STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: April 3, 2020
AT (OFFICE): NHPUC

FROM: Elizabeth R. Nixon, Utility Analyst, Electric Division
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SUBJECT: IR 20-004 Recommendations Regarding Investigation of Electric Vehicle Rate Design Standards, Electric Vehicle Time of Day Rates for Residential and Commercial Customers

TO: Dianne Martin, Chairwoman
Kathryn M. Bailey, Commissioner
Michael S. Giaimo, Commissioner
Debra A. Howland, Executive Director

CC: Thomas C. Frantz, Director, Electric Division
Brian D. Buckley, Staff Attorney

I. Background and Summary of Recommendations

On August 11, 2018, SB 575-FN became effective and requires the Commission to determine whether certain rate design standards for regulated electric distribution utilities should be implemented for electric vehicle charging stations, and whether to implement electric vehicle time of day rates for residential and commercial customers. On January 10, 2020, Staff filed a recommendation pursuant to SB 575 that the Commission open an investigation to examine those two issues. On January 16, 2020, the Commission issued an order of notice soliciting comment on a list of relevant issues identified in the Staff recommendation and scheduled a February 28, 2020 technical session. Various parties filed comments and attended the technical session.[1] Attached to this recommendation are the February 28, 2020 presentations of Eversource, Greenlots, the City of Lebanon, and Chargepoint.

Based on comments filed, the technical session and review of experience in other jurisdictions, Staff makes the following recommendation for the Commission and recommends that the Commission provide a 30 day opportunity for comment on this staff recommendation:

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[1] Comments were filed by a wide range of interested docket participants, including the Office of the Consumer Advocate ("OCA"), Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource"), Unitil Energy Systems ("Unitil"), the New Hampshire Department of Environmental Services (NH DES), Clean Energy New Hampshire (CENH), the Conservation Law Foundation (CLF), Chargepoint, Greenlots, Revision Energy, the City of Lebanon, the Peterborough Energy Committee, and Randolph Bryan.

- ***Cost of Service:*** *Issue guidance that, to the maximum extent practicable, electric vehicle charging rate designs shall reflect the marginal cost of providing electric vehicle charging services*.
- ***Declining Block Rates:*** *Issue guidance prohibiting declining block rates for any separately metered electric vehicle supply equipment*.
- ***Time of Use Rates – Appropriateness:*** *Issue guidance supporting time of use rates as an appropriate rate design component for electric vehicle charging*.
- ***Time of Use Rates – Whole Facility/House vs Separately Metered:*** *Issue guidance that any electric vehicle TOU rates offered by the utilities should provide an option for customers to enroll in a separate rate class specific to electric vehicle charging end use.*
- ***Time of Use Rates – Alternative Metering:*** *Direct the electric distribution companies to file a feasibility assessment within 90 days relating to opportunities for offering an electric vehicle time of use rate for residential and commercial facilities that utilizes interval metering capability of devices other than a utility-owned meter. If an electric distribution company finds such an offering would not be feasible at this time, the assessment should nonetheless include a quantification of costs that would need to be incurred to deploy such a strategy, an explanation of any other barriers that may exist, and a roadmap for overcoming those barriers.*
- ***Time of Use Rates – Energy, Transmission, and Distribution:*** *Issue guidance that any separately metered electric vehicle charging rates developed by the utilities should include a time-varying component for energy, transmission, and distribution. Once a utility has collected data regarding the average annual load shape of 500 electric vehicle rate customers, the Company shall solicit a separate tranche for full requirements, load following energy service within its default service solicitation for the electric vehicle customers using an average annual load shape specific to that customer class.*
- ***Time of Use Rates – Consistency Among Utilities:*** *Issue guidance that any separately metered residential electric vehicle charging rate should: (1) be based directly on cost causation; (2) incorporate time varying energy supply, transmission, and distribution components; (3) have three periods (e.g.- off peak, mid-peak, and peak); (4) be seasonably differentiated (e.g.- summer and winter); (5) have an average price differential between off-peak and peak of no less than 3:1; and (6) have a peak period no longer than four hours in duration.*
- ***Time of Use Rates – Quantification of Incremental Costs:*** *Require each utility seeking approval of an electric vehicle time of use rate to provide an assessment of incremental costs associated with that offering, including but not limited to those costs associated with billing, metering, and marketing.*
- ***Seasonal Rates:*** *Issue guidance expressing a preference for seasonally differentiated electric vehicle charging time of use rates consistent with the underlying cost causation of the summer and winter seasons*.
- ***Interruptible Rates:*** *Issue guidance that interruptible rates are not an appropriate rate design for electric vehicle charging.*

- ***Load Management Techniques:*** *Issue guidance that load management techniques may be an appropriate strategy for electric vehicle rate design, but express a clear preference for delivery of such offerings in conjunction with TOU rate offerings, to the extent reasonably practicable.*
- ***Demand Charges – Peak Coincidence or Volumetric Pricing Structure Alternative:*** *Issue guidance that demand charges may be a component of an appropriate rate design for high demand draw charging stations, but that utilities should explore alternatives to the customer peak demand charges prevalent in New Hampshire, such as the use of volumetric pricing structures or demand charges which are based on coincidence with system peak and other peaks reflective of cost causation. Demand charges are not likely warranted for most residential charging applications.*
- ***Demand Charges – Rate Design Alternative Analyses:*** *Require Eversource to file for review within 90 days the results of any analysis conducted by its affiliates relating to rate design alternatives to demand charges or if it is not available, then file it when it becomes available.*
- ***Demand Charges – Peak Coincidence Billing/Metering Feasibility:*** *Issue guidance directing each utility to file within 90 days a feasibility assessment of incorporating peak-coincident demand charges into its billing and metering system for the purposes of offering an electric vehicle charging rate to commercial and industrial customers*.
- ***Time of Use Rate Proposal Filings for Separately Metered EV Chargers:*** *Open an adjudicative proceeding and direct each electric utility to file within 120 days, consistent with the guidance above: (1) an electric vehicle time of use rate proposal for separately-metered residential and small commercial customer applications; (2) an electric vehicle time of use rate proposal for separately metered high demand draw commercial customer applications that may incorporate direct current fast charging or clustered level 2 chargers. Both proposals should be accompanied by testimony explaining how those rates were developed, any plans for marketing residential electric vehicle time of use rates, and how the rate is consistent with the Commission guidance.*

II. Rate Design Standards for Electric Vehicle Charging Stations

SB 575-FN directs the Commission to consider whether it is appropriate to implement the following rate design standards for electric vehicle charging: cost of service, prohibition of declining block rates, time of day rates, seasonal rates, interruptible rates, load management techniques, and demand charges. Staff provides its recommendations for each of these standards below.

A. Cost of Service

Rates designed under the cost of service standard generally reflect the cost of providing service to a particular customer class. The cost of service standard has been a foundational component of rate design in New Hampshire for decades.[2] Comments were generally supportive of the cost of service rate design standard.[3] While very little information exists regarding the marginal cost of providing these types of services in New Hampshire,[4] Eversource noted during the technical session that one of its affiliates was preparing an April 1 filing regarding recently deployed electric vehicle programs that may provide further data regarding charging behaviors and therefore marginal costs.

Staff recommends *the Commission issue guidance that, to the maximum extent practicable, electric vehicle charging rate designs shall reflect the marginal cost of providing electric vehicle charging services*.

B. Prohibition of Declining Block Rates

Declining block rates price successive blocks of electricity consumed by a particular customer class within a given billing cycle at per unit prices that decrease as usage increases. Staff does not view declining block rates as an appropriate rate design standard for electric vehicles charging because the price signal sent to customers by declining block rates encourages energy usage. Comments were generally supportive of the prohibition of declining block rates.[5]

However, New Hampshire's largest electric utility offers only declining block distribution and transmission rates to its general service customer classes.[6] A blanket prohibition on declining block rates for electric vehicle charging would create a barrier for those general service customers who might seek to install electric vehicle supply equipment (EVSE) at their premise without separate metering.

Staff recommends the *Commission issue guidance prohibiting declining block rates for any separately metered EVSE.*

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[2] Re Pub. Serv. Co. of New Hampshire, Order No 20,504 at 285 (June 8, 1992). ("If we viewed rate design as a house, the important aspects of equity, continuity, simplicity, understandability, and revenue stability are the attributes that make the house livable... The support - the foundation and the frame is the cost studies; particularly, it rests on the marginal cost of service study (MCOSS).")

[3] Unitil Comments at 3. (Stating "All of the Company's tariffs are designed for cost of service; EV-specific rates should conform to this principle to the maximum extent practicable as well."); See also, Eversource Comments at 4. (Classifying the cost of service rate design standard as generally consistent with the Commission's established rate design principles)

[4] Eversource Comments at 6-7. (Stating "cost of service data is limited for these and other charging stations in the Company's service area.")

[5] OCA Comments at 5. (Stating "The OCA does not believe that declining block rates are a fruitful rate design technique in light of the need to send appropriate price signals to electric customers of all rate classes."); Eversource Comments at 4. (Describing benefits associated with a prohibition on declining block rates as "Conservation of energy; increased EE; [and] better energy consumption decision making."); Unitil Comments at 3. (Stating "Rate structures that provide electricity at lower prices for higher levels of usage seemingly run afoul of energy conservation principles and also introduce added environmental costs.")

[6] New Hampshire Grid Modernization Working Group Report, Appendix B, Table B.7 (March 20, 2017). Available at: http://www.puc.state.nh.us/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_APP_FINAL_RPT.PDF

C. Time of Day Rates

Time of day rates, sometimes referred to as time-of-use ("TOU") or Time Varying Rate ("TVR") structures, are designed to reflect the cost of providing service to a class of customer at different times of the day. TVR structures might be: (1) fixed, based on pre-determined time periods that align with electric system cost causation, typically divided into three parts that are described as either off-peak, mid-peak, on-peak, or critical peak periods and generally referred to as TOU rates; (2) variable, based on the real-time costs associated with the electric system, generally referred to as real-time pricing; or (3) some combination thereof, such as a TOU rate structure that includes either a peak time rebate or critical peak pricing. TVR structures may be offered on an opt-in basis, where a customer must affirmatively request service under time of day rates, or an opt-out basis, where time of day rates are the default for a particular class and a customer must affirmatively request not to take service under time of day rates.

Commenters generally agree that rates which vary based on the time of use are an appropriate rate design for electric vehicle charging.[7] Staff concurs with commenters that TOU rates are an appropriate rate design for electric vehicle charging.

Staff recommends the *Commission issue guidance supporting TOU rates as an appropriate rate design component for electric vehicle charging*.

1. Whole Facility/House Meter vs. Separate Meter

The OCA raised questions about whether TOU rates should be offered on a whole facility basis or separately metered.[8] It further suggested that the advantage of not offering a separately metered TOU rate would be that "increased demand from EV charging could provide an incentive for customers to choose whole-house time-of-use rates."[9]

RSA 378:10 requires that utility rates avoid "undue or unreasonable preference or advantage to any person or corporation, or to any locality, or to any particular description

[7] OCA Comments at 6. (Stating "Properly designed time-of-use rates provide the price signals that will guide EV users to charging during hours when the cost of energy is essentially zero (given that, at certain hours and in certain conditions, the wholesale spot price of electricity is negative) and will discourage them from charging at times when the cost of the incremental kilowatt-hour can reach into the hundreds of dollars."); Eversource Comments at 5. (Stating "an EV time of day rate, whether as part of the overall rate for a home or business or as a separate, dedicated EV rate, could encourage a shift in usage or reduction in peak load that results in more optimal and efficient use of facilities and resources."); Unitil Comments at 3. (Stating "Unitil strongly supports the availability of time of day/TOU rates for EV charging, particularly residential and private commercial fleet charging."); NH DES Comments at 4. (Stating "Each utility should develop and offer an EV TOU rate in order to minimize any potential negative impact from increased EV charging."); City of Lebanon Comments at 4. (Stating "TOU and other TVR will encourage more optimal and efficient use of facilities and resources and ultimately be more equitable and rates will better align with cost causation."); CENH Comments at 2. (Stating "CENH supports the development of a statewide, residential TOU rate that is consistent among the regulated utilities and provides an incentive for drivers to provide maximum grid benefits.")

[8] OCA Comments at 6. (Stating that a key question for the PUC to resolve will be "[w]hether such time-of-use rates be offered to residential customers with electric vehicles on a whole-house basis[.]")

[9] OCA Comments at 6.

of service in any respect whatever." In our previous Staff Memorandum in this docket, we observed that this statutory provision requires rate treatment of electric vehicle supply equipment that, *as a general rule*, is consistent with treatment for other end uses within a given rate class under which electric vehicle charging equipment is provided service. Based on Staff review of the comments, we recognize several justifications for why electric vehicle charging could be treated as an exception to this general rule.

First, electric vehicle charging could account for approximately 1/3 of a home's total load and certain level two chargers might account for a significant portion of residential customer's peak demand.[10] That demand is uniquely flexible relative to other end uses due to a significant amount of idle time. This presents a unique opportunity for advanced rate offerings that would not exist if a customer were not offered a separate rate.[11]

Second, without a separately metered rate, customers might be hesitant to adopt a TOU rate due to inflexibility of other customer end uses, or in the case of existing residential TOU rates, due to the duration of the peak period or lack of savings justification. This would result in a missed opportunity to send price signals to a significant amount of flexible load which, without price signals, would likely create a significant draw in the residential sector at the time of system peak when a customer arrives home from work around 6pm.

Third, the load shape associated with electric vehicle charging is likely to vary significantly from that of any other customer class. This means that an in-home charger, which would account for a substantial account of customer load, would result in different costs to the grid than the average home. Consistent with well-accepted standards of rate design, rates should, to the maximum extent practicable, be aligned with cost causation.

Fourth, precedent exists for utilities offering a separate rate for a unique end use at an existing customer's premise. For decades, utilities have offered a separate rate for outdoor lighting end uses at a customer's premise. Likewise, some customers who have embraced utility-controlled or utility-owned hot water heating have been offered a separate rate for that end use.

Based on the reasoning above, Staff recommends the *Commission issue guidance that any electric vehicle TOU rates offered by the utilities should provide an option for customers to enroll in a separate rate class specific to their charging end use.*

2. Alternatives to Secondary Meter

Chargepoint notes that costs associated with a secondary meter for electric vehicle charging can be a significant barrier to TOU rate adoption, particularly for residential

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[10] OCA Comments at 6, citing Vermont Public Utilities Commission Report to Legislature. Page 24, fn 33. (December 13, 2019) This is not necessarily the case for commercial and industrial customers where electric vehicle charging may represent a less significant portion of the customer load.

[11] Under such an approach, existing customers seeking to install EVSE under an existing whole-home or C&I rate, without separate metering, would not be prohibited from doing so. It would simply be another end use under the customer's current rate.

applications.[12] For example, Liberty Utilities recently proposed an electric vehicle charging rate where the total investment required to provide the secondary meter was estimated to be $446,[13] which when combined with $5 monthly cost of cellular data transmittal and computed into a revenue requirement results in an incremental fixed monthly charge to the customer of approximately $11.[14] Chargepoint suggests that as an alternative to the secondary meter, certain EVSE is capable of providing "accurate and verifiable data for the electricity dispensed to an EV… [that] is easily accessible to utilities, secure, and reliable."[15] Chargepoint suggests this "embedded metering capabilities that ChargePoint includes, and that other competitive solution providers also offer, have been vetted for accuracy in other states and are already in use to support utility time-of-use rate billing," citing a pilot recently approved by the Minnesota Public Utilities Commission.[16] Similarly, Con Edison recently piloted a program under SmartCharge NY through which it provided customers an incentive to charge at off-peak times by tracking the EV's charging through the car's diagnostic port.[17]

Staff recommends that the *Commission direct the electric distribution companies to file a feasibility assessment within 90 days relating to opportunities for offering an electric vehicle TOU rate for residential and commercial facilities that utilizes interval metering capability of devices other than a utility-owned meter. If an electric distribution company finds such an offering would not be feasible at this time, the assessment should nonetheless include a quantification of costs that would need to be incurred to deploy such a strategy, an explanation of any other barriers that may exist, and a roadmap for overcoming those barriers.*

3. Energy Supply, Transmission, and Distribution

Eversource currently offers time of use rates with peak and off peak pricing for distribution and transmission service, but not energy. While noting support for "a direct line of sight" between the cost of energy supply and the prices customers see, Eversource suggests that a time varying energy service offering would not be appropriate because "Default Sevice procured by the Company on behalf of customers does not have an on and off-peak rate, nor do suppliers offer on and off-peak pricing."[18]

However, at the technical session, Eversource noted that its Connecticut affiliate offers a time varying rate option for default energy service that customers. It suggested that the time varying rate was imputed from underlying cost causation, and that the Company did not separately solicit that block of energy service, in spite of the likelihood that the load

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[12] Chargepoint Comments at 16.
[13] Docket No. 19-064. Pre-filed Testimony of Heather M. Tebbetts, Attachment HMT-2.
[14] Docket No. 19-064. Pre-filed Testimony of Heather M. Tebbetts. Page 6 of 8, Line 2.
[15] Chargepoint Comments at 16.
[16] Chargepoint Comments at 16, citing, Minnesota Public Utilities Commission. Docket E002/M-17-817. Petition for Approval of a Residential EV Service Pilot Program. Order dated May 9, 2018.
[17] New York Public Service Commission. Case No. 18-E-0138. Department of Public Service Staff Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment. (January 13, 2020).
[18] Eversource Comments at 6.

shape of a customer on a time varying rate may be less costly for a wholesale supplier to procure than the average customer load.

The cost of providing energy service varies during different times of the day according to a number of factors including the locational marginal price of energy. Very few, if any, New Hampshire competitive energy supplier offer a time varying option for residential energy service. Likewise, the New Hampshire' regulated utilities do not offer a time varying option for default energy service, except in the recent Liberty Utility battery storage pilot. When soliciting default service from wholesale energy suppliers that will ultimately be offered to customers, the electric distribution utilities provide potential bidders a MWh estimate of the load required to serve a particular class/block of customers during the period being solicited, as well as a load shape data collected by the Company through a representative sample of interval meters for that class/block. Wholesale suppliers use this information, as well as other inputs, to assess the cost of providing energy service to that class/block during that period to develop a bid.

The load shape of a particular class/block substantially impacts a wholesale supplier's costs – and the bid price they offer to provide default service. This is because it will cost a wholesale supplier more to procure service from wholesale markets on behalf of customer classes/blocks that tend to use a lot of energy during peak times, when energy is more expensive, than it will for customers whose usage is predominantly during off-peak hours, when the cost of energy is generally less.

Staff recommends the *Commission issue guidance that any separately metered electric vehicle charging rates developed by the utilities should include a time-varying component for energy, transmission, and distribution. Once a utility has collected data regarding the average annual load shape of 500 electric vehicle rate customers, the Company should solicit a separate tranche for full requirements, load following energy service within its default service solicitation for the electric vehicle customers using an average annual load shape specific to that customer class.*

4. Consistency Among Utilities

CENH suggests there is value in uniformity of residential charging rates,[19] suggesting that current TOU rate "offerings are not consistent, are not appropriate for EV application, or are absent entirely.[20] Staff recognizes that the existing TOU rate offerings are not consistent among utilities and likely not ideal for encouraging off-peak charging, but a statewide redesign of customer TOU options is not within the scope of this proceeding. The more appropriate venue for such discussions is within a utility's rate case, where utility-specific evidence relating to embedded costs, marginal costs, and other factors can be evaluated to determine the characteristics of a given rate class's rate design. Staff does agree however, that there is value in electric vehicle rate offerings for residential applications being generally consistent across utilities.

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[19] CENH Comments at 3-4. (Stating "CENH supports an opt-in statewide TOU rate for electric vehicle charging.")
[20] CENH Comments at 4.

Based on a review of the comments, Staff recommends the *Commission issue guidance that any separately metered residential electric vehicle charging rate should: (1) be based directly on cost causation; (2) incorporate time varying energy supply, transmission, and distribution components; (3) be three part (e.g.- off peak, mid-peak, and peak); (4) be seasonably differentiated (e.g.- summer and winter); (5) have an average price differential between off-peak and peak of no less than 3:1; and (6) have a peak period no longer than four hours in duration.*

5. Quantification of Incremental Costs

Eversource suggests that embrace of an electric vehicle TOU rate that goes beyond the O-TOD rate the Company offers would result in incremental costs to customers.[21] Staff recognizes that adopting new rates might require modifications to company billing systems, but also recognizes that similar modifications likely would be necessary for the load management strategies that Eversource and Unitil plan on deploying.

Staff recommends *the Commission should require each utility seeking approval of an electric vehicle TOU rate to provide an assessment of incremental costs associated with that offering, including but not limited to those costs associated with billing, metering, and marketing.*

D. Seasonal Rates:

Seasonal rates are designed to reflect the cost of providing service to a class of customer during different seasons of the year.

Several commenters suggest that the default service energy periods, which vary twice per year, are an existing seasonal rate offering.[22] The OCA is skeptical but open-minded regarding whether seasonal rates are consistent with the Commission's rate design principles because in the OCA's judgment such an approach may "be complex, difficult to understand, and potentially disruptive to customers who rely on their vehicles to conduct their day-to-day activities."[23] Eversource suggests that seasonal rates may offer "more efficient pricing" and lead to "a better use of the grid," but that such rates would not align well with the Commission's principles of equity, simplicity, and continuity.[24] Unitil suggests, "Seasonal variability in rates would likely necessitate education, outreach, and communication to ensure customers realize potential rate changes and behavioral attributes that could impact energy bills and peak demand."[25] DES suggests that off peak charging "has the potential to largely mitigate the impact of EVs on the grid

[21] Eversource Comments at 8.
[22] Eversource Comments at 7. (Stating within the "Seasonal Rates" column: "Energy service rates change semi-annually or may change at other times of the year for competitive supply.); Unitil Comments at 4. (Stating "Today, the only seasonal rate the Company offers is basic service with solicitations changing every June 1st and Dec 1st".)
[23] OCA Comments at 5.
[24] Eversource Comments at 4-5.
[25] Unitil Comments at 3.

by shifting load to off-peak hours, which will minimize impact on overall *seasonal* peak."[26] The City of Lebanon suggests that federal law "call[s] for electric utilities to provide electric service [']on a time-of-day basis['] with seasonal variation [']to the extent that such costs vary seasonally for such utility,[']" and argues that utilities should "invest in the billing capacity for 3 tier seasonal TOU rates."[27] Revision Energy identifies off-peak and seasonal incentives as an opportunity for shaping residential customer load.[28] Chargepoint identifies seasonal rates as a "slightly more sophisticated rate structure" that "may not be necessary in all circumstances but could be considered."

Staff agrees with DES and Revision Energy that seasonally differentiated rates for electric vehicle charging present an opportunity for shaping electric vehicle customer load in a way that might benefit all ratepayers. In New Hampshire, and in New England more broadly, the majority of circuits must be built or upgraded based upon forecasted summer peak load capacity. As suggested by City of Lebanon, federal law suggests that seasonally differentiation of rates is appropriate to the extent underlying cost drivers vary by season. Furthermore, seasonally differentiated price signals that more accurately align with cost causation, by sending price signals that discourage charging during summer peaks, would maximize benefits and minimize costs relating to new electric vehicle charging loads. Staff is cognizant of the observations of the OCA and Eversource that such rates may add complexity. However, as Unitil suggests, any concerns stemming from this added complexity could be assuaged with customer education, outreach, and communication. Furthermore, it is likely that the type of customer that purchases an electric vehicle is likely to have a greater visibility into their own energy usage than the average customer, and therefore greater likelihood of responding to price signals. In some cases, as sophisticated charging technologies continue to proliferate, the charger may replace the customer as the primary instrument responsible for responding to price signals.

Staff recommends the *Commission issue guidance expressing a preference for seasonally differentiated electric vehicle charging TOU rates consistent with the underlying cost causation of the summer and winter seasons*.

E. Interruptible Rates

Interruptible rates are designed to reflect the cost of providing service to a class of customers that permits its service to be interrupted during periods of peak electrical demand.

Commenters were not supportive of interruptive rate offerings for electric vehicle charging. The OCA suggests that interruptible rates have the potential to be disruptive to "customer who rely on vehicles to conduct their day-to-day activities."[29] Unitil suggests that interruptible rates would be disruptive to customers, particularly for those who must

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[26] DES Comments at 3. (emphasis added)
[27] City of Lebanon Comments at 2, 5. (Citing 16 U.S.C. §2621(d)(3) and (4))
[28] Revision Energy Comments at 3.
[29] OCA Comments at 5.

charge during peak times for long range travel, and "would likely lead to frustration, interference with commerce, and customer confusion."[30] Chargepoint suggests that "interruptible rates would have a severely negative impact on public charging and long-distance EV travel," suggesting managed charging as a preferred alternative.[31]

Staff agrees with the OCA, Unitil, and Chargepoint that interruptible rates are not appropriate for electric vehicle charging, particularly for public charging stations intended to accommodate long range travel.

Staff recommends the *Commission issue guidance that interruptible rates are not an appropriate rate design for electric vehicle charging.*

F. Load Management Techniques

Load management techniques are offerings of either an electric distribution utility or a third party where, through an agreement between the customer and the electric distribution utility, or the customer and a third party, the customer commits to reductions in load at times of peak electrical demand, typically in exchange for either annual or per-event compensation. Eversource and Unitil are currently piloting such techniques (not specifically for electric vehicles) as part of their statewide energy efficiency program offerings.

Commenters were generally supportive of managed load management techniques for electric vehicles charging. Unitil suggests that all customers have the potential to benefit from electric vehicle rate design structures that "maximize capacity availability and minimize system upgrades and costs," including managed charging offerings where "EVs serv[e] as demand response resources tied to novel rate design structures that potentially include TOU."[32] CLF suggests that the flexibility of demand associated with electric vehicles "facilitates load management and presents significant, untapped potential for grid optimization."[33] Greenlots suggests that the Commission "look beyond time-of-day rate design to facilitated managed charging," and that "EV time-of-day rates represent a rather blunt, but in some cases appropriate, beginning instrument to deliver price signals, especially at low levels of EV market penetration… [but s]hifting peaks and changing local grid constraints will require more sophisticated strategies to ensure that EV load is managed."[34]

Chargepoint defines two different types of managed charging: (1) passive managed charging, often referred to as behavioral load management, which is delivered through time of use rate offerings; and (2) active managed charging, which is delivered by a utility or third party that takes control of charging load. Chargepoint suggests that active managed charging, can "slow down the rate of charge temporarily during times of high

[30] Unitil Comments at 4.
[31] Chargepoint Comments at 7.
[32] Unitil Comments at 4.
[33] CLF Comments at 2.
[34] Greenlots Comments at 1.

demand," a benefit that is unavailable under a static time of use rate structure.[35] Chargepoint clarifies, however, that "load from DC fast charging is unpredictable and is ill-suited to being managed through demand response or load curtailment, due to the inherent need of drivers to charge when they need to at public charging stations."[36]

At the technical session, the City of Lebanon noted that, based on the New Hampshire Constitution and restructuring statute's emphasis on competitive and markets,[37] TOU-based price signals should be preferred over command and control-style load management techniques.

Staff agrees with the City of Lebanon that sending accurate price signals tends to lead to a more efficient allocation of resources than the command and control approach, but Staff does not foreclose potential near-term benefits related to load management strategies. Eversource and Unitil have suggested they are poised to offer electric vehicle load management strategies to their customers, based on a model developed in Massachusetts, as early as January 2021.[38]

Ideally, TOU rates would serve as a floor for encouraging customer behavior modifications related to electric vehicle charging, supplemented by other load management techniques. However, customers should not be required to enroll in a TOU rate as a prerequisite of enrolling in load management offers. For example, a customer taking service under a non-TOU rate that does not differentiate between electric vehicle charging and other end uses should not be prohibited from taking part in other load management services its utility or another third party may offer.[39]

Staff recommends the *Commission issue guidance that load management techniques may be an appropriate strategy for electric vehicle rate design, but express a clear preference for delivery of such offerings in conjunction with TOU rate offerings, to the extent reasonably practicable.*

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[35] Chargepoint Comments at 7-8.
[36] Chargepoint Comments at 11.
[37] N.H. Const. Art. 83; RSA 374-F:1, II.
[38] Eversource Comments at 16-17; Unitil Comments at 4.
[39] Staff notes its recent support for load management *pilots* funded by the system benefits charge (SBC) and delivered in tandem with the companies' energy efficiency offerings. The pilots utilize a non-bypassable volumetric (kWh) charge to fund a program whose ratepayer benefits are based on demand reduction (kW) and avoided transmission cost allocations. The utilities forecast the annual ISO-NE sytemwide peak, and deploy load management strategies to reduce usage during that peak period, reducing the overall capacity needed for procurement by ISO-NE and resulting in a smaller allocation of regional transmission costs to New Hampshire ratepayers. These load management programs differ from the energy efficiency offerings historically funded by the SBC in two ways that are germane to a discussion expanding those offerings to electric vehicles: (1) realization of ratepayer benefits is currently based entirely on a utility's ability to accurately forecast the monthly or annual transmission peak; and (2) the digitally integrated nature of load management programs makes an ex post verifiable analysis of ratepayer savings less resource intensive than a similar process would be for energy efficiency programs. Staff believes that the funding mechanism for these programs, associated performance incentives, and verification of ratepayer benefits need to be explored for these and other such load management strategies.

G. Demand Charges

Demand charges are a rate structure component prevalent in the non-residential customer classes of electric distribution utilities that are intended to recover costs associated with a customer's kilowatt (kW) or kilovolt-ampere (kVa) demand over a given period (e.g., 30-minute interval, hour interval, etc.). Demand charges are commonly based on an individual customer's maximum (or a certain percentage of maximum) kW or kVa demand during a given period, but may also be based on a customer's demand during transmission or distribution system peaks or on off-peak periods.

Commenters provided mixed opinions regarding demand charges, which are prevalent for New Hampshire's commercial customers, but not residential customers. The OCA suggests that "demand charges are to be avoided whenever possible, when imposed either directly or indirectly on residential customers," but expresses an openness to reviewing the appropriateness of such a charges based on facts.[40] Eversource, which has existing demand charges for many of its commercial customer classes,[41] suggests that a benefit of demand charges is that they may lead to a "more efficient use of the grid," and that deployment of time of day offerings in combination with a demand charge structure may "lead to greater efficiency in utilization of the system through improvements in load factor."[42] Unitil suggests that "for customers that cannot manage demand during peak system periods, the demand charge needs to reflect the service being provided."[43]

Several commenters identified the fact that demand charges are currently assessed according to customer peak usage, rather than system peak usage, as their major shortcoming. The OCA cites a report of the Regulatory Assistance Project which identifies a key shortcoming of traditional demand charges, stating:

> [b]ecause traditional demand charges are measured on the basis of individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach inevitably results in a mismatch between the costs incurred to serve the customer and the prices charged if the customer's peak is non-coincident with the system peak… Movement away from demand charges, toward more granular time-varying energy rates, is appropriate.[44]

The City of Lebanon suggests that "Any demand charges for commercial charging stations should be largely based on coincident peak demands, not off-peak demand, which has little impact on most aspects of capacity in the system."[45]

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[40] OCA Comments at 6-7.
[41] Eversource Comments at 3-4.
[42] Eversource Comments at 8.
[43] Unitil Comments at 5.
[44] OCA Comments at 4, citing Lazar, J. and Gonzalez W. Regulatory Assistance Project. "Smart Rate Design for a Smart Future." (July 2015).
[45] City of Lebanon Comments at 5.

Many commenters identified existing demand charges as creating a barrier for direct current fast charge (DCFC) deployment and commercial customer sites due to the high demand draw (50-350kW) and low load factors that may occur.[46] CENH cites a study by the Rocky Mountain Institute (RMI) which suggests that "demand charges can be responsible for over 90% of a charging station's electricity costs… [and] are especially challenging to new charging infrastructure that has not yet reached a sustainable utilization rate."[47] Revision Energy suggests, citing a different RMI study, that "even a more mature EV market may not provide more than 30% utilization rates ten years out."[48] Chargepoint and Greenlots both suggest demand charges present a unique barrier to fleets, including public and private sector fleets.[49]

Several commenters identified strategies from other jurisdictions that have embraced alternatives to demand charges. Chargepoint cites several alternatives to demand charges embraced by other jurisdictions, including: (1) "Replacing or pairing demand charges with higher volumetric pricing;" (2) "A monthly bill credit representing a percentage of the nameplate demand associated with installed charging stations behind a commercial customer's metered service;" (3) "Implement[ing] a "rate limiter" as EV adoption increases, in which the average cost equivalent of a customer's demand charges would be limited to no more than a set cents/kWh value;" (4) "A retroactive and variable credit based on the difference of the effective blended per kWh distribution charge, including demand charges, and an agreed upon target blended rate, multiplied by the volumetric energy throughput in a given billing cycle for commercial customers with dedicated EV charging stations;" (5) Forgiving a portion of billed demand when the customer has a low load factor."[50] CENH suggests several alternatives to demand charges that other states have embraced, including "replacing or pairing lower demand charges with higher volumetric rates, using a rate limiter, forgive a portion of the demand charge while use frequency is low, phase in demand charge as use increases, or develop DCFC specific rate."[51]

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[46] Unitil Comments at 4. (Identifying demand charges at DCFC sites with low load factors as creating a barrier to entry for some competitive market charging infrastructure companies); DES Comments at 3-4 (Stating "At current EV penetration rates and expected low utilization rates for the DCFC at present, the demand charge would be spread across just a few users making the cost per unit of charge (kwh or time) that a station owner must charge to recoup the demand related costs unreasonable, thereby discouraging the use of that station."); CLF Comments at 1. (Stating "Traditional demand charges are known to deter investment in DC fast chargers. Particularly while utilization is low, demand charges incurred can be far greater than the revenue the charging stations can generate.") Revision Energy Comments at 4. (Suggesting demand charges "can dramatically affect the economic viability of DC Fast Charging (a/k/a Level 3 charging or DCFC) and large clusters of level two chargers, such as might be installed at work places.")

[47] CENH Comments at 2. Citing Nelder, C. Rocky Mountain Institute. Rate Design Best Practices for Public Electric Vehicle Chargers & EVgo Fleet and Tariff Analysis. (April 2017)

[48] Revision Energy Comments at 4. Citing Fitzgerald, G. and Nelder, C. Rocky Mountain Institute. DCFC Rate Design Study for the Colorado Energy Office. (Revised February 2020)

[49] Chargepoint Comments at 12. Greenlots Comments at 3.

[50] Chargepoint Comments at 12. Citations Omitted.

[51] CENH Comments at 3.

However, some state regulators, such as the New York Department of Public Service, have been hesitant to embrace alternatives to demand charges for DCFC, such as a purely volumetric rate design:

> Customer demands drive a significant amount of electric utility transmission and distribution-related costs. Conversely, the electric utilities incur very limited, if any, transmission and delivery related costs driven by the volume of energy they deliver. Volumetrically applied TOU rates that are revenue neutral to the existing demand charge rates will not likely generate incremental benefits to charging station developers. Depending on station utilization rates, a TOU rate that is designed as revenue neutral to the applicable demand billed service class will create winners and losers. Under a revenue-neutral volumetric TOU rate, higher utilization stations would see less favorable economics, which could create a disincentive to success.[52]

Unlike many of the participants offering comments in this investigation, Greenlots does not advocate for removal or retiring of demand rates for DC fast charging because, in its view, demand charges "are important for aligning charging behavior with grid conditions."[53] It suggests that the demand charge relief suggested above "is often associated with a trend toward unmanaged DC fast charging, premised on the notion that drivers always need full charging at full speed and that there are not feasible opportunities to align this type of charging with grid constraints."[54] It suggests that rather than eliminating demand charges, technology enabled managed charging strategies can be embraced as a means of "reduc[ing] site and system costs associated with peak or non-grid friendly DC fast charging."

Based on a review of extensive commentary, Staff agrees that demand charges may limit the economic feasibility of certain charging stations, particularly DCFC stations which may be necessary for public charging related to long-distance travel. However, Staff suggests this reality must be balanced with the need to ensure costs are assessed among customers based on cost-causation.

Staff recommends the *Commission issue guidance that demand charges may be a component of an appropriate rate design for high demand draw charging stations, but that utilities should explore alternatives to the non-coincident peak demand charges prevalent in New Hampshire, such as the use of volumetric pricing structures or demand charges which are based on peak coincidence. Demand charges are not likely warranted for most residential charging applications.*

[52] New York Public Service Commission. Case No. 18-E-0138. Department of Public Service Staff Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment. (January 13, 2020).
[53] Greenlots Comments at 3.
[54] Greenlots Comments at 3.

In Connecticut, Eversource developed a kWh variable rate to displace the need for demand charges for certain DCFC charging station applications,[55] but it is unclear to the Staff what the results of this rate offering were, and whether the offering was revenue neutral with respect to the rate design displaced. At the technical session, Eversource indicated that its affiliate would be filing an annual report with the Massachusetts Department of Public Utilities in April regarding the results of certain rate design pilots. Such a rate design may be an attractive alternative to demand charges because it presents the opportunity accurately align price signals with cost causation.

Staff recommends that the *Commission require Eversource to file for review within 90 days the results of any analysis conducted by its affiliates relating to rate design alternatives to demand charges or if it is not available, then file it when it becomes available.*

Staff further agrees with the OCA and City of Lebanon that the price signals sent by the non-coincident peak demand charges which are currently in place for New Hampshire ratepayers do not align with the actual costs incurred by the grid as a result of electric vehicle charging. We understand there may be limitations relating to current metering and billing infrastructure throughout the state which would limit the ability to assess demand charges for electric vehicle charging at times of peak coincident. However, we are aware of a recent order of the Maine Public Utilities Commission which approved a DCFC rate design that includes a two part demand rate in which one part aligns with the customer's peak and the other part is assessed at the time of the transmission system peak.[56] If such a rate design were embraced for the purposes of DCFC in New Hampshire, it might more accurately assign costs based on cost causation than existing non-coincident peak demand charges.

Staff recommends the *Commission issue guidance that demand charges may be a component of an appropriate rate design for high demand draw charging stations, but that utilities should explore alternatives to the customer peak demand charges prevalent in New Hampshire, such as the use of volumetric pricing structures or demand charges which are based on coincidence with system peak and other peaks reflective of cost causation. Demand charges are not likely warranted for most residential charging applications.*

III. Residential and Commercial Time of Day Rates for Electric Vehicle Charging

In determining whether it is appropriate to implement electric vehicle time of day rates for residential and commercial customers, SB 575-FN directs the Commission to consider whether implementation would encourage energy conservation, optimal and efficient use of facilities and resources by an electric company, and equitable rates for electric customers.

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[55] Eversource statement at February 18, 2020 technical session.

[56] Maine Public Utilities Commission. Docket No. 2019-000217. Order of February 25, 2020.

Based on the review of the comments, Staff believes that implementation of electric vehicle TOU rates for residential and commercial customers would encourage energy conservation, optimal and efficient use of facilities and resources by an electric company, and equitable rates for electric customers.

Staff recommends the *Commission open an adjudicative proceeding and direct each electric utility to file within 120 days, consistent with the guidance above: (1) an electric vehicle time of use rate proposal for separately-metered residential and small commercial customer applications; (2) an electric vehicle time of use rate proposal for separately metered high demand draw commercial customer applications that may incorporate DCFC or clustered level 2 chargers. Both proposals should be accompanied by testimony explaining how those rates were developed, and how the rate is consistent with Commission guidance, and plans for marketing residential electric vehicle time of use rates.*

-ATTACHMENT-

February 28, 2020 Technical Session Presentations

EVERSOURCE

NH EV Technical Session

Rates / Managed Charging / Utility Role

February 28, 2020

Rate Design Considerations

Rate design should balance the need to remove barriers to EV adoption with need to send proper price signals and enable efficient charging practices.

- The appropriate rate design depends on customer class, charging type and location, and usage characteristics.
  - Demand Charges:
    - Pro: Send price signal that aligns with cost of infrastructure
    - Con: Can be a barrier to adoption particularly when EVs are not at full saturation.
  - Time of Use / Peak Time Rebates:
    - Pro: Encourages off peak charging.
    - Con: Complexities around whole-house billing vs dedicated service. Not applicable in all applications (e.g. public charging stations along traffic corridors).
- Eversource has implemented a number of rate designs in CT that include these features and meet the goals for EV charging.
- Rates for service where EV charging is part of total home or business load provide additional opportunities and benefits.
- NH standards for rate design should reflect consideration and balance of key rate design principles, goals and objectives of various types of EV

Eversource Rates Support EV Charging Goals

- Current rates in Connecticut provide a number of options for various EV charging applications under consideration
- Rates for each general class of EV charging and potential rate impacts are summarized below.
  - Time-differentiated rate is available for each class.
  - A special rate rider is available as a demand charge alternative.
- These structures provide a useful framework for evaluating New Hampshire rates and applications

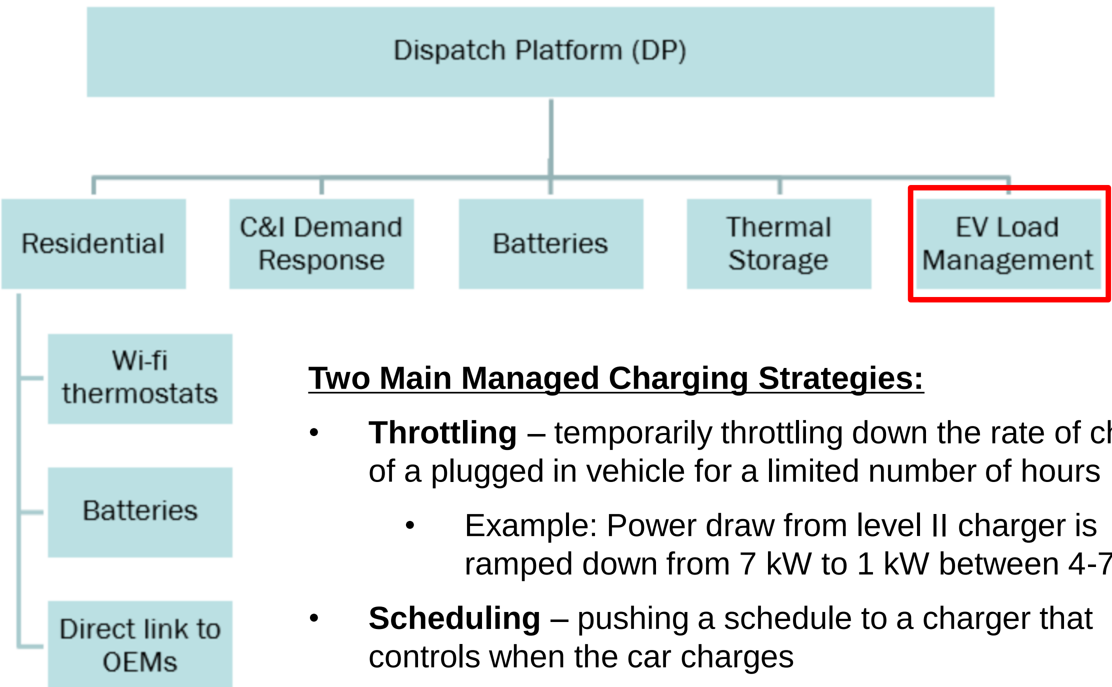
Class	Rate Structure *	Promotes Adoption	Promotes Off-peak charging	Promotes Efficiency	Assumptions & Impacts
Residential	2-part TOU volumetric rates	Y	Y	Y	Assumes BTM EV charging; significant price differential incentive, for EV/ additional end uses
Commercial	3-part with TOU demand and volumetric rates	Y	Y (via TOU demand & volumetric)	Y	Assumes BTM charging; TOU demand and volumetric charges provide load shifting incentive; further incentive for managing charging to avoid higher peak while maximizing total business load
Public	Same as commercial, or rider with all volumetric rates (non-TOU demand rate alternative)	Y	Y (same as commercial, except under rider)	Y	Same as Commercial under standard 3-part TOU rate. Under EV rider, significant cost shifting due to low load factor vs. cost of service – less TOU and load shifting benefit, but lower overall rates and charges;
Fleets	3-part with TOU demand and volumetric rates	Y	Y	Y	Same as commercial, with potential for larger scale load management and load shifting benefit;

* Alternate rate structures are available; peak period = 12 noon – 8 pm

Managed EV Charging Provides Additional Opportunities to Realize Benefits

Eversource is actively testing ways to integrate EV load management into its active demand portfolio, including residential and commercial & industrial customers, and fleets

Eversource C&LM Dispatch Platform System Architecture



Two Main Managed Charging Strategies:

- **Throttling** – temporarily throttling down the rate of charge of a plugged in vehicle for a limited number of hours
    - Example: Power draw from level II charger is ramped down from 7 kW to 1 kW between 4-7PM
- **Scheduling** – pushing a schedule to a charger that controls when the car charges
    - Example: Vehicle is plugged into charger at 5PM but charging does not begin until 12AM

Key Characteristics

- Dispatch Platform software is used to aggregate and dispatch many different assets in a coordinated manner.
- The system architecture is designed to be inclusive of many types of customer assets.
- Dependency for asset integration into dispatch platform is ability to communicate, not ownership, allowing broad participation from different technologies and vendors.
- Vehicle charging can be controlled through a connected charger or through the vehicle's onboard telematics.

Encourage highly efficient, smart, charging infrastructure to enable managed charging benefits

Make-Ready Model

- Overcomes the barrier of the large upfront cost of infrastructure for customers
- Leverages EDC experience as electrical infrastructure provider
- Working with approved contractors, can scale appropriately
- Enables private investment and third party innovation
    - Fills a need not likely to be met by the competitive market
    - Maintains customer choice in EVSE and pricing business model

NH Proposal vs. Approved MA Program

Large Scale

Multi use case

EV adoption

- Supports approximately 3,500 L2 and DCFC charging points at up to 400 sites (municipal, workplace, destination, corridor, apartments)
- 3-5 year program (2018 – 2022)
- $45 million investment, part of larger Grid Modernization program
- Express goal of advancing EV adoption goals as defined in state's commitment to ZEV MOU

Targeted

Corridor

Tourism

- $2 million investment, as part of statewide public-private partnership to create an EV fast charging corridor in NH
- The proposal leverages the availability of VW Settlement Funds earmarked for EV charging infrastructure
- Developed jointly with Liberty, Unitil, NHEC
- Goal of effectuating the RFP released by NH OSI / DES
- This EV fast charging corridor can:
  - promote New Hampshire travel and tourism
  - support commuters and drivers who choose to drive electric

Maximizing Grid Benefits of Electric Vehicles

New Hampshire Public Utilities Commission

February 28, 2020

greenlots
A Member of the Shell Group

- Greenlots Overview
- Managed Charging and Rate Design Considerations
- Regulatory Frameworks

Founded in **2008** with over a decade of experience

Headquartered in Los Angeles, California

Global footprint with offices throughout the US and in Canada, India, and Southeast Asia

Over 150 Employees and contractors worldwide

Working with utilities, cities, automakers, fleets & site hosts across the US and the world

Acquired by Shell in January 2019

Greenlots is powering the future of electric transportation with industry-leading EV charging software and services

greenlots
A Member of the Shell Group

EV Charging Network Software

Operate & monitor networks of charging stations

Smart Charging Optimization

Site-focused energy management

Digital Mobility Solutions

Digital platforms for fleets and auto OEMs to expand their emobility offerings

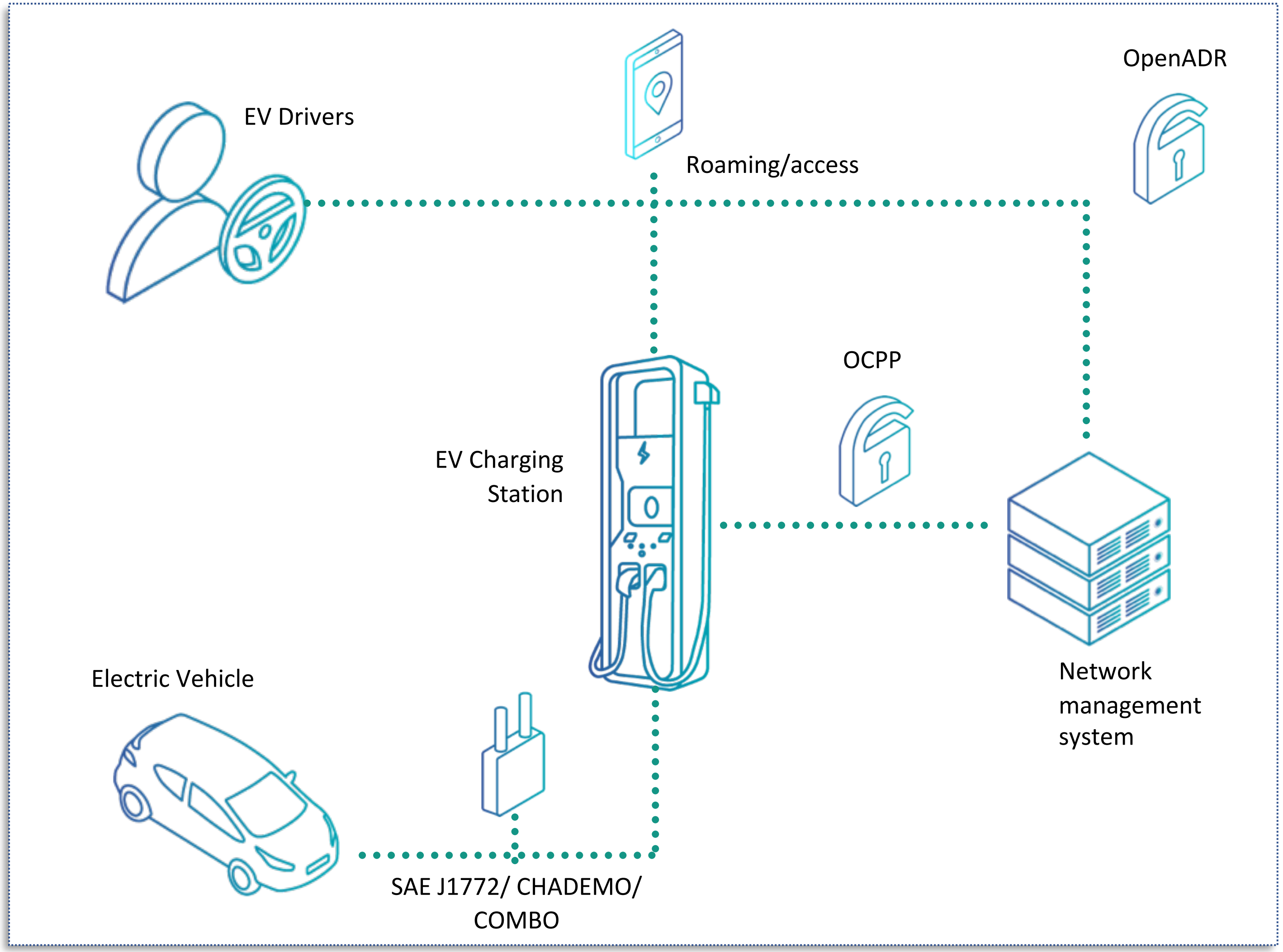
Grid Balancing Services

Aggregate and leverage EV load to maintain grid reliability and efficiency

Our turnkey approach to charging infrastructure

- Choice of hardware
- Program Management
- Engineering & Commissioning
- Software & Mobile App
- Customer Support and O&M

Open standards and interoperability



Open Standards Benefits (OCPP and Open ADR)

Charging stations using OCPP work even after switching network provider – no vendor lock-in

Multiple charging station options

Open ADR enables plug-and-play with utility demand response systems

Managed Charging

Key for reducing system costs and placing downward pressure on rates

Shifts load away from peak periods and addresses grid constraints

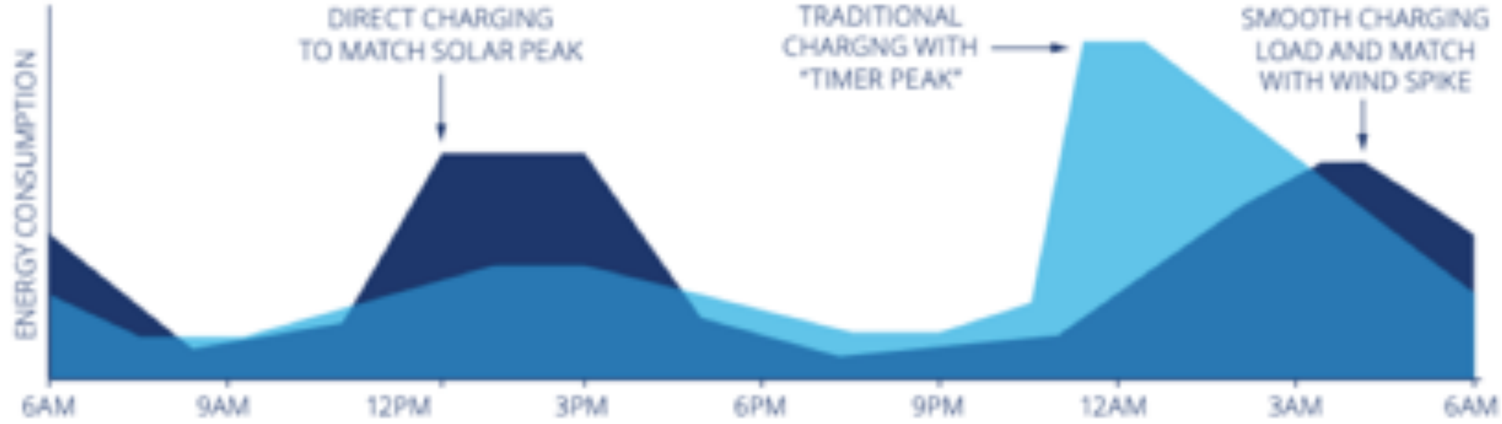
Enables integration of intermittent renewable resources

Technology enables load to be responsive to grid needs

Minimizes need for infrastructure upgrades

Responds to preferences without relying on behavior change

Mitigates site host costs



Source: BMW of North America, 2016 with edits by Smart Electric Power Alliance, 2017

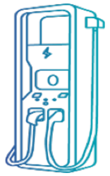
Note: The light blue area illustrates the impacts of a hypothetical TOU residential charging rate with the lowest rate period beginning at 11 pm. The dark blue area shows how managed charging could distribute charging loads with peaks in renewable energy generation.

Technology-Enabled Rates and Managed Charging Solutions

SDGE Power Your Drive

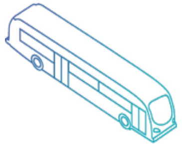
- Utility-owned charging stations at MUDs and workplaces
- Customers respond to hourly day-ahead rates
- Billed directly to utility accounts

BGE EVsmart Program



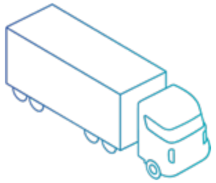
- Rebates for residential and multifamily smart chargers(L2 and DCFC)
- Leveraging customer charging data to design rates

PGE's TriMet Transit Pilot



- PGE owns, operates, and maintains high-powered chargers
- Comprehensive planning support: routes, charger siting, peak mitigation
- Enabling conversion to 100% electric bus fleet

Volvo LIGHTS



- Load management systems respond to building load requirements
- Software shifts and prioritizes vehicle charging times at multiple site locations
- Demand response capabilities help avoid peak demand charges

Los Angeles Police Department

- First city fleet to go all electric
- Project involves smart charging and fee differentiation for fleet and public users
- Supply of high-powered L2 (15kW)

Comprehensive Regulatory Frameworks

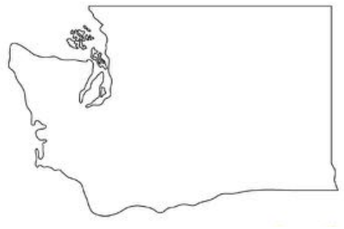
Minnesota

Policy statement

Variety of ownership models

OCPP and OpenADR

Managed charging and rate design



Washington

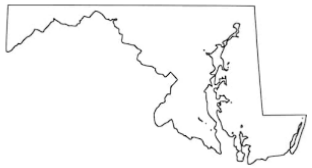
Policy statement

Utility role in market transformation

Interoperability

Portfolio approach

Incentive rate of return



Maryland

Stakeholder process

Variety of ownership models

Portfolio approach

Rate design and incentives

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greenlots
A Member of the Shell Group

Development of TOU Rate Model for Liberty Utilities Battery Pilot

by Clifton Below, Asst. Mayor, City of Lebanon

Docket No. DE 17-189

September 14, 2018

Technical Statement Regarding Time of Use (TOU) Model

by

Heather Tebbetts, Liberty Utilities

Lon Huber, Navigant, for the Office of Consumer Advocate

& Clifton Below, for the City of Lebanon

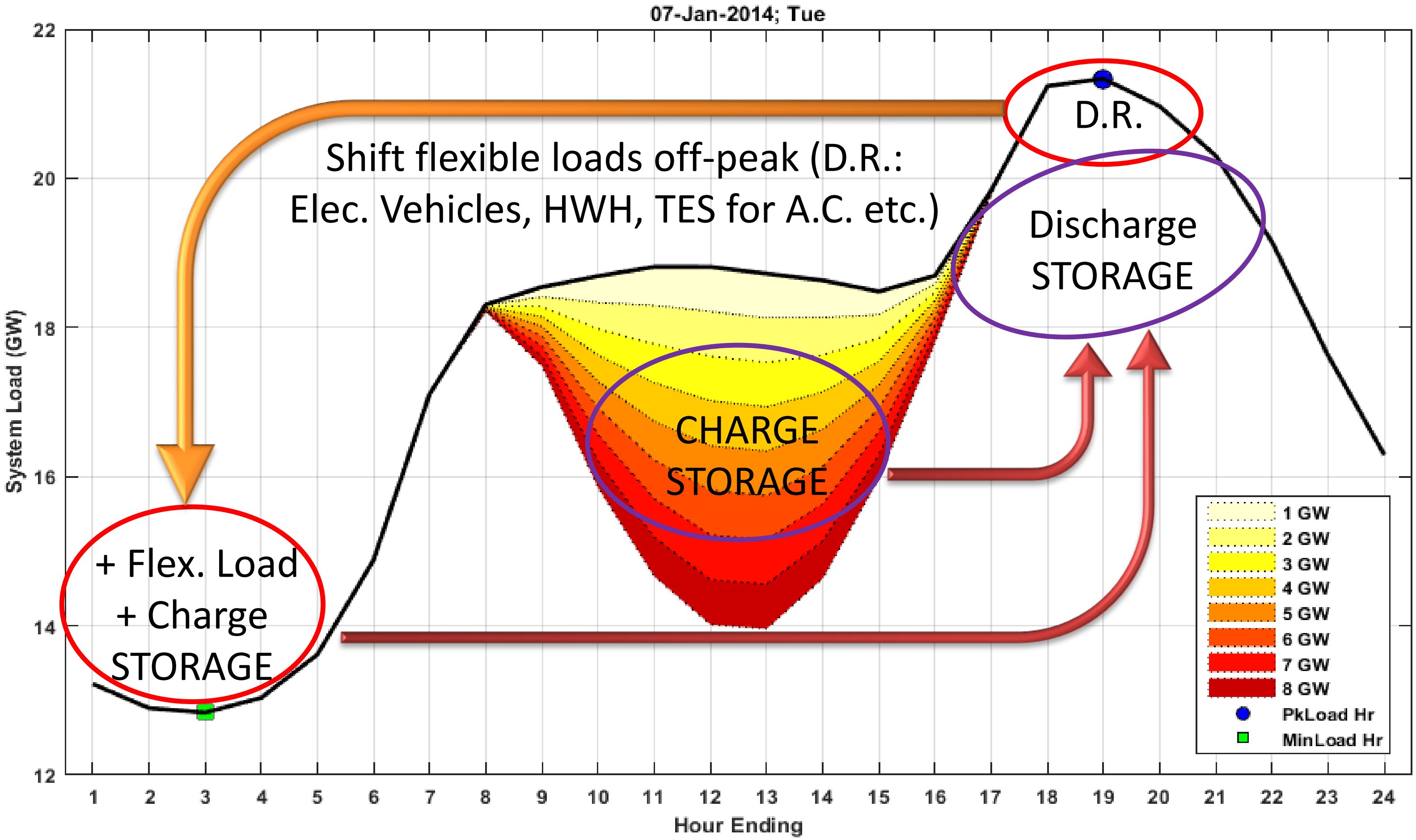
https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TOU.PDF

The Need for Time Varying Rates

Illustrative Winter Impact of Solar at Different Levels of Dev. (from ISO-NE)

from: https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

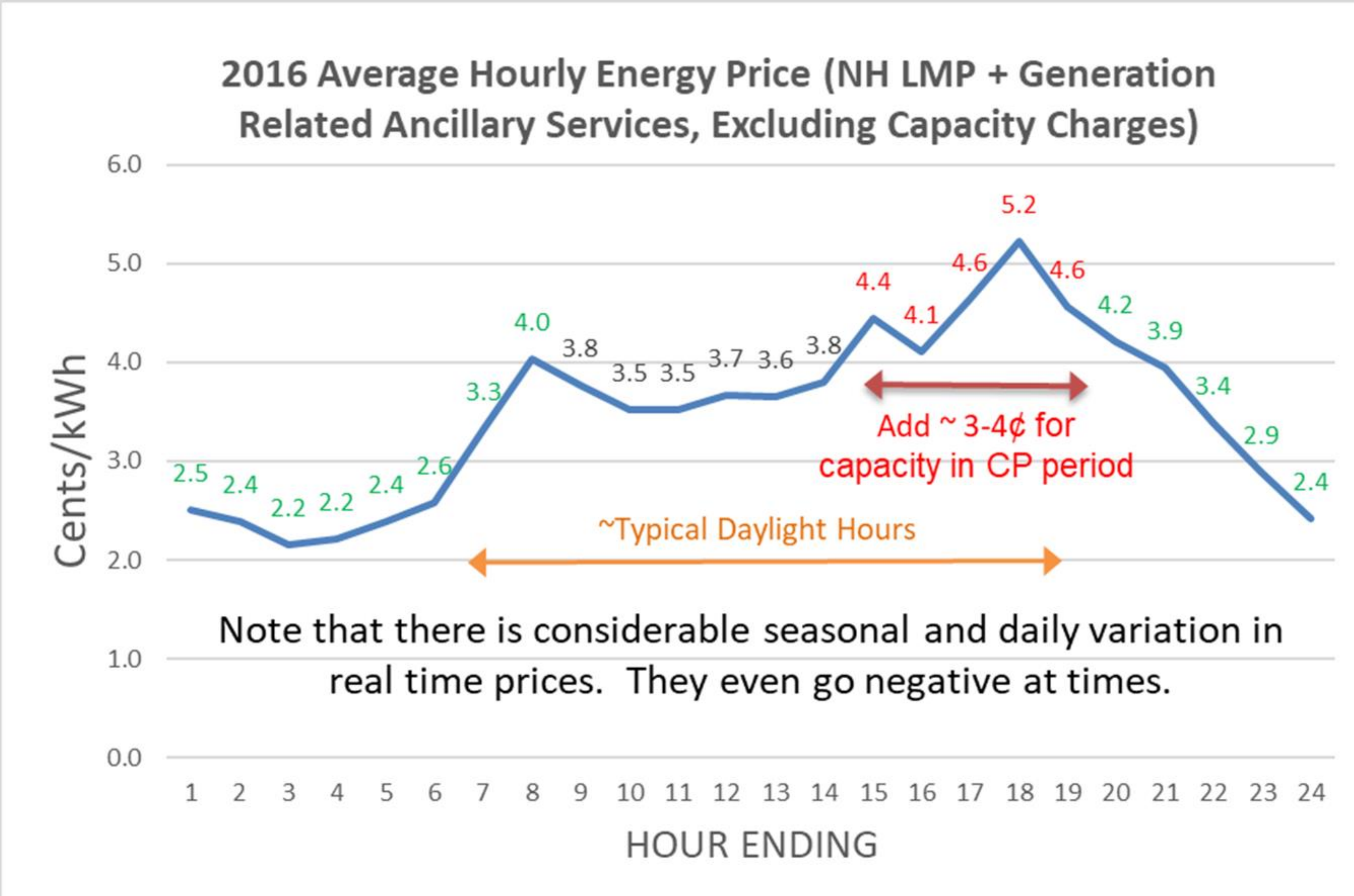
New England's Duck Curve

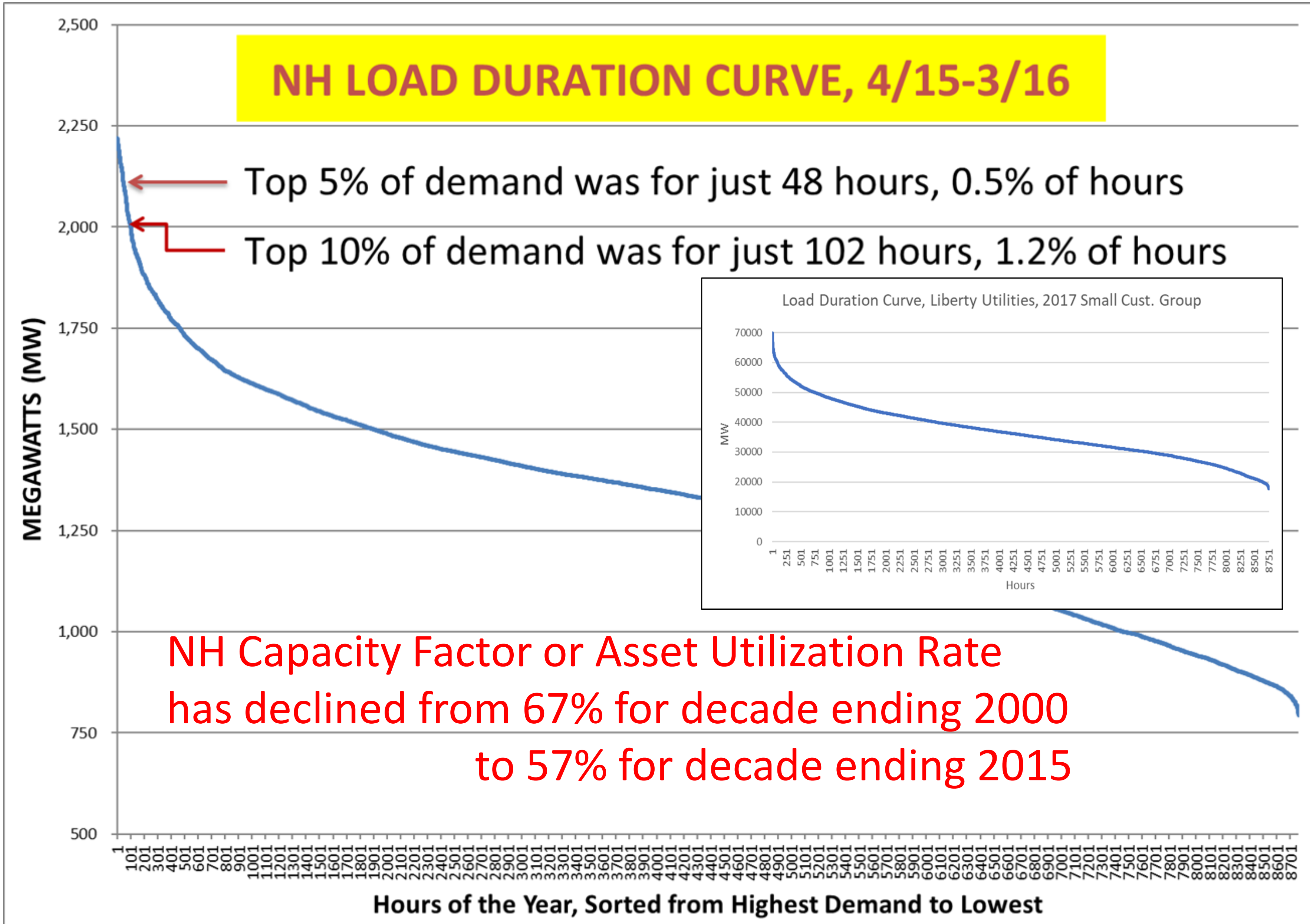


Rate Elements & Methods in Brief

- **Recent Historical Cost Causation Method for Generation** (Energy, Ancillary Svcs, FCM)
- **Historic Experience Cost Causation Method for Transmission** – based on how transmission costs are allocated to distribution utilities
  - probability of Monthly Coincident Peak occurring during any given hour
  - Winter/Summer seasonal differentiation

Average LMPs by Time of Day

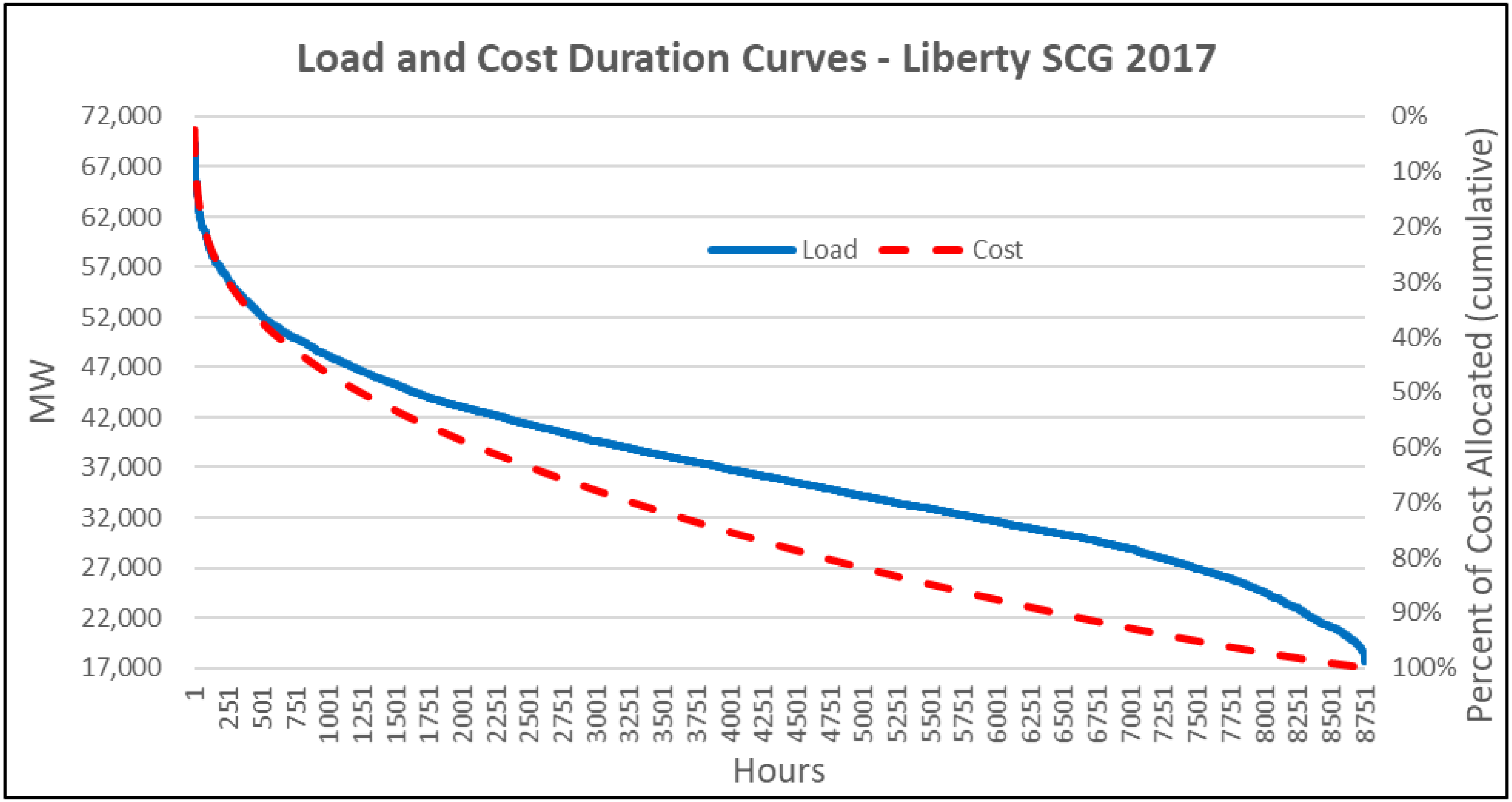




NH LOAD DURATION CURVE, 4/15-3/16
Top 5% of demand was for just 48 hours, 0.5% of hours
Top 10% of demand was for just 102 hours, 1.2% of hours
NH Capacity Factor or Asset Utilization Rate
has declined from 67% for decade ending 2000
to 57% for decade ending 2015
MEGAWATTS (MW)
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
Hours of the Year, Sorted from Highest Demand to Lowest
Load Duration Curve, Liberty Utilities, 2017 Small Cust. Group
MW
70000
60000
50000
40000
30000
20000
10000
0
Hours

Cost Duration Method for Distribution

Developed by Lon Huber, now V.P. for Rate Design and Strategic Solutions at Duke Energy Corporation

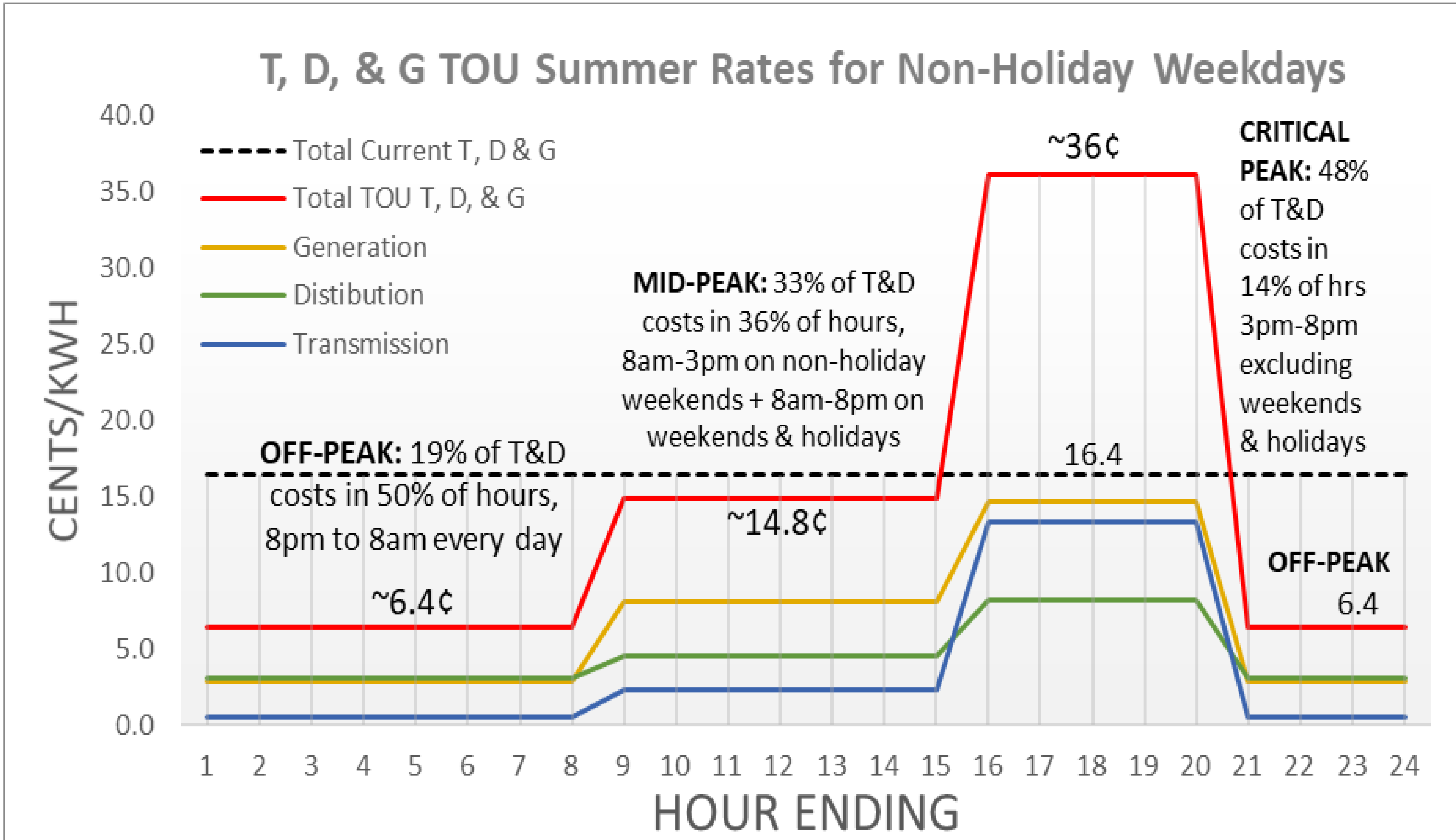


Consensus Results from Data Used for 2018

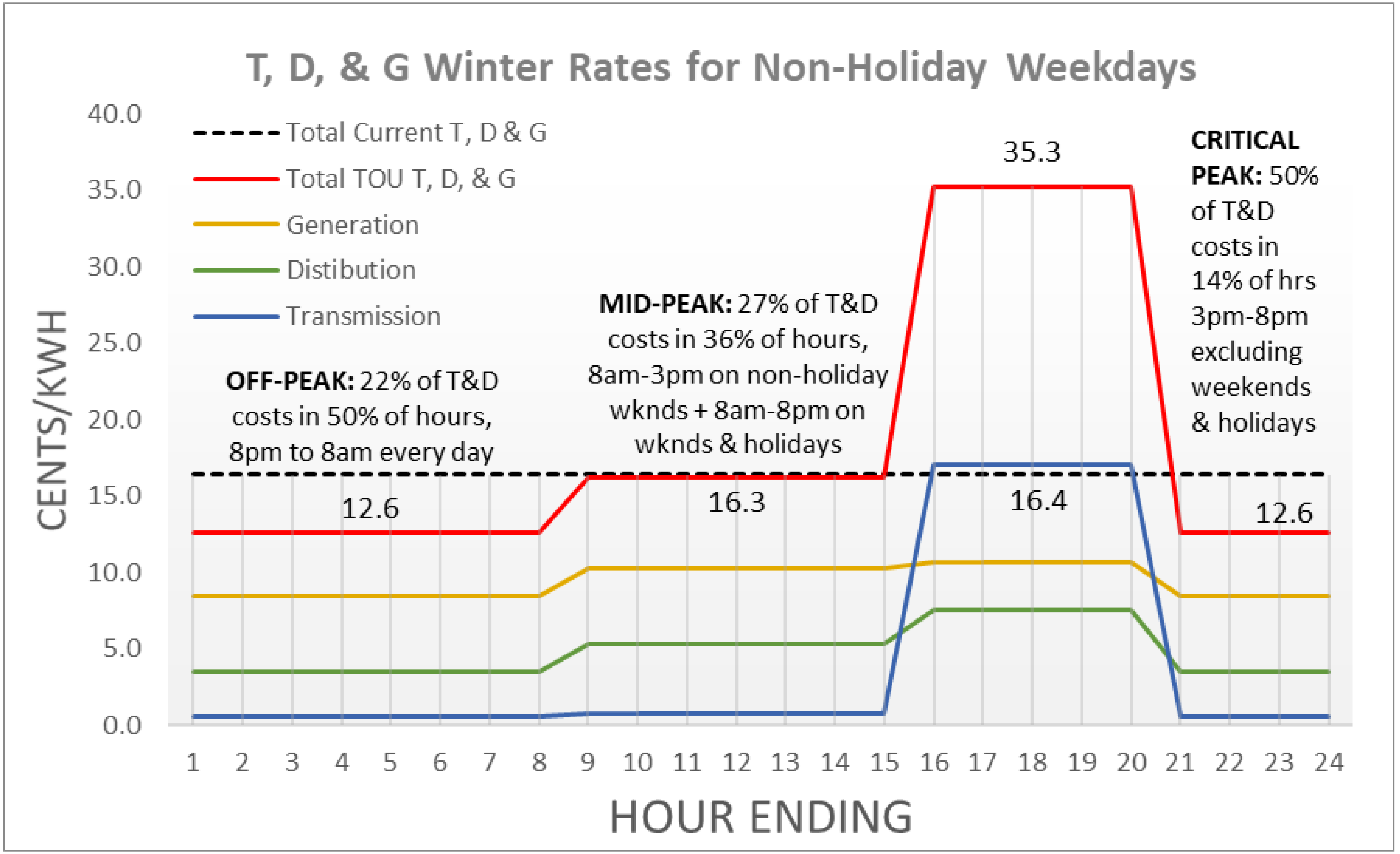
Rates are cents per kWh	Critical-Peak	Mid-peak	Off-peak	Current
Summer Energy (G) Rate =	14.6	8.1	2.9	8.3
Summer Distribution (D) Rate =	8.1	4.5	3.1	4.7*
Summer Transmission (T) Rate =	13.3	2.3	0.5	3.5
SBC and other minor charges/credits =	0.4	0.4	0.4	0.4
TOTAL SUMMER Variable Rate =	**36.4**	**15.3**	**6.8**	16.8
Winter Energy (G) Rate =	10.6	10.3	8.5	8.3
Winter Distribution (D) Rate =	7.5	5.3	3.5	4.7*
Winter Transmission (T) Rate =	17.1	0.7	0.6	3.5
SBC and other minor charges/credits =	0.4	0.4	0.4	0.4
TOTAL WINTER Variable Rate =	**35.7**	**16.7**	**13.0**	16.8

Model designed to update with each refresh of Default Rates, T&D Rates, CP history (T & Capacity), & Annual Hourly Load and Energy Costs Data

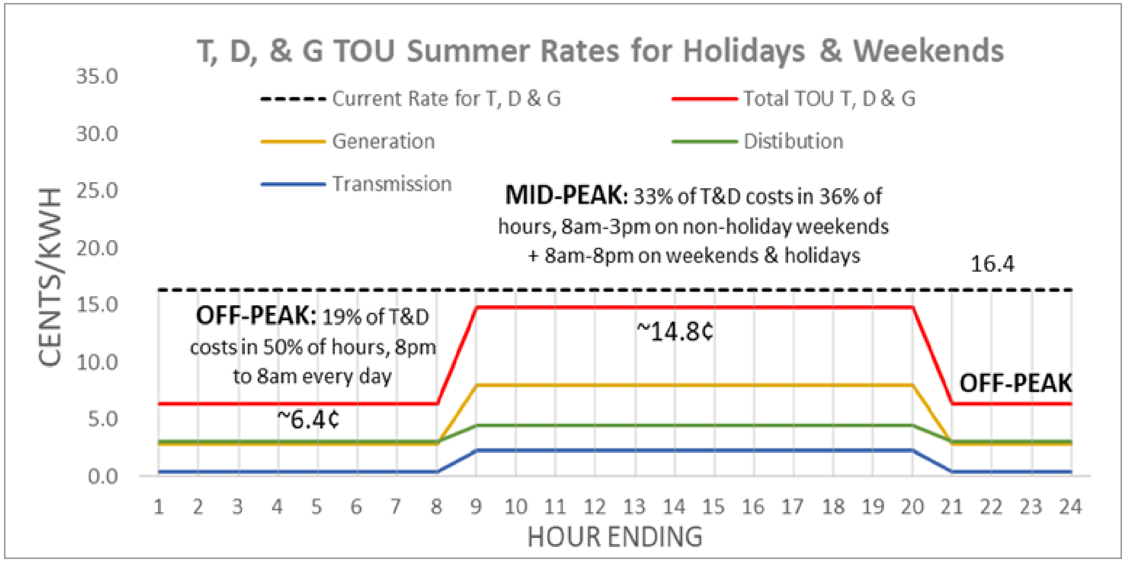
Resulting Summer TOU Rates After considering many permutations

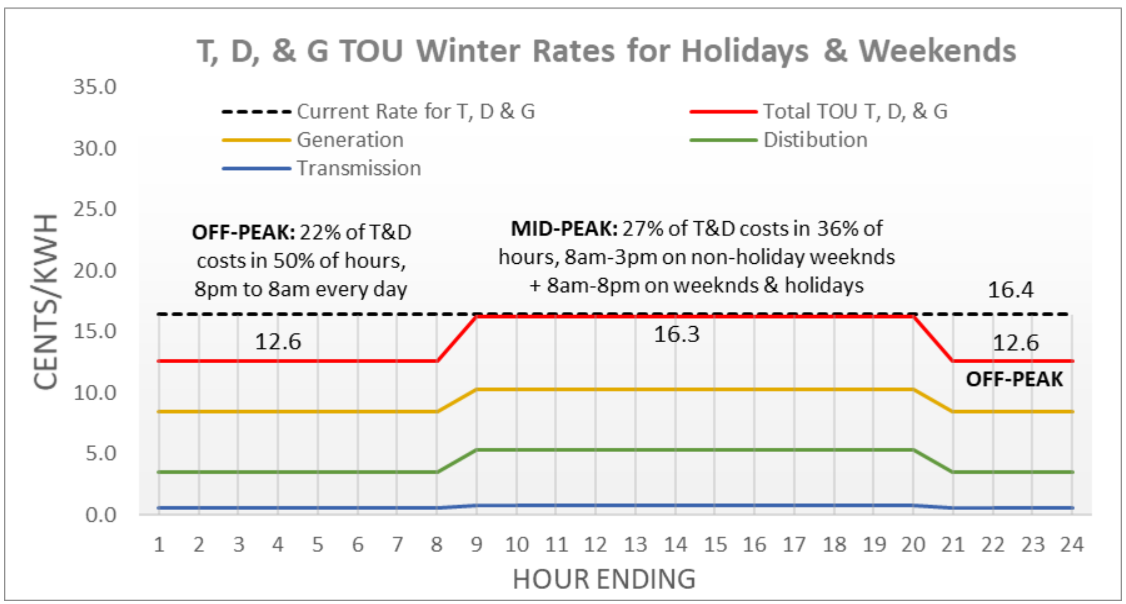


L.U. Winter TOU



L.U. TOU for Weekends & Holidays





	A	B	C	D	E	F	G
1	**SUMMER SEASONAL PERIOD (May 1 to October 31)**			USING Small Customer Group (SCG) load for D&G TOU			
2	TOU Rates For Liberty Utilities		**Wkends & Holidays split between OP & MP**				
3		Hour Beginning (for n-H weekdays):	3:00 PM	8:00 AM	8:00 PM		
4		Hour Ending (for n-H weekdays):	8:00 PM	3:00 PM	8:00 AM		
5		Energy Service Rate Calculation:	**CPP**	**Mid-Peak**	**Off-Peak**	**Total**	
6		2017 LOAD in kWh =	13,598,454	28,996,692	33,337,355	75,932,500	
7		LOAD SCALED TO DE 18-041 forecast	14,072,501	30,007,528	34,499,509	78,579,538	
8		Portion of FCM allocated to Period =	50%	50%		(from FCM Peaks TAB)	
9		RTP + Gen. Related Ancil. Svcs =	$ 0.05109	$ 0.03342	$ 0.02430	FCM/Total ES Rate row 11/19	
10		Ave. RPS Costs for E.S. to 1/19 =	$ 0.00481	$ 0.00481	$ 0.00481	CPP	MPP
11		FCM Cost, net of prior yr recon. =	$ 0.09172	$ 0.04301	$ -	62.7%	53.4%
12		Subtotal E.S. TOU Rate =	$ 0.14762	$ 0.08124	$ 0.02910		
13		Base Revenue =	$ 2,077,330	$ 2,437,716	$ 1,004,010	$ 5,519,056	
14		Portion of Base Revenue =	37.6%	44.2%	18.2%		
15		Revenue Requirement DE 18-041 =				$ 5,469,025	
16		Balance to make up =				$ (50,031)	
17		Portions =	$ (18,831)	$ (22,098)	$ (9,101)	$ (50,031)	
18		Additional Rate =	$ (0.00134)	$ (0.00074)	$ (0.00026)	**Current Rates**	as of 8/1/18
19		**Total E.S. TOU Rate =**	**$ 0.14628**	**$ 0.08050**	**$ 0.02884**	0.08299	
21		**Distribution Rate =**	**$ 0.08139**	**$ 0.04491**	**$ 0.03052**	0.04658	Ave for 650 kWh*
22	For T:	Historic Odds of a Monthly Peak =	76.67%	23.33%	0.00%		
23	Gradual %	Rev Target for C.P. Demand % =	$ 1,798,293	$ 547,306	$ -		
24	0%	Transmission Rate for C.P. D.% =	$ 0.1278	$ 0.0182	$ -		
25		Transmission Rate for Fixed/kWh =	$ 0.0048	$ 0.0048	$ 0.0048		
26	CD Meth?	**Total Transmission Rate =**	**$ 0.13254**	**$ 0.02299**	**$ 0.00475**	$ 0.03460	
27	No	Total T,D & G Rate =	**$ 0.36021**	**$ 0.14840**	**$ 0.06411**	$ 0.16417	
28		Storm Recovery Adjustment =	$ -	$ -	$ -		
29		Stranded Cost Charge =	$ (0.00095)	$ (0.00095)	$ (0.00095)	$ (0.00095)	
30		System Benefits Charge =	$ 0.00457	$ 0.00457	$ 0.00457	$ 0.00457	
31		Electricity Consumption Tax =	$ 0.00055	$ 0.00055	$ 0.00055	$ 0.00055	
32		**TOTAL SUMMER Residential Variable Rate =**	**$ 0.36438**	**$ 0.15257**	**$ 0.06828**	**$ 0.16834**	
33							
34		Fixed Customer Charge/Month =	$14.54	$14.54	$14.54	$14.54	
35	Revenue Check (TOU compared with current rates):						
36		$ 12,061,583	$ 5,127,721	$ 4,578,303	$ 2,355,559	$ 13,228,394	
37	Dist Est.	$ (3,546,029)	$ (1,145,403)	$ (1,347,711)	$ (1,052,915)	$ (3,660,549)	*See note
38		$ 8,515,554	$ 3,982,318	$ 3,230,592	$ 1,302,644	$ 9,567,845	
39	Total revenues, net of D estimate (summer & winter should be looked at together):				-10.998%	=difference	
40	*NOTE: Subtract out Distribution component as the current rate is only an estimated average rate due to change in rates at 250 kWh.						

	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1	TOU Model for Liberty Utilities DE 17-189, Summer FCM and T Cost Calculators													
2	Weekend & Holiday hours split between Off-and Mid-Peak													
3														
4		FCM Cost (Generation Capacity) TOU Allocation Calculator												
5			Est. Cost to Load / kW-mo.	$ 9.36	From ISO-NE 3/19/18 Net Cost to Load "nrcp_forecast_ccp_2018-2019.pdf"									
6			X # of months in period =	6										
7			X Ave. 2017 Cap. Tag for SC in kW =	74,658.57	From: https://liberty-utilities.com/nh/electricsupply/documents/ICAP_Tags_Rec.xls									
8			X Gross up for Dist. Loss Factor =	1.05025										
9			Est. FCM Cost @ 2017 Cap. Tag =	$ 4,192,826		From: www.puc.nh.gov/Regulatory/Docketbk/2018/18-041/TESTIMONY/18-041_2018-06-18_GSEC_ATT_TECH_STATEMENT_URBAN_SIMEK.PDF , p. 128								
10			Less Prior period reconcilliation =	$ 1,611,336	$ 0.00970	& 133								
11				$ 2,581,490	$ 5.49	/kW-mo= close to historic average AND long term conservative (low) forecast								
12		Coincident Hourly Peak Demand Transmission Cost Allocator for Summer Period (May-Oct.)												
13				For the 10 years ending 5/18, the % of 60 summer period months that the system peak occurred for transmission charges										
14			H.E. =	11	12	13	14	15	16	17	18	19	20	21
15				0.00%	1.67%	0.00%	6.67%	15.00%	11.67%	41.67%	6.67%	15.00%	1.67%	0.00%
16		CPP	76.67%	0.00%	0.00%	0.00%	0.00%	0.00%	11.67%	41.67%	6.67%	15.00%	1.67%	0.00%
17		Mid-Peak	23.33%	0.00%	1.67%	0.00%	6.67%	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18		Off-Peak	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19			100.00%											
21														
22				Current Transmission Rate for Rate Class D =		$ 0.03460	/kWh							
23				C.P. Demand portion of rate =		$ 0.02985	(Current Transmission Charges from DE 18-051)							
24				Fixed/kWh portion of rate =		$ 0.00475								
25							(Various reconcilliations, mosly prior period under-recovery from flat kWh rate, from DE 18-051)							
26			% of C.P. Demand part of rate moved to Fixed =			0%								
27			Gradualized C.P. portion of rate =			$ 0.02985				Use D cost/load duration method for all T:			No	
28			Gradualized Fixed/kWh portion of rate =			$ 0.00475				CP =	0.0401	0.0626763		
29										MP =	0.02354	0.036793		
30				Forecast Load for this Group =		78,579,538	kWh			OP =	0.01524	0.0238201		
31			Revenue Target for C.P. Demand Portion =			$ 2,345,599	with gradualization			scaling factor =		1.563		
32			Revenue Target for Fixed/kWh portion =			$ 373,253	$ 0.0048			(to meet same revenue)				
33				Overall Revenue Target =		$ 2,718,852	$ 2,718,852			(Source = Lon Huber model run)				
34														
35		LOAD FORECAST in Default Service Proceedings												
36			Feb-18	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	JAN
37	321,327,841	=Total	27708614	26838427	23234825	22196348	24762926	30469617	30078218	25145803	23355517	24831311	30158660	32547575
38			Summer Total =	156008429		78,579,538	=Summer Total in 2nd Half of 2017 (Aug-Oct)					47.3%		
39			Winter Total =	165319412		87,537,546	=Winter Total in 2nd Half of 2017 (Nov. -Jan. 2019)					52.7%		
40				321327841		166,117,084								
41														

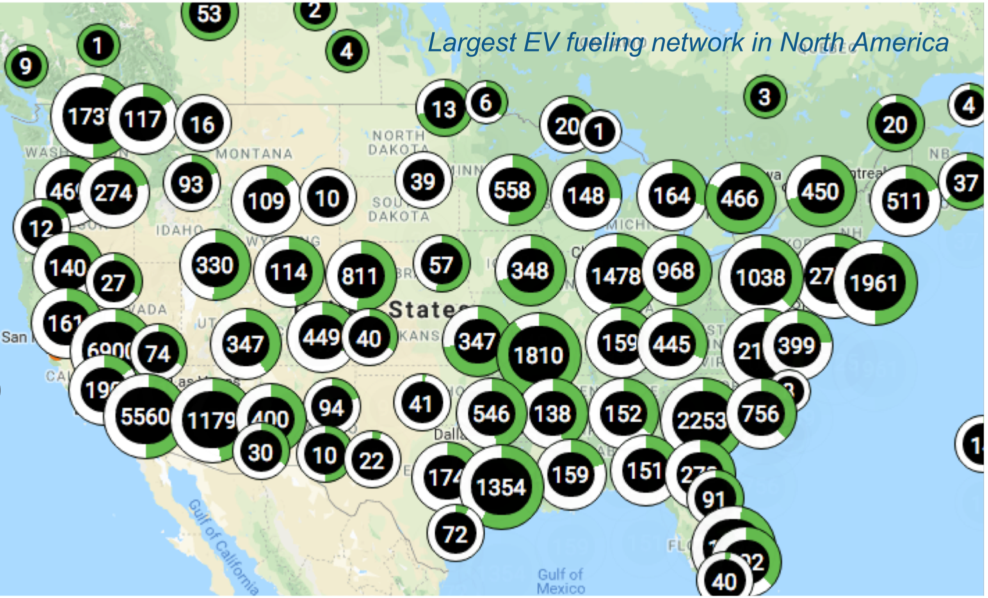
Building the New Fueling Network in New Hampshire

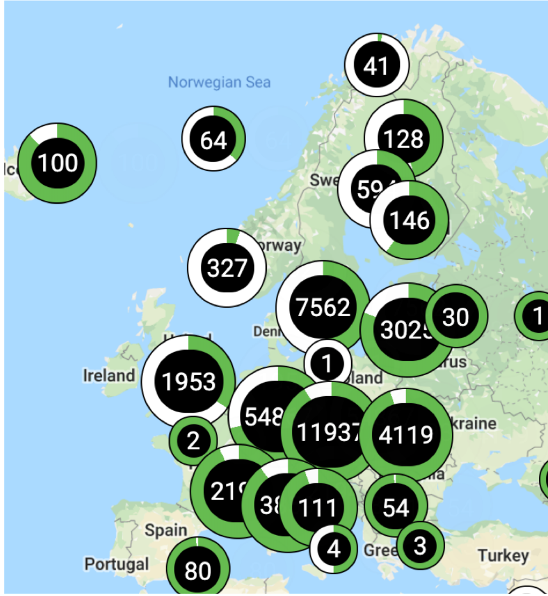
Kevin George Miller – Director, Public Policy

IR 20-004 Technical Session

February 28, 2020

World's Largest and Most Open EV Charging Network





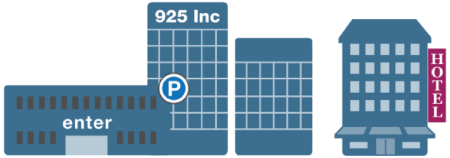
62%
of 2019 **Fortune Top 50** companies use ChargePoint

60%
of 2019 **Fortune 100 Best Companies to Work For®** use ChargePoint

109,700+ ChargePoint spots plus 45,000+ roaming spots

(as of Feb 2020)

Scaling a Broad and Diverse Charging Ecosystem



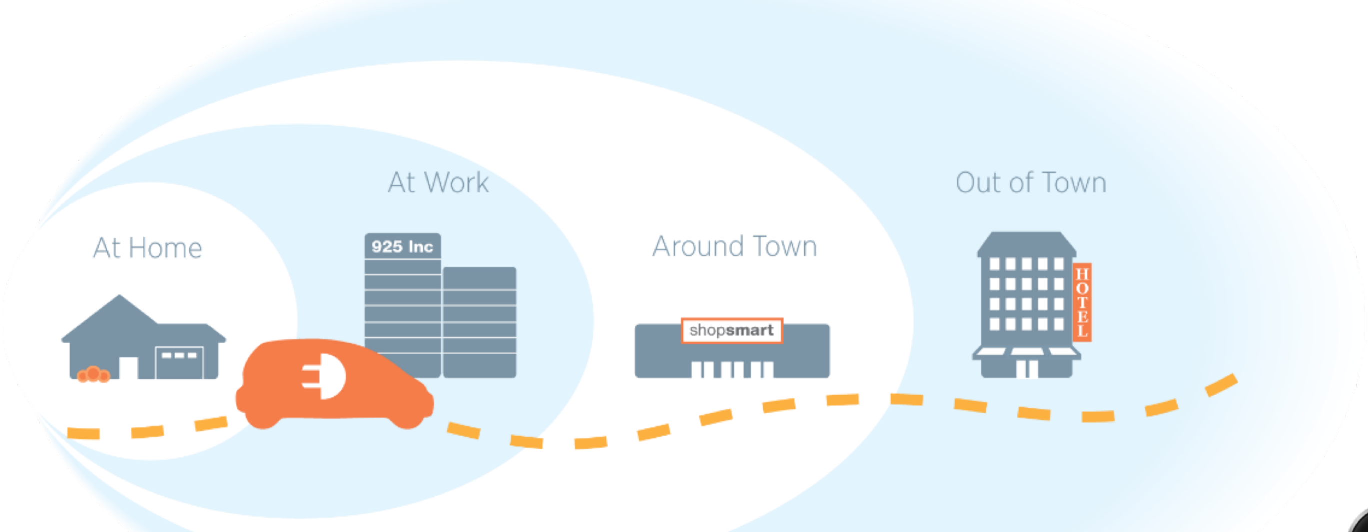
We **provide** a free app guiding drivers to charging spots

We **sell** turnkey charging solutions to various entities

We **enable** utility solutions and efficient grid integration of EV load

Networked Charging & Market Participants

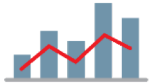
A Day in the Life of an EV Driver



- EV drivers charge when and where it's convenient
- EV drivers seek connectivity, convenience and control of their charging experience – both inside and outside the home

Benefits of Networked Charging Stations






	Smart Charger	Non-networked Charger
Dispense Electricity	✓	✓
Visible to Drivers * through mobile app, turn by turn directions, nearby amenities, real-time availability, 24/7/365 driver support	✓	✗
Waitlist & Driver Alerts * reserve a station, know when car is fully charged	✓	✗
Access Control for Owners * public/private, loyalty rewards, fleet services	✓	✗
Recover Revenue: Session Fees * charge per kWh, hourly, or per driver group	✓	✗
Data Analytics * station usage, # of unique drivers, charging behavior, utilization, revenue, costs, and GHG offset	✓	✗
Remote Access and Maintenance * proactive monitoring & fixes, software updates	✓	✗

Networked EV Charging Provides Value to All

EV Drivers

- Availability
- Consistent User Experience
- Convenience
- Seamless Payment

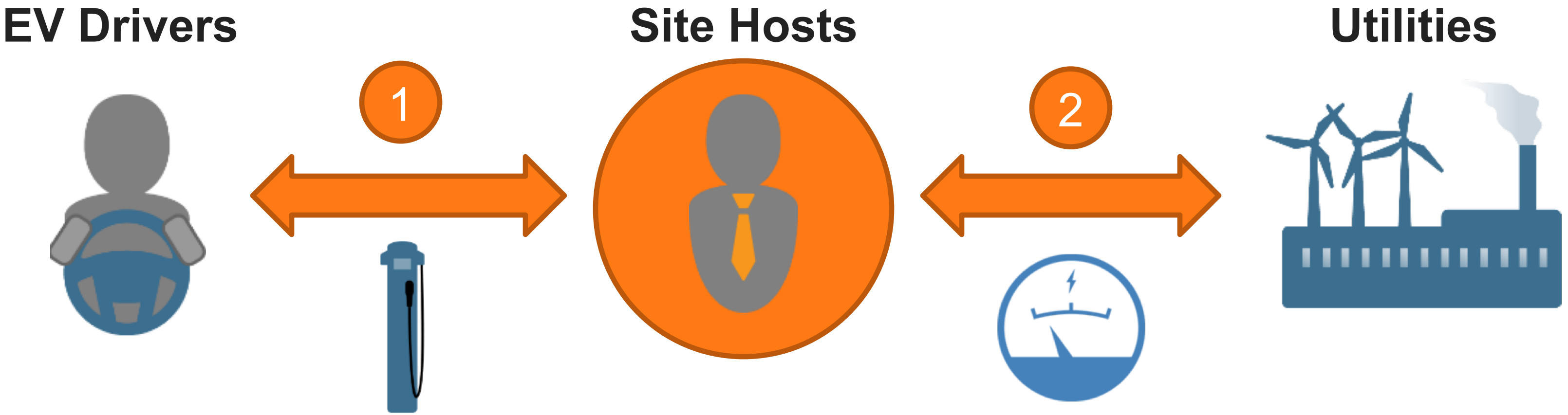
Site Hosts

- Drive up utilization
- Seamless Transaction
- Limited Administration
- Remote Diagnostics

Utilities

- Beneficial Load
- Grid Benefits
- Load Management
- Seamless Integration

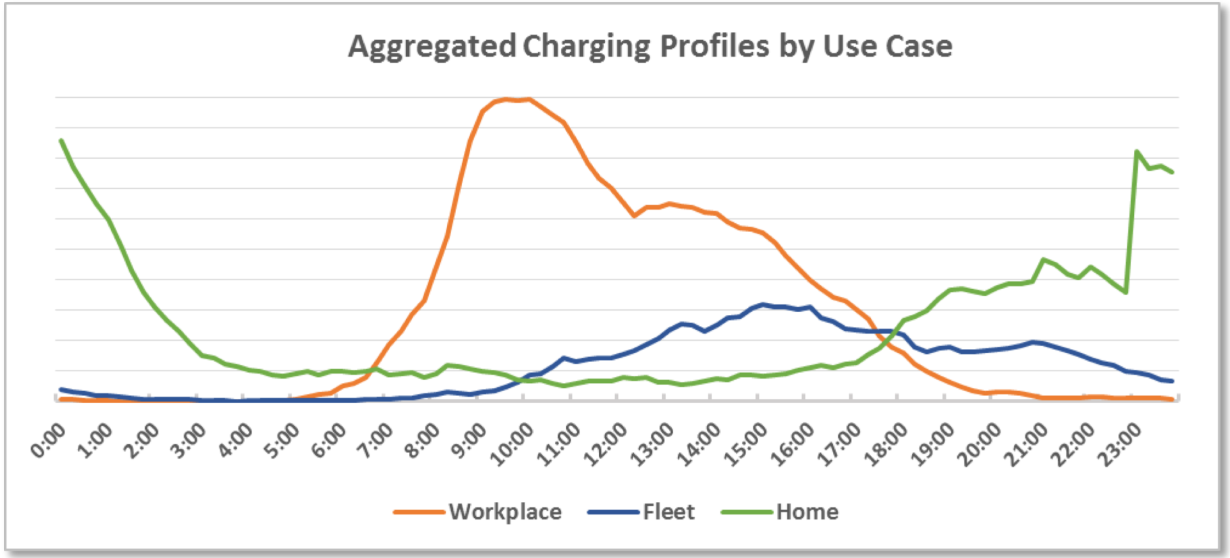
Key Transactions in the EV Charging Ecosystem



- Site host at the center of two transactions in EV charging
- Local property managers (site hosts) are the ideal entity to operate stations and set driver pricing to align interests, increase station utilization, and optimize the driver experience
- Site hosts can incorporate utility price signals and/or participate in load management programs to encourage off-peak charging

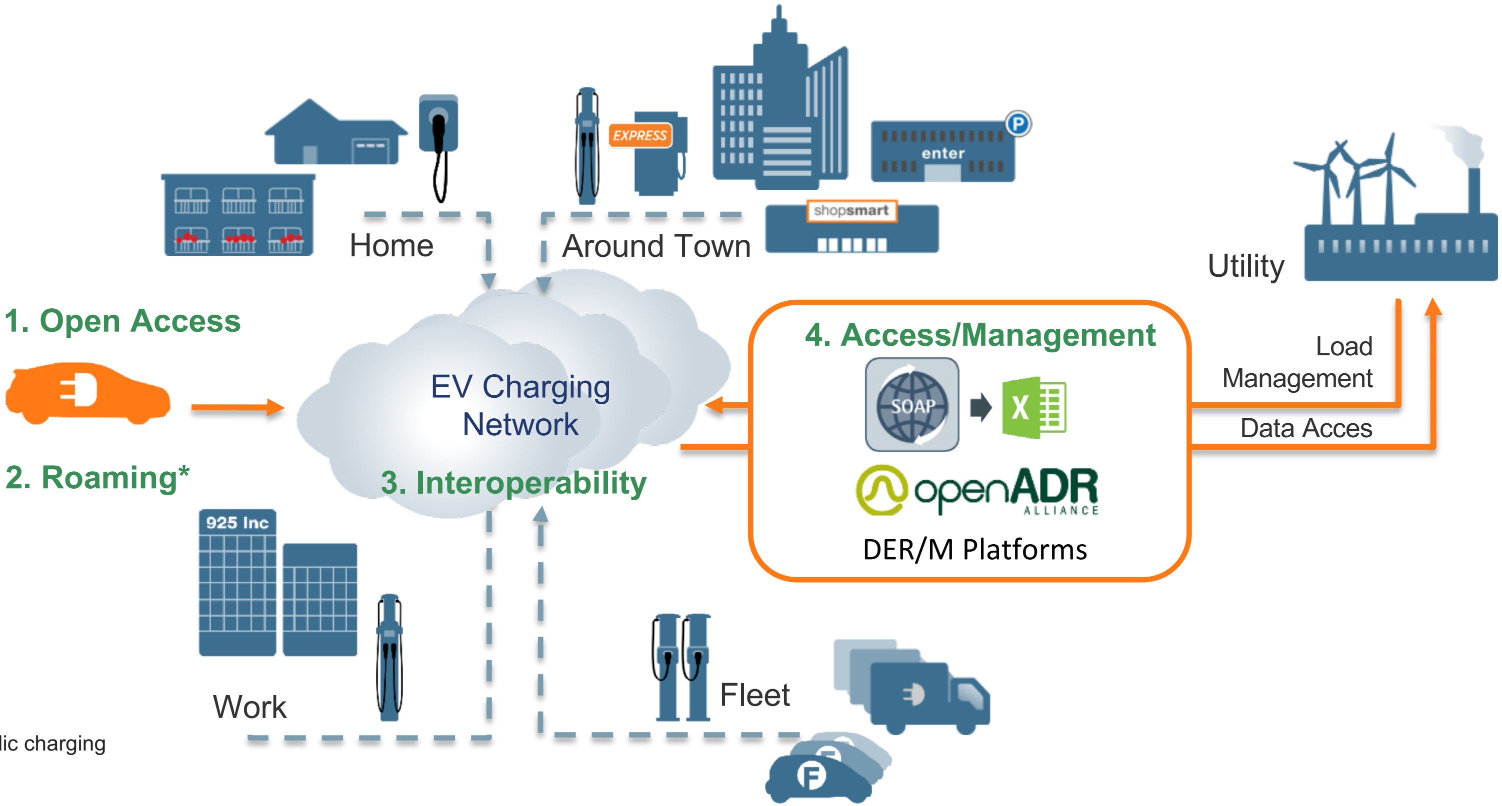
Appropriately Incentivizing EV Charging Behavior

EV Charging Use Case Will Drive Grid Benefits



+ Different use cases can provide different value to the grid
+ Profiles are aggregated loads from customers group use cases

Charging Ecosystem: Open, Innovative, Secure

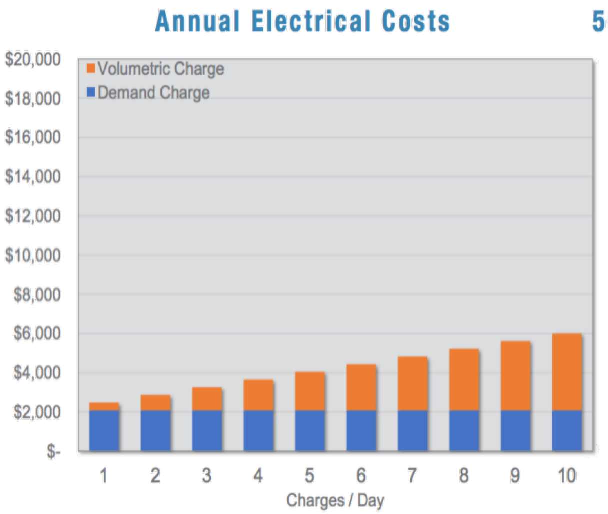


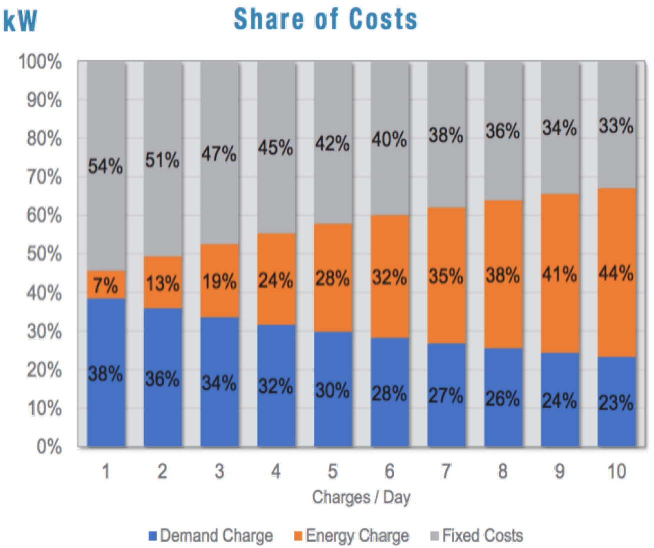
* Applies to public charging

Alternative C&I Rate Design for DC Fast Charging

+ C&I demand charges were not designed for DCFC load profiles.
+ DCFC have a *low load factor*, with sporadic instances of high energy use.
+ Demand charges can account for up to 90% of DCFC site host electricity bill.

50 kW





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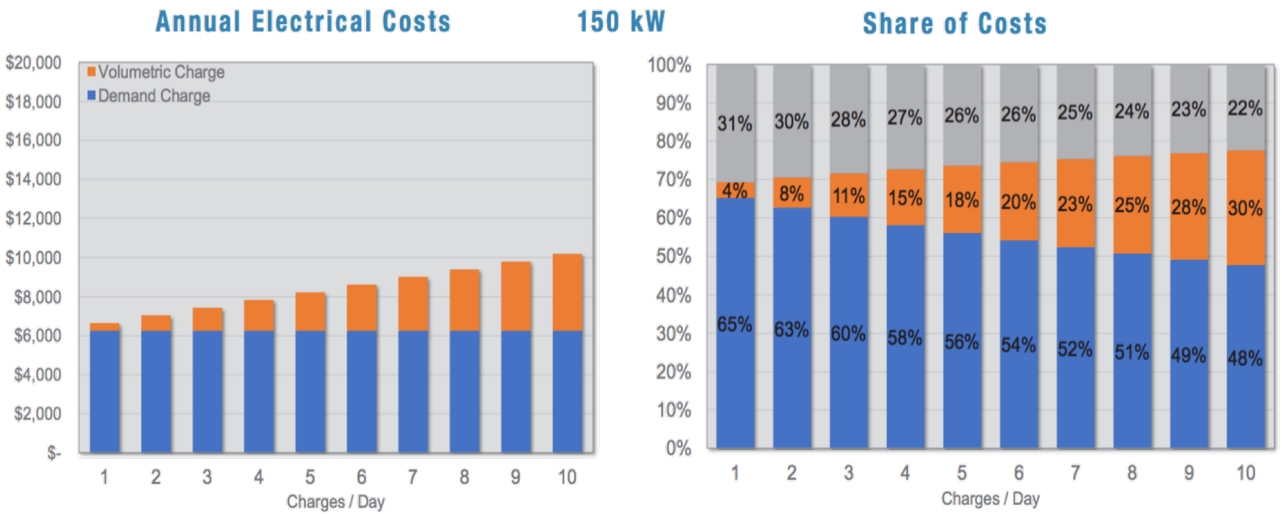

Alternative C&I Rate Design for DC Fast Charging

+ Alternatives to traditional, demand-based C&I rate structures for DCFC can be designed by utilities to be:
  - Revenue-neutral,
  - Track revenues and costs, and
  - effectively reduce operating cost barriers for DCFC site hosts.
+ There are many sustainable ways to alleviate demand charges, e.g.:
  - Replacing/phasing demand charges with higher kWh pricing, based on utilization or load factor (Pacific Power's *Public DC Fast Charger Optional Transitional Rate)*.
  - A monthly bill credit representing % of nameplate demand associated with installed EVSE behind metered service (PECO's EV-FC Rider).
  - "Rate limiter" in which the average cost equivalent of a demand charges is limited to a set ceiling/limit of cents/kWh (Ameren Illinois rates DS-3 and DS-4).

Takeaways

+ Different charging use cases can provide different value to the grid
+ Use case charging patterns are more easily optimized where one entity has control over a number of stations (workplace, fleet)
+ EV charging as is can be good for afternoon over gen relief (duck curve, “lobster claw”, etc.)
+ Large, hidden potential for home charging if networked
+ Most manageable and predictable load for grid services is fleet charging
+ Publicly available charging is not ideal for *active* load management programs
  - Unpredictable utilization; inelastic demand for charging (e.g., corridor rest stop).
  - *Indirect load management* can appropriately incentivize public L2 charging

Keys to a Sustainable Regulatory Framework and Complementary Role for Electric Utilities

Utility Engagement is Vitally Important

+ ChargePoint supports and encourages a greater role of utilities to support EV adoption
+ Utility investment/incentives in EV charging infrastructure can help accelerate access to charging solutions while encouraging grid benefits
+ Various investment models exist and each one can be designed to work alongside the existing competitive market and encourage the development of sustainable future

+ Questions about **ownership** of EVSE overlook the more critical **operational** questions that will shape the market for many years:
  - **Who sets pricing-to-driver, and at what level?**
  - **Are charging services competitive, or are they a utility activity?**
  - **How can we align charging services with onsite activities of site hosts?**
  - **Do customers continue to have choice of different EV charging networks?**
  - **How do we achieve grid benefits?**

Key Regulatory Framework Features

+ Maintain **site host choice** from qualified list of multiple vendors of EV charging equipment and networks
+ Support **site host flexibility** to control pricing and access, consistent with CT statute & on-site needs.
+ **Minimize costs and maximize benefits** by ensuring site hosts have "skin-in-the-game", where feasible, lowering risks to ratepayers and involving site host in the success of deployments.
+ Require **networked capabilities** to maximize reliability, flexibility, control, and grid benefits.
+ Consider equity in terms of the **full range of transportation/grid benefits and community needs**, including support for public and private MHD fleet electrification in addition to support for LDVs.

California	Colorado	Massachusetts
"Programs proposed by electrical corporations shall seek to minimize overall costs and maximize overall benefits…not unfairly compete with nonutility enterprises."	*"…the Commission shall consider whether the investments and other expenditures are…reasonably expected to stimulate innovation, competition, and increased consumer choices in electric vehicle charging and related infrastructure and services"*	**For cost recovery, utility proposals must**: *"be in the public interest; meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and not hinder the development of the competitive EV charging market."*

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