FILED
January 6, 2022
INDIANA UTILITY
REGULATORY COMMISSION

OFFICIAL
EXHIBITS

IURC Cause No. 45616
ChargePoint Exhibit 1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

AMENDED PETITION OF DUKE ENERGY INDIANA, LLC SEEKING (1) APPROVAL OF A PROPOSED ELECTRIC TRANSPORTATION PROGRAM AND AUTHORITY TO DEFER RELATED EXPENSES; (2) APPROVAL OF A PROPOSED ELECTRIC VEHICLE FAST CHARGING (EVFC) TARIFF; AND (3) APPROVAL OF A PROPOSED ELECTRIC VEHICLE SERVICE EQUIPMENT (EVSE) TARIFF	**CAUSE NO. 45616**

IURC
INTERVENOR'S ChargePoint
EXHIBIT NO. 1
2-8-22 AT
DATE REPORTER

VERIFIED DIRECT TESTIMONY

OF

KEVIN GEORGE MILLER

ON BEHALF OF

CHARGEPOINT, INC.

21937087.v1

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q: Please state your name and business address.

A: My name is Kevin George Miller. My business address is 254 E. Hacienda Avenue, Campbell, California 95008.

Q: Please describe your background, experience, and expertise.

A: In my current role as Director – Public Policy, I oversee ChargePoint, Inc.'s ("ChargePoint") regulatory efforts in 20 states and Washington, D.C., including Indiana. I engage on behalf of ChargePoint at utility regulatory commissions, state legislatures, and other state agencies to promote public policies that expand and promote electric vehicle ("EV") infrastructure and advance best practices within the electric vehicle charging industry.

My relevant professional experience appears in my CV, which is attached as Attachment KGM-1 and provides additional detail.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of ChargePoint.

Q: Are you sponsoring any attachments?

A: Yes. I sponsor the following attachments:

Attachment KGM-1: CV of Kevin George Miller
Attachment KGM-2: SCE Rule 29 Electric Vehicle Infrastructure
Attachment KGM-3: Mark-up of proposed EVFC tariff
Attachment KGM-4: Table of States (& Washington, D.C.) Allowing Charging per kWh
Attachment KGM-5: Mark-up of proposed EVSE tariff
Attachment KGM-6: RAP Paper on Demand Charges

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to address the EV program and associated tariff offerings proposed by Duke Energy Indiana, LLC ("Duke Energy" or "the Company").

Q: Please summarize your recommendations to the Indiana Utility Regulatory Commission ("Commission") concerning the Company's proposal.

A: I recommend that the Commission:

- Approve Duke Energy's proposed Residential EV Charging Incentive Program.
- Approve Duke Energy's proposed Commercial EV Charging Incentive Program with the following modifications:
  - Increase the proposed Electric Vehicle Service Equipment ("EVSE") customer incentive to reflect the current EV charging market and be commensurate with programs offered by other utilities.
  - Require all chargers to be networked.
  - Authorize Duke Energy to provide customer incentives to cover the cost of make ready investments up to the utility meter, in addition to customer incentives for EVSE, to further support commercial L2 deployments.
- Direct Duke Energy to ensure that all marketing materials and communications with customers through the Fleet Advisory Program be vendor neutral.
- Direct the Company to revise the proposed Electric Vehicle Fast Charging ("EVFC") tariff to allow site hosts to establish the prices and pricing policies for EV charging services provided at utility-owned EV chargers located on their property.
- Approve Duke Energy's proposed EVSE tariff with the following modifications:
  - Expressly allow for customer ownership and third-party turnkey solutions.
  - Require all chargers to be networked.

- Provide site hosts the ability to choose from at least two (2) vendors of EV charging hardware and software for all options available to customers under the Rate EVSE Tariff.

- Direct the Company to submit one or more alternatives to traditional demand-based tariffs for Commission approval within 6 months from the date of an order in this proceeding.

Q: Please describe ChargePoint.

A: ChargePoint is a world leading EV charging network, providing scalable solutions for every charging scenario from home and multifamily to workplace, parking, hospitality, retail and transport fleets of all types. ChargePoint's cloud subscription platform and software-defined charging hardware is designed to enable businesses to support drivers, add the latest software features and expand fleet needs with minimal disruption to overall business.

ChargePoint's hardware offerings include Level 2 ("L2") and DC fast charging ("DCFC") products, and ChargePoint provides a range of options across those charging levels for specific use cases including light duty, medium duty, and transit fleets, multi-unit dwellings, residential (multi- family and single family), destination, workplace, and more. ChargePoint's software and cloud services enable EV charging station site hosts to manage charging onsite with features like Waitlist, access control, charging analytics, and real-time availability. With modular design to help minimize downtime and make maintenance and repair more seamless, all products are UL-listed and CE (EU) certified, while L2 solutions are ENERGY STAR® certified.

ChargePoint's primary business model consists of selling smart charging solutions directly to businesses and organizations while offering tools that empower station owners to deploy EV charging designed for their individual application and use case. ChargePoint provides charging network services and data-driven, cloud-enabled capabilities that enable site hosts to better manage their charging assets and optimize services. For example, with those network capabilities, site hosts can view data on charging station utilization, frequency and duration of charging sessions, set access controls to the stations, and set pricing for charging services. These features are designed to maximize utilization and align the EV driver experience with the specific use case associated with the specific site host. Additionally, ChargePoint has designed its network to allow other parties, such as electric utilities, the ability to access charging data and conduct load management to enable efficient EV load integration onto the electric grid.

II. SUMMARY OF DUKE ENERGY'S PROPOSAL

Q: Please summarize Duke Energy's Electric Transportation Program ("ET Program").

A: Duke Energy proposes a two-year, $4.3 million ET Program designed to facilitate EV adoption through increased deployment of EV infrastructure throughout its service territory. The ET Program includes the following six components:

- **Residential EV Charging Incentive Program**, which is designed to evaluate three different utility-offered incentives to encourage residential customer EV adoption and home charging without requiring the customer to install a new meter and service. The Company proposes to provide up to 500 residential customers quarterly participation payments to test various incentives. Residential customers will be randomly assigned to one of three groups: Baseline, where customers charge when needed, Off-Peak, where customers are incentivized to charge between 9PM-6AM, or Peak Avoidance, where customers receive an incentive for charging outside the hours of 6am – 9pm.[1]

- **Commercial EV Charging Incentive Program,** which provides a $500 incentive to support installation of 1,200 L2 EVSE.[2] The Company has proposed the following EVSE incentive allocation: 600 publicly accessible locations; 200 workplace locations; 200 multi-unit dwelling locations; and 200 private fleet locations.[3]
- **Electric School Bus Program,** which provides funding for up to $197,000 per electric bus which includes installation of Company-owned EVSE, approximately $85,000, and will assist schools in purchasing an EV school bus with the remaining $112,000.[4]
- **Electric Transit Bus Program,** which provides a $50,000 incentive to offset the cost of EVSE and EVs. The Company states that incentives are available for up to ten large transit buses and 10 shuttle vehicles with minimum capacity of seven passengers. Customers shall be responsible for selection, installation and operation and maintenance of EVSE.[5]
- **Fleet Advisory,** which provides technical analysis for fleet operators interested in converting to electric fleet vehicles. As proposed, this program "will assist customers in selecting appropriate vehicles, EV charging strategies, grid capacity studies at Duke Energy logistical hubs, industrial areas, and various customer locations including municipal fleets."[6]

[1] Gordon, pp. 12-13.
[2] Gordon, p. 16.
[3] Gordon, p. 17.
[4] Gordon, p. 19.
[5] Gordon, p. 24.
[6] Duke Energy Amended Petition, p. 3.

- **Education and Outreach,** which is designed to ensure the program, and its potential benefits are communicated to the Company's customers.

Duke Energy is also seeking Commission approval of two proposed EV tariffs:

- **Electric Vehicle Fast Charging (EVFC) Tariff**, which establishes a regulated rate charged to EV drivers utilizing Duke Energy-owned and operated public DCFC stations. The Company states that the rate ($/kWh) is derived from a statewide average of comparable public charging stations.[7] Duke Energy also proposes a $1.00 per minute idling fee in certain circumstances.[8]
- **Electric Vehicle Service Equipment (EVSE) Tariff,** which establishes a monthly fee for Duke Energy residential or commercial customers seeking to install EV charging infrastructure at their premises. As proposed by the Company, the EVSE tariff will provide customers with utility owned L2 or DCFC charging stations for an "EVSE Monthly Rate" ranging from $17.95 to $1,519.44, depending on the type of EVSE installed.[9]

Q: Will Duke Energy's ET Program and EV charging tariffs contribute to overcoming barriers to deploying EV charging infrastructure?

A: With certain modifications, yes. If ChargePoint's recommendations are incorporated into Duke Energy's proposed program and tariffs, the Company's proposed incentives will help to overcome barriers to deploying EV charging stations by reducing the total cost of EVSE and installation. In addition, the program as proposed underscores the need to holistically

[7] Flick, p. 5.
[8] Flick, p. 6.
[9] Petitioner's Exhibit 3-C (RAF), p. 2.

support EV charging with efforts that encourage charging at home, at work, and in public while also providing education and raising awareness on transportation electrification.

Q: Will Duke Energy's proposed ET Program and EV charging tariffs only create value for participating customers?

A: No. The program has the potential to create value for all customers in Duke Energy's service territory, including those who do not participate in the program. Increased deployment of EV charging infrastructure can create sufficient new load to reduce unit energy costs, resulting in lower electricity rates and net benefits for all ratepayers, irrespective of EV ownership.[10] For example, a state-wide cost-benefit analysis of EV adoption in Indiana conducted by M.J. Bradley and Associates found that net benefits (in the form of reduced electricity bills) to ratepayers could reach $5.6 billion by 2050.[11] Furthermore, a cost-effectiveness analysis of EV charging investments proposed by four utilities in Maryland found that the proposed investments would generate net benefits to all ratepayers due to increased load.[12]

Managed charging, which Duke Energy has proposed, can help ensure that EV charging takes place at times that are most beneficial to the grid. This can support the creation of

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[10] *See, e.g.* M.J. Bradley & Associates (2016-2017), *State-Wide Costs and Benefits of Plug-in Vehicles in Connecticut, Maryland, Massachusetts, New York, and Pennsylvania, Colorado, Illinois, Michigan*, https://www.mjbradley.com/reports/mjba-analyzes-state-wide-costs-and-benefits-plug-vehicles-five-northeast-and-mid-atlantic; Submission to the Maryland Public Utilities Commission re: CASE NO. 9478(2018), https://webapp.psc.state.md.us/newIntranet/Maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C200000-249999%5C221921%5CJointSignatoriesComments_FF.pdf; Gabel Associates, Inc. (2018), *Long Island Cost and Benefits*, https://www.psegliny.com/saveenergyandmoney/solarrenewableenergy/electricvehicles/-/media/2C0D0CC8E48648ECBB38463CD0405826.ashx.

[11] M.J. Bradley & Associates (2018), *Plug-in Electric Vehicle Cost-Benefit Analysis: Indiana*, https://mjbradley.com/sites/default/files/IN%20PEV%20CB%20Analysis%20FINAL.pdf.

[12] Submission to the Maryland Public Utilities Commission re: CASE NO. 9478 (2018), https://webapp.psc.state.md.us/newIntranet/Maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C200000-249999%5C221921%5CJointSignatoriesComments_FF.pdf. (Baltimore Gas and Electric Company found that revenue from residential charging would exceed program costs by two times through 2025, and Potomac Electric Power Company found that program costs would be exceeded by three times through 2025).

widespread grid benefits resulting from more efficient grid utilization and deferred capital upgrades. Some of the same studies referred to above note that benefits to all ratepayers increase when EV charging is shifted off-peak or intelligently managed (e.g. smart charging programs).[13] For example, a study commissioned by PSEG Long Island found that managed charging could generate significant net benefits in the form of deferred and reduced grid impacts, and deliver an additional 30% saving to ratepayers.[14]

In addition, several studies highlight that the expected long-term electric sales from incremental EV load exceeds the marginal cost of grid infrastructure to support that load.[15] According to a NARUC report published in October 2019, EV load that charges during off-peak hours can provide positive net revenue flowing back to all customers due to the efficient use of the existing electric grid.[16] Further, a study by Synapse Energy Economics found that in the territories of Pacific Gas & Electric and Southern California Edison, the incremental electrical sales enabled by EV programs exceeded the costs to the electric system by more than 3 to 1.[17] The addition of new dispersed load during off-peak hours can result in the wider distribution of fixed costs, leading to lower rates for all customers.[18]

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[13] *E.g.* M.J. Bradley & Associates (2016-2017) and Gabel Associates, Inc. (2018).

[14] Gabel Associates, Inc. (2018), *Long Island Cost and Benefits*, https://www.psegliny.com/saveenergyandmoney/solarrenewableenergy/electricvehicles/-/media/2C0D0CC8E48648ECBB38463CD0405826.ashx (and related presentation to the Long Island Power Authority Board of Trustees, https://www.lipower.org/wp-content/uploads/2018/10/EV-Study-LIPA-Board-Presentation-Oct-24-2018-FINAL.pdf).

[15] *See, e.g.*, E3, *Cost-Benefit Analysis of Plug-in Electric Vehicle Adoption in the AEP Ohio Service Territory*, April 2017. https://www.ethree.com/wp-content/uploads/2017/10/E3-AEP-EV-Final-Report-4_28.pdf.

[16] NARUC, Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators, at 21 (Oct. 2019) ("NARUC EV White Paper"), available at https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE (citing Jones et al. "The Future of Transportation Electrification: Utility, Industry and Consumer Perspectives," Lawrence Berkeley National Laboratory (2018), at http://eta-publications.lbl.gov/sites/default/files/feur_10_transportation_electrification_final_20180813.pdf).

[17] Synapse Energy Economics, Electric Vehicles Are Driving Rates Down, at 4 (Feb. 2019), available at https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf.

[18] NARUC EV White Paper at 21.

In effect, prudent investments in EV charging infrastructure result in increases in electric use, exerting downward pressure on retail rates that can benefit all utility customers regardless of EV ownership.

Q: Are there other benefits from Duke Energy's proposed ET Program that you would like to discuss?

A: Yes. Duke Energy has proposed including publicly accessible EVSE in the ET Program – whether that is publicly accessible EV chargers, or electrification of public fleets (school buses, public transit buses, municipal fleets, etc.). This means that all customers throughout Duke Energy's service territory will directly or indirectly benefit including, but not limited to: (i) families with school children will benefit from the availability and use of electric school bus fleets; (ii) public transportation patrons will benefit from the availability and use of electric city bus fleets; (iii) fleet owners will benefit from lower total cost of ownership, and a healthier experience for drivers; and (iv) society will benefit from lower emissions and improved air quality.

III. EVALUATION OF DUKE ENERGY'S ET PROGRAM

Q: Do you recommend the Commission approve Duke Energy's ET Program?

A: With the modifications described later in my testimony, yes. ChargePoint generally agrees with the goals and objectives of the ET Program's EV charging tariffs, which are to advance transportation electrification throughout the Company's service territory, and more broadly throughout Indiana, while gaining an increased understanding of various customer charging behavior. By providing customer incentives for EVSE, and incentivizing off-peak charging, Duke Energy's ET Program will lower market barriers, reduce costs, and increase benefits to ratepayers. The program also provides customer choice in charging equipment and network service which is a necessary feature for utility programs to catalyze sustainable and scalable growth in the EV and EV charging markets. The program as proposed underscores the need to holistically support EV charging with efforts that encourage charging at home, at work, and in public while also providing education and raising awareness on transportation electrification.

<u>Residential EV Charging Incentive Program</u>

Q: Does ChargePoint support Duke Energy's proposed Residential EV Charging Incentive Program?

A: Yes. Addressing residential charging is an important step to advance the adoption of EVs. In fact, over 80% of residential drivers charge at home, necessitating avenues to effectively incentivize EV charging to take place during off-peak periods.[19] Additionally, most personal vehicles are stationary for 22 or more hours daily, meaning there is a massive potential to manage EV charging.[20] Further, studies have demonstrated that residential charging is beneficial to the grid and in the public interest.[21] As such, drivers are often very willing, with the appropriate incentive, to defer charging to times that are more ideal and efficient for the grid. Incentivizing energy consumption, including EV charging, to take place during off-peak periods decreases peak demand pressure on utility assets such that the need for additional capacity and grid infrastructure can be avoided.

ChargePoint appreciates that Duke Energy proposes to offer residential customers a choice among EV charging equipment and software providers that meet certain minimum

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[19] *See* https://www.nrel.gov/docs/fy19osti/73303.pdf at slide 10.
[20] *See* SEPA, The State of Managed Charging in 2021 (November 2021), p. 7. Available at: https://sepapower.org/resource/managed-charging-incentive-design/
[21] *Id.*

specifications. Protecting customers' ability to choose their preferred solution – rather than providing a "one-size, fits-all" solution – is essential to protecting the competitive market for EV charging stations in Indiana. When customers can choose the charging solution that works best for them, charging solution vendors will compete to make high-quality, innovative products that customers want. Creating ongoing competition between vendors through customer choice within utility programs is essential to ensuring that a competitive market can thrive within utility programs and sustainably continue after their conclusion.

Commercial EV Charging Incentive Program

Q: Does ChargePoint support Duke Energy's Commercial EV Charging Incentive Program?

A: Generally, yes. ChargePoint supports the proposal to provide customer incentives up to $500 to offset the cost of qualified L2 EVSE installed at commercial locations such as workplace, multi-unit dwellings, fleet, and other locations. The customer incentives proposed in the commercial program has the potential to increase EV charging deployment at critical locations throughout Duke Energy's service territory. Research has shown that supporting deployment of EVSE at workplaces makes employees six times more likely to purchase an EV.[22]

ChargePoint is concerned, however, that Duke Energy's proposed $500 incentive is well below the $4,000 median rebate offered to multi-unit dwellings and workplace locations, as well as the $4,900 median rebate for public locations.[23] Due to the important role commercial charging will play in furthering transportation electrification, ChargePoint

[22] U.S. DOE, Workplace Charging Challenge, available at: https://www.energy.gov/sites/prod/files/2017/01/f34/WPCC_2016%20Annual%20Progress%20Report.pdf.
[23] See SEPA, Managed Charging Incentive Design (October 2021), at 9. Available at: https://sepapower.org/resource/managed-charging-incentive-design/

recommends that the proposed $500 incentive should be updated to reflect the current EV charging market and be commensurate with other utility programs.

Further, ChargePoint believes that providing customer incentives for only a portion of the cost of the EVSE itself will be insufficient to incentivize the necessary deployment of EV charging infrastructure targeted in the program. Typically, the cost to install a charging station in an existing parking lot or fleet depot is equal to or more than the cost of the hardware itself. Installation costs downstream from the customer of record's utility meter necessary to complete "make ready" construction include trenching or boring, conduit, wiring, labor, mounting, site reconditioning, and landscaping along with signage. These costs are unlikely to experience significant reductions over time and vary greatly with on-site conditions.

Therefore, ChargePoint recommends that the Commercial EV Charging Program be expanded to authorize Duke Energy to provide customer incentives to cover the cost of make ready investments up to the utility meter, in addition to customer incentives for EVSE, to further support commercial L2 deployments. Expanding Duke Energy's program to include utility make-ready work echoes the recently approved EV Infrastructure Rules ("Rules") by the California Public Utilities Commission. The Rules authorize each investor-owned utility to deploy all electrical distribution infrastructure on the utility side of the customer's meter for all customers installing separately metered infrastructure for EV charging stations.[24] For illustrative purposes, Southern California Edison's tariff adopting the Rules is attached as Attachment KGM-2. Following this model would both

[24] Resolution E-5167, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841.

accelerate and simplify how readily EV charging can be deployed across Duke Energy's service territory.

Q: Does ChargePoint have any other recommended modifications to the Company's Commercial EV Charging Program?

A: Yes. ChargePoint appreciates that Duke Energy's Commercial EV Charging Program enables site hosts to choose amongst multiple vendors of EVSE hardware and network providers, which supports the existing competitive market for EV charging station hardware and network services. ChargePoint recommends, however, that Duke Energy and the Commission require any EV chargers installed through the program be networked. Networked or smart charging equipment has the ability to communicate with the cloud and manage the charging of the EV. Smart chargers also enable drivers to locate publicly accessible chargers and determine if the station is in use in real time. As EV adoption increases, the Company also may seek to offer additional programs or incentives for customers that leverage the capability of smart chargers. Encouraging the installation of smart chargers is a way to ensure customers will be able to participate in such programs in the future.

<u>Fleet Advisory Program</u>

Q: Does ChargePoint support Duke Energy's Proposed Fleet Advisory Program?

A: ChargePoint does not oppose the Company's Fleet Advisory program proposal but cautions against a program that duplicates offerings already available in the competitive market. ChargePoint believes that there is a meaningful role for the Company to play in raising awareness of available EV charging infrastructure to support electrification of fleet operations. There are many unique and complex factors that go into fleet electrification decisions and deployment. While ChargePoint supports the position that the Company plays an important role in raising awareness of the available EV charging infrastructure, many of the unique and complex factors that go into fleet electrification decisions and investments can and should be resolved through collaboration with private market actors such as a charging site's EVSE provider. Moreover, established EVSE service providers have a broad range of information available to customers regarding products and service availability and pricing.

ChargePoint believes that the Company can be an effective partner for all interested EVSE providers in their service territory to share their current offerings and market to fleet managers. The Company provided Fleet Advisory services should leverage the expertise of private actors in the EV fleet ecosystem to guide site hosts and fleet operators most efficiently in their EV transition. ChargePoint cautions that blurring the lines between a utility providing customer incentives and a utility offering input on topics such as EV procurement and management, funding options, or EVSE choices fall beyond the scope of a utility advisory function and could adversely affect the market for charging equipment or services.[25] ChargePoint recommends that these services focus on promoting the technical guidance made available through the incentives, as well as education focused on how to manage charging and effectively integrate newly electrified vehicles while mitigating disruptions to business operations.

Additionally, while it is appropriate for the Company to encourage its fleet customers to embrace electrification, it would distort the competitive markets for charging equipment and services, and for light duty (LD) and medium- and heavy duty (MHD) EVs, if the

[25] Petitioner's Exhibit 1, pp. 26-27.

Company were to promote specific vendors or vendor-specific technologies. ChargePoint recommends that the Company ensure that all marketing materials and communications with customers through any fleet planning services be vendor neutral. Further, the Company's Fleet Advisory Program should not pick preferred providers or influence fleet operators' choice of equipment and service providers as long as the providers are capable of meeting the Company's operational requirements.

IV. EVALUATION OF DUKE ENERGY'S EV TARIFFS

Q: Please Summarize Duke Energy's proposed EV tariffs.

A: Duke Energy submitted two proposed EV tariffs for Commission review and approval. The Company proposed the creation of an EVFC tariff that would establish a regulated rate charged to EV drivers utilizing Company-owned and operated public charging stations. The Company states that the rate ($/kwh) will be derived from a statewide average of comparable charging stations.[26]

The Company also proposes the creation of an EVSE tariff for Duke Energy customers seeking to install EV charging infrastructure at their premises. As proposed by the Company, the EVSE tariff will provide customers with utility owned L2 or DCFC EV charging stations for an "EVSE Monthly Rate" ranging from $17.95 to $1,519.44, depending on the type of EVSE installed.[27] These rates include equipment, maintenance, and annual software networking fees, but do not include the monthly charges or and necessary excess facilities associated with the Company's Service Regulations and/or Line Extension Deposit requirements, electrical panel/wiring make-ready costs, costs for work

[26] Petitioner's Exhibit 3-A (RAF), p. 1.
[27] Petitioner's Exhibit 3-C (RF), p. 2

on the Company's side of the meter, non-standard equipment, or any contribution required. Internet connectivity, arranged by the customer and at the customer's expense, may be required for customers to participate in certain Company programs that may be offered in conjunction with other Company tariffs.

EVFC Tariff

Q: Does ChargePoint support the Company's EVFC tariff as proposed?

A: No. As proposed, the Company's EVFC rate will be "available for use by any electric vehicle owner, without preference to the Company's electric service customers" and that the proposed rate "would only apply at Duke Energy Indiana-owned charging stations."[28] ChargePoint appreciates that the Company's proposed tariff will apply equally to Duke Energy customers and non-Duke Energy customers. However, ChargePoint recommends that the Commission direct the Company to allow site hosts to establish the prices and pricing policies for EV charging services provided at utility-owned EV chargers located on their property.

Site host control over pricing is important to ensure that site hosts can achieve their unique goals for hosting EV charging stations. This arrangement ensures the utility remains whole for any costs related to the electricity used by the charging stations while allowing the site host flexibility to price the charging services in accordance with its own goals and to align with its core business. It also encourages site hosts to maximize station utilization through signage, parking enforcement, maintenance, and pricing.

ChargePoint further recommends that the Commission direct the Company to include appropriate tariff language to allow site hosts the ability to establish and adjust pricing for

[28] Petitioner's Exhibit 3, pp. 2-3.

EV charging services. ChargePoint provides recommended changes to the proposed EVFC tariff in Attachment KGM-3.

Q: Would ChargePoint's recommendation to enable site hosts to set pricing for EV charging service constitute third-party sales of electricity?

A: No. ChargePoint understands that currently, third-party sales of electricity are not permitted in Indiana. Under ChargePoint's recommendation, a Network Service Provider may be used to facilitate EV charging transactions, while electricity will be sold directly by Duke Energy to the driver.

Furthermore, the majority position in the United States is that EV charging is widely allowed as a non-utility service, and regulating the price that EV drivers pay would create market imbalances. Attachment KGM-4 to my direct testimony identifies 40 states, plus Washington, D.C., as all having explicitly determined, as of October 28, 2021, that EV charging on a per kWh basis does not constitute utility service. Allowing site hosts to determine pricing is fundamental to market development. If the Commission sets the price for Duke Energy-owned EV charging stations, then naturally, all site hosts will gravitate towards that benchmark, rather than allowing competition to play out. This ultimately will have a stifling effect on EV adoption and will likely decrease utilization of competitively owned charging stations.

Q: Have other regulatory authorities enabled site hosts to set pricing for EV charging services in jurisdictions that did not allow third-party sales of electricity?

A: Yes. As indicated in response to the last question, 40 states plus Washington, D.C., have determined that EV charging on a per kWh basis does not constitute utility service. Buttressing this argument as it applies to Duke Energy, the Public Service Commission of

South Carolina recently approved pilot programs for Duke Energy's sister utilities, Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), enabling site hosts to create alternative pricing mechanisms for EV drivers.[29]

<u>EVSE Tariff</u>

Q: Does ChargePoint support the Company's EVSE tariff as proposed?

A: No. The Company explains that Duke Energy is proposing the creation of the EVSE tariff "for regulated customers desiring electric vehicle charging infrastructure at their residential or commercial premises served by Duke Energy Indiana's distribution system." [30] The Company further states that it "seeks to aid a customer's electric vehicle adoption choice through offering a simple option to obtain EVSE at that customer's location."[31] In other words, Duke Energy proposes to offer its customers a turnkey solution to EV adoption.

ChargePoint acknowledges that there may be instances where a site host would like to have charging options on its property but cannot or does not want to own or operate the charging infrastructure. In these cases, utility ownership is not the only solution. The private sector offers many different business models and products to provide turnkey solutions for site hosts, coordinating all aspects of the charging experience from installation to operation and maintenance, including solutions for site hosts that are not seeking to own or operate their own charging equipment. For example, ChargePoint offers customers a subscription solution for EV charging, "ChargePoint as a Service" ("CPaaS") that is similar to "Software as a Service" ("SaaS") models, which offer access to smart solutions at a reduced

[29] See Order Approving Electric Transportation Pilot and Accounting Order As Stipulated, Docket No. 2018-321-E, Order No. 2020-645; Order Approving Electric Transportation Pilot and Accounting Order As Stipulated, Docket No. 2018-323-E, Order No. 2020-646.
[30] Petitioner's Exhibit 3, p. 7.
[31] Petitioner's Exhibit 3, p. 10.

cost through subscription pricing. Under the CPaaS option, ChargePoint coordinates the installation, operation, and any needed maintenance of the charging infrastructure, providing a single point of contact for site hosts and drivers using the station.

ChargePoint recommends the Commission direct the Company to revise its proposed EVSE tariff to expressly allow for customer ownership and third-party turnkey solutions. Alternatively, ChargePoint recommends the Commission direct the Company to file an additional tariff option that expressly enables third party turnkey solutions or customer ownership of the EVSE within 60 days of the Commission's decision in this docket.

Q: Does ChargePoint have any additional concerns with the Company's EVSE tariff as proposed?

A: Yes, ChargePoint has two additional concerns with the proposed EVSE tariff. As proposed by the Company, the EVSE tariff provides descriptions of multiple EVSE options available to customers electing to take service under this tariff. However, the Company's Amended Petition and proposed tariff do not explicitly provide site hosts the ability to choose from at least two vendors of EV charging hardware and software. ChargePoint believes that one of the main pillars of effective utility investment is the ability for site hosts to choose among multiple, qualified vendors of charging equipment and network software to find the best solution for their specific needs. Protecting customers' ability to choose their preferred solution – rather than providing a "one-size, fits-all" solution – is essential to protecting the competitive market for EV charging stations in Indiana. When customers can choose the charging solution that works best for them, charging solution vendors will compete to make high-quality, innovative products that customers want. Creating ongoing competition between vendors through customer choice within utility programs is essential to ensuring that a competitive market can thrive within utility programs and sustainably continue after they cease.

ChargePoint recommends the Commission direct the Company to provide site hosts the ability to choose from at least two (2) vendors of EV charging hardware and software for all options available to customers under the Rate EVSE Tariff. ChargePoint provides recommended changes to the proposed EVSE tariff in Attachment KGM-5.

Q: Please explain your additional concerns.

A: ChargePoint recommends that the Company and the Commission require any EV chargers installed through the EVSE Tariff to be networked. Under the terms of the proposed tariff, there is an incremental price difference for customers that may choose a networked charger and when presented with the option, many customers may choose the non-networked charger simply because of the lower price. Networked or smart chargers will be vital to ensure that EV charging benefits the distribution grid by enabling customers, the Company and third parties to have advanced load management capabilities to facilitate off-peak charging and other managed charging strategies. Non-networked chargers cannot provide the same depth of information and functionality as networked chargers and ChargePoint recommends the Company use the EVSE tariff as an opportunity to ensure customers can manage EV charging now and in the future.

A smart charger can also collect interval data to inform usage patterns and provide enhanced network communication capabilities between the EV driver and the utility, or third-party systems. These capabilities can be significant to site hosts to enable charging services at their facilities, as well as to utilities and third-party providers since the smart station can enable various demand side management programs. Those programs could include demand response or enable a time of use (TOU) rate specific to EV charging through utilization of the embedded meter. The associated communication and cloud-based technology platform can also be leveraged to provide enhanced station management features like reservations or notifications for charge completion for an improved driver experience through greater visibility and interaction.

Requiring smart charger capabilities now will future-proof investment in EV charging infrastructure. By requiring smart chargers from the outset, the Commission and the Company will enable Duke Energy, third-party providers, vendors, and customers to reap significant benefits from increased functionality and wider future program design options. ChargePoint recommends that the Commission direct the Company to modify the EVSE Tariff to remove the reference to non-networked EVSE. ChargePoint's recommended changes concerning this element of the proposed EVSE tariffs is incorporated in Attachment KGM-5.

V. DEMAND CHARGE CONCERNS

Q: Does Duke Energy address how customers deploying EV charging stations could be affected by existing commercial and industrial ("C&I") rate structures?

A: No. Duke Energy's proposal does not address traditional demand-based rates which represent one of the biggest financial challenges facing EV charging providers. To address the potential for significant costs to operators of EV charging stations from traditional demand charges and as supported by the reasons set forth in my testimony, ChargePoint recommends that the Commission require the Company to submit one or more alternatives to traditional demand-based tariffs for Commission approval within 6 months from the date of an order in this proceeding.

As additional context for my testimony, since Duke Energy filed its case-in-chief, the Infrastructure Investment and Jobs Act (*i.e.*, H.R. 3684, hereinafter, "IIJA"), has been enacted. The IIJA directs each state to consider "measures to promote greater electrification of the transportation sector," including establishing rates that, among other things, promote affordable and equitable EV charging options for residential, commercial, and public EV charging infrastructure.[32] While ChargePoint would also support a dedicated Commission proceeding to address this issue, we are concerned about the Commission approving a capital spending program without any consideration for how to overcome critical operating cost barriers.

Q: Why are demand charges challenging for EV charging providers?

A: Traditional demand-based rates can pose a significant challenge to the deployment of EV charging, particularly at commercial and public charging locations because these charging sites can be dominated by relatively rare, yet very power-intensive, bouts of fast charging. In some markets, demand charges can account for as much as 90% of a site host's electricity costs.[33]

Implementing appropriate rate designs that eliminate, defer, or reduce demand charges is key to unlocking increased investment in the EV charging infrastructure needed to support EV drivers in Indiana, as well as those transiting through the State. As the Company develops demand charge alternatives, it should consider specific use cases as well as alternatives that have already been demonstrated by utilities in other states.

[32] IIJA, Sec. 40431.
[33] Rocky Mountain Institute, 2017. "EVgo Fleet and Tariff Analysis." Available at: https://rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf

Demand charges are not an effective price signal for public charging stations because the only way to avoid or reduce demand charges is to shift or curtail load, which typically are not options for travelers "on-the-go" who must charge their vehicles at a public charging station to complete their travel. Demand charges also do not accurately reflect cost causation. The Regulatory Assistance Project concluded in a November 2020 report that demand charges "provide an inaccurate price signal," "reflect[] an outdated perspective of the engineering and economics of the electric system," and "time-of-use and other kinds of time-varying rates remain more efficient and equitable" than even modified demand charges, such as peak window demand charges.[34] A copy of the Regulatory Assistance Project report is attached to my testimony as Attachment __-XXX. Demand charges can present a particularly high barrier to EV charging stations located in rural areas, where utilization is likely to be more infrequent than in urban areas.

In addition to presenting a major barrier to public charging options, demand charges also present a barrier for electrifying public- and private-sector fleets, including municipal service vehicles, school buses, and public transit buses. Addressing unique fleet charging needs through appropriate rate designs that do not include traditional demand charges will reduce barriers to EV adoption, as fleet operators are uniquely suited to maximize the operational cost savings of transportation electrification. Reducing barriers for fleet operators to electrify their vehicle fleets can create widespread and equitably accessible benefits for ratepayers and the general public.

Q: Are there examples of sustainable C&I rates that Duke Energy could consider?

[34] Regulatory Assistance Project, "Demand Charges: What Are They Good For? An Examination of Cost Causation" at 13 (Nov. 2020), available at https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

A: Yes. In evaluating the alternatives to demand charges that are more appropriate for different vehicle use cases, Duke Energy can adopt or modify models established by utilities in other states. Models that have been employed by utilities in other states include:

- **Eversource Energy (Connecticut)** offers customers an EV Rate Rider (EVRR) which converts any demand charges that might otherwise apply to an equivalent $/kWh charge.[35]
- **PECO (Pennsylvania)**: EV DCFC Pilot Rider: A monthly bill credit representing a percentage of the nameplate demand associated with installed charging stations behind a commercial customer's metered service.[36]
- **Dominion (Virginia)**: GS-2 rate is a technology-neutral, low-load factor rate applicable to customers with a load factor below 200 kWh per kW.[37]
- **Pacific Power (Oregon)**: Schedule 45 which provides a demand charge transition discount paired with an on-peak energy charger transition discount.[38]

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[35] *See* This rate rider was approved by the Connecticut Public Utilities Regulatory Authority in a decision dated March 6, 2019 in Docket No. 17-10-46RE01, available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/78a25b4e83776981852583b50057c9d1/$FILE/171046RE01-030619.pdf (approving rate available to all public EV charging stations for a term of 3 years) ("In the EV RATE Rider, the rate calculation for EV charging stations is based on a per-kWh equivalent to the demand charges applicable to the Company's general service rate schedule that would otherwise apply to the load being served."). This is a successor rate to the EVRR Pilot rate originally approved in Docket No. 13-12-11, by decision dated June 4, 2014. The current Eversource-Connecticut EVRR rate is available at https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/ev-rate-rider.pdf?sfvrsn=e44ca62_0.

[36] *See* EEI, *EV Trends and Key Issues* at 2 (Mar. 2019) ("On December 20, 2018... the Pennsylvania Public Utility Commission approved PECO's five-year EV DCFC Pilot Rider (EV-FC). This rider...will provide a demand credit to the customer's billed distribution demand. The credit...will be equal to 50 percent of the combined maximum nameplate capacity rating for all DCFCs connected to the service. Eligible customers will receive the credit for up to 36 months or until the pilot ends, whichever comes first. (Docket R-2018-3000164).)") at https://www.eei.org/issuesandpolicy/electrictransportation/Documents/EV_Trends_and_%20Key%20Issues_Mar2019_WEB.pdf. *See also* https://www.peco.com/SiteCollectionDocuments/ThirdPartyEV.pdf.

[37] *See* Schedule GS-2, available at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/business-rates/schedule-gs2.pdf?la=en&rev=65c74050107549f299d48689f738e948&hash=7CBE70107AE10C66B8EB5C5A1E248D12.

[38] *See* Pacific Power, Oregon Schedule 45, Public DC Fast Charger Optional Transitional Rate Delivery Service at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-

- **Pacific Power (Oregon)**: Schedule 29 which couples a TOU rate together with a demand charge based on utilization for which the average energy price declines as utilization increases.[39]
- **Public Service Company of Colorado**, a unit of Xcel Energy, offers a low-load-factor rate with a lower demand charge and higher TOU volumetric rates.[40]
- **Madison Gas & Electric (Wisconsin)** offers a low-load-factor rate which provides a 50% discount in the demand charge for customers with load factors below 15%. This technology-neutral rate is targeted not only to DCFC facilities, but also to other types of low-load-factor customers.[41]
- **Xcel Energy (Minnesota)** offers a low load factor rate which forgives a portion of billed demand.[42]
- **NVEnergy (Nevada)** has implemented Schedule EVCCR-TOU in its Northern and Southern Nevada service territory.[43] This rate is applicable to separately metered DC fast chargers by utilizing a 10-year demand rate reduction period which starts at 100% reduction and phases back in at 10% each year. The demand rate reduction is offset with TOU dollar per kWh transition rate adders that are in addition to the normal billed TOU volumetric rates for commercial customers.

regulation/oregon/tariffs/rates/045_Public_DC_Fast_Charger_Optional_Transitional_Rate_Delivery_Service.pdf. Approved in Oregon PUC Docket No. 485 on May 16, 2017.

[39] *See* In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Oregon PUC Docket No. UE 374 (Proposed), available at https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22279.

[40] *See* https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf, at Sheet No. 44.

[41] *See* https://www.mge.com/MGE/media/Library/pdfs-documents/rates-electric/E32.pdf.

[42] *See* Xcel-MN Tariff, available at https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf.

[43] *See* https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/EVCCR-TOU_South.pdf.

- **Tacoma Power (Washington State)**: EV-F rate which has a similar structure to NVEnergy's rate above.[44]
- **SCE (California)**: TOU-EV-8, which provides TOU rates for the initial 5 years with demand charges phased back during years 6-10.[45]
- **SDG&E (California)**: TOU-M, an interim rate, under which sites can switch to a rate with a $2.50/kW demand charge and the cap is waived.[46]
- **Ameren (Illinois):** offers a multi-phase "rate limiter" designed to limit the average monthly cost for customers who limited their total kWh usage during the four summer billing periods of June through September to 20% or less of their annual kWh consumption.[47]
- **DTE (Michigan):** GS-D3 is a low load factor rate where the 1000 kW demand cap for this non-demand general service rate is waived for DC fast chargers through June 1, 2024. [48]
- **Hawaiian Electric (Hawai'i)**: offers Schedule EV-F for separately metered public EV charging facilities with peak demands for EV charging not exceeding 100 kW.[49] The rate is an all-volumetric rate, with no demand charges. The lowest rate is in the midday TOU period when output from the state's high penetration of rooftop solar is greatest.

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[44] *See* Schedule FC, available at https://www.mytpu.org/wp-content/uploads/FC_July_2020.pdf.
[45] *See* CPUC Decision 18-05-040, Ordering Paragraph 45, and SCE Advice Letter 3853-E (filed August 29, 2018) to implement the new commercial EV rates approved in that order. The decision is available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF. *See also* https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-8.pdf.
[46] *See* San Diego Gas & Electric, Interim Rate Waiver, available at https://www.sdge.com/interim-rate-waiver.
[47] *See* Ameren Tariff, available at https://www.ameren.com/-/media/rates/files/illinois/aiel14rtds4.pdf.
[48] *See* https://www.michigan.gov/documents/mpsc/dtee1cur_579203_7.pdf.
[49] Schedule EV-F was established in Hawai'i PUC Final Decision and Order No. 35545 in Docket No. 2016-0328, filed on June 22, 2018, available at https://puc.hawaii.gov/wp-content/uploads/2018/06/DO-No.-35545.pdf.

Each of these foregoing options has been designed to alleviate barriers to EV adoption while reflecting cost-causation and maintaining equity among ratepayers. This list of illustrative examples may be helpful to the Company and the Commission in the development of Indiana-specific rate designs.

VI. SUMMARY AND CONCLUSION

Q: Please summarize your recommendations.

A: ChargePoint recommends the Commission approve Duke Energy's ET Program proposal and associated tariffs with the following modifications:

- Approve Duke Energy's proposed Residential EV Charging Incentive Program.
- Approve Duke Energy's proposed Commercial EV Charging Incentive Program with the following modifications:
    - Increase the proposed EVSE customer incentive to reflect the current EV charging market and be commensurate with programs offered by other utilities.
    - Require all chargers to be networked.
    - Authorize Duke Energy to provide customer incentives to cover the cost of make ready investments up to the utility meter, in addition to customer incentives for EVSE, to further support commercial L2 deployments.
- Direct Duke Energy to ensure that all marketing materials and communications with customers through the Fleet Advisory Program be vendor neutral.
- Direct Duke Energy to revise the proposed EVFC tariff to allow site hosts to establish the prices and pricing policies for EV charging services provided at utility-owned EV chargers located on their property.

- Approve Duke Energy's proposed EVSE tariff with the following modifications:
    - Expressly allow for customer ownership and third-party turnkey solutions.
    - Require all chargers to be networked.
    - Provide site hosts the ability to choose from at least two (2) vendors of EV charging hardware and software for all options available to customers under the Rate EVSE Tariff.
- Direct Duke Energy to submit one or more alternatives to traditional demand-based tariffs for Commission approval within 6 months from the date of an order in this proceeding.

Q: Does this conclude your testimony?

A: Yes, it does.

VERIFICATION

I hereby affirm, under penalties for perjury, that the foregoing representations are true to the best of my knowledge, information and belief.

Dated: January 6, 2022

Kevin George Miller

KEVIN GEORGE MILLER

PROFESSIONAL EXPERIENCE

ChargePoint, Campbell, CA — 2016 – Present
Director, Public Policy
- Plan, direct and implement state and US federal policy and business development focused on company priorities.

Executive Office of Energy and Environmental Affairs (EEA), Boston, MA — 2014 – 2015
Acting Chief Financial Officer
- Lead for fiscally related issues to Governor's Office and House and Senate Ways & Means committees.
- Senior advisor to Cabinet Secretary on policies of seven agencies, 2,600 FTEs, and $500M+ annual spending.

Executive Office of Energy and Environmental Affairs, Boston, MA — 2012 – 2015
Director of Capital and Federal Finance
- Developed and managed $250M+ in annual capital investment programs to support the Commonwealth's energy and environmental priorities.
- Oversaw the Commonwealth's federally-funded initiatives related to energy and the environment.

Executive Office for Administration and Finance, Boston, MA — 2011 – 2012
Fiscal Policy Analyst
- Analyst in charge of $2.6B portfolio for Governor's budget office including statewide collective bargaining, Environmental Affairs, Public Safety, Sheriffs, and Health and Human Services agencies.
- Appointed Secretary's designee on the Regional Greenhouse Gas Initiative Auction Trust Committee.

New Hampshire Democratic Party, Manchester, NH — 2008
Field Organizer
- Responsible for organization and training in Portsmouth, Rye, and Greenland, NH.

Office of State Senator Marian Walsh, Boston, MA — 2006 – 2008
Press Secretary
- Developed and executed communications, public strategy, and stakeholder engagement.

UTILITY REGULATION & GOVERNMENT APPOINTMENTS

Utility Regulation Expert Witness
- Massachusetts DPU: Docket No. 18-150
- New Hampshire PUC: Docket No. DE 19-057
- NYPSC: Case Nos. 19-E-0065 & 19-E-0378
- Rhode Island PUC: Docket Nos. 4770/4780

Statewide Commissions and Working Groups
- Member Representative, New Hampshire Electric Vehicle Charging Infrastructure Commission
- Legislative Chair, Maryland Zero Emission Electric Vehicle Infrastructure Council
- Infrastructure Co-Chair, Massachusetts Zero Emission Vehicle Task Force
- Infrastructure Co-Chair, Drive Electric Pennsylvania
- Infrastructure Expert Member, National Zero Emissions Vehicle Strategy Working Group (Canada)

EDUCATION

Harvard Kennedy School of Government, Cambridge, MA — 2011
Master of Public Policy - International Trade and Finance

Tufts University, Medford, MA — 2005
Bachelor of Arts (Political Science and Drama), *cum laude*

United Nations International School, NY, NY — 2001
International Baccalaureate Diploma

Rule 29 Sheet 1
ELECTRIC VEHICLE INFRASTRUCTURE

A. APPLICABILITY

This Rule is applicable to all Electrical Distribution Infrastructure or Electric Vehicle (EV) Service Extensions on the utility side of the meter for all Customers or Applicants, excluding single-family residences, installing separately metered infrastructure to exclusively support Charging Stations for EV. For purposes of this Rule, Electrical Distribution Infrastructure includes EV Service Extensions as defined in Sections B.3 and I of this Rule.[1] This Rule is not applicable to Applicants who intend to participate in any of SCE's current Charge Ready Programs, such as Charge Ready Transport Program and Charge Ready 2, authorized by the California Public Utilities Commission (CPUC) prior to the effective date of this Rule.

Eligibility. To be eligible for this Rule, Applicant must purchase and install qualified Electric Vehicle Supply Equipment (EVSE) or Charging Stations in the quantity approved by SCE in SCE's sole discretion.[2] Applicant must agree to maintain and operate the EVSE or Charging Stations associated with this Rule for a minimum period of five years.

Incidental Load. An exception to the requirement that eligible meters are to be dedicated exclusively to EV charging is that appliances and apparatus that solely serve the overall EV infrastructure of the site and no other use may be included as load on the EV-dedicated meter. The eligible Incidental Load must be limited to devices directly needed to solely support the EV infrastructure and charging uses of the site itself. The added load included on the EV meter must not include load from any non-EV charging infrastructure facilities, appliances or apparatus.

B. GENERAL

1. Design and Installation. SCE will be responsible for planning, designing, engineering and installing the Electrical Distribution Infrastructure using SCE's standards for material, design, and construction.

   a. Construction and Design Specifications, Standards, Terms, and Conditions for New Extension of Service Project

      (1) In compliance with Section 783 of the Public Utilities Code, SCE will apply only those construction and design specifications, standards, terms, and conditions that are applicable to a new extension of service project for the 18 months following the date the application for a new extension of service project is approved.

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[1] Certain words beginning with capital letters are defined either within the provisions of this Rule or in SCE's Rule 1.
[2] For Applicants that are considered EVSE manufacturers, a proof of commitment to install the EVSE or Charging Station is required.

(Continued)

Rule 29 Sheet 2
ELECTRIC VEHICLE INFRASTRUCTURE

(Continued)

B. GENERAL (Continued)

(2) SCE may adopt modifications to those construction and design specifications, standards, terms, and conditions applicable to a new extension-of-service project only in accordance with any of the following:

(a) An order or decision of the CPUC or any other state or federal agency with jurisdiction.

(b) A work order issued by SCE to implement construction or design changes necessitated by a Customer-driven scope of work modification.

(c) A material-related design change identified by SCE to remedy a construction material defect that could pose a risk to public safety.

(3) Approval date of a new extension of service application refers to the earlier of either the effective date of the contract for the extension of electric service or the date when SCE first invoices the Customer for the extension of electric service. “Invoice” to mean when SCE presents an offer to the Customer for the extension of service in response to an application for an extension of service submitted pursuant to the regulations of the CPUC and applicable specifications of SCE.

2. Electrical Distribution Infrastructure. Pursuant to Public Utilities Code Section 740.19(b), the term Electrical Distribution Infrastructure shall include poles, vaults, service drops, transformers, mounting pads, trenching, conduit, wire, cable, meters, other equipment as necessary, and associated engineering and civil construction work.

3. EV Service Extension. SCE's EV Service Extension shall consist of (a) primary or secondary underground or overhead service conductors, (b) poles to support overhead service conductors, (c) service transformers, (d) SCE-owned Metering equipment, and (e) other SCE-owned service related equipment.

4. Ownership. The Electrical Distribution Infrastructure and EV Service Extension installed under the provision of this Rule shall be owned, operated, and maintained by SCE.

5. Private Lines. SCE shall not be required to serve any Applicant from Distribution Line Extension or EV Service Extension facilities that are not owned, operated, and maintained by SCE.

(Continued)

B. GENERAL (Continued)

6. Special or Added Facilities. Any special or added facilities SCE agrees to install at the request of Applicant will be installed at Applicant's expense in accordance with SCE's Rule 2, Description of Service.

7. Contracts. Each Applicant requesting service may be required to execute a written contract(s) prior to SCE performing its work to establish service.

8. Distribution Line Extension. Whenever SCE's distribution system is not complete to the point designated by SCE where the EV Service Extension is to be connected to SCE's distribution system, the extension of Distribution Line facilities will be installed in accordance with Rule 15, Distribution Line Extensions.

9. Rights-of-Way: Rights-of-way or easements may be required by SCE to install the Electrical Distribution Infrastructure and EV Service Extension, the cost of which will be borne by SCE.

   a. EV Service Extensions. If the EV Service Extension must cross property owned by a third party to serve the Applicant, then SCE may, at its option, install such EV Service Extension after appropriate rights-of-way or easements, satisfactory to SCE are obtained.

   b. Distribution Line Extensions. If SCE's facilities installed on Applicant's property, or third-party property, will be or are designed to serve adjacent property, then SCE may, at its option, install its facilities after appropriate rights-of-way or easements, satisfactory to SCE, are obtained.

   c. Clearances. Any necessary rights-of-way or easements for SCE's facilities shall have provision to maintain legal clearances from adjacent structures.

10. Environmental Studies or Issue Mitigation. Environmental studies or issue mitigation may be required by SCE to install the Electrical Distribution Infrastructure and EV Service Extension, the cost of which will be borne by the Applicant.

Rule 29
ELECTRIC VEHICLE INFRASTRUCTURE

(Continued)

B. GENERAL (Continued)

11. Access to Applicant's Premises. SCE shall have the right to enter and leave Applicant's Premises for Non-Emergency purposes connected with the furnishing of electric service (e.g. meter reading, inspection, testing, routine repairs, replacement, maintenance, vegetation management, etc.). When necessary, SCE will make prior arrangements with Applicant for gaining access to Applicant's Premises. For Emergency purposes only, SCE may enter Applicant's Premises at all times, without notice to Applicant, and may exercise any and all rights secured to it by law, or under SCE's tariffs. These rights include, but are not limited to:

    a. The use of a SCE-approved locking device, if Applicant desires to prevent unauthorized access to his/her property containing SCE's facilities;

    b. Safe and ready access for SCE personnel free from unrestrained animals; and

    c. Unobstructed ready access for SCE's vehicles and equipment to install, remove, repair, or maintain its facilities, and removal of any and all of its property installed on Applicant's Premises after the termination of service.

12. Service Connections. Only personnel duly authorized by SCE are allowed to connect or disconnect service conductors to or from SCE's Distribution Lines, remove meters unless as allowed under Rule 22, Direct Access, remove SCE-owned Electrical Distribution Infrastructure and EV Service Extension, or perform any work upon SCE-owned existing facilities. Installation of passive, non-electrically connected monitoring devices on or near the meter by non-SCE personnel is permitted. Customer is fully responsible for damage to SCE Facilities resulting from the installation of such device. SCE may remove such device if the device creates a safety hazard, interferes with meter functionality or meter reading procedures, and/or if it is necessary to permit work upon SCE-owned facilities, including the meter. SCE is not responsible for validating any data produced from these devices.

13. General Location. The location of the Electrical Distribution Infrastructure and EV Service Extension shall extend:

    a. Franchise Area. From the point of connection at the Distribution Line to Applicant's nearest property line abutting upon any street, highway, road, or right-of-way, along which it already has, or will install distribution facilities; and

    b. Private Property. On private property, along the shortest, most practical and available route (clear of obstructions) as necessary to reach a Service Delivery Point designated by SCE.

(Continued)

Rule 29 Sheet 5
ELECTRIC VEHICLE INFRASTRUCTURE

(Continued)

B. GENERAL (Continued)

14. Limitation: The length and normal route of the Electrical Distribution Infrastructure and EV Service Extension will be determined by SCE according to its planning, designing, and engineering standards and considered as the distance along the shortest, most practical, available and acceptable route.

C. METERING

1. General: The meter and associated metering equipment installed under this Rule shall solely serve the EV load and Incidental Load directly needed to solely support the EV infrastructure and charging uses of the site itself.

   a. Meter All Usage. Delivery of all electric power and energy will be metered, unless otherwise provided for by SCE's tariff schedules or by other applicable laws.

   b. Meter Location. All meters and associated metering equipment shall be located at some protected location on Applicant's Premises as approved by SCE.

   c. Meter Ownership. SCE shall own and maintain all meters and associated metering equipment unless otherwise allowed by SCE's tariffs.

2. Number of Meters. Only one meter will be installed for a single non-residential enterprise on a single Premises, except:

   a. When otherwise required or allowed under SCE's tariffs;

   b. At the option of and as determined by SCE, for its operating convenience, consistent with its engineering design;

   c. When required by law or local ordinance; or

   d. When additional services are granted by SCE.

   A single meter is required for each single enterprise operating in one building or group of buildings or other development on a single Premises such as, but not limited to, a commercial business, school campus, industrial manufacturer, or recreational vehicle park, unless otherwise approved by SCE.

(Continued)

D. EV SERVICE EXTENSIONS

1. Number of EV Service Extensions. SCE will not normally provide more than one EV Service Extension, including associated facilities, either overhead or underground for any one building or group of buildings, for a single enterprise on a single Premises, except:

    a. Tariffs. Where otherwise allowed or required under SCE's tariffs;

    b. SCE Convenience. At the option of and as determined by SCE, for its operating convenience, consistent with its engineering design for different voltage and phase classification, or when replacing an existing service;

    c. Ordinance. Where required by ordinance or other applicable law, for such things as fire pumps, fire alarm systems, etc.; or

    d. Other. SCE may charge for additional services provided under this paragraph, as special or added facilities.

2. Underground Installations.

    a. Underground Required: Underground EV Service Extensions (1) shall be installed where required to comply with applicable tariff schedules, laws, ordinances, or similar requirements of governmental authorities having jurisdiction, and (2) may be necessary as determined by SCE where Applicant's load requires a separate transformer installation of 300 kVa or greater.

    b. Underground Optional. An underground EV Service Extension may be installed in an area where it is not otherwise required and when requested by Applicant and agreed upon by SCE. The cost of which will be paid for by the Applicant.

    c. Beginning August 2, 2010, SCE will no longer accept requests under the Added Facilities provision of Rule 2, Section H, for underground distribution systems that call for specified pieces of electrical equipment to be installed in below-ground structures in circumstances where it is technically feasible to install the equipment above ground. See SCE's Rule 2, Section H.4, for more details.

Rule 29
ELECTRIC VEHICLE INFRASTRUCTURE

Sheet 7

(Continued)

D. EV SERVICE EXTENSIONS (Continued)

3. Overhead Installations. Overhead EV Service Extensions are permitted except under the circumstances specified in Section D.2.a above.

4. Unusual Site Conditions. In cases where Applicant's building is located a considerable distance from the available Distribution Line or where there is an obstruction or other deterrent obstacle or hazard such as plowed land, ditches, or inaccessible security areas between SCE's Distribution Line and Applicant's building or facility to be served that would prevent SCE from prudently installing, owning, and maintaining its EV Service Extensions, SCE may at its discretion, waive the normal Service Delivery Point location. In such cases, the Service Delivery Point will be at such other location on Applicant's property as may be mutually agreed upon; or, alternatively, the Service Delivery Point may be located at or near Applicant's property line as close as practical to the available Distribution Line.

E. RESPONSIBILITIES FOR NEW ELECTRIC DISTRIBUTION INFRASTRUCTURE AND EV SERVICE EXTENSION

1. SCE Responsibilities. In accordance with SCE's design, specifications, and requirements for the installation of Electric Distribution Infrastructure and EV Service Extensions, SCE is responsible for the following including any costs:

   a. Excavation. All necessary trenching, backfilling, and other digging as required including permit fees.

   b. Conduit and Substructures. Furnishing, installing, owning, and maintaining all Conduits (including pull wires) and Substructures on Applicant's Premises or SCE's Franchise Area (or rights-of-way, if applicable) as necessary to install the Service Extension.

   c. Protective Structures: Furnishing, installing, owning, and maintaining all necessary Protective Structures as specified by SCE for SCE's facilities on Applicant Premises. Any decorative or custom protective structures shall be the responsibility of the Applicant to install, own, and maintain.

(Continued)

E. RESPONSIBILITIES FOR NEW ELECTRIC DISTRIBUTION … (Continued)

1. SCE Responsibilities (Continued)

d. Underground Service. A set of service conductors to supply permanent service from the Distribution Line source to the Service Delivery Point approved by SCE.

e. Riser Materials. Any necessary pole riser material for connecting underground services to an overhead Distribution Line.

f. Overhead Service. A set of overhead service conductors and support poles to supply permanent service from a Distribution Line source to a suitable support at the Service Delivery Point approved by SCE. Such support shall be of a type and located such that service wires may be installed in accordance with good engineering practice and in compliance with all applicable laws, ordinances, rules, and regulations including those governing clearances and points of attachment.

g. Metering. When the meter is owned by SCE, SCE will be responsible for the necessary instrument transformers where required, test facilities, meters, associated metering equipment, and the metering enclosures when SCE elects to locate metering equipment at a point that is not accessible to Applicant.

h. Transformer. The transformer where required, including any necessary switches, capacitors, electrical protective equipment, etc. When either a padmounted or overhead transformer is installed on Applicant's Premises, the Service Extension shall include the primary conductors from the connection point at the distribution supply line to the transformer and the secondary conductors, if any, from the transformer to the Service Delivery Point.

i. Government Inspection. SCE will establish electric service to Applicant following notice from the governmental authority having jurisdiction that the Applicant-owned facilities have been installed and inspected in accordance with any applicable laws, codes, ordinances, rules, or regulations, and are safe to energize.

(Continued)

E. RESPONSIBILITIES FOR NEW ELECTRIC DISTRIBUTION...(Continued)

1. Applicant Responsibilities. In accordance with SCE's design, specifications, and requirements for the installation of the Electric Distribution Infrastructure or EV Service Extensions, subject to SCE's inspection and approval, Applicant is responsible for the following including the costs:

   a. Clear Route. Providing a route on any private property that is clear of obstructions which would inhibit the construction of either underground or overhead EV Service Extensions

   b. Applicant's Facility Design and Operations. Applicant shall be solely responsible to plan, design, install, own, maintain, and operate facilities and equipment beyond the Service Delivery Point (except for SCE-owned metering facilities), including obtaining any relevant authority having jurisdiction (AHJ) permit, in order to properly receive and utilize the type of electric service available from SCE. Refer to SCE's Rule 2 for a description, among other things, of:

      (1) Available service delivery voltages and the technical requirements and conditions to qualify for them,
      (2) Customer utilization voltages,
      (3) Load balancing requirements,
      (4) Requirements for installing electrical protective devices,
      (5) Loads that may cause service interference to others, and
      (6) Motor starting limitations.

   c. Required Service Equipment. Applicant shall, at its sole liability, risk, and expense, be responsible to furnish, install, own, maintain, inspect, and keep in good and safe condition, all facilities of any kind or character on Applicant's Premises that are not the responsibility of SCE but are required by SCE for Applicant to receive service. Such facilities shall include but are not limited to the overhead or underground termination equipment, Conduits, service entrance conductors from the Service Delivery Point to the location of SCE's metering facilities, connectors, meter sockets, meter and instrument transformer housing, service switches, circuit breakers, fuses, relays, wireways, metered conductors, machinery and apparatus of any kind or character. Detailed information on SCE's service equipment requirements will be furnished by SCE.

(Continued)

E. RESPONSIBILITIES FOR NEW ELECTRIC DISTRIBUTION...(Continued)

1. Applicant Responsibilities (Continued)

d. Coordination of Electrical Protective Devices. When, as determined by SCE, Applicant's load is of sufficient size as to require coordination of response time characteristics between Applicant's electrical protective devices (circuit breakers, fuses, relays, etc.) and those of SCE, it shall be Applicant's responsibility to provide such coordination in accordance with SCE's Rule 2.

e. Liability. SCE shall incur no liability whatsoever, for any damage, loss or injury occasioned by:

(1) Applicant-owned equipment or Applicant's transmission and delivery of energy, or
(2) The negligence, omission of proper protective devices, want of proper care, or wrongful act of Applicant, or any agents, employees, or licensees of Applicant, on the part of Applicant in installing, maintaining, using, operating, or interfering with any such conductors, lines, machinery, or apparatus.

f. Facility Tampering. Applicant shall provide a suitable means acceptable to SCE for placing its seals on meter rings and covers of service enclosures and instrument transformer enclosures which protect unmetered energized conductors installed by Applicant. All SCE-owned meters and enclosure covers will be sealed only by SCE's authorized employees and such seals shall be broken only by SCE's authorized employees. However, in an emergency, SCE may allow a public authority or other appropriate party to break the seal. Any unauthorized tampering with SCE-owned seals or connection of Applicant-owned facilities to unmetered conductors at any time is prohibited and is subject to the provisions of SCE's Rule 11 for unauthorized use.

g. Transformer Installations on Applicant's Premises. Transformer installations on Applicant's Premises shall be as specified by SCE and in accordance with the applicable provisions in SCE's Rule 16, Section D.1.g.

h. Building Code Requirements. Any service equipment and other related equipment owned by Applicant, as well as any vault, room, enclosure, or lifting facilities for the installation of transformers shall conform with applicable laws, codes, and ordinances of all governmental AHJ.

(Continued)

E. RESPONSIBILITIES FOR NEW ELECTRIC DISTRIBUTION...(Continued)

1. Applicant Responsibilities (Continued)

   i. Reasonable Care. Applicant shall exercise reasonable care to prevent SCE's Service Extension, other SCE facilities, and meters owned by SCE or others on the Applicant's Premises from being damaged or destroyed, and shall refrain from interfering with SCE's operation of the facilities and shall notify SCE of any obvious defect. Applicant may be required to provide and install suitable mechanical protection (barrier posts, etc.) as required by SCE.

   j. Corrective Action. In cases where the EV Service Facilities have become inaccessible or hazardous condition exist or any object becomes impaired under any applicable laws, ordinances, rules, or regulations of SCE or public authorities, the Applicant or owner shall, at Applicant's or owner's expense, either correct the access or clearance infractions or pay SCE its total estimated cost to relocate its facilities to a new location which is acceptable to SCE. Applicant or owner shall also be responsible for the expense to relocate any equipment which Applicant owns and maintains. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service.

3. Installation. SCE will perform all design and installation work required to install EV Service Extensions.

F. PAYMENTS

Applicant is responsible to pay SCE the following non-refundable costs as applicable under this Rule and in advance of SCE commencing its work:

1. Tax. Any payments or contribution of facilities by Applicant are taxable Contributions in Aid of Construction (CIAC) and shall include an Income Tax Component of Contribution (ITCC) for state and federal tax at the rate provided in SCE's Preliminary Statement.

2. Environmental Studies or Issue Mitigation. Environmental studies or issue mitigation may be required by SCE to install the Electrical Distribution Infrastructure or EV Service Extension.

3. Other. SCE's total estimated installed cost for any work it performs that is Applicant's responsibility or performs for the convenience of Applicant.

(Continued)

G. RESPONSIBILITIES FOR EXISTING ELECTRIC DISTRIBUTION INFRASTRUCTURE AND EV SERVICE EXTENSION

1. Service Reinforcement

   a. SCE Owned. When SCE determines that its existing Electric Distribution Infrastructure and EV Service Extension require replacement, the existing Electric Distribution Infrastructure and EV Service Extension shall be replaced as a new EV Service Extension under the provisions of this Rule.

   b. Applicant-Owned. When SCE determines that existing Applicant-owned service facilities (installed under Rule 16) require replacement, such replacement shall be accomplished under the provisions for a new EV Service Extension, except that if SCE determines that any portion of Applicant's existing service conductors can be utilized by SCE, Applicant will convey any such usable part to SCE and an appropriate credit by SCE may be allowed to Applicant. Applicant will replace or reinforce that portion of the Service Extension which Applicant will continue to own under the provisions of this Rule for new services.

2. Service Relocation of Rearrangement

   a. SCE Convenience. When, in the judgment of SCE, the relocation or rearrangement of a service, including SCE-owned transformers, is necessary for the maintenance of adequate service or for the operating convenience of SCE, SCE normally will perform such work at its own expense, except as provided in Sections G.2.b. and G.5 of this Rule.

   b. Applicant Convenience. Any relocation or rearrangement of SCE's existing Service Facilities at the request of Applicant (aesthetics, building additions, remodeling, etc.) and agreed upon by SCE shall be performed in accordance with Section D above except that Applicant shall pay SCE its total estimated costs.

      In all instances, SCE shall abandon or remove its existing facilities, at the option of SCE, rendered idle by the relocation or rearrangement.

Rule 29 Sheet 13
ELECTRIC VEHICLE INFRASTRUCTURE

(Continued)

G. RESPONSIBILITIES FOR EXISTING ELECTRIC DISTRIBUTION...(Continued)

3. Impaired Access and Clearance. Whenever SCE determines that (1) its existing EV Service Extensions have become inaccessible for inspecting, operating, maintenance, meter reading, or testing, or (2) a hazardous condition exists or any of the required clearances between the existing EV Service Extension and any object becomes impaired under any applicable laws, ordinances, rules, or regulations of SCE or public authorities, then the Applicant or owner shall, at Applicant's or owner's expense, either correct the access or clearance infractions or pay SCE its total estimated cost to relocate its facilities to a new location which is acceptable to SCE. Applicant or owner shall also be responsible for the expense to relocate any equipment which Applicant owns and maintains. Failure to comply with corrective measures within a reasonable time may result in discontinuance of service.

4. Overhead to Underground Service Conversion

   a. Rule 20. Where an existing overhead Distribution Line is replaced by an underground distribution system in accordance with Rule 20, Replacement of Overhead With Underground Electric Facilities, new underground services will be installed under Rule 16, Service Extensions.

   b. Applicant's Convenience. Where overhead services are replaced by underground services for Applicant's convenience, Applicant shall perform all Excavation, furnish and install all Substructures, and pay SCE its total estimated installed cost to complete the new service and remove the overhead facilities.

5. Damaged Facilities. When SCE's facilities are damaged by others, the repair will be made by SCE at the expense of the party responsible for the damage. Applicants are responsible for repairing their own facilities.

(Continued)

Rule 29
ELECTRIC VEHICLE INFRASTRUCTURE

Sheet 14

(Continued)

G. RESPONSIBILITIES FOR EXISTING ELECTRIC DISTRIBUTION...(Continued)

6. Subdivision of Premises. When SCE's Electric Distribution Infrastructure and EV Service Extension are located on private property and such private property is subsequently subdivided into separate Premises with ownership divested to other than Applicant or Customer, the subdivider is required to provide SCE with adequate rights-of-way satisfactory to SCE for its existing facilities and to notify property owners of the subdivided Premises of the existence of the rights-of-way.

   When adequate rights-of-way are not granted as a result of the property subdivision, SCE shall have the right, upon written notice to Applicant, to discontinue service without obligation or liability. The existing owner, Applicant, or Customer shall pay to SCE the total estimated cost of any required relocation or removal of SCE's facilities. A new electric service will be re-established in accordance with the provisions of Section E above or Rule 16 for new service and the provisions of any other applicable SCE rules.

H. EXCEPTIONAL CASE

When the application of this Rule appears impractical or unjust to either party, or ratepayers, SCE or Applicant may refer the matter to the Commission for a special ruling or for approval of special conditions which may be mutually agreed upon.

I. DEFINITIONS

Applicant: A person or agency requesting SCE to deliver or supply electric service. Also referred to as Customer.

Charging Station: The equipment that interconnects the electricity grid at a Premises to the Electric Vehicle, whether using alternating current (AC) or direct current (DC), but not including the Electric Distribution Infrastructure. Charging Station is sometimes referred to as Electric Vehicle Supply Equipment (EVSE).

Conduit: Ducts, pipes or tubes of certain metals, plastics and other materials acceptable to SCE (including pull wires and concrete encasement where required) for the installation and protection of electric wires or cables.

Customer: See Applicant.

Distribution Line Extension: New distribution facilities of SCE that is a continuation of, or branch from, the nearest available existing permanent Distribution Line (including any facility rearrangements and relocations necessary to accommodate the Distribution Line Extension) to the point of connection of the last service. SCE's Distribution Line Extension includes transmission underbuilds and converting an existing single-phase line to three-phase in order to furnish three-phase service to an Applicant, but excludes service transformers, meters and services.

(Continued)

I. DEFINITIONS (Continued)

Electrical Distribution Infrastructure: Pursuant to Public Utilities Code Section 740.19(b), the term Electrical Distribution Infrastructure shall include poles, vaults, service drops, transformers, mounting pads, trenching, conduit, wire, cable, meters, other equipment as necessary, and associated engineering and civil construction work.

Electric Vehicle: An electric vehicle is any vehicle that utilizes electricity from external sources of electrical power, including the grid, for all or part of vehicles, vessels, trains, boats, or other equipment (e.g., aircraft, forklifts, port equipment) that are mobile sources of air pollution and greenhouse gases. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles (PHEV), battery electric vehicles (BEV), electric golf carts, or neighborhood electric vehicles (NEV), transit buses, drayage, vocation, short-haul fleets, port applications, ground equipment supporting goods movement, ground support equipment at airports, and long-haul truck stop applications to minimize the idling of diesel engines.

Emergency: Whenever, in SCE's discretion, a condition exists, that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of system integrity or when any other hazardous condition exists or whenever access is necessary for emergency service restoration, and such immediate action is necessary to protect persons, SCE's facilities or property of others from damage, or due to the failure of a protective device to operate properly, or a malfunction of any electrical system equipment or a component part thereof.

Excavation: All necessary trenching, backfilling, and other digging to install Distribution Line Extension or Service Extension facilities, including furnishing of any imported backfill material and disposal of soil as required, surface repair and replacement, landscape repair and replacement.

Franchise Area: Public streets, roads, highways, and other public ways and places where SCE has a legal right to occupy under franchise agreements with governmental bodies having jurisdiction.

Incidental Load: The incidental load is limited to devices directly needed solely to support the EV infrastructure and charging uses of the site itself. The added load included on the EV meter must not include load from any non-EV charging infrastructure facilities, appliances or apparatus.

Premises: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided, excepting in the case of industrial, agricultural, oil field, resort enterprises, and public or quasi-public institutions, by a dedicated street, highway or public thoroughfare or a railway. Automobile parking lots constituting a part of and adjacent to a single enterprise may be separated by an alley from the remainder of the Premises served.

(Continued)

Rule 29 Sheet 16
ELECTRIC VEHICLE INFRASTRUCTURE

(Continued)

I. DEFINITIONS (Continued)

Protective Structures: Fences, retaining walls (in lieu of grading), sound barriers, posts, or barricades and other structures as required by SCE to protect distribution equipment.
Service Delivery Point: Where SCE's Service Facilities are connected to either Applicant's conductors or other service termination facility designated and approved by SCE.

Electric Vehicle Service Extension (EV Service Extension): The overhead and underground primary or secondary facilities (including, but not limited to SCE-owned Service Facilities and Applicant-owned service facilities) extending from the point of connection at the Distribution Line to the Service Delivery Point. When an underground EV Service Extension is supplied from a SCE-designated overhead pole, the beginning point of connection to SCE's Distribution Line shall be where the EV Service Extension is connected to SCE's overhead Distribution Line conductors.

Substructures: The surface and subsurface structures which are necessary to contain or support SCE's electric facilities. This includes, but is not limited to, such things as splice boxes, pull boxes, equipment vaults and enclosures, foundations, or pads for surface-mounted equipment.

Trenching: See Excavation.

(Continued)

Petitioner's Exhibit 3-A (RAF)
IURC Cause No. 45616

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

RATE EVFC – PUBLIC ELECTRIC VEHICLE FAST CHARGING SERVICE

Availability

Public Electric Vehicle Fast Charging (EVFC) services will be available to all electric vehicle owners, without preference to Company's electric service customers, at Duke Energy Indiana (Company)-owned public electric vehicle charging stations where the Company provides fast charging service and accepts payments from the station user (electric vehicle operator).

Character of Service

EVFC services will be available at Company-owned stations with output of 50 KW or greater. The stations will be accessible to the public for charging of electric vehicles. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service". In case of conflict between any provisions of this schedule and the "General Rules and Regulations for Electric Service," the provisions of this rate schedule shall apply.

Rate

The EVFC rate is calculated using a statewide average for EVFC charging offered by individual fast charge stations in Indiana that charge a consumption-based or time-based fee, are greater than 50kW in charging output capacity, offer at least one charging connector and are publicly accessible 24-hours per day. This average rate will be reviewed quarterly and updated when the statewide average changes by more than 10% from the amount listed in this tariff. <u>Site hosts shall have the option of creating alternative pricing mechanisms for EV charging services.</u>

Individual Station Fast Charge Electric Vehicle Energy Rate = (R x D) / K
Where:

R = Rate charge per minute
D = Charging session duration in minutes
K = KWH used per charging event

Energy Charge * .... $0.342505 per kWh

Vehicle Idling Fee .... $1.00 per minute

*Energy charge includes applicable Utility Receipts Tax and Sales Tax

Terms of Payment

The vehicle idling fee may apply following a ten-minute grace period at certain stations located in close proximity to highway corridors or other highly trafficked areas. The Company reserves the right to limit station output (kW or kWh) based upon periods of high demand or high station utilization. The applicable rate (Energy Charge), including applicable taxes, will be visible to the users on the display. Users will be notified when the charging session is complete via the display located at the charging station and have the ability to obtain a detailed receipt.

Issued: **Effective**

40 States and D.C. Allow EV Charging per kWh

(October 28, 2021)

STATE	CITATION	SUMMARY
Alabama	Docket No. 32694	A person who owns, operates, leases or controls EV charging stations in AL is not a utility under *Code Section 37-4-1*, and thus is not subject to the jurisdiction of the Commission, pursuant to Title 37, *Code of Alabama*.
Alaska	Docket No. U-21-022	"the nature of the service provided by an EV charging stations differs from traditional electric service and should not be considered generation, transmission, or distribution to the public within the meaning of AS 42.05.990(6)(A)."
Arkansas	SB 272 (2017) Arkansas Code § 23-1-101(9)	The term "public utility" as defined does not include a person or corporation that purchases electricity from a utility, furnishes electricity exclusively to charge EVs and PHEVs for compensation, and is not otherwise a public utility.
Arizona	Docket No. RU-00000A-18-0284	Arizona Corporation Commission finds "the service engaged by companies to charge batteries for electric vehicles does not qualify electric charging providers as public service corporations under the Arizona Constitution." Further the Commission concludes "based on our constitutional mandate and case law that electric charging providers should not be considered public service corporations."
California	AB 631 PU Code § 216(i)	Amends section 216 of the PUC Code and places into law CPUC decision 09-08-009 exempting electric vehicle charging equipment or providers from regulation as a utility.
Colorado	House Bill 12-1258 Col. Rv. Stats Ch. 40 § 101-104	Persons selling electricity…to the public for use as a fuel in alternative fuel vehicles …are not subject to regulation as a public utility and are not subject to the jurisdiction, control, and regulation of the Commission or any other public regulatory body
Connecticut	HB 5510 (2016) Section 16-1 of the 2016 supplement to gen. statutes	(c) An owner of an electric vehicle charging station, as defined in section 16-19f, as amended by this act, shall not be deemed to be a "utility", "public utility" or "public service company" solely by virtue of the fact that such owner is an owner of an electric vehicle charging station.
DC	Council Bill 19-749	Energy Innovation and Savings Amendment Act of 2012": Public Utility excludes a person or entity that owns or operates electric vehicle supply equipment but does not sell or distribute electricity..."

Delaware	PSC Docket No. 19-0377 – Order No. 9516	"The ownership, control, operation, or management of a facility that supplies electricity to the public only for use to charge plug-in electric vehicles does not make the entity, corporation or person a public utility under 26 *Del. C* § 102 solely because of that ownership, control, operation, or management."
Florida	Fl. Rev. Stat. § 27-366.94	Passed into law in 2012, Chapter 27-366.94 is amended to specify that provision of electric vehicle charging to the public by a nonutility is not considered a retail sale of electricity. In addition rates, terms and services of electric vehicle charging services are not subject to regulation by the Florida Public Service Commission
Hawaii	Ha.Rev. Stat. § 269-1	Hawaii Revised Statutes states that owners and operators of facilities used primarily to charge vehicle batteries for electric vehicles are exempt from the definition of utility
Idaho	Idaho Code Section 61-119	Exempts electricity purchased from a public utility to charge the batteries of an electric motor vehicle
Illinois	220 ILCS 5/3-105 cha 1112/3 par 3-104 enacted 1-24-12	Amends Public Utilities Act. Provides that a company that owns or operates a facility that furnishes or sells electricity to the public for the purpose of charging electric vehicles is not and shall not be deemed a public utility
Kansas	HB 2145 (2021) K.S.A 66-104	The term "public utility" shall not include…: (2) electricity that is purchased through a retail electric supplier in the certified territory of such retail electric supplier, as such terms are defined in K.S.A. 66-1,170, and amendments thereto, for the sole purpose of the provision of electric vehicle charging service to end users.
Kentucky	Case No. 2018-00372	"An EVCS that receives electric service from a jurisdictional electric utility or that obtains electricity from a behind the meter source is not an electric utility as defined by KRS 278.010(3)(a), is not subject to the certification requirements of KRS 278.020(1), and is not subject to the Commission's jurisdiction."
Iowa	Docket No. RMU-2020-2020	"A commercial or public electric vehicle charging station is not a public utility under Iowa Code 476.1 if the charging station receives all electric power from the electric utility in whose service area the charging station is located. If an electric vehicle charging station obtains electric power from a source other than the electric utility, the determination of whether the commercial or public electric vehicle charging station is a public utility shall be resolved by the board."
Maine	LD 593 Sec. 1. 35 -A MRSA § 313-A	" 'Competitive electricity provider' means a marketer, broker, aggregator or any other entity selling electricity to the public at retail, but does not include an electric vehicle charging station provider."

Maryland	SB 997, HB/1280, Chapters 631 and 632, Acts 2012 State Govt. Code 1-101(j)	Electric Vehicle Users and Charging Stations-Exclusions Provides regulatory clarification for owners and operators of PEV Charging Stations and PEV Charging station service companies or provider by excluding them from the definition of "electricity supplier" or a "public service company" as defined in law and regulated by the Maryland Public Service Commission.
Massachusetts	Case D.P.U. 13-182-A	Massachusetts Department of Public Utilities order (August 4, 2014) determines that owners and operators of EVSE are "not subject to the Department's jurisdiction under the current statutory structure either as distribution companies, electric companies, or otherwise."
Michigan	Case Nos. U-17990 & U-20162 Final PSC Order ***Consumers & DTE service areas***	"The proposal indeed appears to be non-controversial, and the Commission agrees with the Staff that the sale of electricity by charging station owners should not be treated as a resale of electricity under the tariff, or as a sale by regulated utilities. This is a necessary change to the tariff language which the Commission approves." "The Commission...finds that DTE Electric should be required to file amended tariffs allowing sale-for-resale for commercial EV charging site hosts."
Minnesota	Minn. Stat. § 216B.02 Subdivision 4.[3])	Minnesota Statute states that the definition of a public utility does not include a retail seller of electricity used to recharge a battery that powers an electric vehicle and that is not otherwise a public utility
Missouri	HB 355 (2019) RSMo 386.020	Term "electrical corporation" shall not include: Persons or corporations not otherwise engaged in the production or sale of electricity at wholesale or retail that sell, lease, own, control, operate, or manage one or more electric vehicle charging stations.
Nevada	SB145, NRS 704.021 (11.)	Nevada statutory definition of a "public utility" or "utility" does not include: "Persons who own, control, operate or manage a facility that supplies electricity only for use to charge electric vehicles."
New Jersey	S. 2252 (c. 362, 2019)	Unless otherwise provided in Title 48 of the Revised Statutes, or any other federal or State law, an entity owning, controlling, operating, or managing electric vehicle service equipment shall not be deemed an electric public utility solely because of such ownership, control, operation, or management. The charging of a plug-in electric vehicle shall be deemed a service and not a sale of electricity by an electric power supplier or basic generation service provider.

New Mexico	HB 521 (2019)	A. The term "public utility" or "utility", when used in the Public Utility Act, shall not include: (1) any person not otherwise a public utility who furnishes the service or commodity only to that person or that person's employees or tenants, when such service or commodity is not resold to or used by others, or who engages in the retail distribution of natural gas or electricity for vehicular fuel."
New York	Case 13-E-0199 NY PSC Declaratory Ruling on Jurisdiction	NY State Public Service Commission declaratory ruling finds that the PSC does not have jurisdiction over (1) charging stations; (2) owners or operators of charging stations; or (3) the transaction between such owners or operators and members of the public.
North Carolina	HB 329	The term "public utility" shall not include a person who uses an electric vehicle charging station to resell electricity to the public for compensation […]. (Some conditions apply).
North Dakota	ND Code § 49-03-01.5 as amended by SB 2091 of 2021	"Electric public utility" means a privately-owned supplier of electricity offering to supply or supplying electricity to the general public. The term does not include a person that uses an electric vehicle charging station to resell electricity to the public if the reseller has procured electricity from an electric service provider that is authorized to engage in the retail sale of electricity within the service area in which the electric vehicle charging service is provided, and the resale is for the charging of electric vehicles exclusively.
New Hampshire	RSA 236:133 as amended by SB 575 of 2018	"IV. An owner of an electric vehicle charging station shall not be deemed to be a "utility," "public utility," or "public service company" solely by virtue of the fact that such an owner is an owner of an electric vehicle charging station. All electricity distribution companies shall make available in tariffs terms and rates for electronic vehicle charging stations and offer such information to the public."
Ohio	PUCO Case No. 20-434-EL-COI	"The Commission finds that any person, firm, copartnership, voluntary association, joint-stock association, company, or corporation, wherever organized or incorporated, which is providing electric vehicle charging service in this state, is not engaged in the business of supplying electricity for light, heat, or power purposes to consumers within this state, and, therefore, does not qualify as an 'electric light company' or public utility pursuant to R.C. 4905.02 and 4905.03. Consequently, the Commission's jurisdiction does not extend to an entity's provision of electric vehicle charging service."
Oklahoma	OAC 165:35-13-1(c)	"Sales of charging services from an electric vehicle charging station, not owned by a regulated utility, for the purpose of fueling an electric vehicle, including the ability to sell on a kWh basis, shall not be considered resale of

		retail electricity, and such sales from electric vehicle charging station shall not be subject to rate regulation by the Commission. Utility service to an electric vehicle charging station shall be provided subject to the utility's terms and conditions."
Oregon	Or. Stats. § 757.005(1)(b)(G)	The statutory definition of "public utility" does not include any corporation, company, partnership, individual or association of individuals that furnishes electricity for use in motor vehicles as long as the entity is not otherwise a public utility.
Pennsylvania	Final Policy Statement Order, M-2017-2604382	52 Pa. Code § 69.3501 (Section 1313 – Public Utility Code) (b) It shall be the policy of the Commission that a person, corporation or other entity, not a public utility, electric cooperative corporation, municipal authority or municipal corporation, owning and operating an electric vehicle charging facility that is open to the public for the sole purpose of recharging an electric vehicle battery should not be construed to be a sale to a residential consumer and should therefore not fall under the pricing requirements of 66 Pa. C.S. § 1313 (relating to price upon resale of public utility services).
Rhode Island	R.I.G.L. Section 39-1-2(20)	"Public utility" means and includes every company that is an electric distribution company . . . provided that the ownership or operation of a facility by a company which dispenses alternative fuel or energy sources at retail for use as a motor vehicle fuel or energy source, and the dispensing of alternative fuel or energy sources at retail from such a facility, does not make the company a public utility within the meaning of this title solely because of that ownership, operation, or sale; and provided further that this exemption shall not apply to presently regulated public utilities which sell natural gas or are dispensers of other energy sources . .
South Carolina	S. 304	"Section 58-27-1060. (A) A person or corporation who uses an electric vehicle charging station to resell electricity to the public for compensation is not an electric utility if: (1) the person or corporation has procured the electricity from an electrical utility, municipality, consolidated political subdivision, the Public Service Authority, or an electric cooperative that is authorized to engage in the retail sale of electricity within the territory in which the electric vehicle charging service is provided; (2) the person or corporation furnishes electricity exclusively for the charging of plug-in electric vehicles; and (3) the charging station is immobile."

Utah	H.B. 19 (2014) Utah Code § 54-2-1	Statutory definitions of "electrical corporation" and "public utility" do not include an entity that sells electric vehicle battery charging services.
Texas	S.B. 1202 (2021) Title 2, Subtitle B, Chapter 37 Subchapter A.	31.002 (6) "The term *(electric utility)* does not include: … (j) a person not otherwise an electric utility who … (iv) owns or operates equipment used solely to provide electricity charging service for consumption by an alternatively fueled vehicle, as defined by Section 502.004, Transportation Code" 31.002 (17) "The term (retail electric provider) does not include a person not otherwise a retail electric provider who owns or operates equipment used solely to provide electricity charging service for consumption by an alternatively fueled vehicle, as defined by Section 502.004, Transportation Code" 37.001(3) "A person who owns or operates equipment used solely to provide electricity charging service for consumption by an alternatively fueled vehicle, as defined by Section 502.004, Transportation Code, is not for that reason considered to be a retail electric utility."
Vermont	Sec. 39. 30 V.S.A. § 203 *as amended by Act No. 59 of 2019*	"(7) Notwithstanding subdivisions (1) and (2) of this section, the Commission and Department shall not have jurisdiction over persons otherwise not regulated by the Commission that is engaged in the siting, construction, ownership, operation, or control of a facility that sells or supplies electricity to the public exclusively for charging a plug-in electric vehicle, as defined in 23 V.S.A. § 4(85). These persons may charge by the kWh for owned or operated electric vehicle supply equipment, as defined in 30 V.S.A. § 201, but shall not be treated as an electric distribution utility just because electric vehicle supply equipment charges by the kWh."
Virginia	Va. Code Ann. § 56-1.2 and 56.1.2:1	Virginia Code makes several stipulations stating that a person not otherwise a public service corporation and who provides electric vehicle charging service at retail is not designated as a public utility, public service corporation, or public service company. In addition, the statute stipulates that electric vehicle charging service does not constitute a retail sale of electricity.
Washington	SHB 1571, Chapter 28 Laws 2011	The 2011 legislation established that the Washington Utilities and Transportation Commission shall not regulate the rates, services, facilities, and practices of an entity that offers battery charging facilities to the public for hire if (1) that entity is not otherwise subject to commission

	Rev. Code of Wash. 80.28.320	jurisdiction as an electrical company; (2) that entity is otherwise subject to commission jurisdiction as an electrical company, but its battery charging facilities and services are not subsidized by any regulated service. An electrical company may offer battery charging facilities as a regulated service, subject to commission approval
West Virginia	W.Va. Code § 24-2D-3	PSC has no jurisdiction over ultimate sale by non-utilities of alternate fuel used for motor vehicles.

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RATE EVSE – ELECTRIC VEHICLE SERVICE EQUIPMENT

Availability

To an individual Customer desiring electric vehicle charging infrastructure at locations served by the Company's distribution system. If safety, reliability, or access negatively affects delivery of service under this Schedule, service may be withheld or discontinued. Customer may choose any applicable rate schedule for electric service.

Character of Product or Service

This offering is available for networked ~~or non-networked~~ Electric Vehicle Service Equipment ("EVSE" or "charging infrastructure"). Networked EVSE contains wi-fi, cellular, or other communications capabilities to connect to the internet for communications, data gathering, and charging load management purposes by the Customer and/or the Company. The Company may provide programs and/or services to help Customers manage charging during off-peak hours. Participating site hosts shall have the choice of at least two (2) vendors of EV charging hardware and software which shall be prequalified by the Company to meet functional requirements. Site hosts shall retain the ability to set pricing for EV charging services.

Contract for Electric Vehicle Service Equipment

The original term of Contract may be from a minimum of four (4) years to a maximum of ten (10) years. Contracts will continue after the original term until terminated by either party on thirty days' written notice. The Customer may amend or terminate the Contract before the expiration of the initial Contract Period by agreeing to pay for service used to the date of disconnection. Customer shall also be liable for the minimum charges which would be due the Company for the remaining period of the contract in accordance with the contract provisions. The Company may require a deposit not to exceed 1/6th of a customer's estimated annual program revenue. The deposit will be returned at the end of the original term, provided the Customer has met all provisions of the Contract. Minimum term of Contract for specific situations shall be:

(a) Four (4) years for Level 2 charging infrastructure installed at a residence and designated by the Company as standard equipment and mounted on a wall.
(b) Four (4) years for Level 2 charging infrastructure at a location other than a residence and designated by the Company as standard equipment mounted on a wall, pedestal, pole, or pad.
(c) Eight (8) years for Direct-Current Fast Charging ("DCFC") infrastructure installed and designated by the Company as standard equipment.
(d) Ten (10) years for Level 2 charging and DCFC infrastructure designated by the Company as non-standard and/or installations including Extra Facilities as described in Rate paragraph (E) below.

Rates

(A) Level 2 EVSE

Level 2 charging infrastructure will be billed for installations of standard equipment installed on the Customer's side of the meter served by the Company's distribution system.[1]

[1] Rates include equipment, maintenance, and annual software networking fees, but do not include the monthly charges for any necessary excess facilities associated with the Company's Service Regulations and/or Line Extension Deposit requirements, electrical panel/wiring make-ready costs, costs for work on the Company's side of the meter, non-standard equipment, or any contribution required under this Schedule. Internet connectivity, arranged by the Customer and at the Customer's expense, may be required for Customers to participate in certain Company programs that may be offered in conjunction with other Company tariffs.

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(1) Residential

EVSE Description	kW ranges	Mounting	EVSE Monthly Rate
~~Non-Networked 240V EVSE 25ft Cord – J1772~~	~~Up to 7.7 kW~~	~~Inside or Outside Wall~~	~~$17.95~~
~~Non-Networked 240V EVSE 25ft Cord – J1772~~	~~Up to 9.6kW~~	~~Inside or Outside Wall~~	~~$19.56~~
~~Non-Networked 240V EVSE 25ft Cord – J1772~~	~~Up to 11.6 kW~~	~~Inside or Outside Wall~~	~~$25.06~~
Networked 240V EVSE 25ft Cord Includes Software – J1772	Up to 9.6 kW	Inside or Outside Wall	$20.60

(2) Non-Residential

EVSE Description	kW ranges	Mounting	EVSE Monthly Rate
~~Non-Networked Ruggedized 208/240V EVSE 25ft Cord – J1772~~	~~Up to 7.7 kW~~	~~Outside Wall~~	~~$19.69~~
Networked Client * 208/240V EVSE, 25ft Cord, Includes Software – J1772	Up to 7.7 kW	Outside Wall	$80.77
Networked Gateway 208/240V EVSE, 25ft Cord, Includes Software – J1772	Up to 7.7 kW	Outside Wall	$94.33

* Networked Client stations must be paired with a Networked Gateway. A Gateway can serve up to 11 Clients. A Client is not able to operate independently.

(B) DCFC infrastructure (Non-Residential)

DCFC infrastructure will be billed for installations of standard equipment installed on the Customer's side of the meter on the Company's distribution system.[1]

EVSE Description	kW range	Mounting	EVSE Monthly Rate
DCFC24 Networked with CCS-1 and CHAdeMO Cables, LED Display, Cellular Modem, Cable Management Hoister, Includes Software	24 kW	Outside Wall	$322.42
DCFC50 Networked with CCS-1 and CHAdeMO Cables, High Resolution Touch Screen Display, Cellular Modem, Cable Management Hoister, Includes Software	50 kW	Customer's Pad	$670.17
DCFC75 Networked with CCS-1 and CHAdeMO Cables, High Resolution Touch Screen Display, Cellular Modem, Cable Management Hoister, Includes Software	75 kW	Customer's Pad	$888.34
DCFC100 Networked with CCS-1 and CHAdeMO Cables, High Resolution Touch Screen Display, Cellular Modem, Cable Management Hoister, Includes Software and two rebuilds	100 kW	Customer's Pad	$1,233.31
DCFC150 Networked with CCS-1 and CHAdeMO Cables, High Resolution Touch Screen Display, Cellular Modem, Cable Management Hoister, Includes Software and two rebuilds	150 kW	Customer's Pad	$1,519.44

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(C) Pedestal or Pole Mounting

A special EVSE pedestal or pole is any Company-owned pedestal or pole installed as a part of an electric vehicle charging system and on which no other Company-owned overhead distribution facilities are installed. A Customer may choose to integrate EVSE with facilities that provide outdoor lighting services pursuant to the provisions contained within the Company's lighting service tariffs.

Mounting Description	Monthly Mounting Rate
Level 2 – Outdoor EVSE Mount (Residential)	$7.86
Level 2 – Universal Pedestal (Non-Residential)	$11.86
30ft Standard Wood Pole (Non-Residential)	$8.55
Protective Concrete Bollard (Non-Residential)	$5.66
Cable Management Hoister (Non-Residential)	$10.48
EV Supplemental Circuit**	$16.50

***Availability expected in 2022*

(D) Make-Ready Costs

To receive service under this Schedule, Customers may need to upgrade their electrical panel/wiring on the Customer's side of the meter prior to the installation of Level 2 and/or DCFC infrastructure. The EVSE Monthly Rate listed does not include estimated electrical panel/wiring make-ready costs.

Customer may elect to have the Company coordinate necessary enhancements and reimburse the Company for the associated cost, or secure necessary enhancements from a qualified 3rd party of their choice. In either case, the Customer and Company shall discuss and determine any necessary make-ready infrastructure and location of equipment prior to the scheduled EVSE installation date.

Any necessary electrical panel/wiring upgrades on the Customer's side of the meter remain the property of the Customer.

Wiring upgrades on the Company's side of the meter are subject to the Company's Line Extension Policy.

(E) Excess Facilities

Customer shall additionally pay an Excess Facilities charge when distribution facilities are requested that exceed distribution facilities normally supplied by the Company to render charging service and/or when EVSE facilities are requested that exceed EVSE facilities normally supplied by the Company to render charging service (e.g. customer chosen EVSE facilities to customize EVSE operation).

In such cases, customer shall pay an Excess Facilities charge of 1.22 percent per month, but not less than $25 per month, of the estimated original installed cost of the Excess Facilities. Excess Facilities that are above normal include, but are not limited to, the following:

- Any distribution transformer and/or primary conductor extension
- Installing underground circuit to deliver energy service to the EVSE
- Distribution-related work before the point of delivery that is above the Company's standard for service

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- Non-standard EVSE not included in the EVSE Monthly Rate provision, above. The Excess Facilities shall be the difference between the estimated installed cost of the non-standard EVSE and the estimated installed cost of the equivalent standard EVSE
- Extra Cords
- Any special EVSE mounting facilities not included in the Monthly Mounting Rate or provided for in the EVSE Monthly Charge

Billing

Customer will be billed monthly based on the pricing offered above.

Special Terms and Conditions

1) Non-Refundable Amounts:

   - Materials and methods of installation other than the Company's materials and methods under this tariff, which created additional cost the customer paid for. The Company's materials and methods are those that are reasonably necessary to deliver service as described in the provisions above.

   - Customer paid estimated cost of installing cables and conduit under paved or landscaped surface areas; however, Customer may cut and replace the pavement or surface in lieu of making the contribution.

   - Service supplied under the Monthly Rates listed above does not include the conversion of existing overhead circuits to underground. In such case, requesting Customer shall pay the corresponding cost. Customer shall pay, in addition to the applicable contribution and charges herein installation costs, plus removal costs, less salvage value of the overhead conductor being removed.

2) The Company will readily maintain, as soon as practical, the EVSE during working hours (7 AM to 7 PM) following notification by the Customer. After hours service is available from 7 PM to 7 AM at a cost of $140 per hour per trip.

3) At the request of the Customer, the Company shall remove or move Level 2 EVSE, as required by the Customer, at a cost of $100 per removal/move for residential Customers or $165 per removal/move for non-residential Customers in addition to applicable termination penalties discussed above due to the varied cost of DCFC EVSE, the Company will perform a cost of removal/move calculation based on actual costs to remove/move DCFC EVSE to determine applicable charges.

4) The installation of EVSE shall be in a location that is readily accessible by truck to support installation and maintenance of Company facilities. The Company reserves the right to refuse service if is not physically feasible to offer service and/or maintain charging equipment.

5) The customer owns all electrical panel/wiring on the customer's side of the meter with the exception of any optional specialty company owned EV supplemental circuit technology. The Company does not warrant any electrical panel/wiring make-ready work on the customer's side of the meter.

6) The customer shall be responsible for the cost incurred to repair or replace any fixture or pole which has been damaged. The Company shall not be required to make such repair or replacement or to make payment to the customer for damage.

7) ~~For networked EVSE installations, t~~The Customer shall provide and be responsible for maintaining communication access through either wi-fi, cellular, or other communications capabilities.

8) Rates shall be updated either up or down when installed equipment pricing varies by more than or equal to five (5) percent.

9) Networking and maintenance are included in the monthly rate with selected networked EVSE.

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10) For networked EVSE, the Customer may access network data for their respective chargers.

11) The Customer is responsible for compliance with local ordinances that may require an electrical inspection prior to Duke Energy installing EVSE.

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REGULATORY ASSISTANCE PROJECT

NOVEMBER 2020

Demand Charges: What Are They Good For?

An Examination of Cost Causation

Mark LeBel and Frederick Weston, with contributions from Ronny Sandoval

Contents

Acknowledgments

Editorial assistance was provided by Ruth Hare and Donna Brutkoski.

The authors would like to acknowledge and express appreciation to the following people who provided helpful insights into early drafts of this paper:

- Janet Gail Besser, Smart Electric Power Alliance
- Paul Chernick, Resource Insight
- Dan Cross-Call and Becky Li, Rocky Mountain Institute
- Karl R. Rábago, Rábago Energy LLC
- Jim Lazar, Carl Linvill and Ann McCabe, RAP

We would also like to thank GridLab for providing funding for Ronny Sandoval's participation in this project. When the report was drafted, Mr. Sandoval was working as an independent consultant. At the time of publication, he is employed at Vote Solar.

The analysis in this paper rests on the shoulders of earlier RAP publications, in particular:

Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Weston, F. (2000). *Charging for distribution utility services: Issues in rate design*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

That said, responsibility for the information and views set out herein lies entirely with the authors.

Executive Summary

Demand charges, rates that are applied to an individual customer's maximum short-term usage (typically 15, 30 or 60 minutes) in a billing period, have existed since nearly the beginning of the electric industry. While utilities often favor demand charges, economists have continually questioned whether they are an efficient form of pricing. With the widespread adoption of advanced metering, this is an opportune time to reconsider demand charges, even for industrial customers, and replace them with more efficient time-varying energy (kilowatt-hour) rates.

Traditional monthly demand charges have always provided a perverse incentive that does not reflect cost causation for shared system costs. Individual customer noncoincident peaks (NCPs) do not reflect the coincident peaks that drive *shared* generation and delivery capacity costs. The price signal that demand charges send — to lower individual customer NCP and to level a customer's load over time — is substantially different than a price signal to reduce usage at the time of coincident peaks. As a result, demand charges penalize customers for usage at times that do not impose particularly high costs and encourage them to waste effort and money shifting loads off their own maximum hour (and sometimes onto high-load system hours).

The historic exception to this rule is a customer that has a nearly 100% coincidence factor with the relevant peaks. The prototypical example of this in the mid-20th century was an industrial customer with very high load factors. Demand charges could be reasonable in the past only as applied to this specific category of customers. But, in today's electric system, even this justification for demand charges falls away. High penetrations of nondispatchable but variable renewable generation means that a 100% load factor is unlikely to be, from a system perspective, the most desirable load shape. Rather, flexible load — load that can respond to swift changes in the availability of supply, perhaps in the middle of the day for solar and late at night with wind — becomes cheaper to serve than unvarying loads in systems marked by high penetrations of variable supply.

Historically, demand charges have frequently been sized to recover most or all shared system capacity costs. Again, this may have been reasonable enough in the mid-20th century for certain customers, but it does not reflect the economics and engineering of a modern electric system. The choices that system planners make are trade-offs between different types of costs. Much "capacity" investment today aims to reduce energy costs and is not incurred to meet peak reliability needs. This means that a significant portion of investment in generation, transmission and distribution plant (and the associated operation and maintenance expense) cannot be reasonably described as demand-related or driven by peak reliability needs. Any pricing structures that reflect the marginal costs of peak system capacity should be sized properly to reflect these distinctions. That includes demand charges, if appropriate, as well as time-varying energy pricing.

It is fair to ask whether a properly sized "peak window" demand charge solves these issues. Although such a charge is superior to traditional demand charges for the pricing of shared capacity costs, peak window demand charges nonetheless retain many of the shortcomings of their traditional counterparts. Customers who have high usage at many times throughout the peak period should be charged more for capacity than customers who have a single high usage interval in that same window. Time-varying energy pricing provides superior incentives to optimize usage at all relevant times. Simple time-of-use rates are fairer and more efficient than peak window demand charges and can be made even more so by overlaying them with pricing that is responsive to critical peak conditions.

A few analysts and economists have identified several narrower applications where pricing structures akin to demand charges could be appropriate and reasonably efficient: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. While more research into these applications might be merited, demand-based pricing would only be a second-best approximation of a more efficient but potentially more administratively complex time- and location-based pricing system.

1. Introduction

Demand charges have existed almost since the beginning of the electric industry in the 1880s. They were originally called Hopkinson rates after John Hopkinson, a British engineer who described the concept in 1892. Hopkinson believed that costs of "plant and conductors"[1] — namely capacity costs — for an electric utility should be charged to customers based on the "greatest rate of supply the consumer will ever take."[2] Shortly thereafter, a meter was developed that could capture the highest kW power draw from the customer, defined over a period of an hour or half-hour, during an entire billing period (now typically a month). These rates became prevalent for industrial customers in the early 1900s.[3]

It did not take long, however, before economists called into question their putative cost-causation rationale. In 1941, future Nobel Prize winner in economics W. Arthur Lewis argued that the cost-causation case for demand charges was often based on "a simple confusion. ... The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak."[4] In 1970, prior to becoming chairman of the New York Public Service Commission, Cornell University professor Alfred E. Kahn wrote that demand charges are "basically illogical."[5] More recently, University of California professor and California Independent System Operator board member Severin Borenstein opined that "it is unclear why demand charges still exist."[6]

Electric utilities and some consultants still make broad arguments for demand charges that are, at their core, the same as those made more than a century ago. In 2016, the Edison Electric Institute (EEI) asserted that "demand charges provide accurate price signals" and "better collect capacity costs [than other kinds of prices]."[7] EEI made this

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1 Hopkinson, J. (1901). *Original papers: Vol. 1, Technical papers*, p. 257. Cambridge University Press.

2 Hopkinson, 1901, p. 261.

3 There was a debate within the electric utility industry about rate design in the 1890s. A time-of-use meter was invented nearly simultaneously with the demand meter, and some industry participants argued that time-of-use rates would be superior. See Hausman, W. J., & Neufeld, J. L. (1984). Time-of-day pricing in the U.S. electric power industry at the turn of the century. *The RAND Journal of Economics, 15*(1). This time-of-use meter disappeared from discussion relatively quickly, however, as an industry consensus formed around demand charges. Neufeld argues that demand charges were a part of utility strategy to discourage industrial customers from relying on distributed generation, known as "isolated plants" at the time. Neufeld, J. (1987, September). Price discrimination and the adoption of the electricity demand charge. *Journal of Economic History, 47*(3), 693-709. In addition, Samuel Insull, president of Chicago Edison (later Commonwealth Edison) and a major player in the industry, happened to own a part of the patent for the demand charge meter. See Yakubovich, V., Granovetter, M., & McGuire, P. (2005). Electric charges: The social construction of rate systems. *Theory and Society, 34*, 597-612.

4 Lewis, W. A. (1941). The two-part tariff. *Economica, 8*(41), 252.

5 Kahn, A. E. (1970). *The economics of regulation: Principles and institutions: Vol. 1, Economic principles*, p. 96. John Wiley & Sons.

6 Borenstein, S. (2016). The economics of fixed price recovery. *The Electricity Journal, 29*(7), 10.

7 Edison Electric Institute. (2016, February). *Primer on rate design for residential distributed generation*, p. 6. https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf

argument simultaneously for two different types of demand charges: (1) the traditional monthly noncoincident peak (NCP)[8] demand charge, based on an individual customer's NCP across an entire billing period, and (2) a peak window demand charge,[9] based on an individual customer NCP within a defined multihour interval, similar to the on-peak period for a time-of-use (TOU) rate.[10] In addition, there has been a push by EEI and many utilities to expand the application of demand charges beyond just the industrial and large commercial customer classes to small business and even residential customer classes.

Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general.[11] For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.

If there is a role for demand charges in today's electric system, it is much narrower than the one it performs for industrial customers in many jurisdictions. Modern versions of

[8] A customer's noncoincident peak is its highest demand, in kilowatts, measured at the meter during the period in question. This customer demand can be measured based on different intervals, typically 15, 30 or 60 minutes. "Noncoincident" means that this demand does not necessarily occur at the time of a system peak.

[9] There is no standardized terminology for this type of demand charge where determination of the maximum demand for the billing period considers only a limited number of peak hours, similar to the peak period for a time-of-use rate. We find the "peak window demand charge" description more apt than the other alternatives.

[10] Less commonly, daily-as-used demand charges are part of the discussion, which we raise later in this paper. As the name implies, it is a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges. In this paper, we do not focus on contract (ex ante) demand charges, although they share many features with these other alternatives.

[11] There are other issues at play in the debate around demand charges, particularly whether residential and small business customers can understand and manage these types of rates and the related potential for inequitable bill impacts. See Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge without a cause? Assessing electric utility demand charges on small consumers.* (Electricity rate design review paper No. 1). https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf; and Lazar J. (2015). Use great caution in design of residential demand charges. *Natural Gas & Electricity*. https://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf. The question of understandability of demand charges by residential and small business customers is a longstanding one. D. J. Bolton notes that a 1948 report by a government commission in Great Britain rejected demand charges for residential customers on two bases: (1) understanding of the rate and (2) the potential reaction to an overload encouraging higher usage levels going forward. Bolton, D. J. (1951). *Electrical engineering economics: Vol. 2, Costs and tariffs in electricity supply*, p. 255. (2nd ed. rev.). Chapman & Hall. We do not delve into these issues at length in this paper.

these charges need to be more rigorously fashioned to achieve economic efficiency and advance the public good than they have been historically. We examine three more nuanced cases where demand charges have been identified as a potentially efficient pricing mechanism: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. In these situations, pricing structures with some similarities to demand charges may be appropriate. In each of these cases, demand-based pricing would only be a second-best approximation of a more efficient time- and location-based pricing system.

Unless we reexamine fundamental ratemaking practices critically in light of the modern electric system and new technologies, we will miss major opportunities to optimize system costs, ensure reliability and improve societal outcomes. While utilities and some consultants have been pushing for new applications for demand charges, regulators and utilities should be moving in the opposite direction by replacing demand charges for industrial customers with more accurate pricing mechanisms.

2. Historic Cost-Causation Argument for Demand Charges

A frequently used but inaccurate cost-causation argument for demand charges begins with the observation that several of the most important cost categories can be denoted in kilowatts (kW) or megawatts (MW).

- Generation capacity is denominated in kW or MW, reflecting the maximum instantaneous power output of a given unit.
- Transformers are rated in kilovolt-ampere (kVA) or megavolt-ampere (MVA), a unit of apparent power[12] closely related to kW or MW.
- Conductors are rated in amps for the level of current that they can handle. For a given voltage, this leads to a maximum kW or MW power flow for that conductor (power equals current times voltage).[13]

From these engineering descriptions, which are accurate but potentially misleading, some analysts conclude that, because generation and delivery capacity can be measured in units of power (kW or MW), their costs are demand-related. Making the leap to retail rate design then becomes easy: Capacity costs are rated in kW, so prices should be reflected

[12] Apparent power is the combination of active and reactive power in an alternating current circuit that needs to be supplied to serve load. This includes the power components that are needed to energize the circuit but don't transfer useful power to the load.

[13] For three-phase power, power is current times voltage times the square root of 3.

in kW.[14] This is the essence of the argument made by EEI, but it rests on several fallacies.

Some earlier writers, including W. Arthur Lewis, D. J. Bolton and James Bonbright, are open to demand charges to a certain extent but are quite candid about their limitations and significant downsides. Important factors in this more nuanced determination include:

- The diversity and coincidence factors[15] of any group of customers who might face a demand charge.
- The relative metering costs for flat kilowatt-hour (kWh) rates, demand rates and time-varying rates.
- The ability (or lack thereof) for customers to economically shift certain types of load.
- The broad similarity of capacity and fuel costs for many generation alternatives (typically thermal steam units) prior to 1960.

Lewis acknowledged the metering problem in his 1941 article, "The Two-Part Tariff." He stated that "the two-part tariff [a demand charge and an energy charge] is superior to having a single undifferentiated price which discourages off-peak consumption, *but inferior to charging different prices at different times*, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly."[16] In the early and mid-20th century, only simple kWh metering was economic for small customers (that is, the system benefit from the response to time-differentiated pricing did not exceed the cost of the metering necessary to support it), while more sophisticated metering could be justified for industrial customers.

In 1951 Bolton noted, with some approval, that demand charges were much more common for industrial customers than residential.[17] He observed that residential customers' peaks are more random, that is to say more diverse (spread out in time) and less likely to be correlated with system peaks: "A metered demand system for such a [residential] consumer would mean making a high charge for payment at times when it was most unlikely to matter."[18] He opined that the load of many large industrial customers is not

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[14] It is worth noting that these "kW" demand measurements are actually measured in units of kilowatt-hours per hour and simplified to be presented as measures of kW demand.

[15] Diversity of demand for a utility reflects the temporal differences in usage among customers. Peak coincident demand at any level of the system is less than the sum of customers' individual peaks because of these temporal differences. The calculated "diversity factor" provides a quantitative measure of these differences; conversely, a "coincidence factor" measures the extent to which these individual peaks do line up. These concepts are defined and discussed further in Section 3.1.

[16] Lewis, 1941, pp. 255-256 (emphasis added). Even in 1941, Lewis thought that it was no longer the case that demand metering would be cheaper than time-based metering, with one alternative being simple timers and another being "ripple control," where a utility sends a high frequency signal to flip an equipment switch.

[17] Bolton, 1951, p. 255. Bolton's proposed ideal "scientific tariff" features a TOU rate and no demand charges, where the on-peak price recovers demand-related costs. See Bolton, 1951, pp. 249-250.

[18] Bolton, 1951, p. 255.

particularly susceptible to shaping, because it is "motive power" (i.e., motors to run large equipment), and the electricity costs represent a small fraction of overall costs for these firms.[19] This type of industrial customer has strong incentives, given a set amount of productive capacity, to have the highest operating factor possible and thus a high load factor.[20] This industrial load pattern implies a significant likelihood that an individual customer's peak in a given month or year is closely linked to the customer's demand at the time of system peak.

Bonbright, writing originally in 1961, stated that traditional demand charges provide some benefits from "a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short period likely to coincide with the heavy loads of other customers."[21] Bonbright then went on to observe that electric rate design in those days "[was] far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists." He noted in particular that there was little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[22]

Up until 1960, most generation options, with the exception of hydroelectric power, had very similar cost characteristics. Steam generation was the predominant capacity type, and there were few differences in cost among coal, oil and natural gas units. Even fuel prices were broadly similar. In such a system, there is a better case that all capacity is similarly situated to serve peak reliability needs and thus can be considered demand-related. As discussed later, this issue goes to the sizing of any demand charges if they can be shown to be a reasonable solution (in limited circumstances at best).

This combination of factors — (1) an industrial customer base with a relatively small number of customers, most of whom had high load factors, high peak-coincidence factors and high levels of consumption and (2) a large number of residential customers with lower coincidence factors and relatively low consumption per customer — provided a rough rationale for the rate designs that prevailed throughout most of the United States in the 20th century and are now lingering into the 21st. In pricing, this typically manifested itself in significant demand charges for large industrial classes to recover nearly all capacity costs and in fully volumetric energy rates for residential and small business customers.

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[19] Bolton, 1951, p. 238.

[20] Load factor is the ratio of an end user's actual energy usage in a period to its maximum potential usage in that period. It is calculated as follows: kWh/(peak demand x total hours), within the specified period.

[21] Bonbright, J. (1961). *Principles of public utility rates*, p. 311. Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

[22] Bonbright, 1961, p. 316.

In this historical context, this could be relatively fair and efficient for a narrow slice of customers that meet the relevant description. To the extent that other customers that could share capacity (e.g., churches and schools; offices and movie theaters) were faced with demand charges, these customers were treated unfairly and often paid significantly more costs than they caused.

3. Why Demand Charges Are Inefficient

Some of these arguments for demand charges held sway in the past, even though the better case for time-varying energy charges was well understood. Today, the features of the modern electric system undermine even the more nuanced historic case for demand charges altogether. This is true for large industrial customers as well as for residential and small business customers.

The original advocates of demand charges often focused on what they thought was a fair and efficient division of historic accounting costs. Modern economists, even those who still advocate for demand charges, recognize that this older perspective is in error and argue (correctly) that rate structures should be designed to efficiently optimize *future* costs.[23] This perspective leads one to the conclusion that rates should be reflective of forward-looking marginal costs. In utility regulation, this concept is translated into different operative regulatory language in different jurisdictions, calling variously for rates that discourage wasteful usage, reflect actual costs or ensure the causer pays those costs. But in each case, the underlying microeconomic principle is the same: Rate design should ensure that the actions customers take to minimize their own bills are consistent with the actions they would take to minimize system costs. The nitty-gritty of designing rates in this framework is how to fairly and efficiently reflect marginal costs in prices. The best way to conceptualize this is to examine how the customer responds to a given rate design — both its form and its magnitude. An efficient rate design will lead to customer behavior that optimizes system costs.

The marginal consumption incentives for customers in any system of time-varying rates are fairly straightforward: (1) discourage usage in periods of relatively high rates and (2) encourage usage in periods of relatively low rates. Prices that achieve these outcomes are charged in a way that is both (1) consistent (all kWh at a given time or system condition are treated the same) and (2) symmetric: If an increase in consumption causes a bill to rise by $10, then the same sized decrease causes a bill to decline by $10.

The incentives presented by a typical demand charge structure are somewhat more

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[23] See, for example, Boiteux, M. (1960). Peak-load pricing. *The Journal of Business, 33*(2), 157-179. (H. W. Izzard, Trans.); Kahn, 1970; and Crew, M. A., & Kleindorfer, P. R. (1979). *Public utility economics.* St. Martin's Press.

complex.[24] If a customer is perfectly flexible (indifferent as to when they take electricity from the grid) and has perfect foresight, a demand charge would clearly incentivize a 100% load factor within the relevant time frame (e.g., each month). Of course, such customers do not exist in the real world,[25] although there are some customers that come close to having 100% load factors because of the nature of their operations: 24-hour supermarkets, data centers and certain types of factories.

Because customers do not have perfect foresight and infinite flexibility, it is only possible to talk about the incentives created by a demand charge at a certain level of generality. The most obvious features of a demand charge are that it directly (1) discourages higher individual customer NCP demand and (2) encourages levelization of load within the relevant time period. The related key feature of all types of demand charges is that they act as a ratchet, even if the ratchet is not applied across multiple billing periods.[26] Once a certain level of demand has been reached, customers then face a *lower* marginal cost for the remainder of the period to which the demand charge applies, as long as they have a power draw between zero and their previous individual demand peaks.

When the demand charge impacts a particular consumption decision, it can be quite punitive — imagine paying $5 to $10 to make toast for a family, which is exactly what can happen with a poorly designed residential demand charge.[27] This shows up as a high marginal cost for a subset of hours and consumption decisions. But otherwise, if a particular consumption decision does not pose a substantial risk of setting the demand charge, then consumption becomes cheaper — defined solely by the other charges without any demand charge implications. This means that optimal customer decision-making under a demand charge is quite complex and depends on the level of foresight and the value of consumption across all of the relevant time periods. Of course, most customer decision-making will not necessarily be optimal but rather based on rules of thumb, particularly for residential and smaller commercial customers.

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[24] Sandford Berg and Andreas Savvides did some theoretical work that incorporated the granular incentives of a demand charge into a traditional economic model of consumption. See Berg, S. V., & Savvides, A. (1983, October). The theory of maximum kW demand charges for electricity. *Energy Economics (5)*4, 258-66. However, this was a two-period model with numerous simplifying assumptions. Such a simplified theoretical model does illuminate certain features of a demand charge, but the authors note numerous areas for further work. To our knowledge, this line of theoretical research has not been pursued.

[25] This is true in particular because customer "utility" from electricity is not solely about the amount of consumption. Customers also enjoy significant convenience benefits for certain usage timing, again assuming that on-site storage and energy management are not cheap and convenient enough to smooth these features out.

[26] Some rates that do not meet this criterion are occasionally described as demand charges, such as annual system coincident peak capacity charges. These types of charges may, however, be better thought of as a type of time-varying rate or perhaps in a third category of their own.

[27] A toaster is approximately 1 kW demand; see Home Energy Saver & Score: Engineering Documentation. (n.d.). *Default energy consumption of MELs*. http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels. If a customer uses it for 15 minutes straight at the time of the customer's individual peak, the monthly demand billing determinant increases by 1 kW with a corresponding bill increase.

As the analysis in the subsections that follow shows, demand charges — whether of the traditional monthly variety or the peak window variety — are inefficient and inequitable for the pricing of shared system costs, as is the continued reliance on them. There are three interrelated reasons for this:

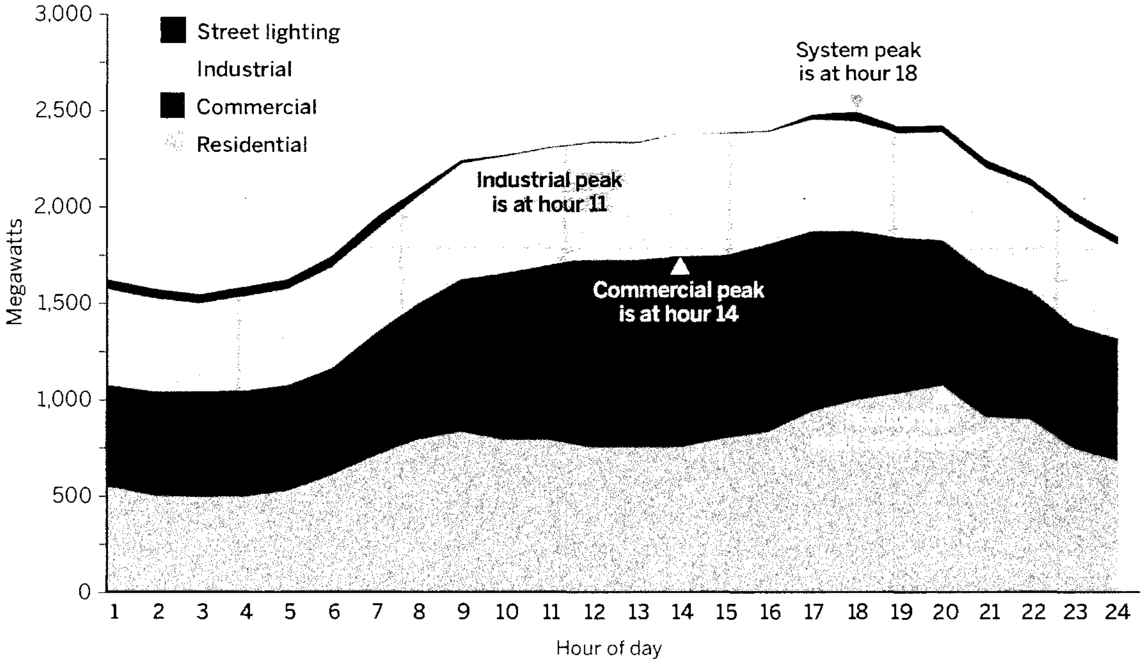
1. Traditional monthly demand charges provide an inaccurate price signal that is unrelated to high-cost periods for nearly all customers and which leads to inefficient customer efforts and investments in response to its incentives. The changes in the electric system due to dramatic increase in wind and solar generation mean that, from a system perspective, very high industrial load factors are not necessarily optimal.
2. Even in cases where a traditional demand charge could be justified, the sizing of demand charges to recover nearly all generation and delivery capacity costs reflects an outdated perspective of the engineering and economics of the electric system. Modern cost allocation and rate design must reflect the trade-offs between different types of expenses and investments. Much capacity investment is designed to reduce energy costs and line losses and should be charged on that basis.
3. Although a reasonably sized peak window demand charge is superior to a traditional monthly demand charge, time-of-use and other kinds of time-varying rates remain more efficient and equitable. These time-varying rate options are enabled by the dramatic decrease in the cost of sophisticated metering over the past two decades.

3.1 Individual Peaks Are Not the Same as System Peaks

Virtually all of the electric system consists of capacity that is shared among customers. With the exception of facilities that serve one or a very few customers, each component of the system is sized to meet an expected peak coincident demand of the customers it serves. The costs incurred to meet peak coincident demand, both short-run variable costs and capacity investment, are a significant portion of overall system costs. As a matter of economic efficiency, it is crucial that prices reflect the marginal costs of meeting the coincident system peak. Peak coincident demand is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as *diversity* of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 1 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

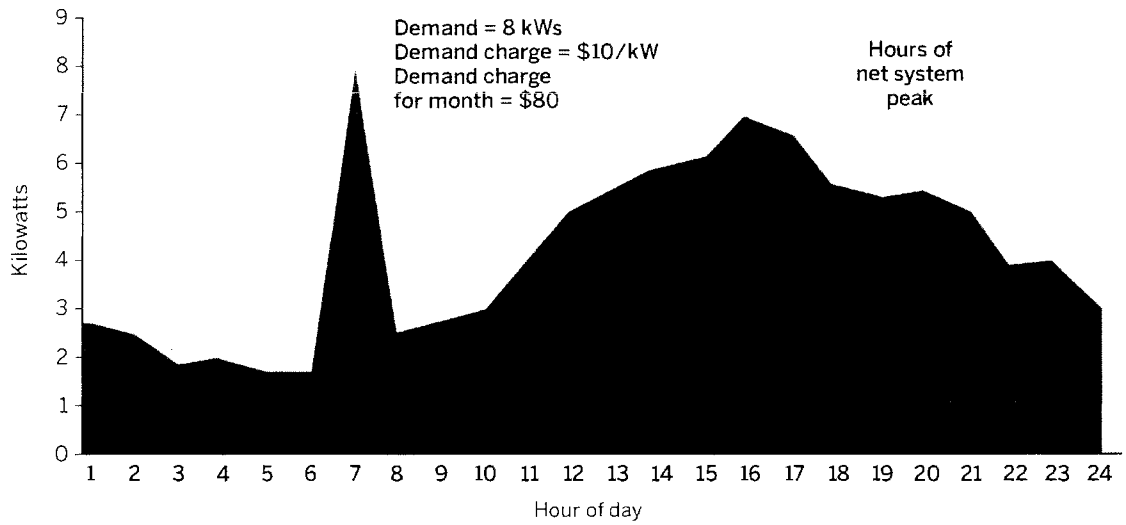
Figure 1. Diversity at the customer class level



Diversity can be quantified as the ratio of the sum of the subgroup peaks to the relevant coincident peak — the diversity factor. In this illustrative example, the diversity factor of the customer classes is 1.1. Diversity factors cannot go below 1 because in the extreme case where all subgroups peak at the same time, the sum of the subgroups equals the overall coincident peak. As long as customers peak at different times, diversity factors are higher as you consider smaller subgroups. Load diversity across individual customers is even greater than across customer classes.

Traditional monthly demand charges impose a rate on each customer that is independent of the system peak, as illustrated in Figure 2 on the next page. These demand charges provide little, if any, incentive to minimize a customer's contribution to system peak, unless a strong correlation exists between the customer's peak and the system's, a circumstance known as a high coincidence factor. In this illustrative example, a residential customer has an electric water heater that runs for nearly a full hour in the morning and a substantial cooling load in the afternoon.

Figure 2. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Demand charges encourage customers to flatten their own load curves relative to their individual maximum usage but do not necessarily encourage them to consume energy in ways that optimize system costs. If we assume that Figure 2 shows customer usage before a traditional monthly demand charge is imposed, we could expect significant changes in usage after application of this charge. It would be reasonable to expect this customer to attempt to reduce the 8 kW demand reached at 7 a.m. In the case of an electric water heater, the individuals living in the house could change their behavior or adjust the settings on the water heater. If the customer could reduce that morning peak, then there would be some incentive to reduce the afternoon peak caused predominantly by cooling load. In this case, the customer would benefit by moving some portion of that load away from hour 16 to other hours, including possibly during the system peak from hours 18 to 21. Furthermore, this customer could increase overall kWh consumption since the marginal cost would be lower at times (often including the system peak) when there is little risk of triggering a higher demand charge.

More generally, a flat individual customer load shape may not, in fact, be what is best for the system and is in fact worse than a low load factor with predominantly off-peak usage. The clearest illustration of this is street lighting load, which, for most systems, falls entirely outside the system peak hours and has a roughly 50% load factor. If we designed and sized a demand charge for street lighting on the same basis as a typical demand charge for industrial customers, it would force this low-cost off-peak load to pay as much for system capacity as an industrial customer using the same amount of power during the peak periods. This is virtually never done, however, and street lighting is treated as a separate rate class without any demand charges.

D. J. Bolton summarized the basic problem facing utilities and regulators in the middle of the 20th century:

> The aim should always be the improvement of the *system* load factor, and the only justification for an elaborate tariff is that it shall contribute directly to this end. ... If these costs are passed on to the consumer as they stand, in the form of a two-part [maximum demand] tariff, the fixed charge will be levied on the consumer's individual [maximum demand] instead of his effective demand on the system. The consequence will be that low-load-factor consumers will be overcharged (since they are given insufficient credit for their greater diversity) whilst the high-load-factor consumers are under-charged.
>
> The weakness of such a tariff when applied to the small individual consumer is that it treats load factor as a variable and diversity factor as a constant. ... But, in practice, diversity factors vary from consumer to consumer almost as much as load factors, and moreover, in the opposite direction.[28]

In other words, diverse customers can efficiently *share* capacity, and rate design should recognize this fact. As Bolton mentioned, it is often the case that small users have *lower* load factors but more diversity and thus less impact on peak. This is still true today because many small residential users have lower levels of heating and cooling usage (smaller residences) and often have similar appliances (microwaves, toasters, dishwashers and dryers) that are used more sporadically than larger residential customers. This means that the load factor for each individual appliance is lower, but the power characteristics are similar for each usage of an appliance.

As described in Section 2, demand charges may present a rough price signal to control peak system demand for customers with a high system-peak coincidence factor. In that case, controlling a customer's individual peak does systematically reduce the overall coincident peak. One case where this could be true historically is large industrial customer classes, where individual customer usage is driven by large equipment that is constantly used throughout every working day of the year. Even for this type of customer, however, there remains the question of whether load can be shifted from peak hours to off-peak hours. A critical peak energy price would produce a superior price signal, to actively reduce usage at critical peak hours, rather than maintain steady usage at those hours if such a shift is possible. Indeed, industrial customers in Texas, faced with significant, narrowly focused transmission charges based on four coincident peak hours, use specialized consultants to help them identify, in advance, the hours to which those

[28] Bolton, 1951, p. 107-108 (emphasis in original). Bolton was writing at a time when, in operations, customer demand was taken largely as a given and much of the resource mix was dispatchable thermal generation. In those circumstances, improvement of system load factor would, all else again being equal including overall kWh consumption, lead to a reduction in total system costs.

charges will be applied and reduce usage sharply in those hours.[29]

For a diverse customer class, however, the share of customers who face this demand charge price signal at system peak times is random and inconsistent. In almost any hour, whether near system peak or the lowest-load hours of the year, some customers will face the demand charge price signal. Also, a substantial number and, at times, a majority of customers (e.g., those customers who have already hit their peaks in the billing period) face a lower marginal cost at system peak times. While this is very blunt and inaccurate, it could be a sharper price signal than a traditional flat kWh rate in some circumstances, although a customer's likelihood of facing those circumstances would vary randomly. In contrast, a well-designed TOU rate provides the broadly correct incentive for all marginal consumption choices by all customers, sending a consistent price signal for on-peak and off-peak periods; a critical peak pricing rate can be even more precise, focusing on specific hours when the electric system is under stress.[30]

The undesirable effects of demand charges are made worse by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. For example, billing demand may be the greater of this month's noncoincident maximum load and 80% of maximum in the previous 12 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to system peak, there remains little incentive to minimize usage at a time of system peak.

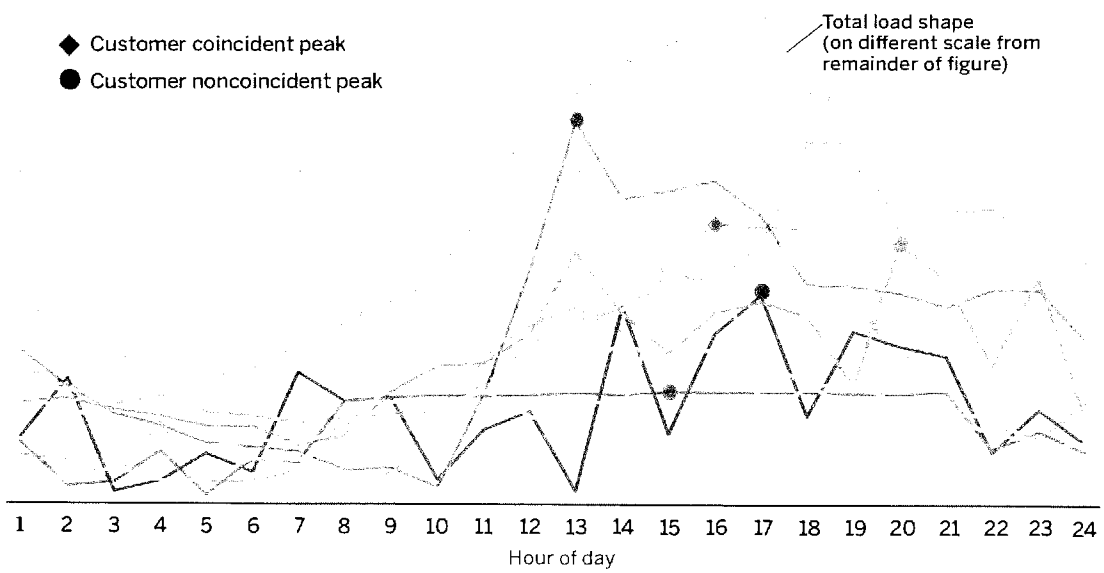
It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. Even at this level, there can be significant diversity among customers sharing a single transformer.

[29] Zarnikau, J., & Thal, D. (2013, September). The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market. *Utilities Policy, 26,* 1-6.

[30] To be more precise, we should say a "relevant component of the system" since different components of the system may hit peaks at different times. It's not unusual to see a systemwide peak occur at a particular hour on a particular day, but for individual elements of the subtransmission and distribution systems to hit peaks at other times. Expressing these peaks in prices and capturing each user's causal relationship to them is a challenge of time-varying rate design and, to the extent that this reflects different peaks in different areas of the system, may require locational distinctions as well. Precision is valuable, but complexity may produce inferior customer response.

Figure 3 shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. The total load shape is on a different scale than the individual customer loads.

Figure 3. Summer peak day load from 10 residential customers on one line transformer

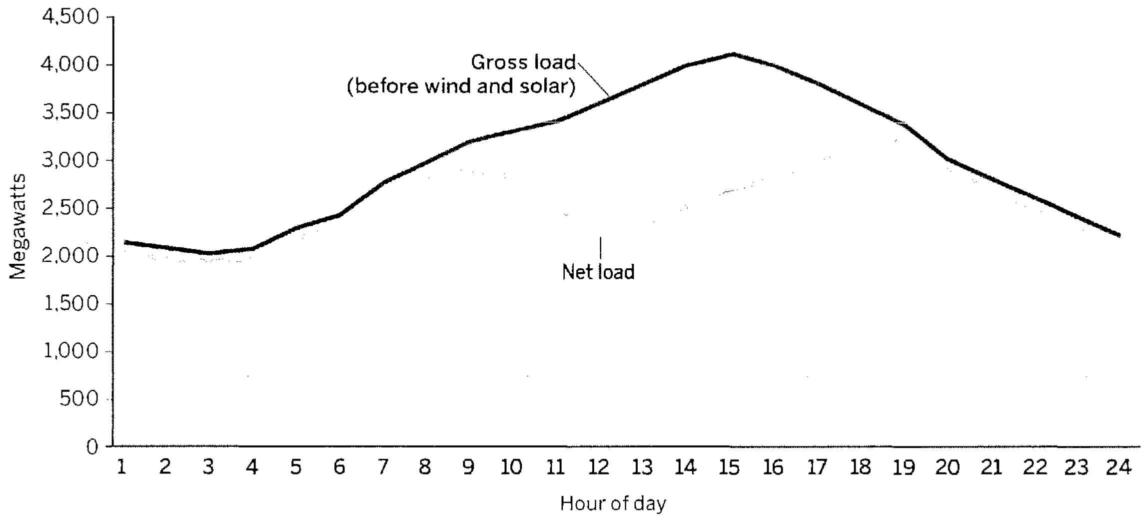


Source: Confidential load research sample

This demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day, which translates into a diversity factor of 1.16. This is just the variation on a particular high-load day. Although not shown in this figure, this coincident peak is only 64% of the sum of the annual NCPs for the individual customers, which translates into a diversity factor of 1.56.

At least two features of the modern electric system are changing the traditional argument that high-load-factor industrial customers should be subject to demand charges. First, the timing of traditional peaks and valleys, and by extension their effect on both short-run variable costs and longer-term capacity needs, is changing due to the increased prevalence of variable renewable resources. In regions where solar generation has increased rapidly, the "duck" curve is now a familiar phenomenon, as shown in Figure 4. Second, relatively low-cost on-site energy storage means that *all customers* have the potential for economically shiftable load and can respond to time-based price signals.

Figure 4. Illustrative net load curve



In such a situation, the benefits of shifting energy intensive industrial load from early evening to midday could be quite large. But this could mean *an increase* in the customer load factor, which is substantially discouraged by demand charges.

3.2 A Significant Portion of Capacity Investment Is Not Demand-Related

Traditional cost allocation terminology makes a distinction among demand-related, energy-related and customer-related costs. This terminology may obscure more than it illuminates. In particular, the term "demand-related" is often used to imply that demand charges are a proper pricing method for recovering costs so designated. Moreover, "demand-related" has typically referred to system peak demand and not individual customer peaks.[31] Other terminology, such as "peak-related," is more descriptive of the concept and avoids confusion with the use of "demand" in other contexts (such as "demand for energy").

[31] See Bolton, 1951, p. 132 (describing demand-related costs as "a cost proportional to system demand") and pp. 143-144 (describing how to spread costs across a wide number of potential system peak hours). In rate design, these same costs might be recovered through demand charges for certain customer classes. When determining the rate in dollars per kW, the total costs are then divided over the larger denominator of individual NCP demand, without accounting for load diversity within the class. This reduces the dollars per kW as charged to each customer from the dollars per kW used to assign costs to each class. This reduction is labeled differently in different jurisdictions, such as an "effective demand factor." However, this reduction is passed through to all customers and does not correct for differences in the timing of individual customer peaks. Customers who have demand highest at peak times receive a discount, and those who have demand highest at other times are overcharged.

Advocates for demand charges sometimes assert that most or all capacity costs are demand-related, which maximizes the size of the demand charge (if one is at all justified).[32] This leads to the large magnitude of the demand charges for industrial customer classes in many states. However, significant portions of capacity costs are not demand-related but are in fact incurred to meet energy needs. Investments in generation, transmission and distribution in the modern electric system may serve either of the two primary objectives of system planners, but the degree to which demand plays a role in each objective is different. These two goals are: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. In many respects, reliability concerns arise predominantly at peak system hours.[33] Meeting system load at least cost, by its very nature, must consider usage patterns across every hour of the year. To meet these two objectives, system planning, investment and operation must jointly consider not only the engineering and physics of the electric system but also the economics of the relevant choices. We see this tension in the evolving landscape of capacity resources.

With respect to generation, most capacity costs may have been demand-related prior to the invention of the modern combustion turbine in the 1960s. In an electric system dominated by largely homogenous steam generation capacity, a MW of capacity built for peak demand could be used equivalently year-round.[34] In such a situation, generation capacity costs could be allocated and charged predominantly at peak times.

The existence of multiple different types of generation capacity, storage and demand response changes this analysis significantly.[35] Aggregate supply (generation, storage and demand response) must be sufficient for systemwide coincident peaks, as well as contingencies across many other hours of the year, such as when outages (unforced and even planned, such as nuclear refueling) combine with other circumstances (e.g., unusual weather) to push demand up against the limit of available resources.

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[32] See Faruqui, A., & Davis, W. (2016, July). Curating the future of residential rate design. *Electricity Daily*, 23. http://files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf. The authors state that "a large share of a utility's costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand." See also the description of an idealized rate design that "recover[s] capacity costs through demand charges" in Faruqui, A. (2019, June 1). 2040: A pricing odyssey. *Public Utilities Fortnightly*, p. 56.

[33] Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[34] Even this historic scenario is a substantial oversimplification due to significant level of hydro generation in many areas.

[35] Bonbright recognized this briefly in a footnote; see Bonbright, 1961, 354, fn 15. By 1970, this was a better understood and less theoretical concept so that Kahn spent multiple pages discussing it; see Kahn, 1970, pp. 97-98. M. A. Crew and P. R. Kleindorfer formalized mathematical models of optimal pricing with multiple different types of generation capacity; see Crew & Kleindorfer, 1979.

The optimal mix of resource types depends on the broader load patterns. Different generation technologies have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for cost allocation and rate design purposes. The kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) is proving much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity that serves only short-term needs must have low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon.

So there is a trade-off between capacity costs and energy costs. Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework.[36] Under any reasonable version of the demand-related classification, it is important to recognize that the capacity costs placed here are to serve relatively short-period peak reliability needs.

Even the appropriate short-period peak reliability capacity costs should be charged on a broader basis than the absolute peak hour of the year for several reasons. One is that, while planners and operators generally have a good idea of when a system peak is likely to occur, they by no means know for sure. Consequently, there is a reliability value to capacity in many hours that should be reflected in prices.[37] A second is that the actual peak can be influenced by pricing structures. For example, if a system peak could be reliably predicted for the 5 p.m. hour on a given day, charging a higher price at that single hour could just push that same peak to 4 p.m. without a meaningful reduction. This is the "whack-a-mole" problem. Taking both of these issues into account, some writers have referred to the relevant set of peak hours as the "potential peak" period.[38] This is a major consideration in the determination of on-peak hours for a TOU rate or a peak

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[36] See Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[37] The operating reserves demand curve mechanism in the ERCOT wholesale market is one means of establishing that value across the entire year. In many areas, the loss of load probability is relatively high for only 50-100 hours per year, which is the typical design criteria for critical peak pricing and demand response programs.

[38] Bolton, 1951, p. 143.

window demand charge. A related challenge is that different elements of the system (e.g., generation, transmission and distribution) may peak at different times, which should be accounted for to the extent possible.

Generation capacity also has some reliability value in off-peak hours. Generation reliability issues may come primarily at peak times but certainly not exclusively. This can be because of generator outages (both planned and unplanned), unusual weather, transmission outages, other operating constraints or a combination of the above. D. J. Bolton commented in 1951 that there had been several times that load needed to be shed in off-peak seasons because of generator maintenance, which was "a definite indication of demand-related expenses on account of generating plant" even in off-peak seasons.[39] A loss-of-energy-expectation study calculates the year-round generation reliability risks and is one of the best ways to allocate demand-related generation capacity costs (but not energy-related generation capacity costs) over the entire year.[40] A probability-of-dispatch method, alternatively, assigns the total costs of generation resources to the hours in which each resource provides service.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of system investments to allocate and charge them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. The transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In many situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy and should be classified on that basis. Last, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year.

Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses, another clear energy-related benefit.[41] There are generally two types of losses incurred across the transmission and distribution system: no-load losses and load losses. No-load losses are incurred primarily to energize transformers (both station transformers

39 Bolton, 1951, p. 143.

40 Lazar et al., 2020, p. 132.

41 See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

and line transformers). Smaller transformers consume less energy in this respect, but overloaded transformers incur high load-related losses, so optimal transformer sizing saves energy.

The system planning considerations for load losses, also known as resistive losses, are more complex. These losses occur as electrical current flows through each element of the system. These losses manifest themselves in the form of heat and reduce the amount of useful power that can supply customer loads. This relationship is represented by the formula:

Load losses (in kW) = $I^2 \times R$

Where I = current (in amps) and R = resistance (in ohms)

Load losses can be decreased by reducing the resistance or reducing the current. Installing conductors with thicker metal wires is a simple way to reduce resistance, but these larger conductors are more expensive. Investments that reduce the current can, however, be much more effective because losses go up with the square of current. Any investment that reduces the current by 50% will reduce load losses by 75%, and any investment that reduces the current by 90% will reduce load losses by 99%. Since the current required to supply load is highest during peak demand periods, system losses are greatest during peak demand periods. There are several different types of capacity investments that reduce current substantially:

- **Higher voltage lines:** There is a direct relationship between the voltage of a line, the current passing through the line and the power delivered.
    - Current (in amps) = power (in kW)/voltage (in volts)
    - As a result, increasing the voltage by a factor of 10 reduces the current by 90%, which in turn reduces load losses by 99%.
- **Siting substations closer to loads:** By siting substations closer to loads, one can reduce the losses incurred by having conductors at lower voltages supply loads across long distances — the latter condition resulting in higher currents and relatively higher losses.
- **Converting single-phase distribution lines to three-phase power:** Three-phase power requires one additional conductor and additional space for the arrangement of the lines. For three phase lines, current = power/(voltage x $\sqrt{3}$). At the same voltage, current drops by 42.3% and load losses are reduced by two-thirds.
- **Distribution level control of voltage and reactive power:** Capacitor banks, smart PV inverters, voltage regulators and other more distributed assets across the system can compensate for voltage and reactive power needs at a local level that would

otherwise need to be met through the supply of upstream resources delivered through the grid — the latter condition resulting in higher currents and greater incurred losses.

- **Optimizing the location and size of line transformers:** Siting transformers closer to customers allows for shorter secondary lines that have low voltage and thus higher losses per foot. For some areas, this may require additional transformers, which comes at a cost. Smaller transformers also have lower no-load losses. Unfortunately, smaller transformers have lower rated capacities and thus higher load losses for a given level of current. Conversely, larger transformers have higher no-load losses but lower load losses. These complex economics should be analyzed to account for trade-offs between capital costs and energy losses. Modern advanced metering infrastructure (AMI) systems provide the ability to prepare heat maps on each transformer, enabling optimal sizing to minimize costs and losses.[42]

All of these factors should be accounted for in both cost allocation and rate design. Energy-related benefits from transmission and distribution capital investments are quite extensive. In a relevant sense, nearly all transmission lines are built with a substantial purpose of minimizing line losses for the delivery of large volumes of energy. Choice of the voltage level for a transmission line, either for a new line or upgrading an old line, involves higher capital costs for higher voltages with the counteracting benefit of lower losses. These costs are energy-related costs, not capacity-related costs. Furthermore, many of these energy benefits from investments to minimize line losses are not static over the course of the year. They increase dramatically at times of system peak because current delivered over the system is much higher, and marginal system losses at the time of peak can be 15-20% in many utility systems.[43] In addition, these benefits can be compounding because they are not limited to fuel costs or wholesale purchases. A more efficient transmission and distribution system can lower generation capacity requirements as well, including reserves.

All of these economic and engineering phenomena should be properly reflected in any analyses of cost causation. More specifically, these distinctions must be passed into rate design or else it gives rise to opportunities for customers to take inappropriate advantage by gaming the rates, with bill savings that far exceed any long-term reduction in system costs. The experience of the British Central Electricity Generating Board, a wholesale provider, provides a stark example of this in the late 1960s. The central board charged the regional boards for generation capacity costs based solely on a narrow peak window. In response, the regional area boards built their own combustion turbines at significantly lower cost to generate during these peak hours. This forced the central board to change its

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[42] See Lazar, J. (2018, October 18). *Smart grid and community benefits — with no rate increase? How Burbank made it happen.* Regulatory Assistance Project. https://www.raponline.org/blog/smart-grid-and-community-benefits-with-no-rate-increase-how-burbank-made-it-happen/

[43] Lazar & Baldwin, 2011, p. 4.

wholesale rates, charging for only marginal capacity costs in a short peak and charging for the bulk of capacity costs in a broader period.[44] The key insight in this scenario is that demand-related costs charged to peak times should only reflect the marginal costs of relatively cheap generation, storage or demand response capacity costs incurred for short-period peak reliability purposes.

Modern examples of this pricing problem can be found in the current practices of several independent system operators and generation and transmission suppliers. For example, ERCOT currently charges on the basis of the highest hour in each of the four summer months for recovery of embedded transmission system costs to distribution service providers. This type of pricing mechanism is inappropriate for transmission costs and furthermore distorts the operation of the wholesale energy markets by over-incentivizing a wide range of customer actions.[45] Similarly, many electric cooperatives, charged by their generation and transmission suppliers on the basis of NCP demand imposed on the wholesale supplier, have installed water heater control systems to mitigate this demand at much lower cost than the avoided demand charges. Since the generation and transmission demand charges include the cost of baseload units and transmission, they greatly overstate the value of localized NCP load reductions. While these are wholesale examples, the same economic proposition also extends to retail rates.

3.3 Time-Varying Energy Rates Are More Efficient Than Peak Window Demand Charges

Once one acknowledges the time-dependent nature of cost in the generation and delivery of electricity to end users on a shared system, one must necessarily acknowledge the superiority (as matters of economic efficiency and fairness) of prices that reveal to those end users that temporal variability in cost to those that do not. The question, then, is simple: What should those prices look like? In some sense, a peak window demand charge does recognize this time dependency. However, a comparison of the incentives presented by time-varying demand charges and time-varying kWh charges reveals why time-varying kWh charges are the better approach.

There are several types of time-varying energy rates to be considered today.[46] Key design choices for these rates include the number of time periods, whether the price for each time period is set long in advance or can itself vary based on system conditions and market

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[44] Kahn, 1970, pp. 97-98.

[45] See Hogan, W., & Pope, S. (2017, May). *Priorities for the evolution of an energy-only electricity market design in ERCOT*, pp. 69-79. Harvard University and FTI Consulting. https://hepg.hks.harvard.edu/publications/priorities-evolution-energy-only-electricity-market-design-ercot-0. We do not endorse the proposed solution of Hogan and Pope but agree with the transmission pricing problem that they describe.

[46] From this definition we exclude seasonal rates and kWh prices that vary from billing period to billing period. These kinds of rates can also reflect the cost-causation basis of rates but provide little or no incentive to manage usage within a billing period.

outcomes, and the actual prices for each time period.[47] The simplest is known as a time-of-use or time-of-day rate, which utilizes a small number of preset time periods and prices within each billing period. The most sophisticated time-varying rates are typically described as real-time prices, which are updated at short, regular intervals (e.g., hourly) based on prices in wholesale energy markets.

There are also options that combined preset time periods with pricing that varies based on system conditions in a predictable manner. With critical peak pricing, or the related peak-time rebate alternative, higher prices for times when the grid is stressed are set well in advance, but the days (and perhaps the hours) where these higher prices apply are actively chosen in response to system conditions. Variable peak pricing, as currently offered by Oklahoma Gas & Electric,[48] adds another layer of price differentiation by allowing more preset options for the on-peak price period. The on-peak price depends on market conditions: low, standard, high and critical. This choice between four different alternative on-peak prices allows for a higher level of precision in marginal incentives. All of these variations share a common goal — to improve the load shape for a utility by decreasing peak period load and shifting some of that to off-peak periods.

In this context, it is most natural to compare peak window demand charges with simple TOU rates because many of the key parameters can be kept constant. For both of these options, the peak time periods and the prices charged are set well in advance and can be set to recover the same categories of costs. Holding those two variables constant, peak window demand charges are inferior to time-varying kWh charges in that same peak window, as a general method for charging peak capacity costs, for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

Peak window demand charges can certainly elicit customer response and incentivize them

47 The options that are available in practice depend on metering technology, which has evolved substantially over time. In the early part of the 20th century, TOU rates could be implemented with meters that operated on timers, where one track would record on-peak usage every day and another track would record off-peak usage every day. No distinction based on weekends or holidays was possible. By 1941, more sophisticated versions were available with remote controls that could switch the meters between tracks on command. Since that time, many more innovations have occurred to enable different types of time-varying rates. Three-period TOU rates became common for large industrial customers in France beginning in the 1950s. With advanced metering infrastructure and a sophisticated data collection and billing system, the possibilities are nearly endless. Even without AMI, simple TOU meters have long been available that track on-peak and off-peak usage based on programmed timers, which can exclude weekends and holidays from on-peak periods.

48 Oklahoma Gas & Electric. (2018, June 18). *Standard pricing schedule: R-VPP variable peak pricing.* https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

to shift load from inside to outside that window.[49] Nevertheless, peak window demand charges share many of the faults of traditional monthly demand charges, just on a different scale. Once again, the key distinction is between the consistent and symmetric marginal incentive of a time-varying kWh rate and the arbitrary effects driven by the demand charge's ratchet.

A close examination of customer behavior reveals why energy-based prices are preferable to demand charges even within a peak window. In any system with significant customer diversity, a large number of customers will not have their individual peaks at the time of the system's peak. Still, it could be that a substantial number of customers peak at the time of the system peak. The proportion of one to the other matters if demand charges are to have a significant linkage to the system peak. Customers who are at risk of setting the individual peak for the demand charge face a high marginal price for consumption, but those who are not face a lower marginal price. This proportion will vary from service territory to service territory and over time as technology evolves.

Customer behavior under a peak window demand charge would likely even vary based on completely arbitrary factors. That could be whether certain customers are at the beginning of their billing period or whether a significant event that led a customer to incur a largely unavoidable peak (e.g., hosting a party during a peak window) happened before that very high-load time. This randomness can be entirely avoided. The fair and efficient solution is to continue to treat all consumption as marginal, a condition that is achieved by time-varying kWh rates.

In the absence of technology that automates response to changes in prices, the ratchet problem for peak window demand charges may be diminished by the inability of customers to respond accurately to its incentive structure. It is unlikely that people going about their daily lives can do more than respond to the broad incentives provided by either an on-peak kWh price in a simple TOU rate or a peak-window demand charge. In both cases, the easiest answer may very well be just "consume less during the peak window period."[50] This could mitigate the harm posed by the ratchet, but it also begs the question about the underlying rationale if there is no customer response.

A modest subset of residential customers may be able to respond to the next rule of thumb presented by a peak window demand charge: to operate as few end uses as possible simultaneously. Fully responding to the incentives posed by a demand charge requires

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[49] See, for example, Stokke, A., Doorman, G., & Ericson, T. (2009). *An analysis of a demand charge electricity grid tariff in the residential sector.* (Discussion Paper No. 574). Statistics Norway, Research Department. https://ideas.repec.org/p/ssb/dispap/574.html

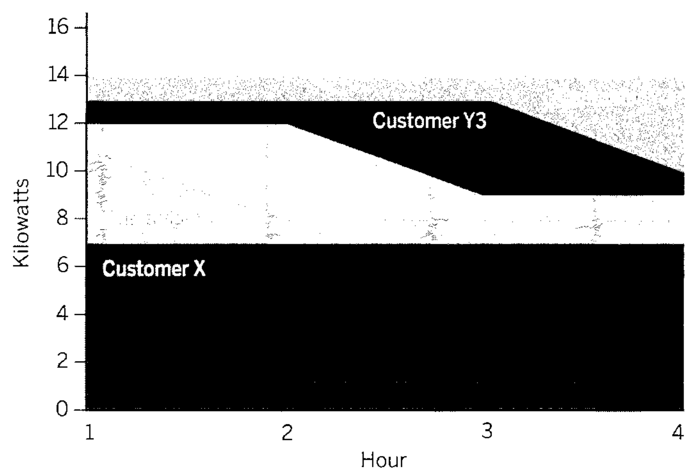
[50] For example, the Mid-Carolina Electric Cooperative has a three-hour peak window demand charge for residential customers. On the relevant page of its website, the peak window demand charge is labeled as an "on-peak charge." None of the advice given to manage this rate is specific to the actual working of a demand charge and could equally apply to a three-hour on-peak kWh rate. Mid-Carolina Electric Cooperative. (n.d.). *Rate structure.* http://www.mcecoop.com/content/rate-structure

customers to track their demand and know whether they are currently at risk of setting a high demand for the billing period — too much to ask of many residential and small business customers.

However, energy management technology, enabled by software and "supercharged" by on-site storage, will be able to adjust usage in a far more responsive manner than ordinary people could manage alone. Such energy management is likely feasible today for larger customers and could very well be widely feasible for smaller customers in the next few years. At least one company, Energy Sentry (http://energysentry.com/index.php), has developed a residential "demand controller" that automatically sheds less critical loads (water heaters, clothes dryers) when priority loads (microwaves, coffee makers, hair dryers) are activated. Such technology would allow customers to respond more effectively —*from their perspective* — to the incentives provided by a demand charge. But that is not to say that the overall efficiency of the electric system will be improved, since customer responses to demand charges do not typically optimize use of the system.

Peak window demand charges also create intraclass cost allocation problems, which are linked closely to the above efficiency concerns. Peak window demand charges still overcharge the low-load-factor customer and undercharge the high-load-factor customer. This is illustrated in the case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a hypothetical is shown in Figure 5 for a four-hour peak period.

Figure 5. Customer load comparison illustrating ability to share capacity

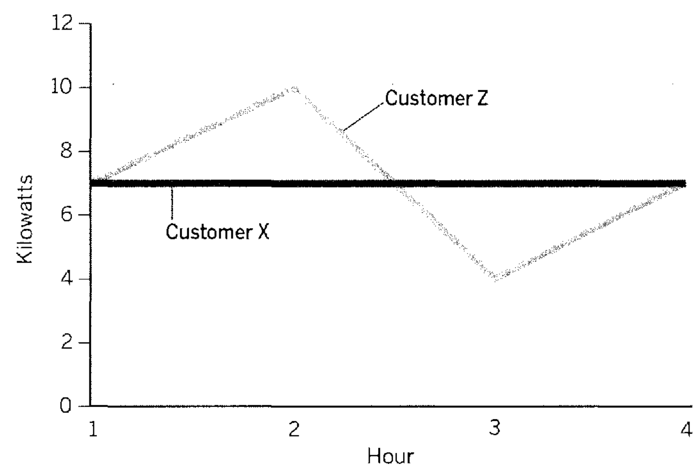


Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Time-varying energy-based charges solve this problem.

Peak window demand charges, though an improvement on monthly NCP demand charges, still come up short in the effort to send accurate information to consumers about peaks and other high-cost events. The occurrence of a peak cannot be known in advance, and, indeed, its timing depends in part on price structure. Shifting hours within a peak period does not necessarily lower the overall peak. Figure 6 is a comparison of two customers with equal kWh consumption in the peak period, one with a flat consumption throughout that period and another that varies.

Compared with Customer X with a flat load pattern, Customer Z with the varying load pattern likely increases the chance of a system peak in hour 2, but by the same token likely decreases the chance of a system peak in hour 3. But the reverse can be said for Customer X compared with Customer Z: Customer X raises the likelihood of a system peak in hour 3 and decreases the likelihood of a system peak in hour 2. Advocates of demand charges consistently fail to explain why these types of discrepancies are justified by cost considerations.

Figure 6. Comparison of two customers



Even well-designed TOU rates do not necessarily reflect critical peak times very well. For example, a four-hour weekday on-peak window for only the highest demand months will include around 200-400 hours annually. These will necessarily contain some days with higher peaks than others and only a limited number of hours that define utility capacity needs for reliability purposes at peak. Simple TOU rates do not distinguish in this regard between the moderate peaks (e.g., ordinary days in the summer) and the very highest peaks (e.g., extremely hot days in the summer). In short, the implication is that simple TOU rates do not provide a sharp enough incentive on actual peak days.[51] In any case, we are no longer bound to simple TOU pricing. Dynamic rates, including critical peak pricing, peak-time rebates, variable peak pricing and real-time pricing, all better address peaking issues because they provide higher marginal prices at the times of maximum system stress. By concentrating customer attention on the hours that actually drive costs, the more dynamic rates produce better results for the electric system and society.

By its very nature, a demand charge cannot present symmetric and consistent marginal incentives in the same way as a time-varying kWh charge. Compared to traditional demand charges, properly sized peak window demand charges have a better cost causation

[51] This is referred to as the needle-peaking problem in Crew & Kleindorfer, 1979, p. 186.

basis because they can be linked to the time periods that drive higher system costs. Daily as-used demand charges[52] applied to peak windows could be a further improvement on peak window demand charges, and, better yet, these peak window daily-as-used demand charges could fluctuate according to system conditions. However, this is only an improvement because it converges on the better solution, a system of time-varying kWh rates. Given the rate design possibilities that AMI offers, what reason is there to retain demand charges at all?

4. What Might Be Left for Demand Charges?

The foregoing demonstrates that the typical argument for demand charges, as used for generation, transmission and shared distribution capacity, is substantially flawed. Even so, we want to investigate if there are any circumstances, however limited, for which demand charges are an efficient rate design.

Some theorists have identified a different and, in our minds, much narrower set of rationales for demand charges. The case for time-varying rates relies substantially on the diversity of load and the lack of a direct relationship between individual customer peaks and the system peaks that drive costs. A diverse set of customers may, in the aggregate, create a predictable load profile much of the time. But what if this diversity goes away in an unpredictable manner? Or, for that matter, in a predictable one? Is there something about the causation of costs in special and *limited* circumstances that warrants charging for peak incurrences of short-term (e.g., 15-minute) demand for individual customers? To answer this question, we consider three cases that, on their faces, might present a marginal-cost justification for demand charges. The first is one that we have carved out from the beginning: capacity costs that are not shared, such as dedicated transformers and service drops, which we term "dedicated site infrastructure."[53] This illustrates some important issues relevant to any broader theoretical case for demand charges. The second is the cost associated with uncertainty in customer behavior. The third is timer peaks, a phenomenon where customers shift usage in response to hours with lower prices.

[52] RAP authors, writing with partners from Synapse Energy Economics, previously recommended daily-as-used demand charges for standby service to large combined heat and power customers, as an alternative to monthly standby demand charges. The purpose was to recognize that different combined heat and power customers would have scheduled and forced outages on different days and could share the same capacity to provide their standby service. This was certainly an improvement on monthly demand charges for such customers, but, in light of the progress made in metering and time-varying energy-based rate structures, there's every reason to think today that such time-varying energy rates are equally appropriate to customers with on-site generation. Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2005, December 1). *Rate structures for customers with onsite generation: Practice and innovation.* National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy06osti/39142.pdf

[53] RAP has previously recommended a small transformer or site infrastructure demand charge for secondary voltage customers, particularly those customers with dedicated site infrastructure. See Lazar, J., & Gonzalez, W. (2015, July). *Smart rate design for a smart future*, pp. 53-54. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

4.1 Dedicated Site Infrastructure

Dedicated transformers and service drops for individual customers are, by definition, not shared infrastructure. The relative importance of this category of cost will vary by customer class. Larger commercial and industrial customer classes, as long as they are taking secondary voltage service, will often have dedicated transformers for each customer or a dedicated transformer bank for customers taking three-phase power. Dedicated transformers will be rare for residential customers in urban and suburban areas, but single-family homes will almost always have a dedicated service drop. The largest industrial customers may have their own primary line (effectively serving as a dedicated service drop) or a dedicated substation (effectively serving as a dedicated transformer). In rural areas, each customer will typically have a dedicated transformer, at which point transformers are customer-specific site infrastructure.

For these customer-specific site infrastructure costs, there is no diversity of demand between the customer meter and point of connection with the shared system. As a result, individual customer NCPs are certainly relevant to the sizing of these components. One might conclude from this that a demand charge can provide a reasonable pricing incentive here. The time period for such a demand charge should have nothing to do with a shared peak since there is no sharing of the infrastructure. Nor should it be limited to peak windows since the peak for an individual customer could occur at any time. The cost of these components may be no more than about $1/kW/month, a fraction of typical demand charges.[54]

There are also other ways of efficiently pricing this category of costs. A similar set of customer incentives may be presented by a connected load charge for a set amount of local capacity. Such a connected load charge can help with efficient sizing, but only if it's accompanied by a fee for overages or the automatic tripping of circuits when demand would cause an overage. Even then, a connected load charge provides no incentive for customers to manage their usage efficiently; that is, there are no cost savings to be gained by keeping their demand below the level of the predetermined connected load. A charge that establishes the relationship of the customer's individual peak demand to the sizing of these components might, however, give the customer some incentive to minimize peaks.

It is worth examining this issue at the level of engineering and planning. What type of customer behavior would minimize the risk of transformer overload and degradation? Or what type of customer behavior would allow utilities to size dedicated transformers more efficiently?

Capacity ratings for the different elements of the electric system are set with many

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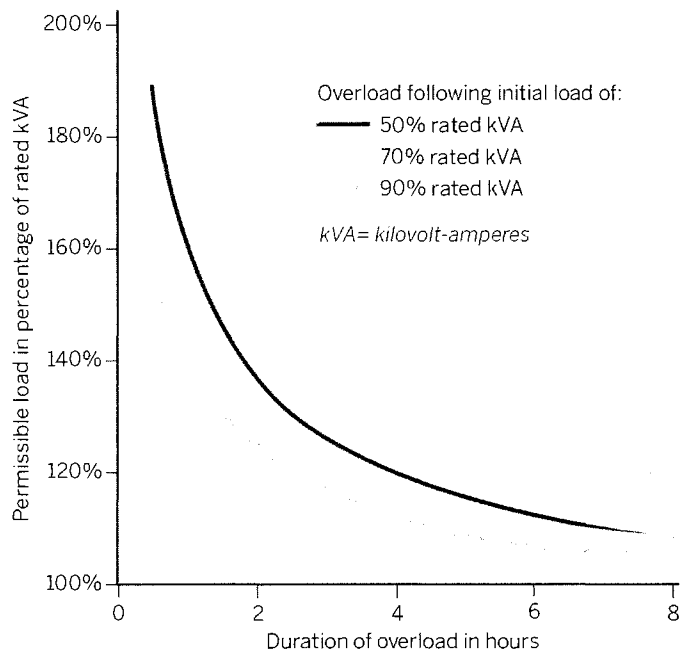
[54] Seattle City Light, for example, has a large general service rate with specific charges for transformer investment; these are $0.27/kW/month. Seattle City Light. (n.d.). *City Light rates.* https://www.seattle.gov/light/rates/summary.asp

engineering limits in mind. Many of the most important considerations revolve around the heating — and overheating — of components, particularly transformers and conductors. This has a number of different implications. For example, effective delivery capacity can be higher in the winter than the summer or higher in the cool nighttime than during the sunny daytime. The capacity ratings for individual system elements are for sustained loads in typical conditions, but loadings can exceed those ratings on a regular basis without necessarily incurring significant damage. As Tom Short colorfully puts it, a conductor rated 480 amps "will not burst into flames at 481 [amps]."[55]

Figure 7[56] demonstrates the maximum overload that a transformer can take without shortening its operating life, by examining two primary variables: (1) the initial load prior to any overload and (2) the duration of an overload. If a transformer has had light loads (50% of its rating), it can sustain a short-term overload of nearly 190% or a four-hour overload of just over 120%.

Figure 7. Permissible transformer overloads for varying periods



Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

The important question then is what kind of rate design incentivizes optimal customer behavior with respect to this equipment. Panagiotis Andrianesis and Michael C. Caramanis have developed an algorithm for dynamic nodal locational marginal costs for distribution systems that offers an intriguing approach to pricing for these customer-specific facilities. For line transformers, the pricing formula is a real-time price per unit of energy that follows the transformer thermal response dynamics, which is essentially the temperature of the cooling oil in each transformer.[57] Similarly, a critical peak energy charge could apply for the few hours per year when a transformer is

[55] Short, T. A. (2004). *Electric power distribution handbook*, Section 3.5, p. 140. CRC Press.

[56] Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

[57] Andrianesis, P., & Caramanis, M. (2019). *Distribution network marginal costs: Part 1, A novel AC OPF including transformer degradation.* arXiv. https://arxiv.org/abs/1906.01570

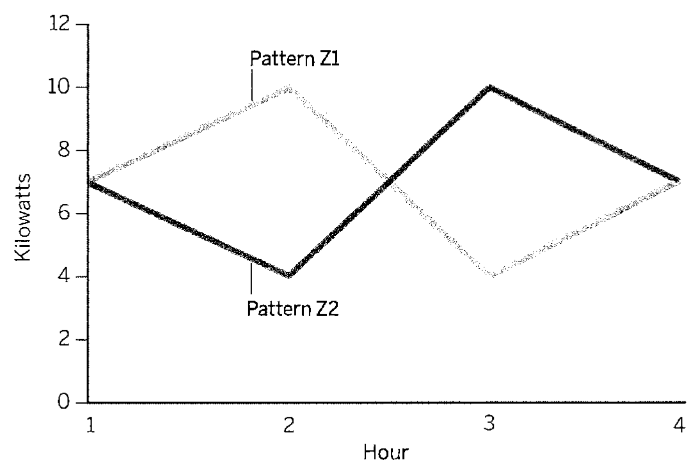
stressed but would require real-time monitoring and pricing to be applied on a transformer-by-transformer basis.

This type of short-run marginal cost pricing does not resemble a demand charge and has the virtue of linking closely in time the incurrence of high marginal costs to the prices charged. These approaches are quite sophisticated and could be costly to administer. To achieve a rate that is more feasible now, a simpler structure would be necessary. A daily-as-used demand charge or a traditional monthly demand charge, based on 15-minute or 30-minute peaks, could certainly discourage the extremely high short-term peaks that would damage a transformer. Those options might not do enough, however, to discourage a sustained, multihour overload.

4.2 Risks of Customer Variance at Peak Times

Load diversity isn't static and can fluctuate in ways that are both predictable and unpredictable. Predictable changes often occur around the weather, one of the few variables that simultaneously affects all customers in a given area. Regarding unpredictable changes, consider a simple hypothetical illustrated in Figure 8.

Figure 8. Two hypothetical load patterns randomly chosen by customers



If there are 10 “random-load” customers who flip a fair coin to determine whether their load profile corresponds to either Z1 (heads) or Z2 (tails) in Figure 8, the average load in each hour across a large number of trials will be 70 kWh.[58] However, system planning must not only deal with the expected average load but rather the chances of higher load. Unfortunately, in any given trial of this scenario, the probability of five heads and five tails — leading to a demand of 70 kW in every hour — is only 24.6%. There is a small but nonzero chance that every customer gets either heads or

[58] In this illustrative example, we consider each customer to have a flat load within each hour. This means that kW and kWh are largely interchangeable as units. Similar examples could, however, be constructed with demand varying in smaller increments (e.g., 30, 15 or 5 minutes), and similar results could be obtained.

tails, leading to a 0.2% probability of a peak load of 100 kW. The full spectrum of potential results for this hypothetical scenario with 10 random-load customers is shown in Table 1.

Table 1. Peak load and probabilities for 10 random-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Peak load (kWs)	Probability
10 heads or 10 tails	10	0	100	0.2%
9 heads or 9 tails	9	1	94	2.0%
8 heads or 8 tails	8	2	88	8.8%
7 heads or 7 tails	7	3	82	23.4%
6 heads or 6 tails	6	4	76	41.0%
5 heads and 5 tails	5	5	70	24.6%

The cumulative odds of a peak of 88 kWh or higher is 10.9%, and a peak of 82 kWh or higher is 34.4%. In this hypothetical scenario, it is clearly beneficial to have customers flatten their load curves to 7 kW every hour within this time period. Table 2 shows the range of possible results and associated probabilities for six random-load customers corresponding to either pattern Z1 or Z2 and four flat-load customers with a demand of 7 kW in each hour.

Table 2. Peak load and probabilities for six random-load and four flat-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Flat load: Number of customers	Peak load (kWs)	Probability
6 heads or 6 tails	6	0	4	88	3.1%
5 heads or 5 tails	5	1	4	82	18.8%
4 heads or 4 tails	4	2	4	76	46.9%
3 heads and 3 tails	3	3	4	70	31.3%

The risk of a peak of 88 kW or higher drops from 10.9% to 3.1%, and the risk of a peak of 82 kW or higher drops from 34.4% to 21.9%. If the customer choices are uncorrelated, this type of risk goes down as the number of customers increases.[59] However, if the customer choices are correlated, between hour 2 and hour 3 in this hypothetical, the risk does not necessarily decrease with a higher number of customers.

[59] The ratio of the variance to the expected total decreases in proportion to the square root of the number of customers.

This simple example is the essence of the argument made by Michael Veall.[60] He demonstrates that, for a given level of average customer demand during a peak, higher variance customers lead to a risk of higher peaks, particularly if they are correlated. This, in turn, results in a need for higher capacity planning margins. Veall constructs a detailed economic model of optimal peak period pricing. He states that the traditional monthly demand charge does not reasonably address this issue, but rather a peak window demand charge can serve as marginal price on a customer's variance. He notes additional caveats: "If there are many small users with uncorrelated demands, the effects of an individual user's variation on total system variation will be small. But if users are large or their demands are correlated, variance charges are important."[61] Finally, Veall's result demonstrates that, if a peak window demand charge is to be imposed, it should be paired with an on-peak kWh rate.[62] The logic around risk and Veall's theoretical model present an argument for a peak window demand charge that is substantially different from those that utilities put forward. And again, we see a more defensible justification for peak window demand charges for larger-volume customers. But the key question of correlations and *levels of risk* has been neglected in the discussion around demand charges and is only a theoretical possibility in Veall's model. Furthermore, Veall's model does not consider the possibility of more granularly dynamic time-varying kWh rates.

Marcel Boiteux, the influential French economist and executive for Électricité de France (EdF), does discuss risk and uncertainty in a 1952 paper, written jointly with his colleague Paul Stasi.[63] When it comes time for tariff design, Boiteux and Stasi describe two different zones of the shared electric system: (1) the "collective network" and (2) the "semi-individual network, whose capacity depends particularly on the uncertainties of consumption of each customer."[64] With respect to the collective network, they find that the "uncertainties of individual consumption" are small enough to be ignored.[65] And, finally, their analysis of the "semi-individual network" is dominated by risk and the irregularities of individual customer's loads. This leads them to a justification for a complex system of subscription-based contract demand charges, with higher prices for contracted demand in

[60] Veall, M. (1983). Industrial electricity demand and the Hopkinson rate: An application of the extreme value distribution. *The Bell Journal of Economics, 14*(2), 427-440.

[61] Veall, 1983, p. 429.

[62] Veall, 1983, p. 431. Veall notes that this on-peak kWh price could, in principle, even be negative, which would be a curious result.

[63] Boiteux, M., & Stasi, P. (1964). The determination of cost of expansion of an interconnected system of production and distribution of electricity. In J. Nelson (Ed. & Trans.). *Marginal cost pricing in practice.* Prentice Hall. (Original work published in 1952).

[64] Boiteux & Stasi, 1964, p. 117.

[65] Boiteux & Stasi, 1964, p. 117

peak periods and lower prices in other periods. However, Boiteux and Stasi offer little but generalities as to the demarcation of the semi-individual network:

> The extent of the zone within which the uncertainties of individual demands have a very marked influence on the collective cost is greater in proportion to the irregularity of the demands considered, and to the correlations among these demands. This extent depends also on the density of consumption, for the number of customers supplied from a given node plays an important role in the "reduction of uncertainties."[66]

Based on these considerations, Boiteux and Stasi largely describe the generation and transmission system (150-220 kV) as the "collective network" and the distribution system (15-60 kV) as the "semi-individual" network.[67] They are discussing these issues in the context of the then-new Tarif Vert for high voltage industrial customers, and the discussion could be read in a manner that is limited to those customers. This could mean that the dividing line for the semi-individual network could vary by the size of customer. Whether residential customer fluctuations are correlated in a significant and pertinent way is another empirical question Boiteux and Stasi do not address. It is unclear whether the irregularities of individual residential customers would ever be significant enough to matter at a level higher than a shared transformer.

4.3 Timer Peaks

Michael A. Crew and Paul R. Kleindorfer (1979) raise another area where a demand charge could theoretically be efficient, which they describe as the secondary preferences of customers, given the structure of time-varying rates, and the shifting of demand to notionally off-peak times. This is colloquially known as a timer peak. This occurs if customers increase their usage substantially during hours with low rates or more specifically right at the time when low-priced hours begin.[68] In the worst-case scenario, TOU rates can theoretically just shift the system peak without reducing it if enough usage is shifted to hours with low prices. The same is true of coincident peak window demand charges. This outcome can be avoided by managing the number of periods in the rate, the hours covered by each period and the relative prices. One utility has designed a TOU rate in which each customer chooses a three-hour peak period of 4-7 p.m., 5-8 p.m. or 6-9 p.m. All of these customers have 6-7 p.m. in their peak period; two-thirds of them have 5-6 p.m. and 7-8 p.m. in their peak period; and one-third have either 4-5 p.m. or 8-9 p.m. in their

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[66] Boiteux & Stasi, 1964, p. 123

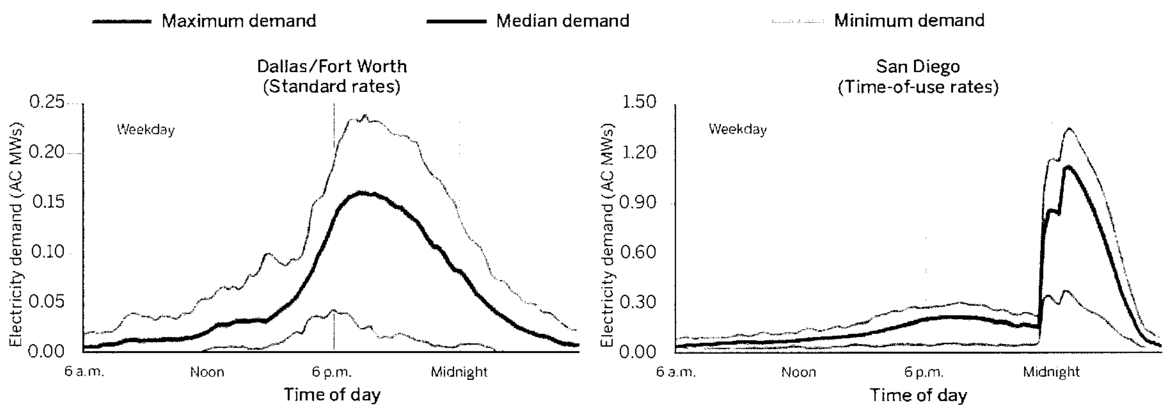
[67] Boiteux & Stasi, 1964, p. 110.

[68] Bonbright mentions this as a possible objection to time-of-use rates. See Bonbright, 1961, p. 362, fn 23: "In Chapter 10 of his book already cited in footnote 10, Davidson suggests this type of rate [time of day and time of season] as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line."

peak period. This provides the utilities with the most powerful pricing signal during the most likely peak hour but substantial peak reduction in the adjacent hours.[69] Another simple solution is to apply different hours to different classes or subclasses. For example, single-family residences may have their tariff shifted one hour earlier than apartments, or secondary general service one hour later than primary general service.

If the more general system peaks are not impacted significantly enough by this phenomenon to warrant changing the structure of the rate, more granular and local issues can theoretically arise. Figure 9 shows a set of results from a San Diego Gas and Electric rate for electric vehicles, where the "super off-peak" rate begins at midnight.[70]

Figure 9. Real-world illustration of timer peak with EV charging on TOU rate



Source: Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the Electric Vehicle Market*

This is a rational customer response to a TOU rate, at least for specific end uses. If an electric vehicle is parked at home in the evening and will not be used again until morning, then the customer has a significant amount of flexibility to choose when charging will begin. The very beginning of the lowest price period is an obvious time to start charging. While this may not present an issue at the generation and transmission level, assuming midnight remains an off-peak period, bunching of EV charging could lead to issues at the more local level.

Again, thinking about a line transformer helps focus the analysis. If five single-family homes are served by one shared transformer and all five of those homes have EVs that start charging at midnight, then impacts at the line transformer level are a possibility. Furthermore, what if those houses have other timed usage that starts at the beginning of the lowest price period? Sending a secondary price signal that discourages households

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[69] Salt River Project. (n.d.). *SRP EZ-3 price plan.* https://www.srpnet.com/prices/home/ez3.aspx

[70] Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the electric vehicle market*, p. 16. M.J. Bradley & Associates. https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

from turning on all of their major end uses at midnight could be effective. A daily-as-used demand charge can send such a signal if it were applied across 24-hour periods. A more traditional monthly demand charge, however, will send that signal in a much more attenuated way. A connected load charge based on a contract demand for the cost of connection, with fees for overages, similar to the Électricité de France Tempo rate for residential customers,[71] would send a similar price signal as well.

There are other ways to deal with this phenomenon besides price signals with demand-charge features. The beginning of the off-peak period with the lowest price could be staggered for different customers, for example, beginning at 10 p.m. for one-third of customers, midnight for another third and 2 a.m. for the last third. For customers with long-duration controlled loads, like water heaters or electric vehicles, this would be easy for the customer to manage and beneficial to the utility. To maximize the benefits of such an approach, one would need to have a relatively even split among those three options for the customers on each shared transformer. Load management programs and smart devices could deal with this type of issue as well. For some loads, particularly water heating and EV charging, we anticipate advanced devices that will enable the utility to manage loads to minimize costs and enable customers to benefit from even lower off-peak rates for enabled devices.

One could even question how much of a problem this poses to the longevity of the shared transformers in question. The ambient temperature has almost always cooled off by midnight, and several hours of low or moderate loads could allow the transformer to cool from significant levels of usage during the day or early evening. In certain circumstances, it could be more convenient and cost-effective to upgrade any potentially affected transformers, particularly where multiple water heaters or EV chargers are served from a single transformer.

5. Conclusion

Demand charges, of either the traditional monthly NCP or peak window variety, are not efficient, as a general matter, for shared system capacity costs because:

- For the vast majority of customers, any peak reduction signal in a traditional monthly demand charge is weak and inaccurate.
- Traditional calculations for demand charges have included far too many costs as demand-related. Ideally, utility commissions will adopt a new time-based classification

[71] Electricite de France. (n.d.). *Tarif Bleu: Regulated sale tariff for electricity.* https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html

and allocation framework for generation, transmission and shared distribution costs.[72] Failing that, the numerous energy benefits from capacity investments should be properly accounted for — that is, reflected in energy, not demand, charges.

- Simple TOU rates are superior to peak window demand charges in their own right, but AMI enables time-varying energy charges, such as critical peak pricing, peak-time rebates and variable peak pricing, that much more accurately target times of system stress and reward end users for shifting their loads to off-peak times.

Although we have shown the significant downsides to using current forms of demand charges, in very limited circumstances there might be cost- and efficiency-related justifications for certain types of demand charges. But such charges would be significantly lower than those prevailing for industrial customers in the United States today. Dedicated site infrastructure is a small portion of utility system costs, and typical demand charges would not necessarily provide an optimal signal to control these costs. The primary concerns around timer peaks are almost certainly limited to local infrastructure.

As for the general risk of customer variance and correlation, little work has been done to investigate the statistical bases of this more sophisticated case for demand charges. We think that it is unlikely that such an analysis would find that a substantial demand charge would be fairer or more efficient than time-varying energy charges. Lastly, there is a better case for demand charge-like structures for large customers, who are more likely to have significant dedicated site infrastructure. One might also argue that high variance at peak times among these customers has a more significant chance of influencing the overall system peak. Any such demand charges may not look like Hopkinson rates and would likely be only a second-best solution to a sophisticated system of time-varying energy charges.

The economic and regulatory principles that underlie these judgments are not new. The inescapable essentials of microeconomic theory are at work here. Boiteux, Bonbright and Kahn follow these principles and theories, as do the other scholars and practitioners we cite. In 1964, Paul Garfield and Wallace Lovejoy[73] also stepped into the fray. They converted principles of economic efficiency and fairness into straightforward criteria for assessing the merits of cost allocation methods and rate designs for generation and delivery capacity costs:

- All utility customers should contribute to capacity costs.
- The longer the period of time that customers preempt others' use of capacity, the more they should pay for the use of that capacity.

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[72] Lazar et al., 2020.

[73] Criteria adapted from Garfield, P., & Lovejoy, W. (1964). *Public utility economics,* pp. 163-165. Prentice Hall.

- Any service that makes exclusive use of a portion of capacity should be assigned all of the costs for that portion of capacity.
- The allocation of capacity costs should change gradually with changes in the pattern of usage.
- More capacity costs should be allocated to on-peak usage than off-peak.
- Interruptible service (or other forms of utility restrictions and control) should be allocated less in capacity costs as the degree of restriction increases.

Only time-varying energy charges can meet all of these objectives simultaneously. Demand charges for shared costs are demonstrably less efficient and less equitable than they.

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