lack of AMI as a requisite foundation, somewhat absurd) regulatory process around animating distributed resources and demand-side technologies. Texas, with its vibrant retail market, relies on smart meters to expedite customer shopping—customers there may switch suppliers almost instantly, while in certain other jurisdictions that allow customer choice

FIGURE 2
Smart Meter Deployment in the United States, 2022



Source: Institute for Electric Innovation (2022).

it requires an entire billing cycle or longer. Texas also has a stand-alone entity, Smart Meter Texas, to allow customers to access their data regardless of their utility.[11]

Less ubiquitous than smart meters but growing in scale are smart devices: thermostats that control cooling and heating systems, clothes washers and dryers, electric vehicle supply equipment, water heaters, refrigerators, pool pumps, and other loads able to automatically interact with AMI and, thus, the grid at large. In its survey of the national potential for demand flexibility, Brattle Group found that nearly 200 gigawatts, or 20 percent of the estimated peak demand in 2030, could be avoided, amounting to $15 billion per year (Hledik et al., 2019). Meanwhile, with the passage by Congress of a large round of tax credits that last until at least 2032, including for the first time a generous investment tax credit for battery storage, customer-sited distributed energy resources not only will be concentrated in rooftop solar but will more often include batteries. This will be especially pronounced in places where redundancy is made all the more important due to wildfire, hurricanes, and other weather-related disruptions to grid-delivered power supply, and where reforms to state net-energy metering policies drive investments that include storage and not only solar.

Smart devices and distributed energy resources do make managing a truly dynamic real-time price, or a demand charge, more plausible. Yet, none of these smart devices or distributed energy resources are required to implement time-varying rates. Indeed, one of the advantages of time-of-use rates that typically have fixed parameters, or tiers, known well in advance (e.g., one price in the day, another toward the evening, and another overnight) is that customers can respond behaviorally in pre-setting the runs of their major appliances and other electric loads. Time-of-use rates could be implemented now in

11 See https://www.smartmetertexas.com/aboutus.

We exist in a time when zero-marginal-cost renewables and resources with high fuel costs drive extraordinary times of abundance at some times of the day and tighter supply conditions at others, with sometimes steep ramps in between. These physical conditions then are mirrored by wide differentials in wholesale pricing.

many places with the metering infrastructure that is already in place, even without customer adoption of smart devices.

Variable Supply, Varying Prices

We now exist in a time when zero-marginal-cost renewables and resources with volatile fuel costs drive abundance at some times of the day and tighter supply conditions at others, with sometimes steep ramps in between. These physical conditions then are mirrored by wide differentials in wholesale pricing. Some examples developed more fully in the introductory paper for this series of white papers on retail pricing illustrate how the interplay of variability and pricing is happening differently in different places (Ela, Lew, and Linvill, 2023).

California and Texas are the electricity markets with the highest levels of renewables in the United States, a picture of where the country is headed with decarbonization. The California Independent System Operator (CAISO) has forecasted its "duck curve" since 2016, where renewables—particularly solar—make substantial contributions to meeting demand in the middle of the day, with a large ramp that must be met by higher-marginal-cost dispatchable resources as the sun sets.[12] High levels of solar lead to an abundance of energy on some days and an intense need for ramping resources as the sun goes down. These grid needs induce volatility in wholesale pricing. In addition, California regulators are seeking to grow flexible load and induce incremental electricity resource development to address the emerging needs by adopting default time-of-use pricing.

In Texas we can look to the Electric Reliability Council of Texas (ERCOT) for the wholesale price impacts of the boom-and-bust spot market in the presence of renewables, fossil units, and record-breaking demand. For example, in the summer of 2022, ERCOT's previous peak demand (recorded in summer 2019) was exceeded on literally dozens of occasions in a single season. Like California, Texas also saw significant intermittency in the performance of wind and solar which, in the presence of high demand, resulted in extreme wholesale prices.

In New England, states have strong climate ambitions, but they significantly lag the states described above in terms of renewable adoption. New England's historically high prices for the winter of 2022-2023 are being driven by geopolitics that drove fossil fuels to record prices. For example, National Grid in Massachusetts saw its utility rate nearly double from its previous winter rate, resulting in the highest rates in the continental United States of any investor-owned utility (Mohl, 2022). In addition to being at the "end of the pipe" for natural gas, New England also sees exposure to oil for peak electricity usage. In January 2022, more than 10 percent of the Independent System Operator of New England's electricity supply derived from oil—a double-digit figure that one typically sees only in developing economies.[13] New England customers pay both for the fuel and for the fixed costs of this infrequently used electric generating capacity through a rate design that does not signal the high cost of this fossil-fuel dependency at all.

The systematic patterns of time-varying performance associated with renewables (and of course demand),

12 See, for example, https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf.

13 This author preliminarily recommended an "Oil Peak Day" together with a tiered time-of-use rate structure to Massachusetts regulators to emphasize the dependency of New England customers on oil during certain days and times, appealing to New Englanders' sensibilities in obviating usage accordingly. NRG Letter (Sept. 26, 2022), Massachusetts Dept. of Public Utilities, Docket 22-BSF-D3, https://www.nrg.com/assets/documents/energy-policy/_2022/massachusetts-nrg-comment-letter-d.p.u.-22-bsf-d3-9_26_2022.pdf.

punctuated by periods of extraordinary demand and dependence on scarce fuels, suggest that time-varying retail rate design that attempts to represent these supply trends would feature both tiered time-of-use rates as well as critical peak prices. This would capture relatively consistent variations, as well as profound scarcity events.

Renewables are making net load look more curvaceous, legacy resources and geopolitics continue to drive capacity and fuel costs, and, at the same time, wholesale energy prices may widen to greater spreads. In this supply situation, retail prices are doing next to nothing to reflect these conditions.

Can Demand Save Itself from Higher Costs?

Electrification will amplify the challenges that exist in the modern electricity economy if rate design fails to evolve. This would be tragic, because the introduction of new loads responding to emergent price signals is an opportunity to make electrification throughout the economy more efficient, while also solving the other latent challenges of integrating a grid that has many renewables, infrequently used capacity, and a lingering dependence on volatilely priced fuels. As described more fully in the introduction to this white paper series, electrification of transportation, heating, and other processes also will drive additional requirements for capacity on circuits of the distribution system with newly electrified loads (Ela, Lew, and Linvill, 2023). Like for energy supply, the pricing of these network elements often has not been closely tied to their marginal cost—in this case, tied to longer-term investments in additional system capacity. Recent authoritative studies have spoken directly to the importance of retail rate design in a decarbonizing and electrifying energy economy.

PJM Interconnection, in its 2022 white paper on emerging characteristics of a decarbonizing grid, identified retail rate design as the second of five "key focus areas for the PJM stakeholder community"—and the only one squarely and exclusively within the jurisdiction of state regulators. Through modeling, PJM found stark evidence of the interrelationship between the reliability value of intermittent renewable investments and demand flexibility. If demand is responsive to price—which axiomatically it cannot be without time-varying rates or some other financial inducement to shift and reduce demand—PJM found that time-varying retail rate design reduced the amount of capacity procured overall and *tripled* the capacity contribution of solar in a scenario where electrification grows demand (PJM, 2022).[14]

If demand is responsive to price—which axiomatically it cannot be without time-varying rates or some other financial inducement to shift and reduce demand—PJM found that time-varying retail rate design reduced the amount of capacity procured overall and *tripled* the capacity contribution of solar in a scenario where electrification grows demand.

Next door, New York is reaching similar conclusions. The state's Climate Action Council suggests that meeting New York's clean energy goals will be expensive, requiring a $27 billion investment in new generation, transmission, and distribution. But an "unmanaged electrification" scenario, absent investment in demand-side efficiency and smart devices to activate that demand, will drive costs still higher—another $14 billion, for a total of $41 billion (NYSCAC, 2022, 8).

In order for demand to achieve these savings, demand will have to be reacting to differences in prices. Time-of-use rates should correspond to the costs that can be avoided by activating demand. Just like any act of utility ratemaking that fixes rates in advance for application over a period laden with uncertainty around actual marginal costs, there will be divergences between regulator-defined rates and actual marginal costs for energy measured by wholesale prices. However, as seen above, general trends of the variability of supply are emergent. Additionally, spot prices are not everything. The vast

14 Specifically, PJM forecasts an electrification scenario where currently high contributions of solar toward capacity, measured by an effective load-carrying capability methodology, deteriorate to 6 percent, but then are buttressed through demand elasticity (demand responding to retail price signals) to 18 percent. See PJM (2022), pp. 3-4.

majority of costs related to the capacity to produce energy when most needed, or to hedge the variability of supply, are incurred in advance—either through ownership of power plants whose costs are associated with the production of energy or through forward purchases from third parties.

A time-of-use rate can signal these costs. It can also recover long-run marginal costs associated with the distribution and transmission networks, often driven by either systemic or local peak demand. At the same time, another attribute of time-varying retail pricing, such as a critical peak price/rebate, can signal extraordinary inflections of the average trends described above. Together, prices that reflect both general trends of a cost structure and its major inflection points over time are the essential ingredients to rates that would better reflect the costs at issue in utility ratemaking.

A more sophisticated variation of time-varying network pricing is California's experimentation with truly dynamic, real-time prices for distribution costs. For example, Southern California Edison partnered with TeMix, Inc., to expose 100 customers served through a particular substation to rates that dynamically reflected scarcity when the system's distribution capacity was constrained, in addition to variably pricing energy supply. Meanwhile, as a cost-of-service-regulated utility, the rates associated with the regulated enterprise were designed to scale to recover no more and no less than the utility's revenue requirement (California PUC, 2022). The California Public Utilities Commission has since launched a comprehensive proceeding to consider whether this style of rate design should be propagated throughout the electric utility systems that it regulates, in addition to considering the role of intermediary firms in providing programmatic responses to these prices on behalf of consumers, and many other important questions (California PUC, 2022).

There are strong reasons founded on the traditional principles of utility regulation to employ time-of-use rates, because they more closely align to the cost-of-service accounting that governs utilities. However, for this rate structure to be effective, experience shows that it needs to be opt-out, as opt-in programs consistently show poor results.

Recent Regulatory Approaches to Time-Varying Rates

There are strong reasons founded on the traditional principles of utility regulation to employ time-of-use rates, because they more closely align to the cost-of-service accounting that governs utilities. In addition, time-of-use pricing is empirically demonstrated for its effects of shifting usage away from peak periods and toward off-peak periods. However, for this rate structure to be effective, experience shows that it needs to be opt-out, as opt-in programs consistently show low levels of enrollment.

Ontario and California have both implemented time-of-use rates as the default product for residential and small commercial customers. These are *opt-out* rates. Customers must take some positive action to avoid being placed on these rates. Likewise, Colorado and Michigan regulators have approved time-of-use rates on a default basis, though implementation is incomplete and targeted to 2023. For one of Missouri's utilities, state regulators have overseen the implementation of opt-out time-of-use rates in tandem with the installation of smart meters. Most recently, Hawaii adopted a an opt-out time-of-use rate. For all other customers of investor-owned utilities across North America, time-of-use rates are *opt-in*, if they exist at all. Despite these rates being more cost-aligned, customers must affirmatively self-select to use them, if the rate option exists at all. In these "opt-in" states, adoption rates remain very low, with only a 3 percent average enrollment rate for customers (Faruqui, Hledik, and Sergici, 2019).[15]

15 Other than the four U.S. jurisdictions described in this section, the only exception to these paltry enrollment levels appears to be Arizona, which combines elements of opt-out strategies to induce enrollment; for example, customers who receive a smart thermostat from the utility are defaulted to the time-of-use rate. See the white paper in this series by Hines et al. (2023).

In California, a pilot program found a 3 to 6 percent decrease in summer peak demand resulting from a pilot of opt-in time-of-use rates (George et al., 2018). The California Public Utilities Commission mandated a transition to opt-out time-of-use rates to begin in 2019, which was completed in 2022.[16] Prior to this, the enrollment in time-of-use rates in California under an opt-in model was paltry, not unlike the FirstEnergy Companies' record described in the introduction. In California, utility outcomes under opt-in enrollment ranged from 0.52 percent to 3.4 percent enrollment.[17]

Ontario's is the longest-tenured opt-out time-of-use rate program in North America, where this has been the default rate design since 2005 for all customers with smart meters, which are now ubiquitous. Customer awareness and responsiveness to the rate structure is substantial, as documented by research commissioned by the Ontario Energy Board (Ipsos Public Affairs, 2014, 12). These rates have also had their intended effect of reducing average demand during the summer on-peak period (Navigant, 2013).

Several other states have also decided to switch from opt-in to opt-out time-of-use rates. In 2015, Michigan's Public Service Commission ordered time-of-use rates to be available to customers on an opt-in basis.[18] The result was a disappointing pace of enrollment. The Michigan Public Service Commission has since ordered both major utilities in Michigan, Consumers and DTE, to implement time-of-use rates on an opt-out basis.[19] The story is the same in Colorado, where regulators determined that smart meter deployment by the state's largest utility, Xcel, should be accompanied by smart rates (Colorado PUC, 2022). Similarly, in Missouri's Ameren service territory, time-of-use rates will be introduced as the default option in tandem with the utility's smart meter deployment (Ameren Missouri, 2020). The same is largely true of Hawaii, whose Public Utilities Commission largely accepted Hawaiian Electric Companies' and consumer advocates' proposals to make time-of-use rates the default rate shortly after the installation of AMI on customers' homes and businesses. That process is expected to commence in 2023.[20]

In contrast, other jurisdictions have wallowed in pilot mode or adopted time-of-use rates only as an opt-in even when results of opt-out pilot programs have been clear successes. One example is Maryland, which in January 2017 convened a stakeholder process to explore a pilot. The pilot ran from June 2019 through May 2021, attracting 3,800 customers, with controls for self-selection bias (net energy metering customers were restricted to a certain percentage of the pilot, for example). The rate was designed to load distribution costs, transmission costs, and costs of the PJM capacity auction into the peak period. In Maryland, this meant a substantial differential between on- and off-peak between 4:1 at the lowest and 6:1 at the highest, depending on the utility. Demand reductions were impressive: reductions of 9.3 to 13.7 percent were seen during the summer months, when

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16 By June 2022, all eligible customers of California's three largest investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) had been transitioned to time-of-use rates. See https://energyupgradeca.org/time-of-use-faqs.

17 California Public Utilities Commission, Decision 15-07-001, p. 90, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.

18 See: *In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 401.11(3) et seq., with regard to DTE Electric Company*, MPSC Case No. U-17689, Order of June 20, 2015. Also see: *In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to Consumers Energy Company,* MPSC Case No. U-17688, Order of June 30, 2015, pp. 31-32.

19 See: *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief,* MPSC Case No. U-20134, Order of May 19, 2020, Exhibit A, p. 3. Also see: *In the matter of the application of DTE Electric Company for approval of its Advanced Customer Pricing Pilots,* MPSC Case No. U-20602, Order of Feb. 6, 2021, p. 6.

20 See: *In the matter of Public Utilities Commission instituting a proceeding to investigate distributed energy resource policies pertaining to the Hawaiian Electric Companies,* HPUC Docket No. 2019-0323, Decision and Order No. 38680 (Oct. 31, 2022), pp. 133-38. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22K01B04701A00323.

the PJM system peaks, and 4.9 to 5.4 percent during the winter months.[21] After these blockbuster results, however, the Maryland Public Service Commission ruled that the program should remain opt-in. The utilities expect to spend only a small amount of money to market the rate's availability and it cannot reasonably be expected that the rate will become the standard on its own. From the beginning of the stakeholder process to deciding to make the rate permanent, more than five years elapsed—a period of time as long as, if not longer than, the time spent to roll out the actual infrastructure of smart meters in the utilities' service territories.

One argument sometimes proffered against time-of-use rates is that social and equity concerns counsel against their widespread adoption. Yet in Maryland's pilot, which specifically recruited a sample of low-to-moderate income customers in order to evaluate these claims, the peak load reductions achieved through the pilot's time-of-use rate were "not statistically different" than reductions achieved by customers outside the low-to-moderate income sample. Across the entire pilot population, an impressive 9.3 percent demand reduction in weekday peak loads for Baltimore Gas & Electric was recorded (Sergici et al., 2021). These findings of tiered time-of-use rates are consistent with a Lawrence

An LBNL study of critical peak pricing found that vulnerable customers were just likely as the residential customer class as a whole to be responsive to time-varying rates and consequently obtained proportional benefits.

Berkeley National Laboratory study of critical peak pricing offered by two other utilities, Sacramento Municipal Utility District and Green Mountain Power, which found that vulnerable customers were just as likely as the residential customer class as a whole to be responsive to time-varying rates and consequently obtained proportional benefits (Cappers et al., 2016). As a collection of consumer advocates has concluded, "[r]esearch in most jurisdictions has shown that on average lower-income customers use less electricity, and use proportionately less electricity during peak periods. Such lower usage customers would thus benefit from a change in rate design from a flat rate to either an inverted tier rate or a time-of-use rate" (Colgan et al., 2017).

21 Letter from Work Group of the Maryland Public Service Commission, "In re PC44 Rate Design Work Group Leader's Report and Recommendations on Full-Scale Time of Use Rate Offerings" (June 3, 2022), Project No. PC 44.

Two Types of Retailers and Their Financial Incentives

One might expect that cost-of-service-regulated utilities themselves would have an incentive to activate demand in order to reduce the cost of serving it. After all, acting in their capacity as retailers, they must buy or produce energy on behalf of their retail customers, and one might think they would have an incentive to lower the costs of those purchases. Simply put, however, these utilities generally do not. To the degree an incentive ever existed at all, modern ratemaking has eliminated any financial advantage a utility might gain by reducing customer consumption during the most expensive hours to serve them. Now, only a perverse incentive exists to grow consumers' peak demand. Against this overarching incentive structure, regulators have occasionally chosen to respond with sporadic and weak countervailing measures, instead of forceful and consistent incentives around energy-supply costs. "Dumb rates" persist in no small part because of this political economy and incentive structure.

In states that have adopted retail competition, the incentives for competitive retailers are better aligned with those of the wider grid. If a retailer can activate customer demand in such a way that its supply costs are reduced, even while keeping its customers satisfied, it has a strong incentive to do so.

Meanwhile, in states that have adopted retail competition, where customers may choose their own supplier, the incentives for competitive retailers are more appropriately aligned with those of the wider grid. A dollar in reduced supply costs for a competitive retailer will mean an increased profit margin, more attractive price offers to retail customers, or both. Those savings can form the basis of inducements for customers to participate in voluntary demand-activation programs, even without time-of-use rates per se. If a retailer can activate customer demand in such a way that its supply costs are reduced, even while keeping its customers satisfied, it has a strong incentive to do so.

However, an incomplete restructuring of the industry has left these competitive retailers typically in the role of supplying only the commodity as a line item on a third party's bill—that of the incumbent utility. Even when competitive retailers do control the billing relationship with the customer, they often face exposure only to that portion of their customers' costs that is related to the generation and supply of energy. Costs related to the delivery of energy, or in some cases even in investments in generation capacity where reliability markets exist, often are simply passed through by regulatory design to end-use customers without any opportunity for intermediation by the retailer. In such a situation, anything a retailer might do on its own to activate demand will appear less economical than it otherwise might be, because the retailer is not in a position to capture the value of demand shaped around avoided transmission, distribution, installed power capacity, and other peak-related costs for which they occupy no position of financial responsibility because of regulators' retail-market-structure decisions.

The question this section explores is whether either of these business models has a full-strength incentive to activate demand on behalf of its customers to support the needs of the power grid. This question is essential because it weighs heavily on what outcome is appropriate:

- Whether utilities and retailers have sufficient incentives to rationally activate demand, or
- Whether time-varying prices must inevitably be pushed down to consumers, should utilities and retailers themselves lack the incentive to do anything about it themselves.

Cost-of-Service-Regulated Monopolies

Traditional utility ratemaking is governed by the concept of a "stated" or "filed" rate. The rate a utility is permitted to charge is static until and unless a utility successfully gains approval of new rates from its regulator. In this model, the utility bears the financial risk associated with any deviation from the revenue generated by those rates, when billed to and collected from customers, and the costs of actually producing, buying, and delivering the electricity needed to serve those customers.

A central characteristic of this form of regulation is that, in general and over time, utility revenues are supposed to match costs—but they never perfectly do. That is a feature and not a bug. The utility has skin in the game, and reductions or increases in costs would be captured by or charged to the utility and not just its customers. Alas, this idealized form of regulation hardly exists any longer. If this form of regulation still existed for the fuel to run power plants and the power purchased and sold at the wholesale market to fill in gaps in a utility's supply-demand balance, the utility would have a profound incentive to try to activate its customers' demand in times when the wholesale price rose above the retail rate at which the utility was obliged to sell them power. That is because the utility, under this bygone regulatory regime, was financially exposed at the margin to fuel and wholesale power prices on behalf of its customers.

Fuel and Purchased Power Trackers: The Absence of Incentive

That incentive has been radically transformed in the past half-century. These monopolies now universally enjoy ratemaking mechanisms colloquially known as "trackers" or more formally as "adjustment clauses," typically designed to recover every dollar of fuel and purchased power costs that utilities incur. Utilities with a fuel-and-purchased-power tracker have no meaningful financial incentive or exposure at the margin, because they are able to surcharge these costs to customers after the fact when present rates are not sufficiently high to recover them. These trackers are more formally a style of deferred accounting that does not exist in more competitive markets, where businesses find it untenable in the presence of competitors to attempt to recover past losses in future prices. But regulation and monopoly make that possible, and it bears re-emphasizing: These trackers did not exist at one time, but they now are ubiquitous. Literally every state in the union that has a rate-regulated energy-supply service provided by a utility employs such a tracker (RRA, 2019).

Regulators continue to have tools at their disposal to disallow imprudently incurred fuel and purchased power costs, even in the presence of a tracker. However, the exercise of this power has become largely theoretical. During the rapid natural-gas price escalations of Winter Storm Uri, Colorado's largest utility, Xcel, "did not issue conservation messaging."[22] Despite finding that it should have, the regulator authorized the full recovery of the utility's costs from customers, coming up with a variety of rationalizations about how this messaging would not necessarily have led to reduced costs.[23] Indeed, in this once-in-a-generation run-up on prices, only a single regulator, of approximately 15 states impacted, made any meaningful disallowance of fuel and purchased power costs, and then only a small fraction of the total costs incurred.[24] In any case, ad hoc disallowances are somewhat beside the point; the long-shot possibility that a cost might someday be disallowed obscures the sad norm that the customers who ultimately pay high prices have no visibility to them, and the utility that does have visibility into wholesale prices is not actually exposed to them except in truly extraordinary circumstances.

There is no real replacement for the incentives provided by a consistent exposure to full-strength marginal costs.

22 *In the matter of the application of Public Service Company of Colorado for recovery of costs associated with the February 2021 extreme weather event for its electric and gas utilities,* Colorado Public Utilities Commission, Proceeding No. 21A-0192EG, Decision No. R22-0279, ¶ 189.

23 *Id.*, ¶¶ 189-190.

24 These proceedings remain in litigation, with utilities having vowed to appeal the regulator's decision (Minnesota PUC, 2022).

Utilities do not have that exposure, and sadly cannot ever again be expected to have it.[25] That leads inexorably to the first policy reform described in this paper's policy recommendations below, because if utilities are not genuinely exposed to marginal costs to inform their behavior, *someone* must be. Prices based on marginal costs must be handed down to consumers.

Peak-Related Capital Investments: A Perverse Incentive

A fuel-and-purchased-power tracker renders a utility indifferent from a financial perspective to the energy costs that activating demand might avoid. Layered on top of this general indifference is a countervailing incentive that actively works against the activation of demand. The net result is a landscape of utility regulation that makes utilities subject to modern cost-of-service regulation incentivized against demand activation.

As described above in the studies that PJM and New York have performed (PJM, 2022; NYSCAC, 2022) an active demand side will reduce the size of capital investments that otherwise would have to be made in delivering and producing electricity. These capital expenditures are the source of profit for the modern electric utility.[26]

The profits of a typical investor-owned utility in the United States are closely tied to making capital investments in "rate base"—the sum of which, less accumulated depreciation, is the basis for the utility's return in the classical formulation of the ratemaking process. Indeed, most investor analysis of regulated utilities treat the growth rate of rate base as a close proxy for the company's overall growth in earnings, because the two are so closely linked. The other key variable is what percentage rate of return a regulator will authorize to be applied to that rate base. The product of the sum of all capital expenditures in rate base, multiplied by the authorized return, is then built into the prices that a monopoly is permitted to charge its customers. Making these capital investments is not just the engine for utility profits; any given dollar of rate base addition has also become relatively more profitable in the last two decades, with a growing premium above a benchmark "risk-free" rate and with returns rising in comparison to what other regulated utilities around the world earn as a profit margin (Dunkle Werner and Jarvis, 2022). Incredibly, profits on capital expenditures have grown even as utilities have outsourced business risk to consumers through mechanisms like the trackers described above.

If utilities are not genuinely exposed to marginal costs to inform their behavior, someone must be. Prices based on marginal costs must be handed down to consumers.

The incentives, then, are as follows: A utility regulated under today's prevailing ratemaking practices is permitted to make a supranormal profit on capital investment, including those capital investments justified on the basis of serving a growing peak demand. But a utility is not able to capture any margin associated with reduced energy costs, including by reducing its customers' peak demand and thereby the utility's cost to serve them; to the extent utilities face any incentive to manage their energy costs, it is not being driven by profit considerations. In this contest of incentives, it is obvious which incentive will prevail. One should not hold out any great hope that an active demand side has a path to fruition through such utilities working under the incentive structure created for them. It will require regulatory initiative.

25 One small thing policymakers can do to put some skin *back* in the game for these monopolies is to make them accountable for at least some fraction of the deviations from a baseline of fuel and purchased power costs, instead of "tracking" them entirely. However, even this attempt tends to run aground against staunch utility opposition. In my own experience as a regulator, certainly the most hard-fought accomplishment was to achieve just a modest sharing mechanism that would have caused the utility to absorb any "overs" and "unders" within a particular band of costs, and then only 10 percent of any deviation beyond that band. That fight sprawled across multiple sessions of the Montana legislature and Commission proceedings alike. Hardly any state, once having adopted such a tracker, has ever made any push to return utility incentives to something like a normal business would face to manage its costs.

26 Utilities that also have a regulatory construct that allows them to own their own power generation resources as a general practice also will face this same perverse incentive as it relates to energy supply and not just delivery.

Competitive Retailers

Unlike regulated utilities, competitive retailers[27] do face exposure to energy costs. They may pursue a variety of hedging strategies, but typically they will always face exposure at the margin even if they enter into hedging arrangements. This incentive is strongly aligned for demand activation. But in many jurisdictions a retailer manages only energy-supply costs, and not other charges that can be avoided by demand flexibility. Additionally, in the United States, the retailer is usually intermediated by a third party—the incumbent utility—in the ultimate billing relationship. with the retail customer. This retail market design thus presents a serious challenge. If a retailer is only responsible for a small portion of the customer's overall bill—the energy-supply costs but not transmission, distribution, or capacity costs—this constrains investments the retailer might make, or products it can offer, to tap into sources of demand flexibility.

Marginal-Cost Exposure: A Profound Incentive

Competitive retailers have no "tracker" that allows them to surcharge their customers when their past revenues failed to cover their past costs. Marginal-cost exposure becomes especially profound when two overlapping phenomena occur: energy prices rise as supply grows scarce, and supply grows scarce because demand has grown in the face of extreme weather or the unavailability of power generation resources. These phenomena are happening more and more often. Under these market conditions, retailers face a potential double-whammy, needing to serve above-average demand at higher-than-usual wholesale prices, but under contractual terms that do not allow them to flow-through or track these costs to their customers. The incentives appear to be well aligned for demand activation.[28]

Retailers face a potential double-whammy, needing to serve above-average demand at higher-than-usual wholesale prices, but under contractual terms that do not allow them to flow-through or track these costs to their customers. The incentives appear to be well aligned for demand activation.

The typical retailer business model is to offer residential and small commercial customers a fixed term and a price structure set forth in advance of the period of usage—either a flat rate or a time-varying rate whose parameters are known in advance, either for one or more years, or at least for any given month. Contrary to the mislabeling of competitive retailers as "unregulated providers," they are subject to substantial regulation that restrains their ability to shift risk to their customers. For example, in Pennsylvania, the largest competitive-retail market in the eastern United States, regulators have adopted a rule colloquially known as "fixed means fixed," prohibiting retailers from including any provisions in their retail contracts that allow them to surcharge customers or change their contracted-for price, even if energy prices, transmission rates, or capacity charges increase.[29] Other laws and regulations, such as the one Texas adopted in the wake of Winter Storm Uri, prevent any pass-through of indexed energy prices to mass-market customers.[30] Ironically, competitive retailers are in this respect subject to more sweeping prohibitions on their pricing activity than cost-of-service-regulated monopolies, since the latter ultimately may pass through the entirety of their

27 Where I simply refer to "retailers" in this section, I mean competitive retailers who do not have a captive base of customers and are generally not subject to regulation that intends to set the prices they offer based on regulators' judgments of cost, even if regulators may exercise substantial regulation, as described below.

28 One notable exception to this is a utility without AMI altogether, where a retailer would be billed for its end users' demand based on a load profile. Here, a retailer might have a general incentive for conservation within a month, after which a single meter reading is taken, but no particular incentive to save at times or days of extraordinarily high prices. Remarkably, restructured retail states like Massachusetts, New Jersey, and New York still have not ubiquitously installed AMI, even while others, like Pennsylvania and Maryland, have. Finally, even with AMI, a regulator will have to have made the decision to actually bill based on the actual demand of retailers' customers. It is consequently possible that PJM would allocate costs to a particular transmission-owning utility based on its coincident peak demand, but then load-serving entities within that transmission service territory would not encounter the same allocation, broken down to their level.

29 Pennsylvania Public Utility Commission, *Guidelines for Use of Fixed Price Labels for Products With a Pass-Through Clause,* Docket No. M-2013-2362961 (Order entered November 14, 2013).

30 H.B. 16, 87th Leg., Reg. Sess. (Tex. 2021), https://capitol.texas.gov/tlodocs/87R/billtext/pdf/HB00016F.pdf.

TABLE 1

Average Uri Costs Incurred per Residential Customer

Entity Type	Average Impact of Winter Storm Uri per Residential Customer
Power competitive suppliers, Texas	$82
Power utility monopolies, Texas	$498
Gas utility monopolies, Texas	$351
Power utility monopolies, all Uri-impacted states	$283
Gas utility monopolies, all Uri-impacted states	$342

Source: Sharfman and Merola (2022).

marginal cost exposure to customers while competitive retailers typically may not.

An especially profound example of retailers' role in intermediating the risk of the wholesale and retail markets emerged from Winter Storm Uri. In the introduction to this paper, I surveyed the exception to the rule, Griddy, which washed its hands of any intermediary role—using AMI to expose its customers directly to wholesale prices. But more than 99.5 percent of residential and small commercial retail customers in the ERCOT competitive market were served under the fixed-rate products described above, and not a product where retail prices were directly indexed to wholesale prices (Sharfman and Merola, 2022, 26). In other words, it is retailers' problem if wholesale prices rise above their retail fixed prices and those retailers are left unhedged, or "short," as extreme weather drives up their customers' demand. A popular aphorism among retailers' supply desks is, appropriately enough, "long and wrong, or short and fired."

For that reason, many competitive retailers went bust in the wake of Winter Storm Uri (Sharfman and Merola, 2022, 27). Not a single investor-owned utility did. The only difference is whether regulation permitted the pass-through of costs to customers—or not. The ratepayer impact to residential customers of competitive retailers in Texas was less than it was for ratepayers of ERCOT's remaining monopolies, Texas's monopoly gas utilities, and indeed other states' monopoly power and gas utilities whose wholesale purchases were affected by the storm (Table 1). The fact that retail competition existed in much of Texas protected consumers from an even worse outcome of the brutal winter storm (Sharfman and Merola, 2022, 6).

Missing Incentives from an Incomplete Restructuring

Retailers do not always bear exposure to the full range of costs needed to provide customers energy. In many restructured markets in the United States with retail competition, the competitive retailers are responsible only for intermediating energy supply costs. This drives a profound incentive to manage those costs through dealmaking on the supply side and innovative offers on the demand side; however, for delivery costs and even generation capacity costs—both of which are typically incurred on a demand-related basis—retailers have no ability to monetize demand-based reductions in those costs because those rate elements are merely passed through to customers.

In PJM, transmission costs are billed to the retailer for the aggregate demand of the customers it serves. If a retailer in PJM can reduce the peak demand of its aggregate portfolio of customers, it will consequently reduce the transmission and capacity costs to serve it.[31] In the other eastern restructured markets, the New York Independent System Operator and the Independent System Operator of New England, transmission costs are passed through directly to residential and small commercial customers. If a retailer were to offer a demand-response retail product to its customers, it would obtain no financial advantage from activating this demand to reduce those transmission charges.

Additionally, in practically all of the eastern markets, the incumbent utility bills customers directly, and retailers' energy-supply charges are merely rolled up to that utility's bill to a retail customer. This style of utility-consolidated billing has at least three negative effects related to a robust retail trade in demand-flexibility products. First,

31 See footnote 28.

it makes the retail competitors' product obscure, often listed only as a single line item at the back page of a customer's bill. Second, it completely eliminates the retailer role in managing a utility's distribution rates, even in those places like PJM that may otherwise make transmission and capacity costs the responsibility of a retailer. Third and finally, in this model, the utility typically purchases the supply-related receivables of the competitive retailer, on the sound logic that if it is the entity responsible for billing and collecting charges from a retail customer, it should own all the receivables appurtenant to that bill. In this kind of retail market design, the retailer has less interaction with its customers in general, and indeed has no direct financial relationship with a consumer at all. It is relegated to being a mere commodity supplier whose "retail" services are in fact rebilled by someone else. These three obstacles can deprive a retailer of being in a strong position to offer bundled or interactive products that focus on the demand side of the retail market. Retailers have a clearer pathway to product innovation when they truly own the retail customer relationship and are responsible for billing their customers for all charges. This model, called supplier-consolidated billing, exists in North America only in Texas, Alberta, Georgia, and most recently Maryland (Kavulla, 2022).[32]

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Even in ERCOT, a particularly advanced retail market, transmission and distribution costs are simply passed through to customers. ERCOT designs its transmission rates so that the costs of the grid are entirely allocated to customer usage at the peak hours of each of the four summer months, an allocation and rate design methodology known as Four Coincident Peak (4-CP). Interestingly, 4-CP rates do face large commercial and industrial customers directly, and active customer efforts to avoid those charges are responsible for the majority of demand response achieved in ERCOT each year (ERCOT, 2021).

For residential and small commercial customer classes in ERCOT, however, 4-CP is employed only for cost allocation purposes. The actual transmission rate that any customer within that class will be charged is derived by taking the customer class's total allocated costs, dividing it by the kilowatt-hours the class consumed in a prior period, and deriving a cents-per-kilowatt-hour rate. That rate is then passed through directly to customers without any intermediation by retailers. Put another way, if a residential customer in the Texas competitive retail market saves energy during one of the 4-CP hours, the customer will only receive a 1/8,760th reduction (that is, one hour of the 8,760 in a year) in the transmission costs it is billed, and not the 1/4th reduction that a large commercial or industrial customer would achieve.

This transmission rate design may make sense from the perspective of policymakers who do not wish to expose less sophisticated customers directly to demand charges. However, in a competitive retail market, that need not be the choice on the table; the retailer could be exposed to 4-CP demand-based transmission rates, even while having to price them into a cents-per-kilowatt hour rate offer to its retail customers. In such a scenario, the retailer would then retain the incentive resulting from exposure to transmission costs at the margin, and would be incentivized to do what was necessary to get its customers to reduce their demand, such as by offering products and shared savings for customers who had devices automated at the behest of the retailer in response to this demand.

Indeed, retailers that offered to shield customers from difficult-to-understand demand charges, but offered some other service that allowed them to flex demand automatically around the relevant 4-CP hours (like through smart thermostats) could prove attractive to customers, and the approach profitable to retailers. Yet because retailer-offered programs do not allow either customers or retailers to avoid 4-CP transmission costs

32 In Texas, only electricity is open to retail competition, while for Georgia, competition is limited to natural gas. Alberta allows retail competition and supplier-consolidated billing for both commodities, and Maryland's implementation, to be complete in December 2023, focuses thus far on electricity, and is optional on the part of retailers. For a fuller discussion, see Kavulla (2022).

Nowhere do competitive retailers face full-strength incentives around the marginal cost to provide all of the products that its customers need, and which together constitute electricity service from the power plant, to the grid, to the smart meter, and on into the appliances in one's home.

at all, Texas's retail market design removes more than half of the value that programs like retailer-offered smart thermostats could otherwise monetize, as I explore in the policy recommendations section below.

The upshot is that nowhere do competitive retailers face full-strength incentives around the marginal cost to provide all of the products that its customers need, and which together constitute electricity service from the power plant, to the grid, to the smart meter, and on into the appliances in one's home. The importance of this missing incentive is magnified because, at least until very recently, the costs of energy supply have been declining even as the rate elements associated with energy delivery have been increasing. For a sample of 37 utilities in the PJM, New York, and New England footprints, delivery rates typically began the 2010s lower than energy-supply rates, but by the end of the decade these delivery rates were higher than energy-supply rates in nearly each one of these utilities (Sharfman, 2022). Looking at this sample over the past decade, delivery costs for mass-market customers grew 46 percent in PJM, 32 percent in New York, and 27 percent in New England—all while energy supply costs fell (Sharfman, 2022, 2).

Finally, competitive retailers, to make demand activation work, may have to make investments—such as buying smart thermostats and paying customers a bill credit or other remuneration to get them installed and activated in their homes. Of course, in a competitive retail market, customers may shop around and may "strand" the demand-activation asset that a retailer has paid for. Too bad: Customer choice is the foundation of the competitive retail markets. However, the additional risk of stranded assets in competitive markets means that having truly full-strength price signals around all cost elements required to serve customers is crucial for demand activation to really have a chance. Alternatively, it may mean that investments in the "hardware" of demand activation—smart thermostats are again a profound example—should be borne through transmission and distribution costs and be interoperable across retailers who manage the "software" of demand activation. These considerations are more fully explored as this paper moves to a discussion of specific policy recommendations.

A Reform Agenda for Retail Rate Design and Market Structure

Two business models occupy the space of the electricity industry involved in providing retail service to customers: the utility that has its costs more or less fully recovered through regulated rates, and the competitive retailer that has a greater opportunity to make a profit or a loss at the margin in serving its customers.[33] An easy, and proper, solution to ensure appropriate attention to demand is to put it to competition at retail, in the same way that generation costs are disciplined by a competition at wholesale. But this paper takes the status quo of a hybrid market as a given, where some states have utility monopolies, others have competitive retailers, and quite a few have both. Consequently, let us consider the reforms based on the business models at hand and in full awareness of the incentives that face them.

REFORM 1

Make Time-Varying Rates Opt-Out for Regulated Utilities and Default Service Providers

Regulated utilities, acting as a representative for demand, typically lack a persistent and routine incentive to manage the fuel and purchased power costs they face because those costs are passed through in the trackers that are now commonplace in utility regulation. The flat, round-the-clock prices that utilities charge likewise convey no incentive to customers to shift usage between times when the cost to supply them is higher or lower.

A utility with an earnings model that is indifferent to the cost to serve demand cannot be expected to activate demand in ways that reduce those costs. So regulators must take the initiative.

Utilities thus cannot be expected to care about economically efficient rate design. It simply is not core, or even positively correlated, to their earnings model. As one utility CEO candidly observed following a major wholesale price shock: "Because the higher natural costs are pass-through costs for our business, they did not impact this quarter's utility results. . . . We are off to a great start for the year. So let's check the utility earnings box as being on track" (Edstrom, 2022, 6).[34]

The Necessity of Regulatory Initiative in Rate Design

A utility with an earnings model that is indifferent to the cost to serve demand cannot be expected to activate demand in ways that reduce those costs. So regulators must take the initiative. The obvious way to do so is to proactively require the adoption of rate designs that will encourage a more active demand side even if the utility does not lift a finger to otherwise encourage it. As I describe above, such decisions are well founded in the

33 A reader may ask where public- or consumer-owned utilities fit into this dichotomy, and the answer is, it depends. While their rates are generally cost-of-service-based, they lack traditional profit incentives altogether, and one must typically examine them through a lens of institutional incentives, which are open for debate and multifarious throughout their industry. To the extent their rates may be adjusted to cover past losses, to the extent they possess a monopoly, and to the extent that no manager bears strong direct financial responsibility for losses, then I would tend to classify them for my purposes here as being similar to the cost-of-service-regulated, investor-owned utilities I discuss in this paper.

34 Quoting the transcript of CenterPoint Energy Q1 2021 Earnings Call (May 6, 2021), https://cubminnesota.org/wp-content/uploads/2022/06/CUB-CP-Energy-Transfer-White-Paper-updated-5.31.22.pdf.

basic philosophy of ratemaking, which is that the prices of cost-of-service-regulated industries should relate to the costs when and as the service is being provided. Prices are not simply intended to be a vessel for revenue adequacy on the part of the utility.

Despite major investments in smart meters, only a paltry enrollment onto time-varying rates has been achieved: Single digit percentages, if that, are the norm in each jurisdiction with opt-in time-varying rates that require some positive action on the consumer's part. Meanwhile, opt-out jurisdictions achieve nearly universal enrollment. Consumers were not given a chance to opt-in to smart meters. They had a chance, instead, to opt-out of the installation of this hardware, at least in certain jurisdictions. The software of rate design should follow the same logic as the hardware that it rides atop.

Government always has a role in the "choice architecture" facing consumers, whether acknowledged or not. As the Nobel laureate Daniel Kahneman observed, "the default option is naturally perceived as the normal choice," often relegating alternatives to an obscure destiny (Kahneman, 2011). By requiring a consumer to make an affirmative choice to adopt a more complicated, but also more cost-reflective rate, state regulators are in effect deciding that such time-varying rates will be vastly undersubscribed. These regulators are making a decision to use more expensive fossil-powered energy, retain more expensive capacity, and spend more on delivering that energy, and they are doing all this while delaying the customer familiarity with time-varying rates that will be necessary in any energy transition that avoids a massive and impractical overbuild. To rectify these things requires regulatory courage to make time-varying rates the opt-out.

The exact parameters of the time-varying rate design that a regulator may select is, meanwhile, best left to the regional differences in cost structure. But in general, a time-of-use rate with a critical peak price add-on is a reasonable compromise to face customers with both routine contours of price differentials, including demand-related portion of transmission and distribution investments that can be allocated to peak periods (the time-of-use rate) and with events representative of unusually stark scarcity conditions (critical peak price).

Utility Supply Service in Restructured vs. Monopoly Markets

Most residential and small commercial customers continue to take service from the incumbent utility even in places open to retail competition.[35] This retail service is cost-of-service regulated and goes by a variety of names in the restructured jurisdictions, such as basic, standard-offer, or default-supply service. In these circumstances, the time-varying rate should *be* the basic-service, standard-offer, or default-supply product. Customers may "opt-out" by shopping with a third-party retail supplier that does face incentives, and that—if it sells a flat-rate product—is agreeing to absorb the risk that a customer may use a great deal of energy during peak times when the wholesale cost is very high, which would shift costs onto that retailer. Multiple utility-sponsored rate offerings in these jurisdictions would be confusing and redundant, muddying the waters on consumer shopping by introducing numerous "default" products sponsored by the incumbent utility.

Meanwhile, for utility-monopoly jurisdictions, public policy considerations may dictate that consumers be allowed to opt out of time-varying rates and instead

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35 Again, this stickiness has a lot to with regulatory policies that have made incumbents the provider of *first* resort—a default option, rather than a genuine provider of last resort. The exception is Texas's ERCOT, where default rates were set at levels that encouraged shopping and where utilities are foreclosed from competing in the competitive retail market, though they continue to have ratepayer funds reserved for demand-side conservation activities.

purchase a round-the-clock flat-rate product offered by that utility. Just like smart meter tariffs often permit customers who pay a special fee associated with the labor and technology costs of manual meter-reading to avoid smart meter installations, customers who elect to avoid a more cost-based time-varying rate should expect to pay a risk premium associated with the possibility that their energy usage during critical times will be higher. This risk premium should be determined, wherever possible, by a market mechanism (e.g., putting out this set of opting-out customers to bid through a full-requirements contract).

A Word of Caution: Real-Time Retail Pricing

Real-time pricing to end-use customers is possible, but politically fraught—at least without some other type of intermediation. Griddy's collapse in Texas endangered the entire framework of customer choice, and Texas's political response—one that would happen in virtually every state under similar conditions, I posit—was to go quite a ways further than outlawing total real-time price exposure, and prohibited any residential or small commercial customer exposure to electricity-wholesale price indexes generally. Thus, for example, it is now arguably unlawful for residential customers to be paid a rebate based on their actual savings in the wholesale market, and more approximate approaches are instead developing, such as flat or graduated rebates that are not directly tied to wholesale price indexes.

Experiments in real-time pricing are ongoing. Illinois's ComEd and Ameren have day-ahead hourly price offerings.[36] California has also authorized a pilot, and one of its state regulators has spoken of "scaling demand flexibility under a comprehensive policy roadmap that encompasses a unified universally accessible dynamic economic retail electricity price signal": a mouthful, but as clear a vision as any state regulator has articulated.[37] The state has a major, ongoing proceeding in this regard.[38] For customers who have an array of smart devices that automatically interface with highly dynamic prices, these rate designs could be quite advantageous. But as Texas shows, all these experiments are just one wholesale price blowout away from screaming headlines that will engender a massive political backlash.

It is prudent to rely on a properly incentivized intermediary—which is to say, a retailer or something like one—to step into the breach between this volatile retail rate design and the customer. The presence of a retailer can shield a customer from extreme risks, even while sharing savings to the retailer's and the customer's mutual advantage.

Instead, it is prudent to rely on a properly incentivized intermediary—which is to say, a retailer or something like one—to step into the breach between this volatile retail rate design and the customer. The presence of a retailer can shield a customer from extreme risks, even while sharing savings to the retailer's and the customer's mutual advantage. The retailer can also act as a band conductor for the major automated services that are resident in a customer's home or business, while owning or contracting for the platform services of a distributed energy resource management system.

REFORM 2

Ensure That Competitive Retailers Are Exposed to All Relevant Grid Costs

Competitive retailers are exposed to marginal price signals for energy, but not always for transmission, distribution, and generation capacity costs. The lack of retailer exposure to all costs relevant to providing a retail customer with electricity service will diminish the retailer's incentive and ability to activate demand—even if the incentives for energy supply itself are well aligned.

36 See, for example, https://hourlypricing.comed.com.

37 Darcie L. Houck (California Public Utilities Commissioner), Twitter post, July 1, 2022, https://twitter.com/HouckCPUC/status/1542979017011212288.

38 California Public Utilities Commission, *Rulemaking to Advance Demand Response through Electric Rates*, R.22-07-005, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K285/496285639.PDF.

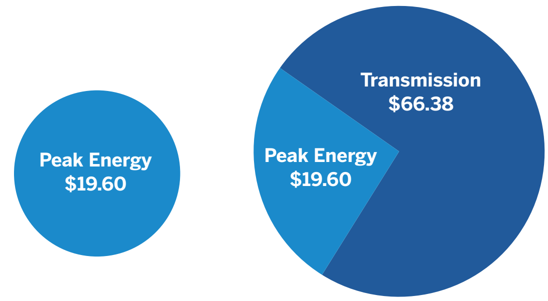
Consider a not-so-hypothetical case study from ERCOT in the presence of the regulatory incentives described above. In this case, a retailer has taken the initiative of installing a smart thermostat in one of its residential customer's homes at a cost of $100—perhaps as part of an attractive offer of service, where the retailer is given the ability to activate the smart thermostat during only the peak hours of the summer in order both to reduce the retailer's costs to supply the customer and to share some of those savings with the customer. In general, however, the retailer has agreed to sell the customer electricity at a flat rate of 10 cents per kilowatt-hour for a one-year term.

Let us further posit that it is a hot summer, and in each of the peak hours of the four summer months in ERCOT, the wholesale price reaches the cap of $5,000 per megawatt-hour.[39] The retailer activates the smart thermostat, which achieves a 1 kilowatt savings in each of these four very hot hours. The savings from energy thus are $19.60, assuming a $0.10 per kilowatt-hour flat-rate retail contract.[40] There are additional savings from reducing demand by 1 kilowatt, as these hours are the 4-CP hours on which transmission cost allocation is based—but due to the utility regulatory decision to flatten this rate and pass it through to retail customers, neither the retailer nor its mass-market (residential or small commercial) customers may avail themselves of any advantage around avoiding transmission costs by flexing a smart thermostat (or any other source of demand). At transmission rates in ERCOT as of this writing, a 1 kilowatt reduction in those four peak hours would translate to a $66 savings—that is, if residential customers or their retailers were actually exposed to this transmission rate design (as described above, neither is, even though large commercial and industrial customers are).

Figure 3 illustrates the effects of the missing piece of the pie for the retailer exposed only to savings around energy and not transmission. Such a retailer is going to have a dramatically reduced ability to monetize any smart thermostat investment that it might make.

FIGURE 3

Potential Savings from a Retailer Able to Monetize Transmission Avoided Costs



An illustration of the the savings that accrue to a retailer that installs a smart thermostat in a residential customer's home at a cost of $100. If the retailer is exposed only to savings around energy costs, it saves $19.60 during the hypothetical four peak demand hours (left). If, however, it is exposed to savings around both energy and transmission costs, it saves more than $85 during the hypothetical four peak demand hours (right), dramatically improving its ability to monetize the smart thermostat investment.

Source: NRG Energy.

In the above scenario, it is not realistic to expect a retailer to make a $100 investment in a smart thermostat to gain the possibility of $19.60 in annual energy margin savings, which still must be shared with the customer—a customer who could always shop away from the retailer before the cost of its smart thermostat investment is recovered. Meanwhile, it is conceivable that a retailer that stands to gross more than $85 in annual benefits will invest $100 in a smart thermostat, while still having money left over to compensate the customer through shared savings for the automated control of the customer's thermostat during certain hours.

The major proposition of this paper is that someone, somewhere must bear the exposure to all relevant costs on behalf of demand if demand is to have a real chance to participate in a two-sided market. But many states have chosen, even in the context of introducing retail competition, to continue to simply pass through certain flat charges to consumers. Often, in the name of making

39 This was recently reduced from $9,000 per megawatt-hour, but still stands as the highest price cap of any North American electricity market. Yet even so, as seen in this example, avoided energy margins in a few hours hardly constitute particularly large savings for reasonable estimates of demand reductions at the premises of a residential customer using air conditioning.

40 $5 per kilowatt-hour of wholesale benefit minus $0.10 per kilowatt-hour in foregone retail revenue, this difference multiplied by the four hours.

The major proposition of this paper is that someone, somewhere must bear the exposure to all relevant costs on behalf of demand if demand is to have a real chance to participate in a two-sided market.

such rates digestible to mass-market customers who have no particular desire to closely track their demand day-in, day-out, regulators will alter what had been a demand-based cost allocation (per-kilowatt during peak hours) into a rate designed to be a flat and volumetric energy charge (per-kilowatt-hour) on the customer's bill. This may be right in the name of important principles of easily understood and simple rates, if indeed such a charge were to be passed along directly to an end-use customer. However, in the presence of an intermediary retailer that is in a position to understand a more complex rate and bear the retail pricing risk associated with it, and that may rationally invest and optimize in demand activation at scale to reduce demand, the integrity of demand-based cost allocation should be preserved in the rates for these grid costs. Those rates should face competitive retailers on behalf of customers, and retailers could then be left with the dilemma of how to bake those costs into retail price offerings while at the same time making investments and taking other steps to activate demand.[41]

Unlike cost-of-service-regulated utilities, where regulators must take the initiative to design retail rates that appropriately reflect all costs, competitive retailers have a natural incentive to balance the competing interests of attracting customers while managing the costs they are exposed to. It need not be regulators' job in this case to ensure that a particular time-varying rate is widely extant, but instead to ensure that a full-strength price signal representing the time-varying costs of all electricity services and needs faces the retailer. This provides an incentive for retailers to activate demand in an economically efficient manner and thus build ways to reduce these costs in the plans and products they will offer to customers across the competitive retail landscape.

REFORM 3

Put Competitive Providers in Charge of the Customer Bill

Would we see the same set of products and services in the communications space if they all had to be billed through AT&T? A crucial feature of restructured, competitive-retail markets is who is authorized to bill customers for their charges. Supplier-consolidated billing, which allows whomever is the competitive supplier to act as the billing agent, allows different retailers to visibly brand their products, leading to greater product differentiation. Demand flexibility is a product that is contingent on customers' willingness to subscribe to a product, buy an appliance, or change their behavior. If the retail energy plans that are being sold to customers are simply relegated to a line item on the back page of a monopoly utility's bill, that marketplace will be hampered. Indeed, a fair number of customers may never end up knowing the competitive marketplace exists.

An energy bill may only get a few seconds attention from a typical consumer. But it matters. Seeing a brand and a style on an envelope, and getting relevant information in the bill itself continue to be the primary way—and of course the only financially binding way—in which information is conveyed to retail electricity consumers. There should be space enough in the retail market design to represent different products in different ways. While at one time, the absence of smart meters meant relatively little product differentiation, there is now technological capability for innovation—and those innovations will necessarily have different "looks," which regulators should permit. For example, there are profound differences between billing a tiered time-of-use price structure, like this paper proposes for cost-of-service-regulated utilities, and a subscription-based product with added inducements to further reduce the flat charge by installing and

41 I write on the premise that demand charges imposed on residential and small commercial customers directly are unlikely to be popular, and therefore competitive retailers—whose business in trade is attracting and retaining customers—will do something to intermediate these charges, either because it is good for business or because the regulator were to require this kind of intermediation.

Meanwhile, this paper does not take a position on rate design for grid costs per se. It may well be appropriate to have 12-CP, or average energy-and-demand, or even recognize that some grid costs are incurred entirely to supply energy and are not demand-related. But inasmuch as utility regulators have determined to allocate costs to a demand function, putting someone in a position to manage and avoid those costs is a better alternative than simply translating them to purely volumetric, per-kilowatt-hour charges that pass through to customers.

Demand flexibility is a product that is contingent on customers' willingness to subscribe to a product, buy an appliance, or change their behavior. If the retail energy plans that are being sold to customers are simply relegated to a line item on the back page of a monopoly utility's bill, that marketplace will be hampered. Indeed, a fair number of customers may never end up knowing the competitive marketplace exists.

automating certain smart devices, which a competitive retailer might instead offer.

Additionally, supplier-consolidated billing reinforces that a competitive provider is ultimately responsible for collecting revenue associated with its cost structure. If this is not the case, and billing instead is done exclusively by an incumbent monopoly, a moral hazard created through a lack of incentives tends to re-emerge: Retailers' receivables are purchased by the utility acting as the billing agent, retailers become indifferent to the customer billing interaction, and utilities are of course made whole regardless.[42]

REFORM 4

Encourage Public Investment and Standards for Automated Devices

Will customers invest their own capital in the devices that are useful, albeit not strictly necessary, in responding to time-varying prices? Some will, many will not. Retailers may make these investments in order to build for themselves a virtual power plant among their customers. But the risk of load migration in an environment with a high rate of shopping—a good thing generally—will also mean a high risk of stranded assets among these highly distributed devices.

Virtually every state has a program that funds energy efficiency investments through ratepayer dollars. It is increasingly clear that demand activation is an important feature of such interventions. Causing the deployment of more devices that are interoperable across competitive firms entails benefits that are not always captured in the retailer-customer relationship, which is especially the case if the retailer is not exposed to all relevant costs as proposed in Reform #2. In general, governmental programs should move away from saving energy across all hours and focus on investments that can activate demand at times when energy is scarce. Too few energy efficiency programs clearly dedicate themselves to this proposition.

In addition to getting more smart devices into homes, governmental authorities can establish standards to ensure that devices are "smart" by default.[43] Standards have been used to ensure that more devices are energy-efficient, but in an era when energy is sometimes abundant and sometimes not, it seems equally or more important to ensure that these devices can intelligently react to those conditions if consumers want them to. Standards ensure the *possibility* of demand activation at homes and small businesses. How many cool features of our own appliances do we never operationalize? Setting standards on the interoperability of electricity-intensive appliances with the electricity marketplace at least sets the table for retailers to develop customers' plans and other offerings that do automate them without relegating such products to a narrow, boutique corner of the industry. There is a reason why the Federal Communications Commission sets minimum standards of upload and download speeds when it doles out broadband subsidies. The same kind of thinking should apply to electric utility regulators and standards-setting bodies.

42 A fuller explication of the advantages and policy surrounding supplier-consolidated billing can be found in Kavulla (2022).

43 For example, see "CTA-2045-A: Modular Communications Interface for Energy Management," which has been codified in several states for particular appliances. https://standards.cta.tech/apps/group_public/project/details.php?project_id=192.

Conclusion: A Two-Sided Market Where Demand Acts as Demand

Regulation's attempt to date to activate demand has been to jerry-rig it as a supply resource, bidding into energy and capacity programs. Or, sometimes demand activation has been relegated to niche utility programming, where all comers must subordinate their innovative spirit to become the vendors to a monopoly. This model of demand response—a term this paper has avoided, since demand inevitably is responsive to the incentives with which it is faced—has been a poor substitute for what should be our goal: a marketplace where smart meters and automated devices make possible a genuinely two-sided marketplace where demand is active.

The status quo of demand response has been defined by endless arguments about how the wholesale market for supply should accommodate demand acting as a supply resource. Is demand response really showing up?[44] Has the regulator appropriately defined the baseline usage on which demand reductions should be established and compensated? What obligations does demand have to pay for the option to use energy, which it has foregone? These are immensely thorny questions, and, so long as demand response is a jerry-rigged supply resource, all of them need government-defined answers within the administrative construct that is the wholesale electricity markets.

In the paradigm this paper lays out, retailers' end-use customers have agreed to pay them a retail price for what they might use, and the retailer has agreed to serve the customer at that price. When the marginal cost exceeds that price, an opportunity for shared savings emerges, and there is no need—except through private commercial agreement, not government intervention—to calculate a baseline. The retailer retains responsibility for privately managing the costs to serve demand, drawing on supply (owned resources, contracted resources, financial hedges, and the spot market) as well as demand (inducing its retail customers to reduce their needs). Under time-varying rates, customers are themselves faced instead with this incentive, since we must concede that certain retailers—cost-of-service regulated utilities—do not face that incentive.

When retailers serve demand, all demand is demand. In nearly every other market, we have empowered consumers to decide whether, when, and how to buy products—and those decisions inform but are not supply-side decisions. So too it should be in the electricity economy. Treating demand response as a lucrative source of supply will, in some ways, drive demand participation into an administrative construct, rather than a freer market that is characterized by demand's genuine elasticity and its ability to say "no" to supply's too-high offers

When retailers serve demand, all demand is demand. In nearly every other market, we have empowered consumers to decide whether, when, and how to buy products—and those decisions inform but are not supply-side decisions. So too it should be in the electricity economy.

44 For example, see the criticisms related to the CAISO 2020 outages associated with demand response in CAISO (2020).

to sell their goods, as other consumers do in every other two-sided market.[45] It is high time for demand to act like demand, the co-equal and opposite force to supply, and not just a junior-varsity source of supply.

This role for demand is made possible by the consumer-facing, digital and internet-connected technological advances that have transformed our lives in so many ways—but not yet, not really, in the electricity sector, even if the smart meter hangs on the side of your house. Much of other sectors' technological change does not seem to have made us better people. We can entertain ourselves to death on streaming services, have packages endlessly brought to our door by couriers, and camp out permanently on social media, all while disconnected from our families and nature. But the consumer technology revolution as applied to our electricity networks need not be consumptive. It can instead give us better information about what we are using and, importantly, allows us to adjust our consumption in ways that benefit us as well as the power grid that serves us, so long as regulators take steps to enable that. These are welcome developments in a time of what can seem like a throwaway culture, living up to an important and timely exhortation that "technologically advanced societies must be prepared to encourage more sober lifestyles, while reducing their energy consumption and improving its efficiency."[46]

The consumer technology revolution as applied to our electricity networks need not be consumptive. It can instead give us better information about what we are using and, importantly, allows us to adjust our consumption in ways that benefit us as well as the power grid that serves us, so long as regulators take steps to enable that.

45 It will be important to continue to allow retailers, or others, to offer certain reliability services into forward markets that are quintessentially administrative in nature, where they exist, using demand activation or to self-supply those services with their portfolio of demand.

46 Pope Francis, *Laudato Si*, (Vatican City: Libreria Editrice Vaticana, 2015). ¶193, quoting Pope Benedict XVI, "Message for 2010 World Day of Peace."

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Why Is the Smart Grid So Dumb?

Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector

By Travis Kavulla

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

This white paper is available at https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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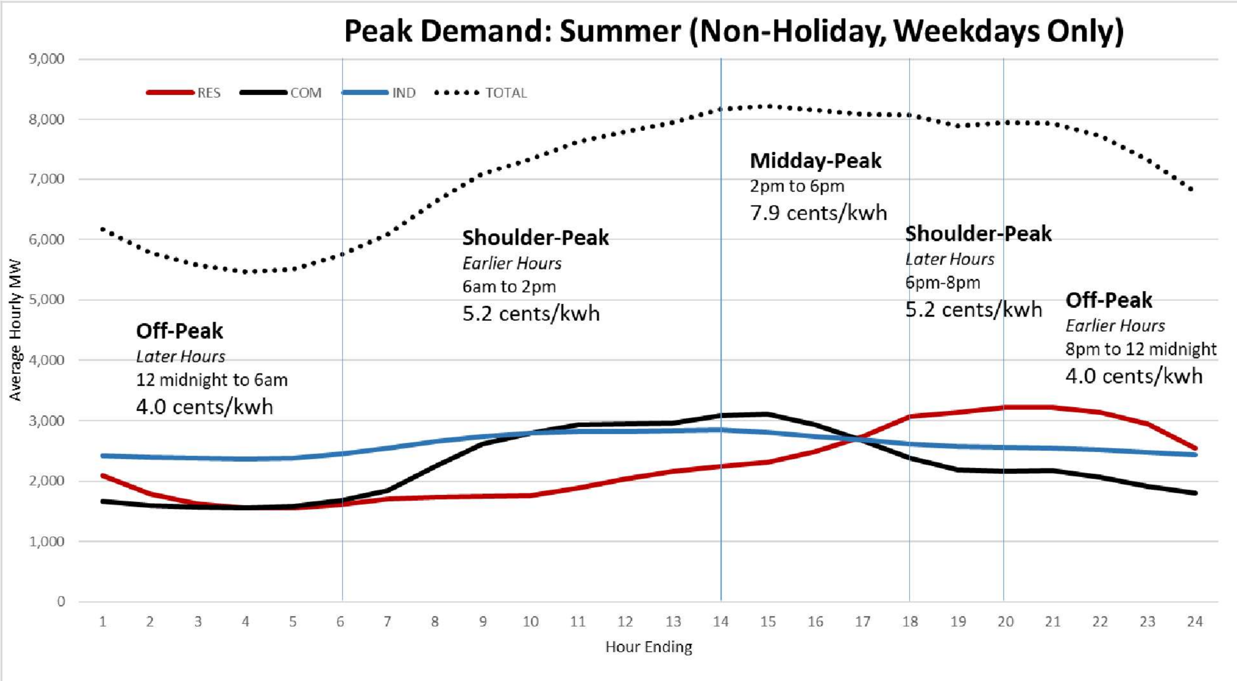
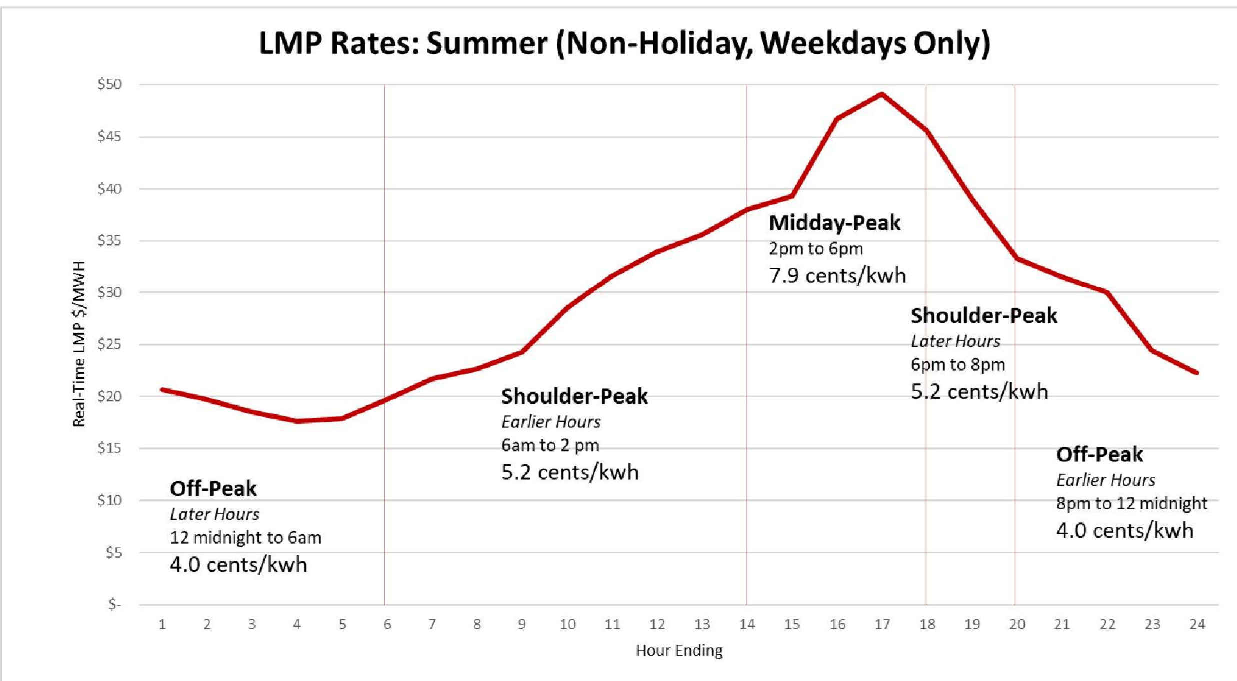
Charts: Summer





Charts: Winter