Electric Vehicle Charging Implications for Utility Ratemaking in Colorado

David Hurlbut, Ph.D

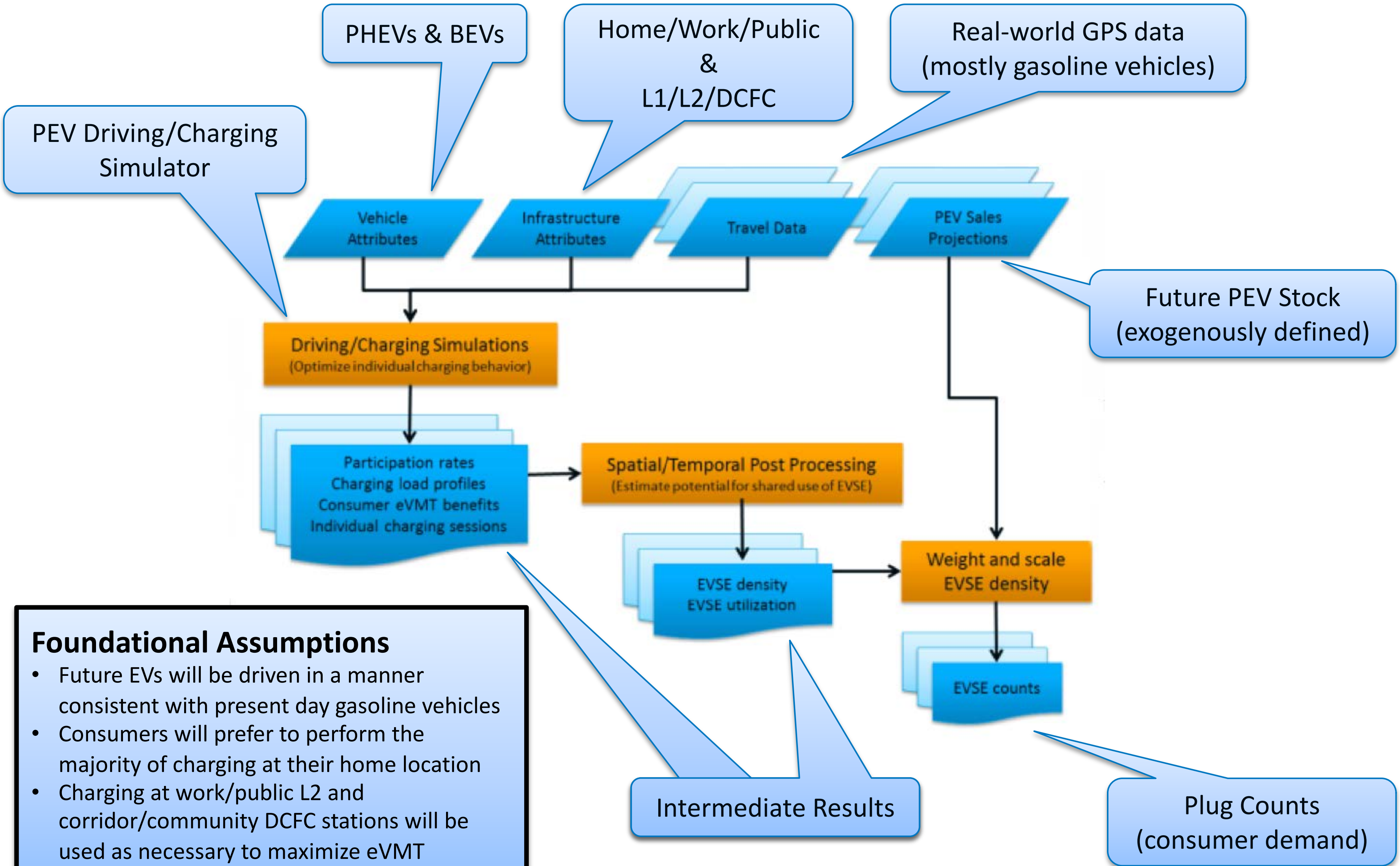
New York ISO Environmental Advisory Committee

October 23, 2019

Highlights of Research for the
Colorado Public Utilities Commission

Electric Vehicle Infrastructure Projection Tool (EVI-Pro)

Electric Vehicle Infrastructure Projection Tool (EVI-Pro)



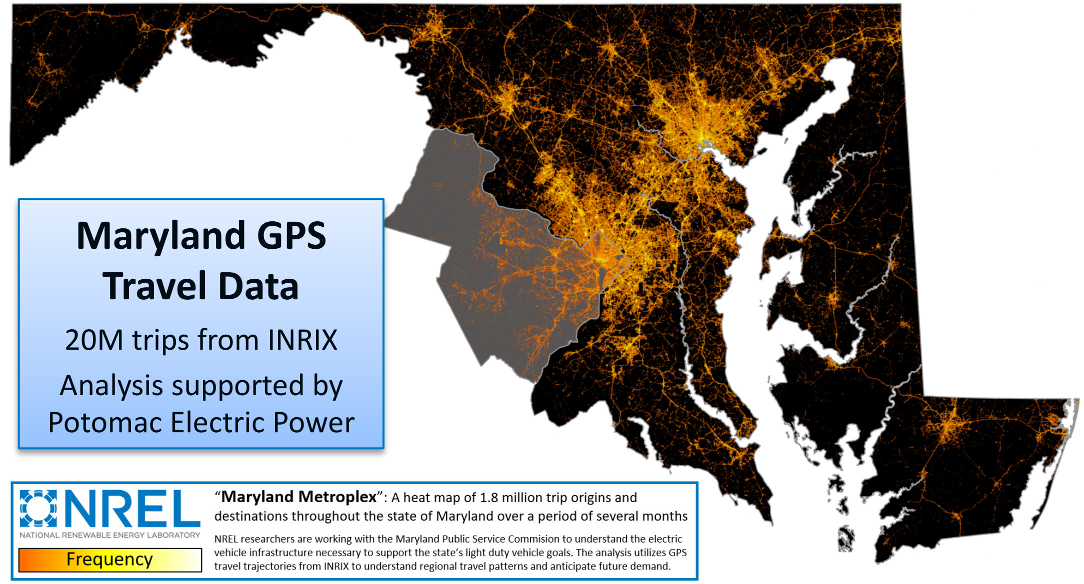
Foundational Assumptions

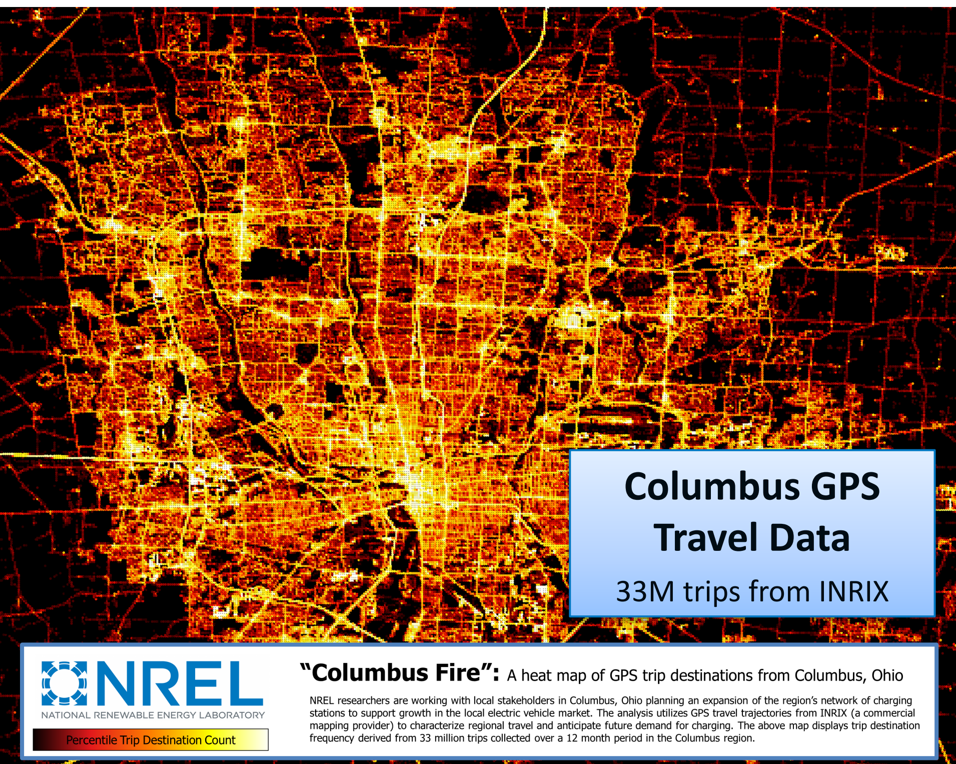
- Future EVs will be driven in a manner consistent with present day gasoline vehicles
- Consumers will prefer to perform the majority of charging at their home location
- Charging at work/public L2 and corridor/community DCFC stations will be used as necessary to maximize eVMT

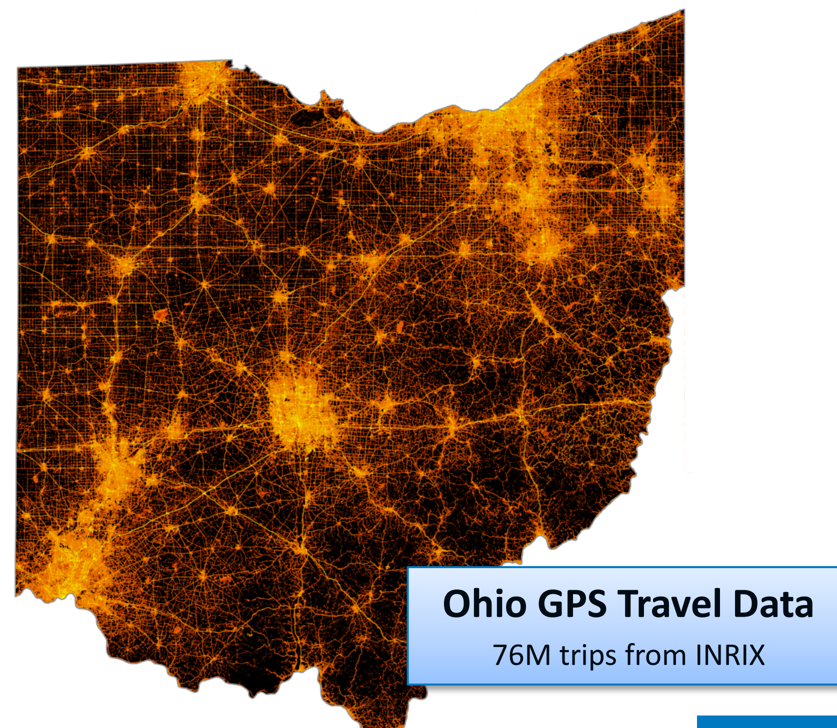
Consumer Travel Data

One of the fundamental inputs to EVI-Pro is geographically resolved, real-world travel data from the area of interest.

NREL has acquired numerous travel data sets for use in simulating consumer charging requirements by power level, location, and time of day.



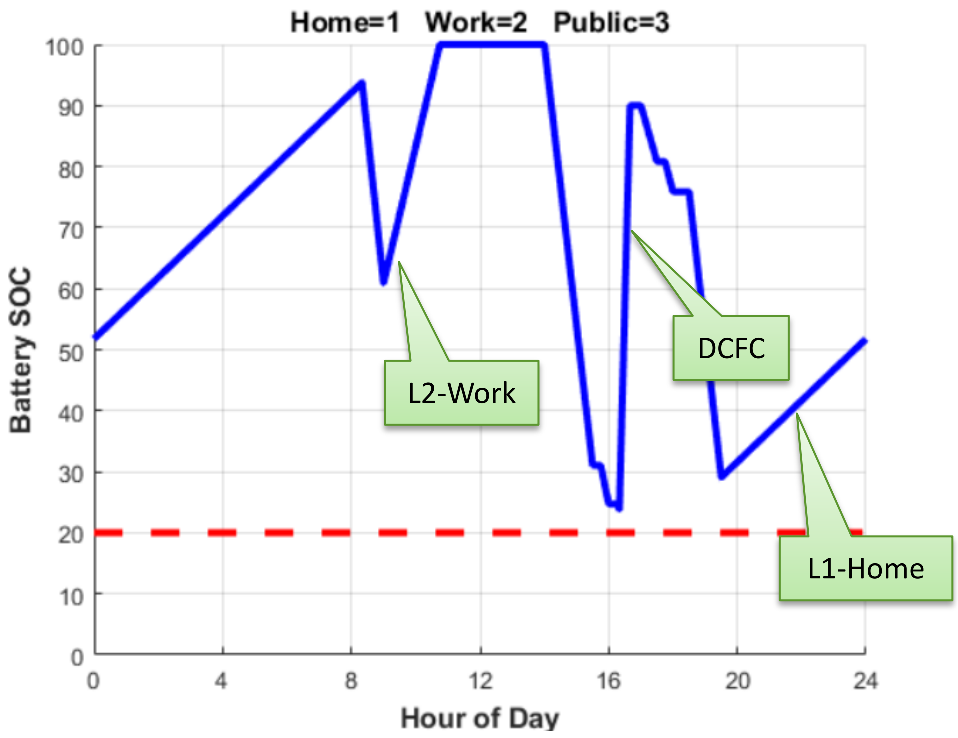




Driving/Charging Simulations

Destination	Departure	Arrival	Drive Miles	Dwell Hours	Simulated Charging
Work	8:20 AM	9:00 AM	32.8	5.00	L2
Public	2:00 PM	3:30 PM	68.9	0.25	---
Public	3:45 PM	4:00 PM	6.3	0.25	---
Public	4:15 PM	4:20 PM	0.9	0.67	DCFC
Public	5:00 PM	5:30 PM	9.2	0.25	---
Public	5:45 PM	6:00 PM	5.0	0.50	---
Home	6:30 PM	7:30 PM	46.8	12.83	L1

Simulated charging behavior for a BEV100 under an example travel day

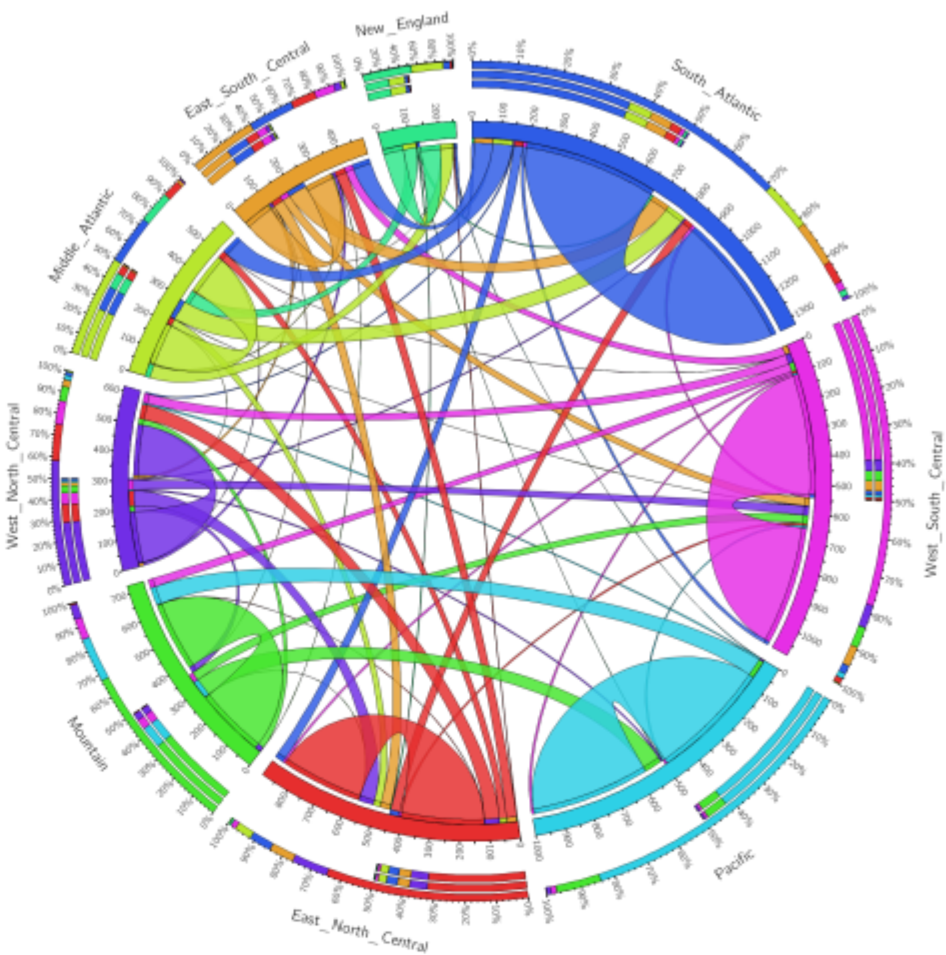


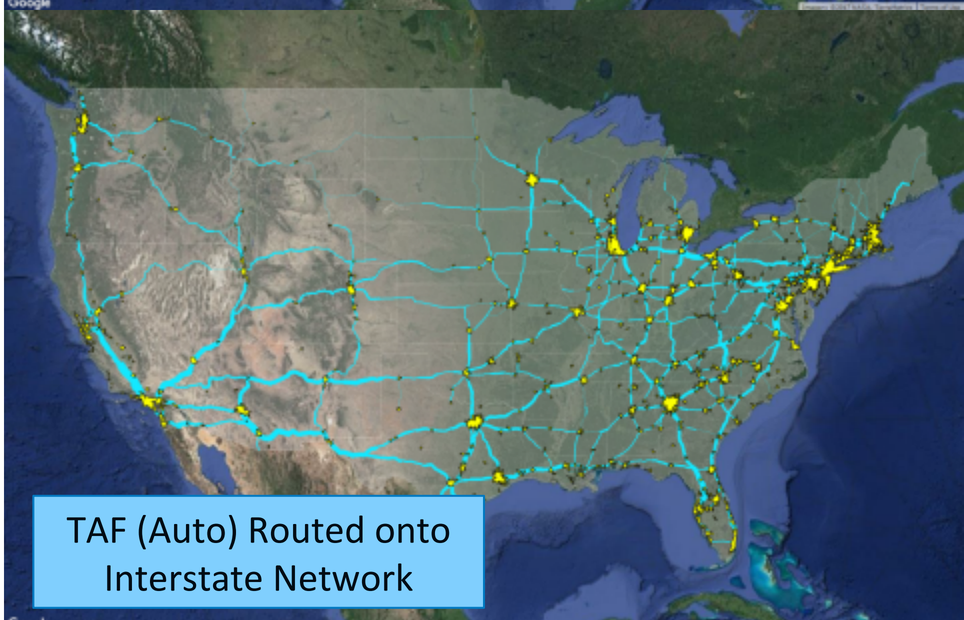
Bottom-up simulations are used to estimate percent of vehicles participating in non-residential charging, derive aggregate load profiles, and investigate spatial distribution of demand

Long Distance Travel Data From FHWA Traveler Analysis Framework (TAF)

TAF Auto Trips by Census Division

Implies that the majority of long distance auto travel is regional and limited to intra-division movements





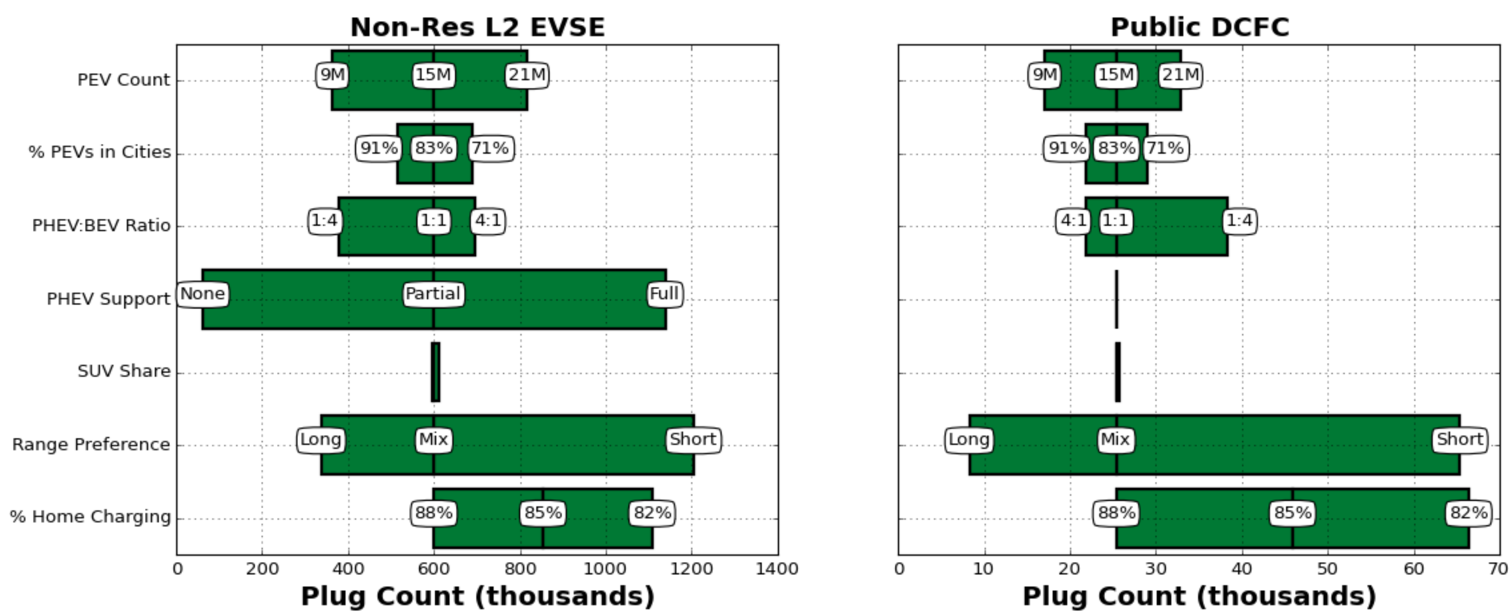
National PEV Charging Analysis: Results

Central Scenario

		Cities	Towns	Rural Areas	Interstate Corridors
PEVs		12,411,000	1,848,000	642,000	---
DCFC	Stations (to provide coverage)	4,900	3,200	---	400
	Plugs (to meet demand)	19,000	4,000	2,000	2,500
	Plugs per station	3.9	1.3	---	6.3
	Plugs per 1,000 PEVs	1.5	2.2	3.1	---
Non-Res L2	Plugs (to meet demand)	451,000	99,000	51,000	---
	Plugs per 1,000 PEVs	36	54	79	---

Estimated requirements for PEV charging infrastructure are heavily dependent on:
1) evolution of the PEV market, 2) consumer preferences, and 3) technology development

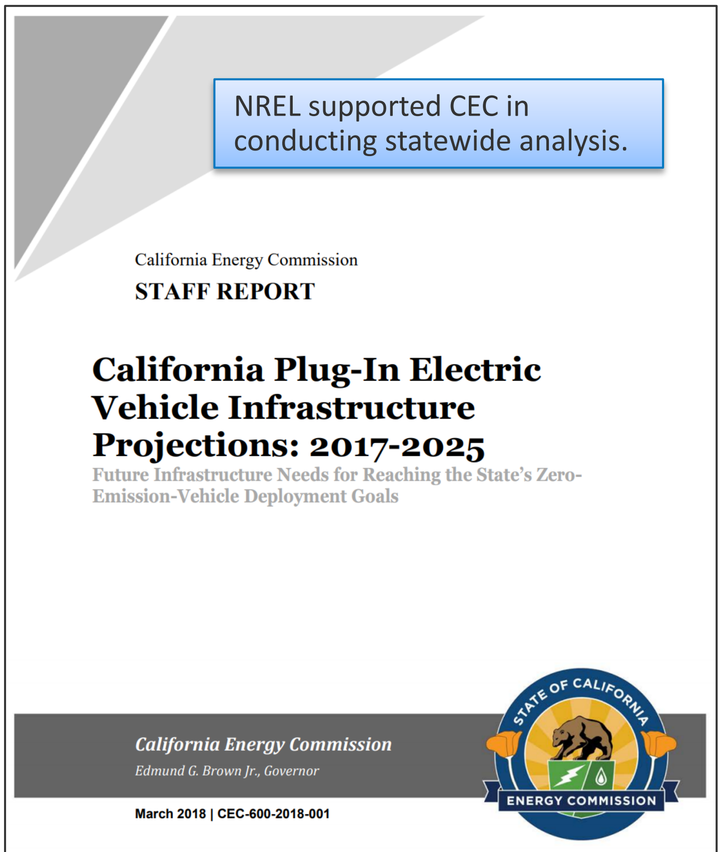
Sensitivity Analysis



Assessments in Massachusetts, Maryland, California, Colorado, Columbus

Objective: To provide guidance on PEV charging infrastructure requirements to regional stakeholders.

Approach: Superimpose existing regional driving data with simulated PEVs and identify work/public EVSE requirements that meet anticipated consumer demand.


California Energy Commission

STAFF REPORT

California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025

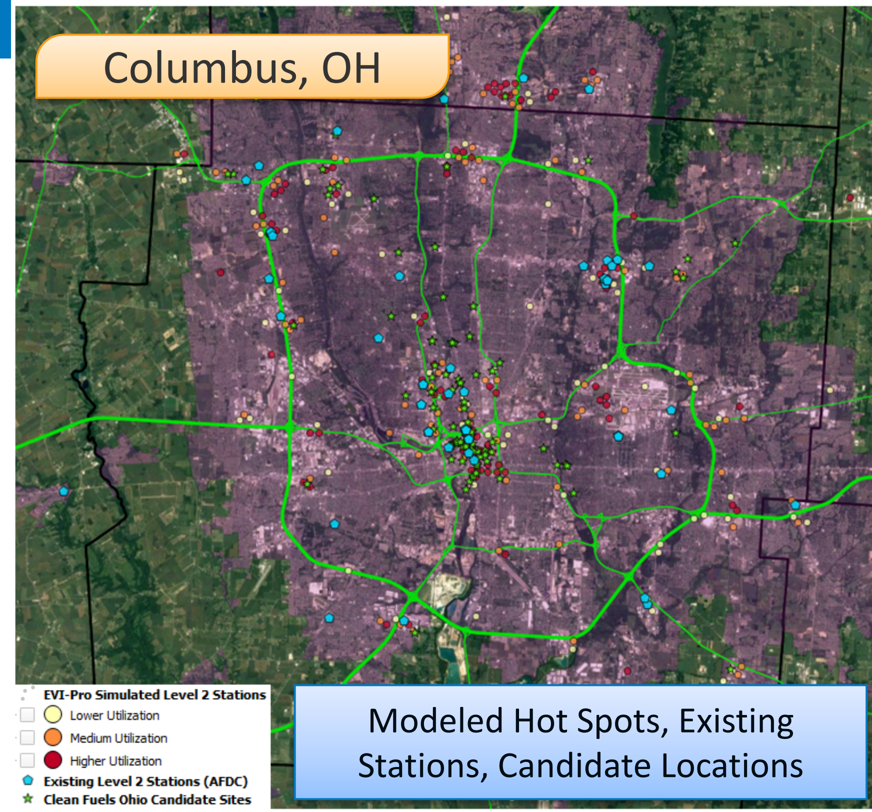
Future Infrastructure Needs for Reaching the State's Zero-Emission-Vehicle Deployment Goals

California Energy Commission

Edmund G. Brown Jr., Governor

March 2018 | CEC-600-2018-001

NREL supported CEC in conducting statewide analysis.

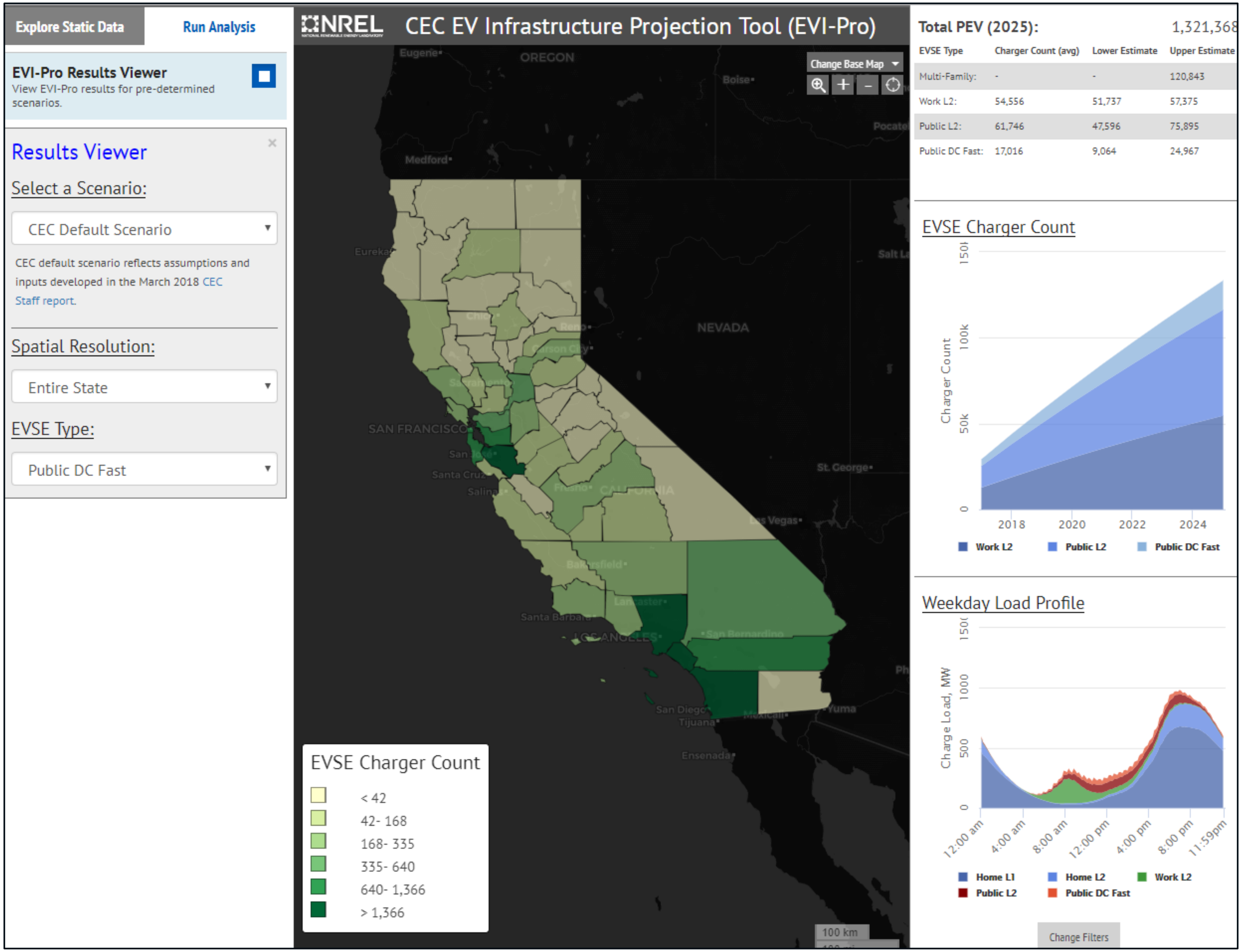


Modeled Hot Spots, Existing Stations, Candidate Locations

Significance & Impact

- State agencies in MA, MD, CA, and CO are using demand projections from EVI-Pro to assist in planning statewide EVSE growth supporting PEVs.
- Related organizations have inquired on the potential to run similar analysis in additional states.

California Statewide Analysis: maps.nrel.gov/cec



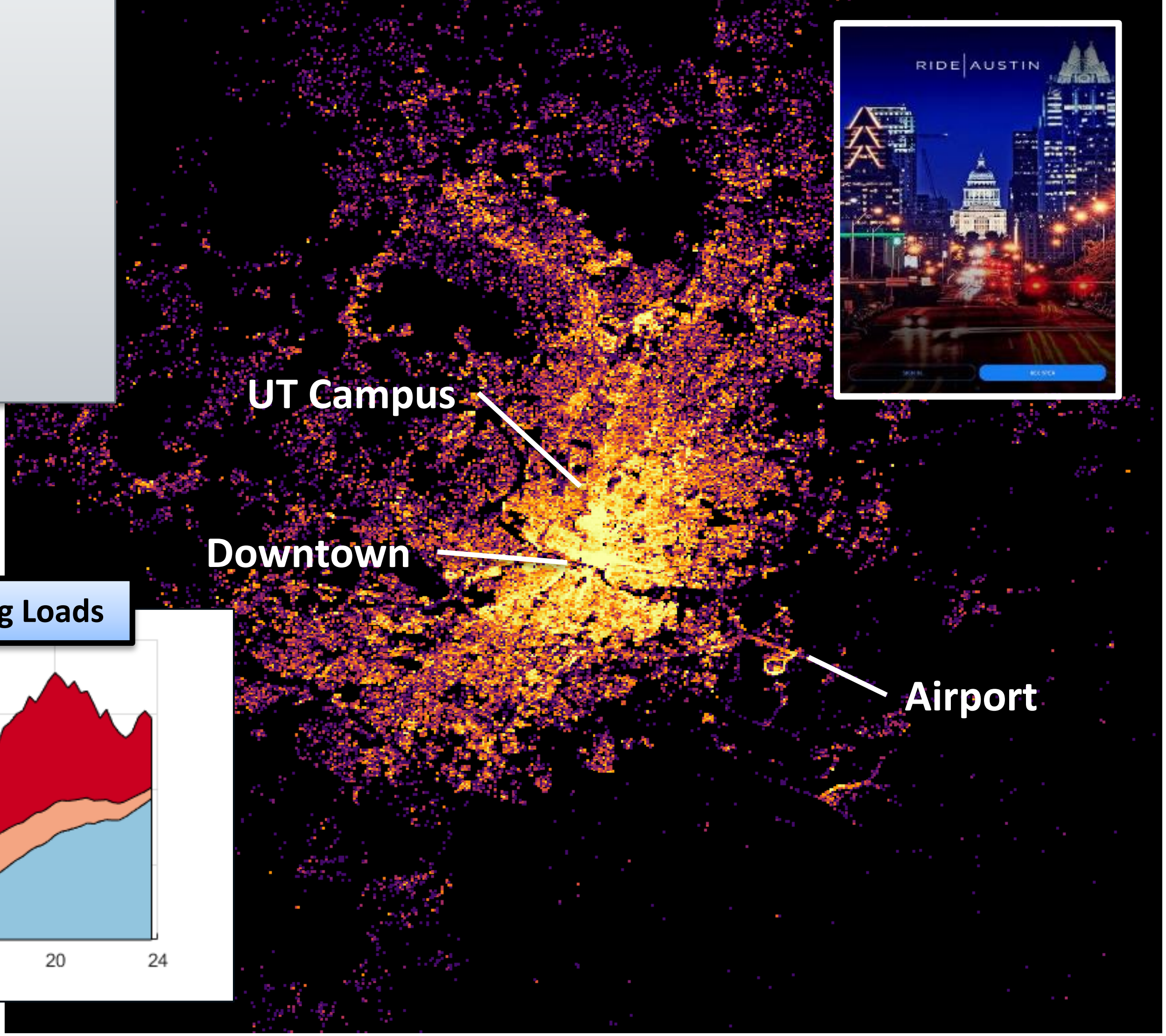
Transportation Network Companies: RideAustin Case Study

By the numbers

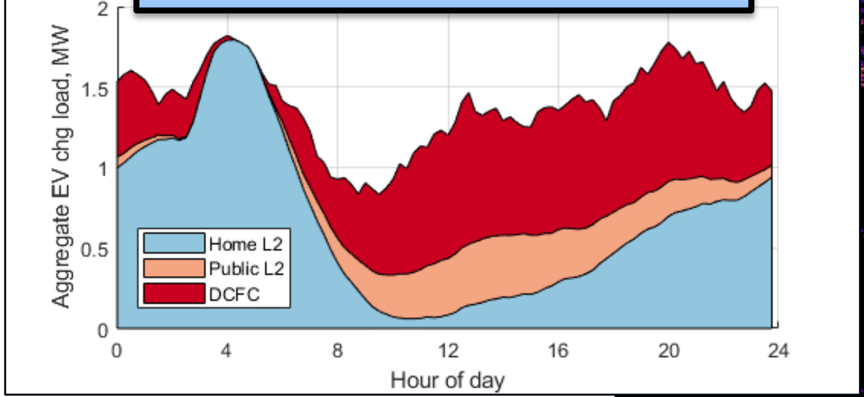
- Sample duration: 10 months
- Period: June 2016 to April 2017
- 4,961 unique drivers & vehicles
- 261,000 unique riders
- 1.49 million trips

Largest US TNC dataset currently available to researchers

Heatmap of RideAustin trip destinations



Simulated Weekend Charging Loads



EVI-Pro Lite Online

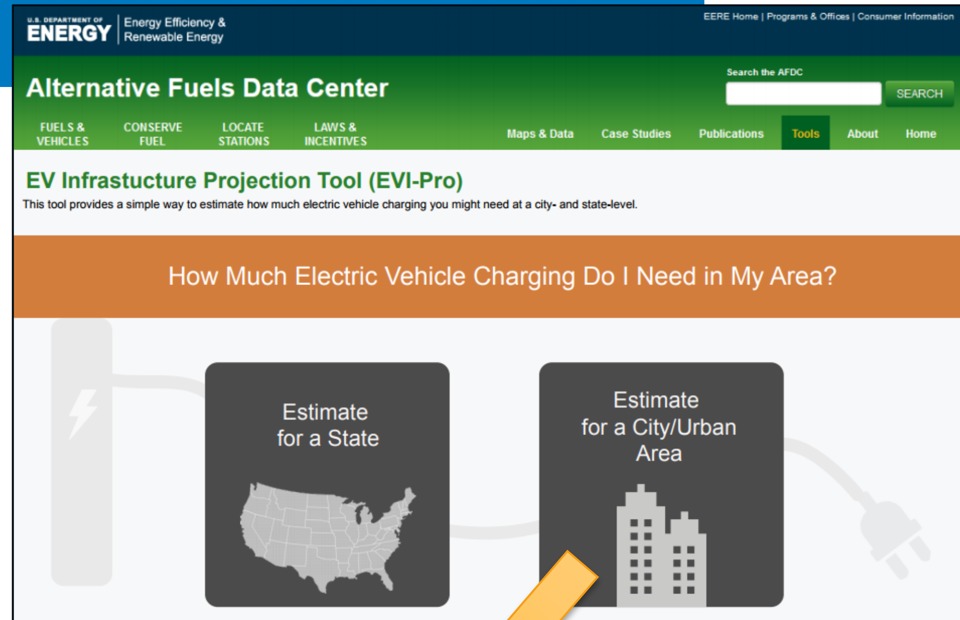
Objective: Make analytic capabilities of EVI-Pro model accessible to broad group of stakeholders for EVSE investment decisions.

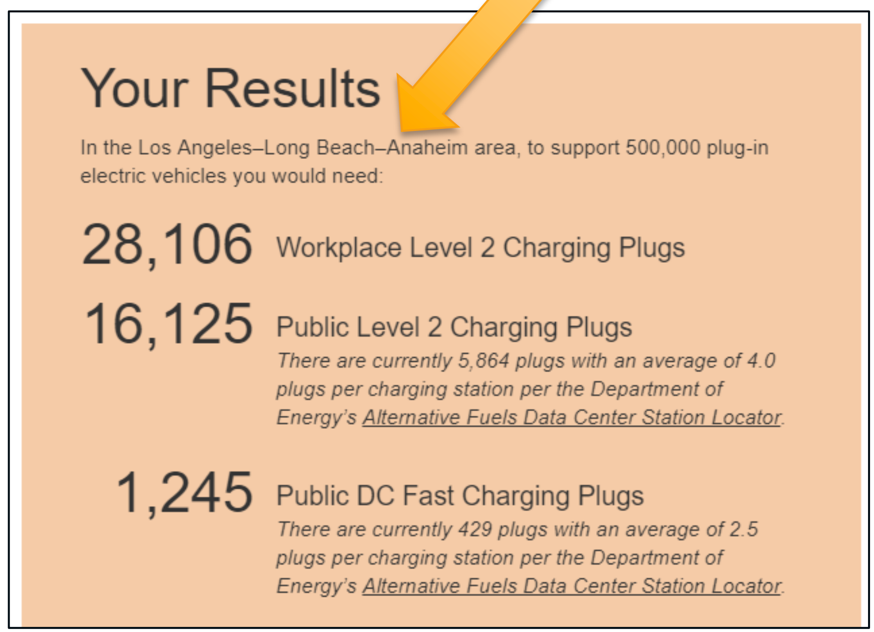
Approach: Develop a simplified, web-based interface for EVI-Pro that gives users access to a limited number of critical input variables.

Significance & Impact

- EVI-Pro “unlocks” an unlimited number of scenarios for planners to explore regarding EV charging infrastructure requirements.
- Ability to rapidly develop scenarios and explore sensitivities will help users understand the key drivers for investment.

afdc.energy.gov/evi-pro-lite





Analysis for Colorado Public Utilities Commission

Implications of EV Growth on Electricity Ratemaking

Major existential gap

- The behaviors we observe in today’s nascent EV market might change as the market matures
  - Example: No way to know empirically today whether home charging will continue to dominate 10 years from now
  - Example: Cost of L2 “smart” chargers in the event of increased demand for control functions
- The value of looking at today’s phenomena is to form questions, recognizing that the answers might change as EVs become mainstream

Areas investigated

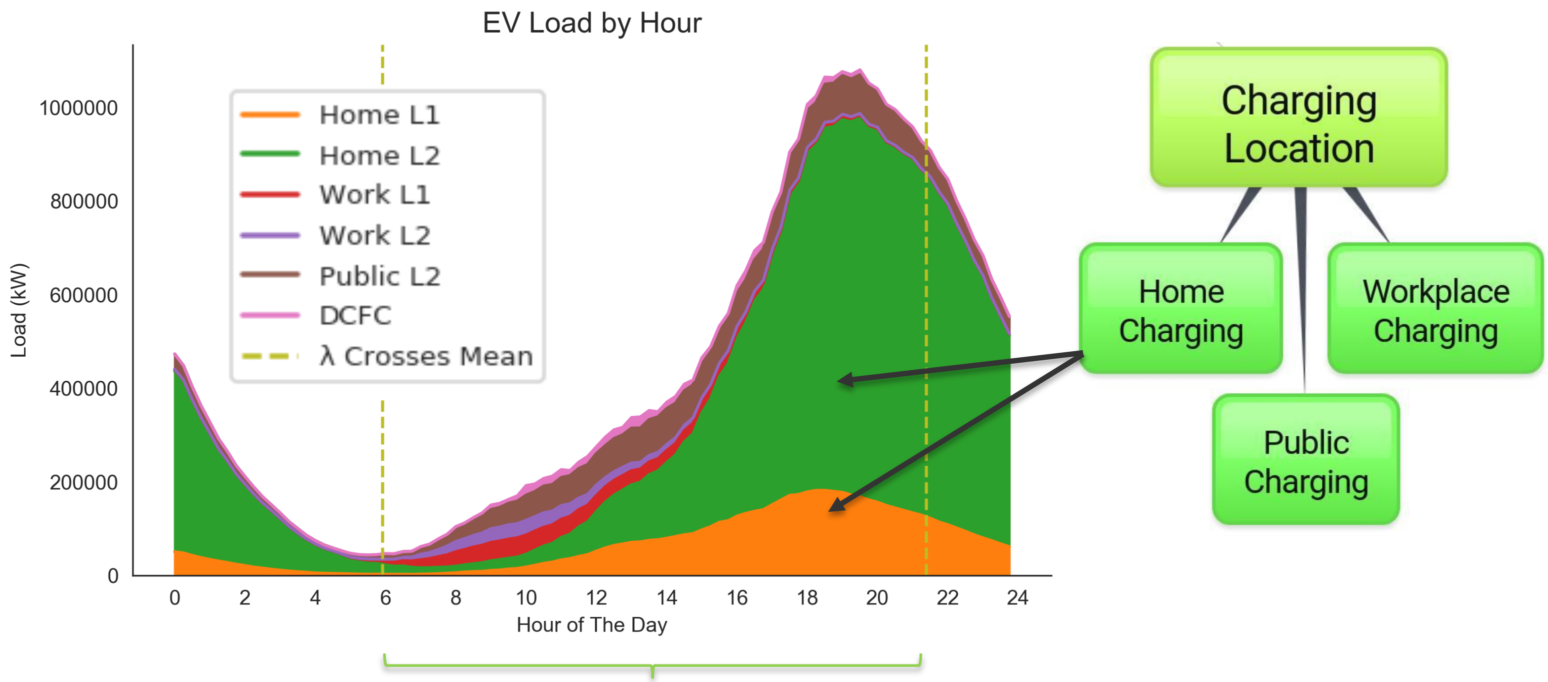
- Multifamily residential charging access
- Time-of-use rates (passive demand response)
- Smart charging (active demand response)
- Fleet charging
- DC fast charging

Home charging with time-of-use rates

Passive demand response

Most EV charging today happens at home

At present, the tendency is for more than 80% of EV charging load (and as much as 93% under some scenarios) to happen at home, mostly in the evening. The rest is divided between public charging and workplace charging.



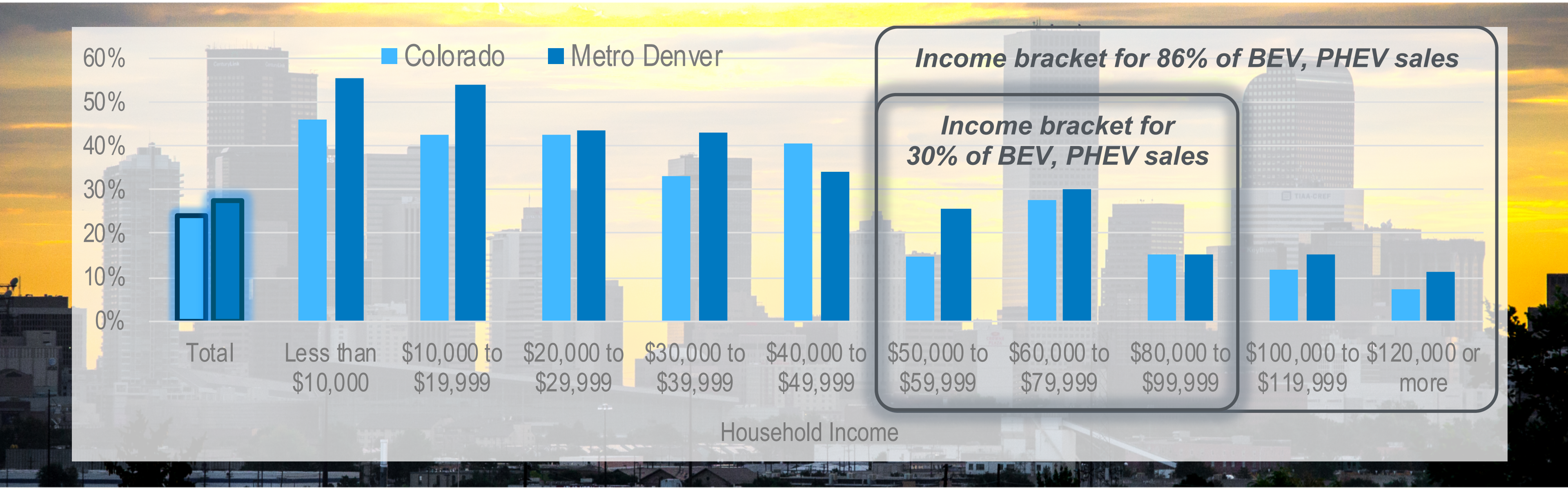
Hours when system cost is above the daily mean

NREL simulation for Colorado using EVI-Pro, with electricity costs from Colorado utility rate books

Unknown: EVs and multifamily residential customers

- Known: The income bracket known to purchase the most EVs includes many who live in multifamily housing.
- Regulatory question: Do submetering rules affect infrastructure for EV charging in multifamily housing, and could this affect EV demand?

Multifamily housing by income (% of all housing)



(Muehlegger and Rapson; U.S. Census Bureau, American Housing Survey. Photo by Dennis Schroeder, NREL 27455)

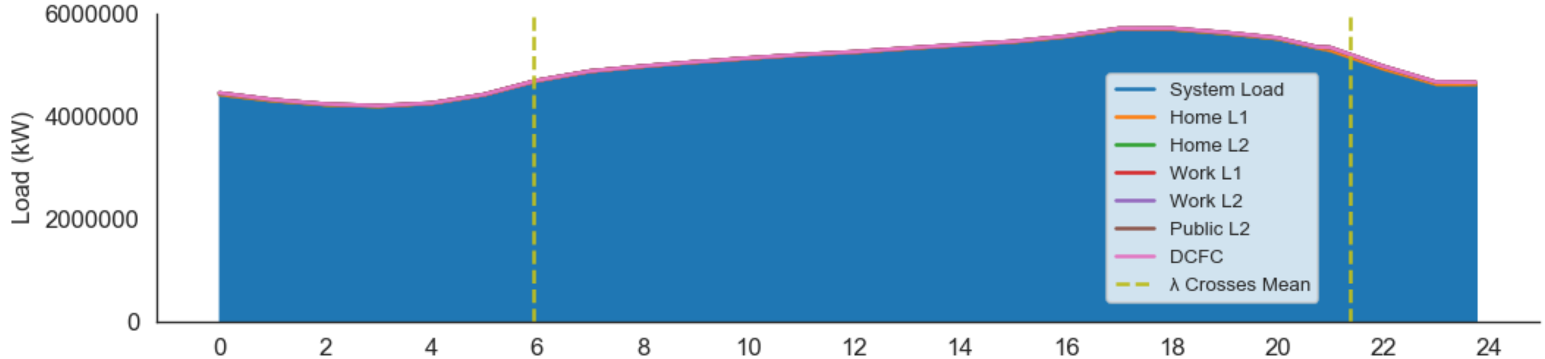
Eight modeled scenarios

- Scale of EV adoption is based on scenarios outlined by the Colorado Energy Office (CEO 2015)

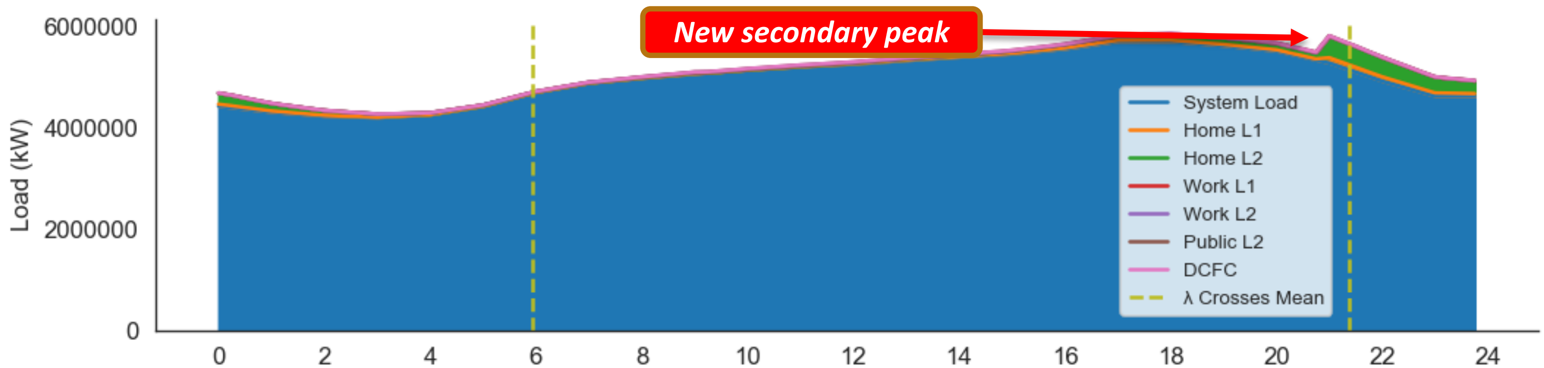
Number of EVS	Charging Behavior	Description
CEO Medium 2030 Adoption (302,429 EVs)	100% No Delay (all immediate on-demand charging)	Business as usual
	50% No Delay / 50% TOU	Moderate utilization of existing TOU rates
	50% No Delay / 50% Demand Response	Moderate utilization of controllable charging
	34% No Delay / 33% TOU / 33% Demand Response	Split between various programs
CEO High 2030 Adoption (940,000 EVs)	100% No Delay	BAU with high EV adoption
	50% No Delay / 50% TOU	High utilization of existing TOU rates
	50% No Delay / 50% Demand Response	High utilization of controllable charging
	34% No Delay / 33% TOU / 33% Demand Response	Split between various programs

No delay / TOU scenarios: average load

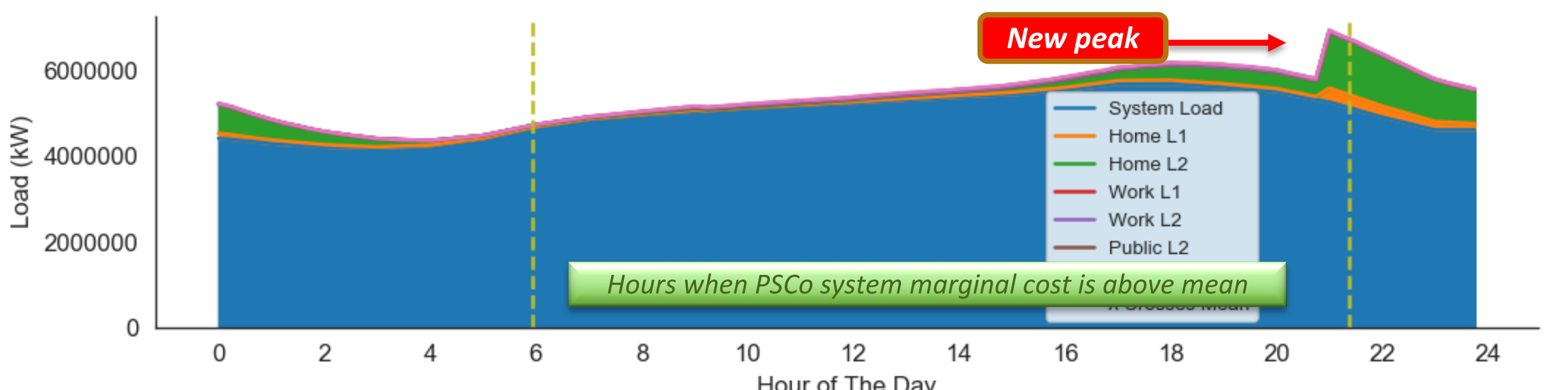
<u>Low</u> EV adoption, 50% utilization of existing TOU plan (average load by hour)



<u>Medium</u> EV adoption, 50% utilization of existing TOU plan (average load by hour)



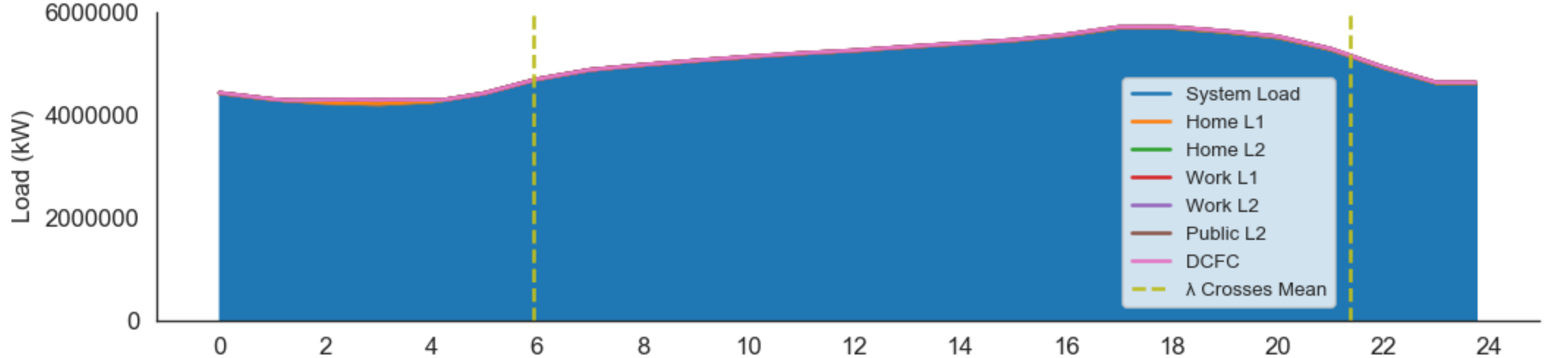
<u>High</u> EV adoption, 50% utilization of existing TOU plan (average load by hour)



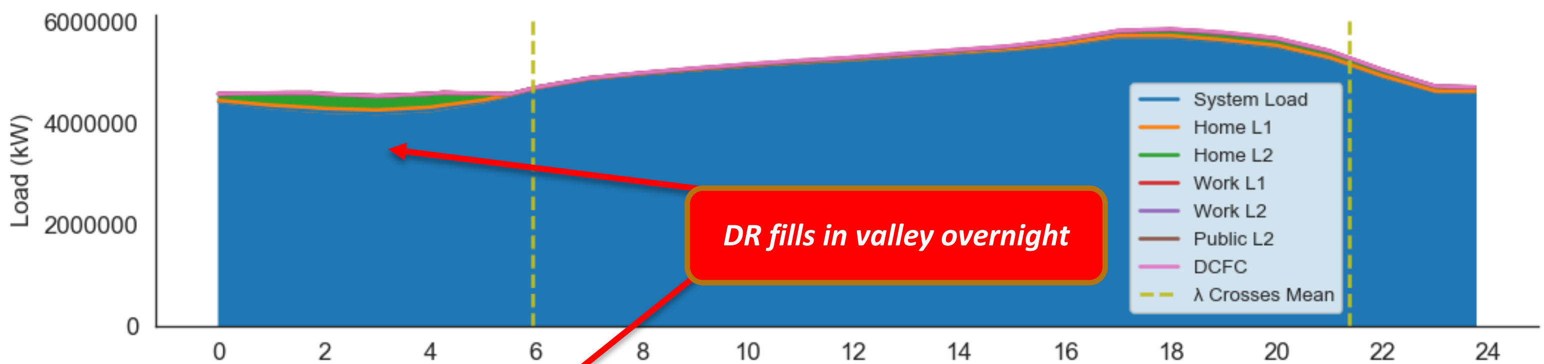
(BCS Incorporated 2015)

No delay / DR scenarios: average load

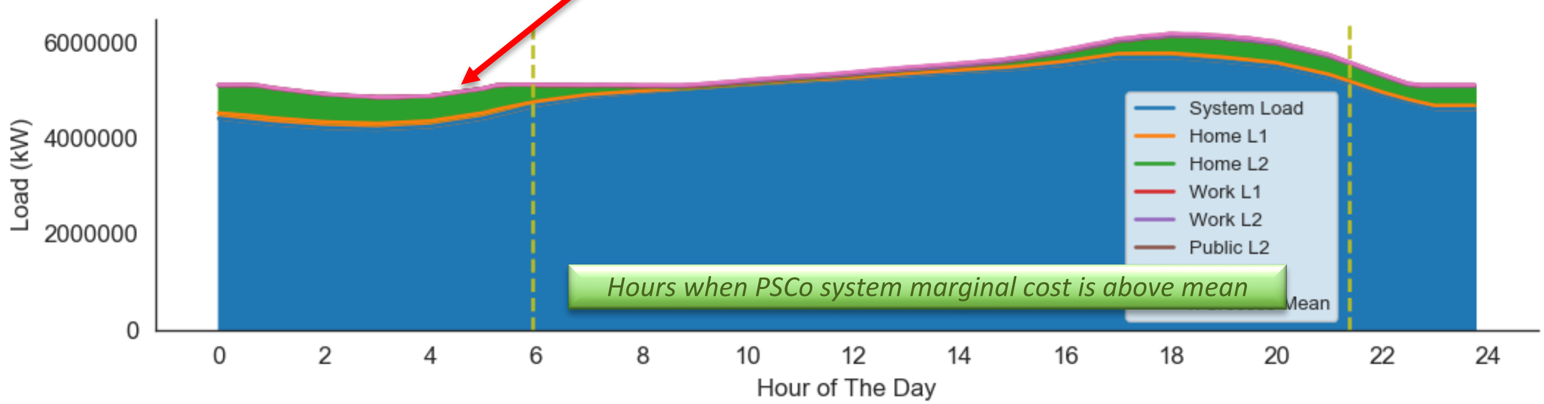
Low EV adoption, 50% utilization of residential DR charging (average load by hour)



Medium EV adoption, 50% utilization of residential DR charging (average load by hour)



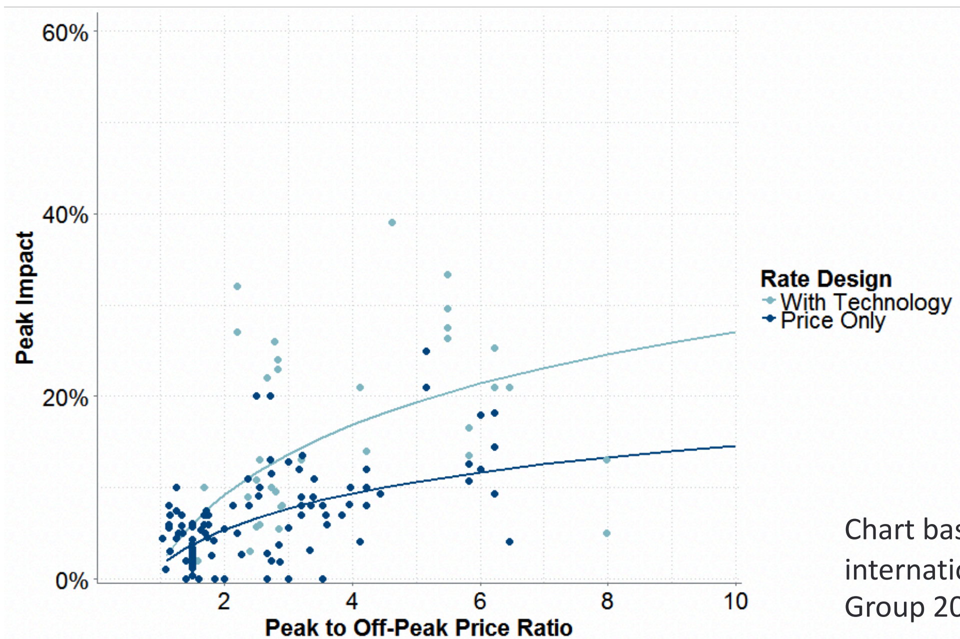
High EV adoption, 50% utilization of residential DR charging (average load by hour)



(BCS Incorporated 2015)

Residential TOU rates

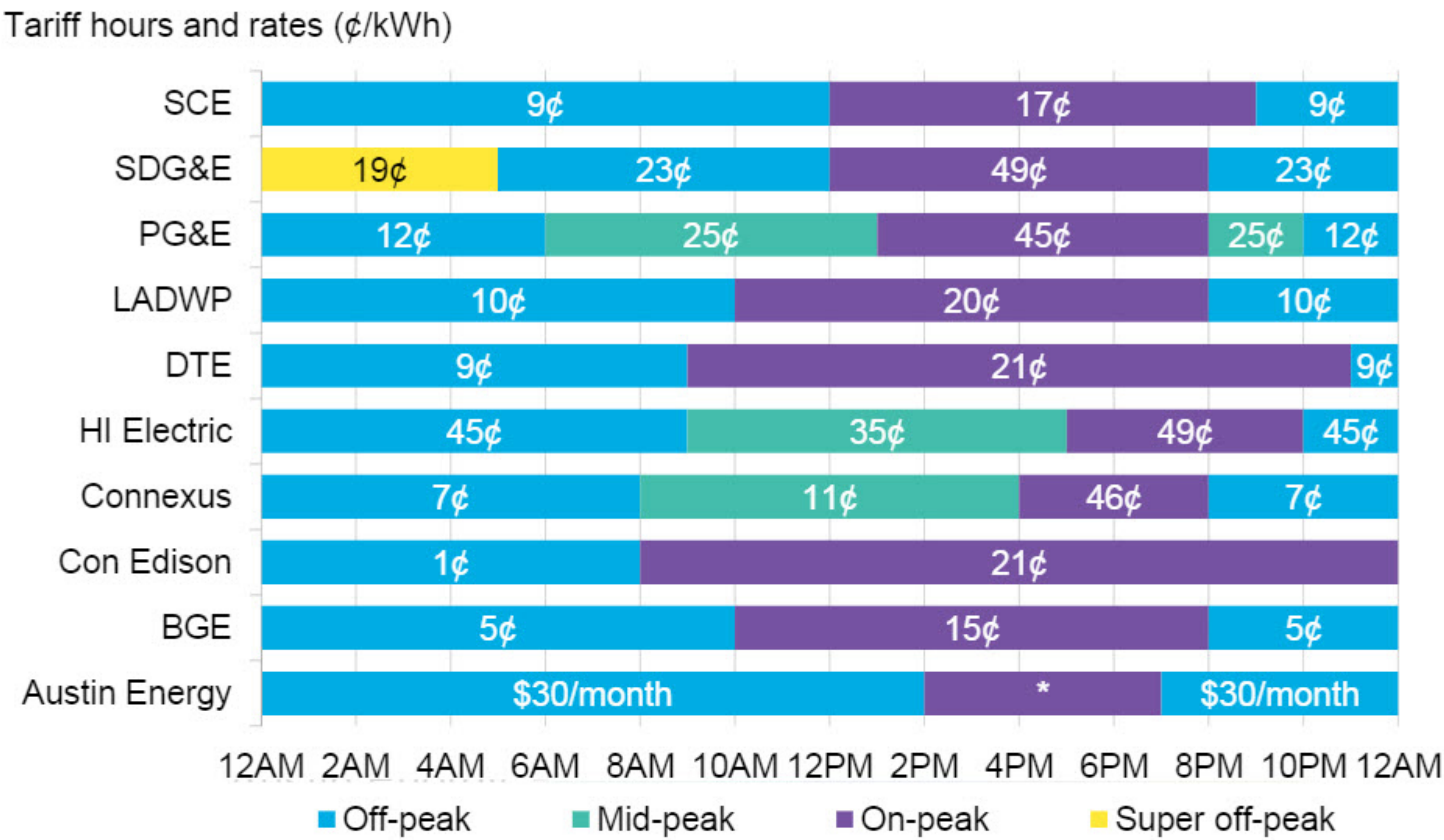
- 14% of US utilities offer residential TOU rates, 48% of IOUs offer a TOU rate
- Among two-period TOU programs, 71% have a price ratio of at least 2:1
- Price elasticity is 0.3-0.5 (Nexant, 2014)
- Opt-in TOU programs tend to have <20% enrollment, whereas opt-out (default) TOU programs have seen >90% participation (Whited et al., 2018)



As the price ratio increases, customers shift usage in greater amounts, but at a declining rate

Chart based on database of TOU rates in recent pricing pilots, including international pilots (15 of 38 TOU pilots in the database). (The Brattle Group 2017)

Utility TOU rates specific to EV customers



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)

Insights

- What EV charging behaviors might systematically increase or decrease the utility's cost of service in Colorado?
  - *Charging during periods with low system cost*
- How would load profiles change if they reflected reasonably achievable behaviors that reduced the cost of service?
  - *TOU rates would likely mitigate peak load growth by shifting charging load to low-cost hours*
  - *However, the 9 p.m. TOU transition period could result in a new evening peak as well as a brief but steep demand ramp, if EV charging is not spread out using DR*

Insights

- Multifamily residences are a potential regulatory gap for EV at-home charging infrastructure
- Demand response (DR) can be used to distribute the overnight charging of EVs during times when the cost of energy is less expensive to flatten the daily load profile.

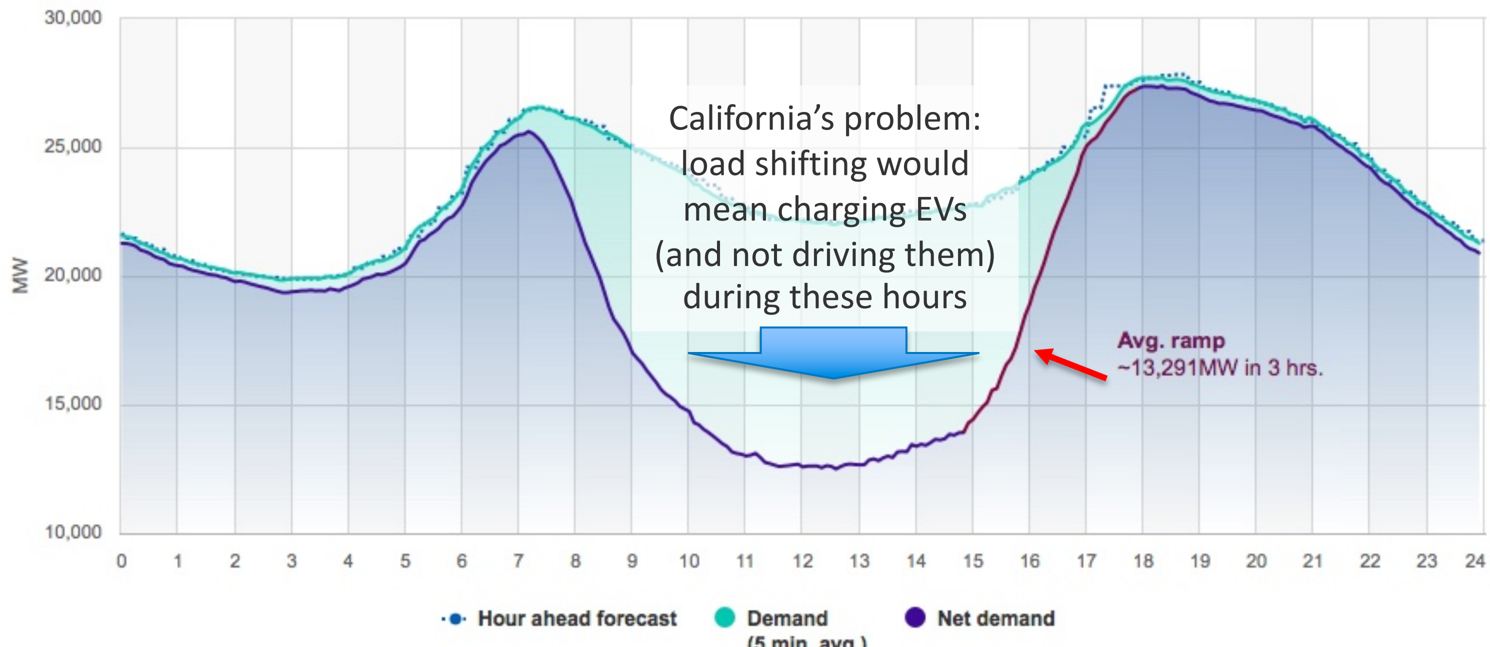
Controlled smart charging as active demand response

Flexibility for integrating high penetrations of variable renewable resources

EV charging and integrating renewables

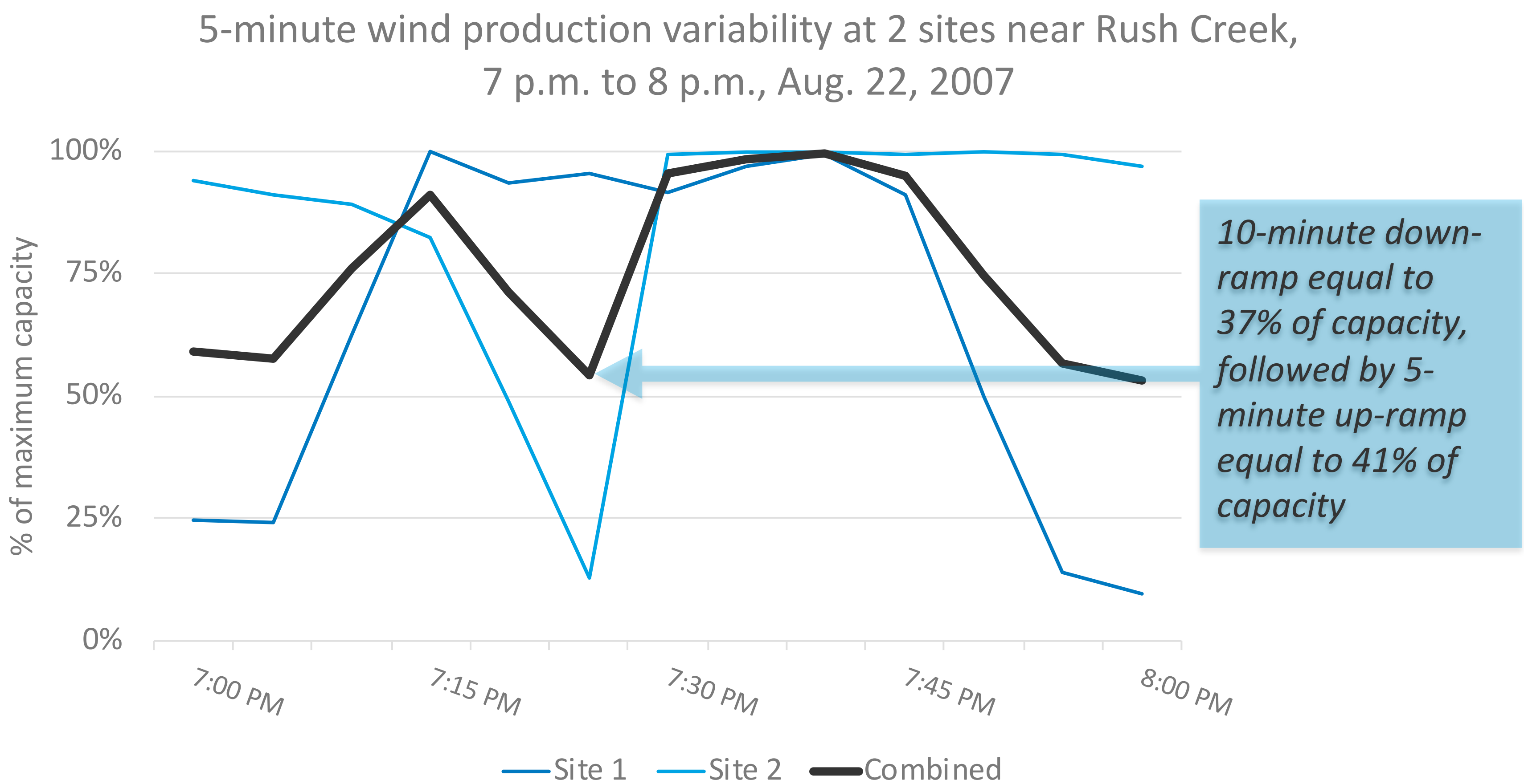
- Many EV-DR studies to date have focused on California, where the system is solar-heavy.
  - Integration problem: GW of net demand increase over 3 hours prior to peak
- Colorado is wind-heavy; conclusions about DR drawn from a solar-heavy system might not be applicable to Colorado

CAISO demand and net demand (demand minus renewables), January 24, 2019



(CAISO 2019)

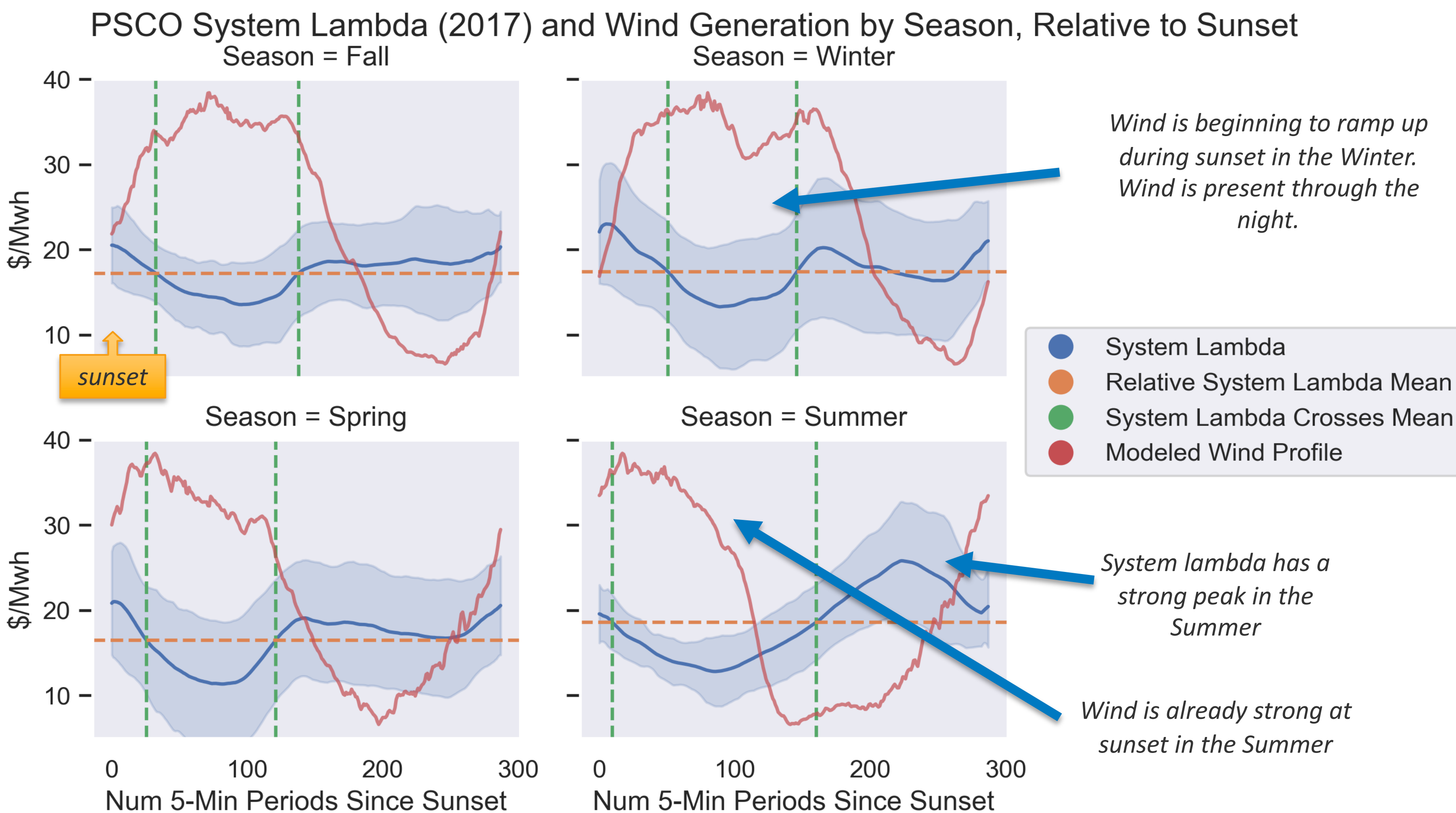
Colorado's problem: Intra-hour wind variability



Data from NREL Wind Toolkit (Draxl et al. 2015). Site 1: 39.066589N 103.14948W. Site 2: 39.004436N 102.40137W. Annual data for 2007 was representative of 20-year average (1997-2017)

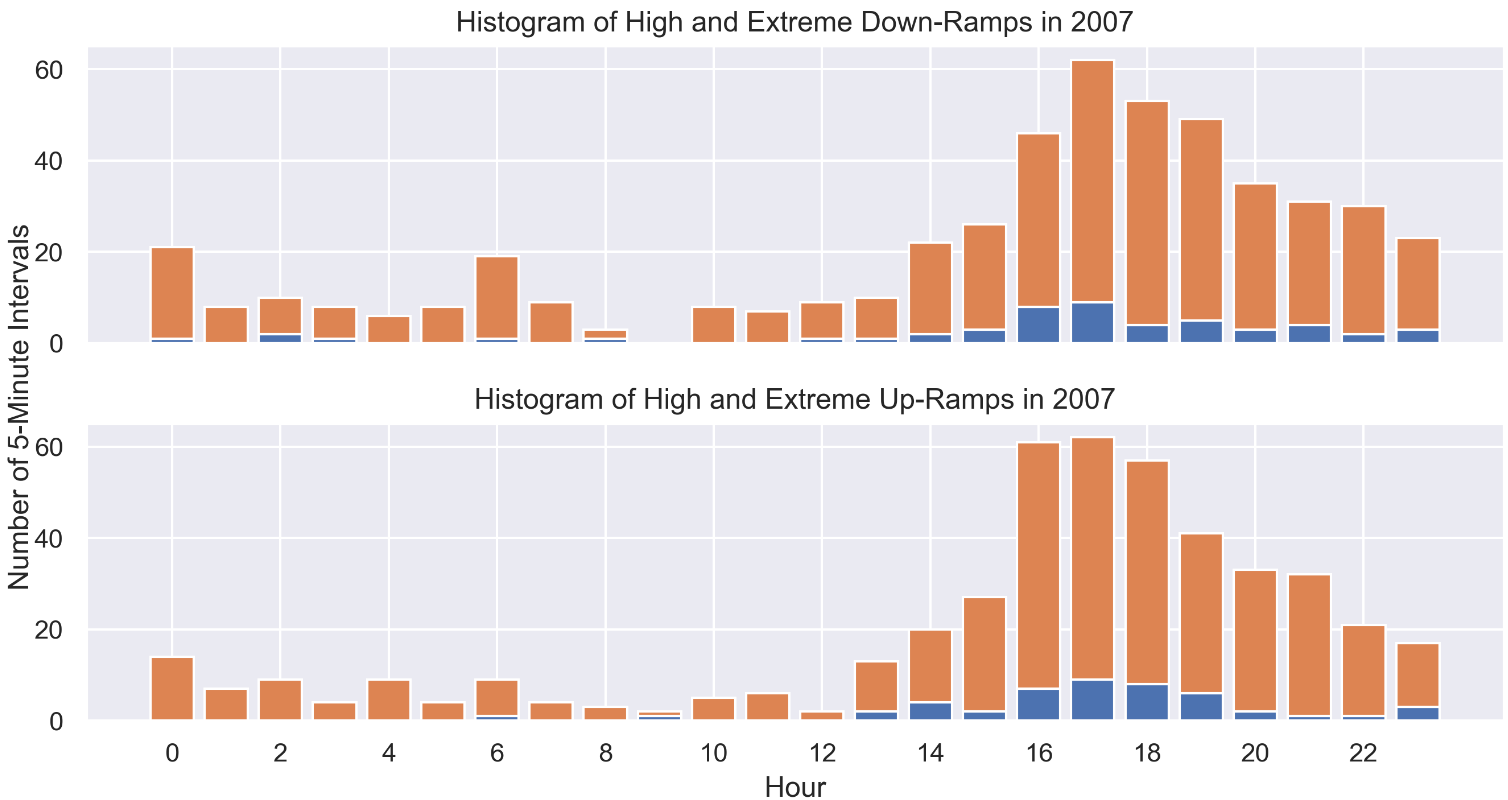
Model methodology

- The seasonality of wind and system lambda were explored. Winter offers the longest duration of overnight wind. Winter and Spring also have a secondary morning peak in system lambda after sunrise.



Intra-hour variability of Colorado wind

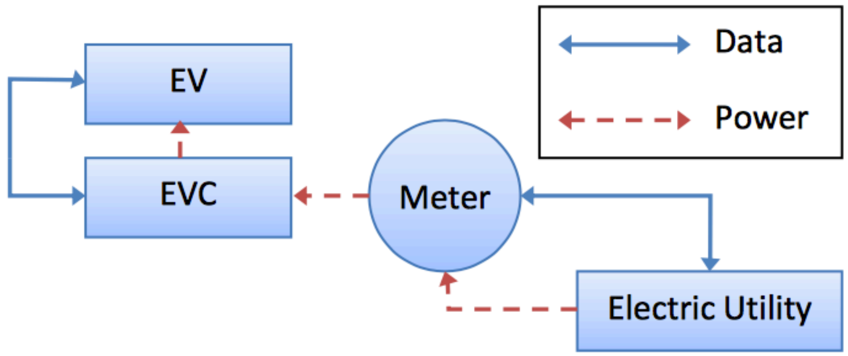
- High ramps at two test sites tend to occur in the afternoon, early evening
  - Coincident with charging patterns
- Need for further study of actual output from Colorado wind plants

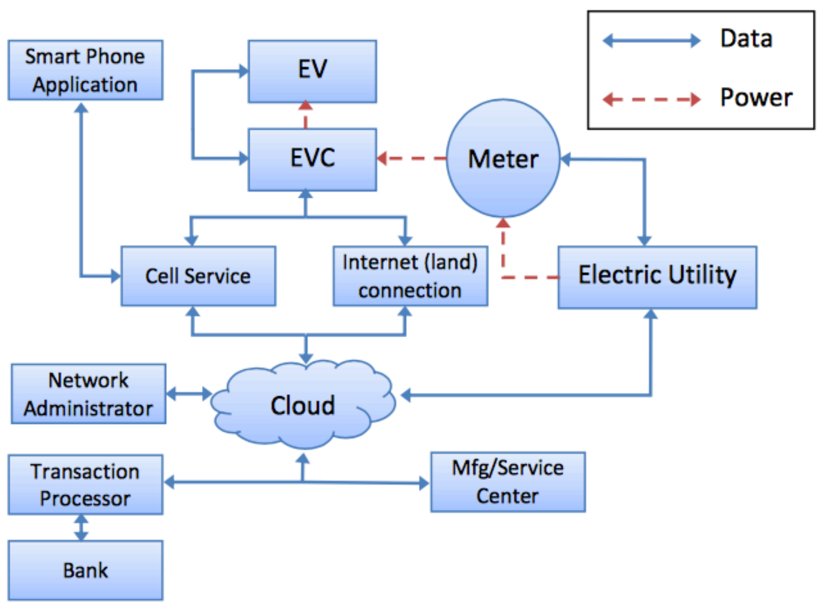


High wind ramping: 1% of 5-minute intervals with the greatest change in wind output
Extreme wind ramping: 0.1% of 5-minute intervals with the greatest change in wind output

Calculated for two sites from NREL Wind Toolkit (Draxl et al. 2015)

Networked vs. non-networked chargers





- **Non-networked chargers** communicate and provide charge to the electric vehicles that are directly connected. Can be programmed.
- **Networked chargers** allow vehicles, charging stations and/or the customer to adjust charging profile based on price or load signals from the utility. Networking provides utilities or aggregators with data to optimize charging across multiple stations.

(Local Government Commission et al. 2018)

EVSE with control capabilities

- Approximately one-third of EV charger manufacturers offer charging stations with utility control capabilities (Smart Electric Power Alliance 2017)
  - Includes Level 1, Level 2 and DCFC

EVSE with control capabilities

- Charging station communication protocols
  - Smart chargers receive load or price signals from the utility and communicate with the vehicle to manage the charging voltage or current. Common protocols include:
    - Open Automated Demand Response (OpenADR) 2.0
    - Smart Energy Profile (SEP) 1.x and 2.0
    - Open Charge Point Protocol (OCPP) 1.5, 1.6 and 2.0
    - Open Smart Charging Protocol (OCSP)
- Attachments
  - After-market products such as FleetCarma SmartCharge Manager (vehicle attachment) and GreenFlux DUO and PLUS (charger attachments) can also provide EV load management.
  - Attachments may have limited number of protocols they support, but can work across EVSE manufacturers.

Considerations for EV charger deployment

- Programs to incentivize deployment of EVSE with control capability should consider:
  - Capital costs
  - Ongoing program management needs
  - Interoperability of communication protocols
  - Avoiding path dependence
  - Deploying EVSE appropriate to targeted customer segment

Colorado EV Load Model: Insights

- What EV charging behaviors might systematically increase or decrease the utility’s cost of service in Colorado?
  – *The ability to vary charging load up or down in the evening to balance load and maintain system stability*
- How would load profiles change if they reflected reasonably achievable behaviors that reduced the cost of service?
  – *Controlled charging, if used extensively and if EV adoption were high, might mitigate the tendency for a new peak to form under existing TOU rates*
- Note: Controlled charging is similar in some ways to inverter-based power generation, which uses power system programming to respond to grid conditions that are detected

Fleet Charging

Commercial fleets

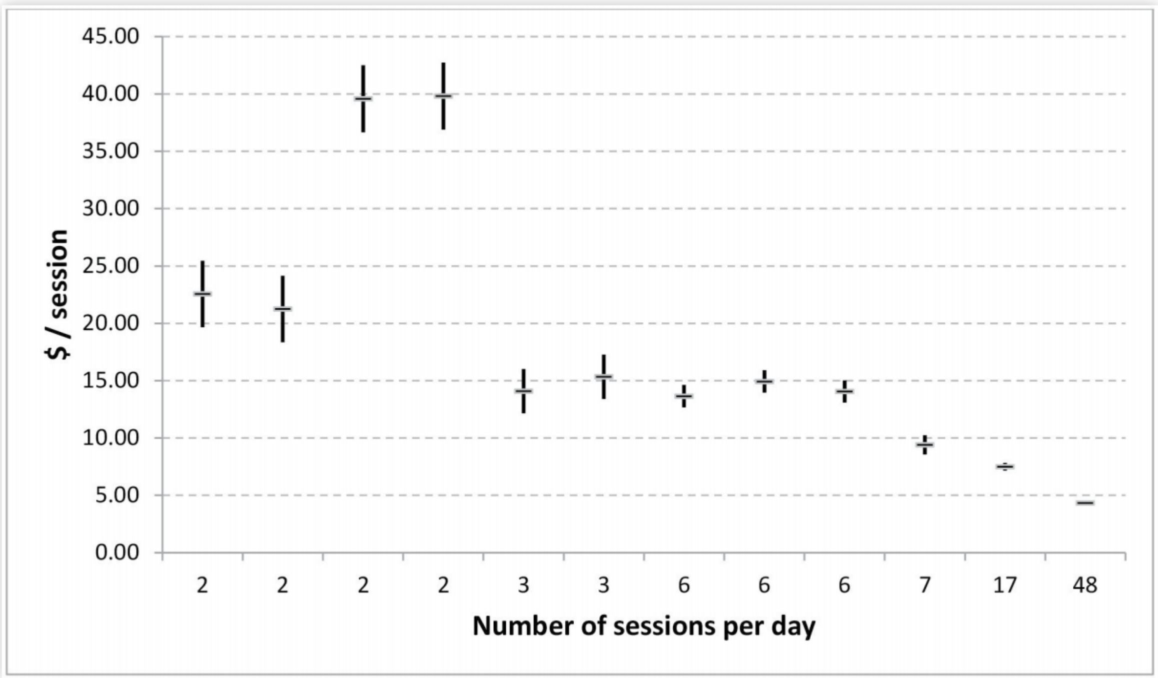
Based on limited field test data and economic modelling (variable costs, vehicle costs):

- For long distance routes, degradation costs, rather than energy costs, are limiting factor.
- Fleets using **short routes with more flexible charging** (i.e. within-city delivery) will be more responsive to utility rates/grid needs.
- Considering DC fast charging costs, including accelerated battery degradation and possible demand charges, DCFC infrastructure is likely not cost-effective as sole charging resource.
- Frequency-response resource may not be economical.
  - **ERCOT/Frito Lay Pilot:** 12 Smith Electric trucks tested use of EV charging as frequency response resource (within 1 second) of 100 kW. Small load, pilot costs, and low prices made it uneconomical.

(Schücking et al. 2017; Pelletier et al. 2018; Mitchem 2015)

Fast charging network for electrified ride-hailing services

- **Results:** Modeling a hypothetical ride-hailing fleet of 3,726 PEVs in Columbus, Ohio, using EVI-PRO identified the need for 12 DCFC stations across the city.
- Operation costs dominate the total costs. Modeling suggests DCFC station siting should prioritize locations with **high utilization** rather than **minimal installation costs**.
- DC Fast Charger Total Cost = capital cost ($40,000) per plug + installation costs + operating costs (electricity and maintenance)



Total cost of charging infrastructure per site, assuming 10-year amortization period

(Wood et al. 2018)

Battery electric bus fleets charging

Photo by Leslie Eudy, NREL

1. **Plug-in charging (Level 1 or 2)**
   – **Use:** overnight charging with buses with large battery packs and higher range (1-8 hours).
   – **Consideration: managed charging** to avoid a new system peak when the buses are plugged in.
2. **Overhead conductive charging (DC Fast Charging)**
   – **Use:** on-route or layover charging, using fast charging at 175-450 kW power for a period (5-20 minutes). This charging is used with buses with smaller, lighter battery packs.
   – **Consideration:** high energy demand, with limited flexibility for shifting their demand. The Foothills Transit Agency, which uses two overhead conductive chargers, has used **software control to manage their demand** to stay within their rate tier bounds.
3. **Wireless inductive charging (DC Fast Charging)**
   – **Use:** smoother on-route charging, as buses can be charged during routine stops (i.e. transfer), with similar charging patterns as overhead conductive charging.

(Transit Cooperative Research Program 2018)

EV bus charging case study

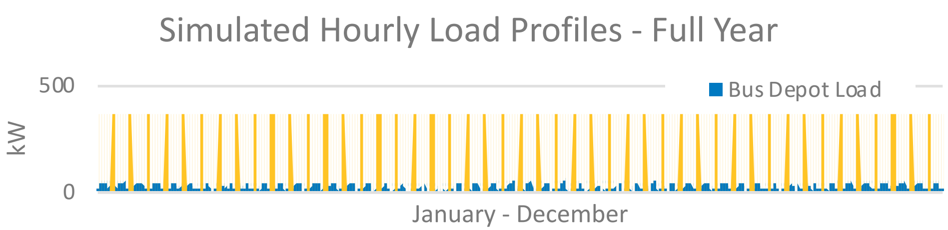
- NREL study explored cost of charging six EV buses purchased by the City of Missoula, Montana
- Two charging locations compared:
  - Charging at existing bus depot
  - Charging at university campus
- Assumes no change in electricity rates

Methodology Notes:

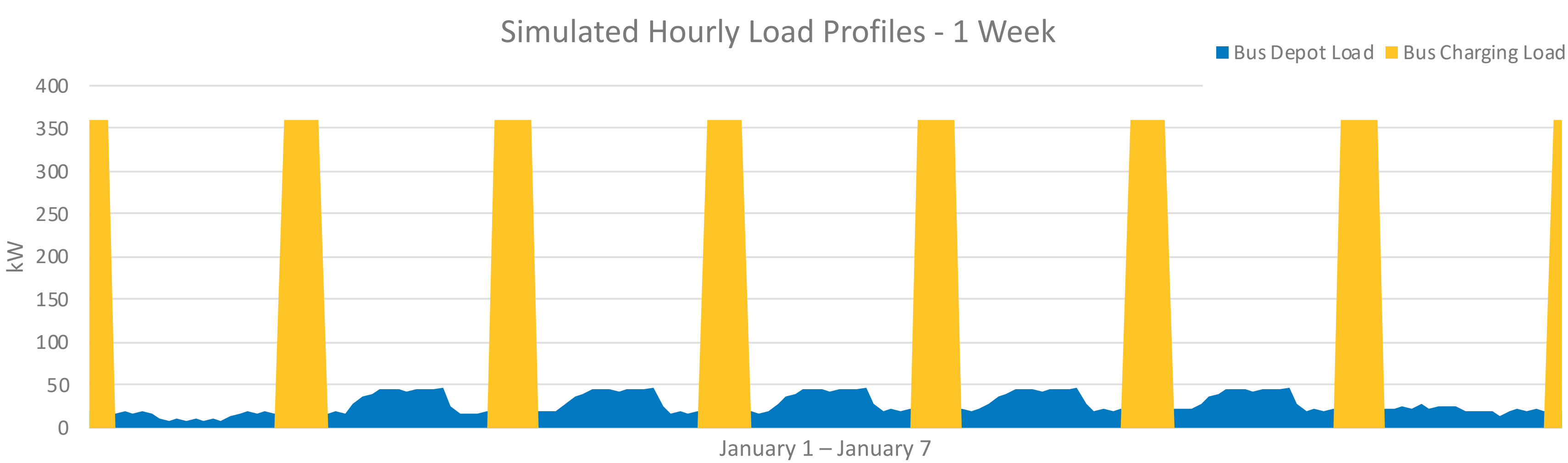
- Both cases assume each bus charges at 60 kW for 5 hours (from 11 pm – 4 am)
- Simulations were conducted using NREL's REopt Model https://reopt.nrel.gov/
- Assumes depot load shape is equivalent to the DOE's commercial reference building load profile for a warehouse in climate zone 6B, scaled to REopt's actual annual energy consumption of 188,081 kWh from May 2017- April 2018
- Uses actual 15-minute interval data for the university campus (down-sampled to hourly data)

Bus depot & bus charging loads

- Simulated bus charging load is large relative to existing bus depot load

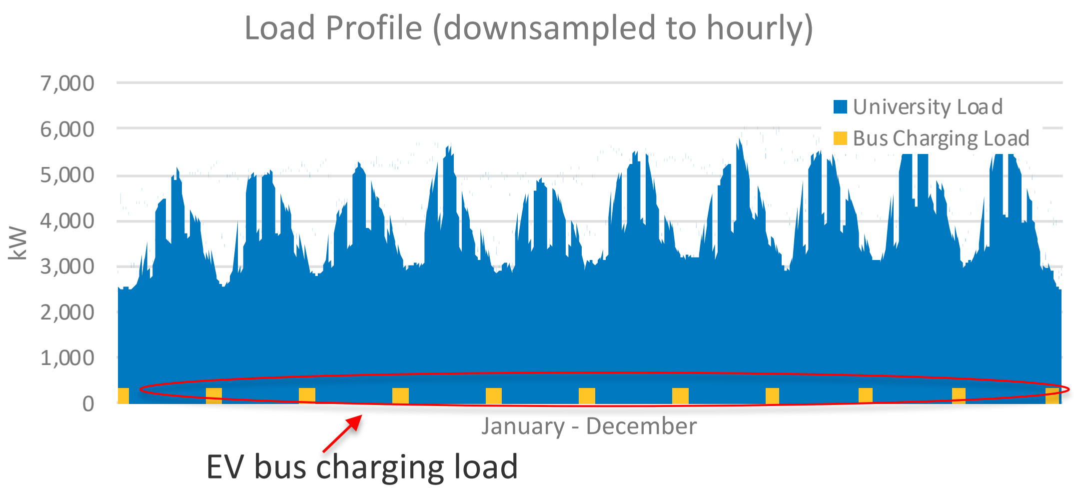


	Depot	Buses	Total
Max Peak (kW)	59	360	384
Annual Load (kWh)	188,081	657,000	845,081

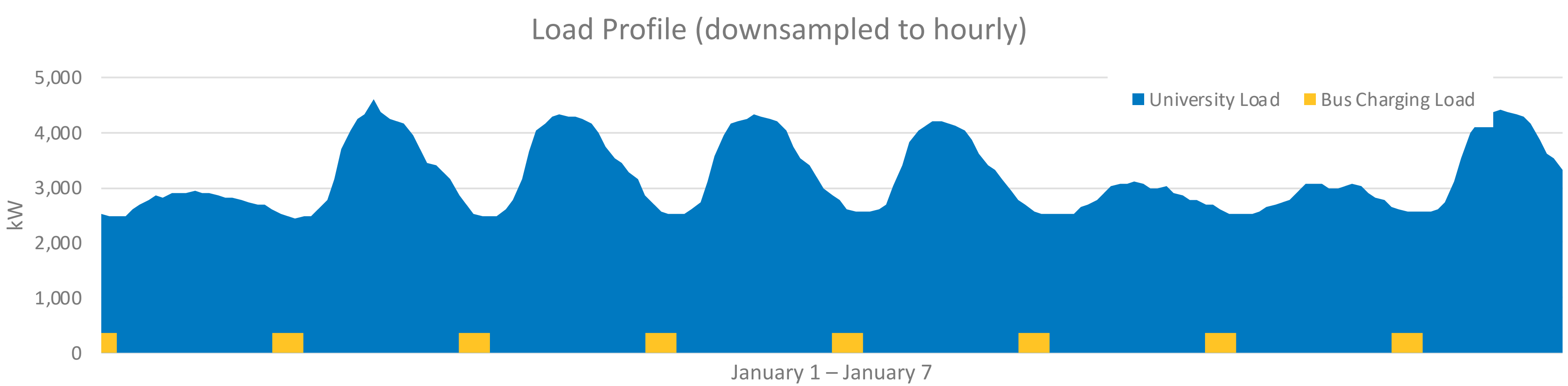


University & bus charging loads

- The load from charging the EV buses is very small relative to university load
- The peaks of the EV buses are out of alignment with the peaks of the university



	University	Buses	Total
Max Peak (kW)	**6,078**	360	**6,078**
Annual Load (kWh)	34,541,951	657,000	35,198,951



Cost of electricity

	Bus Depot	Bus Depot + Elec Buses	Incremental Cost Buses	University	University + Elec Bus	Incremental Cost Buses
Purchased Utility Electricity (kWh/yr)	**188,081**	845,081	657,000	**34,541,951**	35,198,951	657,000
Year 1 Utility Electric Costs (Energy $)	**$14,801**	$66,507	$51,706	**$2,625,187**	$2,675,203	$50,016
Year 1 Utility Electric Costs (Demand $)	**$5,757**	$44,626	$38,869	**$569,120**	$569,120	$0
Year 1 Total Utility Cost ($)	**$20,558**	$111,133	$90,575	**$3,194,290**	$3,244,323	$50,033
Blended Rate of Electricity ($/kWh)	**$0.109**	$0.132	$0.138	**$0.0925**	$0.0922	$0.0762
Lifecycle Cost of Electricity	**$394,822**	**$2,134,217**	**$1,739,395**	**$75,948,156**	**$77,137,710**	**$1,189,554**

Note: If demand charges were only charged based on day-time peak, the load of charging the buses would not add demand charges to the depot's electricity cost. In that scenario, the annual cost of electricity would only increase by $51k (not $90k).

Insights for bus fleet charging

- Both rate structures include similar energy and demand charges
- Bus charging demand identical in both cases
- Electric bus charging load overshadows existing bus depot load, resulting in significant increase in demand charges.
- University campus load overshadows charging load, resulting in zero increase in demand charges.
- Whether or not EV chargers can be placed behind building load on the same meter greatly impacts potential costs.
- Giving charging station owners the ability to select the rate structure that suits their situation could encourage charging station deployment.

Public Direct-Current Fast Charging (DCFC)

DCFC load factor and demand charges

- Usage of DCFC stations is currently relatively low, especially in early stages of market development.
  - EEI estimates average load factor of 2% for DCFC stations
  - "Highly utilized" DCFC stations in California to have 15-20% load factor, though a few have >50% load factor
- At low utilization with standard rate schedules, demand charges tend to dominate monthly bills for DCFC stations.
- Public Service Co. of Colorado's Secondary General Low-Load Factor rate results in lower bills up to approximately 11% load factor compared to the Secondary General rate.
- Adding DCFC to an existing large commercial account may reduce the need for transformer upgrades, the total installation costs, and the impact of demand charges.

(Energetics Incorporated 2015; Electrify America 2018)

Alternative rates to manage DCFC load

- If desired, alternative rate structures can be designed to decrease demand charges.
  - Energy-only rate with monthly energy consumption thresholds (2,000; 3,000; 5,000; 8,000 kWh)
    - PSEG Long Island (<2,000 kWh), Village of Akron (<7,500 kWh)
  - Hybrid rates with peak power threshold classes (50, 60, 75, 100, or 200 kW) and monthly energy consumption threshold
  - Rate limiter, maximum allowable rate that customers can be charged
    - Developed in California for electric buses

(Energetics Incorporated 2015)

Rate structures that support PV or storage

- NREL analyzed which CO rate structures allow addition of solar PV or battery storage to be economic (Muratori et al., forthcoming)
  - Rates with the following characteristics support addition of PV or batteries:
    - **Demand charges:** > $10/kW (batteries improved economics)
    - **Time-of-use:** > 3.5:1
    - **Energy costs:** > 0.128/kWh (PV improved economics)

Utility	Demand charge	Energy charge	PV/Battery
Sangre de Cristo Electric Association	Peak: $30.1/kW Off-Peak: $4.2/kW	Peak: $0.0483/kWh Off-Peak: $0.02835/kWh	B: 21 kW
	--	Peak: $0.53/kWh; Off-Peak: 0.15013/kWh Super off-peak: $0.04305 /kWh 12.3: 3.5: 1	B: 15 kW
	$30.1/kW	$0.06173/kWh	B: 19 kW
San Luis Valley REC	--	Peak: $0.344/kWh Off-peak: $0.055/kWh 6.25: 1	B: 12 kW PV: 11 kW
Black Hills	$22.8/kW	$0.00573/kWh adj. $0.04324698/kWh	B: 14 kW
Intermountain Rural Electric Association	$17.25/kW	$0.05344/kWh (buy/sell rate)	B: 7 kW
	Peak: $10.03/kW Off-peak: $7.2/kW	$0.05344/kWh	B: 7 kW
Xcel	Peak: $15.8/kW (June-Sept) Off-peak: $12.8/kW (Oct-May)	$0.00473/kWh with $0.02683/kWh	B: 7 kW
United Power	$16/kW	$0.0575/kWh	B: 5 kW
Springfield Municipal Utilities	$14.54/kW	$0.0911/kWh, with 0.005/kWh adjustment	B: 5 kW PV: 4 kW
	--	$0.1455, with 0.005/kWh adjustment	PV: 4.55 kW
	--	$0.1374/kWh, with 0.005/kWh adjustment	PV: 2.11 kW
San Luis Valley	--	$0.128/kWh	PV: 2.80 kW
La Plata Electric Association	$14.2/kW	$0.061/kWh, buy/sell	B: 5.06 kW

TOU

Energy

Insights (Recap)

Insights

- What EV charging behaviors might systematically increase or decrease the utility's cost of service in Colorado?
  - *Charging during periods with low system cost*
  - *The ability to vary charging load up or down in the evening to balance load and maintain system stability*
- How would load profiles change if they reflected reasonably achievable behaviors that reduced the cost of service?
  - *TOU rates would likely mitigate peak load growth by shifting charging load to low-cost hours*
  - *However, the 9 p.m. TOU transition period could result in a new evening peak as well as a brief but steep demand ramp, if EV charging is not spread out using DR*

System impacts of charging behaviors

- How would load profiles change if they reflected reasonably achievable behaviors that reduced the cost of service?
  - *Controlled charging, if used extensively and if EV adoption were high, has the potential to mitigate formation of a new peak under existing TOU rates*

Getting ready

- Are there “make-ready” investments by the utility that might encourage desirable load growth for EV charging?
  - *High-density residential buildings (condos and apartments) are a potential focus area where EV demand might currently be suppressed due to the lack of L2 (240v) charging capability*
  - *A review of PUC rules that govern master metering could*
    - *identify possible amendments specific to EV charging in multifamily residences, and*
    - *inform the design of utility programs to target make-ready investments in multifamily developments where the chances of both EV use and cost recovery are high*

Thank You

www.nrel.gov

PR-6A20-73303

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the Colorado Public Utilities Commission. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

NREL
NATIONAL RENEWABLE ENERGY LABORATORY