Medium Heavy Duty EV Ecosystem Straw Proposal

2021 Stakeholder Meeting
How to Determine Rates

Wednesday, September 15, 2021
1:00 p.m. – 5:00 p.m.
Via webinar

Question and Answer

- Questions should be typed into the Q & A tab on your screen.
- During the Q & A period, the moderator will use those questions as the basis of discussion with the panel.
- Please keep questions specific to the presentations and the topics discussed by the specific panel.
- A separate meeting will be held on September 24th for public comment.

Comment Deadline

- All comments are due by October 5th.
- Comments on specific stakeholder presentations and topics should be submitted two weeks after the panel is held via the directions listed in the Public Notice.

www.nj.gov/bpu

Comments

- Members of the public may file written comments regardless of whether they participate in the public meetings.

- Please submit comments directly to **Docket No. QO21060946** using the “Post Comments” button on the Board’s Public Document Search tool.

- Written comments may be submitted electronically to **board.secretary@bpu.nj.gov** in PDF or Word format. Please include the subject line “MHD EV Infrastructure.” All comments must be received on or before the comment deadline of **5:00 p.m. ET on October 5, 2021.**

Brief Break

The Stakeholder Meeting will resume after a short break.

HOW TO DETERMINE RATES

Ratemaking Basics for MD and HD EV Charging

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Assistant Deputy Ratepayer Counsel

New Jersey Division of Rate Counsel

NJ BPU STAKEHOLDER MEETING

September 15, 2021

HOW TO DETERMINE RATES
Ratemaking Basics for MD and HD EV Charging

NEW JERSEY ELECTRIC VEHICLE INFRASTRUCTURE ECOSYSTEM

2021 MEDIUM AND HEAVY DUTY STRAW PROPOSAL

IN THE MATTER OF MEDIUM AND HEAVY DUTY ELECTRIC VEHICLE CHARGING ECOSYSTEM

NJ BPU Docket No. QO2106094

DISCLAIMER

The comments of the presenter and content of the slides do not necessarily constitute a legal opinion, or represent the position and policies of the Division of Rate Counsel, the Board of Public Utilities, the State of New Jersey, or the presenter, and are intended only to facilitate the exchange of ideas and discussion for the Panel and Stakeholder group.

TOPIC OVERVIEW

- TRADITIONAL UTILITY RATEMAKING PROCESS
- BONBRIGHT PRINCIPLES
- MD/HD EV CHARGING ISSUES

TRADITIONAL UTILITY RATEMAKING PROCESS "BASE RATE CASE"

- a/k/a "Rate Base/ Rate of Return" or "Cost of Service" traditional utility regulation
- Base Rate Case: a key regulatory proceeding where a utility's Revenue Requirement and Customer Rates come under review.
- 3 Basic Steps in Determining Customer Tariff Rates:
  - STEP 1: Determine Utility's Revenue Requirement
  - STEP 2: Determine Cost Allocation to the Customer Classes
  - STEP 3: Determine the Appropriate Rate Design (Prices) for Each Customer Class

STEP 1: Determine Utility's Revenue Requirement

- Objective: Determine how much revenue a utility needs in order to earn a fair rate of return on its investment in Rate Base, the assets needed to serve its customers [Revenue Requirement]:
  - Determine a fair Rate of Return (ROR %) on the Utility's assets [Rate Base], in consideration of the return on similar investments
  - Examine a utility's Test Year expenses
- Revenue Requirement Formula:
  - Revenue Requirement = [ROR% x (Rate Base)] + Operating Expenses + Depreciation + Taxes

STEP 1: Determine Utility's Revenue Requirement

- Objective: Translate the Revenue Requirement into an Increase or Decrease in the Total Revenues to be collected from Ratepayers:
  - Examine utility's Test Year Revenue
  - Compute the Revenue Deficiency (or Overage) needed to meet the Revenue Requirement, and the resulting increase (or decrease) from Current Revenues to be collected from ratepayers
- Revenue Increase/Decrease Formula:
  - Revenue Requirement – Current Revenue = Revenue Deficiency (or Overage)

STEP 2: Determine Cost Allocation to the Customer Classes

- A Class Cost Of Service Study ["CCOS"] is a study in which the total utility's cost of service (Revenue Requirement) is spread or allocated to its customer classes
  - Customer Class or Class of Service – A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service. Common classifications include residential, commercial, primary service and industrial
  - The allocation of the total company cost of service to the individual customer classes can provide a revenue requirement target for each customer class, so that each class of customers pays the costs that the utility incurs to serve that class

Adapted from a Michigan PSC "Cost of Service Ratemaking" presentation

STEP 2: Determine Cost Allocation to the Customer Classes

- CCOSS/Ratemaking Steps:
  - Functionalization (Transmission/Generation/Distribution): Generally, only Distribution in NJ, since late 1990's restructuring/unbundling
  - Classification: utility costs classified as Fixed (by customer, i.e. meters), Energy (kWhs), and Demand (kW)
  - Allocation: costs and associated revenues allocated to the different customer classes – i.e., residential, commercial, industrial, etc. [Unitized Rate of Return]
  - End Product - Utility Tariff Charges and Rates: Customer charges, per kWh Charges, and Demand Charges

STEP 2: Determine Cost Allocation to the Customer Classes

- Types of Costs and Allocations - basic:
  - Demand-dependent Costs – need to be allocated by some method
  - Energy-dependent Costs – allocation based on energy consumption
  - Customer-dependent costs - allocation based on number of meters
- CCOSS Issues – Classification and Allocations
  - Classification of Costs
    - Issues: Customer charge - level of customer support needed; Infrastructure sizing – peak load, planning load (i.e. “overbuilt” system)
  - Class Allocation Methodologies: Coincident Peak; Non-coincident Peak, Mixed; Average and Excess, etc.
  - Load Factor: ratio of average load to peak load during a specified period of time.

STEP 3: Determine the Appropriate Rate Design (Prices) for Each Customer Class

- Basic Utility Tariff Components (see EDC websites):
  - Customer Charge ($)
  - Energy/Distribution per kWh Rate ($/kWhr)
  - Demand Charge based on kW ($/kW)
  - Surcharges (i.e. SBC, etc.)
  - Tariff Terms – conditions of service, etc.

BONBRIGHT RATEMAKING PRINCIPLES

“CRITERIA OF A SOUND RATE STRUCTURE”

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

    (a) in the control of the total amounts of service supplied by the company;

    (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Source: James Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961, page 291.

MD/HD EV CHARGING - RATEMAKING ISSUES FOR CONSIDERATION

A. DEMAND CHARGES

- Utility Tariff Examples (see NJ EDC websites)
  - Atlantic City Electric
  - JCP&L
  - PSE&G
  - Rockland Electric
- Mitigation of Demand Charges (Customer Side)
  - <u>Patterns of Usage (Peak Demand, Load Factor, etc.)</u>: Ice Cream Trucks vs School Buses vs Package Delivery
  - <u>Technology</u>: Energy Storage; Managed Charging
  - <u>Business Operations</u>: Entire Commercial Operation Load (day/night load)

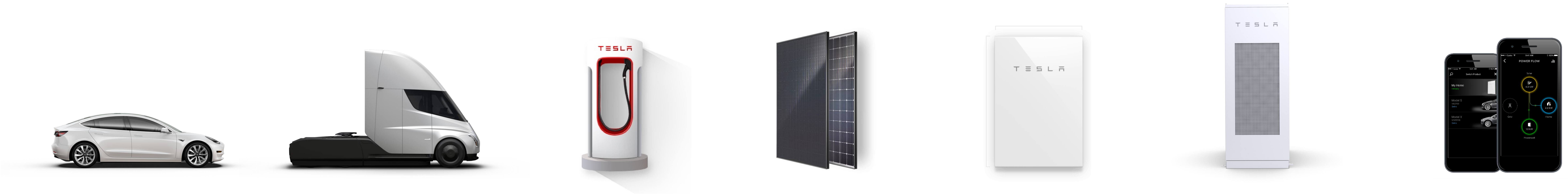
MD/HD EV CHARGING - RATEMAKING ISSUES FOR CONSIDERATION

B. INFRASTRUCTURE COSTS

- “Cost to Serve” Issue
- Service Upgrades – Who Pays?
  - Utility Side (Transformers, service connections, etc.)
  - Customer Side (“Behind the Meter”)

TESLA

PRODUCT SUITE



Vehicles | Semi | Charging | Solar | Powerwall | Powerpack | Software

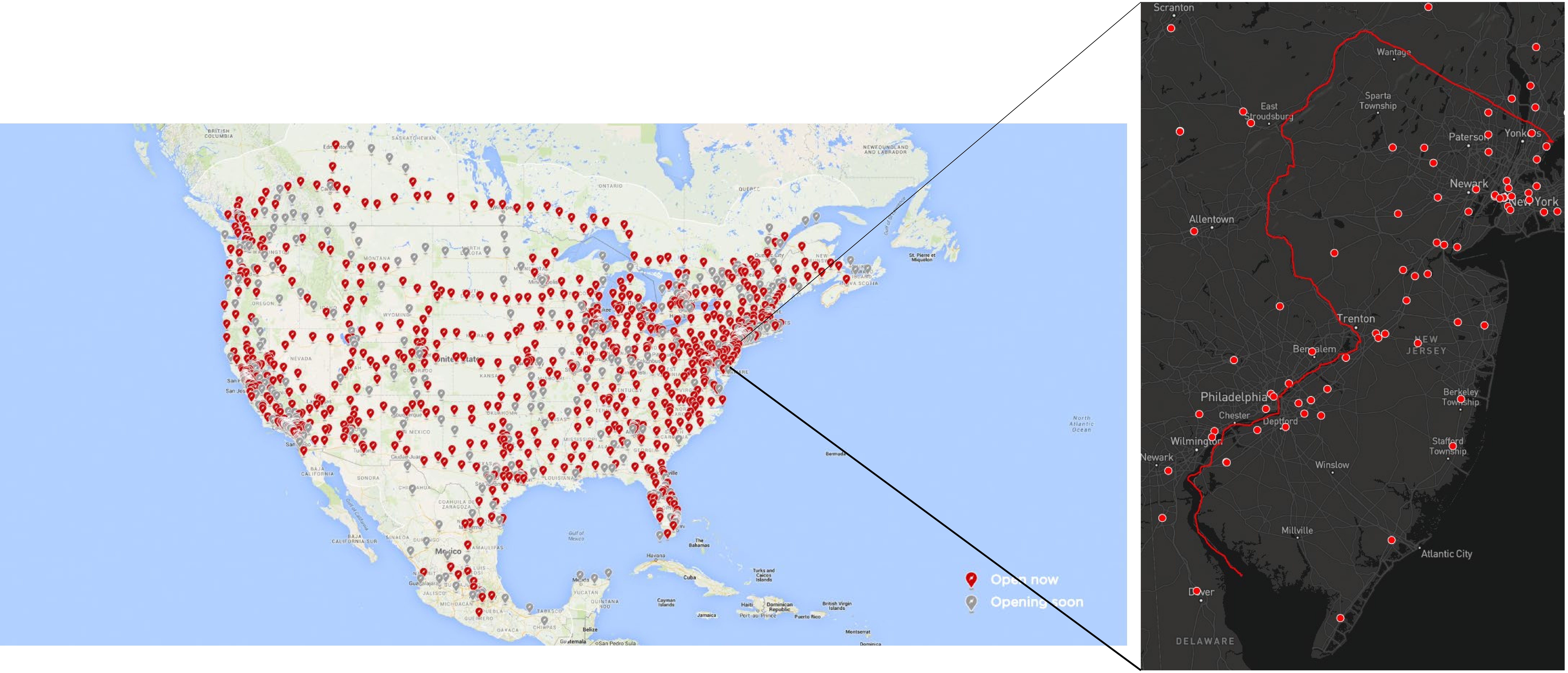
TESLA CHARGING

Supercharging

Destination Charging

Where You Park

SUPERCHARGING



~29,000 Light-Duty BEVs in New Jersey as of December 2020.

https://www.drivegreen.nj.gov/dg-electric-vehicles-basics.html

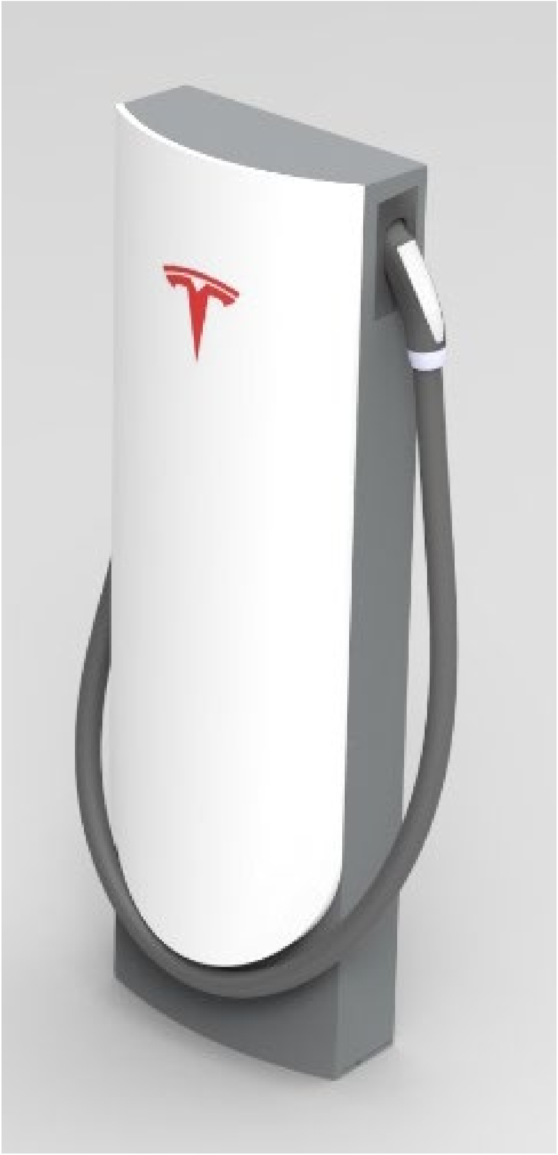
TESLA CHARGING EQUIPMENT

Semi Charging (??? kW)

Supercharger V3 (250 kW)

Supercharger V2 (120kW)

Supercharger (72kW)



Wall Connector

Max Output Power	250 kW	120 kW	72 kW	7-17 kW
Typical Charge Time	20-30 minutes	30-40 minutes	50 minutes	4-8 hours
Target Use Case	Long Distance	Long Distance	Urban Fast Charging	Destination Charging (Public + Work + Home)

TRANSPORTATION-ELECTRIC UTILITY NEXUS

RATE DESIGN CONSIDERATIONS

Public Fast Charging

Home Charging

MHD Fleet Charging

DEMAND CHARGES

- Electricity represents the majority of operating costs for DCFC stations.
- Absent an EV charging rate, DCFC customers take service under commercial rates that include both energy and demand components.
- At current rates of EV adoption, utilization of DCFC stations are low, and demand charges account for the majority of electric costs.
- **Demand charges can account for up to 90% of a station's monthly electric bill, resulting in prohibitively high operating costs and costs well above average rates.**

RATE DESIGN CONSIDERATIONS

Ex. Utility Rates:
Fixed charge = $100
Demand charge = $8/kW
Energy charge = 10 c/kWh

Shopping Center

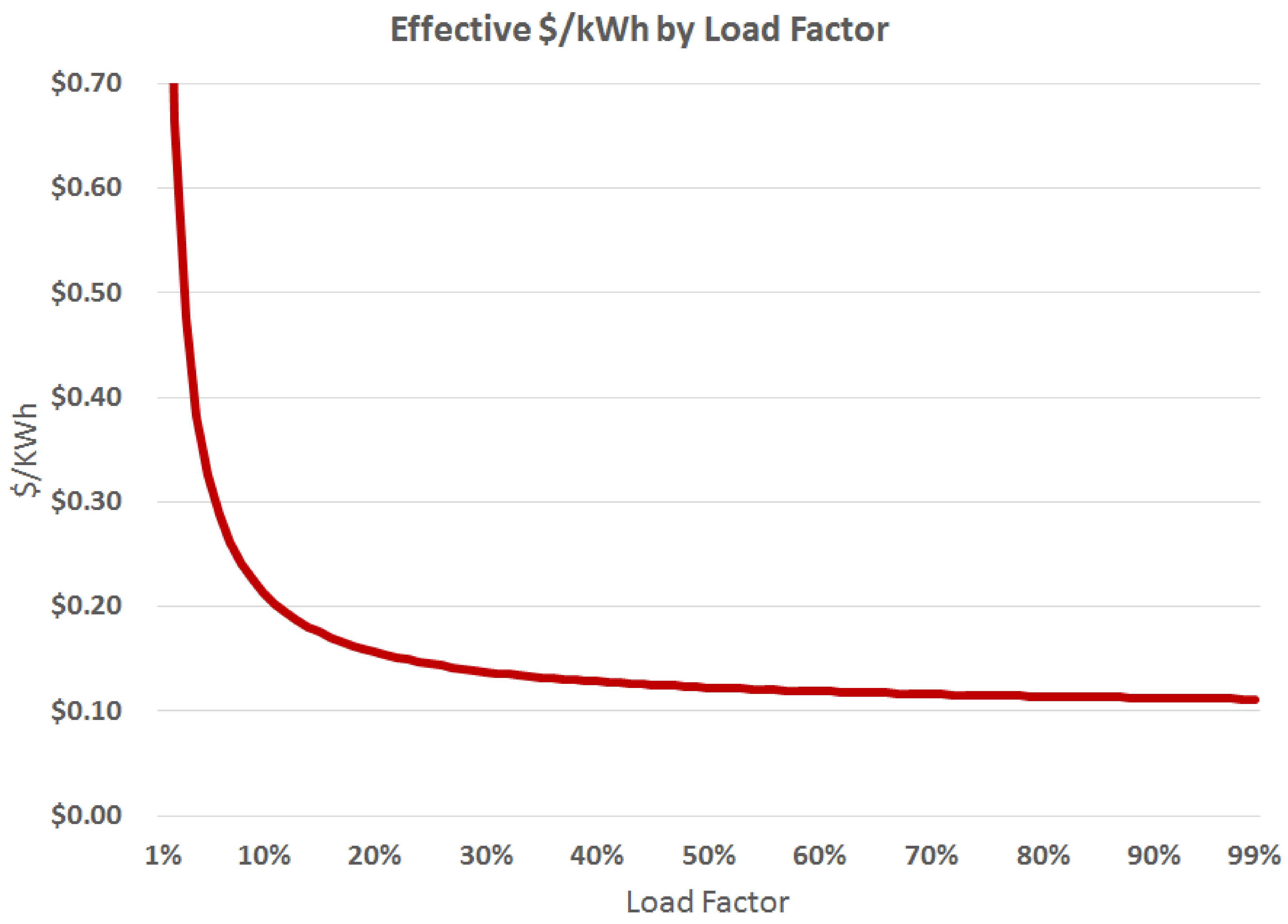
750 kW & 270,000 kWH

- Fixed charge = $100
- Demand charge = $6000
- Energy charge = $27,000
- **Effective Rate = 12.2 c/kWh**

Supercharger

750 kW & 54,000 kWh

- Fixed charge = $100
- Demand charge = $6000
- Energy charge = $5400
- **Effective Rate = 21.2 c/kWh**



ASSUME 8 LDV DCFC = 1 MHD CHARGER

8 x 75 kW LDV / 1 x 500 kW MHD		Current Commercial Rate
		PSE&G
500 kW max demand		Large Power & Light (LPL)
load factor	kWh_thru	Above 500 kW
2.5%	10,800	$ 10,039
5%	21,600	$ 10,795
7.5%	32,400	$ 11,551
10%	43,200	$ 12,307
15%	64,800	$ 13,819
20%	86,400	$ 15,331
25%	108,000	$ 16,843
30%	129,600	$ 18,355
35%	151,200	$ 19,867
40%	172,800	$ 21,379
45%	194,400	$ 22,891
50%	216,000	$ 24,403

Total Monthly Electricity Bill

8 x 75 kW LDV / 1 x 500 kW MHD		Current Commercial Rate
		PSE&G
500 kW max demand		Large Power & Light (LPL)
load factor	kWh_thru	Above 500 kW
2.5%	10,800	$0.93
5%	21,600	$0.50
7.5%	32,400	$0.36
10%	43,200	$0.28
15%	64,800	$0.21
20%	86,400	$0.18
25%	108,000	$0.16
30%	129,600	$0.14
35%	151,200	$0.13
40%	172,800	$0.12
45%	194,400	$0.12
50%	216,000	$0.11

Effective Cost per kWh

PSE&G Large Power & Lighting (Secondary):

Fixed charge = $347.77

Demand charge = $3.53/kW

Summer On-Peak Demand Charge = $8.39/kW

Energy charge = 7 c/kWh

PSE&G BGS-CIEP (> 500 kW) Demand Charges:

**These charges based on coincidence w/ system peaks (50% coincidence of site peak assumed)*

Transmission Charge = $12.13/kW

Capacity Charge = $10.96/kW

EV charging stations have lower load factors than regular commercial customers – can be as low as < 5%

P S E & G E X A M P L E - R A T E L P L

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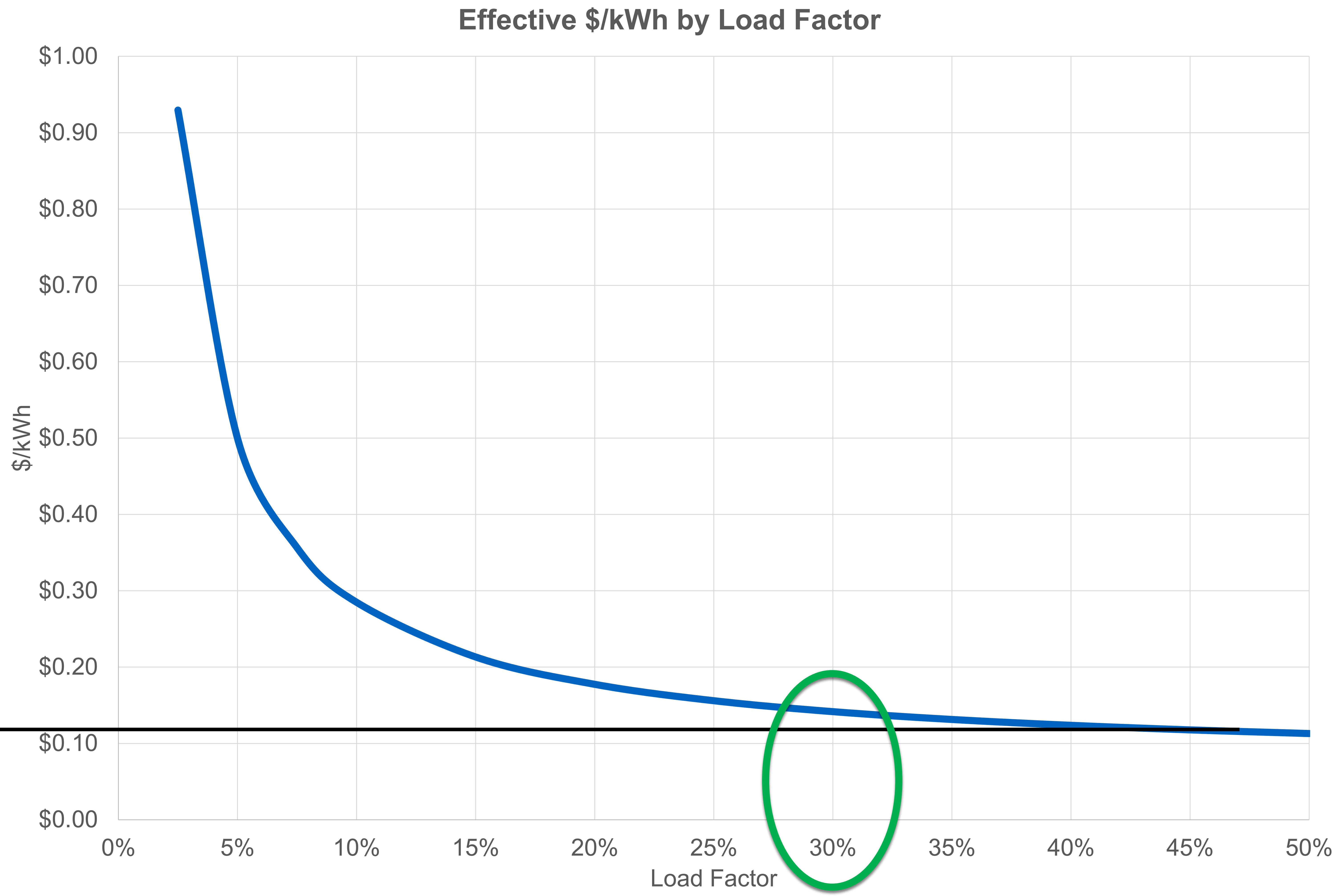
2019 Average Commercial Electricity Price* = $0.1219/kWh

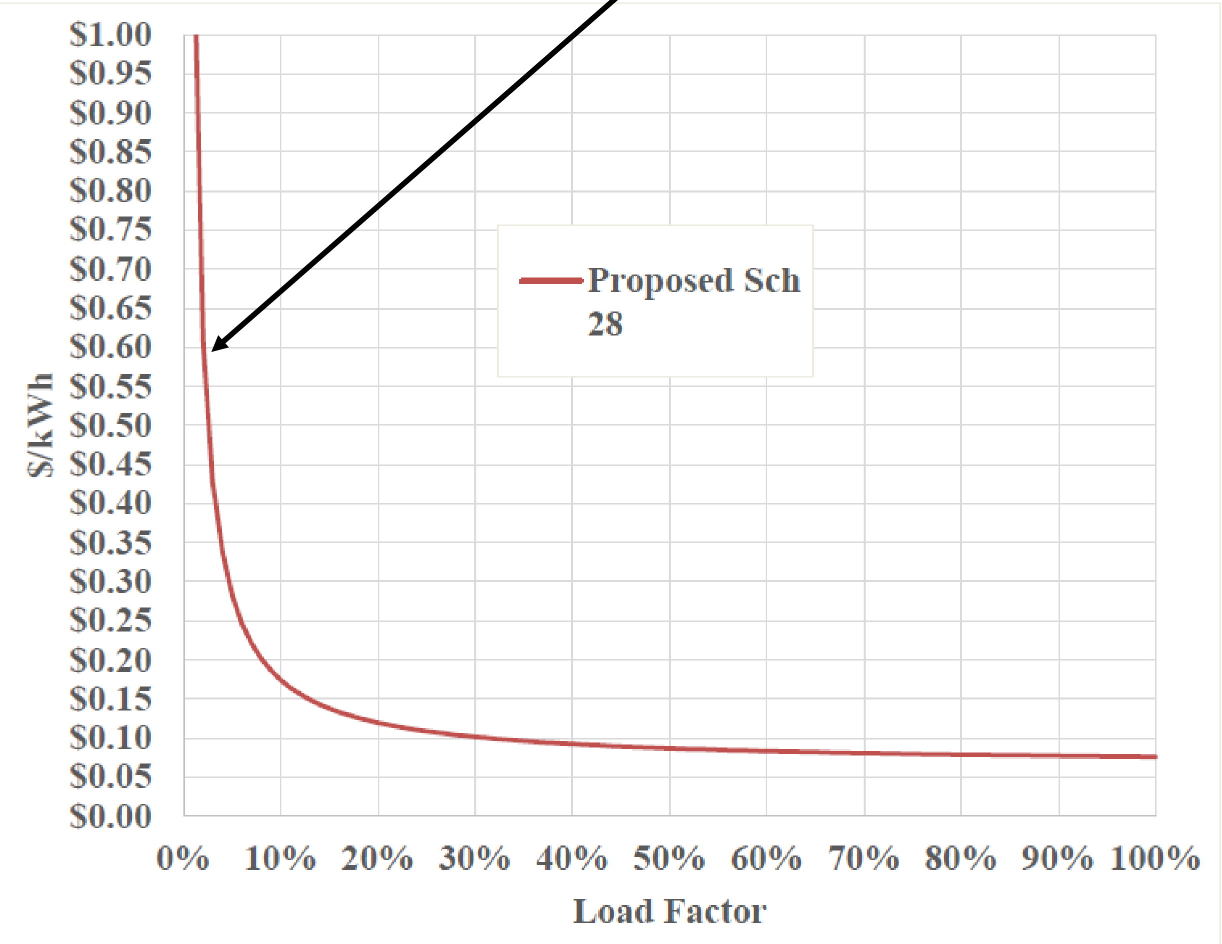


*EIA-861 Table 7: https://www.eia.gov/electricity/sales_revenue_price/

EXAMPLE – PACIFIC POWER OREGON

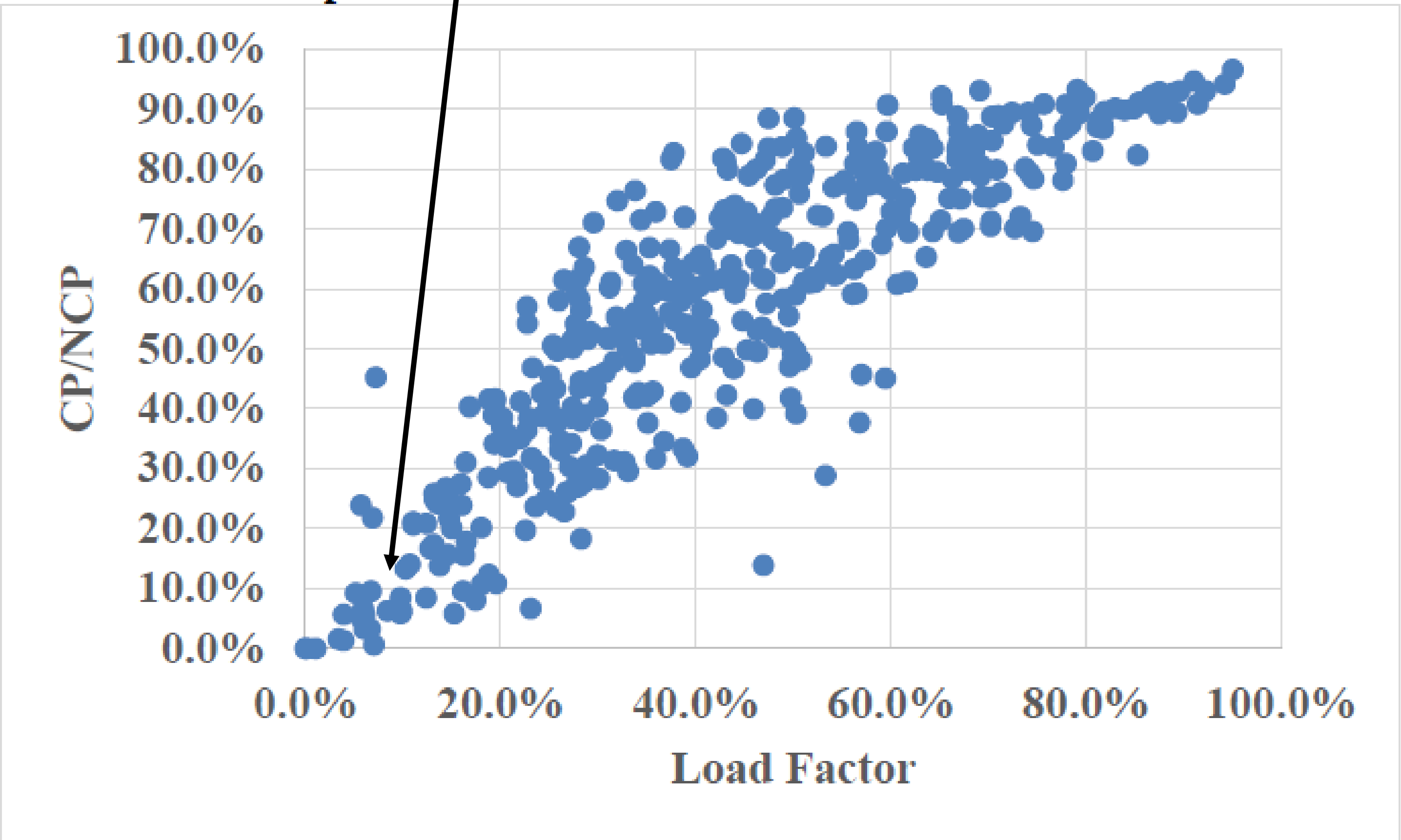
Non-EV Rate
- High cost at low load factors.

Figure 3. Average Demand and Energy Cost Relative to Load Factor for Combined Schedule 28 Prices



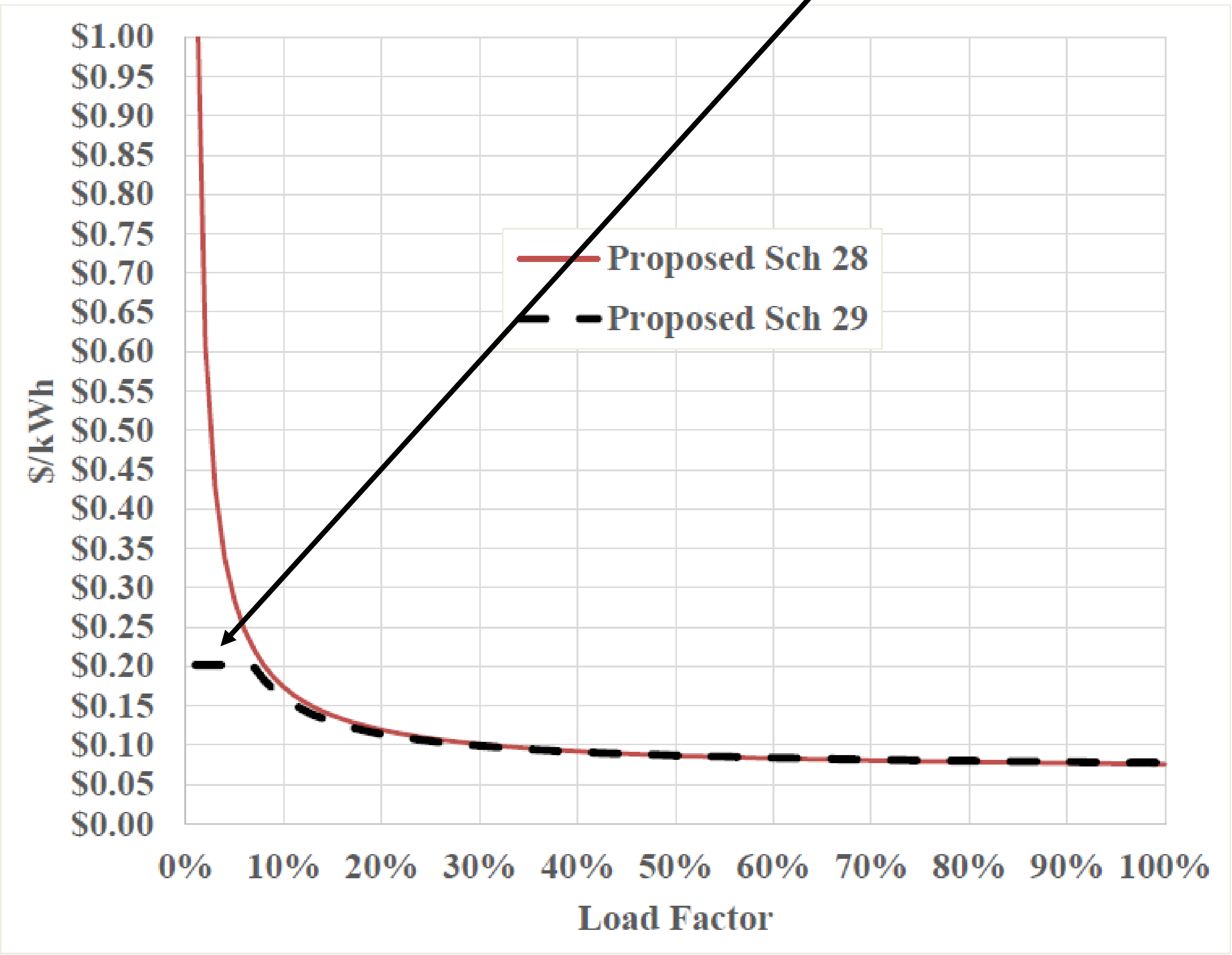
System Data
- Low load factors have low coincidence w/ system peaks.

Figure 2. Schedule 23, 28 and 30 Coincidence with Monthly System Peaks as Compared to Individual Customer Load Factor



EV Rate
- Low load factors have price effectively capped @ $0.20/kWh

Figure 4. Comparison of Proposed Schedule 29 Price to Average Energy and Demand Cost.



COMMERCIAL EV RATE DESIGN PRINCIPLES

Commercial EV rate(s) should:

1. Be technology agnostic and accessible to all non-residential EV customers.
2. Be made available to new and existing stations.
3. Remain optional
4. Consider characteristics and needs of all non-residential charging, including fleet charging.
5. Incentivize intelligent and manageable scheduling where appropriate.
6. Provide certainty and stability for long-term investments.
7. Data requirements should be able to be satisfied by interval meter data which utility already has access access to.

COMMERCIAL EV RATE EXAMPLES

Utility	EV Charging Rate Design
Southern California Edison, CA	Approved demand charge free rate for all non-residential DCFC load for a five-year period, followed by the phase-in of a modest demand charge over the following five years. Time-of-use (TOU) volumetric energy charges increased to recover costs previously recovered in the demand charge.
Xcel Energy, CO	Approved time-of-use EV charging rate with critical peak pricing.
Eversource, CT	Approved three-year demand charge free rate for all DCFC charging load with increase in volumetric energy charge to recover costs previously recovered in the demand charge.
Ameren, IL	10-year declining demand charge limiter starting at 30% load factor threshold.
PSE&G, NJ	4-year demand charge rebate on PSE&G’s demand charges.
Con Edison, NY	Approved economic development rate for DCFC, that includes a bill discount for seven years.
Pacific Power, OR	Declining demand charge discount over 10 years starting with 100% discount in year 1.
PECO, PA	Proposed five-year pilot rate in which the customer receives a fixed demand credit, initially equal to 50% of the combined maximum nameplate capacity rating for all DCFCs connected to the service to the customer’s billed distribution demand.
Dominion Virginia	Non-demand commercial rate below usage of 200 kWh per kW of billed demand.
Madison Gas & Electric, WI	Low load factor rate.

B G S C O M P O N E N T S M U S T B E A D D R E S S E D

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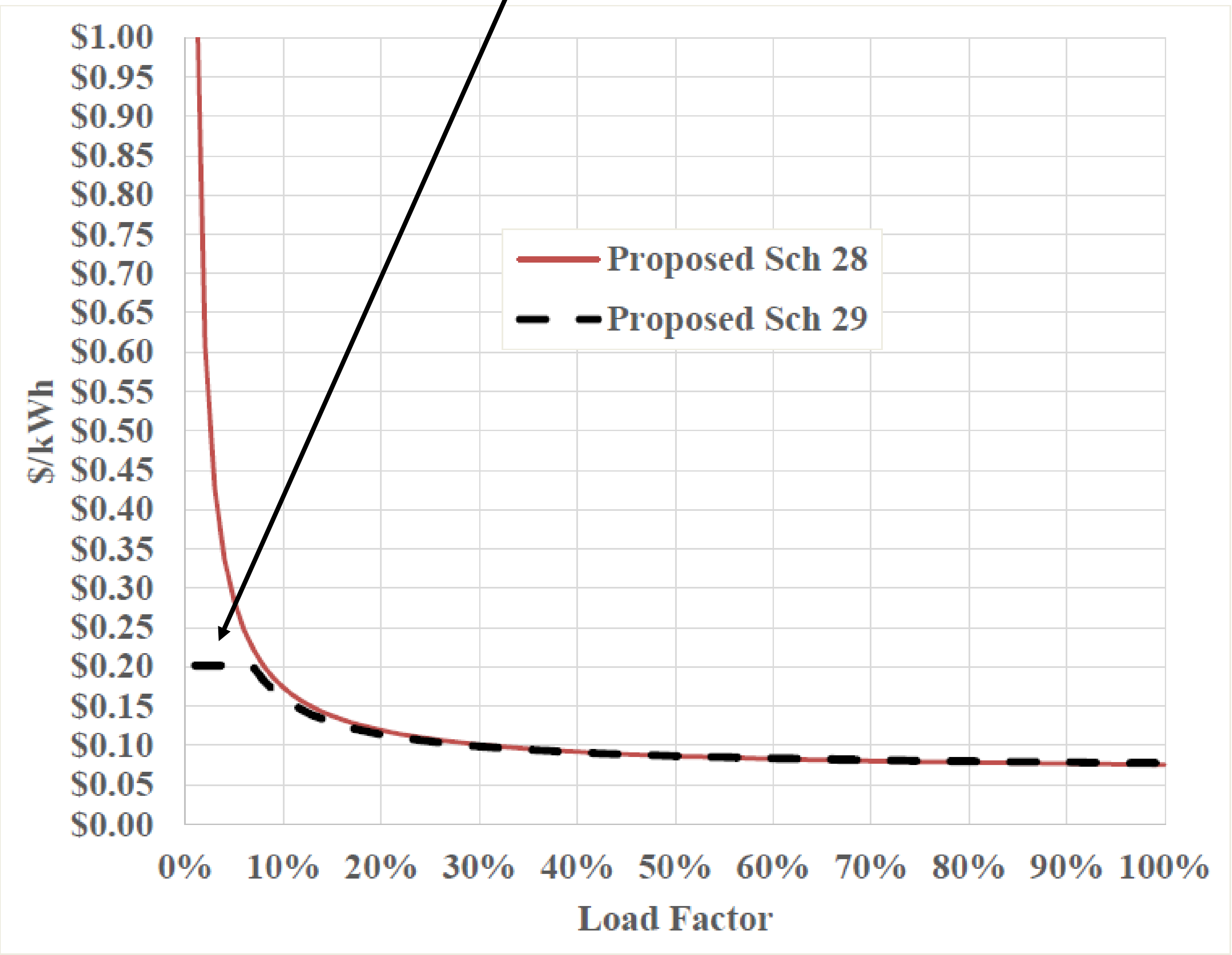
EV charging stations have lower load factors than regular commercial customers – can be as low as < 5%

How do we prevent MHD fleets from being exposed to uneconomic operating costs?

Figure 4. Comparison of Proposed Schedule 29 Price to Average Energy and Demand Cost.



ERICK FORD

EXECUTIVE DIRECTOR

NJ ENERGY COALITION

9/15/2021

NJBPU MHD STAKEHOLDER PANEL

HOW TO DETERMINE RATES

HOW TO DETERMINE RATES

- Understanding the current regulatory process in NJ
  - Rate must make utilities whole.
  - Safe, adequate, and proper utility service at reasonable non-discriminatory rates.
- Marginal pricing
- Capacity needs
- Demand charges
- Proper build out of the system
- Stand-by charges
- BGS Auction

TECHNOLOGY AND TOOLS

- AMI
- Time of Use
  - Charging vs Using the vehicle.
- CIP adoption
- Subsidy and incentives - demand charge credit to customer
  - incentive structures that provide temporary relief to charging stations, and which phase out as EV deployment grows and charger usage increases
  - Sliding scale that allows for adjustment to rates as needed
- Rules that allow for the development of roll ins to make adjustments to the rates as needed to fit the growth and or slow down of the adoption MHD EVs
  - BPU is capable of this as shown from the infrastructure investment rule established in 2017

WHAT OTHER STATES ARE DOING

MARYLAND

- Order number 88997
  - https://www.psc.state.md.us/wp-content/uploads/Order-No.-88997-Case-No.-9478-EV-Portfolio-Order.pdf

MASSACHUSETTS

- Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid
  - https://www.nationalgridus.com/media/pdfs/our-company/d.p.u._21-91_national_grid_notice_of_public_hearing_and_request_for_comments.pdf

CONCLUSION

Rates must ensure proper build out of the grid, along with proper and fair recovery for the companies providing the services.

Thank You

Rate design for MHDVs

Presentation for NJBPU stakeholder panel (September 15, 2021)

Elizabeth B. Stein
Lead Counsel, Energy Transition Strategy

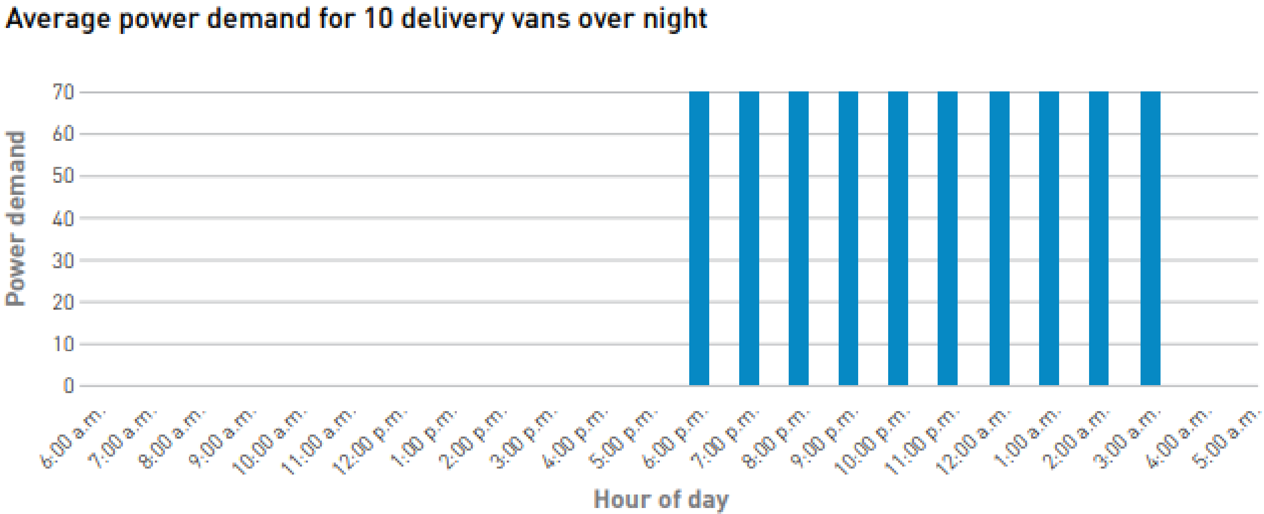
Principles to keep in mind

- Electric rates serve two distinct functions:
  - Cost recovery for utilities
  - Price signal for consumers
- Therefore, rapid electrification of truck and bus sector requires balancing
  - bill manageability (for truck and bus charging customers) with
  - system cost containment.

One size will not fit all.

- Truck and bus operators are tremendously diverse – no one commercial rate structure is going work for all of them, especially in the short term.
  - Use cases are tremendously variable -- some highly predictable and/or flexible, others not. Not all users have the same load shaping potential.
  - Individual small loads are unlikely to affect system costs, while large loads may be important drivers of costs.
  - Some truck and bus operators have long experience with sophisticated electric pricing, and may have significant non-charging loads. Others will be completely new to sophisticated electric pricing, and may need simplified buying options early on.

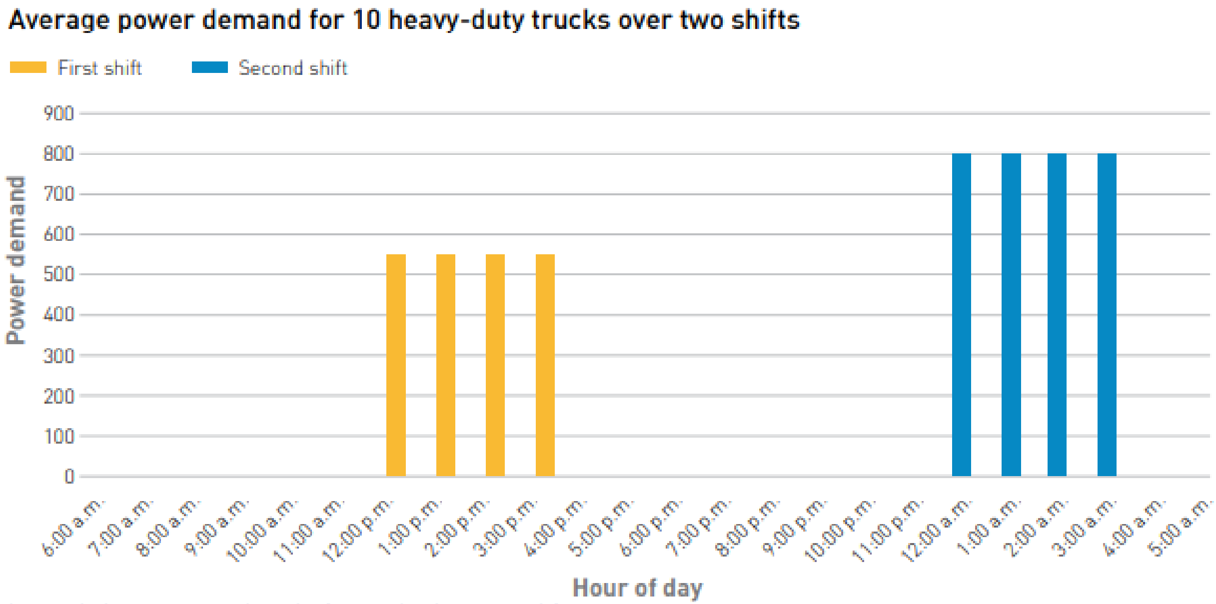
Charging Profile: Delivery Truck



CITY DELIVERY VANS

A fleet of 10 delivery vans uses 0.7 kWh of electricity per mile. All vans travel an average of 100 miles per day. They return to the fleet yard by 6 p.m. and must be ready to depart by 4 a.m.

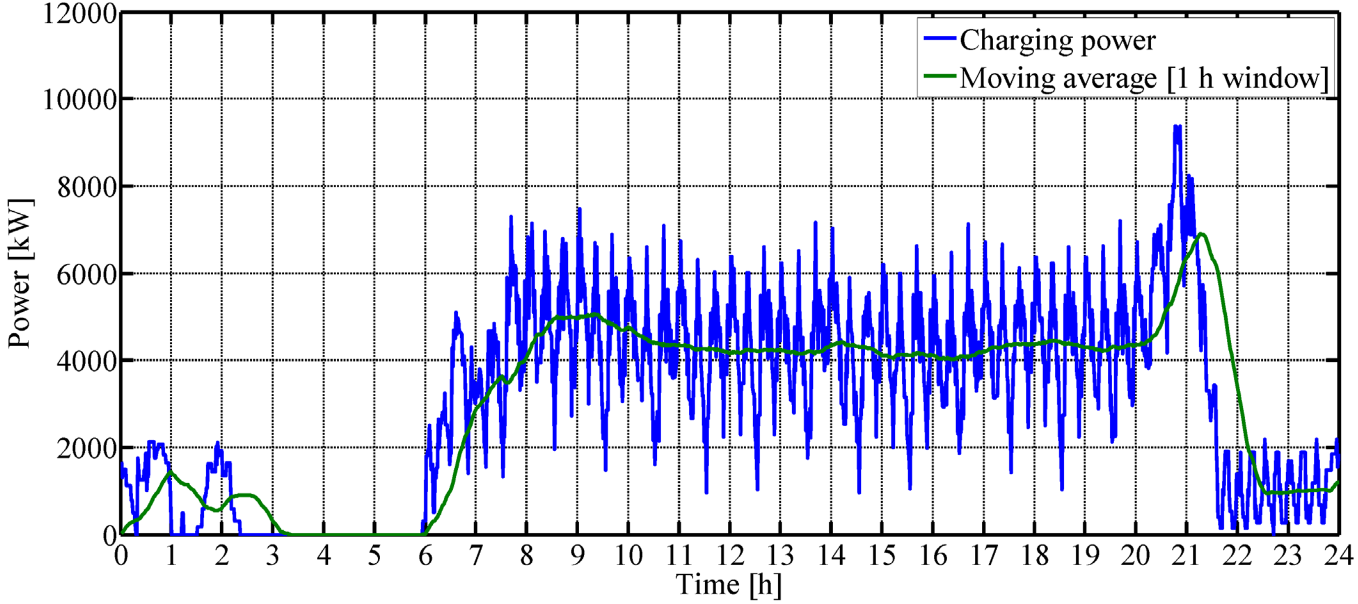
Charging Profile: Class 8 Truck



LOCAL CLASS 8 TRUCKS (TWO SHIFTS)

Ten class 8 semi-tractors use 2.2 kWh of electricity per mile. All 10 trucks are used for two shifts per day and travel an average of 150 miles during the first shift and 100 miles during the second shift. The first shift returns to the fleet yard by 12 p.m. and must be ready to depart by 4 p.m. The second shift returns to the fleet yard by 12 a.m. and must be ready to depart by 4 a.m.

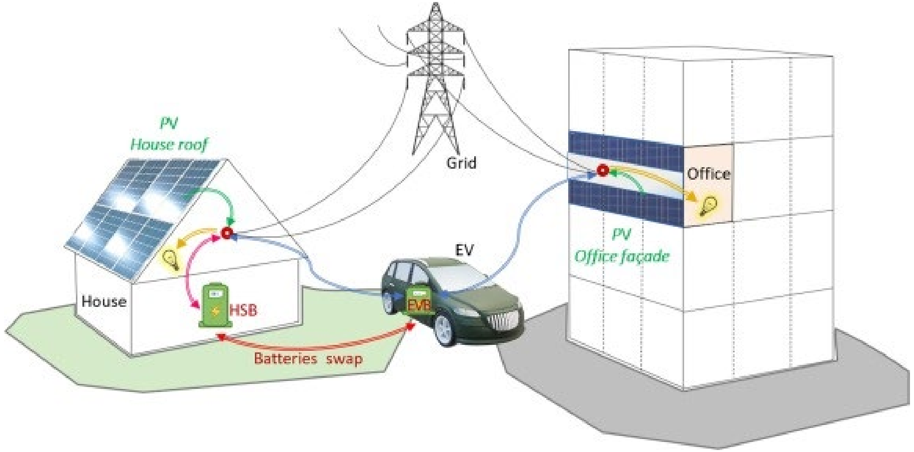
Charging Profile: Transit Bus



Aggregate of 44 Charging Stations (Terminal Stops) (500kW Capacity) over 23 individual bus routes.

Robust Vehicle-Grid Integration supports lower total cost of ownership, lower grid costs, better environmental outcomes, and greater resiliency.

Robust Vehicle-Grid Integration supports lower total cost of ownership, lower grid costs, better environmental outcomes, and greater resiliency.



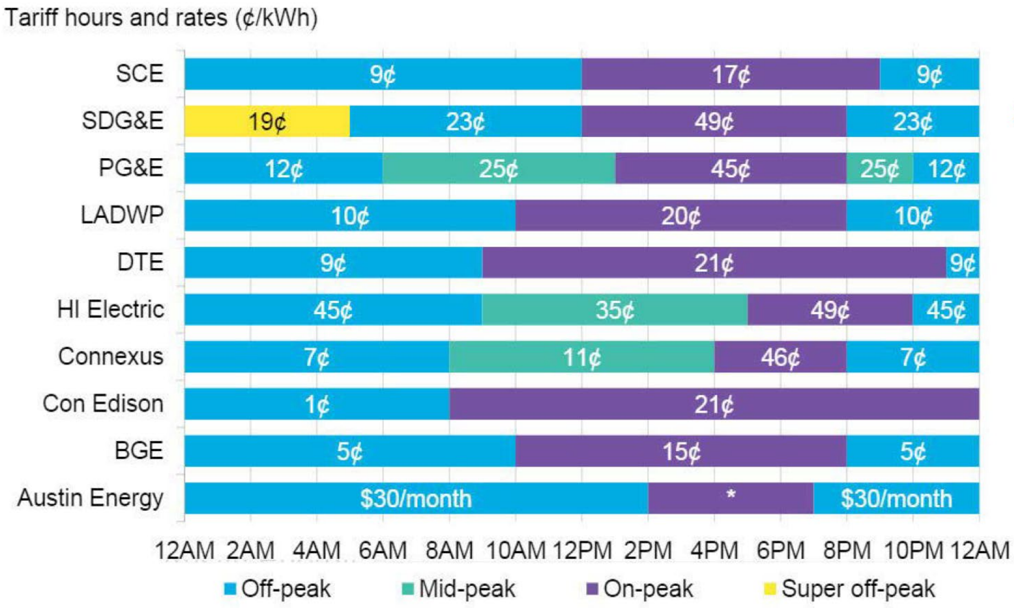
VGI: Rates Can Signal When and How To Charge

Incentivize Charging:

- During off peak moments
- When there is a surplus of renewables

AND

- To discharge when and where useful for system reliability



Peak to off-peak ratio

1.89: 1
2.58: 1**
3.75: 1
2: 1
2.3: 1
1.4: 1
6.57: 1
21: 1
3: 1
--

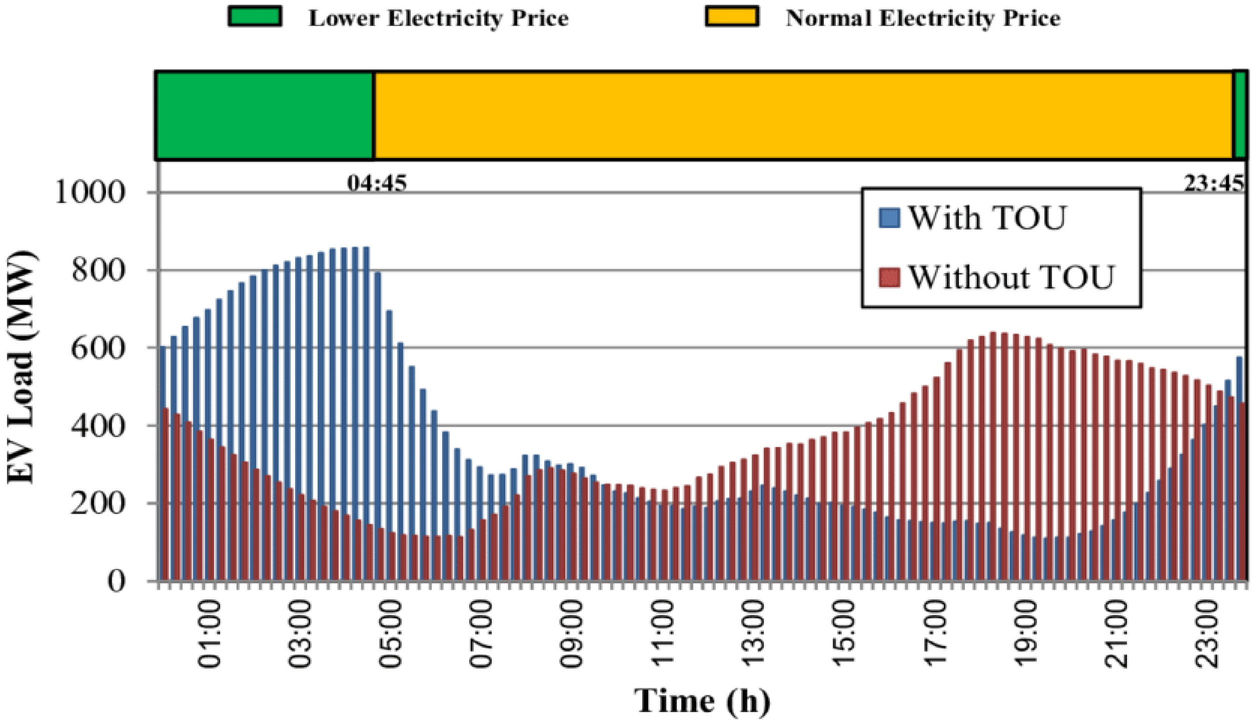
*indicates charging is discouraged **ratio of peak to super off-peak rates

(Bloomberg New Energy Finance 2017)

Managed Charging includes a wide range of possible behaviors. They'll yield different charging costs, different grid outcomes, different environmental outcomes, and different resiliency outcomes.

So what kind of vehicle-grid integration is possible will depend on the price signals vehicle owners see, what kinds of behaviors those price signals incentivize, and what kinds of programs support their ability to respond to those signals.

Load Shifting: Minimizing Cost in response to a volumetric Time of Use (TOU) Price Signal



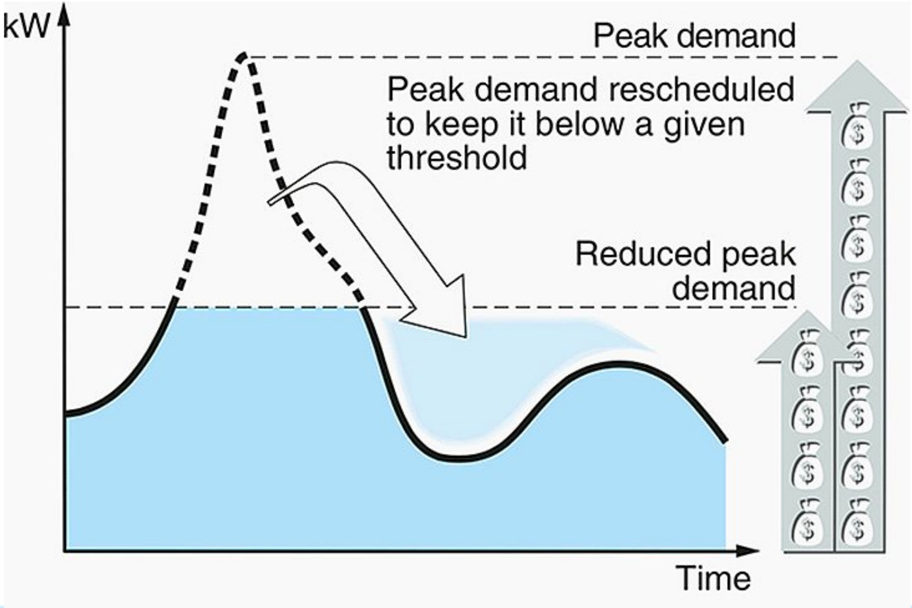
Only works if you can shift charging time and shape

Load flattening: Minimizing Cost in response to a demand-based price signal

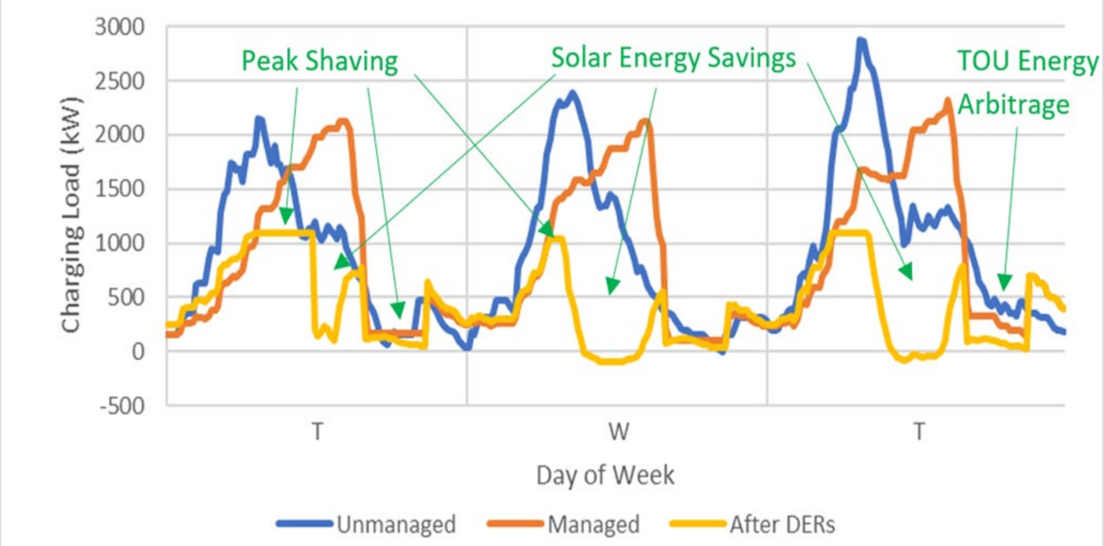
How?

- Lower Demand (KW)
- Lower On Peak Charging

Option 1: Managed Charging : Lower Peak Demand



Solar and Storage complement efficient rates for charging medium and heavy-duty vehicles.



Scenario	Energy	Demand	Fixed	Total Bill	Total DER Savings
Current Technology DER $2/W	$42,521	$174,190	$3,061	$219,771	$433,648
Current Technology DER $5/W	$167,902	$239,441	$3,061	$410,404	$624,281
Advanced DER $2/W	$57,286	$256,206	$3,061	$316,552	$1,016,746

For More Information See Here

Principles to keep in mind

- Over the long term, cost-reflective pricing is essential – but that's not the end of the conversation.
  - Embedded versus marginal costs – looking backwards versus forwards.
  - The exact same rate structure may be cost-reflective with respect to one class and not cost-reflective with respect to a different class, especially one that doesn't yet exist.
  - Pricing can be more or less complex while still being roughly cost-reflective.
- Feasibility and understandability are also essential – so simplified transitional rates have a role to play.

Robust Education and Outreach are Key

- Some fleet owners may never have encountered complex commercial electric pricing prior to transitioning their fleets. For them, existing commercial rates and other complex price signals may be impossible to manage at the same time as they're mastering completely new vehicle technology. They may need…
    - Ongoing support as they learn how to understand the pricing environment and manage their load;
    - Tools and other forms of assistance;
    - Utilities should provide solar and storage programs as part their targeted outreach to fleets;
    - Transitional Rates: Simplified rates that incentivize approximately the right charging behaviors – including load flexibility – while being more understandable and less risky than more granular/precise rates.

Learn from Fleets and Vehicle Owners

- Outreach is a two-way street – utilities can provide fleet owners with information about the utilities' own systems, and help them optimally site charging and manage load, but utilities have a lot to learn from fleet owners too.

- Some fleet owners, especially those with a presence in other jurisdictions, <u>do</u> have experience with charging electric trucks and buses.

- Even fleet owners who are completely new to electrification know their own business needs – route lengths, dwell times and locations, operating conditions, etc.

- Truck and bus owners' input is **key** to evaluating the suitability of existing electric rates in this time of transformation, and developing new rates – whether transitional or permanent – to meet currently unmet needs.

Thank you!

Elizabeth B. Stein
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ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

Rockland Electric Company

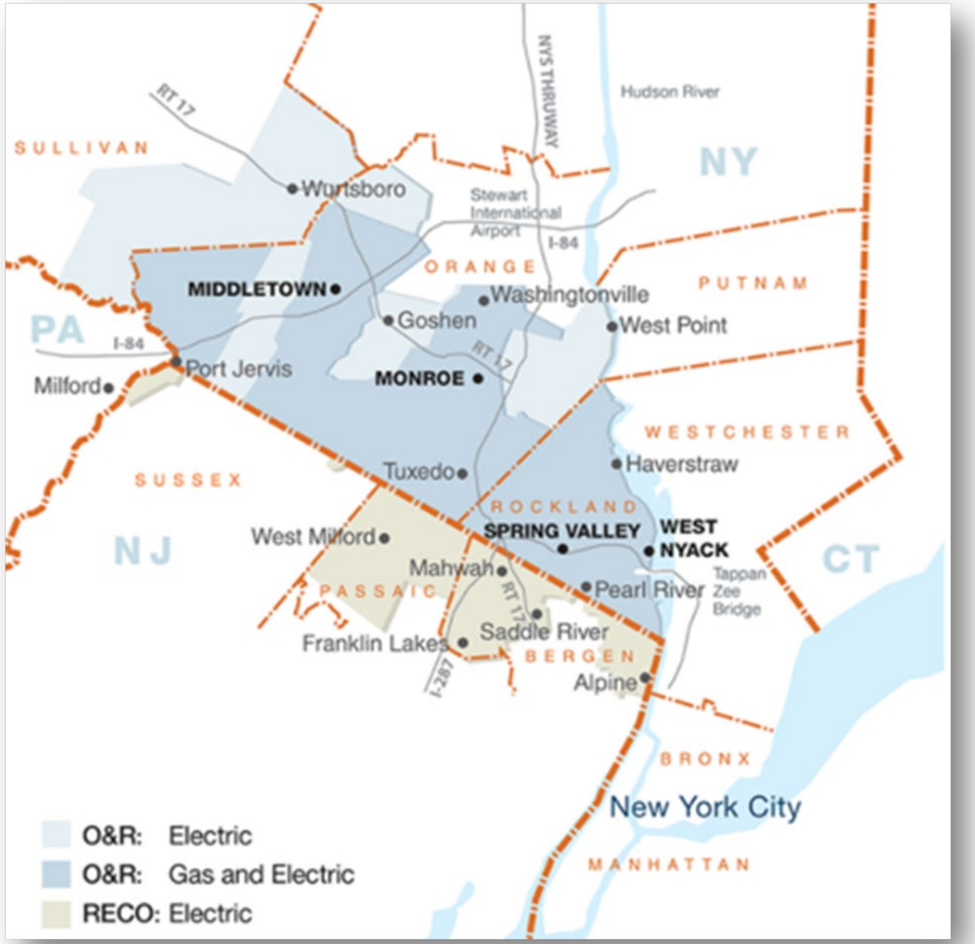
NJ MDHD EV Stakeholder Meeting
How to Determine Rates

September 15, 2021

Rockland Electric Company
Electrification Portfolio Management
Brian Picariello

Orange and Rockland Utilities, Inc. delivers electric and gas in New Jersey and New York.

- 73,000 Rockland Electric Company (RECO) electric customers
  - 70,000 residential (96%)
  - 3,000 commercial / industrial (4%)
- 230,000 Orange and Rockland (O&R) electric and gas customers
  - 230,000 electric customers
  - 130,000 gas customers



Light-duty EVs (LDVs) per customer in RECO territory is 3X the per customer adoption in O&R territory

O&R NY Territory

- 2,800 LDVs on the road
  - About 1% of total LDVs
- 132 L2/DCFC plugs deployed
  - 21 LDVs per plug
- Programs (LDV + MDHD)
  - Education and outreach, EV TOU, DCFC per plug incentive, Charge Smart, Make-Ready, MDHD Pilot, Fleet Assessment Service, Managed Charging

RECO NJ Territory

- 2,750 LDVs on the road
  - About 2% of total LDVs
- 39 L2/DCFC plugs deployed
  - 70 LDVs per plug
- Programs (LDV only)
  - Currently in Settlement discussion for LDV programs, the majority of which leverages these existing NY programs

Rate and program design should allow all customers to realize the benefits of transportation electrification

ORU Operational Support Strategy

1. *Maintain* existing cost-based rate structure
2. *Layer on* managed charging-based positive incentives
3. *Finally add* utility-initiated active load management

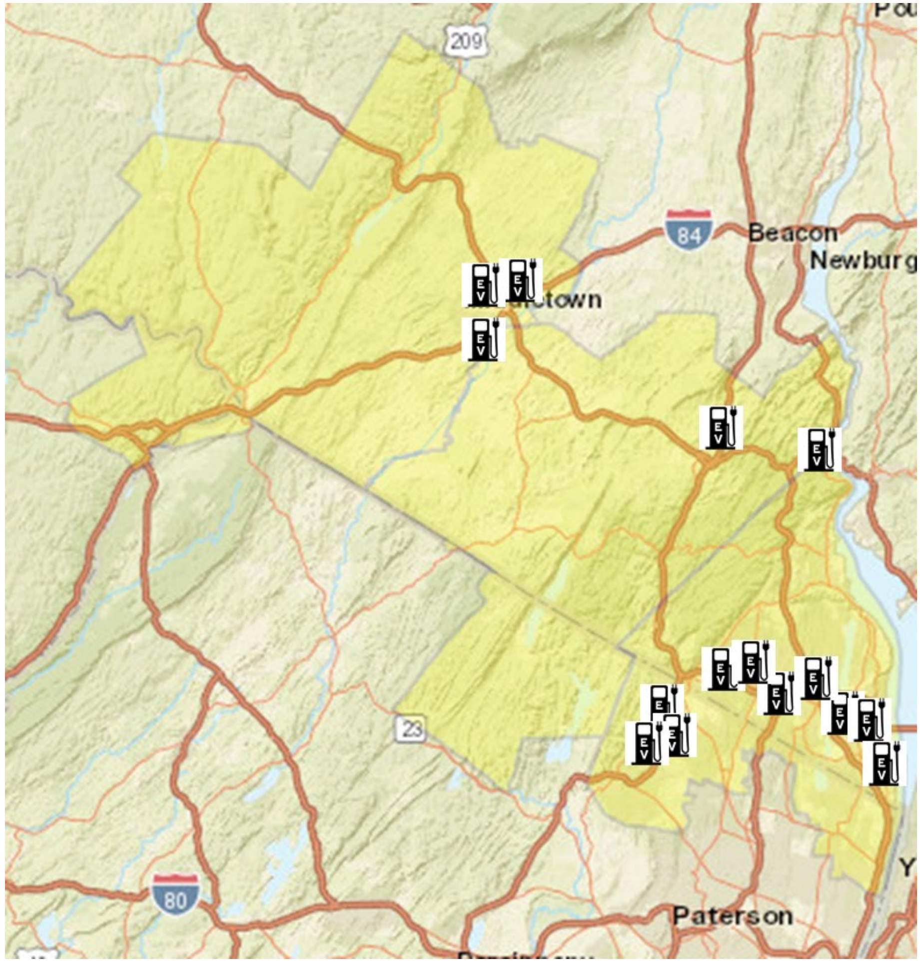
Considerations

- Equity
- Evolving market and technology
- Cost of service study
- Tariff changes
- Demand charges

Thank you

ORU has joined the Electric Highway Coalition to encourage travel corridor charging

- RECO
  - 3 travel corridors
  - 30 miles including highways / parkways
  - 9 L2 and 2 DCFC plugs
- O&R
  - 5 travel corridors
  - 150 miles including highways / parkways
  - 19 L2 and 42 DCFC plugs



September 15th , 2021

NJ Electric Vehicle Infrastructure Ecosystem 2021 Medium and Heavy Duty Straw Proposal

How to Determine Rates

Jigar J. Shah
Jigar.Shah@electrifyamerica.com

electrify america

electrify america

electrify canada

The *fastest growing* open ultra -fast network

NUMBER OF STATIONS

May 2018
1

Today
650+

2021
800

2025
1,800

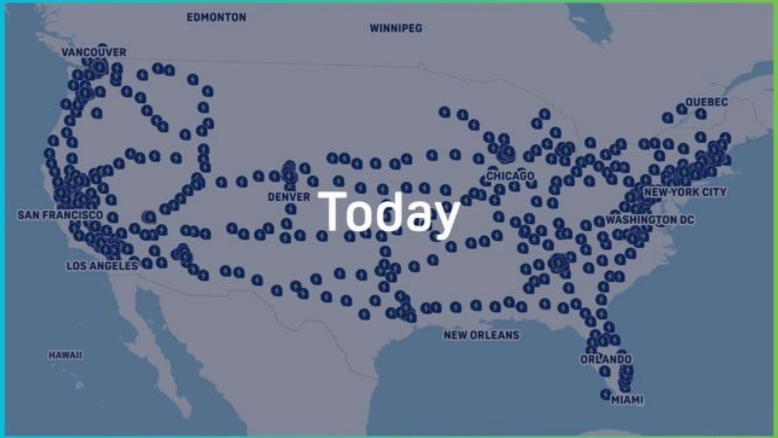
NUMBER OF CHARGERS

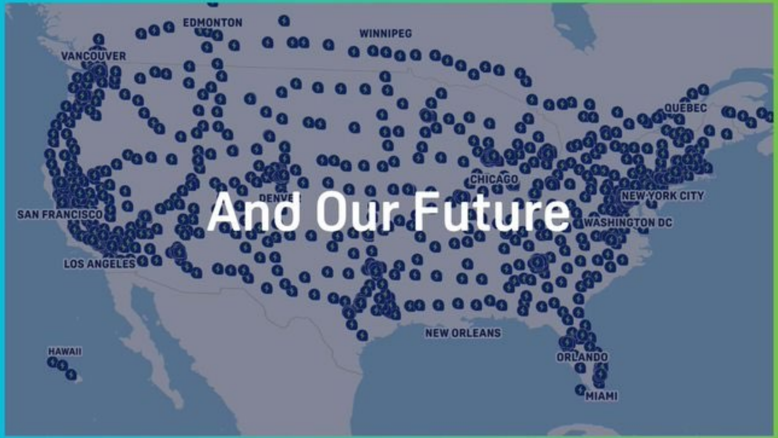
May 2018
4

Today
2,800+

2021
3,600

2025
10,000

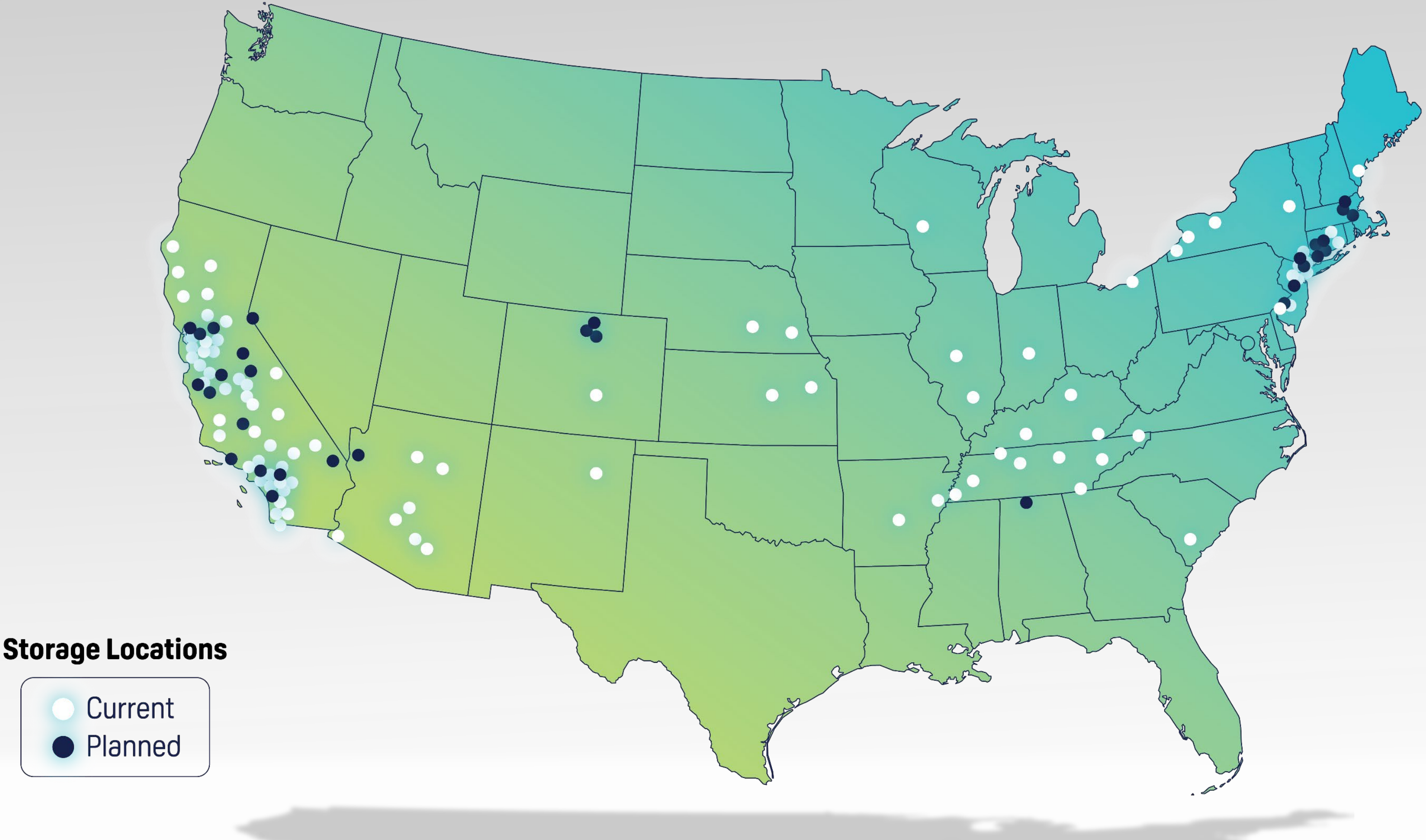




Tackling the challenges of fleet electrification

Electrify America is investing $25 million in Long Beach and the Wilmington neighborhood of Los Angeles to install ultra -fast EV charging infrastructure. This investment will support the electrification of public transit and freight trucks serving the community

Electrify America has the largest deployment of battery storage systems coupled with DC fast charging in the United States



electrify america

In New Jersey, Electrify America has 13 Sites Operational with 64 DCFC ranging from 150 kW to 350 kW each, with 10.8 MW demand exposure

Utility	Transmission Capacity (RSCP & CIEP)	Generation Capacity		Total Capacity Demand Charge Exposure $/kW -mo	
		< 500 kW (RSCP)	> 500 kW (CIEP)	< 500 kW (RSCP)	> 500 kW (CIEP)
PSE&G	PJM Pass thru per Cap Tag	PJM Pass thru per Cap Tag		$18.25	$24.06
JCPL	Tariff item, volumetric	Embedded in volumetric BGS Rate	PJM Pass thru per Cap Tag	N/A	$8.87
ACE	Tariff charge, demand	Embedded in volumetric BGS Rate	PJM Pass thru per Cap Tag	$4.20	$15.07

Capacity charges are treated differently in each EDC, with a ‘cliff ‘at 500 kW resulting in substantial increased risk

NJ rate reform to date has focused on EDC distribution demand, which does not mitigate sufficient risk for light -duty investment, and is even a larger obstacle to investment in medium -duty and heavy -duty charging

The BGS demand charge framework results in cost volatility and uncertainty for medium -duty and heavy -duty operators that inhibits investment in fleet electrification within New Jersey

Bill Example from September 2020 Invoice for a DCFC Station at a Shopping Plaza

Charges	PoD ID:	Rate - LPLS
Delivery		
Distribution Charge	51 kWh @ $0.00549019	$0.28
Distribution Charge	759 kWh @ $0.00483531	3.67
Distribution Charge	257 kWh @ $0.00540856	1.39
Distribution Charge	1043 kWh @ $0.00483221	5.04
Summer Demand charge	122 Kw @ $8.94950819	1,091.84
Annual Demand Charge	122 Kw @ $3.76172131	458.93
Societal Benefits	2110 kWh @ $0.00844075	17.81
Service Charge		370.81
Sub-Total Delivery		**$1,949.77**
Supply		
Basic Generation Charge	51.000 kWh @ $0.03431372	1.75
Basic Generation Charge	759.000 kWh @ $0.03781291	28.70
Basic Generation Charge	257.000 kWh @ $0.04630350	11.90
Basic Generation Charge	1043.000 kWh @ $0.04985618	52.00
Transmission Charge	110.000 Kw @ $12.9351818	1,422.87
Generation Charge	130.928 Kw @ $5.64737871	739.40
Sub-Total Supply		**$2,256.62**
Total electric charges		**$4,206.39**

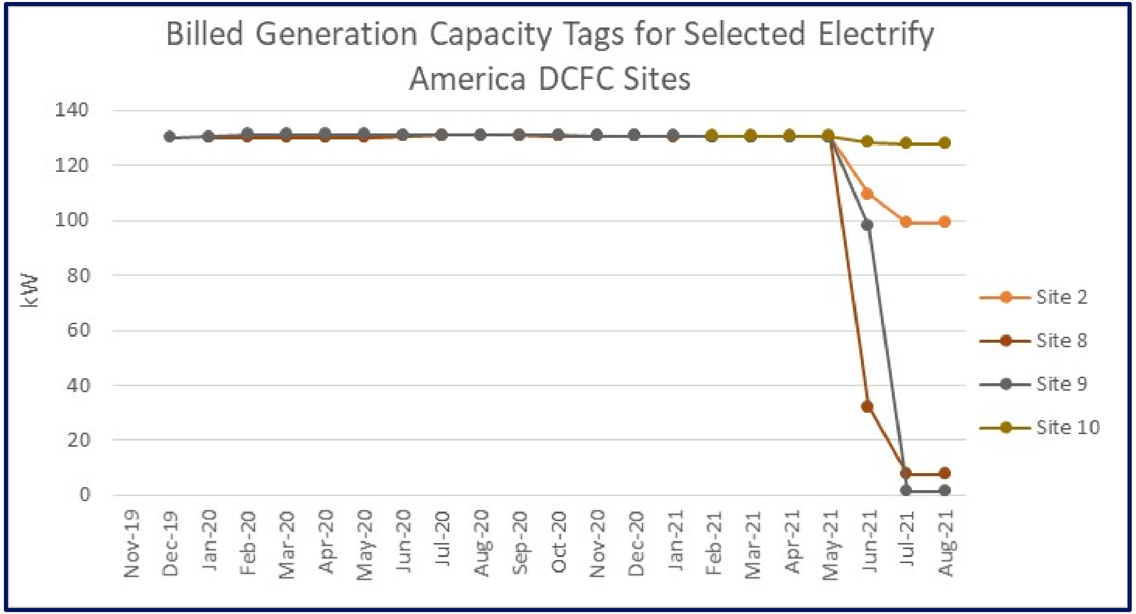
Capacity Tag charges represent 51% of the total bill

The unit cost of capacity charges is $2,162 ÷ 2,110 kWh = $1.02/kWh.

All-in effective cost is $1.99/kWh

Multiples of fossil fuel equivalency from capacity demand charges alone

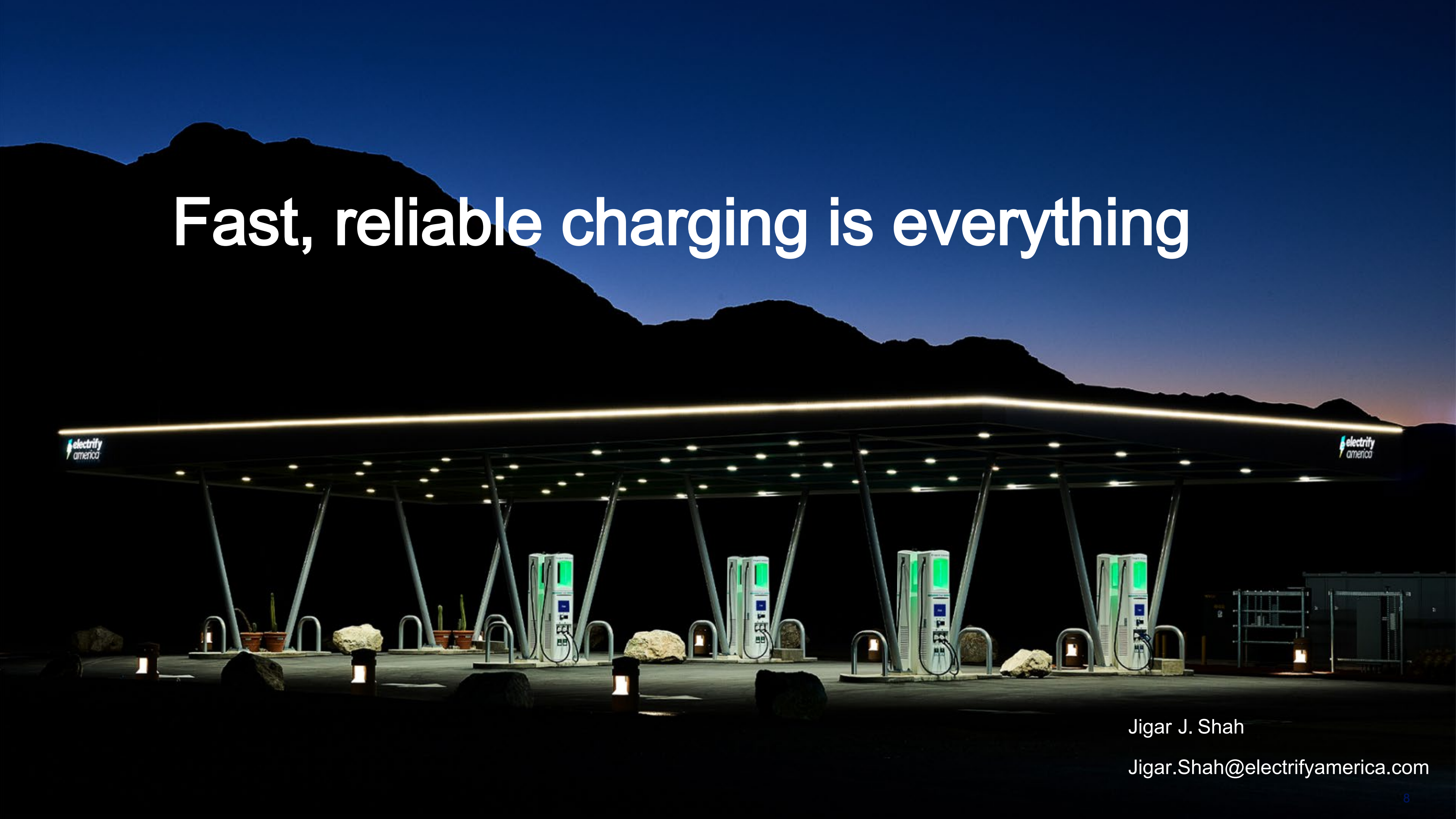
The NJ BPU should approve rate reform that provides a stable cost/kWh comparable to class averages, including commodity costs



Electrify America's initial assigned capacity tags across multiple NJ locations did not reflect cost -causation – no third party supply options that would tolerate capacity tag risk at a reasonable cost/kWh

Tag reset variability shows current framework leads operators to 'roll the dice' for tag assignment if charging services are maintained during tag hours given inelasticity for DCFC use case

Fast, reliable charging is everything



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Alliance for Transportation Electrification

New Jersey BPU Workshop on Medium-Heavy Duty (MHD) EV Charging Ecosystem

Panel on Rate Design and Setting Just & Reasonable Rates

Presented by
Philip B. Jones

ATE Executive Director
Former Washington UTC Commissioner
Past President of NARUC

September 15, 2021
Trenton, NJ

Background: ATE EV Rate Design Task Force (established 2020)

Goals: **Be proactive in state proceedings. Do not play defense.**
Find common ground with all stakeholders, including private EV charging companies.

Context

- **Residential rates:** 80% + charging is done at home.
- **C&I rates:** Applicable to public charging, including DC fast charging, which is critical to alleviating range anxiety.
- Challenge is that public charging experiences low utilization in these early years of EV adoption.
- Solution is to support market transformation, while observing cost of service ratemaking principles along with public policy.

Rate Design Principles

- ✓ A useful document for commissioners, staff, and parties in state proceedings.
- ✓ Recognizes that each state and utility are different, with unique precedents and rules for cost of service.
- ✓ A common denominator is that rates have to continue to meet the specific J&R standard and be sustainable over time.

What are the Goals of These Principles?

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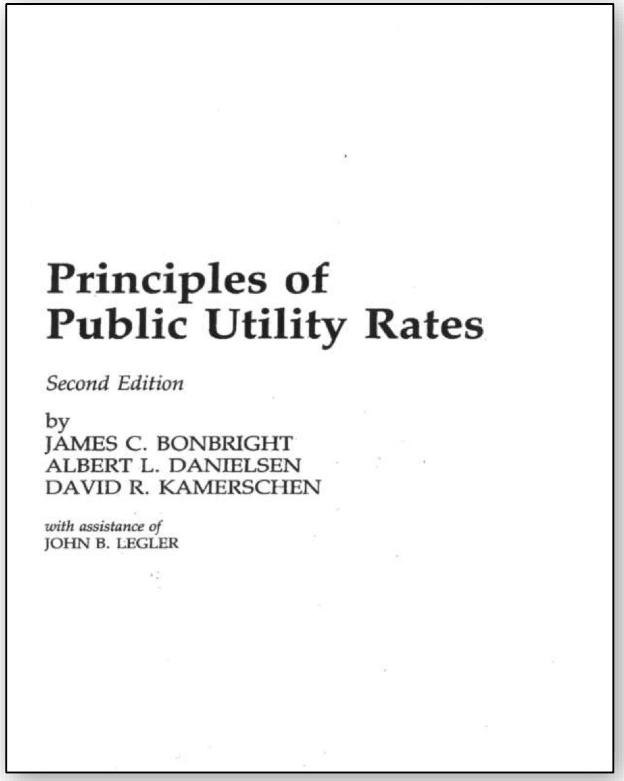
- Provide customer benefits – fuel savings and incentives for off-peak use.
- System benefits for all – reliability, integration, data, resiliency, lower rates.
- Positive environmental and public health benefits.
- Retain cost-reflective rates based on cost of service studies and core principles.

Some specific issues

- Support the principles of "beneficial electrification."
- Work collectively to demonstrate benefits.
- Technology such as managed charging is an important factor in rate design.
- Support state public policy goals – both Legislative and Executive.
- Recognize there are dynamic issues with market development and stress the need to be flexible.
- Be mindful of differences between approved rates and transitional relief.
- Consider equity in identifying use cases and in cost recovery.

Back to Basics of Ratemaking and Bonbright

- Why? Because ratemaking principles should be technology agnostic.
- EV charging is not an exercise in the "Utility of the Future."
- Simply use the traditional regulatory toolbox.


Principles of Public Utility Rates

Second Edition

by
JAMES C. BONBRIGHT
ALBERT L. DANIELSEN
DAVID R. KAMERSCHEN

with assistance of
JOHN B. LEGLER

Bonbright's Four Principles

Capital Attraction Function	Efficiency Incentive Function
Establishes revenue requirements to attract adequate investment.	Regulation intended to compel market-like performance.
Demand Control Function	**Income-Distributive Function**
Scarcity Supply and demand Get the price signals right	Can address with equity / low-income programs and incentives.

Why Commercial Rates are Important for EVSPs

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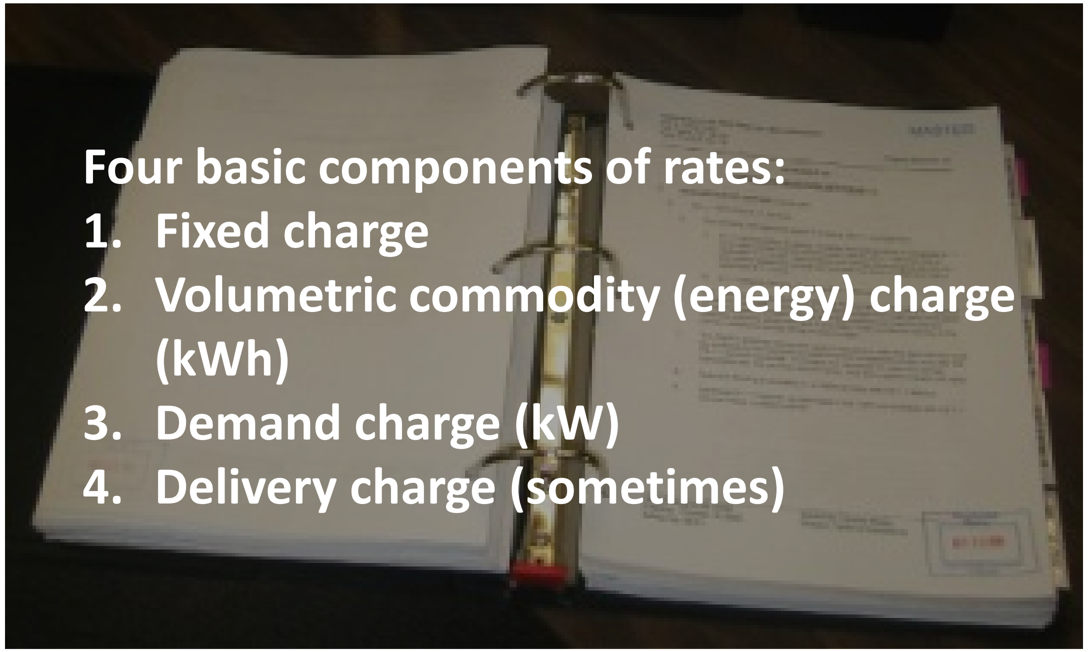


Four basic components of rates:

1. **Fixed charge**
2. **Volumetric commodity (energy) charge (kWh)**
3. **Demand charge (kW)**
4. **Delivery charge (sometimes)**

- ✓ Commercial rates are a complex area of ratemaking. Many commercial rates have been in place for decades.
- ✓ Demand charges are determined by an instantaneous peak; if volumetric use is low, there are few kWh over which to spread the demand charge.
- ✓ The demand charge component is typically the most contentious issue debated before public service commissions.

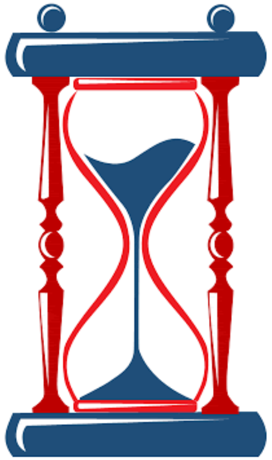
Consumers have range anxiety and will not buy an EV without adequate public charging (DC fast charging is particularly important).

DC fast charging may incur high fixed demand charges, but utilization can be very low.

The result is that high demand charges are spread across very few kWh, which affects EVSP profitability.

The Solution: Transitional Relief

- The concept is to offer a path to profitability by altering the demand charge component of rate structures on a temporary basis to help meet public policy objectives and better fit today's public charging business models.
- The goal is to get us past this period of low utilization.
- Different companies adopt different terms – "discount," "credit," "subsidy," "economic development," to name a few. We adopt the term transitional relief.
- We believe this framework can satisfy the J&R standard by increasing volumetric commodity charges while lowering demand charges.



Other options: Utility tariffs are far from uniform, but the following have been shown to be based on cost of service at their core as well as J&R.

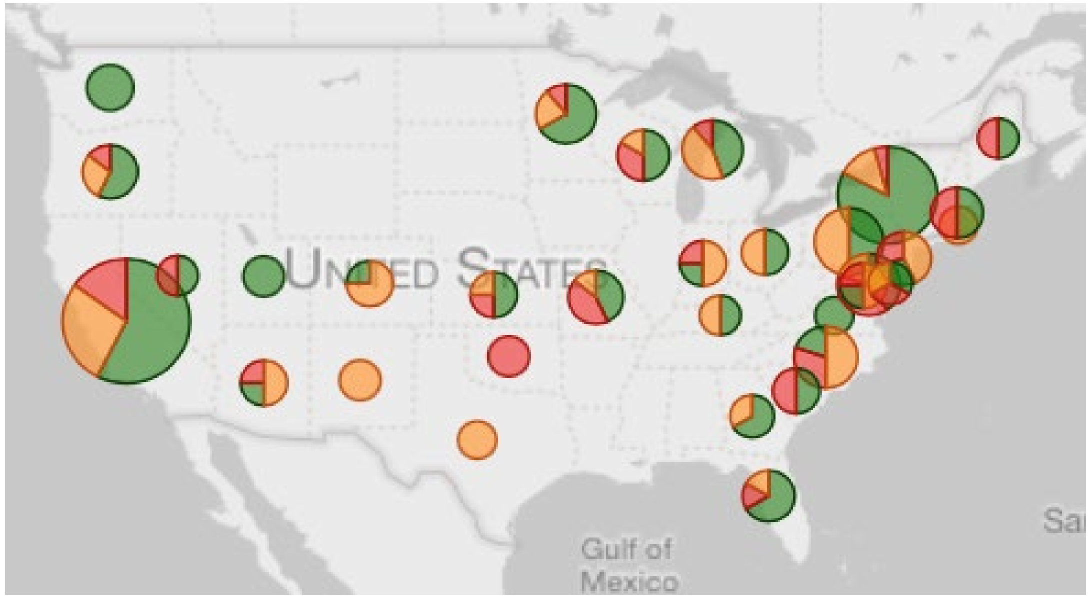
Non-demand charge C&I rates below a certain demand level.	Demand limiters, where a maximum demand level is applied to reduce rates.
Non-demand charge subscription rates with higher volumetric rates.	Rebates to offset the effect of the demand charge.

Some Examples of Transitional Relief of Demand Charges

We did not perform a comprehensive review of all the existing approved tariffs; examples of transitional relief include:

- Economic development rate or demand charge “holiday” (Southern California Edison in CA and National Grid in RI).
- TOU Rate for commercial less than a threshold kW (Portland General in OR).
- Demand charge credits (BGE in MD and PECO in PA).
- Subscription rates, namely the offer of a fixed monthly rate with TOU rates instead of the demand charge, which is based on cost-of-service study (PG&E, SDG&E, Xcel Minnesota).
- DCFC targeted rate with temporary waiving of demand restrictions (DTE Energy in MI).
- Distribution demand charge and a seasonal energy charge for low-load factor customers (Xcel Energy/Public Service CO).

Utility EV Filings in the United States



Source: Atlas Public Policy, “Atlas EV Hub.” Available: https://atlasevhub.com.

Retail Sales from EVSPs to EV Drivers

- In most states, EVSPs that are not otherwise regulated utilities have been specifically exempted from public service commission regulation.
- PSCs in those states thus may have limited or no ability to set the price at which electricity is offered to EV drivers.
- Pricing by private EVSPs is typically by the kWh unless doing so would classify the EVSP as a utility, in which case energy is sold by the minute or session. Dwell time charges may also be imposed to encourage turnover.
- Some EVSPs charge higher rates for faster charging, while others give away electricity for free.
- For utility-operated charging stations, prices to drivers are typically are set in relation to the private market.
- Goal is generally to offer pricing that customers will accept.

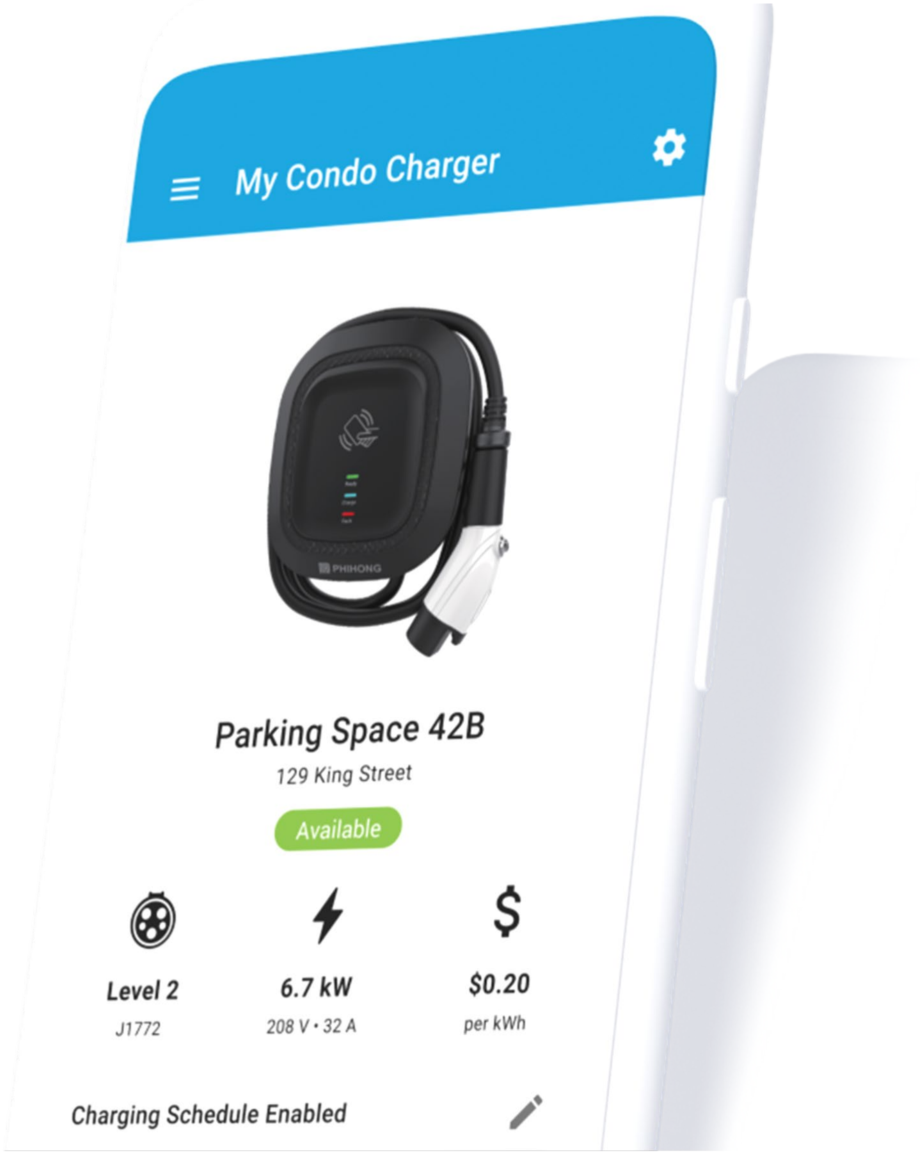


Image courtesy of ChargeLab.

ADDITIONAL POINTS ON MEDIUM-HEAVY DUTY (MHD) USE CASES (COMMERCIAL RATES)

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California (CPUC approved: Southern California Edison, or SCE)

Program name: Charge Ready Transport

- Pilot of 5 years, approved in fall 2019
- Total authorized spend of $365 MM, with approx. $200 MM for infrastructure
- 870 sites, 894 vehicles (focused on vehicles electrified, not on ports)
- Separate meter is required, and at least 2 EVs by fleet (and other eligibility factors)
- Rate design is mostly volumetric, and an EV-TOU approved rate that is similar for other C&I customers. But demand charge waivers are built into economic development rate (10 yrs)

California (CPUC approved): San Diego Gas & Electric (SDG&E)

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Program name: EV High Power (EV-HP) Charging Rate for MHD (Applic. No. 19-07-006)

- Approved in 10-2020, per a Settlement Agreement (most parties signed)
- Uses marginal cost
- Optional for separately metered EV charging load; aggregated load of 20 kw or greater
- equal percentage marginal cost to allocate distribution costs over an 11-year period
- Subscription and energy charges should be recovered in year 1 from the most recently-Commission approved C&I marginal distribution demand revenues.
- Covid-19 impacts and uncertainties generated pause for 3 years
- Afterwards, the distribution demand revenues are phased into rates in a linear progression over an 11-year period.
- Customers will pay the full EV-HP rate – reflecting the fully loaded EPMC-scaled cost of service approved by Commission – starting in Year 11
- Allows additional incentives for fleets to charge during super-off-peak by default, but allows them to op out of the super-off-peak incentive

Massachusetts (pending at DPU): proposed by National Grid (August 2021)

Program name: Demand Charge Alternative Offering

- 10-year scope, and separate metering is required
- All existing and new customers are eligible, including DCFC and L2 EVSE customers
- Available under the General Service demand rate (GS-2). Average use will exceed 10,000 kwH per month, but not exceed 200 kW of demand; and the G-3 rate (greater than 200 kW)
- In first year, customers receive 100% discount on normal demand charges, which decline over a 10-year period (see chart below)
- But the program is focused on low-load utilization, and load factor threshold must remain under 15% during the entire program period.

Formula for monthly load factor calculation:

$$\frac{\text{Monthly kWh}}{\text{Monthly Max15-Minute Demand x Monthly Hours}}$$

Load Factor Threshold	Enrollment Years	Demand Charge Discount
None	1	100%
≤ 5%	2 to 9	100%
≤ 10%	2 to 9	75%
≤ 15%	2 to 9	50%
≥ 15%	2 to 9	0%

Best practices emerging from utilities and fleets for MHD use cases

- ***Fleet planning services***: establish and implement, with Commission approval, a group of dedicated staff who can work with fleet operators especially small-medium fleets.
- ***TCO analysis***: assist the fleet operators in helping to calculate an accurate TCO analysis incorporating rate design issues for the cost of electricity as fuel input, along with other aspects of operations and infrastructure. Compare to conventional fuel model.
- ***Early (preliminary) site assessments:*** get an early idea of the site, easements and ROW issues, location of electrical infrastructure and metering.
- ***Grid capacity issues:*** seek early engagement with distribution engineering of the relevant feeders and capacity, availability of 480/277 volt 3-phase service, location of substations.
- ***Planning:*** seek to coordinate the medium and long-term planning issues of utilities (loads and resources), fleet operators, transit agencies, OEMs in a constructive process.
- **Availability of State/Local Government incentives:** if available, the fleet planning group should make the fleet operators aware of such incentives, as well as utility-specific policies such as line extension policies and/or CIAC, make-ready incentives.
- ***Rate design issues:*** examine the current approved tariffs under the C&I rates (general service), and see what is applicable. If it is necessary to modify or clarify these for use by fleets, commercial EVSPs, determine how to clarify and streamline.

Colorado (Approved by CO-PUC): Xcel Energy/Public Service of Colorado

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Name of program: Commercial S-EV Rate with CPP

- Settlement Agreement (partial) in October 2019 between PSCO, RTD (public transit), and most parties including EVSPs, city of Denver, CEO (energy office), others
- Focus of tariff is on fleets primarily, and especially public transit operator in Denver RTD, but also for public charging to address demand charge issues
- Rate structure: generally, TOU pricing with a seasonal difference for summer and winter with on-peak and off-peak rates (about 3x difference in summer, and over 5x in winter)
- Energy TOU rate window: on peak hours are defined as 12-9 pm
- Utility deploys interval data meters than can help assess EV charging loads at host sites
- Introduces a critical peak pricing (CPP) rate: $1.50 per kwH
- Separately metered, and certification by host site that it will only be used by customer for EV charging loads and ancillary usage
- After 19 months, utility gets data on voluntary basis from EVSPs and host sites for review and analysis, including load factors, type and number of chargers, location
- Per agreement, PSCO is now in process of developing a “S-EV version 2.0 rate” intended more for public charger deployments.

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