Energy Research and Development Division

FINAL PROJECT REPORT

Distribution System Constrained Vehicle to Grid Services for Improved Grid Stability and Reliability

Appendices A-H

California Energy Commission

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Technology Requirements and Development

1. Local Transformer and Feeder Optimization Parameters

The identification of the TMS hardware components, features, and the accuracy/resolution specifications for monitoring and metering of transformer voltage, current, temperature, power factor, reactive/active power, etc. are delineated in this section**.**

a. Transformer Monitoring System – Hardware Description

The Transformer Monitoring System (TMS) hardware consists of a ACU VIM II revenue grade meter Transformer Power Meter Unit (TPMU)) and a router running specific apps for SEP 2.0 applications. The ACU VIM are high-end multifunction power and energy meters manufactured by Accuenergy. All monitored data is available via a digital RS485 communication port running Modbus RTU and DNP 3.0 protocols, additional communication options include: Modbus, Ethernet, Profibus DP, and BACnet. The TMS is mounted at the local Distribution Transformer. The Monitoring system is housed in an environmental enclosure suitable for outdoor use. Egress is provided for the split core CT's used in the system. *Important: Not all features and capabilities are used by the TMS.*

2. System Hardware Features

a. Transformer Power Meter Unit (TPMU) hardware features

Features:

- 100ms Refresh, True-RMS Measuring Parameter
- ANSI C12.20 (0.2 Class) and IEC 62053-22 (0.2S Class)
- 16 MB Onboard Memory
- Power Quality Analysis
- Over/Under Limit Alarm
- Multiple Communication Ports (E.g.: Ethernet, RS485)
- Supports Modbus RTU, DNP 3.0, BACnet IP, BACnet MS/TP
- Web Server and Email Sending, SNTP
- Switch Status Monitoring
- Waveform Capture
- Measure Individual Harmonics from 2nd to 63rd
- Physical Anti-Tampering Seal
- 50/60Hz and 400Hz Rated Frequency Metering
- Modular Design
- Data Logging
- TOU, 4 Tariffs, 12 Seasons, 14 Schedules
- Class Leading Warranty

Metering:

- Voltage V1, V2, V3, Vlnavg, V12, V23, V31, Vllavg
- Current I1, I2, I3, In, Iavg
- Power P1, P2, P3, Psum
- Reactive Power Q1, Q2, Q3, Qsum
- Apparent Power S1, S2, S3, Ssum
- Frequency F
- Power Factor PF1, PF2, PF3, PF
- Energy Ep_imp, Ep_exp, Ep_total, Ep_net, Epa_imp, Epa_exp,
- Epb_imp_Epb_exp, Epc_imp, Epc_exp
- Reactive Energy Eq_imp, Eq_exp, Eq_total, Eq_net, Eqa_imp,
- Eqa_exp, Eqb_imp, Eqb_exp, Eqc_imp, Eqc_exp
- Apparent Energy Es, Esa, Esb, Esc
- Demand Dmd_P, Dmd_Q, Dmd_S, Dmd_I1, Dmd_I2, Dmd_I3
- Load Features
- Four Quadrant Powers

Monitoring:

- Power Quality
- Voltage Harmonics 2nd to 63rd and THD
- Current Harmonics 2nd to 63rd and THD
- 400Hz type, only support 2nd to 15th
- Voltage Crest Factor
- THFF (TIF)
- Current K Factor
- Voltage Unbalance Factor U_unbl
- Current Unbalance Factor I_unbl
- Max/Min Statistics with Time Stamps

Figure A-1: Specifications - Accuracy and Resolution

Parameters	Accuracy	Resolution	Range
Voltage	0.20 percent	0.1V	10V~1000kV
Current	0.20 percent	0.1mA	5mA~50000A
Power	0.20 percent	1W	-9999MW~9999MW
Reactive Power	0.20 percent	1var	-9999Mvar~9999Mvar
Apparent Power	0.20 percent	1VA	0~9999MVA
Power Demand	0.20 percent	1W	-9999MW~9999MW
Reactive Power Demand	0.20 percent	1var	-9999Mvar~9999Mvar
Apparent Power Demand	0.20 percent	1VA	0~9999MVA
Power Factor	0.20 percent	0.001	-1.000~1.000
Frequency	0.02 percent	0.01Hz	45.00~65.00Hz (50 or 60Hz type)
Energy			

Primary	0.20 percent	0.1kWh	0-99999999.9kWh
Secondary	0.20 percent	0.001kWh	0-999999.999kWh
Reactive Energy			
Primary	0.20 percent	0.1kvarh	0-99999999.9kvarh
Secondary	0.20 percent	0.001kvarh	0-999999.999kvarh
Apparent Energy			
Primary	0.20 percent	0.1kVAh	0-99999999.9kVAh
Secondary	0.20 percent	0.001kVAh	0-999999.999kVAh
Harmonics	1.00 percent	0.10 percent	
Phase Angle	2.00 percent	0.1DEG	0.0 DEG ~359.9 DEG
Unbalance Factor	2.00 percent	0.10 percent	0.0 percent~100.0 percent
Running Time		0.01h	0~9999999.99h

Source: EPRI

The TPMU shall measure the Voltage, Current and Phase of the secondary output of the Local Distribution Transformer and will send this data on request to the Transformer Controller (router) for processing using wired RS-485 connection. Transformer temperature measurements are included.

a. TMS Router

The Transformer Monitoring system router hardware is an N Series Wi-Fi Router having a high throughput CPU. The open source embedded code allows system changes. ASUS router provides AiCloud service: Access, stream, share, sync. Supports up to 300,000 sessions for P2P clients. Applications with USB2.0 port: printer server and FTP files sharing.

Features:

Networking Standards	IEEE 802.11b IEEE 802.11g IEEE 802.11n
Product Segment	N300 complete networking: 300 Mbps Coverage Medium homes
Data Rate	802.11g: 6,9,12,18,24,36,48,54 Mbps 802.11n: up to 300 Mbps
Antenna	External antenna x 3
Transmit/Receive	MIMO technology 2.4 GHz 2 x 2
Memory	32 MB Flash128 MB RAM
Operating Frequency	2.4 GHz

Encryption

64-bit WEP
128-bit WEP
WPA2-PSK
WPA-PSK
Radius with 802.1x

Firewall & Access Control Firewall

NAT and SPI (Stateful Packet Inspection)
intrusion detection including logging

Logging Dropped packet, security event, Syslog Filtering：Port, IP packet, URL keyword, MAC address

WAN Connection Type Internet connection type

Automatic IP, Static IP, PPPoE(MPPE supported), PPTP, L2TP
Ports RJ45 for 10/100/1000 BaseT for WAN x 1, RJ45 for 10/100/1000 BaseT for LAN x 4, Support Ethernet and 802.3 with max. bit rate 10/100/1000 Mbps and auto cross-over function(MDI-X) USB 2.0 x 2

SmartQo SWMM User definable rules for IP/MAC/Port Upload and download bandwidth management ACK/SYN/FIN/RST/ICMP with highest priority first:

- Guest Network: 2.4 GHz x 3
- VPN server: IPSec Pass-Through, PPTP Pass-Through, L2TP Pass-Through, PPTP Server
- VPN client: PPTP client, L2TP client
- Enhanced media server Image: Jpeg Audio: mp3, wma, wav, pcm, mp4, lpcm, ogg Video: asf, avi, divx, mpeg, mpg, ts, vob, w mv, mkv, mov
- AiCloud personal cloud service
- 3G/4G data sharing
- Printer Server Multifunctional printer support (Windows only) LPR protocol support
- Download Master Support bt, nzb, http, ed2k Support encryption, DHT, PEX and magnet link Upload and download bandwidth control Download scheduling
- AiDisk file server Samba and FTP server with account management
- IPTV support
- OS Support

Windows® 10 Windows® 8.1 Windows ® 8, 32bit/64bit Windows® 7, 32bit/64bit
Windows® Vista 32bit/64bit Windows® XP , 32bit/64bit
Mac OS X
Linux

b. Transformer Monitoring System – Software

The TMS module has the following IEEE2030.5 function sets. Each of these Servers control clients in the EVSE and/or PEV:

- DCAP Server – TMS device capabilities for use by EVSE and PEV.
- Demand Response Server – Controlling Demand Response Client in the EVSE.
- DER Server – Controlling DER Client in the PEV.
- EDEV Server – Controlling the EDEV clients in EVSE and PEV.
- EPwrStat Server – For PEV state information.
- Flow Reservation Server – Controlling the charging of PEV.
- FSA Server – Controlling FSA Clients in EVSE (DR) and PEV (DER).
- Time Server – Serving Time Clients in EVSE and PEV.

The energy-balancing algorithm implemented in the Transformer Controller using the input from the TPMU and by controlling either the EVSE load or PEV Load and Generation optimize secondary voltage from the transformer.

c. Functional specifications

The TPMU will collect data every 1 minute and upload data to a server for permanent storage

The TMS will perform the following algorithms:

- If the transformer temperature is too hot, will indicate a load reduction to the EVSEs
- If the transformer current is above a threshold, will indicate a load reduction to the EVSEs
- If the transformer voltage is below a threshold, will attempt to request power to flow to grid

Algorithm Rule Set

1. Transformer will not be overloaded or T MAX rise above XMR Tmax [Over Arching]
2. TMS will ask for energy to hold up grid voltage if TPMU voltage is < 219V ac [Voltage Regulation]
3. Pure Electric Vehicles are priority charged to User SOC Min
4. Hybrid Electric Vehicles will be charged to User SOC Min next
5. Time of Day (TOD), Weather (WX), and Photo Voltaic (PV) capacity are impactors to the Grid Control schema
6. A leading Power Factor measurement from the TPMU will determine if excess power is flowing into the grid – Vehicles will charge to above User SOC Max but can charge to Vehicle Battery Max SOC
7. During times when grid is stable based on Voltage, PF and Utility DR controls, TMS will attempt to charge vehicles to Battery SOC Max
8. TMS Charging Priority is Battery Max SOC, but if the vehicle Min SOC is maintained the vehicle may participate in V2G operations

3. V2G System Algorithm Implementation

The Transformer Management System (TMS) app performs the following high-level functions

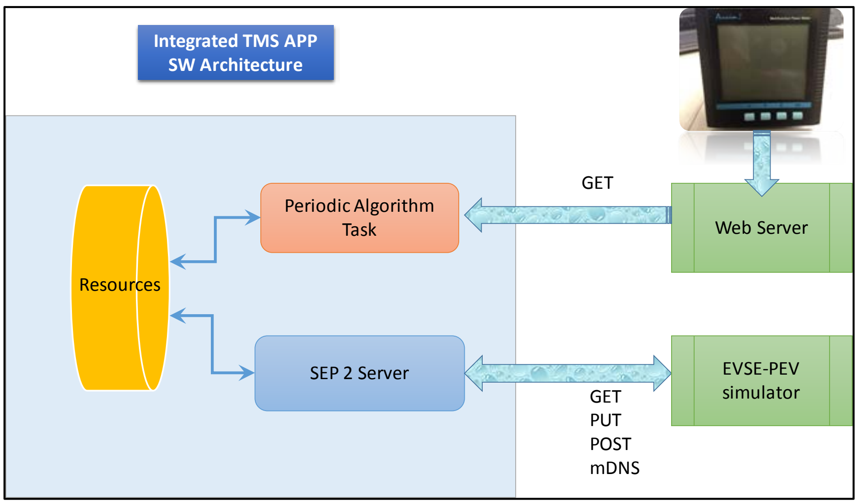
1. TMS app executing on a Linksys Gateway / Router.
2. Read Transformer parameters from ACUVIM energy meter.
3. Execute algorithms that
    a. Collect the following constraint or parameter data (Inputs)
        i. Voltage, Current, Temperature of Transformer
        ii. Number of connected vehicles, current SOC of battery of vehicles, Time charge must be ready
    b. Decide to do one of the following functions (output)
        i. Discharge Available Vehicle battery to support the grid during peak periods
        ii. Schedule charge so that the transformer is not over loaded, and all vehicle are charged and ready to go by the time specified
        iii. Hold off charging of some vehicles if Transformer is too hot or taking too much current.
4. Upload transformer and algorithmic data to the Keypath server

This section details all the algorithms used in the EVSE and TMS that supports the complete functioning of the system.

EVSE Algorithms

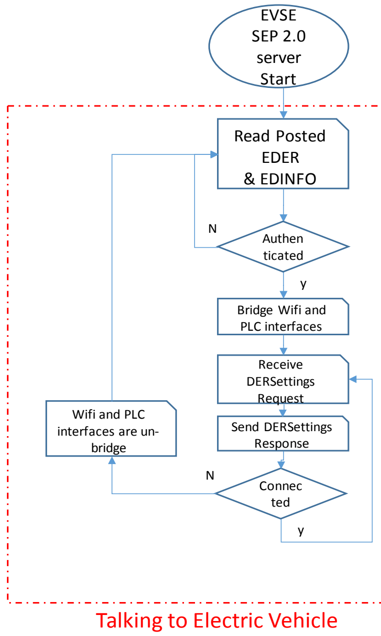
The basic flowchart for the EVSE SEP 2.0 Client implementation is shown in Figure 49. The SEP 2.0 client communicates to the SEP 2.0 server running on the TMS through the Wifi interface, and after successful authentication, downloads the whitelist of allowed SEP 2.0 clients that are associated with Electric Vehicles. Then it continuously polls the state of vehicles (connected, disconnected, sleeping) and reports them to the TMS. Once on vehicle joining and vehicle leaving the EVSE SEP 2.0 client will report these changes to the TMS using mfinfo field, as there is no special SEP 2.0 message for this purpose. In addition, the SEP 2.0 client checks to see if any DR events are scheduled for the EVSE. If an event is available and a non-zero duty cycle is specified, the EVSE will toggle the pilot line to wake up the vehicle connected to this EVSE.

Figure A-2: Integrated TMS APP Software Architecture



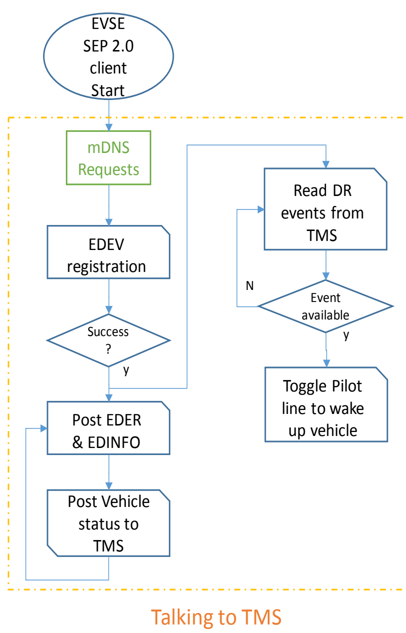
Source: EPRI

Figure A-3: High-level Flowchart of SEP 2.0 Server Executing in the EVSE



Source: EPRI

Figure A-4: High-level Flowchart of SEP 2.0 Client Executing in EVSE



Source: EPRI

Transformer Management System Algorithm

The major components of the TMS app are:

1. Transformer Management Engine
2. SEP 2 Server

The different algorithms and pseudo-code for the Transformer Management engine are explained below.

The algorithm task will execute periodically as a sub-task in the main application. This task will perform the following

- ✓ One time initialize Function will perform the following
  - Read program parameters from file
    - Read the GridNominalVoltage (default: 240V)
    - Read the GridVoltageRangePercent (default: 15 percent)
    - Read the TransformerRatingKW (default: 50)
  - Read Battery capacity from file (each line will contain sfdi, <batterycapacity in KW> (default value: 25 KW, e.g., Tesla 75KW, Chrysler 50KW etc.)
- ✓ Get the webpage of data from the webserver running on the ACUVIM energy meter
- ✓ Read the voltage, current and power for the 2 phases from the energy meter every 10 seconds. Upload the parameters read to a cloud server for archival storage.
- ✓ If voltage is zero, exit function
- ✓ Method of reading temperature (Not implemented in this iteration)
- ✓ If temperature is zero or out of range, exit function
- ✓ Read DREvent, start Time, and DurationInMins from webpage.
- ✓ Get the number of edev registered in the resources section. Vehicles that have connected would be posting DERSetting and DERAvailability to the server at regular intervals. The EVSE that is connected to the vehicle will report the availability of vehicle by reporting the PEV SFDI to the TMS, and hence the TMS will use this info to identify the list of available vehicles.
- ✓ For each of the connected vehicles (assumes the vehicle has posted the required resources)
  - Get the DERSettings Resource: Read the parameters SetMaxChargeRate, SetMaxChargeRateMultiplier, SetMaxDischargeRate, SetMaxDischargeRateMultiplier from the DERSettings resource.

- Get the DERAvailabilty Resource: Read the availabilityDuration and maxChargeDuration from the DERAvailability resource

- Get the DERStatus Resource: Read the current SOC from the DERStatus resource. Any data available in the server will be used as it. It is the responsibility of the vehicle to post DERStatus at regular pre-defined intervals.

- Get the PowerStatus Resource: Read the target SOC and TCIN (Time Charge is Needed) from the field PEVInfo.

- If the vehicles go to sleep, the last previous value is used stored till next reported signal is received.

✓ Compute the time in seconds required to charge each of the devices

- Charge Time in seconds =

((1000*Battery Capacity KWh) *(targetSOC-currentSOC) / (maxChargeRate W)) * 3600

- Charge time available = Minimum (computed charge time in seconds, availability duration)

✓ V_lower = (1 – (GridVoltageRangePercent/100)) * GridNominalVoltage

✓ V_upper = (1 + (GridVoltageRangePercent/100)) * GridNominalVoltage

✓ If (Va+Vb) is in range (V_lower, V_upper)

- If DREvent is 1 and current time is in range (start time, start time + durationInMins)

  - GridSupport needed: Schedule Vehicle Discharge

- Else

  - IF Current <= THRESHOLD_CURRENT

    - Schedule Normal Charging

  - ELSE

    - Do not allow any vehicles to charge.

  - END IF

- End if

✓ ELSE If (Va+Vb) < V_lower

- GridSupport needed: Schedule Vehicle Discharge

- ✓ ELSE If (Va+Vb) > V_upper
  - PV Support: Not implemented in this phase.
- ✓ END IF

Schedule Normal Charging

- ✓ Allocate weight factors to each device as per the following criteria
  - Vehicles that need to have charge earlier will get a highest weight factor of 8 (the project team is assuming here a max of 8 vehicles), and the weight factor will drop to 1 for the vehicle that needs to be ready last.
  - Update the weights obtained in the previous step per the target SOC – current SOC. Vehicles with difference of (target SOC – current SOC) in the range 90-100 will get the highest weight factor of 9, and so on till it reaches 1 (see table below)
  - Update weight factor obtained in the previous step per the vehicle type (Vehicle types are identified in a vehicle_types.txt file (format: each line contains <vehicle allocated sfdi>=<PEV or HEV or Other>). PEV type vehicles will get highest weight factor of 50, HEV will get a weight factor of 10, and other will get a weight factor of 1.
- ✓ Max Power Allowed = Transformer Rating
- ✓ CurrentPower = 0;
- ✓ Iterate through the list of weight factors and perform for each vehicle in descending value of weight factors: while CurrentPower < Max Power Allowed
  - Compute the current required for charging this vehicle
    - CurrentPower += vehicle charge rate
    - Instruct this vehicle to Charge (i.e. setup DERControl for this vehicle to charge at maximum capacity)
  - End if

Grid Support: Schedule Discharging

- ✓ Setup Grid Support for 30 mins (which will be checked during the next algorithm iteration loop)
- ✓ For each vehicle in Active Vehicle list
  - If vehicle type is HEV

        - If currentSOC > (MinSOC_HEVDischarge)
            - Compute DeltaSOC -> how much will the Battery SOC reduce if discharged at discharge rate reported by device for 30 mins
            - TmpValue W-Sec = (Batt Capacity W-sec) * ((targetSOC-currentSOC+DeltaSOC) / 100)
            - ChrgTimeTargetSOCSecs = TmpValue W-sec / (Max Charge Rate W)
            - If (current time + (ChrgTimeTargetSOCSecs)) < TCIN (Time Charge Is Needed)
                - Setup Discharge at max capacity (i.e setup DERControl for this vehicle to discharge at maximum capacity)
            - End if
        - End if
    - Else if vehicle type is PEV
        - If currentSOC > (MinSOC_EVDischarge)
            - Compute DeltaSOC -> how much will the Battery SOC reduce if discharged at discharge rate reported by device for 30 mins
            - TmpValue W-Sec = (Batt Capacity W-sec) * ((targetSOC-currentSOC+DeltaSOC) / 100)
            - ChrgTimeTargetSOCSecs = TmpValue W-sec / (Max Charge Rate W)
            - If (current time + (ChrgTimeTargetSOCSecs)) < TCIN (Time Charge Is Needed)
                - Setup Discharge at max capacity (i.e. setup DERControl for this vehicle to discharge at maximum capacity)
            - End if
        - End if
    - End if
- ✓ End for
- ✓ Sample values for
    - MinSOC_HEVDiscarge = 25 percent (parameter)

- MinSOC_EVDischarge = 50 percent (parameter)

Table A-1: Sample Computation of Delta SOC

batt cap KWh	Specified	25
batt cap Wh	batt cap KWh * 1000	25000
batt cap W-Sec	batt cap Wh * 3600	90000000
discharge rate W	Specified	6600
discharge time mins	Specified	15
discharge time secs	discharge time mins * 60	900
current SOC	Specified	60
energy available W-sec	(current soc/100) *batt cap W-sec	54000000
discharge energy W-sec	discharge time secs * discharge rate W	5940000
energy remaining after discharge W-sec	energy available W-sec - discharge energy W-sec	48060000
new SOC	(energy remaining W-sec / batt cap W-sec) *100	53.4
delta SOC	current SOC - new SOC	6.6

Source: EPRI

Weighing Factor for Vehicle Charging Priority

Weighing factor allocated based on the following parameters

- ✓ time to charge is earlier gets higher weight factor
- ✓ (target soc – current soc) higher gets a higher weight factor

Let us assume there are 8 vehicles and the target and let us assume that T_i represents the timeChargeisRequired parameter for that vehicle. Let us sort the timeChargeisRequired variable so that $T_1 < T_2 < T_3 < T_4 < T_5 < T_6 < T_7 < T_8$ which implies timeChargeisRequired is least for T1 which corresponds in this case to vehicle 1

Table A-2: Charge Time and Weight Factor

Sorted time charge is required variables	Weight factor
T1	8
T2	7
T3	6
T4	5
T5	4
T6	3
T7	2
T8	1

Source: EPRI

Similar weighting factor for battery (target soc – current soc) is shown below.

Table A-3: Target -Current SOC and Weight Factor

Target soc – current soc	Weight factor
90-100	18
80-89	16
70-79	14
60-69	12
50-59	10
40-49	8
30-39	6
20-29	4
0-19	2

Source: EPRI

Similar weighting factor for Vehicle types is shown below (server has a list of SFDI and vehicle types as a text file: Each line is <sfdi value>=PEV/HEV/OTHER).

Table A-4: Vehicle Type and Weight Factor

Vehicle type	Weight factor
Electric Vehicle	50
Hybrid Electric Vehicle	10
Other	1

Source: EPRI

Instructing PHEV or PEV to charge/discharge pseudocode

- ✓ Identify the SFDI (LFDI) of device that needs to be instructed to charge, say {pev-id}.
- ✓ Read the /edev/{pev-id}/der/1/derg (setting reported by the device) resource and read the attribute "setMaxChargeRate" and "setMaxDischargeRate" and the corresponding multiplier field. Let the read value of setMaxChargeRate be MAX_CHARGE_RATE and multiplier be MAX_CHARGE_RATE_MULTIPLIER. Similarly let the read value of setMaxDischargeRate be MAX_DISCHARGE_RATE and corresponding multiplier be MAX_DISCHARGE_RATE_MULTIPLIER.
- ✓ Read the /edev/{pev-id}/der/1/dera DERAvailability. Read the attribute availabilityDuration and store it in variable AVAILABILITY_DISCHARGE_SECS. Read the attribute maxChargeDuration and store it in variable AVAILABILITY_CHARGE_SECS. Read the readingTime attribute and store it in AVAILABILITY_UPDATE_TIME.
- ✓ Read the /edev/{pev-id}/der/1/ders DerStatus data for device. If it contains an attribute "stateOfChargeStatus", then read the value and store data as CURRENT_SOC
- ✓ Read the Powerstatus object for device {pev-id}, then if it contains a PEVInfo object, read the attribute "timeChargeisRequired" into variable TIME_CHARGE_REQUIRED, and then read the attribute "targetStateOfCharge" into the variable TARGET_SOC
- ✓ Read the /edev/{pev-id}/der/1/derp DERProgramList which contains a DERProgram definition. From that definition read the href attribute of the DERControlListLink
- ✓ Get the DERControl defined in the DERControlListLink read above
- ✓ Update the following parameters in the DERControl if it exists else create a DERControl in the DERControlListLink defined earlier.
    - o Generate a new mRID value and update the mRID field

  - Update Description (if charging set to “Charging DER”, and if discharging set to “Discharging DER”)
  - Update Creation Time
  - Update duration field of “Interval” and update start field of “Interval” as current time
    - Computation of duration could be a fixed value of 30 mins (1800 secs)
  - Update opModFixedFlow field of “DERControlBase” with values according to the following rules
    - If needed to charge set this value to MAX_CHARGE_RATE x 10 ^(MAX_CHARGE_RATE_MULTIPLIER)
    - If needed to discharge
      - If (AVAILABILITY_UPDATE_TIME + AVAILABILITY_DISCHARGE_SECS) > current time, then
        - set this value to MAX_DISCHARGE_RATE x 10 ^(MAX_DISCHARGE_RATE_MULTIPLIER)

- ✓ If the charge rate is non-zero (i.e. 25 percent or 100 percent), and the vehicle reported SOC is less than the required target SOC, and the vehicle is connected and sleeping, a DR Event with a duty cycle of zero for a duration of 2 seconds is scheduled for the EVSE connected to the vehicle. When the event reaches the EVSE, the EVSE will toggle the pilot line and wakeup the vehicle.

- ✓ If discharge rate is non-zero, and the vehicle reported SOC is greater than MININUM SOC, and the vehicle is connected and sleeping, a DR event with a duty cycle of 0 for a duration of 2 seconds is scheduled for the EVSE connected to the vehicle. When the event reaches the EVSE, it will toggle the pilot line to wake up the vehicle.

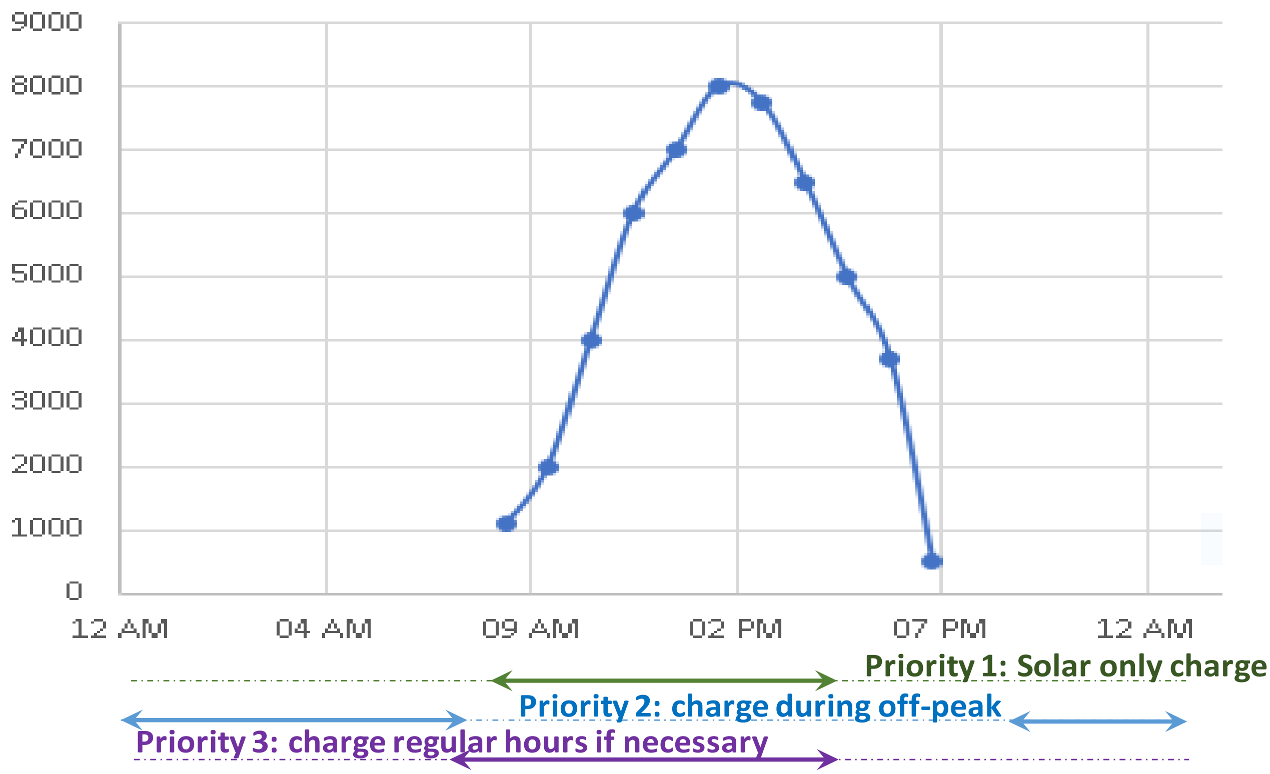
Charging based on Solar and Home usage Data from Flat file Charging is based on the following three priorities

Priority 1: Charge all vehicles using solar production (based on available solar data)

Priority 2: Charge vehicles off peak hours (8 PM to 7AM)

Priority3: If vehicles still need to charge, charge during regular hours (7 AM to 5PM, avoid neck of Duck curve)

Figure A-5: Optimal Charging Times Based on Priorities Relative to Solar and Home Energy Usage Data



Source: EPRI

- ✓ Solar data for the next day will be read from a website and written to a flat file in csv format. The file shall contain the data in the following format
  - Each line will specify the power generated by the solar panel and will contain the following values separated by commas
  - Hour (24-hour format, range 0-23), minute (range 0-59), second (range 0-59), watts
  - Data will be provided in 5-minute intervals
  - The file will contain data for 24 hours i.e. 1 day.
- ✓ Home usage data file format: TBD
- ✓ The data in the solar data file is read by the TMS algorithm into an array of double
- ✓ Sort the data in array according to maximum value
- ✓ For each element in sorted array with values > 0 **and** time charge is required by is in the available time set of the solar data **and** vehicle still needs charging
  - **Utilize Solar Only Power**
  - Tmp_power_watts = – 8* solar power watts read from file
  - For each vehicle that needs to charge in order of priority and tmp_power_watts < 0
    - Set vehicle to charge at 100 percent
    - Tmp_power_watts += vehicle charge rate watts

        - End for
- ✓ End for
- ✓ Are there any vehicles that still need charging?
- ✓ If Yes
    - Avoid charging during peak hour (neck of Duck curve between 5 and 8 PM)
    - For times between 8 PM and 7 AM
        - If vehicle needs charge and time charge is required is in this time period
            - Tmp power watts = 8*power consumption read from file
            - For each vehicle that needs to charge in order of priority **and** tmp power watts < transformer power watts
                - Set vehicle to charge at 100 percent
                - Tmp power watts += vehicle charge rate watts
            - End for
        - End If
    - End for
- ✓ End if
- ✓ Are there any vehicles that still need charging?
- ✓ If Yes
    - Set vehicles to charge between 7 AM and 5 PM (including solar time slots already used)
        - If vehicle needs charge and time charge is required is in this time period
            - Tmp power watts = 8*power consumption read from file
            - For each vehicle that needs to charge in order of priority **and** tmp power watts < transformer power watts
                - Set vehicle to charge at 100 percent
                - Tmp power watts += vehicle charge rate watts
            - End for
        - End If

        - If vehicle needs charge and time charge is required is in this time period and transformer is not over currenting (assuming a transformer of capacity of 75 KW and 8 home usage read from file)
            - Set to charge at 100 percent
        - End if
- ✓ End if

SEP 2 Server

The SEP 2 server will perform the following tasks

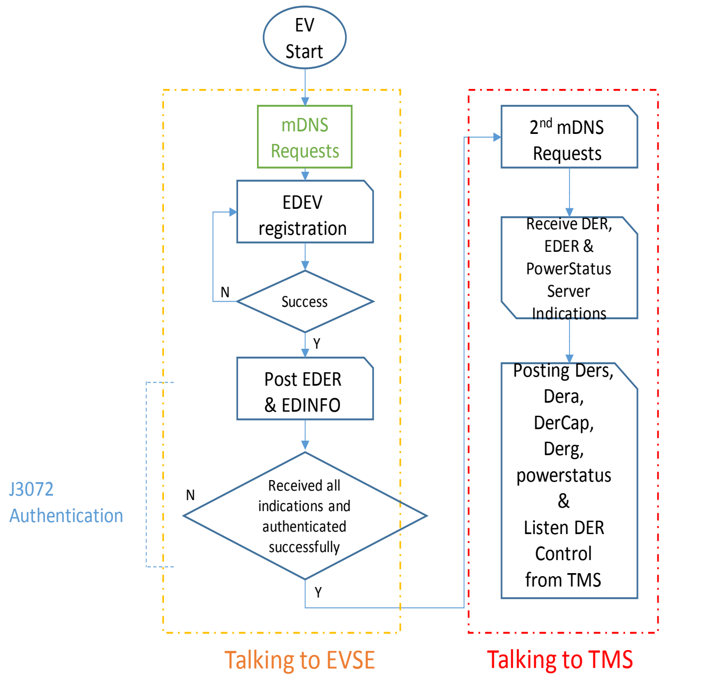
- ✓ Out-of-band registration of SFDIs in whitelist of the SEP 2 server (file in the same directory as server). Additionally, whether the SFDI has been assigned to the EVSE, PEV or EVSE-PEV emulator is also included in the out-of-band registration.
- ✓ On Startup load up basic resources from a file
- ✓ Respond to mDNS queries about the SEP 2 server.
- ✓ Authenticate and create secure communication channels with clients.
- ✓ Respond to data for GET commands from the clients
- ✓ Respond and update resources for POST/PUT commands from the clients
- ✓ Create DER and DR resources for use by the clients based on the algorithms described above.

Electric Vehicle Algorithms

The SEP 2.0 client in the electric vehicle will have to communicate with two SEP 2.0 servers and maintain connection to both of them. A high-level flow diagram of the system is shown in Figure 111 below. The SEP 2.0 client must perform the following steps in sequence.

- Send out the mDNS and locate the EVSE SEP 2.0 server.
- Post the DEVICE Info
- Read the DERSettings periodically.
- If the setStorConnect field is true (part of J3072 protocol), start a new process with the next step.
- Send second mDNS request. The client will receive responses from both the EVSE SEP 2.0 server and TMS SEP 2.0 server. The client will need to differentiate the two servers and store them so that it can report the required messages to the different servers.
- Post the DERSettings, DERCapability, DERAvailability, DERStatus, and PowerStatus messages to the TMS SEP 2.0 server.
- Listen for and read any DERControl messages setup by the TMS SEP 2.0 server and send the information in those messages to the “CAN to SEP” process executing in the electric vehicle subsystem.

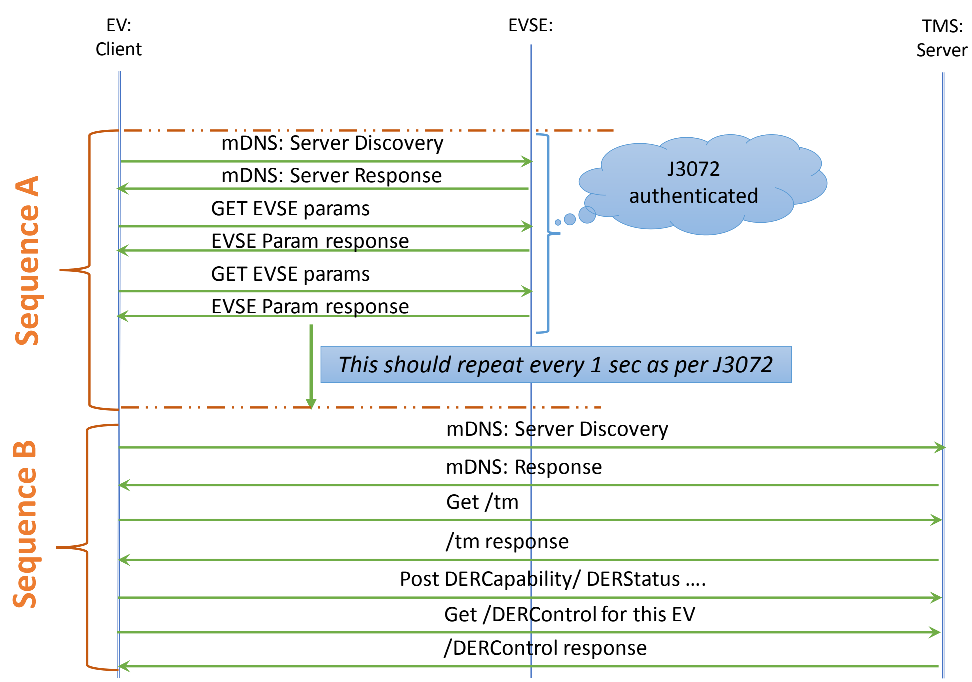
Figure 10: High-level Flowchart of the SEP 2.0 Client in the Electric Vehicle



Source: EPRI

A high-level sequence diagram indicating the two continuous signals being exchanged is depicted in Figure A-7 below.

Figure A-7: Sequence Diagrams in an Electric Vehicle SEP 2.0 Client



Source: EPRI

4. V2G System Configuration Requirements

Table A-5: High-level V2G System Architectural Requirements

Ref. ID	High Level Requirement
S1.0	The system consists of one TMS and up to 8 Customer Premises
S1.1	The system shall support more than one EVSE/PEV at each customer premise up to a maximum of 12 per complete system
S2.0	The TMS is mounted at the Local Distribution Transformer
S2.1	The TMS communicates over the shared 240v to each Customer Premise using HomePlug AV PLC bridge
S2.2	A Phase coupler will be used at the TMS to ensure that the PLC signal is sent to both phases
S2.3	The TPMU shall measure the Voltage, Current and Phase of the secondary output of the Local Distribution Transformer and will send this data on request to the Transformer Controller for processing using wired RS-485
S3.0	The Transformer Controller hardware shall be based upon a standard commercial product
S3.1	The Transformer Controller will act as a IEEE2030.5 (SEP2.0) server for communication to the EVSEs and PEVs at each Customer Premise over Ethernet to the TMS PLC Bridge
S3.2	The energy-balancing Algorithm will be implemented in the Transformer Controller using the input from the TPMU and by controlling either the EVSE load or PEV Load and Generation
S4.0	A commercially available PLC to WiFi Access Point Gateway shall be deployed in each premise and will use a Unique WiFi SSID for each premise. It may be plugged into any 15A socket and shall be sited within WiFi range of the EVSE
S4.1	All the PLC Gateways shall use a common encryption passcode, randomly configured using the push button method. This unique key will not be known by anyone as this is self-generated
S5.0	The EVSE shall be based upon a commercially available product and modified to add the WiFi, HomePlug™ GP and Computing to implement IEEE2030.5 functionality
S5.1	The EVSE shall connect to the WiFi Access Point in each premise and Auto-discover the Server at the TMS
S5.2	The EVSE shall use HomePlug™ GP over J1772™ Pilot Connection as specified in SAE J2847/2 to communicate to the EVSE
S5.3	The EVSE shall implement an IEEE2030.5 Client to communicate with the TMS IEEE2030.5 Server to manage the loads of PEV using J1772™ that do not communicate or authenticate correctly

S5.4	The EVSE shall implement an IEEE2030.5 Server to communicate to a PEV to Authenticate and Authorize connected PEVs and to implement SAE J3072 for DER Capable PEVs
S5.5	The EVSE shall configure the EVSE as an IP bridge when a PEV has been Authenticated
S6.0	The PEVs may be commercially available PEVs (just with Load control) or prototype PEV with DER capability
S6.1	PEV shall connect to the EVSE using SAE J1772™ and may communicate using HomePlug™ GP over J1772™ Pilot Connection as specified in SAE J2847/2
S6.2	PEV may implement an IEEE2030.5 Client that Authenticates and Authorizes to the EVSE and implements SAE J3072 for DER
S6.3	The PEV may implement the IEEE2030.5 Client to communicate to the TMS, when the EVSE has bridged the connection, after the PEV has been Authenticated
S6.4	The ISMs of the participating PEVs are compliant with section 4.3.3 of SAE J3072 specifications and indicate system type A1 (SEP2.0).

Source: EPRI

Table A-6: High-level System Requirements for the EVSE

Ref. ID	High Level Requirement	Project Responsibility
E1.0	Shall be based upon a SAE J1772 Level 2 EVSE	AV
E1.1	Shall support charging a single PEV	AV
E1.2	Shall support bidirectional power flow	AV
E1.3	Shall support the measurement of the voltage, current, power, energy, and grid frequency at the PEV side of the EVSE	AV
E1.4	Shall support the state and control of the SAE J1772 pilot wire	AV
E1.5	Shall support the EVSE data in E1.3 and E1.4 and be made available over a serial port to the software – see E3.0	AV
E1.6	Shall support communications to the PEV using HomePlug-GP PLC over SAE J1772 Pilot wire as defined in SAE J2931	AV
E2.0	Shall communicate with the Home Gateway using 802.11n Wi-Fi Client	AV
E2.1	WiFi Client shall use WPS Mode to discover the Home Gateway	Kitu
E3.0	Shall use a Linux Processor with required resources to support the communications and load management software	AV

E4.0	Shall support a communications software bridge mode when data traffic is destined to PEV from Wi-Fi Interface to HP-GP Port	Kitu
E4.1	Shall support a IEEE2030.5 Client on the Wi-Fi Port (software requirements defined below)	Kitu
E4.2	Shall support a IEEE2030.5 Server on the HP-GP port (software requirements defined below)	Kitu
E4.3	Shall provide a means of provisioning and storing the SAE J3072 interconnection parameters	Kitu

Source: EPRI

Table A-7: High-level Requirements for the TMS Application

Ref. ID	High Level Requirement
A1.0	The energy balancing application shall reside on the Transformer Controller only
A1.1	It shall be possible to load a different application for testing
A1.2	It shall be possible to download data sets from the application for offline analysis
A2.0	The Local Distribution Transformer state shall be obtained from data provided by the TPMU
A2.1	The PEV Departure Time and amount of Energy required at Departure Time will be obtained from the PEV using the IEEE2030.5 Flow Reservation Function Set (Set by the user at the PEV or PEV App)
A2.2	Other parameters may have to be hard coded by the application, such as amount of discharge allowed or the list of approved ISMs
A2.3	The TMS is provisioned with each of the participant EVSE and PEV SFDIs and default PIN (111115)
A2.4	The Application shall obtain the state of the PEV or EVSE using IEEE2030.5 Function Sets
A2.5	The Application shall set the charge or discharge of the PEV using the IEEE2030.5 Function Sets
A2.6	The compliance of PEV's Inverter System Model to SAE-J3072 is verified using the Inverter System Information detailed in Section 4.6.4.7 of the SAE-J3072 specifications. The EVSE uses this information to give authorization for the PEV to discharge into the grid
A3.0	The application shall always ensure that the PEV has the requested energy by the requested departure time

Source: EPRI

APPENDIX B: Technology Deployment, Test, and Data Collection Details

Test Protocol

Assumptions

The following components were available, and system integrated prior to testing:

Table B-1: Required Components Prior to Testing

Sub-System	Description	Alternative Configuration
1	TMS with TPMU	TMS with Transformer Emulator
2	Gateway	None
3	EVSE	University of Delaware for Phase 1 or AV for Phase 2 or None if using PEV emulator
4	Honda Accord PEV or Chrysler Pacifica or any PEV with J1772 Control (load only)	PEV Emulator (EVSE not required)

Source: EPRI

Note: The Transformer emulator was used with the PEV Emulator and EVs but the TMS with the TPMU was only used with EVs. I.e. The Lab and Field Testing used the Transformer emulator, but the Demonstration phase only used the TMS with TPMU.

Initial Test setup and procedure

The initial Test setup may be completed in the lab, if the Transformer and PEV emulator are used and is recommended as the first step.

Initial setup would use the following configuration:

- Sub-System 1: Configured with Transformer Emulator
- Sub-System 2: Connected
- Sub-System 3: Not used
- Sub-System 4: PEV Emulator connected to Gateway – with a single PEV configured as connected and charging

Testing Use Cases

There were two main Use Cases but many different Scenarios:

Use Case #1 Residential

- Typically arrives in late afternoon or evening

- Long dwell times
- May include PEV's that are used and charged during the day

Use Case #2 Day Time Charging E.g. Workplace

- Typically arrive in the morning
- Long dwell times for Workplace
- Short dwell times for some other scenarios (Shopping, Eating etc.)

Scenarios varied dependent upon:

- Arrival and Departure Time of each PEV
- Vehicle Type: Battery Capacity, max. Charging Rate
- Vehicle SoC at arrival
- Energy required at Departure Time (This was calculated by the PEV based upon the Drivers desired state of Charge at departure time and accounts for other non-battery loads such as cabin conditioning)
- Participation in Utility or ISO events

There were three distinct phases for each session:

1) The arrival session and preparing the battery for the Phase 2.
    a. Dependent upon the next phase first event requirements i.e. load or a generation to balance the transformer
2) Participation in balancing events i.e. Over or under generation
3) Restoring the battery to drivers requested battery state by departure time

Notes:

1. *For each use case session 1 and 3 are identical*
2. *Phase 1 and 2 may never get executed if PEV dwell time is less than Phase 1 + Phase 3*
3. *Participation in Utility or ISO events will be executed only if Phase 3 can be completed*

Initial Test Procedure

The TMS simulated a Utility Demand Response Load Control to reduce the connected PEV load to 10 percent.

Required Result: The PEV Emulator shall reduce the charge and the Transformer Emulator shall report the same reduction

This initial setup may be used to test other configurations of TMS, EVSE and PEV's

Test Procedure

For each use case defined, the testing protocol shown in Table B-2. shall be used to define the scenarios for the use cases to be tested.

The results shall be captured, together with the input data for later analysis

Notes:

1) The PEV details shall be recorded for up to 8 PEV's
2) PEV Types that are not available may use the PEV emulator

Table B-2: Test Protocol

	Use Case 1	Use Case 2
Setup		
Transformer Profile		
Utlity Events		
ISO Events		
To be completed for up to 8 EV's		
EVSE #n		
EV #n		
EV Arrival Time #n		
EV Departure Time #n		
SoC #n		
Required SoC #n		
Battery Threshold #n		
Any other EV events (early departure)		
Result (vs Time)		
EV #n Charge profile		
New Transformer Profile		

Source: EPRI

Results

Information required to be stored and kept for analysis for each PEV and the Transformer is L1-L2 Voltage, Current and Frequency Vs Time at 15 second intervals. This was recorded by the TMU in a file and downloaded and archived at regular intervals.

Transformer Monitoring System Integration and Test

Transformer Monitoring System (TMS)

The Transformer Monitoring System (TMS) is an EPRI developed hardware and software solution to enable the technologies to support V2G grid and aid mitigation of excess PV or DER generation on the grid. Further the hardware and software were constructed to operate on mixed data originating from simulation data files or real-time meter data, or a combination of both. A simple internet file may be posted by the utility to request voltage or frequency grid support from all devices "listening" on the web.

The hardware constraints were to use commercial off-the-shelf devices and open source code for the system. The hardware consists of an internet router, revenue grade meter, and required vehicle charging / discharging devices, while the software is an OpenWRT router code running in a Linux environment.

The EPRI innovation in the TMS system was to demonstrate a commercial internet router running not only router code as an ordinary router, but to also show the feasibility of running TMS code on the router itself.

Specifically, in the V2G application, EPRI code was developed to concurrently run a simple AI engine to solve vehicle charging, grid support, and excess PV production based on one residential transformer providing power to eight (8) homes with a mix of vehicle charging, PV, and V2G capabilities. This AI engine was set with a "rule set" to protect the transformer, charge all vehicles to be always "ready-for-use" and modify the local duck curve to lower distribution energy peaks and raise energy dips from excess PV. Further the utility can post a file on the internet to the router for 24-hour look-ahead for grid support, PV, or modify the grid support on-the-fly for any 5-minute interval within the 24-hour period.

Finally, the TMS code running concurrently on the router can monitor files posted as a simulation file of energy, PV production, vehicle charging, and transformer temperature profiles to show data graphical results of the simulated data. Data need not only be files of simulated data but may also be real data collected from other sources. An important feature that may be also used is real-time weather as it affects the grid distribution.

Plots of the simulation and duck curve modification results are provided in this report. This system was deployed to the field and results posted in the EPRI report.

Transformer Monitoring System (TMS): Software Components

The TMS has several firmware and software components. The LinkSys router transformer controller (TC) runs a Linux kernel operating system in firmware that executes various programs that communicate with the subsystems that monitor the power and transformer power monitoring unit (TPMU) loading, etc. and communications between the EVSE and PEV over power line carrier hard-lines (PLC router).

The TMS code utilizes the embedded TMS SEP server for those data and communications to the other components, charge controllers, and PEVs. The TMS app uses an AI algorithm to perform the transformer monitoring, reading the various vehicle parameters, and establishing the controls to permit the charging or grid hold up functionality of the vehicle battery. The algorithm is composed of a set of rules that govern the TMS system behavior. The rule set is listed below.

Transformer Monitoring System Functionality

The TMS is composed of the following hardware: LynkSys Router that runs the algorithm, SEP2.0 server, and communications package to read the revenue grade power meter hardware, the associated PLC interface modules, and a PLC router to communicate with the external individual EVSE controller modules. Each EVSE controller module has the PLC router to provide interface to the PEV.

The TMS algorithm software reads the various control files from the utility for DR overrides and the simulation data files as required or posted. The algorithm prioritizes the SOC, minimum PEV SOC, and time to full charge to permit the best local strategy to support the grid or absorb excess PV generation as to meet the driver needs to return to destination. The algorithm uses the vehicle parameters to optimize the grid level support as determined by each individual PEV.

Figure B-7: Transformer Management System Internal Components

Source: EPRI

The TMS system functions in real-time data, simulation data or dual mode of some simulation data, and real-time power data. The TMS also reads files provided via internet to allow PV data real or forecast, to be added to the algorithm results. Documents and pictorials of the system are previously detailed in the TMS report.

The Transformer Monitoring System Integration Test and Evaluation includes the following sub tasks.

1. Integrating available Communications and an available Communication API onto an external transformer management platform:
    a) Using available SEP2.0 Server with Time, Price, DR, Flow Reservation and DER Function sets for connection to Multiple Level 1 or 2 EVSE over HomePlug PLC and;
    b) Using available SEP2.0 Client with Time, Price, DR, Flow Reservation and DER Function sets to communicate over external 4G Modem over Ethernet to the EPRI VGI platform.

2. Design and Integrate communication interface to EPRI transformer measurement platform.
3. Designing a downloadable application layer for the platform that provides the algorithm to manage the charge and discharge of the connected Vehicle via the EVSE based upon: the transformer measurement data of AC current and voltage, Power Factor, and Total Harmonic Distortion (THD) and; the load parameters set by the EPRI VGI platform.

Integrating Communications and Communication APIs

Specific SEP2.0 Server and Client code is written to permit standardized communications to the various components. These are SEP2.0 standardized commands to allow the functions of DR, Time, Pricing, DER control, and Flow Reservation to set the vehicle charging function, vehicle charging rates and error reporting. The Client code is written in the same manner to allow communications to the EPRI VGI platform over external 4G Modem or Ethernet.

SEP2.0 communications testing and validation consists of verbose logging of output commands to insure compatibility and built in error logging of any non-valid SEP2.0 commands resulting in an error code generation and log entry.

Log file reporting will be monitored and reported as a method to evaluate the overall performance at a system level.

TMS Communication Interface and Design

The TMS communication interface takes the form of several applications running simultaneously. These include an application to send the power meter logged data to a specific web server established to permit flexible JSON data strings to be logged and archived. Web service to read files posted to allow DR control from the utility, simulation data, or PV forecast or actual data read as JSON data files. Data is on a 24 hr time period and is based on 5-minute interval data. Each file is specific to that of DR control, PV, or simulation. Data may be changed at any point and will be scanned by the TMS before each 5-minute interval to permit changes on the fly.

Testing and validation consists of logging of data files read by the TMS to insure compatibility and built in error logging of any non-valid data resulting in an error code generation and log entry. The data files are scanned to detect out of range data, invalid data, and malformed data records. They are logged and ignored for that 5-minute interval. A report is generated of the error and reported as a method to evaluate the overall performance at a system level.

TMS Platform Application Layer Design

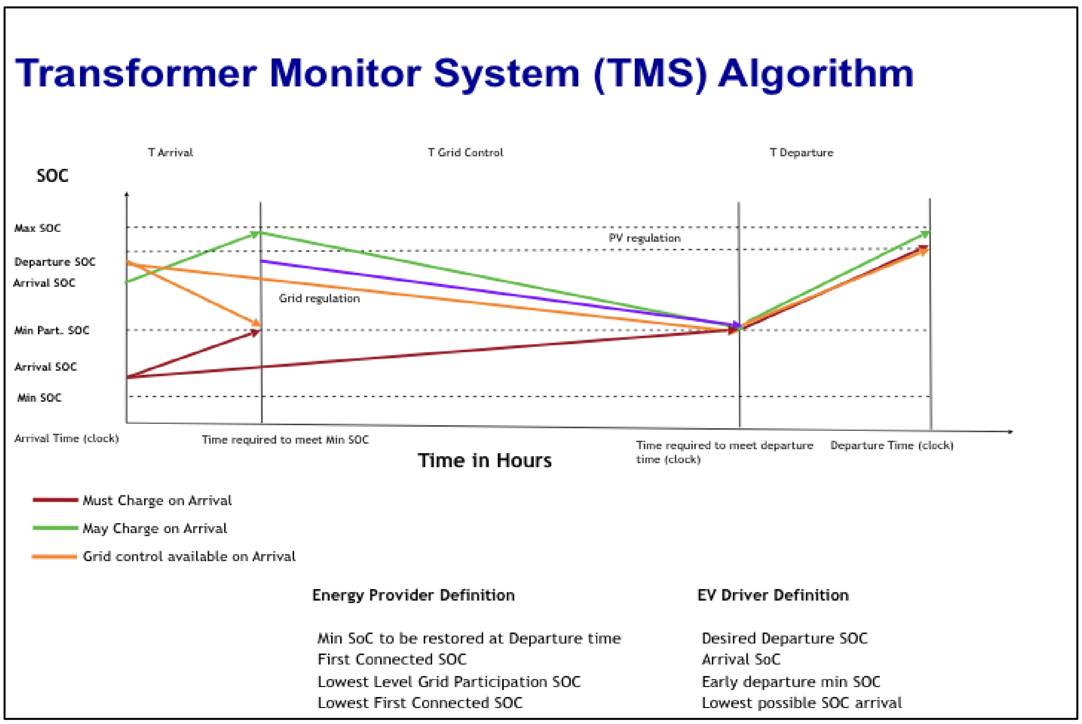
The application layer design for the platform provides the algorithm code to manage the charge and discharge of the connected Electric Vehicles via the EVSE based upon the transformer measurement data of AC current and voltage, Power Factor, Total Harmonic Distortion (THD) and the load parameters set by the EPRI VGI platform. These data are read by the power meter and passed to the algorithm for processing. In addition to the power meter parameters, the SEP2.0 servers and clients associated with driver and PEV preferences for individual vehicles are processed. The overall goal of the TMS system is to support the grid when called for by the utility and reduce or eliminate over-excitation of the serving transformer while maintaining the vehicle at a specific SOC to permit return to home preferences.

Log file data is monitored and reported as a method to evaluate the overall performance at a system level. PEV SOC departure data will be compared to PEV arrival data as a further check on the efficiency of the system. It is expected that data curves of the vehicle SOC and transformer load data will allow validation of the algorithm and system performance. It may also be advantageous to have historical data sets to compare the overall system loads before the TMS deployment.

Transformer Monitor System (TMS) Algorithm

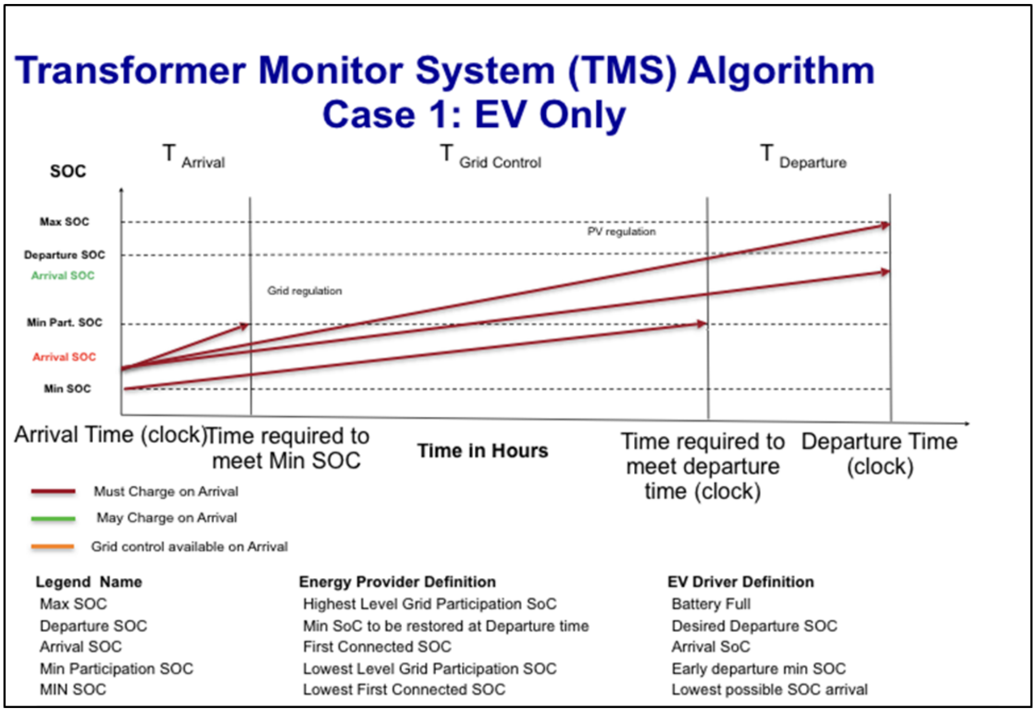
The algorithm is to optimize utilization of the PEV energy storage capacity in a controlled manner that complies with the PEV owner constraints and need for charging. There are 3 cases for the algorithm; PEV charge only, Grid Regulation (charge/discharge per Grid needs), and Excess PV Control (charging/discharging for over/under generation). The time phase segments depending on customer departure time and SOC determines the transition through the control cycles for arrival, grid control, and departure. The following graphs (Figure B-2, B-3, B-4, B-5) depict the representative cycles and definitions of the parameters for each of the algorithmic control segments and reflect relative charge/discharge profiles for each. These represent the design parameters for the algorithms.

Figure B-2: Transformer Monitor System (TMS) Algorithm



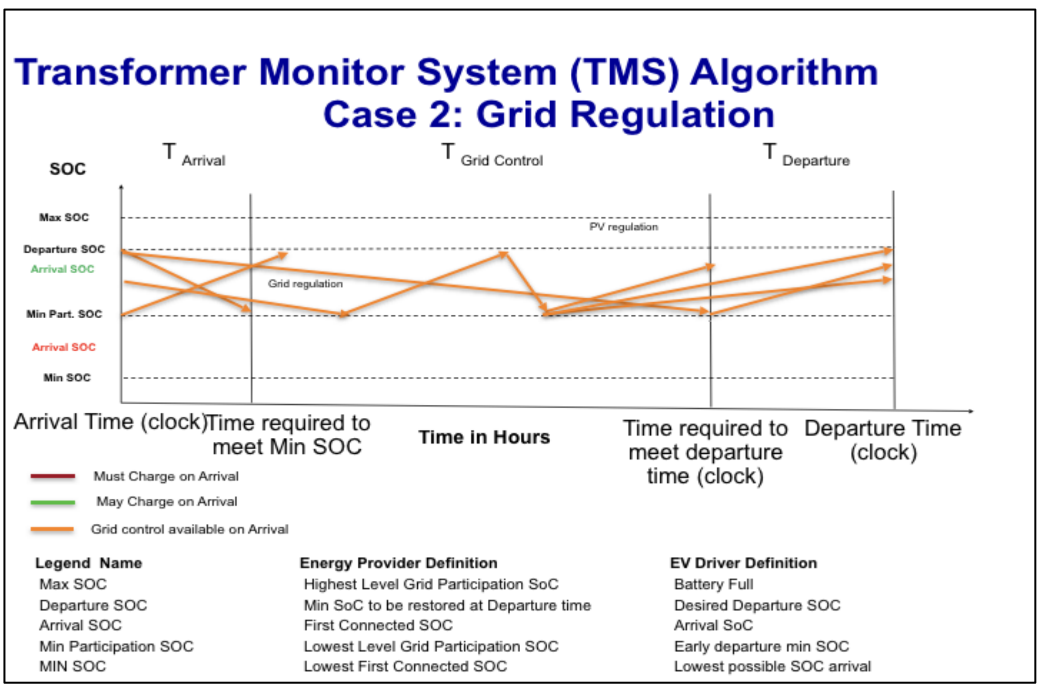
Source: EPRI

Figure B-3: Transformer Monitor System (TMS): Case 1: PEV Only



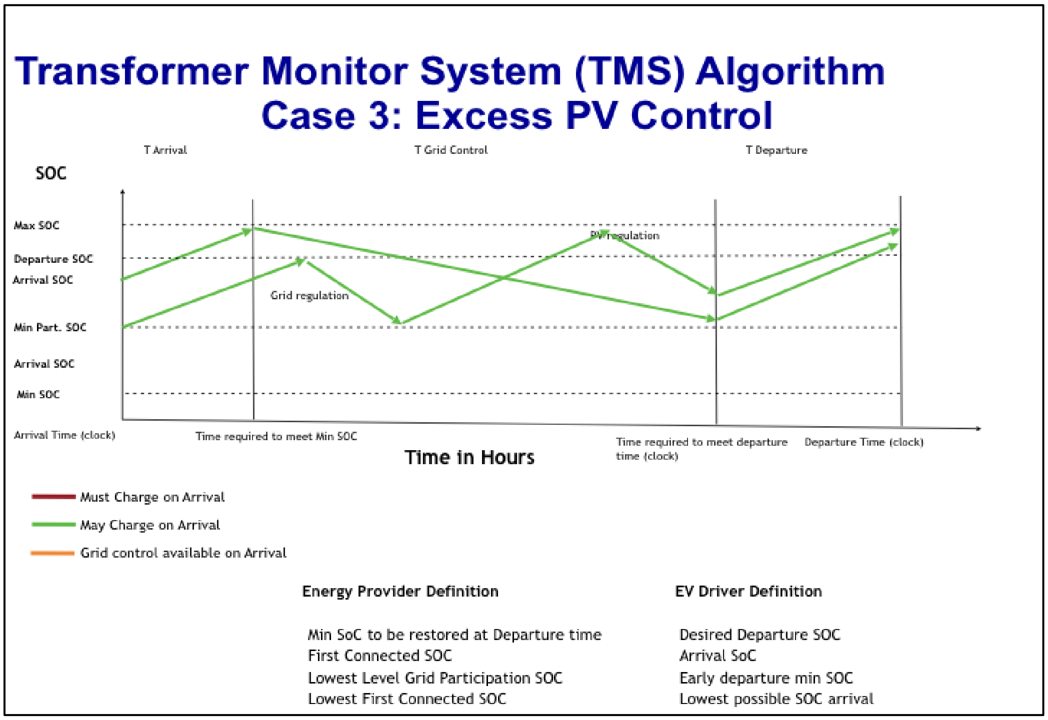
Source: EPRI

Figure B-4: Transformer Monitor System (TMS): Case 2: Grid Regulation



Source: EPRI

Figure B-5: Transformer Monitor System (TMS): Case 3: Excess PV Control



Source: EPRI

Transformer Emulator (TE) Test / Verification Device

Design of the Transformer emulator (Figure B-6) serves two purposes. The first is a test safety issue; to provide 240 vac, but at low current capability and a 25A ac or more, but at low voltage (Phantom Loading). Secondly, it must also provide an isolated 240 split phase that resembles the normal power feed to the residential customer from the utility distribution feeder.

A variac is used to provide the source voltage to the voltage and current sources. The variac also allows the voltage to be sagged to a point where the TMS can react as if the local service points need a grid support to hold the local voltage to nominal during a vehicle-to-grid support function.

The isolation transformer is a 750 VA 4-winding 1:1 transformer. The input windings are parallel connected to the variac, while the secondary windings are configured as a 240 v with neutral. These voltage points are set up as a 4 wire (L1, L2, N, and GND) output to the TMS unit. The current sources are derived from 110v 100W incandescent lights series connected to 25 – 30 turns of 18 ga wire returning to the neutral point on the isolation transformer. The turns of wire passing thru the window of the CT thus provide the Ampere-turns to permit an isolated current output to the TMS.

No provision is made to allow a phase angle change from this test unit. Other test equipment may allow a test to a leading power factor to test the excess PV functionality of the TMS.

Temperature data is also taken from this device since actual transformer data will not be used due to safety concerns with the 480Vac site transformer. Representative temperature heating profiles as specified by the manufacturer for 100 percent overload for 24 hours was used.

Figure 6: Transformer Emulator with Phantom Loading

Source: EPRI

Transformer Emulator Construction

The Transformer Emulator (Figure B-7) will be in a single enclosure with connection to the TMS. Source voltage connection will be 110 vac input to the TE device. Outputs L1, L2, N, G, A1, and A2 will be provided as terminal strip connections with a wire pigtail color coded and marked as:

- L1 – Red
- L2 – Black
- N - White
- GN – Green
- A1 Polarity – Orange
- A1 Return - White
- A2 Polarity - Brown
- A2 Return - White

Figure B-7: Transformer Emulator Internal Components

Source: EPRI

Transformer Emulator / Simulator

TMS simulation testing with Transformer Emulator Interface allowed the TMS testing for grid sag <219 volts, and data recording of known current and voltages. The Transformer Emulator (TE) contains the following elements

- 0.75 Kva Transformer
- Variac to vary output voltage and current
- Incandescent light to provide load
- Loading CTs to provide current

The common Phantom Loading scheme was used for safety during these tests to provide an apparent current of 100 A at 240 Vac to the TMS revenue grade meter. The Phantom loads presented were 100 A @ 1 Vac and 240 Vac @ 0.500 VA.

Measurement and Verification Plan Results

Transformer Monitor System

Transformer Power Meter Unit (TPMU) Hardware as one subsystem of the TMS was checked for accuracy using the EPRI RFL watt-hour meter test stand. Known voltage and current was applied to the TPMU and accuracy recorded as within meter manufacturer specification.

TPMU Power Measurement test verification method consisted of:

- Connecting the Transformer Power Meter unit as a Form 2S common 240v ac house meter. The Form 2S meter was chosen to match the site deployment conditions.
- A Full Load test (240 VAC @ 30 A) was performed per the RFL meter tester instructions and successful results were accuracy of +/- 0.2 percent.
- A Light Load test (240 VAC @ 3.0 A) was performed per the RFL meter tester instructions successful results were accuracy of +/- 0.2 percent

Communications to SEP 2.0 Servers and Clients

All SEP 2.0 IEEE 2030.5 Server and Client tests were lab tested at FCA and Honda prior to site testing. The TMS, Kitu, Honda, and FCA software permitted communications to the TMS, EVCC and EVSE. All systems were final tested on site with the full TMS, PV and vehicles connected.

TMS Low-Voltage V2G Simulation Test

The transformer low voltage test was lab tested using the Transformer Emulator test set. The Variac in the TE allowed voltages applied to the TMS to be sagged to the TMS control setpoint of 219 Vac and the TMS grid control response commands to be recorded. The TMS sent the commands to support the grid in the lab test as captured in the command log files.

PV Over- Production Test

The PV over-production test was validated in simulation from the scenario use cases of summer sunny and cloudy days and winter sunny and cloudy days. The simulation files show the TMS commanding the participating vehicles to charge toward vehicle maximum SOC during peak solar production time of between 11am and 2 pm.

In actual site deployment the two PV generation cases of summer sunny and cloudy days were recorded and additionally during peak grid loading during 6pm to 9 pm, vehicles were discharged into the grid. The PV overgeneration “belly of the duck” and the grid loading “head of the duck” were shown to be mitigated by the V2G TMS system.

Transformer Power Meter Unit (TPMU) Logging Test

With all TE and TMS hardware connected per the TMS system info, logging into the website from the browser permitted observations readings from TPMU. Only last 1000 readings are available on the website for display; however, all data is archived and stored. System Admins can retrieve the data. The TMS records data each minute and uploads data to the website every 5 minutes. The data is JSON formatted.

TMS Site Test and Data Recoding

The TMS was installed on the test site and a 240v AC Split-phase power supply connected. CTs on 240v AC Mains supply to EVSE Charging Stations were installed prior to energization. DO NOT OPEN CTs while mains are energized.

All parts in the TMS were verified as on and working. The Power meter was verified as showing a 240 Vac voltage reading, along with a nominal current, Phase angle, and THD. LinkSys router powered on and connected, a D-Link powered on and connected. Wi-Fi indicators were solid.

Summary

The overall goal to support the grid when called for by the utility and reduce or eliminate over-excitation of the load serving transformer while maintaining the vehicle at a specific SOC to permit return-to-home preferences was demonstrated. Any additional use cases may require modification of the TMS algorithm. The c language coding permits rapid changes and remote downloads to the TMS. It is expected that during the testing period, that new learnings may mandate the need for minor changes in the system. Also, the website will extensively be used to monitor the TMS remotely.

Successful outcomes are the PEV owner always having the required vehicle SOC to complete the drive, the potential to show grid load improvement and noting the fact that PEV support during drive home time will be limited, transformer over-excitation is minimized, and validation that PEV charging time occurs during 11pm to 6 am time frame.

Measurement and Verification Plan

Purpose

Purpose is to identify the protocols used from end to end to ensure compliance to M&V rules established within the appropriate California Independent System Operator (ISO) and Distribution Service Operators (DSO) jurisdictions.

Background

There is significant variability in the rules and requirements for M&V between these jurisdictions which is further complicated by the applied rules and criteria based on the specific type and category of demand response (DR), distributed energy resource (DER), and capacity bidding programs. Examples of such programs are the California ISO Proxy Demand Response (PDR), Non-Generating Resource (NGR), Distributed Resource Auction Mechanism (DRAM) and Distributed Energy Resource Provider (DERP) programs; and utility DSO demand response programs such as SCE Capacity Bidding Program, SCE Power Save Day Program, PGE Supply Side/Excess Supply Capacity Bidding Program, and SDG&E Dynamic Pricing Program.

The primary basis for these programs is they are mostly driven by the resources' capability to reduce, curtail, or shift load in response to dispatchable demand response signals or commands from the respective service operator and require capacity minimums of either 100kW or 500kW and higher. These programs are mostly structured through aggregators such as schedule coordinators that are either certified and/or registered with the California ISO and utilities. Electric Vehicles can participate in most of these programs with basic V1G managed charging functionality, albeit Electric Vehicles at an average charging load capacity of 3kW to 5 KW will require aggregation of 20 to 33 vehicles (all plugged-in and charging at the same time) to achieve the minimum 100kWcapacity threshold. 100KW is the lowest threshold requirement purposely established to enable Electric Vehicles to participate in California ISO/DSO aggregation demand response programs and to achieve some level of compensation. Examples are the PDR, DRAM and DERP programs as well as some utility capacity bidding programs. PG&E's Supply Side/Excess Supply Capacity Bidding Program includes the capability to reduce charging load or increase charging load depending on the conditions of the distribution system. The most obvious need of concern currently is the capability of Electric Vehicles to absorb over-generation of renewables and mitigation of ramping from under-generation of renewables, which is the objective of the PG&E Supply Side/Excess Supply Program, ability to increase or decrease charging load at the appropriate points along the Duck Curve. Most of these programs utilizing Electric Vehicles as a DR resource are in a pilot phase with the purpose to evaluate the fidelity of the process and procedures, the factors affecting the level of customer engagement and participation (i.e. compensation/convenience/automation), and the value proposition to the customer and the ratepayer. The M&V requirements are based on meter verifiable data of the decrease or increase in Electric Vehicle charging load.

There are residential demand response programs such as SCE's Save Power Day Program that can include residential Electric Vehicle charging management at the individual customer level. SCE does contracts with an aggregator for specific connected residential load devices (i.e. Nest for thermostats) to provide the customer engagement and device communications for demand response signaling and control. SCE pays the customer a direct credit ($/kWh) for every kWh curtailed during the prescribed date and time. The M&V is based on the customer whole house meter information verifying the kWh reduction versus an established 10/10 average baseline.

There are no programs presently with any clear definitive guidelines for including and compensating Electric Vehicle V2G energy generation onto the grid. The CPUC Proceeding R 15-03-011 Energy Storage Procurement Framework and Design Program dictating the IOUs purchase 1.3 GW of battery storage includes V2G as a procurable energy storage resource. However, V2G especially utilizing the on-vehicle inverter, still faces the challenge for meeting the CPUC Rule 21 interconnection requirements. The California ISO DERP Program is endeavoring to include V2G as an authorized distributed energy resource with the capability to be aggregated with other customer owned DER assets such as battery energy storage and solar. Even these other DER assets are challenged by the Rule 21 Smart inverter functional and communications requirements. The M&V requirements for the DERP Program are still being defined by the California ISO who is intending to administer the program through their certified schedule coordinators. V2G is presently relegated to small scale pilots within controlled environments such as this project being sponsored by the California Energy Commission.

Preliminary value assessments and cost avoidance modeling directly indicate there is significant potential value to both the customer and the utilities for utilizing V2G as a dispatchable distributed energy resource.

Application

This V2G technology development and implementation project focuses on monitoring and control of 4 V2G capable Plug-In Hybrid electric vehicles at the residential transformer level. The Transformer Management System (TMS) is installed and connected to the transformer and monitors the transformer voltage, current, temperature, and the grid power conditions. It has the embedded IEEE 2030.5 Server Client software, algorithms, and PLC/Wi-Fi communications devices to communicate through the EVSEs with the vehicles to regulate charging and discharging. The TMS measures the solar input and the simulated residential load data and formulates the charging/discharging profile for each individual electric vehicle. The vehicles upon plug-in communicates to the TMS its SOC, min/max SOC, and time charge is needed. Per these inputs and constraints, the TMS determines the utilization of the Electric Vehicles V2G capability to maintain optimum load balance at the transformer circuit.

The TMS is a Virtual End Node for OpenADR 2b communications with an aggregator, energy service provider, utility DSO or ISO, and will receive and execute OpenADR Virtual Top Node requests. It will be able to enact push commands to the Electric Vehicles to charge, stop charging, curtail charging, or discharge according to the signal parameters and within the constraints of the transformer and the Electric Vehicles' battery SOC/capacity and availability.

The TMS has the IEEE2030.5 Server Client software which can enable the TMS to receive DSO Rule 21 SIWG communications either directly from the DSO or from an authorized aggregator. This requires the Electric Vehicles onboard inverter to be a four quadrant Rule 21 enabled or compliant smart inverter. J3072 is utilized for authentication of the Electric Vehicle onboard inverter to meet IEEE 1547 interconnection requirements and is implemented into the EVSE and EVCC communications hardware. However, the demonstration Electric Vehicles are not tested or certified to IEEE1547 at this time. The Honda Accord PHEV was self-tested by Honda and passed all criteria for the exception of one THD parameter. The automakers with the standards bodies still need to address the process for Electric Vehicle onboard inverter certification to IEEE 1547 and UL 1741 requirements.

The TMS has the meter telemetry to monitor and record the transformer conditions and the Electric Vehicle charging/discharging data parameters (start time, end time, kWh consumption/output, charge/discharge power, dwell time, etc.). Data is captured and recorded in 1 min intervals. The system is enabled based on load, solar generation, transformer, and grid conditions to manage Electric Vehicle charging/discharging in real time to maintain a balanced residential transformer load profile thus mitigating reliability issues upstream from the transformer to the feeder. Additionally, in a real residential environment there will be whole house meters measuring the household load profile. The whole house meter and the TMS embedded meter will be able to provide the meter data for measurement and verification of the Electric Vehicle performance for the specific DSO/ISO programs.

The Measurement and Verification Plan for this V2G project is to address monitoring and recording of all intervals of charging power flow data for both charging and discharging within each of the use case scenario control tests.

The control schemes and algorithm validation use cases fall into four areas: Peak Shaving, Over-generation Mitigation, Ramping Power support, and Ancillary Services.

Peak Shaving: In the Peak Shaving mode, the algorithm will attempt to lower the demand charged by the utility by monitoring the KW max during the nominal demand interval each hour and reduce the charging from 100 percent charge rate to a lower value based on the number of PEVs and the anticipated departure time. In this mode of operation a ramp down in charge rate command to the vehicle may be initiated from the end of the previous hour through the end of the demand interval of the current hour. After that time the rate may be ramped up to the max vehicle charging rate. This would be continuous loop until the vehicle SOC user minimum requirements are met. Other influences on the controls algorithm are local grid support (voltage hold up override mode) from the local TMS, and wide-area grid support (brown-out mitigation) as an input from the utility to the TMS device.

<u>Over Generation Mitigation</u>: In the Over-generation Mitigation mode of operation, the algorithm will seek to maximize the local PV generation consumption by charging the vehicle at max charge rate and for duration to maximum vehicle charge until past peak sun-time generation. Local TMS will determine power flow either forward or reverse, use day-ahead solar forecasts of downloaded solar generation data files to minimize the over generation placed back on the grid. As PV systems become more sophisticated, the PV generation curtailment may be from the TMS directly communicating to the PV systems.

<u>Ramping Support:</u> To support Ramping Power mode, the algorithm may set for discharging vehicles into the grid or charging vehicles from the grid. The charging or discharging mode will depend on the positive or negative ramp rate to support grid function. The time of day is very important in the algorithm as the rate of climb or fall of grid power usage will determine certain factors. A regulator or similar device may be used in concert.

<u>Ancillary Services</u>: Ancillary Support will mean a direct input command or solar forecast day-ahead file. In this mode, the TMS will follow direct input control from the utility. The TMS will attempt to deliver power to the grid from V2G operation or PV to grid control operations. V2G operation will be based on minimum vehicle SOC and maintain vehicle usability. PV will obviously depend on time of day and weather factors.

Plug-in Electric Vehicle and Electric Vehicle Supply Equipment IEEE2030.5 and J3072 Integration

The complete V2G integrated system consists of the following components:

- PHEV/ PEV vehicles
- AeroVironment EVSE modified
- 75 KVA transformer
- Solar Panel with inverter connected at the output of the going to the grid
- Energy meter
- Transformer monitoring system

The system consists of a 75 KVA transformer connected to the grid and the solar inverter output. Four EVSEs are powered by the transformer, and there are four vehicles in this system that connect to the four EVSEs. Three vehicles are FCA PHEV vehicles and one is a Honda PHEV vehicle. The Energy meter and the Transformer Monitoring System (TMS) are housed in a Hoffman box, and the energy meter measuring probes are connected to the input side of the transformer. This system has been setup at parking lot in UCSD San Diego,

Component functions

The different parts of the system components perform the following tasks.

- **PHEV/PEV Vehicles**: Vehicles are fitted with a V2G system that supports charging/ discharging from the on-board battery. It receives commands from Transformer Monitoring System over SEP 2.0 (IEEE 2030.5) and reports status to the Transformer Monitoring System using SEP 2.0 messaging as well.
- **EVSE**: The main function of the EVSE was to implement the SAE J2931/4 protocol over the pilot line. In addition to that, for this system, additional support for J3072 protocol was added to ensure safety of the system. In this process, the Electric Vehicle communicates to the EVSE using the J3072 protocol, and only when authenticated over J3072, attempts to communicate to the Transformer Monitoring System. The EVSE uses the J3072 protocol to ensure that the system is safe in case of both charge/discharge conditions. Once the EVSE authenticates Electric Vehicle using the J3072 protocol, it then permits the Electric Vehicle to look for and communicate with the Transformer Monitoring System for charge/ discharge commands.
- **Energy Meter**: The energy meter is a high-grade monitoring system that is capable of analysis a lot of parameters in the quality of the power supply. The energy meter is mainly used for the calculation of Voltage, Current, Power, Third Harmonic distortions in Voltage and Current for the two phases in the system.
- **Transformer Monitoring System**: The Transformer monitoring system controls and implements algorithms to perform the following functions
    - Schedule vehicle charging to consume solar power when available. Higher priority is given to higher power available. This helps to raise the belly of the Duck curve.
    - Schedule vehicle discharging in the evening based on typical house loads. Higher priority is given to times of highest power consumption. This helps to reduce the head of the Duck curve.
    - Ensure that the vehicle is charged before it is expected to be driven after supporting Duck curve.
    - Support ISO/DSO messaging for Grid Support
    - Store all measurements for post-analysis at a remote location

System Overview

The system consists of a single 75 KVA Transformer, a Transformer Monitor System, and four EVSEs mounted on two poles connected to Vehicles at the UCSD site chosen for the demonstration.

Figure B-8: UCSD Site View - Main Charging Island with 2 Vehicles Parked on Either Side

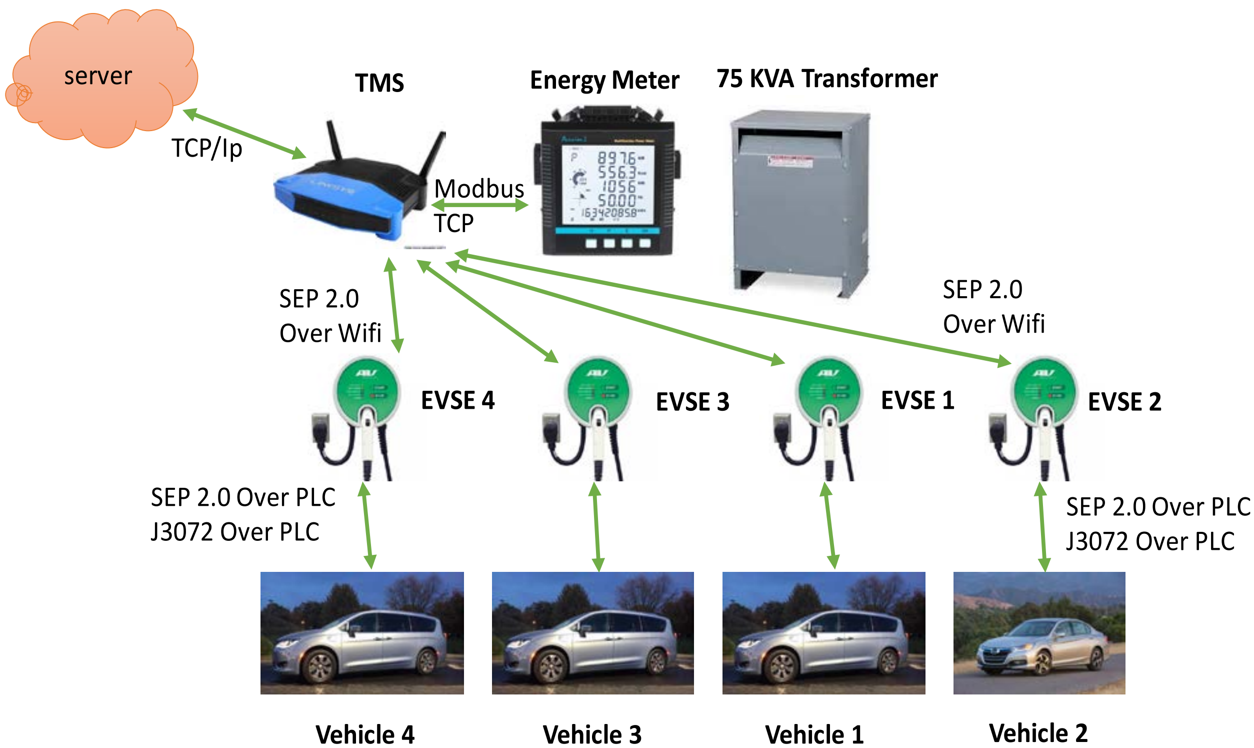
Source: EPRI

Hardware Overview

The four EVSEs are powered by the output of the 75 KVA transformer. The cables from each of the EVSEs is connected to the four vehicles as shown in Figure 60. The Energy meter measures the voltage on the two phases, and a Current Transformer (CT) is connected to the output lines and the output of the CTs is connected to the energy meter. The energy meter in addition to the recording the voltage and current also computes power, third harmonic distortions in Voltage current and power as well. The energy met er is connected by an Ethernet cable to the TMS. The TMS is connected to the World Wide Web by through a local internet connection.

A communication view of the complete system is provided in the figure below. In the communication connectivity of the complete system deployed at UCSD site, the EVSEs communicate to the TMS over Wifi, and the communication protocol between the EVSE and TMS is SEP 2.0. Each of the vehicles will communicated to the EVSEs on the PLC layer, and the communication protocol is J3072 between the vehicle and EVSE. In addition, the vehicle Communicates with the TMS using the SEP 2.0 protocol, but the packets are routed through the EVSE, and hence the SEP 2.0 messages go through the PLC till the EVSE, and then uses Wifi to reach the TMS. The TMS reads the energy meter (which monitors the voltage, current, power and Third Harmonic distortion in Voltage and Current) using the Modbus-TCP protocol. The collected data is uploaded to the server for archival purposes using HTTP POST protocol. The TMS also reads the ISO/ DSO commands from the server in the cloud to implement those commands.

Figure B-9: Communication Protocols Between the Various Systems



Source: EPRI

Vehicle Hardware Implementation by University of Delaware - Honda

As a background, the University of Delaware designed the VSL (Vehicle Smart Link) which is installed into the Honda Accord with the bidirectional on-board charger. The VSL is responsible for communication with the internal vehicle systems and was first installed in the vehicle in 2014. That earlier VSL communicated to the UDel EVSE using single-ended CAN.

For this project, University of Delaware was first tasked with modifying the VSL hardware to communicate using HomePlug GreenPhy PLC. The project team chose to use the STMicroelectronics ST2100 using IoTecha MEVSE cover board as an add-on communication module to the VSL. The project team designed a extended base motherboard which would interconnect original VSL to the PLC communication module. The IoTecha SDK was used to generate the firmware images for the MEVSE module.

There was also a need to preserve the functionality and data logging capabilities of the vehicle with the existing NUVVE/UDel system. The project team implemented some Python code that handles two functions: one was to parse the status of the vehicle as reported to the NUVVE/UDel aggregator, and the other was to reroute the local charge/discharge commands back to the aggregator as a signal request. In this way, the project team blended the two systems together for this experiment.

The next task was to implement the SEP2 communication protocol for SAE J3072 and SAE J2836/3. For this, the KITU SDK was used to implement the SEP2 communication. The SDK provides the framework for sending and decoding SEP2 messages. The SDK release provided to UDel had some skeleton functions for this application. Our main job was to map or transform the signals from the UDel Python aggregator bridge interface to the UDel SEP2 client application.

An AeroVironment EVSE which was modified to have communication hardware based on the ST2100 and IoTecha and Kitu software. An EPRI TMS system with software running on a WiFi router was provided. These hardware pieces were used to do development and testing at the University of Delaware, working with EPRI and Kitu to implement the messages and sequences required to complete the communication and the J3072 handshaking and authentication procedure.

In early April, at Honda Research and Development Americas in Torrance California with the entire setup (including the Honda Accord, modified VSL, AV EVSE, and TMS), a demonstration of solar peak charging and transformer overload discharging was completed. At this point, primary development work for UDel on the project was complete.

In May, UDel transported the vehicle to the UCSD campus. The most severe issue that affected reliability at the site with multiple vehicles and multiple charging stations was that neither Kitu, AV, nor UDel coordinated on the development of the SLAC protocol. This cause of the communication issue was not resolved until after UDel personnel had left UCSD. However, given the tests in Torrance, the system functioned when isolated and implementing SLAC or vehicle/station specific keys (which was done for the other vehicles) would have enabled coexistence.

Vehicle Hardware Implementation by FCA

PEV control software update

An Electric Vehicle Communication Controller (EVCC) was developed for the Pacifica PHEV vehicles to translate Smart Energy Profile 2.0 (SEP2) commands using PLC protocol to CAN. The PEV Supply Equipment (EVSE) and PEV conduct authentication through the J3072 protocol process signals, then the Transformer Monitoring System (TMS) becomes the SEP2 or IEEE 2030.5 server to the vehicle client. The EVSE module enables the PLC bridge between the TMS and PEV. The present vehicle production CAN software was updated to process these converted SEP2 commands and provide the response. A very basic and straightforward way has been selected to keep the integration simple while maintaining the reliability of the system. Since the TMS is the Server and the PEV is the Client almost all the controls are from the TMS, not the PEV so the vehicle behavior is controlled by TMS while the vehicle is connected to the smart charger and smart grid.

New Onboard Charger (OBC) installation and Integration

Current production OBC is only capable of charging, and is not Bi-Directional, so Current Ways OBC was chosen, as it is a 6.6 kW charger/discharger, and has the same form factor as the production OBC to reduce the assembly complications.

During the integration, the OBC SW had some issues but was taken care after a few iterations. The main issue was the inability to wake up the PEV on the J1772 Control Pilot toggle. All the OBC's wake up on plugin but if any initial charging/discharging completes, the vehicle will go to sleep to save the vehicle 12V battery. If the DER command is sent after this, the OBC needs to wake up the vehicle on the B2-B1-B2 state toggle, which required a hardware change in the OBC. After this was updated, the OBC is working as expected for the complete connected session.

OBC CAN to CAN SW implementation for communication between Hybrid Control Processor (HCP) and EVCC on CAN

The EVCC was added as a separate module on this project and normally would be included internal to the OBC. Since it was a separate module and separate supplier and since the OBC was the only module connected to the vehicle CAN bus, the OBC had to "pass thru" these CAN messages.

During the initial testing, the CAN-CAN SW on OBC didn't process all the values and required several updates. Future plans would be to include the EVCC internal to the OBC, so the same supplier was working both parts.

CAN-Sep2

The communication with utility companies is accomplished using SEP2 – Smart Energy Profile 2. Vehicles communicate using CAN and the EVSE is SEP2 but the EVSE starts as a Client to the TMS, then is a Server to the PEV (EVCC), then a bridge between the TMS and PEV. The communication was as follows:

Vehicle <CAN> OBC < Filtered CAN> EVCC <PLC> EVSE – from EVSE to TMS and Servers is SEP2.

EPRI was responsible for the SEP2 to CAN software integration and the microgrid interface to the TMS. Kitu was responsible for the SEP2 software. The implementation of SEP2 was completed at EPRI and Kitu but the final system that included the vehicle CAN was not completed until all the components were assembled in FCA's lab for the complete CAN – SEP2 communication.

Summary of any individual lab system test integration issues, resolutions, learnings

The testing at FCA can be divided in 3 main parts:

1. **Component and System Testing and validation:**
   - Monitored the CAN messages on the EVCC and verified communication from HCP to EVCC
   - Tested all the modules by pinging each other's IP address to check communication among them
2. **Vehicle Level testing:**

To evaluate the response of the vehicle for this project, signals of EVCC involving all the possible test cases are poked into the vehicle CAN bus and validated the response of the vehicle.

- The vehicle was not going to sleep when it reached 100 percent SOC due to the OBC control strategy. This was solved by a HCP software update
- Issue of keeping the OBC temperature within operating range was solved by calibrating vehicle thermal systems
- Vehicle not able to go to sleep was due to the OBC sleeping strategy and the issue was solved by implementing a hardware timer circuit to de-assert the OBC wakeup line after two minutes after the vehicle initially woke up
- OBC not going to sleep when the EVSE connector is plugged in to the vehicle was fixed by OBC software update
- Issues with OBC not going to charge mode when EVSE is plugged in are fixed by software updates on OBC

3. **System Level testing:**

- Few connection issues with TMS, EVCC and EVSE were solved by software updates on them
- EVSE needed to be restarted (power removed then reapplied) for every test due to some socket issues in EVSE software. This was solved by a software fix and after that, it worked without restarting it
- The time interval between each TMS command was long, that caused serious time delays in the EVCC response. This was solved by reducing the time interval between TMS commands
- EVCC staying in same state (i.e., TMS found) even when the EVSE is unplugged was solved by a software fix
- Had issues with getting the TMS to send out the appropriate commands with respect to DER/solar/default events. Those issues were solved by software updates
- Had issues with EVSE communication when more EVCC certificates were added to TMS list. This was solved by a software update on the EVSE from Kitu

Learning:

Make sure all the EVCC, EVSE certificates are added to TMS list and make a note of what certificate goes in which EVSE/EVCC/TMS.

Knowledge of control strategies of all the components from the beginning of the project would have reduced changes and eliminated “work arounds”.

EVSE - EVCC

AeroVironment, Inc. (AV) developed and installed a communication board on the model EVSE-RS Level 2 PEV charger to enable bi-directional power flow from the PEV to the grid. The EVSE-RS with communication board has the following functionality:

- Communication from the EVSE motherboard to the communication board via the BOB protocol
- PLC communication via HomePlug GreenPhy between the charger and the vehicle
- WiFi communications from the charger to a cellular gateway

- Bi-directional power flow between the charger and the grid

The communication board communicates to the EVSE-RS (charger) control board over the UART port, which has been used historically by other communications modules (EVDATA, Raspberry Pi, many others). The Base Off Board (BOB) protocol allows communication between the EVSE main board and the communications board. The communications board is also connected to the pilot wire to enable HomePlug GreenPhy communications to the vehicle.

Kitu Systems was responsible for communications software installed on the communications board and all of the final software that runs on the communications board, including SEP2, SAE J2847/3 and J3072.

The charger units produced for this project were UL listed. The communications board was considered outside the UL safety boundary for because it is low voltage, and outside the software boundary because of the nature of the BOB protocol.

AV Tasks

1. Define physical packaging of Communications Board into RS

The Communications board mounts to a carrier board that in turn is mounts to the EVSE main board. AV conducted a packaging study to determine a feasible and optimum placement of the Communications board. An initial concept is shown below.

2. Select Suitable power supply and installation strategy in RS

The Communications board can accept 10 to 30V DC input. This rules out using the 5V power available on the EVDATA connector as has been done with the Raspberry Pi. At regulated 10V, a secondary power regulator onboard the Communications can be bypassed, increasing efficiency and reducing heat load. A 10V supply was thus selected. The power rating of the Communications board is listed in the documentation, but the WiFi card added additional load. The chosen power supply allows for compatibility with other types of PCIe cards that may draw more power. AC power connection to the power supply comes from spare terminals on the always-powered side of the main contactor.

Figure B-10: EVSE Communications Board Mounting Concept

Source Aerovironment

3. Develop carrier board for Communications

The carrier board provides the means to mount the Communications board to main EVSE board and provides the necessary interfaces. The interfaces include, at a minimum:

- 10V power (or AC power if power supply mounted to carrier board)
- UART connection to EVSE meter port (isolated as in Gen1 Raspberry Pi carrier
- Connections for HomePlug GreenPhy (see documentation)
- Three high density connectors to the Communications board
- Holes for mounting screws to fasten Communications to carrier board
- USB (nice to have) Alternate interface for WiFi
- Review Communications interface documentation to see if other interfaces are wanted

For final project implementation, AV developed a Communications board that did not require a carrier board, and instead mounted directly to the EVSE main board without an interface.

4. Select WiFi module and antenna for Communications

AV worked with IoTecha to select and develop the WiFi module, antenna, and firmware for the Communications board.

5. Develop HomePlug GreenPhy connection to pilot wire

AV developed the wiring and coupling means to the pilot wire.

6. Modify EVSE firmware for bidirectional energy metering

The firmware on the EVSE board assumes that power will always be flowing from the grid to the vehicle, so it does not pay attention to the sign of the measured power – it reports the absolute value of the measured power. For this case, the EVSE supports bidirectional power flow so it needs to keep track. The absolute value calculation was removed from the firmware and replaced with a factor of +1 or -1 to multiply the power by. The factor was calibrated based on the first time the unit is powered up. The reported power without the absolute value could be positive or negative, depending on which orientation the current sensor is installed (not controlled in manufacturing). The factor value of +1 or -1 is selected at this first startup in order to make the reported power and current positive. That way, when reverse power flows, the power will be reported as negative, and the reported rms current should have its sign matched to the reported power.

7. DVT test of system

The system went through a full DVT of the base EVSE functions.

8. Production of 10 units for deployment

AV built and tested 10 units for deployment and use for the overall project. UL listing was not required, was satisfied nonetheless by AV's choice of communications board design. AV used stock production model EVSE-RS units.

9. Support deployment for Demonstrations

AV supported installation of the chargers.

EVSE Summary

Current	±30 Amps
Voltage	208 or 240V
Power	±7.2 kW

- Integrated bidirectional-capable energy metering (not revenue grade)

- Current, Voltage, Power, and Frequency monitoring and reporting

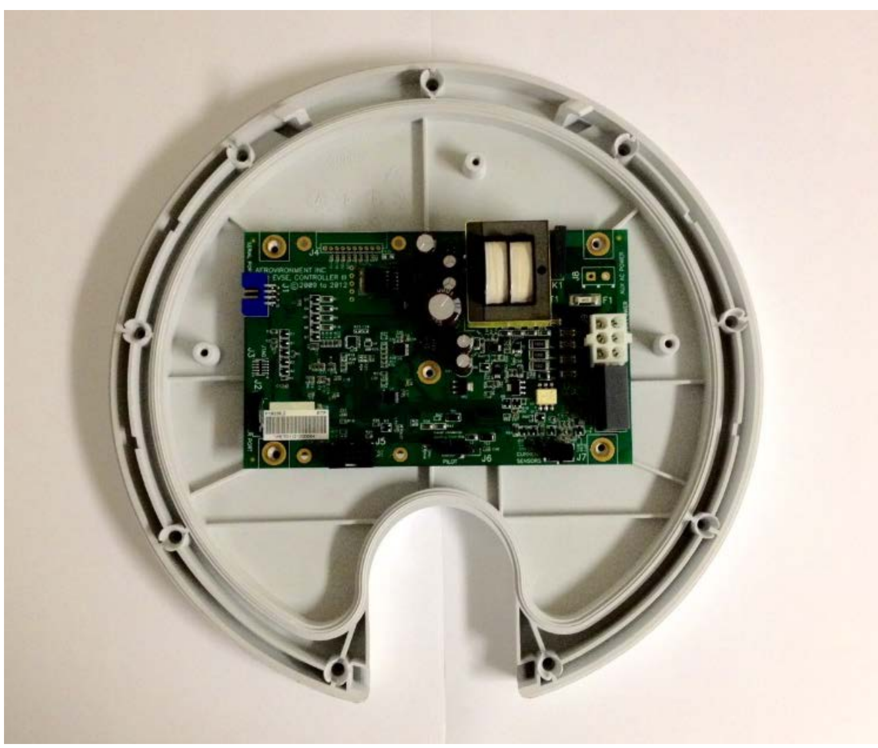
- Integrated IoTecha Communications module, which enables:

- SAE J2847/3 communication to vehicle using HPGP PLC over pilot wire
- SEP2.0 communications
- WiFi communications to SEP2 Gateway.
  - SEP2 software developed by Grid2Home

Figure B-11: AV EVSE RS Control Board

Source Aerovironment

Figure B-12: EVSE Communications Module



Source Aerovironment

AeroVironment originally planned to use the Tatung Communications board, or some derivative to support the communications for the bi-directional control functionality of the EVSE. The project team changed plans to contract with IoTecha to design a derivative of the Tatung board that was purpose built to install in the EVSE RS without the need for a separate adapter board.

The principals of IoTecha designed the original Tatung Communications board, so they were well prepared to quickly implement a board layout and manage the production of a small quantity of boards that are needed for the project. AV, Kitu, and IoTecha worked together to make sure the board specifications for hardware and Linux distribution and drivers were suitable.

System Lab Testing Prior to Deployment (FCA)

System Lab test integration issues, resolutions, learnings (FCA). The system testing at FCA can be divided in 3 main parts:

1. **Component and System Testing and validation:**
   a. Monitored the CAN messages on the EVCC and verified communication from HCP to EVCC
   b. Tested all the modules by pinging each other's IP address to check communication among them
2. **Vehicle Level testing:**

   To evaluate the response of the vehicle for this project, signals of EVCC involving all the possible test cases are poked into the vehicle CAN bus and validated the response of the vehicle.

   a. The vehicle was not going to sleep when it reached 100 percent SOC due to the OBC control strategy. This was solved by a HCP software update
   b. Issue of keeping the OBC temperature within operating range was solved by calibrating vehicle thermal systems
   c. Vehicle not able to go to sleep was due to the OBC sleeping strategy and the issue was solved by implementing a hardware timer circuit to de-assert the OBC wakeup line after two minutes after the vehicle initially woke up
   d. OBC not going to sleep when the EVSE connector is plugged in to the vehicle was fixed by OBC software update
   e. Issues with OBC not going to charge mode when EVSE is plugged in are fixed by software updates on OBC
3. **In-Field Pre-Deployment testing:**
   a. Repeat the Vehicle-Level System testing in the field combing parts 1 and 2

System Commissioning

The TMS system was installed per the written instructions provided by EPRI. All safety and building codes as applicable will be followed for voltage levels of 240 V AC. All required PPE safety equipment as mandated for electrical construction will be used and best practices for equipment installation followed. EPRI personnel were on site to monitor and advise during TMS deployment and installation. The data logging equipment gives info on vehicle status including but not limited to SOC.

Log file reporting from the TMS was monitored and reported as a method to evaluate the overall performance at a system level.

OBC, CAN – SEP2, integration

PEV – OBC integration required following activities:

1. **PEV control software update**

   An Electric Vehicle Communication Controller (EVCC) was added to the Pacifica PHEV vehicles to translate Smart Energy Profile 2.0 (SEP2) commands using PLC protocol to CAN. The PEV Supply Equipment (EVSE) and PEV initially process signals, then the Transformer Module System (TMS) becomes the SEP2 server to the vehicle and the EVSE module functions a bridge (between the TMS and PEV). The present production CAN software was updated to process these converted SEP2 commands and provide the response. A very basic and straightforward way has been selected to keep the integration simple while maintaining the reliability of the system. Since the TMS is the Server and the PEV is the Client almost all the controls are from the TMS, not the PEV so the vehicle behavior is controlled by TMS while the vehicle is connected to the smart charger and smart grid.

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   During the integration, the OBC SW had some issues but was taken care after a few iterations. The main issue was the inability to wake up the PEV on the J1772 Control Pilot toggle. All the OBC's wake up on plugin but if any initial charging/discharging completes, the vehicle will go to sleep to save the 12V battery. If the DER command is sent after this, the OBC needs to wake up the vehicle on the B2-B1-B2 state toggle, which required a hardware change in the OBC. After this was updated, the OBC is working as expected for the complete connected session

3. **OBC CAN to CAN SW implementation for communication between Hybrid Control Processor (HCP) and EVCC on CAN**

   The EVCC was added as a separate module on this project and normally would be included internal to the OBC. Since it was a separate module and separate supplier and since the OBC was the only module connected to the vehicle CAN bus, the OBC had to "pass thru" these CAN messages.

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4. **CAN-Sep2**

   The communication with utility companies is accomplished using SEP2 – Smart Energy Profile 2. Vehicles communicate using CAN and the EVSE is SEP2 but the EVSE starts as a

Client to the TMS, then is a Server to the PEV (EVCC), then a bridge between the TMS and PEV. The communication was as follows:

Vehicle <CAN> OBC < Filtered CAN> EVCC <PLC> EVSE – from EVSE to TMS and Servers is SEP2.

EPRI was responsible for the SEP2 to CAN software integration and the microgrid interface to the TMS. Kitu was responsible for the SEP2 software. The implementation of SEP2 was completed at EPRI and Kitu but the final system that included the vehicle CAN was not completed until all the components were assembled in FCA's lab for the complete CAN – SEP2 communication.

5: System Level Testing Process:

a. Few connection issues with TMS, EVCC and EVSE were solved by software updates on them

b. EVSE needed to be restarted (power removed then reapplied) for every test due to some socket issues in EVSE software. This was solved by a software fix and after that, it worked without restarting it

c. The time interval between each TMS command was long, that caused serious time delays in the EVCC response. This was solved by reducing the time interval between TMS commands

d. EVCC staying in same state (i.e., TMS found) even when the EVSE is unplugged was solved by a software fix

e. Had issues with getting the TMS to send out the appropriate commands with respect to DER/solar/default events. Those issues were solved by software updates

f. Had issues with EVSE communication when more EVCC certificates were added to TMS list. This was solved by a software update on the EVSE from Kitu

Learning:

1. Make sure all the EVCC, EVSE certificates are added to TMS list and make a note of what certificate goes in which EVSE/EVCC/TMS
2. Knowledge of control strategies of all the components from the beginning of the project would have reduced changes and eliminated "work arounds".

EVSE PEV Integration Set-up, Test, and Results (J3072)

The vehicles arrived on site on 05-09-18. EVSEs were fully functional. As soon as the TMS setup was completed the EVSE successfully joined but the vehicles were not joining.

After trying to debug for almost 2 days, found that the COM boards in the EVSE at the Site were not working properly, so replaced one of the onsite EVSE's Com board with the Com board of the additional FCA's EVSE that was previously used in FCA's lab to determine if can communicate with the new items at the site. The test was successful and the PEV joined the network, this meant that the EVSE com boards in the site EVSE were not communicating.

Next day, after more debugging and help from IoTecha found that all issues were because the EVSE and EVCC needed the SLAC (Signal Level Attenuation Characteristics) implemented. Since the SLAC was not implemented in the EVSEs, the EVCCs needed to be assigned a stationary NMK ID and this IDs needed to be made in pairs, which meant the each PEV was paired with an EVSE. As of that moment and requirements of the project, the pairs were made.

Testing continued over the next couple of days to get all the bugs cleared out from EVCC, EVSE and TMS for a stable communication system. At this time, the PEV would join the network each time the PEV was plugged in. This also took care of the issue that the PEV was faulting randomly that was thought to be some noise in the Grid. The OBC was very sensitive to this and didn't have any reset/retry strategy for the faults.

Next day stared 24-hour testing to get some additional data, the test was successful and the PEVs joined the network charged during the day with solar power and discharged during the evening to support the grid. This provided data to start the reports and analyze if the control algorithms were working properly.

APPENDIX C: Value Assessment Modeling Assumptions and Distribution Model Framework Details

Cost and Benefit Assessment Framework

Introduction

Minimal attention has been given to develop a holistic approach to consideration of V2G and understanding the economics that drive the success of V2G services with fleet of PEVs. This is particularly important because the market for traditional ancillary services (regulation, reserves, etc.) is relatively small, and increased market participation by energy storage and flexible loads may reduce market prices even in the face of increasing demand. There are other avenues emerging where application of V2G as a distributed resource may be of high value – especially around balancing PV generation at the local distribution level to mitigate the 'Duck Curve' effect at the transmission level proving distribution capacity utilization and through asset upgrade deferment.

PEV Grid Impacts Model

E3 has turned its unique expertise in the area of economic analysis in the energy sector to focus specifically on the value proposition of electric vehicles and, in particular, managed charging. Specifically, E3 has developed a model that takes in information about a system's grid operations and costs, as well as assumptions about electric vehicle adoption and charging behavior, and calculates a full set of cost and benefit components to fully capture the economic conditions under a certain scenario. E3 has had the opportunity to conduct managed charging economic potential analysis for a geographically wide range of clients for several different purposes:

- **CalETC** explored the economic impact to the grid from adoption of both light- and heavy-duty electric vehicles across the state of California
- **SDG&E** hired E3 to evaluate vehicle-grid-integration potential for residential electric vehicles that charge at home, at work and in both locations
- **EPRI** worked with E3 to develop cost-benefit analysis to the grid for light- and heavy-duty vehicles, including electrified forklifts and buses
- **Several utilities in the Pacific northwest** have sought E3's help in determining the economic opportunity for a wide range of heavy-duty electric vehicle technologies, specifically focusing on fleet vehicles such as taxis, delivery trucks and truck stop electrification

These cost-benefit components range from incremental energy costs to meet new load to transmission and distribution upgrade deferral to a given customer's monthly bill. Some of the key components of the above-mentioned cost/benefit analysis that the project team tracked are listed below:

- **Electricity supply costs:** energy generation, losses, generation capacity, additional RPS compliance cost associated with incremental load, ancillary services and emissions compliance costs
- **T&D upgrade costs:** sophisticated feeder-level logic used to track what amount of incremental load would trigger a required upgrade for a specific feeder and attribute some portion of that upgrade cost to the electric vehicles responsible for the load
- **Societal costs:** criteria pollutants, carbon emissions associated with electricity generation and fossil fuels, reduced oil imports dependence
- **PEV ownership costs and benefits:** incremental vehicle cost compared to a similar internal combustion engine vehicle, avoided vehicle O&M cost, federal and state PEV incentives, avoided gasoline cost
- **Charging costs:** personal charging equipment, customer utility bills, public charging infrastructure costs
- **Program administration costs:** rebates, advertising, education

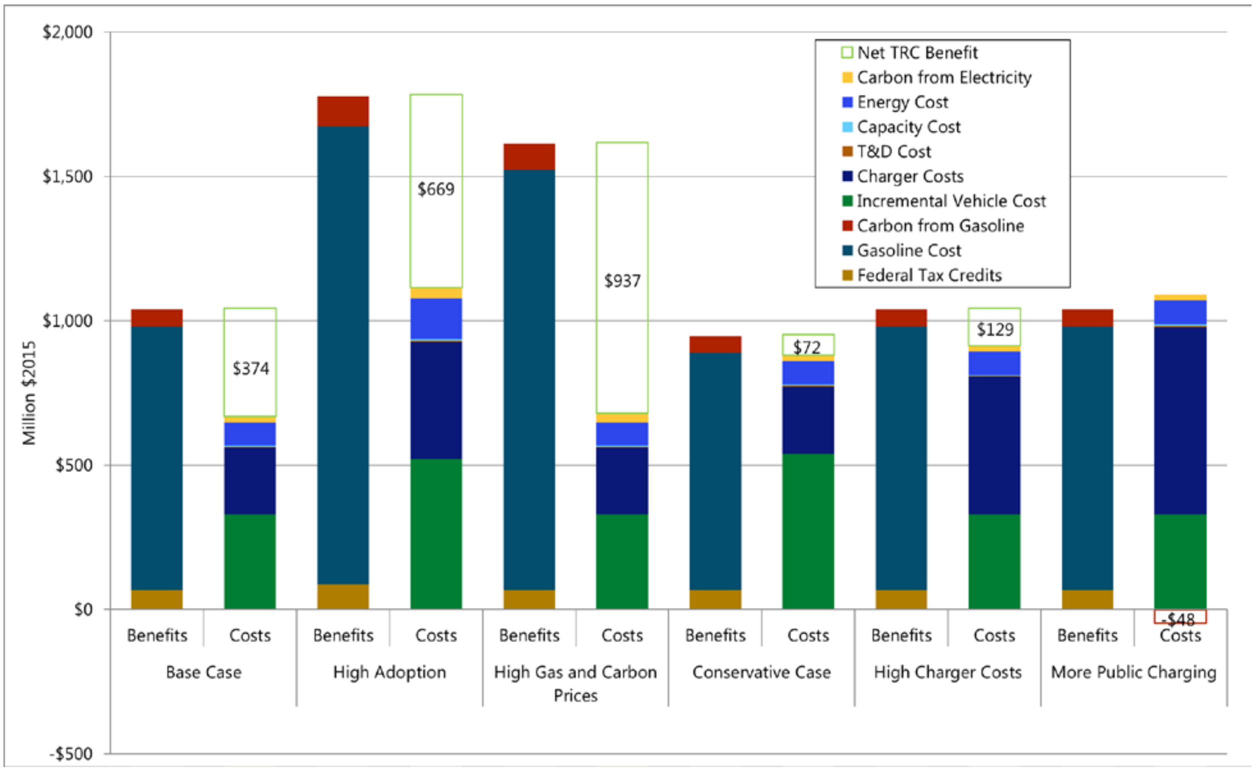
While many of these costs and benefits are realized with mere electric vehicle adoption alone, a good deal of them can be drastically expanded with managed charging:

- **Lower marginal costs:** in hours of high demand, utilities are forced to use more expensive power to meet peak load. By encouraging customers to avoid consuming electricity in these peak hours, and to instead consume it in periods with lower demand, the value to the utilities and thus to ratepayers is proportional to the differential between what marginal costs would be in peak demand hours and what it is in hours with lower load.
- **Reduced emissions:** marginal emission rates of electricity also vary greatly, both over the course of a given day as well as seasonally. With managed charging, utilities can incentivize consumers to maximize their electricity consumption at times when marginal emissions are lowest, thereby displacing significant amounts of carbon
- **Avoided curtailment:** with increasing RPS requirements and corresponding larger solar portfolios, one of the primary challenges facing electricity grids in the future is curtailment. To maintain certain system reliability and meet ramping needs, curtailment can be a common occurrence all year long. To meet RPS requirements, utilities are forced to procure replacement renewable energy, which in itself will be curtailed to some extent. This phenomenon can result in significant costs to utilities and ratepayers alike. As curtailment is most problematic in the middle of the day when solar is at its most productive, managed charging that moves load from evenings and mornings to the middle of the day can help combat this challenge.
- **T&D deferral:** each distribution locale has its own aggregate load profile. Certain utility feeder sites may be morning-peaking, while others see their highest demand in the middle of the day. Incremental load added to a feeder's peak hours is most problematic and thus most costly to a system because it can trigger capacity upgrades. By managing

local charging to avoid adding load to a feeder's current peak, the grid can benefit by deferring these upgrades.

Each of these cost and/or benefit components are viewed in aggregate to determine the overall cost effectiveness of a proposed PEV adoption scenario. Below is a sample of how several different scenarios might differ:

Figure C-1: Relative Scenarios Differentiation of Cost Effectiveness



Source: E3

To best evaluate the additional value in managed charging, E3 has developed an hourly load profile optimization feature in our modeling which seeks to minimize customer bills. Given a rate, a customer preference parameter (how much more a customer prefers minimizing their bill to constantly maintaining a fully-charged battery) and driving characteristics in the form of hourly kWh used and availability to charge, E3's optimization model will produce a load profile to meet all of the given customer's energy needs while also minimizing their monthly bill. This logic can be tweaked to minimize costs to the utility or the grid itself by replacing a customer rate with utility/system marginal costs.

Integrated Distributed Energy Resource Model (IDER)

E3 has developed the Integrated Distributed Energy Resource Model (IDER) that simulates the optimal operation of DER technologies and evaluates their economic impact from multiple perspectives. IDER consists of the following three modules:

- **Optimal DER Dispatch**: This module uses mathematical programming to optimize the hourly dispatch of the storage, maximizing the benefits to the end customer or utility.
- **Economic Impact Quantification**: This module quantifies the various costs and benefits incurred as a result of purchasing the DER and operating it according to the optimal DER dispatch.
- **Cost-Effectiveness Tests**: This module produces the CPUC Standard Practice Manual cost effectiveness tests for demand side programs.

The dispatch optimization includes discharging batteries to provide grid benefits. This module will be utilized to model the V2G benefits that PEVs can provide. The methodology of each module will be discussed in detail in the remainder of the section. First the project team presented the optimization problem formulation of the Optimal DER Dispatch module. Next the team described the calculation of different economic impacts, including system level avoided costs, distribution deferral value, and distribution operation cost savings. Finally, the project team reviewed the cost effectiveness tests performed for this study.

Optimization model for storage dispatch

The hourly battery charging and discharging profile used in economic calculations is determined by an optimization model, which dispatches the battery to maximize the benefits to the controlling entity. All households and storage units are modeled as a single aggregate customer. The model assumes that the battery controller has perfect foresight for important optimization inputs such as system and distribution system load, PV generation, energy avoided costs, and AS market prices. Thus, the benefits shown in this analysis are the maximum benefits possible under ideal conditions.

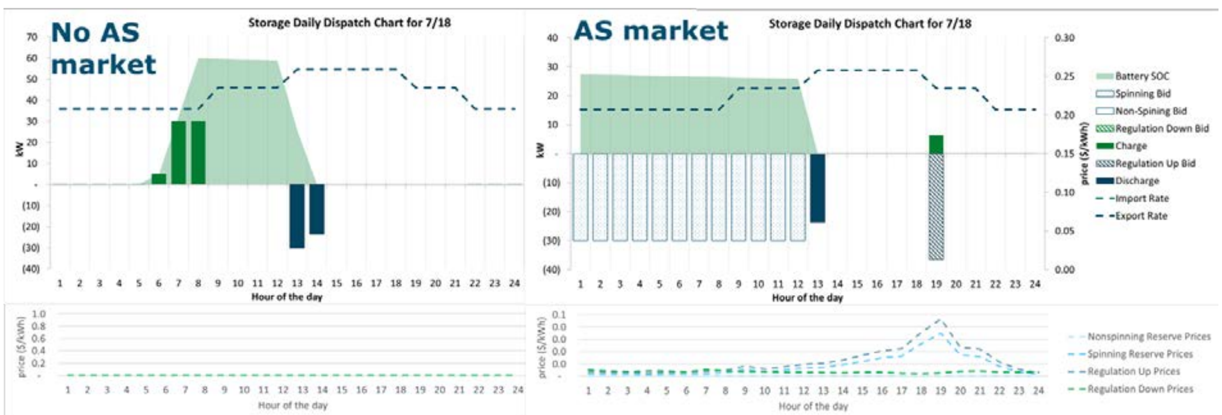
The optimization model dispatches the storage from either the customers' or utility's perspective. When batteries are dispatched from customers' perspectives, the behavior of the batteries is determined by the retail electricity rate that the customer is facing, and the amount of power generated by the PV system. Under customer dispatch, charging of the storage is restricted to be from the PV system. Customers are assumed to be on a retail rate with symmetric net energy metering (NEM) where the customer's bill is credited for exports to the electric grid at the same rate charged for imports from the electric grid. The batteries will generally charge when retail rates are low, and discharge when rates are high.

When dispatched from the utility's perspective, a slightly more complicated optimization model is used. For distribution deferral, the primary objective of the optimization model is to reduce the net distribution feeder load to be below the threshold which would trigger an upgrade. The dispatch of storage required to defer distribution upgrades is limited to a relatively small number of hours (~200 hours per year). For the remaining hours of the year objective of the optimization model is to maximize the cost of delivering energy to the customer and maximize revenues from grid services, including V2G.

Valuing V2G Services

In order to estimate the V2G revenue provided by vehicles, E3 will employ the methods used to model AS revenue earned by energy storage in wholesale markets. The model co-optimizes to maximize energy price arbitrage and ancillary service revenues. The project team modeled participation in four ancillary service (AS) markets: regulation up and down, spinning and non-spinning services. Batteries are paid once they submit bids for providing AS services, but it is hard to predict whether the bid is called by the operator and requires energy from batteries. In the model, the project team calculated the expected percentage of AS bid being called in historical California ISO AS market and use this as an estimate. The analysis assumes that 15 percent of bids are called for regulation up and down service, and none of the bids for spinning and non-spinning reserve being called.

Figure C-2: Illustrative Dispatch of Storage Without and With Ancillary Services



Source: E3

Quantifying Distribution System Deferral Value

The largest potential local benefit of installing DERs is from deferring a distribution upgrade from the original installation year to a year farther in the future. Many distribution upgrades are driven by load growth. When the load exceeds the carrying capacity of the local distribution network, an upgrade must be made. DERs are able to reduce peak loads on the distribution network and delay the upgrade. The amount of DER provided load reduction that can be relied on for planning purposes is known as the reliable load reduction. If the reliable peak load reduction from DERs is great enough to delay a distribution network upgrade, then the deferral value created by the DERs can be calculated by the present worth method. The rest of the section will cover criteria for choosing an investment plan, estimating the reliable peak load reduction, and estimating the deferral value by the present worth method.

For this project, E3 worked with EPRI to incorporate other types of distribution infrastructure investment that can be avoided or deferred with V2G services.

Investment Plan

The locational avoided cost of distribution investment calculation requires the identification of potentially deferrable projects in distribution investment plans. The examples below describe deferral of load growth driven investments, which has been how distribution deferral value has been quantified to date in DER avoided cost modeling. For this project, E3 will work with EPRI to also identify investmetns and upgrades that can be deferred with V2G services.

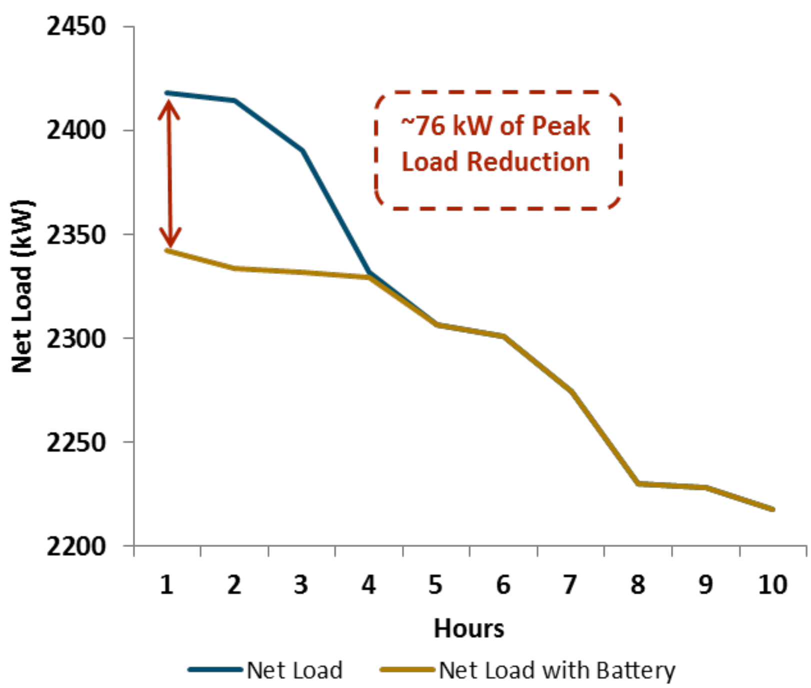
Load and DER forecasts for the investment plan should include all areas that have an impact on the potential investment. For example, if load on feeder A and feeder B both impact a transformer upgrade plan, then the load and DER forecast used in a deferral analysis should include the forecasts for both feeders.

The deferrable capital investment considered should include only works or materials that could be deferred through the reduction in peak demand in the area. Examples of costs that would not be included are sunk costs, and land costs that the utility will incur even if DER might be able to defer the project by a few years. There could still be some costs when deferring projects, for example, the renting of storage units for raw material, and deferral program planning costs.

Determination of Reliable Load Reduction

The reliable load reduction by DERs varies by technologies and is dependent on 1) the control of DER measures during peak period 2) the overlap of DER output with peak period and the 3) for renewable DERs, the uncertainty of the output. The following section focuses on the method for determining the reliable load reduction for battery and DG PV.

Figure C-3: Reliable Peak Load Reduction of Storage



Source: E3

- A battery is a reliable DER resource, thus the reliable load reduction by a battery is simply calculated by the difference between network peak load with and without the battery. Figure C-3 shows the highest 10 load hours with and without a battery. The difference between two highest load points is the peak load reduction of the battery. Batteries are dispatchable by either utilities or customers, and utilities have good predictions of distribution peak load day. As a result, a battery can be adequately charged for the peak load day by informing either the customer's or utility's battery operator ahead of time.

- DG PV needs to be derated to account for two factors 1) the uncertainty of future PV output and 2) the coincidence between PV shape and peak load period.
  - A dependable output shape is determined to derate PV for the uncertainties of PV output. First, the project team calculated the distribution of PV output in each hour and season. From these distributions the team took the percentile corresponding to the planning rule determined by the model user. In this study, 95 percent reliability is chosen, the model takes the 5th percentile of each hourly and seasonal distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 95 percent of the time. This is the dependable PV measure output.
  - The second step is derating PV for the coincidence between PV dependable shape and peak load period: PCAF values identify distribution system peak load periods, and by multiplying hourly dependable PV output shape with the hourly PCAF values, the project team can have the reliable load reduction by PV.

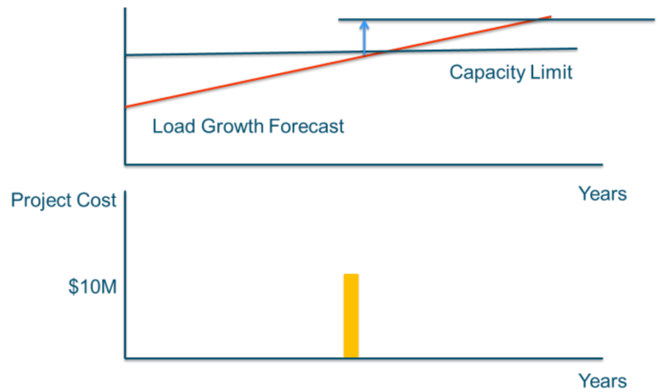
After the reliable peak load reduction is determined for each technology, deferral value can be calculated based on the present worth method. The contributions of each technology toward deferral value are allocated based on the reliable peak load reduction at original installation year.

Present Worth Method

Economically meaningful estimates of distribution capacity costs require a method that captures the area- and time-specific nature of lumpy distribution investments. One such method is the Present Worth (PW) method. The essence of the PW method is that the value of deferring a local expansion project for a specific period of time reduces the present value of the project cost due to the time value of money. A one-yr. deferral value equals the difference between the present value of the expansion plan and the present value of the same plan deferred by one year, adjusted for inflation and technological progress.

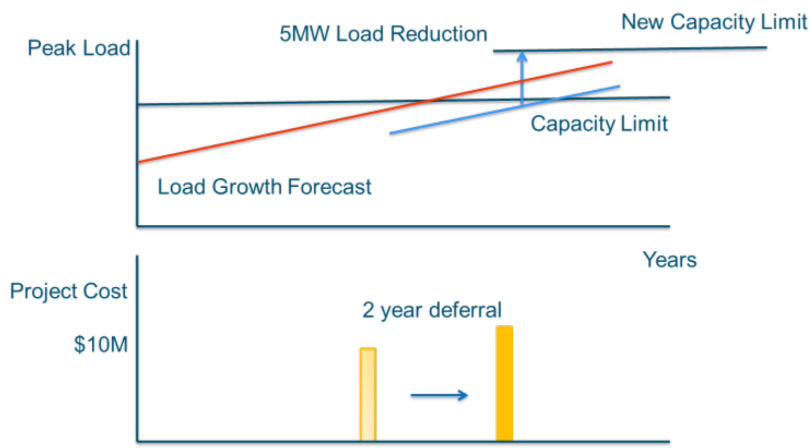
Figure C-4 below shows a network T&D investment of $10M. The project is needed to prevent the load growth from exceeding the area load carrying capability. In Figure C-5, the load growth is reduced from the red line to the blue line, which allows the investment to be deferred by two years. The deferral results in a savings of about $1M if inflation is two percent and the utility WACC is 7.5 percent ($\$10M - \$10M*(1.02/1.075)^2$). If the project team further assume that 5MW was needed to achieve that deferral, the avoided cost per kW is $200/kW ($1M/5MW)

Figure C-4: Investment in Distribution Project Due to Load Growth



Source: E3

Figure C-5: Project Deferral of Network Investment



Source: E3

Vehicle-to-Grid Benefits

E3 plans to integrate our PEV Grid Impacts and Integrated Distributed Energy Resources models to evaluate the benefits of managed charging and V2G. This is feasible because both models have been developed in Python and designed to be modular.

In addition to the aforementioned benefits of managed one-way charging, enabling vehicles to participate in vehicle-to-grid behavior allows for further value to be realized. This value can be created via ancillary services, using the storage technology in electric vehicles for load-following and frequency response purposes as well as providing reserves of other sorts. Electric vehicles, effectively managed in aggregate, have the potential to operate on the grid in the same way as any other storage might, while gaining other unique benefits such as directly replacing gasoline consumption.

E3's electric vehicles model is capable of modeling vehicle-to-grid interactions in addition to one-way charging – price signals for ancillary services are treated as a potential revenue stream, which effectively reduces the customer's utility bill, which is the objective function being minimized. In short, in each hour, a customer is subject to certain charges – volumetric energy charges (possibly subject to TOU periods), demand charges, etc. In addition to these, E3 can model V2G opportunities that present themselves revenue streams for the customer or utility. That is, each hour might have a regulation up price, a regulation down price, a spin price and/or a non-spin price. Then, for each of these services that an electric vehicle can provide in a given hour, the model will solve for an optimal bid for which the customer will be compensated as whatever the stated price is. This serves as a means of offsetting, either partially or entirely, the customer's conventional utility bill.

Proposed Structure of E3's Analysis

Given the flexibility of both the assumptions and inputs to E3's electric vehicles model can be used to address several different questions in the sphere of the economics of electric vehicle adoption. In the past, E3 has used this model to "solve for the headroom" of certain PEV adoption – that is, seeing how cost effective electric vehicles might be to a particular grid, and using the delta between benefits and costs as a measure of how much money could be invested to encourage or support adoption. Additionally, E3 has used the logic in this model to measure the impact that different rate schemes – flat, TOU, real-time, demand-charge, etc. – can have on effectively managing the grid.

A combination of these two kinds of analyses E3 will compare a totally unmanaged rate scenario, a V1G/managed charging scenario and a V2G scenario including ancillary services. E3 will put together a range of potential value of electric vehicles, to help utilities determine how cost effectiveness varies across different programs and thus if they are financially and economically feasible endeavors. A more targeted analysis for this project's purposes might be to run two cases: in one, vehicles merely manage their own V1G charging, opting to minimize their bills subject to their driving constraints. In the other, additionally, vehicles are able to perform V2G benefits such as ancillary services and discharging to the grid in peak hours. E3 can then analyze the difference in costs and benefits under the two scenarios to determine the incremental benefits of vehicle-to-grid capabilities. These incremental benefits, compared to the incremental costs of installing or developing the necessary technology, can help speak to the cost-effectiveness of V2G.

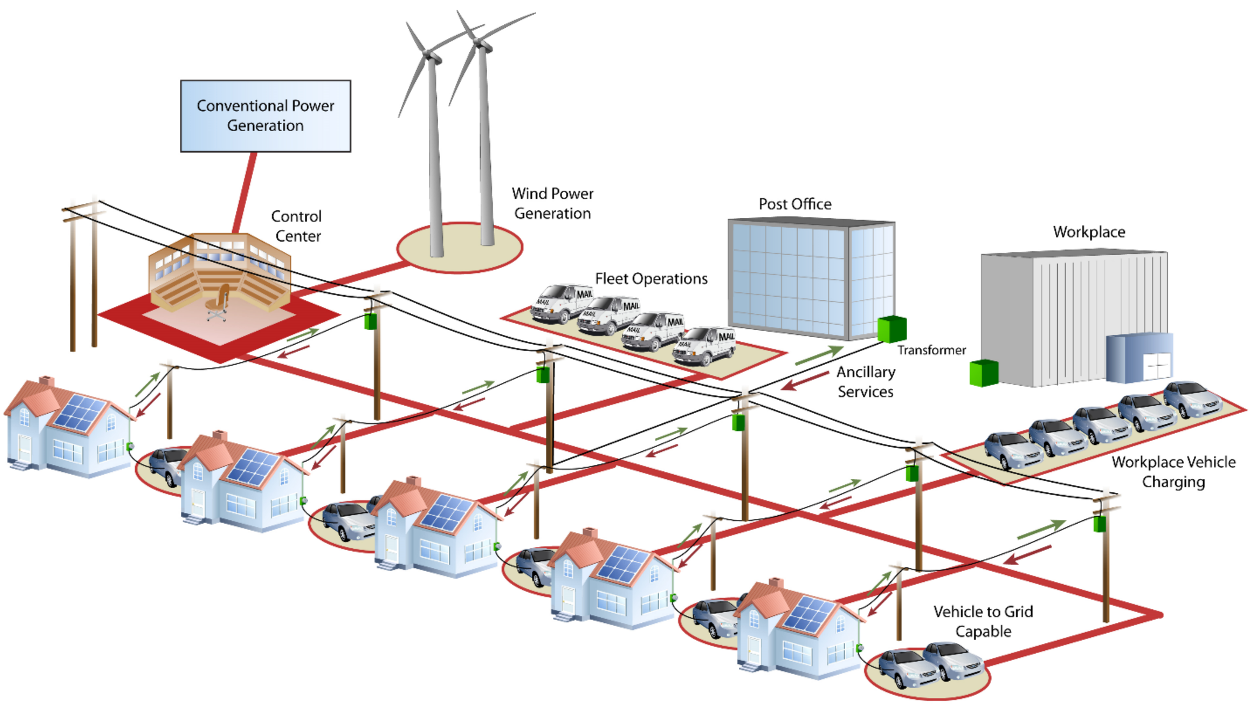
Circuit Specific Avoided Distribution Cost Estimate Methodology

Background and Process

Among the next developments in "greening the grid" will be the requirement of storage capabilities that will help enable further adoption of renewable power generation. The largest obstacle to current grid storage solutions is finding a scalable solution that is cost-effective. Given typical driving patterns, about 85-90 percent of the total vehicles are expected to be in a "parked" state at any given point throughout the day. Furthermore, it is expected that electric vehicles will constitute a significant portion of total automobiles in service by the end of the next decade. One could then foresee a significant quantity of electric vehicles will be connected to the electric grid and available for dispatch if called upon. The available idle energy associated with such a large aggregate source represents a potential resource from which to support utility system operations. With hundreds of thousands of plug-in vehicles being deployed in the near term, a low-cost storage mechanism could be deployed with the invention and deployment of V2G capabilities.

The analysis proposed in this project address these issues by applying a systems approach to an existing/upcoming distributed non-stationary energy storage asset – the plug-in electric vehicle. A key enabler of this approach is that the upcoming electric vehicle could be used as a distributed storage device. The analysis proposed here applies a systems approach to an existing/upcoming storage asset – the plug-in electric vehicle – to provide V2G capabilities. A system overview is shown in Figure C-6.

Figure C-6: System Overview PEV as a Distributed Resource



Source: E3

Grid operators use a variety of tools commonly referred to as “ancillary services” to reliably operate the electrical system. The Federal Energy Regulatory Commission (FERC) defines ancillary services[1] as “those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.” Load following, for example, is the balancing of generation to normal time-varying changes in load. Another ancillary service is operating reserves in the form of spinning and non-spinning reserves which are called into service to provide system reliability in the event of a major grid disturbance such as the loss of a generator or transmission line. In all, it’s estimated that

[1] U.S. Federal Energy Regulatory Commission 1995, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket RM95-8-000, Washington, DC, March 29

ancillary services accounts for 5-10 percent of the total cost of electricity which in the U.S. alone equates to approximately $12 billion per year[2].

Ancillary services focus on reducing these deviations at different timescales. The system flexibility/reliability functions and ancillary services that are required can be grouped into the following categories:

- *Inertial Response* (cycles to 1-2 seconds)
- *Primary Frequency Response* (cycles to 5-10 seconds)
- *Regulation* (10 seconds to several minutes)
- *Load Following/Ramping* (several minutes to few hours)
- *Dispatchable Energy (*sub-hourly and hourly*)*
- *Contingency Spinning Reserve*
- *Contingency Non-Spinning Reserve (*within 10 minutes*)*
- *Replacement or Supplemental Reserve (*30 to 60 minutes*)*
- *Voltage Support*
- *Load Leveling & Standby Power (t*ypically in the timeframe of minutes to hours*)*
- *Energy Peak Shifting (*typically in the timeframe of hours*)*

PEV Charging and Discharging Assessment

As customer adoption of plug-in electric vehicles (PEV) continues to grow so does the potential for adverse consequences to distribution system operations and assets. These concerns are amplified considering that geographically clustering of PEV adopters within particular neighborhoods or socioeconomic regions can lead to significant concentrations of PEV on particular feeders even though overall adoptions may be relatively small.

Recognizing the unpredictability in identifying specific customer adoption, vehicles types, and charging patterns, a proactive risk mitigation strategy is recommended to mitigate system-wide and localized risk to the distribution system. The strain on power delivery systems requires adjustments in asset management, system design practices, or even application of advanced controls which properly account for the particular nature of the newly emerging load.

PEV electrical charging characteristics have quickly evolved since the initial offerings in 2010. The first mass-produced PEVs charged at relatively low rates (up to 3.7 kW), traveled between 35 and 75 miles per charge, and there was little public infrastructure. Over the course of the first few years a host of additional PEV models had been introduced including a battery electric vehicle offering a range of up to 265 miles as well plug-in hybrid electric vehicle (PHEV) offering an electrical range of 10-15 miles.

Charging rates in new vehicle models have also increased dramatically from 3.7 kW to upper ranges between 7.0 – 19.2 kW. In order to provide context for these demands, several PEV charging rates are compared graphically against average peak summer demand of number of typical household appliances.

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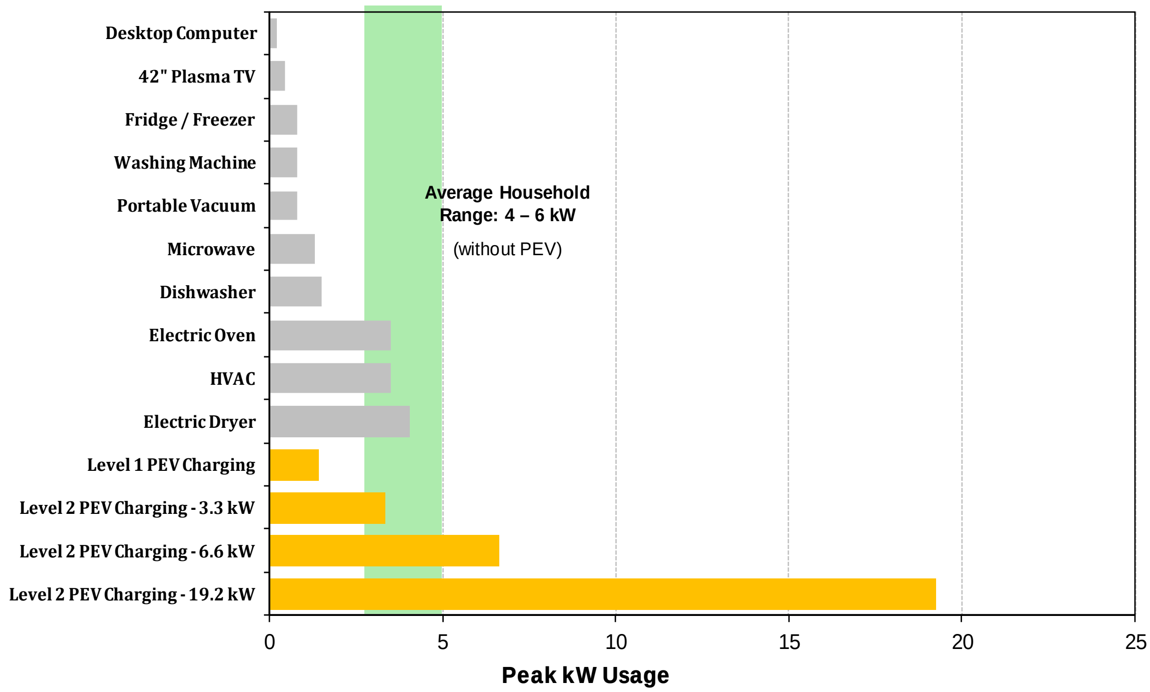
[2] Letemdre, S. Kempton, W. (2002). The V2G concept: A new model for power? Public Utilities Fortnightly

Figure C-7: PEV Load Comparisons with Avg Household Appliance Loads



Source: E3

Accordingly, increased customer adoption of PEVs with the distribution system has raised a variety of potential system impact concerns as well as need for future advanced operations such as controlled charging strategies, V2G (discharging), and providing ancillary services.

Customer Charging Habits

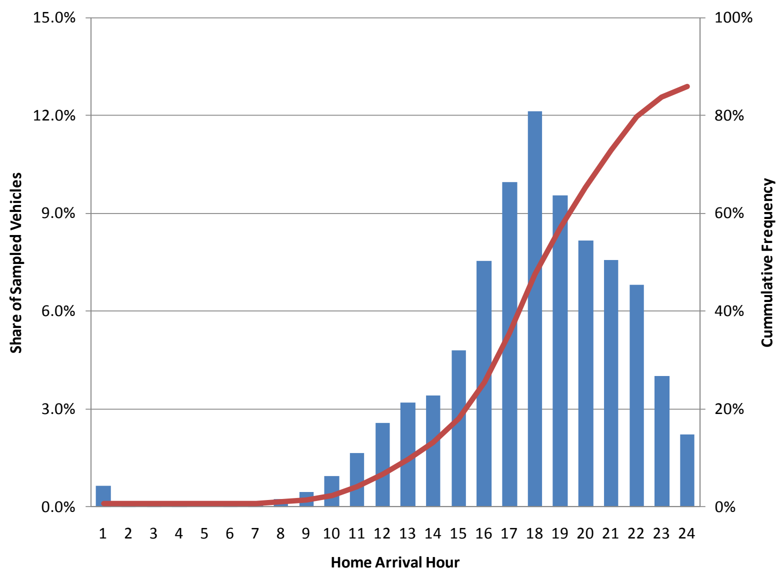
The modeled PEV demand is based on likely customer behavior. Likely customer charging behavior is derived from U.S. driving pattern data from the 2001 National Household Travel Survey (NHTS 2001)[3]. Assuming customers with no incentive to do otherwise will likely plug-in the vehicle when arriving at their residences, residential customer home arrival time data is used to generate PEV interconnection time probabilities. The resulting customer PEV charge time probability distribution used for the stochastic analysis is shown in Figure 75. Features of the dataset include:

- Analysis looks at a simple case; charging once per day at home, as soon as the driver arrives home. This represents the arrival time for the longest dwell time and does not consider multiple home arrival times per day.
- People arrive at home throughout the day, although the highest rates of home arrival (12 percent) unsurprisingly occur during the peak hours of residential electricity use between 5-6 pm.
- Over 70 percent of vehicles arrive at home by 8 pm and nearly 50 percent of home arrivals occur between 3-7pm.

[3] NHTS 2001 Unweighted Travel Day Data: Summary by Home Type, Purpose, End Time of the Last Trip, and Miles per Vehicle

- The probability distribution contains a 14 percent chance that vehicles remain stationary (are not driven) during the day. This probability is easily seen by the cumulative distribution in Figure C-8 not reaching 100 percent.

Figure C-8: Customer Home Arrival Times



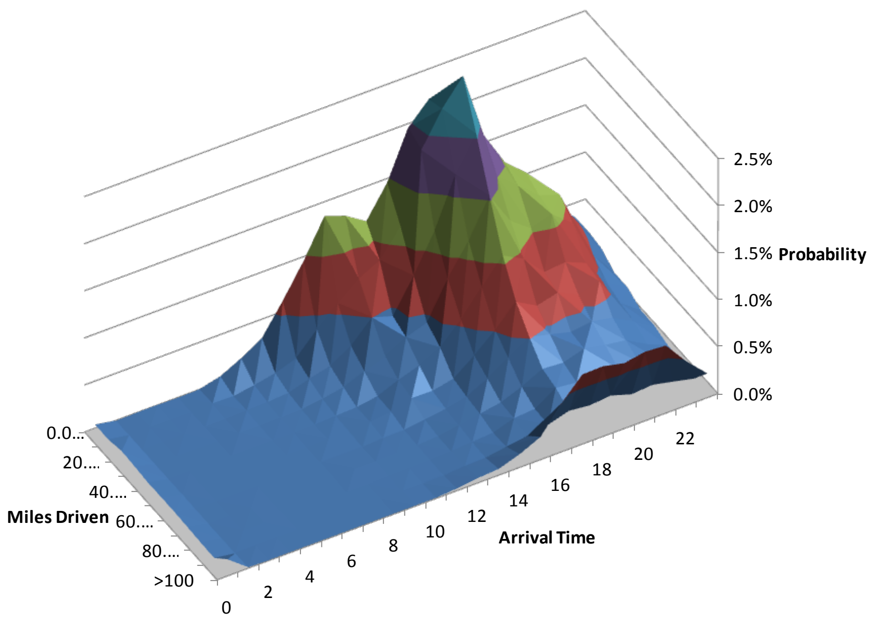
Source: E3

Battery State of Charge

Typical daily driving distances are also obtained from the National Household Travel Survey. For each possible home arrival time, a joint probability is derived for the associated miles driven that day. Assuming a fixed depletion rate and battery size, the amount of energy required to recharge the battery is tied to the associated miles driven. Relationships between projected home arrival times and miles driven are represented in the study by the probability distribution shown in Figure C-9. General features of this distribution to note include:

- Early morning arrival times coupled with long miles are unlikely,
- 74 percent of trips are less than 40 miles a day, and
- 36 percent of vehicles are driven less than 20 miles per day.

Figure C-9: Joint Probability Relationship between Arrival Time and Miles Driven



Source: E3

PEV Demand Characteristics and Projection Sensitivity Evaluations

In this section, probabilistic examinations of PEV demand are performed to evaluate expected to gain a further understanding of the temporal and spatial diversity inherent to PEV load. Additionally, the evaluations demonstrate the potential application of a probabilistic approach for future impact evaluations.

General findings for this section include:

- Home arrival time (considered to be the uncontrolled charging start time) has the largest influence on the total and worst-case PEV demands.
- The maximum total PEV demand may be between 0.43 - 0.94 kW/PEV depending on the makeup of the PEV fleet.
- The worst-case PEV demand, for assets serving less than 30 customers, is more sensitive to the charge level than overall PEV penetration.

Demand for a Single PEV of Unknown Type

Given the complexity of the factors influencing the PEV load profiles – both probabilistic as the physical characteristics – Monte Carlo analysis was used to determine the probability distribution of the demand from a single PEV of unspecified type. To achieve an acceptable estimate of the distribution, thirty thousand random daily charging profiles were generated and used to create histograms for the PEV charging at each hour of the day. A large number of simulations were required to unsure a sufficient number of non-zero charging values were generated across each hour. Note week days and weekends or seasonality is not represented. Similar analyses could be performed for these cases through the specification of associated vehicle usage probability functions.

Letting the random variable *B* be the demand per PEV, the probability distribution for the demand for a single PEV – of unknown type – at hour *h* is designated $p(b; h, n = 1)$. Unless otherwise noted, the analysis examines the results only for the peak hour (hour 17 or 5 pm) and the variable "*h*" will be subsequently dropped from the notation.

In this analysis, the home arrival and miles driven data presented earlier is assumed in the analysis along with the distribution for the various vehicular charging levels and battery sizes detailed in Table C-1.

Table C-1: Vehicular Mix (10/40/40/10) Distribution

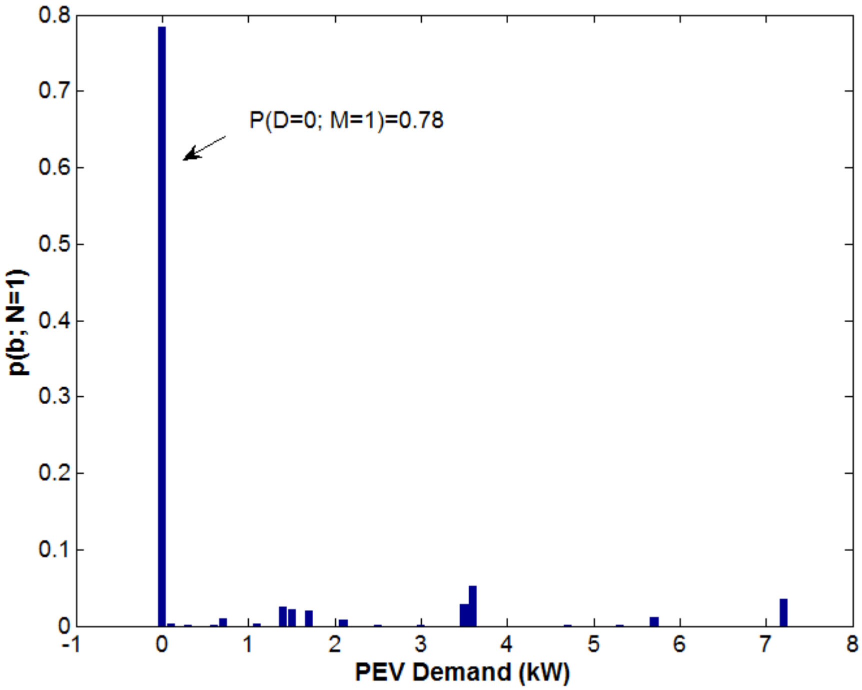
Vehicle Type	p(Vehicle Type)
120 V – 12 A – 4 kWh	10 percent
240 V – 15 A – 8 kWh	40 percent
240 V – 30 A – 8 kWh	40 percent
240 V – 30 A – 24 kWh	10 percent

Source: E3

The calculated probability mass function (pmf) is provided in Figure C-10. A few characteristics of note for the distribution are:

- Non-Gaussian,
- $E[B; N=1] = \square = 0.74$ kW/PEV,
- $P(B = 0; N=1) = 0.78$, and
- $P(B \geq 3.6; N=1) = 0.171$

Figure C-10: Probability Mass Function for Single PEV Demand



Source: E3

Given this set of PEV characteristics assumptions, approximate 20 percent of PEV will charge during hour 17 (typically assumed to be the peak hour for most circuits). This finding served as the basis for the conservative assumption, used in the asset analysis portion of the study, that there is a 30 percent probability that a PEV charges during the peak hour.

Demand for Fixed Number of PEV

The total demand for n PEV can be found by n summations of B as in (1). Note that the calculation of B_n is also normalized by n to keep the variable in terms of demand "per" PEV.

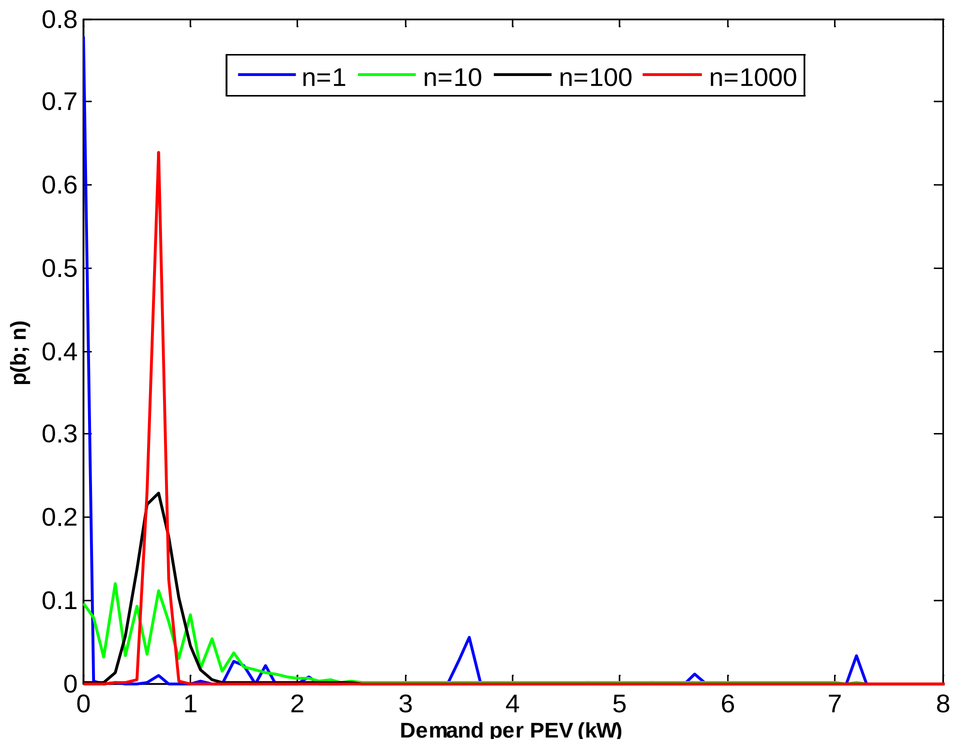
$$B_n = \left(\sum_{1}^{n} B\right)/n \tag{1}$$

The associated probability mass function, $p(b;n)$, can therefore be determined for increasing numbers of PEV through recursive convolutions as shown in (2).

$$p(b;n) = p(b;n-1) * p(b;1) \tag{2}$$

The probability functions of $p(b;n)$ for increasing order of magnitude values of n are illustrated in Figure C-11. It can be shown, that the mean remains constant for the normalized distribution for all values of n. However, the variance decreases linearly with increasing values of n. Additionally, following the Central Limit Theorem, the distribution takes on a Gaussian shape with sufficiently large values of n. Thus, for large numbers of PEV, the likely demand during the peak hour can be reasonably approximated using the distribution mean. Thus, for the example assumption set, the total PEV demand at the head of a feeder could be reasonably approximated using 0.74 kW/PEV.

Figure C-11: Demand per PEV Probability Mass Functions for Sample Values of n

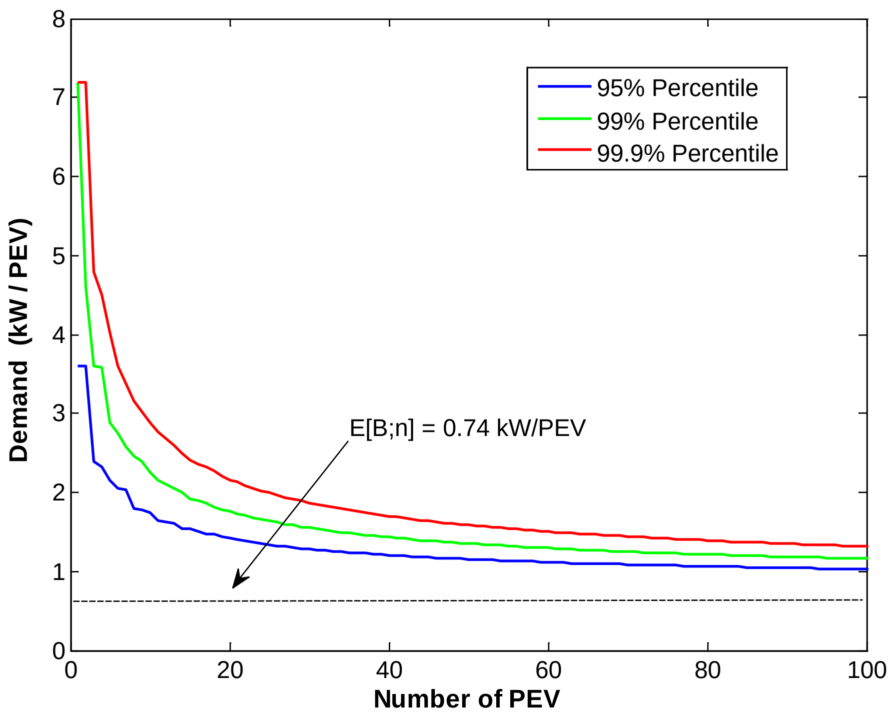


Source: E3

Instead the variance, a common 95th percentile metric is used to examine the impact of increasing *n* on the nature of the distributions. High percentiles values, greater than 95 percent, are selected to compare conservative estimates of the maximum PEV demand expected for each *n*.

Percentile lines plotted in Figure C-12 below indicate the potential worst-case demand/PEV that would be expected for 95th percent of the cases. Note that the lines converge – along with the variance – towards the mean value as *n* is increased. Thus, the average demand is a useful statistic when evaluating the expected demand for a large number of PEV and the 95th percentile provides a bound for the worst-case estimates.

Figure C-12: Demand for PEV Percentiles



Source: E3

PEV Demand for a Single Residence

Letting X again denote the number of PEV per residence and D the demand per residence, the probability function describing the total PEV demand for a single residence is given by:

$$p(d|x) = p(b; N = x) = \begin{cases} p(b; N = x - 1) * p(b; N = 1), & X \geq 1 \\ 1, & X = 0, D = 0 \\ 0, & otherwise \end{cases} \tag{3}$$

The joint probability mass function for D and X is then defined by (4). Note that the distribution $p(x)$ was derived and values used in this section were taken from the example distributions.

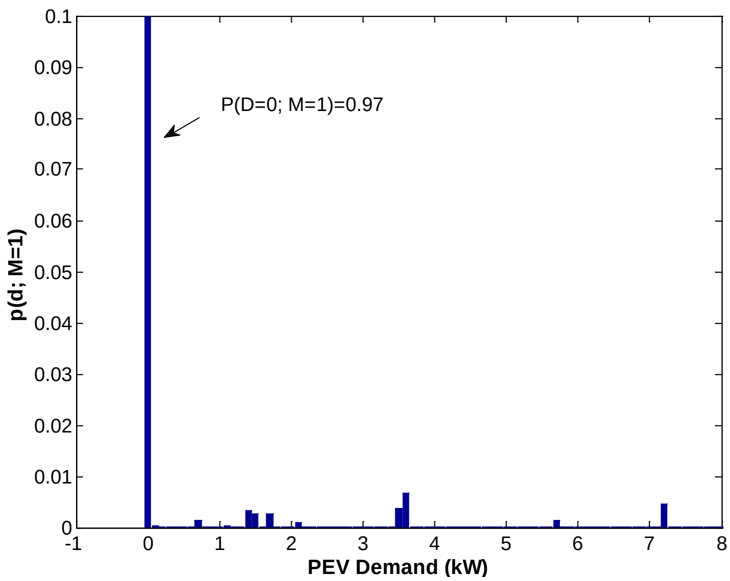
$$p(d, x) = p(d|x) \cdot p(x) \tag{4}$$

The probability mass function for D is therefore the marginal probability; where M denotes the number of residences.

$$p(d; M = 1) = \sum_j p(d, X = j) \tag{5}$$

The resulting PEV demand per residence probability distribution, assuming 8 percent market penetration, is plotted in Figure C-13. As shown, the probability that a randomly selected household will have a PEV charging during the peak hour is very low – note this assumes no knowledge of the number of PEVs at the residence or any other indicating factors. As the probability that a residence has zero PEV is relatively high at 8 percent penetration, the resulting probability that any random residence will have a PEV charging at the peak hour drops to less than 3 percent. A summary list of the probability distribution characteristics for the example market penetration is provided in Table 20: Sample p(d; M=1) Characteristics

Figure C-13: Probability Mass Function for PEV Demand for a Single Residence



p(b; M=1) (8 percent Market Penetration)

Source: E3

Table C-2: Sample p(d; M=1) Characteristics

Market Penetration	P(kW)	P(D; M=1)	*P*(*D*=0)	*P*(*D*>3.6)
2 percent	0.025	0.336	0.993	0.002
4 percent	0.049	0.475	0.985	0.007
8 percent	0.099	0.671	0.971	0.013

Source: E3

PEV Demand for Fixed Number of Residences

For m residences the total PEV demand per number of residences, D_m, is simply another summation of the random and normalized variables as was done for B_n.

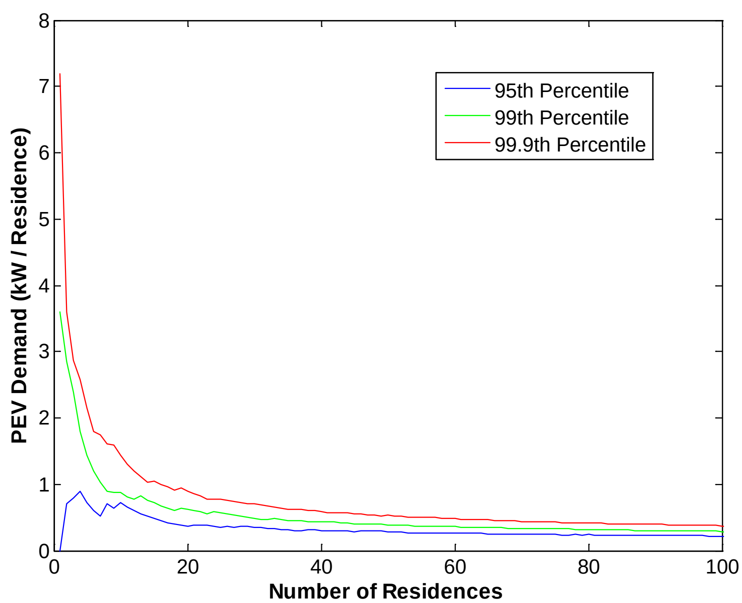
$$D_m = \left(\sum_{i=1}^{m} D_i\right) / m \qquad (6)$$

The probability mass function for D_m can then be determined for every possible number of households served in the circuit (i = 1, 2, 3,…, *m*) through recursive iterations of the convolution of $p(d)$ or

$$p(d; m) = p(d; m - 1) * p(d; 1)$$

As was done for the demand per PEV distributions, $p(b; n)$, the percentiles for increasing values of m are calculated from each $p(d;m)$. The resulting percentiles indicators are shown in Figure C-14. Again, these lines indicate the worst-case PEV demand per number of residences based on the level of confidence concerning the likelihood of occurrence. Recall that $p(D=0, M=1)$ was 97.1 percent for the 8 percent penetration level which accounts for the zero value shown for the 95 percent percentile line at $m = 1$. More importantly, this figure indicates that that assets serving very few customers have the potential to see relatively high PEV demands per residence even though the probabilities of this occurring may be fairly low.

Figure C-14: PEV Demand per Residence Percentiles (8 percent Penetration)

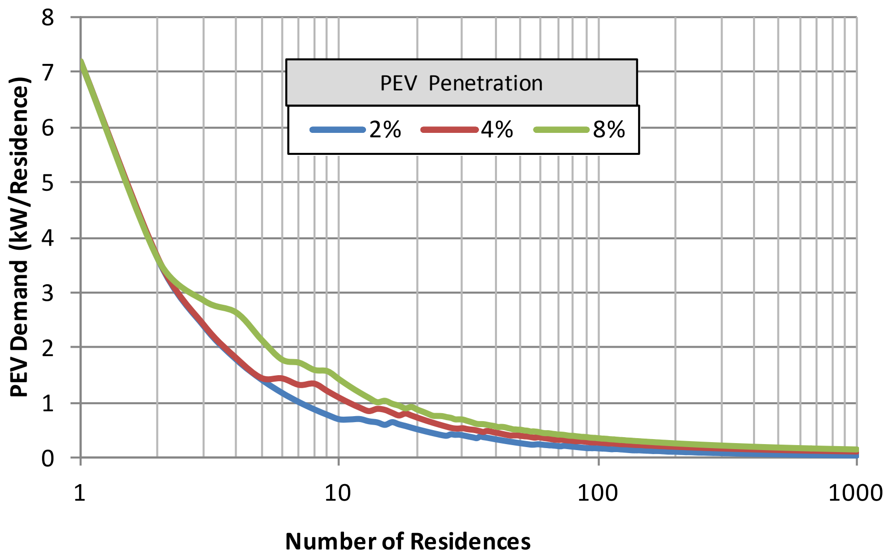


Source: E3

Peak Hour PEV Demand Projection Sensitivities

The change in the projected worst-case demand (specifically for the 99.9th percentile demand) given increasing PEV market penetration is illustrated in Figure C-15. As shown, the largest deviation in projected demands for these market penetrations occurs within the $1 < m < 30$ band.

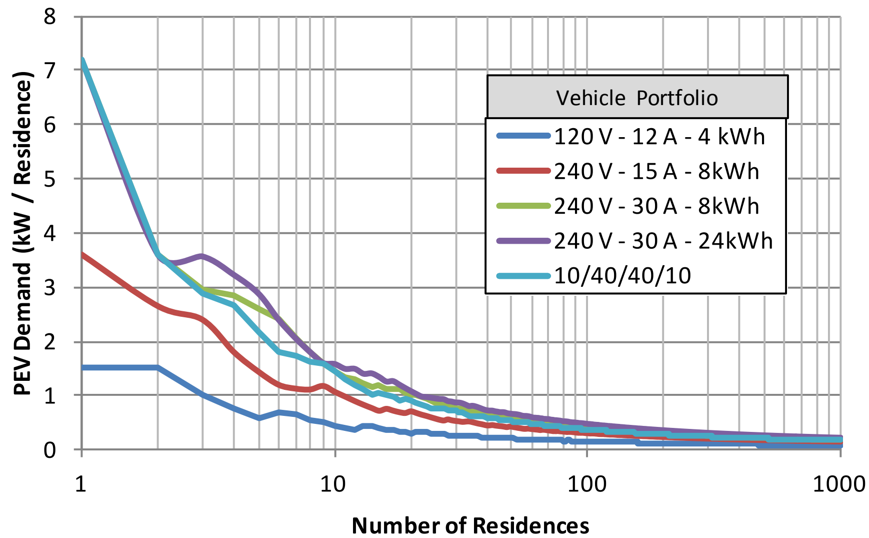
Figure C-15: 99.9th Percentile Demand



Source: E3

In Figure C-15 the sensitivity of the percentile lines to assumed PEV type distribution is shown. In this case, a 99.9th percentile lines were calculated assuming the PEVs are composed of only a single type – with a line for each potential charging rate/battery combination – or a diverse mix as previously defined by the distribution in Figure C-16. As expected, vehicles with the faster charging rates can result in higher projected PEV/residence demands for assets which serve a relatively low number of customers. In contrast, very little difference can be noticed in the expected assets serving more than 100 customers given the benefits from diversity in the charging times and durations. Note that the assumed vehicle charging rate had a much larger influence on the 99.9th percentile projected demands in Figure C-16 that the resulting changes across the examined penetration levels. This indicates the potential diversity benefits from lower charging rates on system impacts. For example, for assets serving between 2 to 10 residential customers, the "240V-15A-8kWh" percentile line at 8 percent penetration level shows a similar demand maximum demand projection as the mixed distribution at 2 percent penetration.

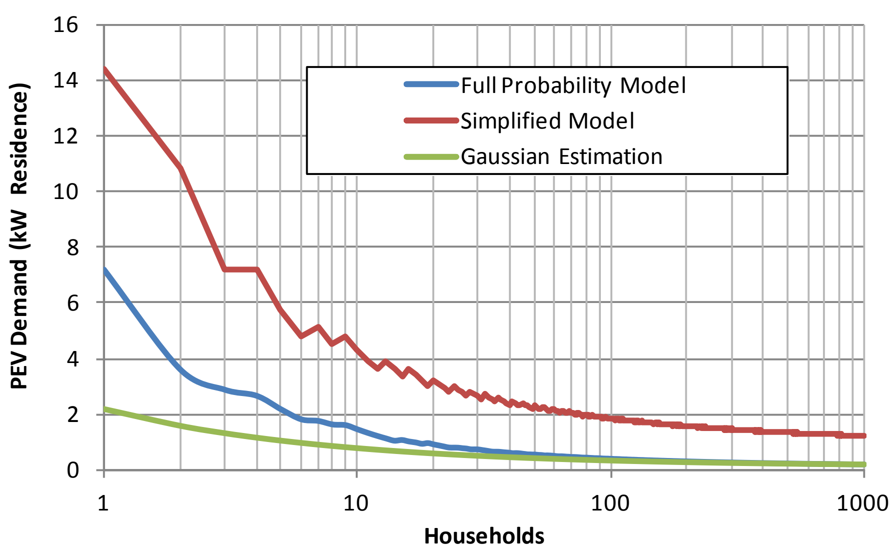
Figure C-16: 99.9th Percentile for Varying Vehicle Portfolios (8 Percent Market Penetration)



Source: E3

The projected 99.9th percentile demand lines using the full set of probabilities (Figure C-17) is compared to the simplified projection model (used in the asset analysis and detailed elsewhere) and the projection utilizing Gaussian tables. The conservative nature of the simplified model is clearly shown by estimates that are more than twice the full diversity model projection. Additionally, the inaccuracy in the estimates when assuming the PEV demand probabilities are Gaussian given a few residences is low is clearly shown. Conversely, the Gaussian assumption provides a reasonable and quick approximation when examining the additional loading expected on assets serving a larger number of customers such as the substation transformer.

Figure C-17: Percentile Demand Estimate Comparisons (8 Percent Market Penetration)

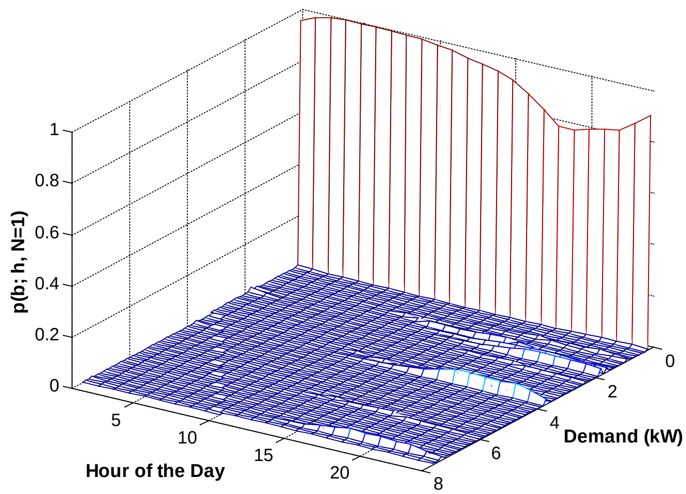


Source: E3

PEV Hourly Demand Sensitivities

As electric vehicle charging is not limited to the peak hour alone, it is worthwhile to similarly examine the probabilistic projections and the associated sensitivities at other hours. The various distributions and figures developed for the peak hour can be summarily determined for other hours using the previously outlined calculations and assumptions.

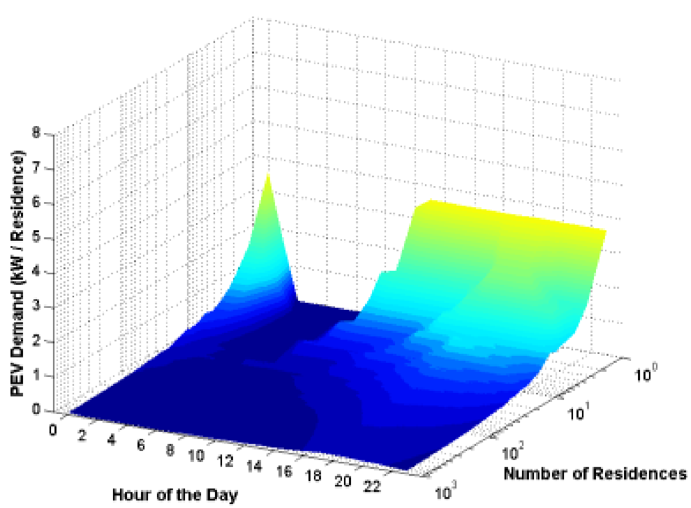
Figure C-18: Example Distributions for p(b; h, N=1)



Source: E3

The probability distributions for the demand for a single PEV are plotted in Figure C-19 for each hour of the day. Here the project team will again use *h* to represent the particular hour of the day. For example, the probability distribution for the peak hour demand for 5 pm used in the previous sections is therefore $p(b;\ h{=}17,\ N{=}1)$. Note the probabilities here are for a single PEV of unspecified type but assuming the probabilistic mix case.

Figure C-19: 99.9th Percentile PEV Demand Per Residence and Hour Mixed PEV

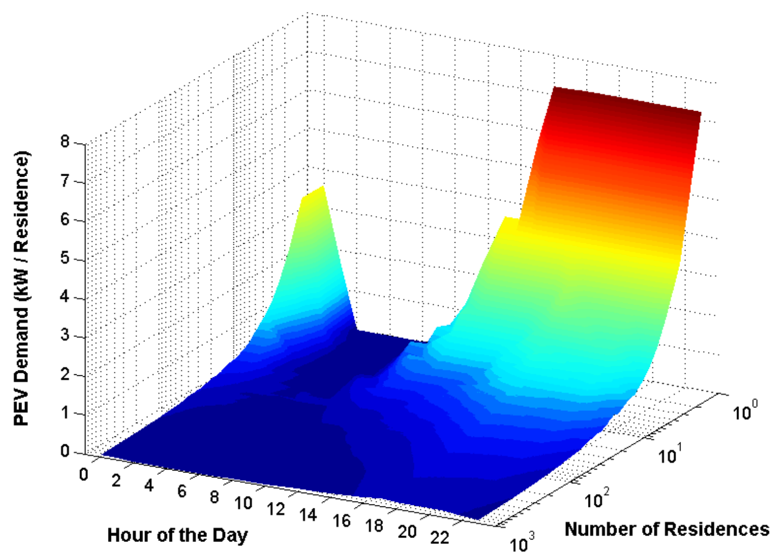


8 percent penetration and mixed PEV portfolio

Source: E3

The 99.9th percentile for each hour of the day for increasing number of residences is plotted in Figure C-20. As shown, the 99.9th percentile is relatively constant between 3pm and midnight. Thus, worst-case PEV demand does not significantly change during these hours. Given residential loads are already high during these hours, adjustments to charging behavior – via charging start times and/or charging rates – are desirable in order to reduce/shift these additional worst-case demands. For example, limiting the charging to 3.6 kW – by assuming the entire fleet is of the 240V-15A-8kWh type – the resulting 99.9th percentiles display a much lower PEV demand but spread across a wider section of hours.

Figure C-20: 99.9th Percentile PEV Demand Per Residence and Hour All 240V-15A-8kWh PEV Portfolio

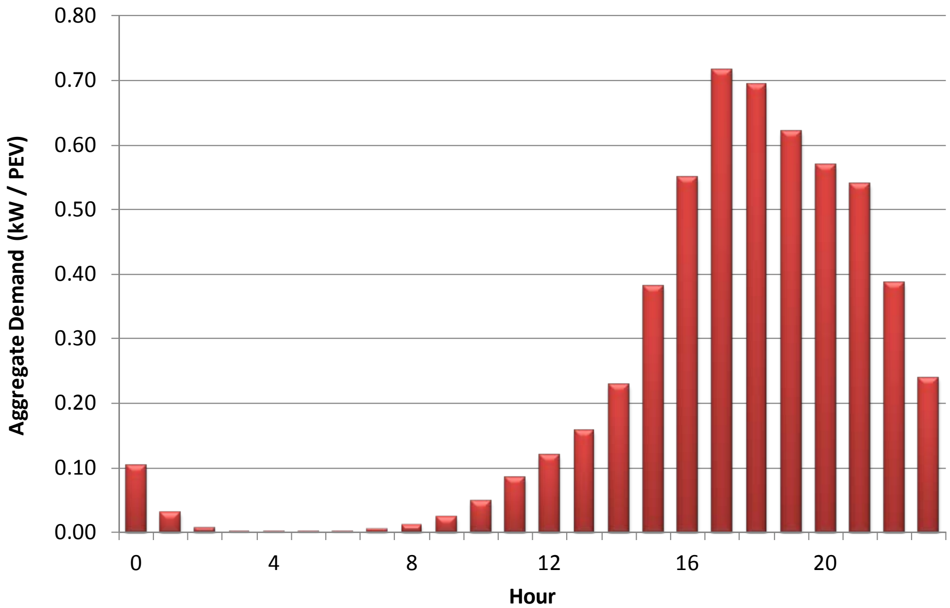


8 percent penetration and all 240V-15A-8kWh PEV portfolio

Source: E3

While the extremes of the distribution do not change dramatically during these evening hours, as indicated by the 99.9th percentiles, the average demand per PEV exhibits much larger variations. Recall that the normalization of the probability distributions results in the mean being constant as the number of residences increases. Thus, the average demand "per residence" can be plotted independently of the number of residences as in Figure C-20. The average demand for m residences can then be quickly determined by scaling the results in Figure C-20. As indicated, the majority of the uncontrolled demand is projected to occur during the later afternoon to evening hours.

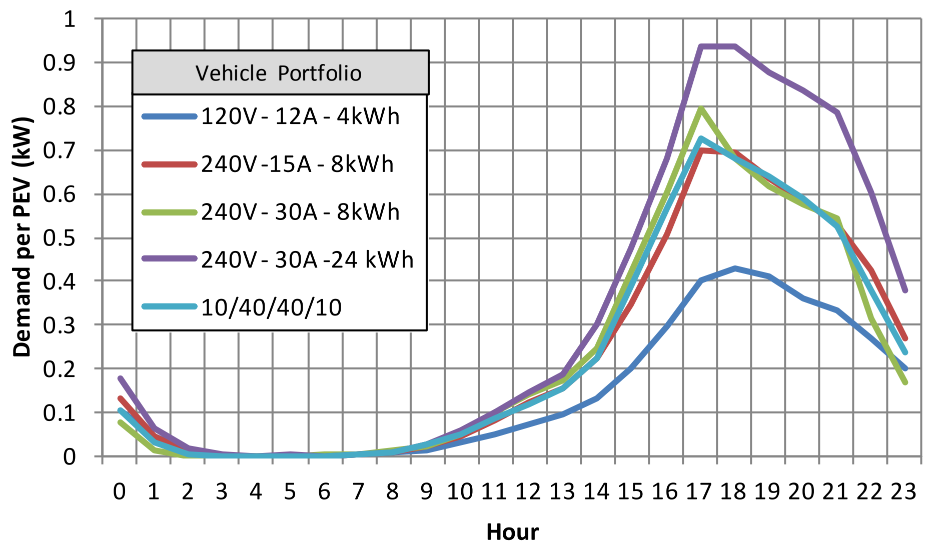
Figure C-21: Average Demand Per PEV for Each Hour of the Day (10/40/40/10Mix)



Source: E3

Up to this point in the estimates a PEV portfolio consisting of a 10/40/40/10 mix (as summarized in Figure C-21 is assumed. To evaluate the sensitivity to vehicular types, the average hourly demand was calculated and plotted in Figure C-22 for each vehicle type. Clearly, the projected average demand is also significantly influenced by battery size. Consequently, the maximum demand is expected to range between 0.43 and 0.94 kW/PEV given the selected vehicle types.

Figure C-22: Average Hourly Demand per Vehicle Type

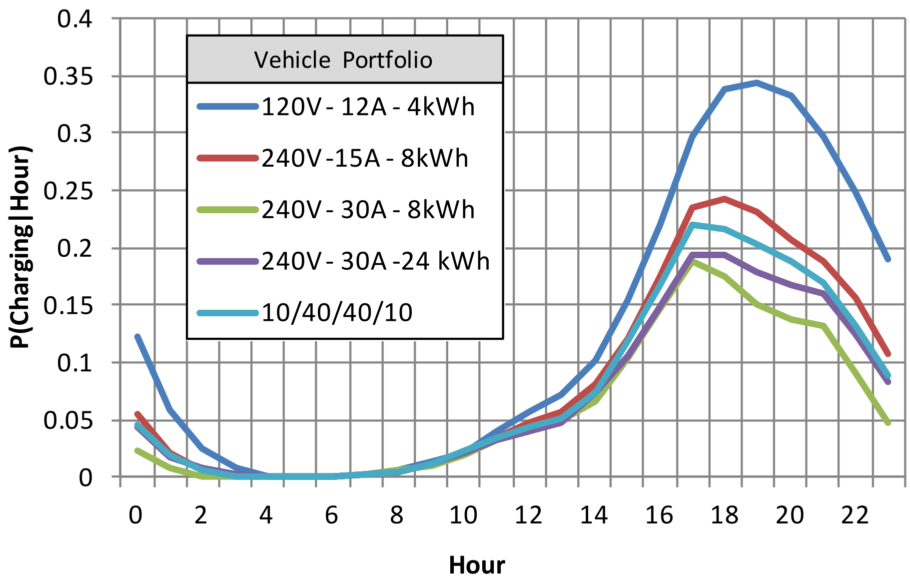


Source: E3

As can be seen, the hourly variation in the average demand is mainly driven by home arrival time. While longer duration charging profiles can skew the peak PEV demand slightly, due to the overlapping of multiple PEV charging profiles, the projected peak demand is expected to be skewed only by an hour or so from the peak in home arrival times. Finally, doubling the charging rate (15 to 30A) for the 8kWh battery size is shown to increase the average peak demand by 100 watts/PEV or approximately 14 percent.

In Figure C-23 the probabilities of a single plug-in electric vehicle charging at each hour are plotted for each vehicle type as well as assuming the vehicle mix. Note that the shorter the expected charging duration the closer the correlation of the probability with the home arrival times as shown in Figure C-23.

Figure C-23: PEV Charging for Given Hour Probability Mass Functions

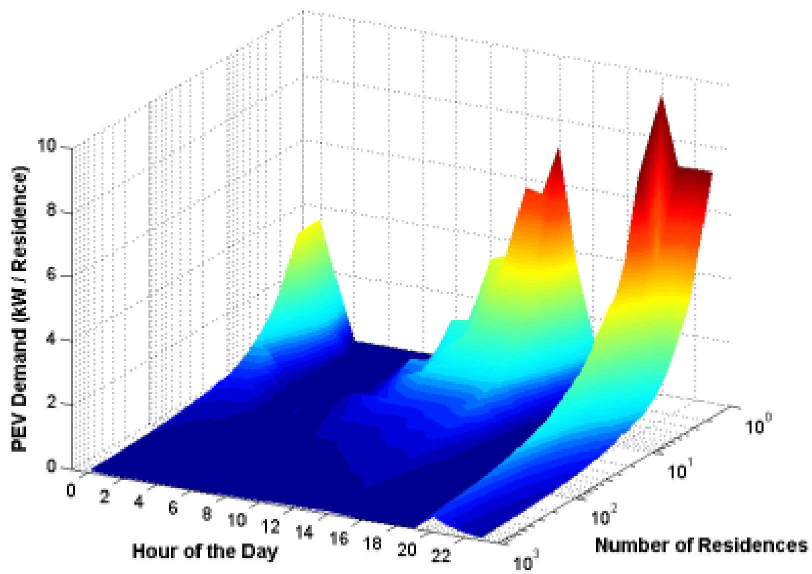


Source: E3

For uncontrolled PEV charging, customer behavior undoubtedly has a significant impact on the expected PEV demand. While home arrival times (charging start times) and miles driven can vary somewhat between regions, small variations are expected to result in small changes to the projected demand and should be analyzed in context of the particular impact study.

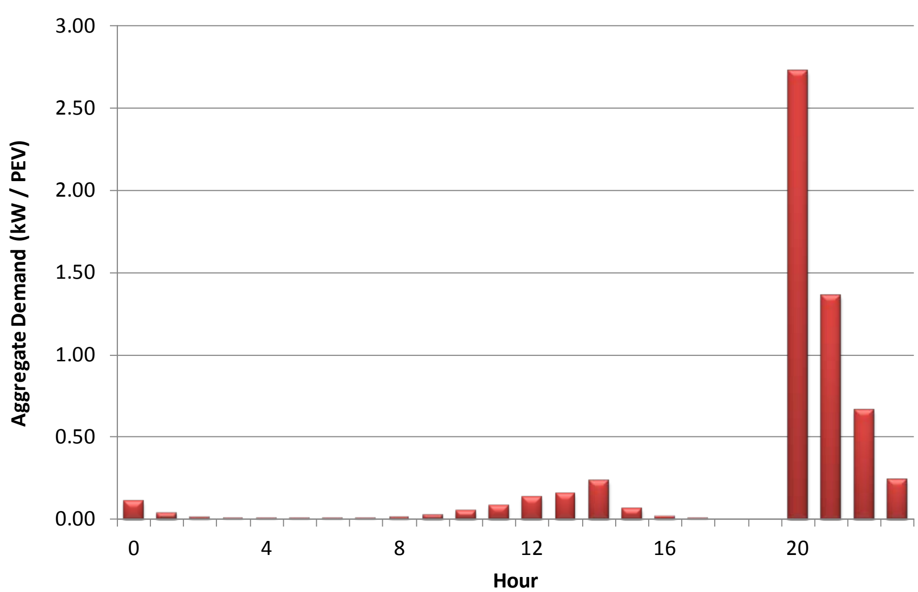
In contrast, much larger changes to these values – through "smart charging" controls or other means – can have significant impacts. An example Time-of-Use (TOU) case which delays any PEV arriving home between the hours 16-20 to charging at hour 21 was evaluated. The bearing of this program on the worst-case loadings is illustrated by Figure C-24. As shown, the TOU rate has the intended effect of shifting the demand but also increases the worst-case PEV loading during hours 21 and 22 significantly. The TOU rate also influences the projected average loading in a similar fashion as shown in Figure C-23 where the maximum expected PEV demand is shown to increase over 300 percent - however now at hour 21.

Figure C-24: 99.9th Percentile PEV Demand per Residence and Hour



Source: E3

Figure C-25: Average Hourly Demand per PEV for an Example TOU Case



Source: E3

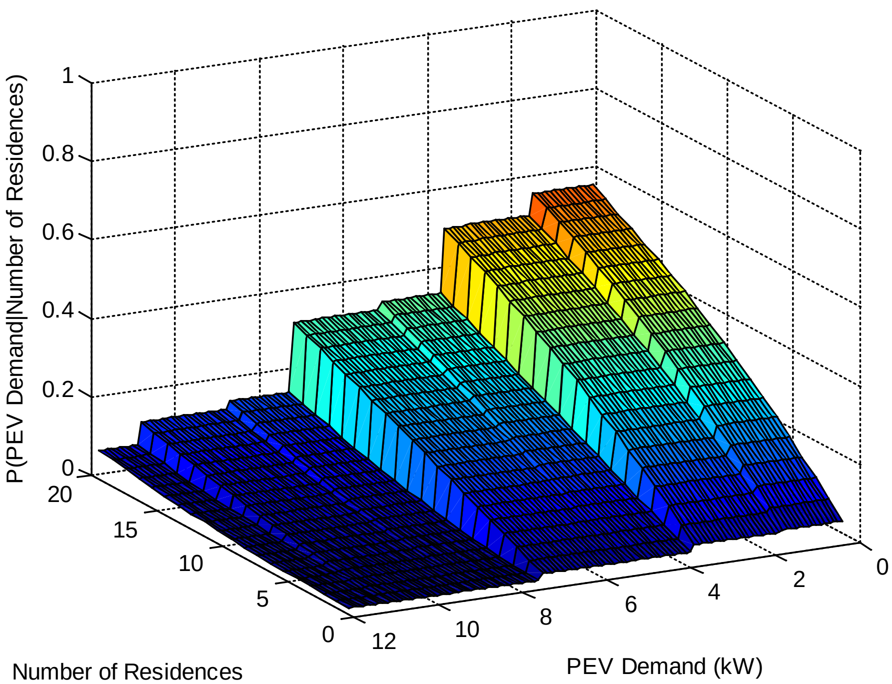
Probabilistic Demand Projection

Using the probability distribution calculated in (7), the probability that PEV demand for given number of residences exceeds a specified amount can be readily calculated.

$$P(D \geq kW;\ m) = 1 - F(d; m)$$

Hence a table of probabilities across a combination of residences and potential PEV demand could be derived, as shown in Figure C-26, and used as a look up table to determine the probability of PEV demand exceeding an asset's thermal ratings – given the assets available capacity and number of connected residences. In this manner, a probabilistic assessment of the potential impacts across a wide section of system assets could be quickly accomplished.

Figure C-26: Example P(D ≥ kW; m) Matrix



Source: E3

Overview of Avoided Cost Methodology

Distributed energy resources (DERs) can either positively or negatively impact local T&D costs depending on its location on the distribution grid as well as the timing and direction of its effect on net load. In general, DER provides benefits by reducing the loads on the T&D system at times of peak demand, thereby allowing the deferral or avoidance of T&D capacity additions. In some cases, where there are high amounts of uncontrolled distributed generation on the local system, additional DER could exacerbate the reverse flow problems in the area and trigger or accelerate the need for capacity or protection additions to accommodate the reverse flow. While the methodology discussion presented herein focuses on the deferral case, the methodology is equally applicable to the acceleration case.

Project Deferral Value

The deferral value of DER is the difference in the net present value of any T&D capacity projects before and after the installation of DER. The project costs include project upgrade capital costs ($DefValCap$), ongoing O&M costs ($DefValOM$), and impacts on losses ($DefCostTransLosses$ and $DefCostDistLosses$).

(1)	$DefValTot[a] = DefValCap[a] + DefValOM[a] - DefCostTransLosses[a] - DefCostDistLosses[a]$

Deferral value of a capital project

$DefValCap[a]$ is the present value of capital deferral savings at the DER installation year y. The savings are for all projects p that are affected by DER installed in area a.

(2)	$DefValCap[a] = \sum_{p \in P} DefValCap[p, a]$

Where:

P is the set of projects that can be deferred by DER in location a

To calculate the deferral value for a single project deferred by DER in location a ($DefValCap[p, a]$), the capital cost of the project is first converted to revenue requirement costs based on the revenue requirement multiplier. The revenue requirement adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs. Levelized revenue requirement costs in real terms are then calculated based on the Real Economic Carrying Cost (RECC). Finally, deferral values are calculated based on the number of years deferred and the levelized revenue requirement costs.

(3)	$DefValCap[p, a] = \sum_{yr=1}^{deferral\,years[p,a]+1} \frac{RECC[p] \times RRC_y[p]}{(1 + disc_{real}[inv])^{yr-1+OriUpgradeYr[p]-DERinstalledYr}}$

(4)	$RRC_y[p] = Capital_{costyr}[p] \times RRMultiplier[inv] \times Einf[inv]^{y-costyr}$

(5)	$RECC[p] = \frac{disc - Einf[inv]}{1 + disc} \times \frac{(1 + disc)^{blife[p]}}{(1 + disc)^{blife[p]} - (1 + Einf[inv])^{blife[p]}}$

(6)	$disc_{real} = \frac{1 + disc}{1 + Einf[inv]} - 1$

Where

- $DefValCap[p, a]$ = NPV of the deferral values in DER installation year
- inv = the investment equipment types for the project
- $Capital_{costyr}[p]$ = The capital investment in the cost year specified by users for project p
- $RRMultiplier[inv]$ = Revenue requirement multiplier that adjusts the engineering cost estimate for the capital project to total revenue requirement cost levels for the types of

investment. The adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs.

- $Einf[inv]$ (percent/yr) = the equipment inflation rate
- $RRC_y[p]$ = revenue requirement costs in DER installation year y for the project p
- $RECC[p]$ = Real economic carrying charge for the project p. RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral.
- $disc$ = nominal discount rate
- $blife[p]$ = book life of the upgrade project p
- $disc_{real}$ = discount rate net of project inflation (percent/yr)
- $OriUpgradeYr[p]$ = original upgrade year for the project p
- $deferral\ years[p,a]$ = number of years that the project (p) can be deferred due to DER installed in the location a = deferred upgrade year – original upgrade year

Deferral value of avoided incremental O&M

In addition to deferral capital investment, the deferred O&M costs also contribute to the total deferral value. $DefValOM[a]$ is the net present value of the O&M deferral saving for all projects p that are affected by DER installed in area a.

(7)	$$DefValOM[a] = \sum_{p \in P} DefValOM[p,a]$$

(8)	$$DefValOM[p,a] = \sum_{yr=1}^{deferral\ years[p,a]+1} Capital_{costyr}[p] \times Einf[inv]^{y-costyr} \times OMFctr[inv] \times \left(\frac{1+OMesc[inv]}{1+disc}\right)^{yr-1+OriUpgradeYr[p]-DERinstalledYr}$$

Where:

- $DefValOM[p,a]$ = NPV of deferred O&M cost at the DER installation year
- $OMFctr[inv]$ = O&M factor for the investment type, O&M factor is the ratio of annual O&M costs to project capital costs
- $OMesc[inv]$ = O&M escalation rate for the investment type

Deferral cost of transmission losses

Finishing a new T&D upgrade project will generally result in lower electrical losses, creating savings from reduced energy consumption. When a T&D project is deferred, then these savings are foregone. Formulae below define the cost of foregoing the efficiency improvements of T&D projects in an area a.

(9)	$DefCostTransLosses[a] = \sum_{p \in P} DefCostTransLosses[p, a]$

(10)	$DefCostTransLosses[p, a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedTransLosses[p, yr + OriUpgradeYear]}{(1 + dist[inv])^{yr-1+OriUpgradeYr[p]-DERinstalledYr}}$

(11)	$AvoidedTransLosses[p, y] = AreaMWh[p, y] \times WeightedEnergyAC[y] \times \Delta LossMWh \text{ percent}[p] + AreaMW[p, y] \times AGCC[y] \times 1000 \times \Delta LossMW \text{ percent}[p]$

(12)	$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t, y] \times SystemLoad[t, y]}{\sum_{t \in T} SystemLoad[t, y]}$

Where:

- T is the set of timesteps in the year y
- $AvoidedTransLosses[p, y]$ is the nominal avoided costs ($) for transmission losses at year y after the project p upgrade
- $AreaMWh[p, y]$ is energy consumption in the transmission area affected by the project p upgrade
- $EnergyAC[t, y]$ is the energy avoided cost at the timestep t
- ΔLossMWh percent[p] is baseline area average annual loss factor minus average loss factor after the project p is completed.
- AreaMW[p, y] is the peak MW for the affected area
- AGCC[y] is the avoided generation capacity cost in $/kW
- ΔLossMW percent[p] is baseline area peak loss factor minus peak loss factor after the project p is completed
- $SystemLoad[t, y]$ is the system load at the timestep t

Deferral cost of avoided distribution losses

Similar to transmission system losses, the project team model energy losses on the distribution system that would be avoided with the deferred upgrade project using the following formulae.

(13)	$DefCostDistLosses[a] = \sum_{p \in P} DefCostDistLosses[p, a]$

(14)	$DefCostDistLosses[p,a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedDistLosses[p,y]}{(1+dist[inv])^{yr-1+OriUpgradeYr[p]-DERinstalledYr}}$

(15)	$AvoidedDistLosses[p,y] = AreaMWh[p,y] \times WeightedEnergyAC[y] \times \Delta LossMWh \text{ percent}[p] + AreaMW[p,y] \times (AGCC[y] + ADC[a,y]) \times 1000 \times \Delta LossMW \text{ percent}[p]$

(16)	$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t,y] \times DistLoad[t,y]}{\sum_{t \in T} DistLoad[t,y]}$

Where:

- $DefCostDistLosses[p,a]$ is the NPV deferral values at the DER installation year
- T is the set of timesteps in the year y
- $AvoidedDistLosses[p,y]$ is the nominal avoided costs ($) for distribution losses at year y after the project p upgrade
- $AreaMWh[p,y]$ is energy consumption in the distribution area affected by the project p upgrade
- $EnergyAC[t,y]$ is the energy avoided cost at time step t on year y
- $\Delta LossMWh\ percent[p]$ is baseline area average annual loss factor minus average loss factor after the project p is completed.
- $AreaMW[p,y]$ is the peak MW for the affected area
- $AGCC[y]$ is the avoided generation capacity cost in $/kW
- $ADC[a,y]$ is the avoided distribution cost in $/kW for location a
- $\Delta LossMW\ percent[p]$ is baseline area peak loss factor minus peak loss factor after the project p is completed
- $SystemLoad[t,y]$ is the distribution load at the timestep t

Attribution of Deferral Value

T&D Topology

DER systems located at location a might have impacts on multiple capacity projects located electrically upstream from location a. Flow factors and location-specific loss factors to identify the impacts of DER systems to the surrounding potential upgrade projects.

Flow factors

Flow factors represent the impact percent of the DER project to the T&D upgrade project located in the upstream locations. For example, in the following table for the DER systems installed in DPA2, 100 percent of its load reduction affects the T&D upgrade in DPA2. And only 90 percent and 50 percent of its load reduction would affect the T&D upgrade projects in DPA 1 and DPA3.

Table C-3: Flow Factors

flow factors	DPA1	DPA2	DPA3
DPA1	1	0.9	0.8
DPA2	0.8	1	0.5
DPA3	0.8	0.5	1

<--Affected T&D project (p)

Source: E3

Loss factors

Loss factors indicate the transmission and distribution losses between DER installation location and the potential T&D upgrade location. 10 percent losses are entered as 1.10 loss factor.

Table C-4: Loss factors

DER installation location (a) -->

loss factors	DPA1	DPA2	DPA3
DPA1	1.1	1.12	1.15
DPA2	1.12	1.05	1.1
DPA3	1.15	1.1	1.05

<--Affected T&D project (p)

Source: E3

The load impact on T&D upgrade project p by the DER systems at location a at time t would be:

(17)	$LoadReduction[p,a,t] = \frac{LoadReduction[a,t] \times FF[p,a]}{LF[p,a]}$

Contribution of DER to peak load reduction

The reduction in peak load for project p due to DER in area a, $PeakReduction[p,a]$, is given by the following formulae.

(18)	$Peak\_after\_DER[p,a] = Max_t \left(Load[p,t] - \frac{DERNetDischarge[a,t] \times FF[p,a]}{LF[p,a]} \right)$

(19)	$Peak[p] = Max_t(Load[p,t])$
(20)	$PeakReduction[p,a] = Peak[p] - Peak\_after\_DER[p,a]$

Where:

- $Load[p,t]$ is the project load at time t
- $Peak\_after\_DER[p,a]$ is the project p peak load after the effects of DER in area a
- $Peak[p]$ is the original peak load for project p
- $PeakReduction[p,a]$ is the reduction in project p peak load due to DER in area a

Allocation of deferral project value to a DER

Deferral value attributed to DER located in area a is based on expected reductions during peak load times. This method assumes that deferral is achieved for a project, and that DER in each area contributes to the deferral. Given the full value of a deferral project ($DefValTot[p]$) the value allocated to DER in area a ($DefValTot[p,a]$) is proportional to the ratio of DER peak reduction provided by DER in area a for project p to the total reduction needed for project p, such that $DefValTot[\,a] = \sum_p DefValTot[p,a]$.

(21)	$DefValTot[p,a] = DefValTot[p] \times \frac{PeakReduction[p,a]}{kWNeeded[p]}$

Where:

- $DefValTot[p]$ is the total deferral value of a project p
- $kWNeeded[p]$ is the peak load reduction needed to successfully execute the deferral project p

APPENDIX D: Vehicle to Grid Extension of Energy StorageVET Operation Manual

StorageVET® Overview

The revenue generated by the PEVs in providing ancillary services and capacity (resource adequacy) to the grid is calculated by using StorageVET[4]®.

The primary capability of StorageVET® is to support the understanding of energy storage project operations and economics. The tool has been designed with caveats to capture policy or market related rules, commercial decisions (by a range of actors) and constraints along with infrastructure planning and research. StorageVET® provides a range of technical results like battery dispatch, State of Charge (SOC) and State of Health (SOH) profiles and financial results like Pro Forma and Net Present Value (NPV).

When the storage system can provide many such services, the various revenue streams are "stacked" on top of each other to achieve the total value for the project. StorageVET® also provides the flexibility to prioritize the different services selected based on which the final technical and financial results are computed.

The "compatibility" of the different services provided are dictated based on several factors.

Location of the storage system:

The ESS can participate in certain services only if it's located at certain locations. For instance, customer sited system can only perform customer bill reduction, demand response and backup power reservation. Similarly, a distribution level connected system may offer wholesale services, but only after reserving a certain amount of power and energy capacity for distribution level services. In other words, the distribution level services will always hold a higher operational priority as compared to other wholesale market services.

Time-Related Operation:

Distribution level services generally have time-series requirement of power and energy reservations. In such a case, the power and energy requirements for these services are translated into a time-series constraint profile based on which the storage system's operational schedule is compiled.

Prioritization in Selection Among Applications:

Some of the use cases will have certain "primary services" that will always hold a higher priority as compared to the other "secondary services". For instance, in the case of the Grace Feeder, the primary service that the storage system is expected to perform is phase balancing. However, the

[4] Storage Value Assessment Tool (StorageVET), https://www.storagevet.com/; Documentation found at https://www.storagevet.com/documentation/

phase balancing requirement is not prevalent throughout the year. Hence, during the times with no phase balancing needs, the storage system can offer other “secondary” non-distribution level services such as participating in the day ahead market by providing resource adequacy and ancillary services.

StorageVET® has been designed as a model which has “perfect foresight” of the various data that are provided as input. This applies to the various aspects of the tool’s operation described above.

Typically, energy storage technologies can be integrated to the grid at three possible locations: the transmission system, the distribution system and at the customer’s premise. In this analysis, each PEV is assumed to be an individual storage system of a uniform power and energy capacity. These PEVs are then aggregated together by taking the number of PEVs into account.

Grid Services Overview

A brief description of all the services offered by the storage system is provided below.

Ancillary Services

The ESS offers ancillary services in the day ahead market based on the ancillary services price. The ancillary services offered by the ESS includes Frequency Regulation, Spinning Reserves and Non-Spinning Reserves.

Frequency Regulation

The California ISO uses frequency regulation to follow the real-time imbalance of electricity supply and demand in between 5-minute economic dispatch instructions. The California ISO dispatches Frequency Regulation signal and manages separate products for Frequency Regulation Up and Frequency Regulation Down.

The ESS is assumed to follow sample regulation signals that the California ISO has published. StorageVET® does not model the regulation dispatch explicitly. Rather, this is an external calculation which is translated into an energy usage associated with the regulation operations and requiring energy charging to make-up for efficiency losses. StorageVET® determines the amount of energy absorbed and injected as well as the impact on storage degradations following the customized signals.

Spinning Reserves & Non-Spinning Reserves

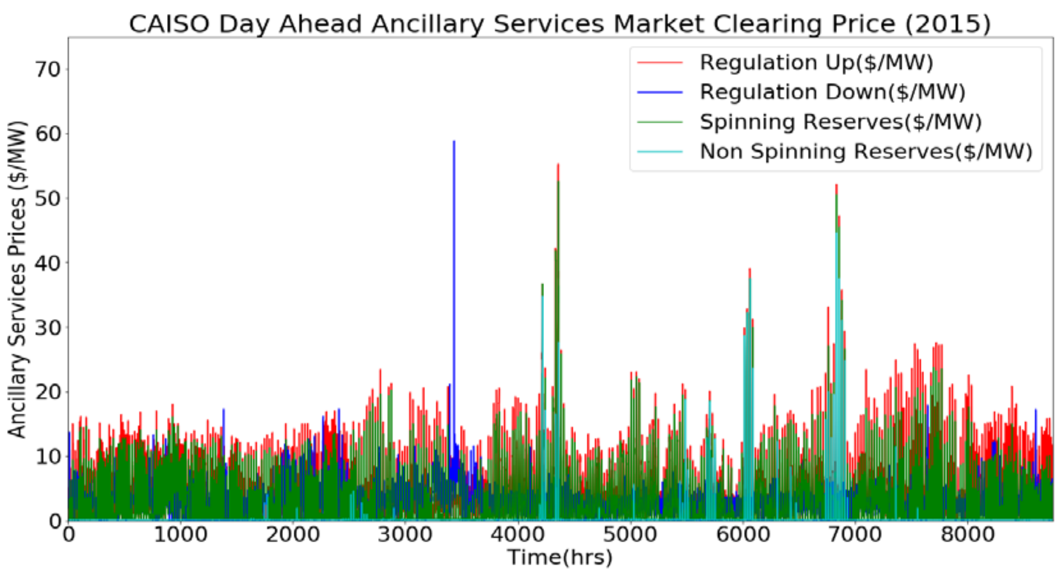
Spinning reserves and Non-Spinning reserves are employed primarily to protect the system against contingencies, particularly unplanned outages of major facilities such as transmission lines or generators. Spinning Reserves are acquired from units that are synchronized and can provide full awarded capacity in 10 minutes. On the other hand, Non-Spinning reserves must be started (if needed) and synchronized with the full award available in 10 minutes. When dispatched, both these two types of resources must be capable of sustaining its awarded capacity for 30 minutes.

In StorageVET®, an ESS offering spinning reserve and non-spinning reserve service is modeled to reserve its awarded capacity for the awarded hours. Moreover, it is also assumed that the California ISO market allows spinning and non-spinning reserve service commitment during scheduled charging hours. From a technical standpoint, spinning and non-spinning reserves being contingency resources, can provide both load reduction and can also discharge energy. In a way, if the reserves can stop charging, it equates to added generation. For instance, a 1 MW ESS can provide 1 MW of spinning/non-spinning reserve and 1 MW of added generation (by stopping charge), thus effectively providing 2 MW of reserve response.

StorageVET co-optimizes the ancillary services offered along with the wholesale energy price. This wholesale energy price is usually the Locational Marginal Price (LMP) for a specific node. However, since the PEV(s) are distributed all around California, a flat energy price of $40/MWh was assumed as the energy price for the co-optimization.

For the Vehicle to Grid analysis, the ancillary services were offered based on the California ISO Ancillary Services Market Clearing Price for 2015, as shown in Figure D-1.

Figure D-1: California ISO Ancillary Services Clearing Price (2015)



Source: EPRI

Resource Adequacy

Resource adequacy is a reliability requirement which ensures that there are sufficient generation and non-generation resources available to meet the forecasted peak load along with reserve requirements, generally one to three years ahead. In California, to qualify for system or local area resource adequacy, a storage resource is rated at the maximum output which can be sustained for at least four consecutive hours and be available for at least three consecutive days.

In StorageVET®, a storage asset eligible to provide resource adequacy receives the monthly capacity payments and either reserves the capacity or is dispatched for the designated hours on the designated days. Based on the 2015 RA Report published by CPUC, the monthly payment for resource adequacy is set at $3/kW-month. The storage asset is fully charged up to the capacity eligible for resource adequacy prior to the designated hours. It was also assumed that the minimum bidding increments for resource adequacy is 0.1 MW for a duration of four hours.

Input Data Summary

Based on the various grid services described in the previous section, the input data required for performing the services are summarized below.

Table D-1: Input Data Summary

Data	Services Associated
Day Ahead Wholesale Energy Price	$40/MWh (Flat Value)
California ISO Ancillary Services Market Clearing Price (2015)	1. Frequency Regulation 2. Spinning Reserves 3. Non- Spinning Reserves
Monthly Capacity Payment (Resource Adequacy)	$3/kW-month (CPUC's 2015 RA Report)

Source: EPRI

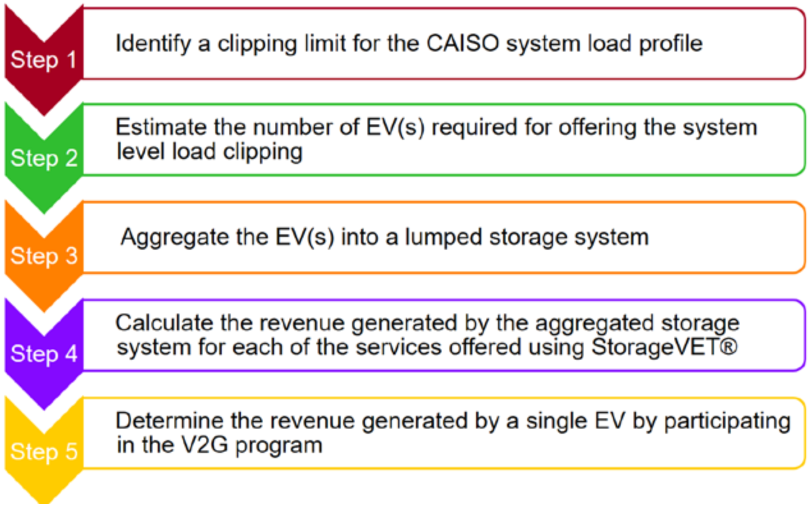
Vehicle to Grid StorageVET® Analysis

The impact of employing electric vehicles (PEVs) to offer grid services is analyzed by using StorageVET.

ISO Level Analysis

This impact is analyzed from the macroscopic level, i.e., from the perspective of the Independent System Operator (ISO). This is briefly described in the flow chart below in Figure D-2.

Figure D-2: Level Analysis Flowchart



Source: EPRI

A clipping limit of 750 MW was identified as the target for the aggregated storage system. Two cases were modeled separately based on the capacity (power and energy) reservation made by a single PEV. The capacity reservation values were 3 kW, 6 kWh and 6 kW,30 kWh respectively. Based on these numbers, the number of PEV(s) required to provide a 0.75 GW clipping was determined to be around 250,000 for the 3 kW, 6 kWh and 125,000 for the 6 kW, 30 kWh cases respectively.

For both cases, 10 percent of the vehicles were assumed to be capable of providing frequency regulation as a service along with spinning and non-spinning reserves. The remaining 90 percent of the vehicles were assumed to be capable of providing only spinning/non-spinning reserve based on these assumptions, the summary of number of PEV(s) required is presented in Table D-2 below.

Table D-2: Electric Vehicle Summary

Capacity of one PEV	Number of PEV(s)		Total
	Frequency Regulation + Spin/Non-Spin	Spin/Non-Spin	
3 kW, 6 kWh	25,000	225,000	250,000
6 kW, 30 kWh	12,500	112,500	125,000

Source: EPRI

The next step was to aggregate the capacity of the PEV(s) into a single storage system and then model the system in StorageVET® to calculate the revenue of offering each service.

Table D-3: PEV Aggregated Capacity

Capacity of one PEV	Aggregated Capacity	
	Frequency Regulation + Spin/Non-Spin	Spin/Non-Spin
3 kW, 6 kWh	75 MW, 150 MWh	675 MW, 1350 MWh
6 kW, 30 kWh	75 MW, 375 MWh	675 MW, 3375 MWh

Source: EPRI

Financial Results Summary

The financial results for the two cases of the analysis are summarized in Table D-4 and Table D-5.

Table D-4: Revenue Summary for 3 kW, 6 kWh Reservation

Annual Revenue Generated ($)	Regulation + Spin/Non-Spin		Spin/Non-Spin	
	Overall	Per Vehicle	Overall	Per Vehicle
Frequency Regulation	$5,809,000	$232.36	N/A	N/A
Spinning Reserve	$373,400	$14.94	$20,000,000	$88.89
Non-Spinning Reserve	$9,330	$0.37	$340,100	$1.51
Total	$6,191,730	$247.67	$20,340,100	$90.40

Source: EPRI

Table D-5: Revenue Summary for 6 kW, 30 kWh Reservation

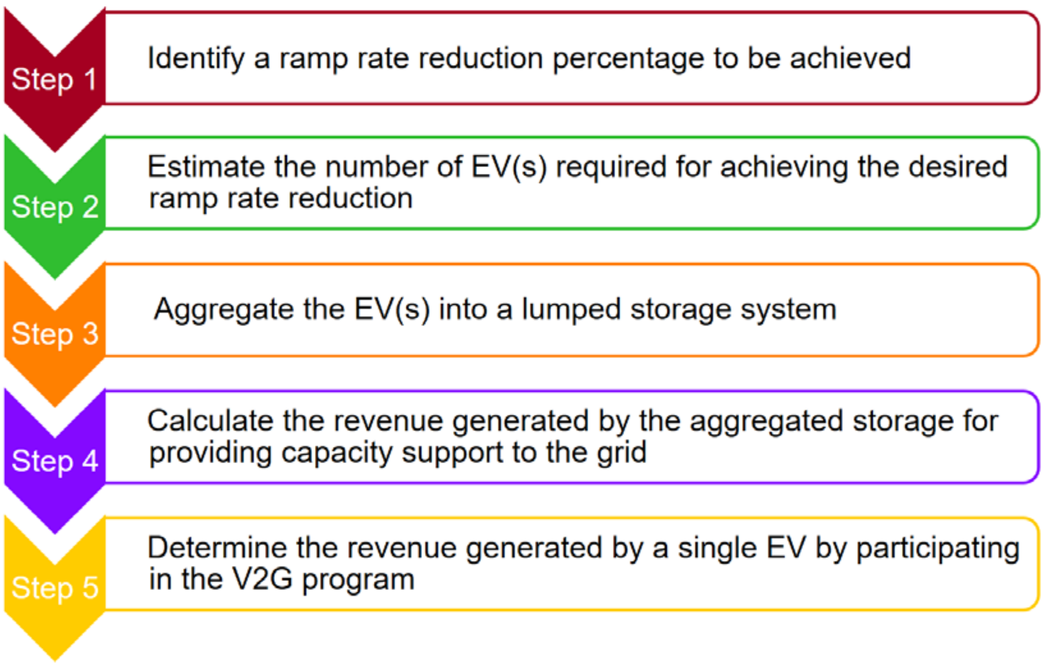
Annual Revenue Generated ($)	Regulation + Spin/Non-Spin		Spin/Non-Spin	
	Overall	Per Vehicle	Overall	Per Vehicle
Frequency Regulation	$6,271,074	$501.69	N/A	N/A
Spinning Reserve	$533,670	$42.69	$23,750,000	$211.11
Non-Spinning Reserve	$18,161	$1.45	$459,500	$4.08
Total	$6,822,904	$545.83	$24,209,500	$215.20

Source: EPRI

Impact on the California Duck Curve

The analysis of the employment of PEV(s) to provide capacity support to the grid was also been performed on a macroscopic level to study the impact on the California Duck Curve. The key steps in involved in this analysis have been summarized below.

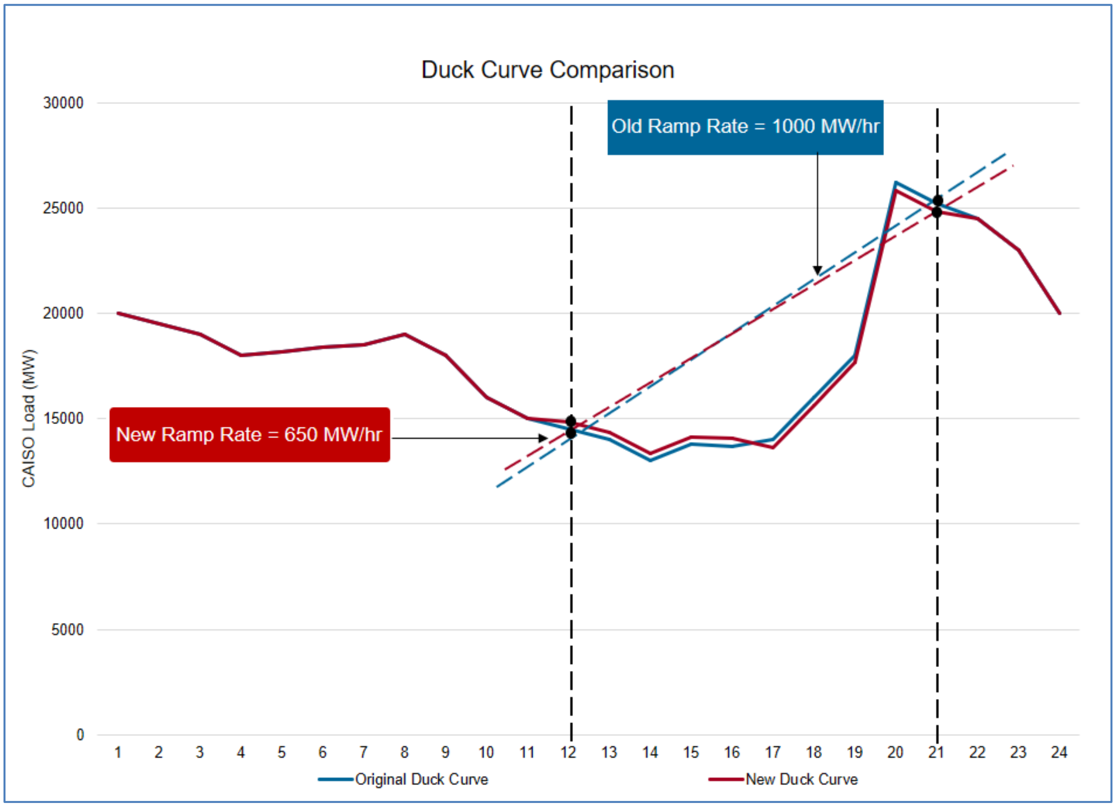
Figure D-3: Ramp Rate Mitigation Flowchart



Source: EPRI

As a first step, a ramping percentage reduction of 35 percent was assumed as a target reduction value. Assuming that the capacity reserved for the service, is 6 kW, 30 kWh per PEV, the number of PEV(s) required for providing a 35 percent reduction in ramp rate reduction was estimated to be around 58,333. The impact of providing capacity to the grid is represented graphically in form of two duck curves as shown in Figure D-4 below.

Figure D-4: Duck Curve Ramping Mitigation



Source: California ISO

Since, the charge/discharge duration of one PEV is 5 hrs, the PEV was assumed to charge from hours 12 to 17, where there was surplus PV generation and net load was low. From hours 17 to 22, the PEV was assumed to discharge when the PV generation started to drop and load started to spike up. Based on the assumptions made above, the ramp rate is calculated as

$$Original\ Ramp\ Rate = \frac{(24{,}500\ MW - 14{,}500\ MW)}{(22{:}00\ - 12{:}00)} = 1{,}000\ MW/hour$$

$$New\ Ramp\ Rate = \frac{(24{,}150\ MW - 14{,}850\ MW)}{(22{:}00\ - 12{:}00)} = 650\ MW/hour$$

$$Change\ in\ Ramp\ Rate = 1 - \frac{(650\ MW/hour)}{(1000\ MW/hour)} = \mathbf{35.00\ percent}$$

Based on the assumption that the value of providing capacity support is $3/kW-month*, the approximate revenue that each PEV would generate is about $216 per year.

**Source: 2015 Resource Adequacy report*

Assuming that about 308,333 PEV(s) sign up for the V2G program, then the average revenue that one PEV generates will be around $126.91 (Table D-6)

Table D-6 Revenue Summary for Cumulative Services

	3 kW, 6 kWh reservation		Capacity Participation	Total
	Regulation +Spin/Non-Spin	Spin/Non-Spin		
Number of PEV(s)	25,000	225,000	58,333	308,333
Revenue ($)	$6,191,370	$20,340,100	$12,599,928	$39,131,398
Revenue per PEV($)	$247.67	$90.40	$216.00	$126.91

Source: EPRI

Increasing PV penetration along a feeder

A bottom up approach can also be utilized to evaluate PEV(s) as a resource to increase PV integration on a feeder; however, this will require feeder level impact analysis information on the type of customers on the feeder, the amount of potential PEV(s) that could be utilized at those locations, including customer load profiles and generation profiles. Moreover, this also involves applying a probabilistic approach to integrate the different parameters together as a part of this analysis. Once an individual feeder analysis is complete, the results could be rolled up for a system level assessment with the assumption on the number and type of similar feeders. This wasn't considered as part of the scope for this analysis.

APPENDIX E: Integrated Resource Planning Consideration for V2G Capable PEVs

Integrated Resource Planning Model inclusive of Vehicle to Grid Capable Plug-in Electric Vehicles

Introduction

This interim deliverable document fits within the context of a larger project, titled 'Distribution System Constrained Vehicle to Grid Services for Improved Grid Stability and Reliability'. The complete report and context with the findings and linkages can be found separately (of which this document forms a chapter). As such it shares all of its assumptions and assertions with the design, development, demonstration, data and value analysis phases of this project. The focus of this document is to discuss unique aspects of assimilating the growing class of V2G (Vehicle to Grid) capable Electric Vehicles into Integrated Resource Planning processes. In this discussion, earlier work on Integrating DERs into IRP[5] is heavily adopted as a framework for V2G-capable PEVs, which are:

- A generalized case of stationary storage in that
  - They are mobile resources with primary purpose for mobility, but are plugged in 20-22 hours every day, and are capable, subject to system constraints, of sending and receiving power and energy from the grid in response to a variety of grid service signals
  - Their location is varying, but primarily (about 97 percent) focused around workplace and residential locations – which are dispersed at the edge of the distribution grid for retail purposes and at potentially advantageous locations in fleet scenarios (including Mobility-as-a-Service (MaaS) fleets such as UBER, LYFT, MAVEN etc)
- A specialized case of stationary storage in that they are, by design, constrained in terms of energy and demand/capacity availability for grid support purposes given that their primary purpose is mobility. Demand from PEV battery recharging varies geospatially and temporally and has specific implications for planning and modeling exercise
- Unlike stationary storage, as behind-the-meter (BTM) customer-procured resources, V2G capable PEVs may help alleviate upward rate pressure experienced by ratepayers due to the infrastructure investments being made by IOUs and POUs to facilitate SB350[6] regulatory-driven expansion of transportation electrification
- On the flip side, at 6-20kW each and 10-30kWh each, PEVs offer most system benefit when treated in an aggregated manner, rather than on a unit basis. As such, most participation

[5] Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning. EPRI, Palo Alto, CA: 2018. 3002010821, to be published

[6] Transportation Electrification Activities Pursuant to Senate Bill 350, http://www.cpuc.ca.gov/sb350te/

scenarios of PEVs into the IRP process must consider the aggregator role as a key enabler to their effective participation in the IRP

- Finally, the primary purpose of PEVs remains zero emission mobility, and this aspect must take precedence over their participation in grid-support functions, which can be accounted through appropriate capacity and energy estimation assumptions.

Historical Context[7]

As of 2015, more than 30 states required electric utilities to do some form of resource planning to demonstrate company investment plans to meet electricity demand are in the public interest.[8] In addition, in many states companies must seek power plant investment preapprovals by obtaining a Certificate of Public Convenience and Necessity (CPCN)[9]

Current resource planning practices are rooted in the 1970s. In that era, rapid load growth coupled with concerns over rising costs, reliability, and environmental protection led to the development of least-cost planning[10] processes, with a goal of minimizing the total costs of an electric utility's[11] power generation resource portfolio, subject to reliability and emissions constraints (4). Growing regulatory, cost and demand uncertainties contributed to the

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[7] Source: Adapted from United States Environmental Protection Agency Energy and Environment Guide to Action 2015. Based on research conducted for EPA by Synapse Energy Economics, updated from Synapse 2013. Additional updates by EPRI 2018.

[8] These planning requirements typically fall into one of four categories: (i) IRPs; (ii) Plans submitted to obtain discrete approval for specific power generation or demand response resources; (iii) Plans associated with providing default electric service in competitive states; and, (iv) Long-term asset procurement planning.

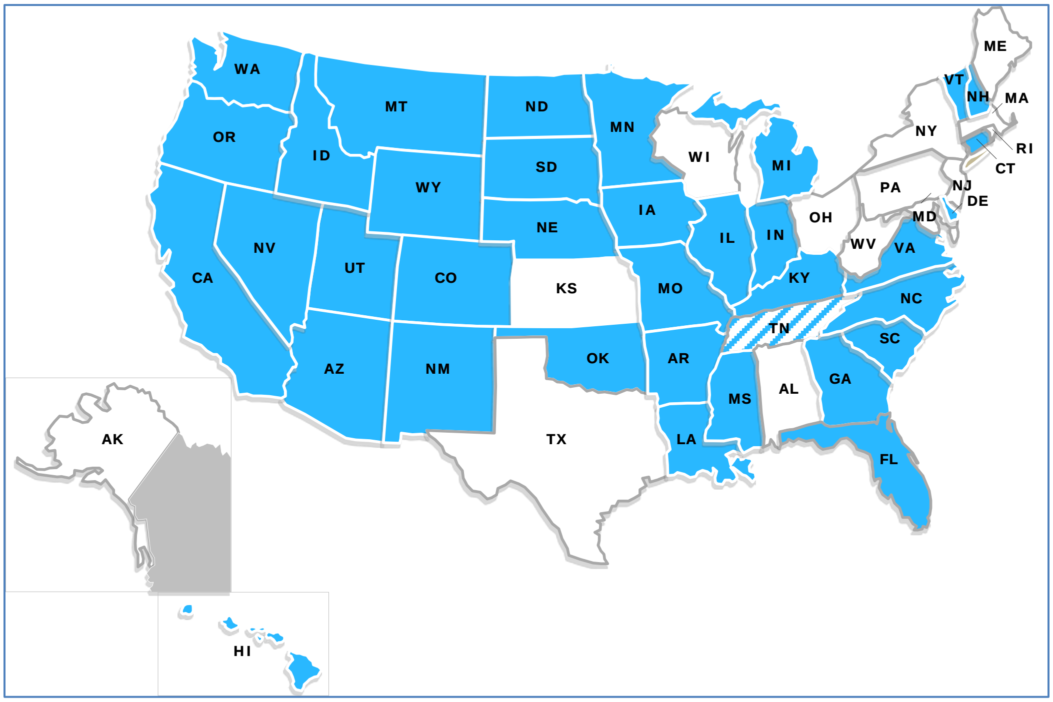
[9] Adapted from Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning. EPRI, Palo Alto, CA: Forthcoming July 2018. 3002010821

[10] "Least-cost planning" refers here broadly to any planning process designed to minimize costs subject to a set of constraints, rather than more narrowly to formal integrated resource planning.

[11] "Utility" here refers to any entity that acquires electricity resources to serve end-use customers.

development of IRP in the 1980s. Figure E-1 highlights the States that Required Integrated Resources Planning as of 2015[12]

Figure E-1: States that Required Integrated Resources Planning as of 2015



Source: EPRI

Electric system resource planning has undergone three important changes since the 1980s. First, the passage in 1978 of the Public Utility Regulatory Policies Act[13] (PURPA) and the Energy Policy Act[14] (EPAct) in 1992 formalized and standardized IRP. In response to PURPA, individual states developed formal electricity resource planning processes, and began to require electric utilities to conduct resource planning under state oversight. The EPAct codified and standardized the evolving planning processes under federal law. By the early 1990s, all but nine states had some variant of an IRP process in place.

Second, the introduction of regional wholesale power markets in California, the Northeast, the Midwest, and Texas shifted responsibility for key aspects of resource planning. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that operate regional transmission grids and manage regional wholesale power markets now have some planning responsibilities that previously were solely the responsibility of electric companies, particularly related to resource adequacy and transmission planning. FERC Orders 890 and

[12] The project team have highlighted TN in Figure 95 because the 1992 Energy Policy Act requires the Tennessee Valley Authority (TVA) to prepare IRPs, and TVA is responsible for delivering electric service to most consumers and regions in the state. California and Florida have been added to the original version of Figure 95. With passage of SB-350 in 2015, electric companies in CA are required to submit IRPs. Electric companies in FL are required to submit IRPs in the form of Ten Year Site Plans.

[13] The Public Utility Regulatory Policies Act (PURPA, Public Law 95-617, 92 Stat. 3117, enacted November 9, 1978) was passed by Congress as part of the National Energy Act. This federal law was envisioned to promote energy conservation and greater use of domestic energy and renewable energy sources

[14] §111 of the 1992 Energy Policy Act (102 Congress HR 776).

1000 mandated regional transmission planning requirements which typically are implemented by the RTOs/ISOs in regions where they operate.

Third, the structure of electric companies has changed significantly. The rise of regional wholesale power markets was accompanied by the divestiture of utility-owned generation assets in some regions and altered the role of utilities. Rather than building, owning, and operating generation resources, some utilities began to purchase energy and capacity through a combination of bilateral and centralized market transactions. In recent years, an increasing number of companies with historic resource planning responsibilities have restructured and are no longer vertically-integrated. This restructuring also was pushed forward by the advent of retail consumer choice in some regions of the country.

Contexts and approaches[15]

The planning process differs significantly across states, and it differs depending on the business structure of the electric company engaged in it. Companies with resource planning responsibilities today include a range of organizational structures, including investor-owned utilities (IOUs), generation and transmission cooperatives (G&T), publicly-owned utilities (POUs), load-serving entities (LSEs), "wires only" distribution companies, independent power providers (IPPs), and community choice aggregators (CCAs).

Each of these types of organizations has different responsibilities for generation (G), transmission (T) and distribution (D) systems and operations planning. Regardless of the many differences in planning processes, most resource planning processes are completed administratively and consider costs, benefits and risks over the long term.

Several vertically-integrated electric companies continue to operate and conduct IRPs as part of the process to obtain approval to construct specific new facilities, retire existing facilities, and as a part of routine communications with state PUCs. For Load-serving entities (LSEs) operating in restructured electricity markets, resource planning may be used to inform how they procure electricity to meet demand from customers who do not choose to buy electricity from a competitive electricity supplier. In regions where the grid is managed by an RTO or ISO, like California, regional transmission planning often is done by the RTO or ISO. Also, resource planning studies now are being conducted by public policy organizations, particularly in states with retail open access policies and with third-party administrators of energy efficiency and renewable energy programs.

State public utilities commissions (PUCs) typically are the state regulatory agencies that oversee development and implementation of IRPs. PUCs in different states take different roles in the IRP process. Typically, PUCs do not require or enforce specific IRP findings or outcomes, but rather engage in formal proceedings to approve the content of an IRP, and to acknowledge the IRP process was completed appropriately. In some states, such as California, Indiana, Georgia and Oregon, the review and evaluation of IRPs are conducted in formal regulatory dockets in which commission staff and stakeholders may issue formal or informal discovery and submit

[15] Op.Cit., EPRI 2018, Forthcoming.

comments on an IRP's assumptions and development. Electric cooperatives and municipal utilities often are not be subject to state PUC oversight. Typically, boards of directors appointed by member-customers are responsible for oversight of electric cooperatives, and municipal governments that supply electric services regulate their own utilities.[16, 17]

Evolution of Resource Planning in the State of California[18]

In recent years, CA has adopted a variety of policies and programs that have significantly altered how resource planning is conducted. First, in 2003, energy regulators adopted a "loading order" to guide future energy decisions. This order provides a hierarchy of preferred resources to be used to close projected capacity needs. It prioritizes demand-side options by increasing EE and DR, and then meeting new resource needs first with VER and DER, and second with "clean" fossil-fueled generation.[19] Prior to 2012, the work by California ISO, Energy Commission and CPUC between 2006 and 2010 was done to align the TPP (Transmission Planning Process) and LTPP (Long-Term Procurement Plan). At the end of 2010, a Joint Scoping Memo and Ruling institutionalized the 2010 LTPP Standardized Planning Assumptions[20]. These were subsequently refined in 2012 and 2014 and build upon the template established in 2010. In 2012[21] (OIR 3/27/2012, Scoping Memo 1), the State of California established its Long-Term Procurement Plan (LTPP) proceedings to accomplish safe, reliable and economically efficient electricity supply in California.

Second, CA adopted a distribution resource planning requirement that requires IOUs to develop Distribution Resources Plans (DRPs) which are intended to be blueprints for integrating DER into distribution operations, planning, and investment.[22]

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[16] EPA 2015, p 7-27.

[17] In rare cases, such as in Kentucky and to a very limited extent in Minnesota, the state PUC reviews and regulates cooperatively owned utilities.

[18] EPRI 2018 Forthcoming.

[19] The loading order was adopted in the 2003 Energy Action Plan prepared by the energy agencies, and the Energy Commission's 2003 Integrated Energy Policy Report (2003 Energy Report) used the loading order as the foundation for its recommended energy policies and decisions.

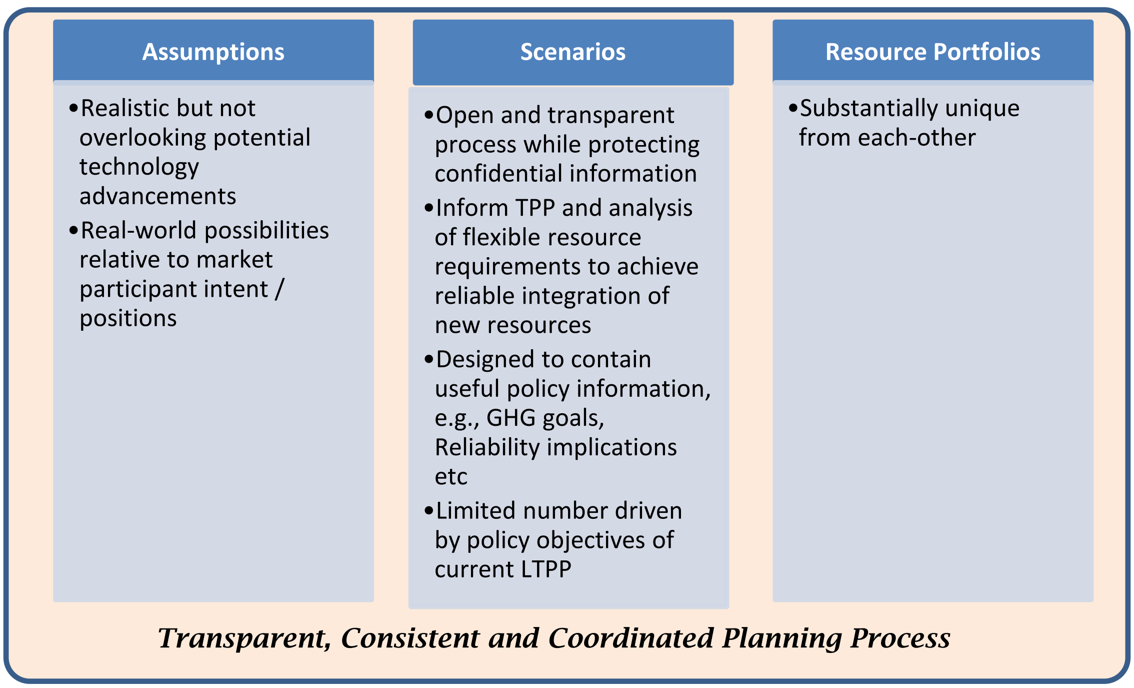
[20]2010 LTPP Standardized Planning Assumptions Joint Scoping Memo and Ruling http://docs.cpuc.ca.gov/EFILE/rulc/127542.pdf

[21]Order Instituting Rulemaking, 3/27/2012, Scoping Memo 1 http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/162752.PDF

[22] For more on these plans and the DRP proceeding, see CPUC, "Distribution Resources Plan (R.14-08-013)," http://www.cpuc.ca.gov/General.aspx?id=5071 .

Third — and perhaps most significantly — CA enacted Senate Bill 350 in 2015[23] which mandates the CA Public Utilities Commission (CPUC) to adopt a new IRP process that requires LSEs to meet GHG emissions targets that reflect the electricity sector's contribution to achieving economy-wide GHG emissions reductions of 40 percent below 1990 levels by 2030. SB-350 also requires electric companies to: (i) procure at least 50 percent eligible renewable energy resources by 2030 (i.e. 50 percent RPS); (ii) double end-use EE savings in electricity and natural gas by 2030; and, (iii) achieve a series of other legislative objectives that impact long-term resource planning. The current LTPP proceeding is R.13-12-010[24]. In its current version (c2016), it has the latest set of assumptions around Flexible Loads and Resources that should be used by procurement planners for modeling and procurement filings in the next LTPP / IRP process.

Figure E-2: 2016 LTPP Guiding Principles Summary



Source: EPRI

Other recent CA legislative and regulatory decisions also are likely to impact electric resource planning in the state, including: (i) incentive programs to increase DG deployment[25]; (ii) initiatives aimed at better integrating DR into the wholesale energy markets and the CPUC's resource adequacy planning process[26]; (iii) annual EE savings targets set by the CPUC; (iv) an energy storage mandate requiring IOUs to procure 1,325 MW of storage by 2020[27]; and, (v)

[23] SB-350 is the "Clean Energy and Pollution Reduction Act of 2015." For more information, see "Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements," State of California Public Utilities Commission, February 19, 2016. Rulemaking 16-02-007.
[24] Planning Assumptions & Scenarios for The 2016 Long-Term Procurement Plan Proceeding and the California ISO 2016-17 Transmission Planning Process http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673
[25] CPUC, "Distributed Generation in California," http://www.cpuc.ca.gov/PUC/energy/DistGen/.
[26] See California ISO's Demand Response Initiative online: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/DemandResponseInitiative.aspx .
[27] Decision Adopting Energy Storage Procurement Framework and Design Program. Decision 13-10-040. California Public Utilities Commission, San Francisco, CA 2013.

aggressive zero emission vehicle goals requiring 1.5 million PEVs and fuel cell PEVs to be on the road by 2025.[28] These initiatives are expected to drive DER penetrations much higher over the next decade.

The Figure E-3 describes the guiding principles of this set of planning assumptions:

Figure E-3: State of California Initiatives Targeting DERs

Distributed Generation Programs	•Incentive Programs: California Solar Initiative, Self Generation Incentive Program, New Solar Homes Partnerships, Net Energy Metering tariff •Interconnection and communications for smart inverters per CPUC Rule 21 •20 GW goal by 2020
Zero Net Energy Mandate for New Buildings	•All new residential construction by 2020, effectively requiring rooftop PV •All new commercial construction by 2030 •Explicit Title 24 requirement for rooftop PV in most homes starting 2020
Demand Response	•Demand Response Auction Mechanism for CAISO integration •Tool for Resource Adequacy Planning •2020 requirement to have OpenADR 2.0b as the DR standard protocol
Utility-Sponsored Energy Efficinency Programs	•CPUC sets energy saving targets
Energy Storage Mandate	•1325 MW of storage by 2020 •32 percent at distribution level (425 MW) •15 percent on customer side (200 MW)
Distribution Resource Planning	•IOUs to develop Distribution Resource Plans (DRPs) •Blueprints for integrating DER into distribution operations, planning and investment
CA Governor ZEV Action Plan	

Source: EPRI

The California electric system is large, diverse and rapidly expanding to incorporate all the customer-sited (Behind the Meter or BTM) renewable DER assets as a growing class of resources. By some estimates[29], the renewable generation accounts for over 50 percent of the daily demand already (RPS requires 33 percent at present). The electric system in California includes the following key entities:

- Three large Investor-Owned Utilities (IOUs), two very large and many smaller municipals and a good number of smaller utilities and co-ops.
- The California Public Utilities Commission (CPUC) has the statewide authority to set and supervise the resource adequacy planning process, along with utility EE and DR programs across utilities in its jurisdiction.
- The California Energy Commission (Energy Commission) is the policy and planning organization that provides electric demand forecasts used in resource planning, as well as maintains load and resource data, as well as under SB350, has the responsibility to oversee IRP for Publicly Owned Utilities (POUs)[30].

[28] Office of the Governor. 2013 ZEV Action Plan. Office of the Governor, Sacramento, CA 2013.
[2929] In May 2018, the average of renewables serving load was over 36 percent, with the maximum during one 5-minute dispatch interval reaching nearly 74 percent (per the California ISO's Monthly Renewables Performance Report)
[30] Publicly Owned Utilities Integrated Resource Plans, http://www.energy.ca.gov/sb350/IRPs/

- The California Independent System Operator (California ISO) is responsible for managing the wholesale energy and ancillary services market that spans the state as well as operates the long-term transmission planning process.

The economic underpinnings for DER as a resource class for the planning process is enabled through CPUC and legislative decisions as well as California ISO activities, shown in Figure 96.

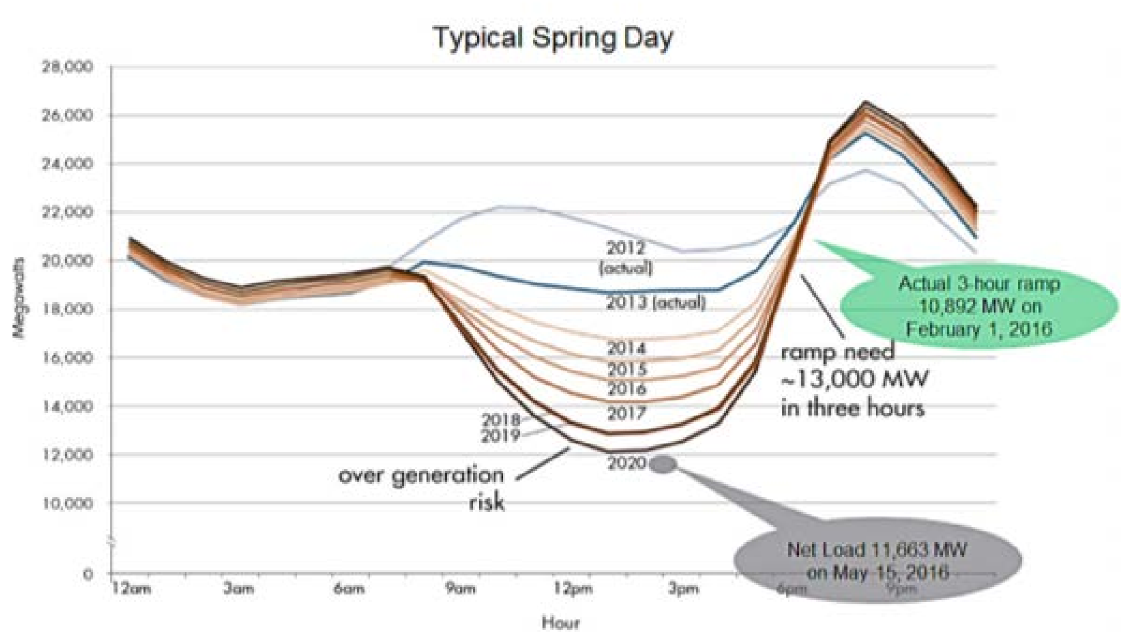
Integrated Resource Planning Process for DERs

While the specifics of regulatory and planning treatment may vary from region to region, broadly speaking the principles remain the same. The fundamental treatment criteria and planning assumptions are similar in a variety of jurisdictions.

Approach to DER in IRP: Load Modifiers or Supply Resources

Heretofore, 'traditional' DERs such as EE and DR have been treated as load modifiers – to change the load (increase or decrease) in response to an external signal in sync with demand forecasts. This can be scheduled day-ahead or in real-time. With increased renewable penetration (likely to reach and the rise of the famous 'Duck Curve[31]' signifying increasing need to manage oversupply and resultant backflow of power upstream (from resources toward the substations), as well as steep ramp-up required during summer afternoons as a result of steep fall of renewable generation at the end of the day with the simultaneous load pick-up the evening with Air Conditioners being turned on, the need to manage resource/load parity in real-time has become even more acute.

Figure E-4: Duck Curve with Observed Net Load on California ISO from 2016 Data



Source: California ISO

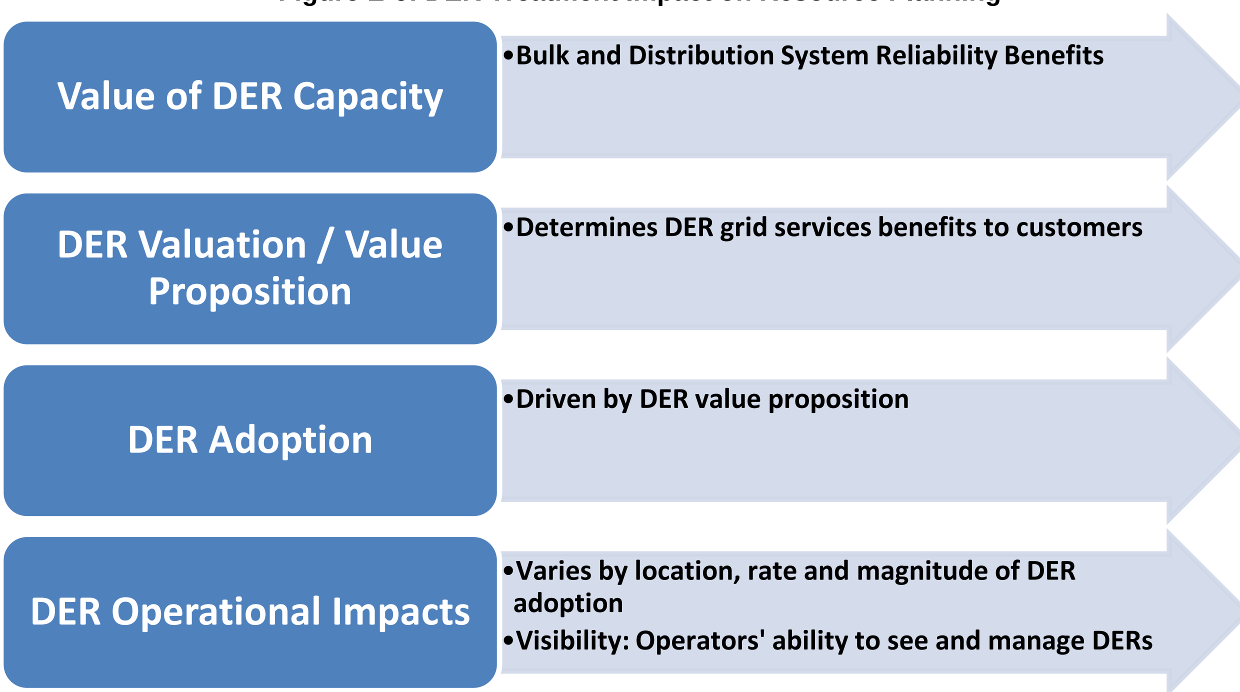
[31] Flexible Resources Help Renewables, Fast Facts, California ISO, 2016, http://www.caiso.com/Documents/Flexibleresourceshelprenewables_FastFacts.pdf

In fact, the California ISO is recommending the following measures[32] to mitigate effects of over-supply:

- Expanding the California ISO control area outside of California to balance California oversupply with neighboring states' loads
- Increase participation in Western Energy Imbalance Market – again, with the same end objective
- Electrification of transportation – specifically for absorbing the 'shiftable' charging to oversupply periods of the day
- Change Time-Of-Use rates to encourage consumers to consume more energy during an oversupply period
- Increase Energy Storage
- Increase the flexibility of power plants for faster response to ISO dispatch instructions

Whether treating DERs as load modifiers or supply resources[33,34], the end result is the same operationally, but they are treated very differently for planning purposes.

Figure E-5: DER Treatment Impact on Resource Planning



Source: EPRI

Additionally, the structure of a utility does affect the DER treatment. A vertically integrated (i.e., owning generation, transmission and distribution network all the way to customer) utility lacks

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[32] ibid

[33] California ISO defines Load Modifiers A voluntary load reduction, load shifting, or energy efficiency program that modifies the underlying load, which is captured in the natural load and affects future load forecasts. Non-dispatchable means dynamic rates and tariffs, energy efficiency programs and or permanent load shifting programs'. California ISO definition of a Resource (Dispatchable) is 'A demand response resource configured as a generation substitute and dispatchable by the ISO or IOU/DRP when and where needed and in the amount of energy needed'.

[34] ISO Demand Response Lexicon, 2013, http://www.caiso.com/Documents/Lexicon-DemandResponseandEnergyEfficiencyRoadmapWorkshop.pdf

the regular procurement process and therefore may not allow it to treat a DER as a resource. For a distribution utility (wires only or DSO including substations) with access to the wholesale market, procurement plans are a must and mechanisms do exist to participate in both the load and resource side of procurement processes.

To-date, DR has sometimes been treated as a Supply resource, but usually is treated as load modification for long-term planning, to enable its participation through market product such as DRAM[35] (Demand Response Auction Mechanism) in California ISO and through a Distributed Energy Resource Provider (DERP) mechanism[36] with a minimum of 500kW threshold to bid into wholesale markets.

Role of Aggregators

California ISO energy market enables aggregators to participate as Scheduling Coordinators, as DERPs or through DRAM, while working with several commercial/industrial customers as the actual entities participating in this process. The latest round of DRAM pilot has also allowed residential / BTM coordinators (e.g., OhmConnect) to participate. DERPs or 'Scheduling Coordinators' are contractually responsible for meeting their market commitments and get compensated (or penalized) based on their verified performance[37].

The BTM resources have been found to be challenging in terms of M&V treatment as a wholesale or retail asset and jurisdictional issues between system operators and regulators. *This is particularly relevant for PEVs as the CPUC has instituted submetering requirements for PEVs* through Ruling 13-11-002[38] and subsequent Resolution E-4651[39]. The submetering pilot[40] has completed phase 1[41] in 2017 and Phase 2 finished in end of April of 2018.

Electric Vehicles as a Special Class of DERs

All Electric Vehicles (PEVs) have on-board batteries that need to be recharged from the grid. PEVs have the following characteristics which make them suitable to be treated as Load Modifiers (LMs) or Resources, both energy-constrained. (This energy constraint actually poses an operational risk that needs to be mitigated through aggregation of a large pool of PEVs.) These are:

- PEVs are driven for 2 hours on average and remain parked and potentially plugged in for 20+ hours / day. This makes them almost as easily available as a BTM stationary storage device.

[35] California's DRAM Tops 200 MW as utilities pick winners for distributed energy, GreenTechMedia, 7/26/2017, https://www.greentechmedia.com/articles/read/californias-dram-tops-200mw-as-utilities-pick-winners-for-distributed-energ#gs.T63Ix24
[36] Distributed Energy Resource Provider Participation Guide with Checklist, California ISO, v1.0, 8/26/2016, https://www.caiso.com/Documents/DistributedEnergyResourceProviderParticipationGuideandChecklist.pdf
[37] http://www.caiso.com/participate/Pages/BecomeSchedulingCoordinator/Default.aspx
[38] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M081/K786/81786001.PDF
[39] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K049/97049639.PDF
[40] http://www.cpuc.ca.gov/general.aspx?id=5938
[41] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453395

- PEVs are parked almost 97 percent of the time either at a workplace (daytime) or residential (evening / overnight), with which it is easier to associate their locations relative to the distribution system segments
- PEVs have on-board chargers that can accept charge power from any wall outlet or an Electric Vehicle Supply Equipment (EVSE, or charge station). All EVSEs are compliant with SAE J1772 charge couplers and the interoperability is proven.
- PEV Charger capacity (power) has grown steadily from 3.3kW to 19.2kW on the AC side, with most of the PEVs currently at 7.2kW level. That means most PEVs can charge at 7.2kW rating.
- PEV battery storage capacity has continued to rise and is fast approaching sizes where a significant portion (up to 50-60 percent) of it remains unutilized on a day-to-day commute, and can be made available for grid services without compromising daily mobility needs of about 15-20kWh round-trip
- For the vehicles to receive exogenous charge modification signals in the form of direct load modification or pricing tariff, no dedicated / specialized communications pathway is required as all vehicles have access to an PEV Original Equipment Manufacturer (OEM) designed and integrated Telematics system, such as GM OnStar or direct 4G LTE link to the vehicle.
- The California ISO and CPUC as well as the Energy Commission have created a VGI Roadmap[42] that defines mechanisms through which individual and aggregated sets of PEVs can be integrated into California grid to provide grid services and to participate in energy markets at appropriate context
- Prevailing communications standards do exist and have been developed both in the SAE (Society of Automotive Engineers) and IEEE (Institute for Electrical and Electronics Engineers) that span the entire range of grid/vehicle communications both in terms of signaling, physical layer communications, and cybersecurity, encompassing all possible communication pathways. These are under the umbrella of J2836, J2847, J2931 and J3072. These application layer protocol standards are based on both IEEE2030.5 (SEP2) for AC charger / utility or aggregator communications and IEC/ISO 15118 for charger/PEV communications.

In the 2016-2017 timeframe, pursuant to CPUC ruling R.13-11-007[43], in response to State Bill 350, covering Transportation Electrification, the CPUC, Energy Commission, ARB, and California Governor's Office (GOBiz) established a multi-agency VGI Working Group to understand the need for and the requirements of a grid/vehicle communications standard[44]

Electric Vehicles in California

The PEV installed base in California is fast-approaching 500,000 vehicles. By the end of May 2018, the nationwide installed base of PEVs was about 850,000. The PEV market nation-wide is

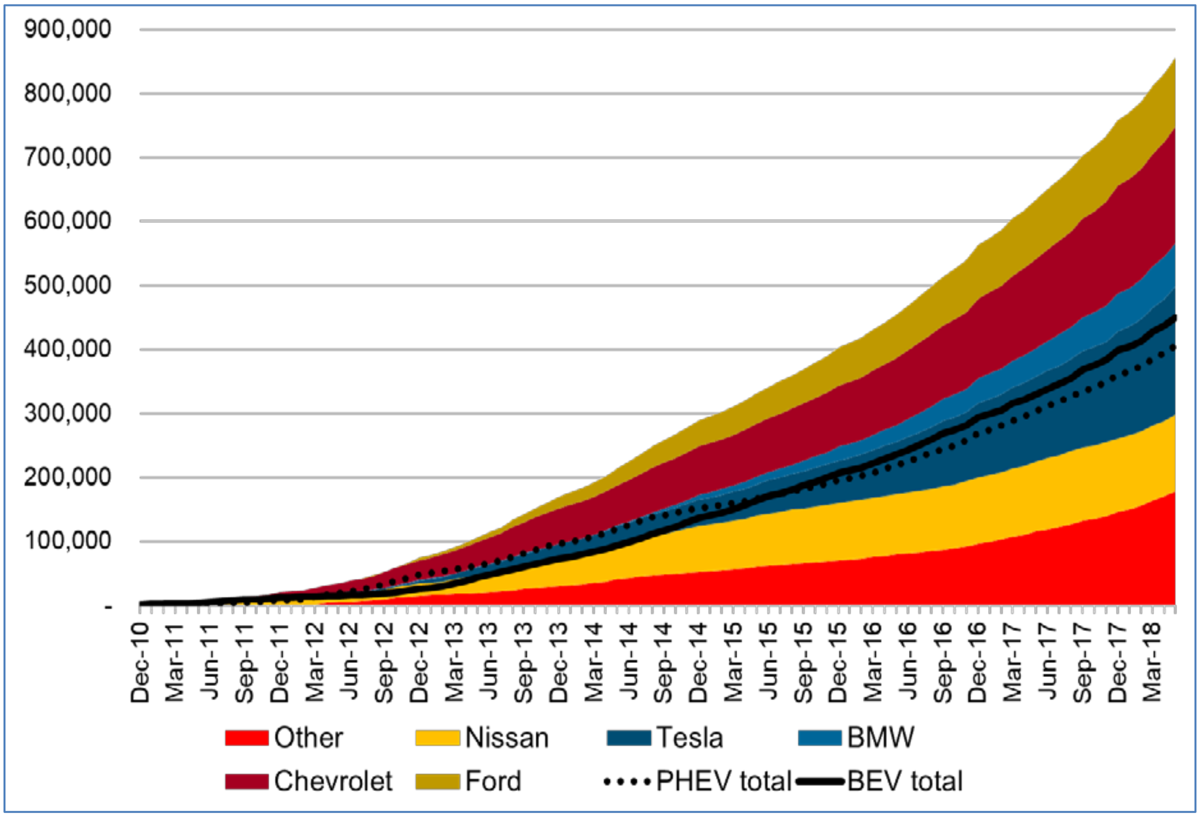
[42] California Vehicle-Grid Integration Roadmap, California ISO, 2014, https://efiling.energy.ca.gov/getdocument.aspx?tn=217997

[43] https://apps.cpuc.ca.gov/apex/f?p=401:56:14519318719481::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1311007

[44] California Vehicle-Grid Integration Working Group, www.cpuc.ca.gov/vgi and the Working Group Report http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M211/K654/211654688.PDF

growing at about a 20 percent annualized rate. The State of California accounts for more than 50 percent of the total vehicle sales nation-wide and is on pace to accelerate even further. PEV sales growth forecasts vary by region, and an EPRI analysis[45] indicates that there is a strong possibility for PEVs to acquire, in an optimistic scenario, about 60 percent market share by 2050, which translates to roughly 40 percent market share of new vehicle sales in 2030 (i.e., about 8-10M new vehicle sales/year) sold. This meshes well with the State of California Governor's mandate of 5 million PEVs by 2030.

Figure E-6: PEV Installed Base is 850,000 In the US - 5/31/2018



Source: EPRI

Given the necessity of estimating the potential impact of PEVs on utilities, EPRI has created a simplified methodology that provides three scenarios to estimate the market adoption of PEVs. The Low and High trajectories are intended to be used as plausible bounding scenarios. The Medium scenario may be considered a middle-ground estimate, but it is not intended to be used as a sales prediction.

The three proxy scenarios were developed as follows:

- **Low Scenario:** The Annual Energy Outlook 2015 (AEO 2015) Reference case was selected as the fundamental component of the Low scenario.[46] This version of AEO uses a vehicle choice model and assumptions that are generally unfavorable toward PEVs. In fact, the

[45] Plug-in Electric Vehicle Market Projections: Scenarios and Impacts, EPRI, Palo Alto, CA:2017, 3002011613

[46] *Annual Energy Outlook 2015.* U.S. Energy Information Administration, Washington, DC: 2015. DOE/EIA-0383(2015).

actual PEV market shares in 2015 and 2016 were about 50 percent higher than forecasted by the AEO 2015 Reference case. In light of this, the proxy Low scenario was set as the AEO 2015 Reference case multiplied by 1.5 (50 percent higher). The low proxy represents how PEV sales may grow if battery costs remain high, regulations that drive PEV sales are canceled, and incentives are reduced.

- **Mid-Range Scenario:** Two external scenarios provide a moderate long-term outlook for PEV adoption. These are the "Midrange PEV" scenario from National Research Council's *Transitions to Alternative Vehicles and Fuels* report and the "Portfolio" scenario from the NREL *Infrastructure Expansion* report. [47, 48] These two estimates were chosen as a proxy for the Medium scenario from about 2035 onward, since other more recent scenarios predict significantly higher PEV sales in 2025. The Medium scenario long-term proxy was determined as a simple year-by-year numerical average of the NREL and NRC estimates.
- **High-Scenario:** The High scenario proxy is an average of two scenarios that employ assumptions that are highly favorable toward PEV adoption: the "Optimistic PEV" case in Appendix H of the NRC report and the "Electrification" case of the NREL report.

These proxy scenarios were then modified to account for regional differences, especially to account for the effects of the California Zero Emissions Vehicle (ZEV) mandate and sales-to-date in each region.

The California ZEV program uses a credit system and does not require the sale of a specific number of advanced vehicles. The credit structure is defined such that vehicles that provide greater zero-emissions capability earn more ZEV credits per vehicle, and the program includes several flexibilities that offer vehicle manufacturers options to comply with the program in diverse ways. In December 2011, CARB staff released a report that defined a proposed revision of the ZEV and tailpipe emissions regulations called the Advanced Clean Cars program. These modifications were approved by the Board in January 2012.49 The staff report provided an expected trajectory of annual sales of different advanced vehicle types that would be required for manufacturers to comply with the regulation. These estimates assumed a significant number of fuel-cell electric vehicles (FCEVs) would be sold in California: less than 0.2 percent of new sales through 2017 but ramping up to 2.5 percent of sales by 2025. If these FCEV sales occur, the required PEV sales were less than 2.1 percent through 2017 and then ramping to 12.9 percent of new sales in 2025. In 2012, EPRI requested that CARB provide another scenario that assumed greater numbers of PHEVs with either 10 miles or 40 miles of all-electric range. This scenario increased the PEV estimate to 15.4 percent of sales by 2025.

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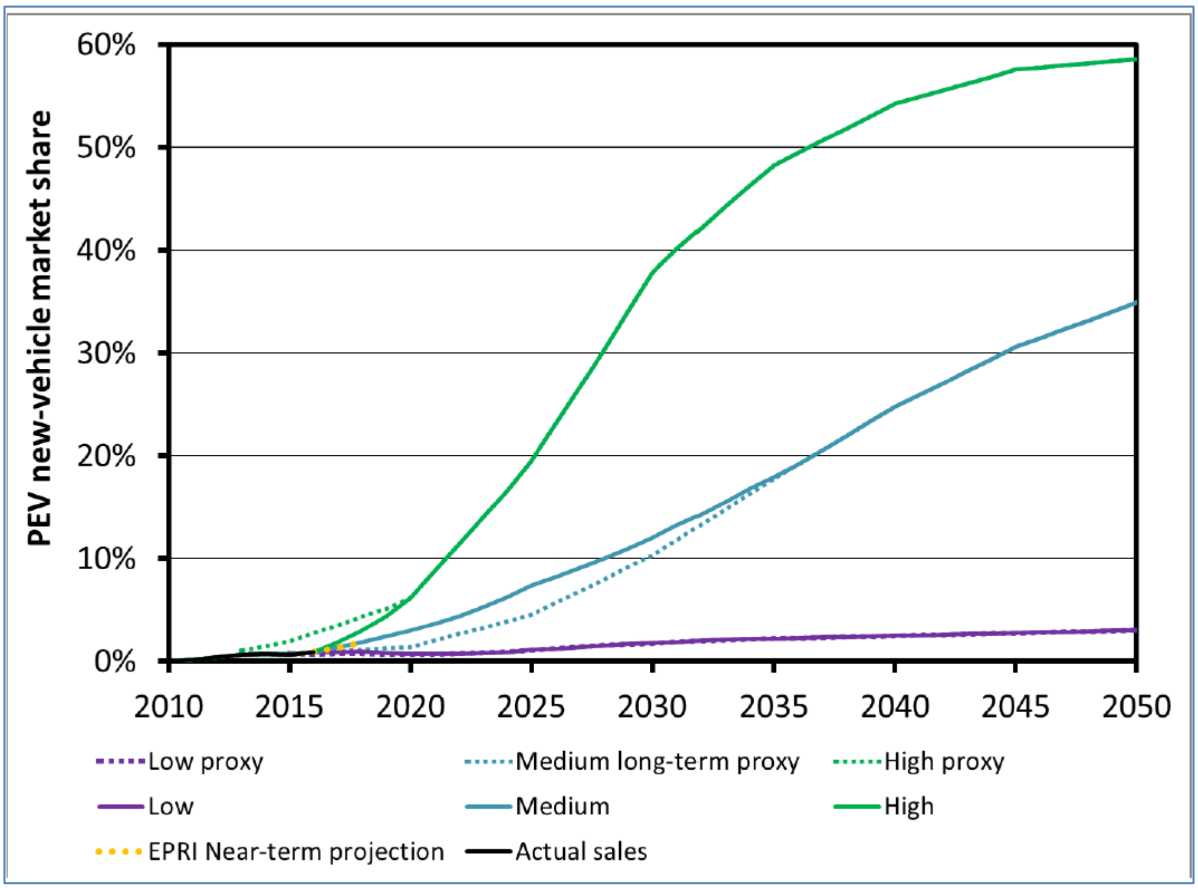
[47] *Transitions to Alternative Vehicles and Fuels*. National Research Council, Washington, DC: 2013.

[48] Alternative Fuel Infrastructure Expansion: Costs, Resources, Production Capacity and *Retail Availability for Low-Carbon Scenarios*. Prepared for the U.S. Department of Energy by National Renewable Energy Laboratory, Golden, CO: 2013. DOE/GO-102013-3710.

[49] Staff Report: Initial Statement of Reasons, Advanced Clean Cars, 2012 Proposed Amendments to the California Zero Emission Vehicle Program Regulations. California Air Resources Board, Sacramento, CA: 2011.

After modification to account for the ZEV mandate, the projections are also modified to account for the trajectory of the actual local PEV sales using historical county-level sales data for 2010 through 2016. Beyond 2016, the regional projection (or national projection for the High case) is shifted up or down depending on the level of the local historical PEV sales relative to the average sales in the larger region. Specifically, the local sales bias is based on the local PEV market share in 2013 through 2016. As the projection advances farther into the future, the local effects diminish somewhat and the projections trend toward the projection for the larger region. This homogenization effect assumes that PEV technology becomes increasingly mainstream and that the geographic distribution of PEVs becomes relatively uniform. However, in areas where the local PEV sales rates from 2013 through 2016 are significantly different than the regional sales rate, that difference continues to impact the localized estimate over the long term (through 2050).

Figure E-7: EPRI Forecast for US-Wide PEV New Vehicle

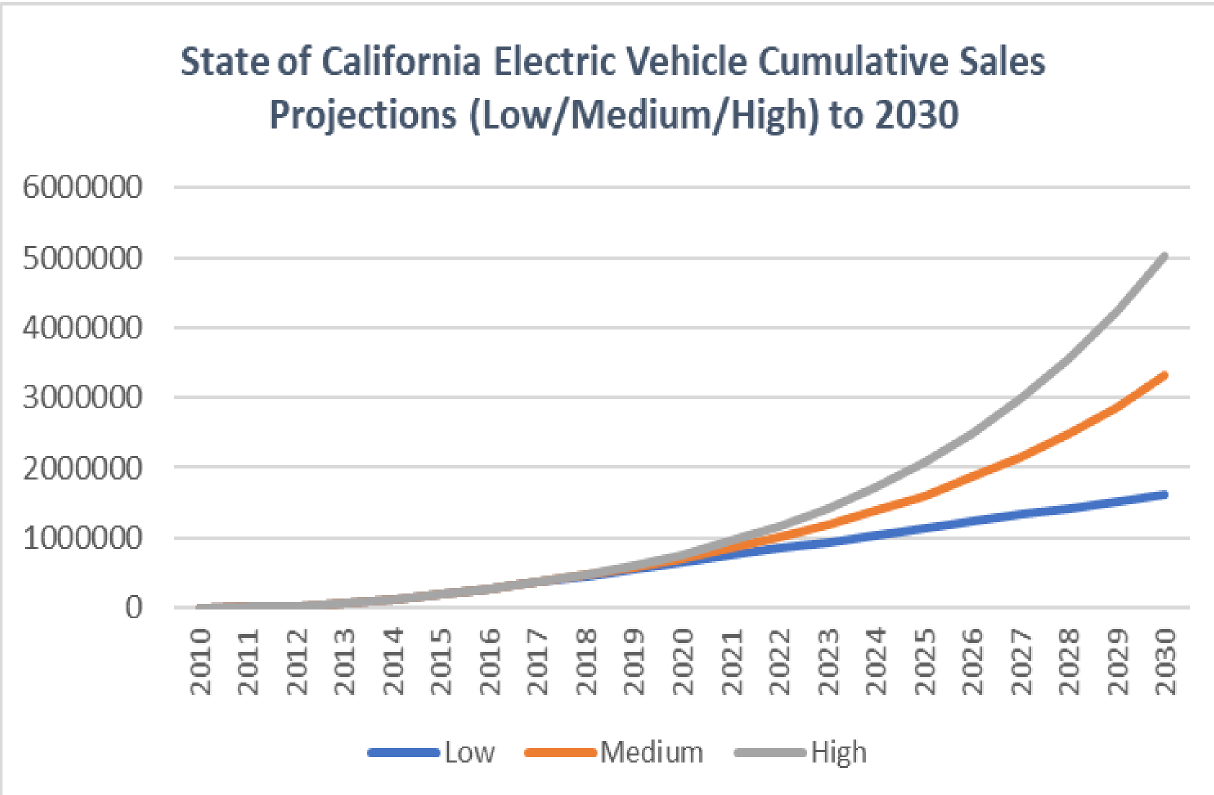


Market Share to 2050, Low, Medium and High Projections

Source: EPRI

For the State of California, this translates to the cumulative installed base of anywhere from 1.6M to 5M by 2030, as shown in Figure 101. The target of 5.0M vehicles is used by the California Governor's Office for 2030, per the Executive Order[50].

Figure E-8: State of California PEV Fleet Projections to 2030, Low/Medium/High Scenarios



Source: EPRI

Electric vehicles have the following capabilities that make them particularly attractive as Flexible Loads (increase or decrease) in response to both Summer Peak events and for Overgeneration Mitigation through appropriate pricing mechanisms.

- **Charge Power:** 3.3-7.2kW AC from grid
- **Discharge Power for Reverse Power Flow-Capable PEVs**: 3.3-7.2kW AC to grid
- **Smart Inverter Functions**: When the grid-tied inverter is connected to a powered EVSE, it acts as a current source. It has the capability to place its current vector at any leading or lagging phase angle compared to grid Voltage phasor. This means that Smart Inverter on-board can provide leading or lagging VARs for Voltage Support. The signaling for this is codified in SAE J2847/3. Furthermore, there is effort underway for on-board grid-tied bidirectional smart inverters equipped with IEEE2030.5 and SAE J3072 functions to be 'interconnection qualified' compliant with CPUC Rule 21.

[50] Governor Brown Takes Action to Increase Zero Emission Vehicles and Fund New Climate Investments, California Governor's Office Press Release, 1/26/2018: https://www.gov.ca.gov/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/

- **Bandwidth**: The bidirectional (or unidirectional) charger has the capability to respond to charge / discharge current commands within 25-100ms. *This is a very important feature if PEVs, in an aggregated manner, were to be used as an Inertia Resource to balance system frequency fluctuations.*
- **Signal Latency**: Over the internet or Telematics link, the signal latency depends mainly on the update rate that is set up between the signaling entity and the PEV. This is currently set up in a manner that the PEVs can very readily respond to 5-minute ahead price signals. Some manufacturers' PEVs can respond today at 250ms latency level, meaning they can participate even in a Regulation Reserve market.
- **Availability / Participation:** The PG&E/BMW iChargeForward[51] program currently underway is finding that the availability of customers at any given time on average is about 15 percent of total in terms of kW. This means that today's effective multiplier against the capacity available is about one-seventh or 15 percent. If the incentives hold, the participation becomes seamless and more streamlined in terms of avoiding customers' daily driving and charging routine, this rate can go as high as 30 percent by 2030 (our assumption that needs to be validated).

When all capabilities above are combined, the cumulative available Load Modifier capacity is between +/-3.5GW to +/-10GW[52], or a swing of twice that value (i.e., 7-20GW), if 100 percent of the vehicles are equipped with bidirectional charging equipment, but on average only 15 percent-30 percent were available at any given time for grid services. This is also the capacity available over the ramp-period for ramping mitigation. Appropriate management of PEV discharge power during this interval has the potential to reduce the duration of extreme ramps.

PEVs with bidirectional power capability are as capable as the stationary storage systems that are grid-tied and can provide grid services of a fully grid-integrated storage system. Moreover, they can deliver these services at a fraction of the acquisition costs for equivalent amount of stationary storage because PEVs are procured primarily for mobility purposes *by PEV owners,* and utilities are not required to pay for their acquisition costs. This makes them a very attractive resource / load modifier entity to be studied carefully for IRP / DRP integration.

PEVs as DERs in the Context of IRP

This project demonstrated on-board V2G capable grid-tied PEVs' technical capabilities in an interoperable manner to accomplish the following Load Modifier and Resource functions:

[51] iChargeForward: PG&E's Electric Vehicle Smart Charging Pilot; Final Report, http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf

[52] At 1.5M Vehicles in 2030, +/-7.2kW each, and 30 percent available the number is +/-3.24GW
At 5M Vehicles in 2030, +/-7.2kW each and 30 percent available, the number is +/- 9.72GW. Incidentally, these values on the + side are on the conservative side (i.e., pessimistic) because each vehicle equipped with AC/DC on-board charger (that is 100 percent of them) can be made to provide Load Modifier services today. So, on the load modifier side, there is a significant upside. On the Resource side, the outlook is going to depend squarely on available incentives

Table E-1 Grid-Tied Vehicle-To-Grid Capable PEV Capabilities as Load Modifier and Resource

Context	Grid Function	Load Modifier	Resource
Facility	Charge Scheduling	X	x
	Local Demand Charge Reduction (Peak Shaving)	X	
	Local Backflow Prevention	X	
Local Transformer	Thermal Constraint-Based Load Limiting	X	
	Capacity-based Load Limiting	X	x
	Transformer-level backflow prevention	X	
DSO/ISO Level	Peak Shaving	x	X
	Oversupply Mitigation	X	
	Ramping Support	x	X

Legend: X = Primary function, x = Secondary Function (market-dependent)

Source: EPRI

These services have been demonstrated experimentally using open standards-based technologies and are the superset of services that have been analyzed for value assessment.

Requirements for PEVs to be Included in IRP / LTPP Portfolio

For a Load Modifier or a Resource to be included in the IRP / LTPP portfolio of DERs, it must pass several tests to confirm reliably and accurately its potential over a specified time horizon. Some of these are:

Reliable PEV Growth Forecast

For a DER to be included in the LTPP / IRP process, a reliable forecast of its market adoption is critical. This is the foundation upon which all the procurement plans are built. Any scenario assessment is subject to input uncertainties and modeling imprecision. What is known for certain is the state of California 2030 target for PEVs to reach 5 Million. While preparing the scenario assessment, EPRI looked at the PEV growth numbers from a variety of factors, also benchmarking our own numbers against publicly available data which are driven by automotive manufacturer product plans, manufacturing and supply chain investment numbers to ensure these numbers are triangulated and show potential. Given the major impact that regulations and incentives have had on PEV sales in the near-term, these were accounted for as well.

Furthermore, EPRI[53] bound the forecast through three scenarios – minimum, medium and high numbers. Minimum growth numbers are based on 'Business as Usual' PEV adoption from customers, Maximum growth numbers are based on growth rates significantly accelerating up as per-kWh battery costs reduce (they have seen cost reductions at an annualized rate of 14 percent per year since the last 10 years, currently at 15 percent of the numbers seen in the early days and are likely to go down further within 5 years). This has also led to Automotive OEMs having more freedom to make this technology available across multiple class of vehicles (crossovers, SUVs, vans etc) while also providing ever-increasing driving range numbers. With relentless focus on infrastructure (including fast charging) from public agencies, especially in the state of CA and elsewhere, the appeal of PEVs to customers is bound to increase. Coupled with petroleum price hovering around $70/bbl[54] with an OPEC target to between $80 and $100/bbl[55], PEVs will continue to make more economic sense, especially if coupled with a variety of ownership models. However, achieving 5M vehicles installed base in CA by 2030 remains a tall order, so the project team also created a mid-range forecast (which is simply arithmetic average of the minimum and maximum forecasts) to have a realistic feel for what the volume may look like in 2030. Back in 2011, a Presidential[56] goal of 1M vehicles US-wide by 2015 seemed out of reach at the time, yet in mid-2018, the project team find the installed base at 856,000 PEVs and will likely reach the 1M mark nation-wide in another 12 months. Over 50 percent of these vehicles are in California. Policy and technology forcing do make an impact on nudging the industry in a certain direction, and in case of PEVs, the economics and exogenous factors (VW diesel scandal, for example) happened to have given the right impetus for industry to voluntarily and seriously look at developing PEVs as an alternative.

Availability of PEVs as Mobile Resources

At the end of 2017, the relative share of PEV installed base in CA among the IOUs was 30 percent PG&E, 40 percent SCE and 10 percent SDG&E. If the project team maintain this ratio to be constant (remaining 20 percent dispersed across the rest of the state), the project team can derive IOU-specific PEV capacity availability numbers. The aggregate 2030 numbers for V2G capable PEVs in the range of 7GW-20GW[57] even with 30 percent penetration of the grid-support technologies on vehicles, one can expect a 30 percent / 40 percent / 10 percent share of this installed base to appear across PG&E, SCE and SDG&E territories, meaning SCE could see a resource base of about 3GW, PG&E about 2GW and SDG&E up to 1GW to apply toward their procurement plans at the lower range, and roughly 3 times as much at the higher range in 2030. A strong case can therefore be made that at a macro level, this presents significant market participation opportunity for PEVs and procurement opportunity for planners at LTPP / IRP system level procurement or for PEVs to participate in the ISO energy markets.

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[53] Plug-in Electric Vehicle Market Projections: Scenarios and Impacts, EPRI, Palo Alto, CA:2017, 3002011613

[54] Per Platts, August 2018 Futures for Brent Crude were being priced at $74.74/bbl on 06/20/2018

[55] OPEC's new price hawk Saudi Arabia seeks oil price as high as $100 – sources, REUTERS, 4/18/2018, https://www.reuters.com/article/us-opec-oil-exclusive/exclusive-opecs-new-price-hawk-saudi-arabia-seeks-oil-as-high-as-100-sources-idUSKBN1HP1LB

[56] https://www.cheatsheet.com/automobiles/will-obama-executive-action-build-momentum-for-electric-cars.html/?a=viewall

[57] Calculated as follows: 30 percent of 1.5M vehicles at

The second factor affecting PEV inclusion as a resource class is physical availability given that PEVs are mobile. Therefore, when one starts focusing on whether a specific PEV is charging, where and at what time (geospatially and temporally), more uncertainty is introduced. However, in general, PEVs tend to congregate on weekday day-hours at workplace locations and evening hours at residential areas. Likewise, on weekends, they could be plugged in at home or away at any third location (commercial, recreational etc). So, even when inclusion of specific PEVs in specific energy markets may be difficult to attain a particular service level commitment *individually,* if means of aggregation of these vehicles were to be introduced (either through actual aggregators or *Scheduling Coordinators,* or through the IOUs or POUs themselves acting as aggregators) were to be brought into the mix to manage a group of PEVs that can participate through them, then the complexity of managing individual customer preferences for mobility, participation, etc. could be managed by this aggregator.

Role of Aggregators / Scheduling Coordinators or DER Providers

By their very nature, V2G capable PEVs are BTM resources, and collectively they represent a meaningful entity across the IOU distribution grids: about 150,000 in PG&E territory, 200,000 in SCE territory and 50,000 in SDG&E territory as of this writing in June 2018. Which means that on average, they represent about 150MW, 200MW, and 50MW of load across the distribution systems whose summer peaks amount to 20GW, 30GW and 7GW respectively (approximately, assuming ISO peak procurement need of about 73GW). Since the ISO market allows any loads >500kW to be eligible bidders, the presence of aggregation function is essential to PEV participation in helping distribution and the ISO grid. Indeed, the currently underway Phase 2 of the PG&E/BMW iChargeForward Program utilizes Olivine as the Scheduling Coordinator, while BMW acts as the aggregator for a fleet of their participating vehicles (about 250 of them) as well as locally sited stationary storage. As the PEV proliferation grows across CA 3x-10x in the next 12-15 years, managing PEVs just as Load Modifiers may have a huge beneficial impact on the grid. Add to that V2G capabilities and selective additional benefits may be realized. There is therefore a need to have a dialog among the multiple state agencies, IOUs and other stakeholders about appropriateness of creating incentive mechanisms that are sustainable through business case-derived benefits to the grid. These benefits could be through utilization of PEVs for grid services that improve asset utilization and defer upgrades as well as increase utilization of clean energy that is generated at the same location as PEV charging and is coincident.

Customer Participation Estimate and Incentives Required to Stimulate Participation

Once the PEV potential for assisting the grid, both as a Load Modifier and as a Resource is estimated, the next challenge becomes translating these benefits into incentives that are meaningful enough to attract PEV owners to participate in the grid services market. As with all other customer-oriented programs, the true potential of PEVs as grid resources can only be realized if customer participation can be maximized and sustained. This requires an understanding of what attracts the customers to new programs, as well as what turns them away from participation. Here again, BMW's recent experience implementing iChargeForward[58] is a useful reference. BMW found that there is a threshold of up-front payment (lump-sum) to attract the customers (in hundreds of dollars), followed by a payment at the end of the program, that was based on the participation performance (below 50 percent participation rate would result in zero end of pilot payment, and above 90 percent participation rate would yield 100 percent of the end of the pilot payment – or something along these lines), both collectively representing some estimated value to the grid based on the grid services that the program was designed to deliver. In addition, BMW minimized customer intervention once the one-time participation set-up was completed to register their vehicle with the program. Customers were automatically opted into the program and would only need to intervene through the mobile App if they wanted to opt out at any time. All other processing would occur in the background, silently and seamlessly.

PEV Technical Capabilities vis-à-vis Grid Services

All Electric Vehicles have on-board chargers and an ability to 'listen' to the grid conditions (at varying levels), through either open standard (IEEE2030.5 or IEC/ISO15118) or proprietary protocols through secure Telematics link or 4G LTE connection. As a result, it is possible, today, for utilities to signal to PEVs to modify their charging pattern according to some grid constraints, for example, avoiding charging during peak periods and shifting it during off-peak intervals, or, intentionally charging during times when PV across distribution is providing more generated energy than can be absorbed by existing load. In other words, the unidirectional power flow capability of the PEVs can be deployed to use PEVs in Load Modifier role today.

When Reverse Power Flow (RPF) capability is added to PEVs, as is being demonstrated in this project, as well as situational awareness of the local and macro distribution system so the on-board bidirectional power conversion system can respond either automatically or in response to grid signaling to provide grid services such as 'peak shaving' or 'ramping support', the value of the PEVs can be further enhanced for the grid. The BMW project successfully demonstrated that not only can these services be delivered, but also that use of open standards that are vetted by OEMs and within Society of Automotive Engineers (SAE) can result in a signaling system that is robust and secure end to end using the prevailing Cybersecurity best practices.

It should be noted that the technologies being demonstrated on this project, while being integrated on-board two OEMs (Fiat Chrysler Automobiles and Honda R&D America), this is the first-ever implementation of this standardized technology and requires further robustness in specific areas (interconnection requirements being a major one) that will need to be worked across OEMs, IOUs, SAE, IEEE and UL for harmonization and results shown to CPUC to obtain guidance on which specific set of requirements are adequate to qualify V2G capable PEVs as a 'generating' resource to pass Rule 21 screen. The BMW project demonstration is the first successful step to validating and identifying key implementation / operational barriers that can now be assessed through experimentation and testing.

[58] BMW iChargeForward – PG&E's Electric Vehicle Smart Charging Pilot, Phase 1 Report, Pacific Gas & Electric Company, 2016

Value Assessment

In the value assessment phase of this project, considerable effort was spent by the team on developing value assessment tools to identify value at local facility level to customers through rates and demand charge mitigation, at the distribution transformer level as well as distribution system level to both create asset upgrade deferment as well as capacity avoidance for summer peaks as well as ramping. Preliminary numbers resulting from this analysis are encouraging enough to sharpen the analysis assumptions and create a peer review process where these local, distribution and ISO level benefits can be better quantified. Especially in the case of distribution system benefit assessment section of the project, a methodology has been created and presented that can be applied to 'at-capacity' distribution system segments for value maximization.

Cost Assessment

Costs for the V2G capable PEVs include on- and off-vehicle hardware and software piece costs, engineering development as well as infrastructure development / operations/ maintenance costs, as well as service/support costs. To the extent that they are known, they were factored into the Value assessment (value is benefits net of costs) of distribution system constrained V2G services. However, these cost assumptions need to be verified to ensure no hard or soft costs (including obsolescence) are ignored.

Distribution System Integration and Contribution of this Project

California public agencies, directed by the legislative action (AB327, section 769) have taken on comprehensive reform measures to enable large-scale integration of distributed resources and creation of a regulatory framework to allow these investments to occur. CPUC has instituted, in response to AB327 utilities section 469, through R.14-08-013[59], instructed IOUs to create Distribution Resource Plans with the following key elements:

Annual Grid Level Scenarios and Assumptions:

Scenarios and assumptions form the foundation of the Grid Modernization-related Distribution Resource Planning process.

Growth Scenarios

Scenarios estimate the growth of DERs across the distribution system driven by BTM adoption due to the NEM and ToU tariffs and system-wide planned growth of FTM DERs to comply with regulatory directives.

Role of PEVs

Preparing PEV growth forecasts by distribution system location contributes to scenario development. The challenge integrating PEVs into a typical scenario is addressing the mobility behavior. Vehicles are parked part of the day at commercial / workplace locations and around

[59] Distribution Resources Plan, http://www.cpuc.ca.gov/General.aspx?id=5071

residential locations overnight, and sometimes, these locations may belong to different utility territories given the commuting distances.

Integration Capacity Analysis (ICA)

The Integration Capacity Analysis creates an estimation of additional DER capacity that can be integrated at individual nodes in the system, helping DER providers to interconnect the forecasted DER. This analysis is essentially a distribution system wide hosting capacity analysis through EPRI DRIVE[60] (Distributed Resource Integration and Value Estimation tool) , performed for specific locations on the distribution grid as needed. Hosting capacity can be defined as the integration capacity in the distribution system governed by 'headroom' at any given feeder before backflow results. ICA by definition is static in nature and looks at the worst-case scenario, while computing hosting capacity, which allows, in theory, for PV installation matching only the spring-time (light-load) conditions. That would leave significant opportunity for adding hosting capacity *if dynamic adjustments to a variety of parameters were to be made in accordance to real-time conditions*. Flexible loads are a potential enabler of increasing hosting capacity, in addition to Volt/VAR optimization functions of smart inverters, per CPUC Rule 21.

Locational Net Benefits Analysis (LNBA):

LNBA is the analytical process used to estimate the benefits that can be realized by siting a DER at a given node on the distribution system. The value is in the form of avoided distribution / transmission upgrade costs or Resource Adequacy related benefits or avoided costs.

Role of PEVs in LNBA:

Earlier in the project, LNBA methodology was used to identify the value that can be accrued to integrating V2G capable PEVs into a specific segment of the distribution system. PEVs as flex loads offer specific services that can be applied toward cost avoidance as well as Resource Adequacy computation. As the number of PEVs grow in specific distribution systems, their usefulness to the IOU will only continue to increase. Furthermore, V2G capable PEVs and the services they can provide through localized management further enhance their value to the distribution system. The value analysis segment in this report explains the use cases, the process used for assessing location-specific value as net benefits.

Grid Needs Analysis (GNA):

This is the distribution planning process that identifies the distribution system locations that would benefit most from specific grid services, the specific DERs – type and amount with the grid services they would enable – in an open and transparent manner as the basis for the GRC (General Rate Case).

PEVs as a part of GNA:

IOUs are developing their plans for public charging infrastructure under their rate-based SB350 Transportation Electrification related commitments. If ICA and LNBA are performed by accurately accounting for the beneficial grid impacts provided by managed PEV charging (and

[60] EPRI Distribution System Integration and Value Estimation Tool, v1.0, https://www.epri.com/#/pages/product/3002008297/?lang=en

discharging), then additional incentives can be designed around the capability of PEVs to provide grid services.

Grid Modernization Plans (GMPs):

At periodic intervals, typically every three years, IOUs are expected to present GMPs for the future 10 years, providing detailed distribution modernization plans as the sum of all of the GNA efforts, in a prioritized order, so that the Grid Modernization keeps pace with the need of the distribution grid under increased DER / renewable penetration.

PEVs as a part of GMPs:

Given the periodic and continual nature of the GMP process, PEVs as a growing and cost-effective class of DERs and Flex Loads can become a regular part of the ongoing process and may be thought of as grid resources as much as ZEVs that create positive environmental impact and less as a load that must be served.

Grid Modernization Plan Review, Approval and Investments:

Review and approval steps are performed for each GRC update, which is informed by appropriately performed 'design of experiments' and pilot projects.

PEV Infrastructure Planning as a part of GMP Investments

PEV-related services and incentive plans may be proven through pilot studies to deliver reliable value in line with GMP data. Approved investments may then be deployed in the form of what was proposed as a part of the GRC, and at-scale performance may be assessed.

V2G Capable PEV Impact on Operations

Screening Tools

The very first aspect of how to assess PEV operational impacts is to leverage existing screening tools for interconnection / grid integration purposes. This project relied on using CPUC Rule 21 as the requirement to interconnect the V2G capable PEVs. However, the learnings derived from that process need to be socialized with the IOUs to ensure that an appropriate suite of standards are defined for the agreeable OEM interconnection requirements. These may be published along with the value / incentives available to customers for vehicles equipped with a given suite of VGI technologies.

Production simulation models

In addition to the regional system model, these models also incorporate intermittent generation and V2G capable PEVs having accurate representations of load and reverse power flow capability. The combined model dispatches the PEVs in terms of data and control system integration requirements to synthesize a set of value-added use cases as defined in LNBA.

Pilot projects – nature and scope

As mentioned, the LNBA informs the nature and scope of the services that could provide the best value from PEVs at particular locations on the distribution grid. The best possible distribution system segments for these integration scenarios may be validated both in terms of technology performance and consumer participation data to maximize consumer interest and acceptance.

Interconnection standards for effective integration of V2G capable PEVs into the grid

As mentioned, one major discovery of this project was the gap in what was previously considered to be an appropriate interconnection standards suite. IOUs, Energy Commission, standards bodies and OEMs as well as network providers have yet to coordinate an effort to ensure a consensus set of standards is developed, verified, and adopted.

Summary and Scope for Future Work

Summary of the Report

This project overall explores the topic of understanding technical feasibility of open, scalable approach to V2G-equipped PEVs, and is primarily an exercise in assessing technical feasibility. PEVs capable of V2G services are at least 5 years away and their scale introduction is going to need a way for this feature to be incentivized through electric utility program offerings or market participation.

Learnings from this project can be carried forward to create a set of operational assumptions, and coupled with growth forecasts, can assist in creating planning assumptions for IRP process in the next 10-year scenario planning phase.

By starting this process early when the PEVs are at the cusp of achieving mass-market appeal, studying the approaches to model and assess the capabilities of PEVs at scale could provide sound foundation to build future IRP scenarios inclusive of PEVs in an applicable context.

The report also describes the growth scenarios of PEVs in the California grid and the potential of impact they can have if the 5M vehicles by 2030 because of California Governor's Executive Order or even a smaller number of PEVs were to be made available for sale in CA.

Since PEVs are going to be primarily behind-the meter resources, their accounting for grid services may be accommodated in the context of distribution system planning. Therefore, the PEV role in the DRP was also described.

Key Take-Aways from This Report

The key take-aways of this report are as follows:

- Guaranteed verifiable availability and performance of PEVs to deliver the services they commit is a key factor in them obtaining storage-like treatment in the LTPP and the IRP planning and procurement processes at the ISO / market level. This is currently governed by SB350 and CPUC Scoping Memo R.16-02-007[61]. Whereas avenues of value are identified in earlier chapters, it's important to note the need to conform to the existing process. The fact that PEVs are mobile and *only* available 20-22 hours a day at varying locations needs to be factored in.

[61] Integrated Resource Plan and Long Term Procurement Plan, http://www.cpuc.ca.gov/irp/

- The issue of Interconnection Requirements per CPUC Rule 21 under R.17-07-007[62] also must be resolved through uniform requirements based on common sense and consensus. This is critical for reverse power flow capable PEVs (being treated like generating resources). Specifically, harmonization among IEEE2030.5, IEEE1547, SAE J3072 and SAE J2847/3 as well as UL1741 is critical. This was a key learning of the project itself.

- Dynamic Rate tariffs may be beneficial for PEV customers and others but may need changes to account for low or no cost consumption, spring excess supply periods, and incentive curtailment during peak intervals. CPUC R.12-06-013[63] Residential Tariff Rulemaking is addressing this and specific provisions for PEV charging are in the mix. A recently held[64] ZEV Tariff Design workshop made initial contributions to this effect.

- In the siting of public /commercial infrastructure[65] the IOUs may prioritize focusing on installations at sections of distribution systems where there are likely to be excess supply issues or intentionally couple solar plus charging to reduce grid impacts, while also helping local commercial establishments. In other words, PEV infrastructure planning may need to be done jointly with Distribution System Planning *and* Distribution Resources Planning[66].

- Lastly, the DRP[67] process across IOUs is underway, and the plans generally are updated every three years, with the 10-year horizon each time. So if even some of them start including PEVs they may justify inclusion in electric utility DRPs and other related planning exercises including pilots targeting PEVs for grid services.

Gaps and Future Work Focus

- *Analysis and Forecasting of PEV V2G Adoption* – Given that the forecasted PEV growth, as well as load growth, as a function of IOU and Distribution System Segments sets the foundation for all the planning and procurement work, forecast model refinement, and validation are worthy exercises that have not yet taken place.

- *Interconnection Requirements Formulation for V2G Capable PEVs* – This project clearly showed the gaps in what is expected from the utility side to connect any Generating Resource (such as a V2G capable PEV) to the distribution system. Utilities would like to treat these PEVs as equivalent to stationary storage, subject to UL and IEEE standards. Automotive OEMs who carry the on-vehicle inverter prefer to certify to their own certification body (as against UL). So, this divergence in requirements needs to be reconciled and homogenized.

- Rate and Incentive Design: Clearly, the work in this space has already begun with CPUC ZEV Rate Design workshop in response to California Governor Brown's EO B-48-18

[62] Interconnection Rulemaking, http://www.cpuc.ca.gov/General.aspx?id=6442455170
[63] Residential Tariff Rulemaking http://www.cpuc.ca.gov/general.aspx?id=12154
[64] CPUC ZEV Rate Design Forum, 6-7 June, 2018, http://www.cpuc.ca.gov/energy/electricrates/
[65] Zero Emission Vehicles, http://www.cpuc.ca.gov/zev/#Infrastructure
[66] Distribution Resources Plan http://www.cpuc.ca.gov/General.aspx?id=5071
[67] ibid

requiring 5M PEVs in California by 2030. IOUs have recommended tariff revisions that need to be validated through pilots involving real customers, OEMs, utilities, and third-party stakeholders, to create required datasets for analyzing and verifying tariff effectiveness and design recommendations.

Through the leadership of California Governor's office (GOBiz), ARB, CPUC, Energy Commission, and the IOUs, state of California is setting the standard globally in terms of providing a regulatory and technical framework to maximize PEV adoption as well as grid preparedness so PEVs can act as grid resources as a matter of routine at some point in the future.

APPENDIX F: V2G Incentives and Tariff Quantification Methodology

Background

Vehicle-to-Grid (V2G) services can be designed to deliver grid benefits at local (facility), distribution system as well as ISO levels. Owing to their ability of the vehicles to send *and* receive power to and from the grid, V2G capable vehicles have flexibility to perform services both on the load and supply side. This report describes the process of translating the quantified grid benefits into incentive and tariff structures that can be deployed to reward / incent the participating customers and PEVs. In developing this Incentive and Tariff Quantification Methodology (ITQM), industry-standard practices such as the one described in the CPUC Standard Practice Manual[68] and Bonbright's Principles on rates[69]. CPUC recently held a ZEV Rate Design Forum[70] addressing enhancing PEV adoption through appropriate rate structures. Among the discussion topics, one was 'Key concepts underlying electric rate design[71]'. This presentation elaborates on ten key principles of effective rate design that can be adopted to PEV related tariffs. These are worth repeating:

1. **Electricity as a basic necessity**: Universal access to Electricity, especially affordably to economically or health-disadvantaged individuals. *This however may be placing the burden of subsidizing electricity to the disadvantaged customers on the utilities, while it's the policy driving this allocation.*
2. **Marginal cost basis**: Rates should be designed based on marginal cost
3. **Cost causation:** Rates should be aligned and correlated with the cost drivers. What costs more should be priced higher
4. **Conservation and energy efficiency**: Progressive tariffs to reward energy savings
5. **Peak demand consideration**: Rates should discourage both coincident and non-coincident peak demand
6. **Stable, understandable and enabling customer choice** – this is self-explanatory
7. **Avoid cross-subsidies:** In following the principle of fairness, one class of customers should not bear the burden of paying for consumption of another class of customers. If societal good

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[68] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, 2001, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

[69] Totten, J., "Tariff Development II: Rate Design for Electric Utilities", Briefing for the NARUC / INE Partnership, PUC of Texas, http://pubs.naruc.org/pub/53B194CB-2354-D714-5143-65B5D342C2D6

[70] ZEV Rate Design Forum, CPUC, June 6-8, 2018,

[71] Levin, R., 'Key Concepts Underlying Electric Rate Design', ZEV Rate Design Forum, CPUC, June 6-8, 2018, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457672

is the driving principle for the subsidies, then the costs of implementation of such subsidies should be more broadly spread.

8. **Explicit and transparent Incentives:** Incentives should be directly correlatable to incentive-deserving customer choices and should be obvious (Customer did X and hence got an incentive Y, etc)
9. **Encourage economically efficient decision making:** For example, load shifting via off-peak charging shifts energy consumption during hours of inexpensive electricity. Similarly, *energy consumption during **excess supply (belly of the 'duck') period** can receive similar subsidies.*
10. **Customer education:** Educated customer is informed customer and a better consumer of electricity.

This document describes a methodology to correlate the incentives and rates that are attributable to the participating PEVs as utility assets to compensate for their participation in the value-added grid services. Since energy services enabled by V2G capable PEVs are comprised of two types – load shifting by explicit or tariff mechanisms and market-oriented grid services, where PEVs offer services by participating in ISO market. In general, charging pattern modification to better utilize grid capacity results in a variety of savings. These can be incentivized based on marginal cost principles. Following table, again adapted from the same reference[72] illustrates this principle:

Table F-1 Marginal Cost as Incentive Driver

Type of Marginal Cost	Basis for Allocation	Incentive Units
Energy	Generation	Cents/kWh or $/MWh
Capacity	Generation, Distribution	$/kW or $/kW/year
Customer	Final Line Transformer, Service Drops, Meters, Billing, Customer Service	$/customer/year or $/customer/month

Source: EPRI

Tying incentives to marginal costs is the best way to reward causality directly. Secondly, rewarding grid-friendly behavior also promotes energy conservation and consequently, economically efficient decision making. As a matter of fact, CPUC recently announced[73] a decision that allows Time of Use tariff revision that incentivizes specific grid-friendly energy use behavior. This effectively correlates rate / price of each kWh consumed at different times of the day with the costs associated with serving that kWh at that time, i.e., a temporal correlation between the rates and costs. The most important principle of the rate design has been the

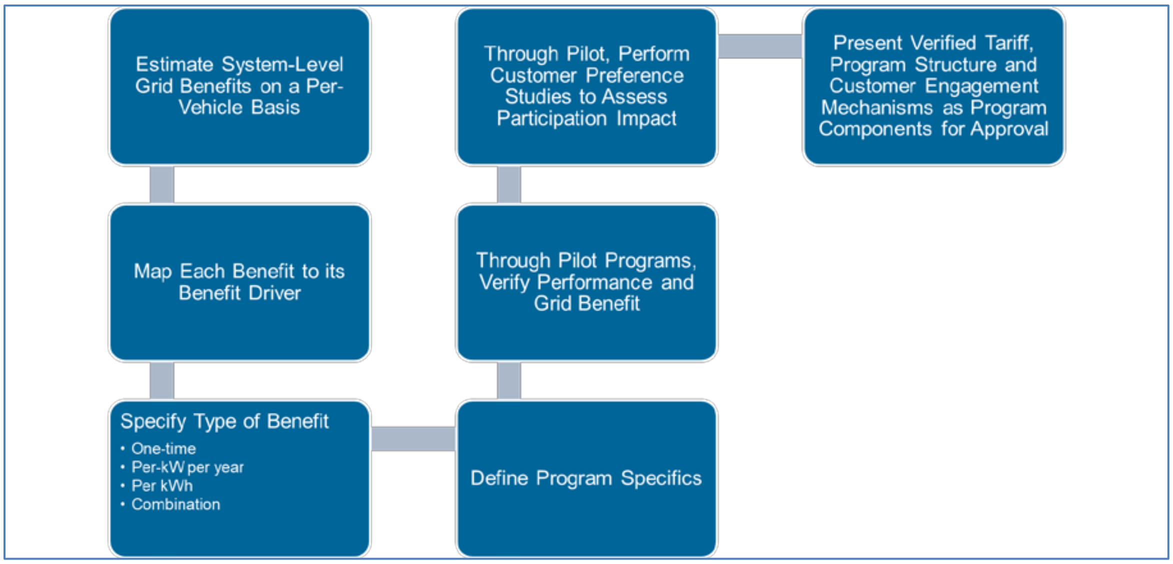
[72] ibid
[73] D17-01-006, CPUC, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M197/K810/197810230.PDF

concept of 'Equal Percent Marginal Costs[74]', which effectively enables equitable allocation of rates against cost drivers for class of customers and individual customers.

Incentives and Tariff Quantification Methodology Process Flowchart

Figure F-1 describes the process flowchart that identifies the steps necessary to translate macro-level cumulative system benefits to per-vehicle, per-year incentives that can be rolled out in terms of a variety of compensation mechanisms for the participating PEVs in utility programs. Each of the steps in this process are described in the ensuing paragraphs:

Figure F-1: Incentives and Tariff Quantification Methodology Flowchart



Source: EPRI

Estimate System Level Grid Benefits on a Per-Vehicle Basis

Previous chapters discuss a variety of methods and approaches in estimating grid-level benefits on ISO-wide, DSO-wide and per-vehicle basis for the use cases that are implemented and relevant to V2G capable vehicles randomly located and mobile across distribution systems. These use cases assume the vehicles to be either at home or at work, plugged in and available for extended periods of time. These grid level benefits are calculated through one of the following mechanisms

- Avoided / deferred capacity upgrades
- Avoided / deferred generation procurement
- Avoided / deferred distribution system overvoltage mitigation costs

These avoided costs are assessed at

- Local facility level,
- Distribution feeder level as well as

[74] 'Rate Design Basics', ORA, August 1, 2011, http://www.ora.ca.gov/uploadedFiles/Content/Energy/Customer_Rates/rate_design/RateDesignBasics_August_2011FINAL.pdf

- DSO / ISO level

Furthermore, through a variety of co-optimization and dispatch algorithms employed in the valuation models, value-stacking of these benefits to compute their cumulative value.

Map Each Benefit to its Value Driver

When value-stacking is applied, each stack of value has a value-driver among the drivers described above, and at this step, the ordered pairs of value-driver and value are compiled so that the nature of the benefit (one-time or recurring) can be assessed. Once the nature of the benefit is assessed, in terms of one-time, per-kW or per-kWh (or a combination thereof), appropriate incentive method can be assessed.

Specify Type of Benefit

Depending on the type of grid service, the type of benefit may be different. Assign, to each program-specific service, appropriate type of incentive. Incentive types could be one-time or per availability or per event, in the form of per-kW, per-kWh or one-time lump-sum benefit per year.

Define Incentive Program Specifics

Based on the highest value-drivers (or the ones that the utility wants to address), incentive program specifics can be defined. For example, if only availability is being incentivized for spinning or non-spinning reserves, then a per-kWh value may be applied. If the resource is utilized for a service like peak shaving, then a per-kW value can be assigned for incentives, etc. This incentive program now needs to go through technology and market tests. Depending on the size of the sample, PUC approval may be required. While setting up pilot program incentive structures, also keep in mind the popularly offered incentives and allow as much diversity of incentive structures as possible to collect customer participation data for analysis purposes.

Through Pilot Programs, Verify Technology Performance and Grid Benefits

Conduct technology pilot (such as this project, on a larger sample size), gather data and verify the performance of the technology as per the program requirements. Use the data gathered through the pilot to assess how closely the data resembles the assumptions used to create valuation model. If needed, modify the valuation model to refine the assessed benefits.

Through Pilot Programs, Conduct Customer Preference Studies

Conduct customer preference studies applying Discrete Choice Experimentation and similar statistical analytical methods. The aim is to find out which specific incentive mechanisms generate superior participation from the customers. Given that all of the incentive programs are designed to encourage consumers to modify their PEV charging / discharging behavior, the focus is to find the most promising approaches to maximize participation.

Determine Effective Consumer Program Structure

If previously designed steps are implemented effectively, they have helped identified the following:

- Type of programs and corresponding grid services

- Incentive structures
- Consumer engagement strategies
- Program implementation blueprint
- Measurement and Verification strategy
- On- and off-vehicle technology components
- Interconnection guidelines

These become the incentive program packages for further consideration by utilities for engaging V2G capable vehicles for grid services.

TOU Rates vs. Marginal Costs

CPUC avoided costs developed for DER represent the marginal cost of delivering energy in each hour, including an allocation of system, transmission, and distribution capacity costs to peak load hours. Figure F-2 shows the average hourly CPUC avoided costs for DER overlayed with the SCE TOU periods in 2016. Figure 105 shows revised TOU periods proposed by SCE in the CPUC Residential Rate Reform Proceeding and CPUC avoided costs for 2030, reflecting higher penetrations of renewable generation.[75]

Figure F-2: 2016 SCE TOU Periods and Average Hourly CPUC Avoided Costs for DER in 2016

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1	2	3	4	5	6	7	8	9	10	11	12
1	$43	$41	$33	$38	$38	$39	$42	$44	$45	$47	$52	$53
2	$42	$39	$32	$36	$37	$38	$41	$42	$43	$45	$51	$52
3	$41	$38	$31	$35	$36	$38	$40	$41	$42	$44	$50	$51
4	$41	$38	$32	$37	$37	$38	$40	$42	$43	$46	$51	$52
5	$42	$40	$35	$43	$41	$40	$42	$44	$46	$49	$54	$54
6	$47	$46	$40	$48	$43	$42	$42	$46	$48	$53	$60	$62
7	$51	$49	$42	$46	$40	$41	$42	$46	$48	$54	$65	$69
8	$52	$49	$38	$37	$33	$38	$42	$44	$46	$50	$59	$71
9	$47	$45	$33	$30	$29	$40	$43	$45	$46	$47	$51	$59
10	$44	$41	$31	$29	$30	$41	$44	$46	$47	$48	$48	$53
11	$44	$40	$31	$31	$30	$43	$45	$48	$49	$49	$47	$48
12	$43	$39	$31	$32	$31	$45	$48	$51	$51	$51	$48	$47
13	$42	$39	$31	$32	$30	$46	$51	$53	$53	$52	$47	$46
14	$41	$38	$32	$32	$31	$48	$53	$77	$538	$54	$47	$46
15	$42	$39	$32	$33	$31	$50	$56	$289	$910	$58	$49	$47
16	$44	$41	$35	$36	$34	$54	$60	$530	$1,266	$72	$52	$55
17	$55	$46	$40	$41	$38	$55	$60	$596	$1,166	$72	$65	$67
18	$66	$56	$46	$50	$46	$60	$61	$331	$1,899	$87	$85	$87
19	$66	$65	$54	$58	$52	$62	$62	$521	$1,175	$76	$77	$84
20	$61	$58	$50	$62	$59	$60	$60	$157	$327	$65	$68	$76
21	$58	$56	$45	$53	$53	$54	$56	$55	$55	$58	$65	$72
22	$54	$51	$41	$48	$46	$48	$51	$52	$51	$55	$60	$66
23	$50	$47	$38	$43	$42	$44	$48	$48	$49	$52	$57	$62
24	$46	$44	$34	$41	$39	$41	$45	$46	$47	$48	$52	$57

Super Off Peak

Off Peak

On

Super Off Peak

Pacific Local Time, Hour Ending; Climate zone 9: Burbank Glendale

[75] CPUC Rulemaking 12-06-013

Source: EPRI

There are two key challenges for TOU rates with respect to incentivising V2G dispach. The first is properly aligning the TOU periods for peak loads net of PV generation that are occuring later in the evening. The second challenge, with respect to V2G, is that TOU rates provide an on-peak price that is averaged over a relatively broad period of six to eight hours in the day over four to six Summer months without special emphasis on the very highest system peak load hours.

Figure F-3: Proposed SCE TOU Periods and Average Hourly CPUC Avoided Costs for DER in 2030

Off Peak

Super Off

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
1	$105	$106	$98	$100	$97	$97	$100	$103	$101	$107	$116	$112
2	$102	$101	$95	$95	$93	$95	$98	$95	$97	$102	$113	$110
3	$100	$99	$94	$93	$90	$93	$95	$93	$95	$101	$111	$107
4	$100	$97	$98	$99	$94	$94	$96	$94	$97	$104	$113	$109
5	$104	$102	$108	$118	$105	$100	$100	$102	$106	$113	$119	$114
6	$117	$123	$127	$134	$111	$105	$102	$108	$112	$122	$135	$128
7	$128	$131	$137	$126	$102	$102	$101	$107	$112	$124	$144	$148
8	$129	$132	$120	$97	$14	$95	$99	$99	$103	$113	$129	$152
9	$118	$119	$100	$14	$14	$99	$102	$101	$103	$108	$113	$122
10	$109	$106	$14	$14	$14	$15	$106	$107	$107	$110	$105	$111
11	$107	$102	$14	$14	$14	$18	$110	$112	$113	$115	$102	$99
12	$105	$101	$14	$15	$15	$22	$114	$118	$117	$118	$105	$98
13	$102	$99	$14	$15	$15	$24	$121	$124	$123	$121	$102	$95
14	$100	$99	$15	$17	$15	$29	$129	$132	$133	$126	$103	$95
15	$102	$101	$15	$17	$15	$33	$137	$138	$306	$135	$107	$98
16	$110	$107	$108	$18	$16	$142	$147	$154	$1,347	$145	$115	$112
17	$135	$122	$127	$112	$17	$145	$151	$576	$2,883	$239	$146	$144
18	$171	$154	$152	$139	$121	$158	$154	$501	$2,851	$214	$195	$189
19	$172	$182	$183	$165	$139	$162	$153	$664	$1,584	$185	$177	$183
20	$156	$160	$166	$174	$160	$160	$147	$256	$520	$154	$155	$164
21	$150	$152	$146	$150	$141	$142	$137	$126	$130	$138	$147	$152
22	$133	$137	$131	$132	$122	$121	$126	$122	$121	$129	$134	$142
23	$124	$123	$118	$118	$108	$113	$112	$116	$117	$117	$125	$133
24	$114	$116	$103	$110	$101	$104	$105	$108	$109	$110	$116	$120

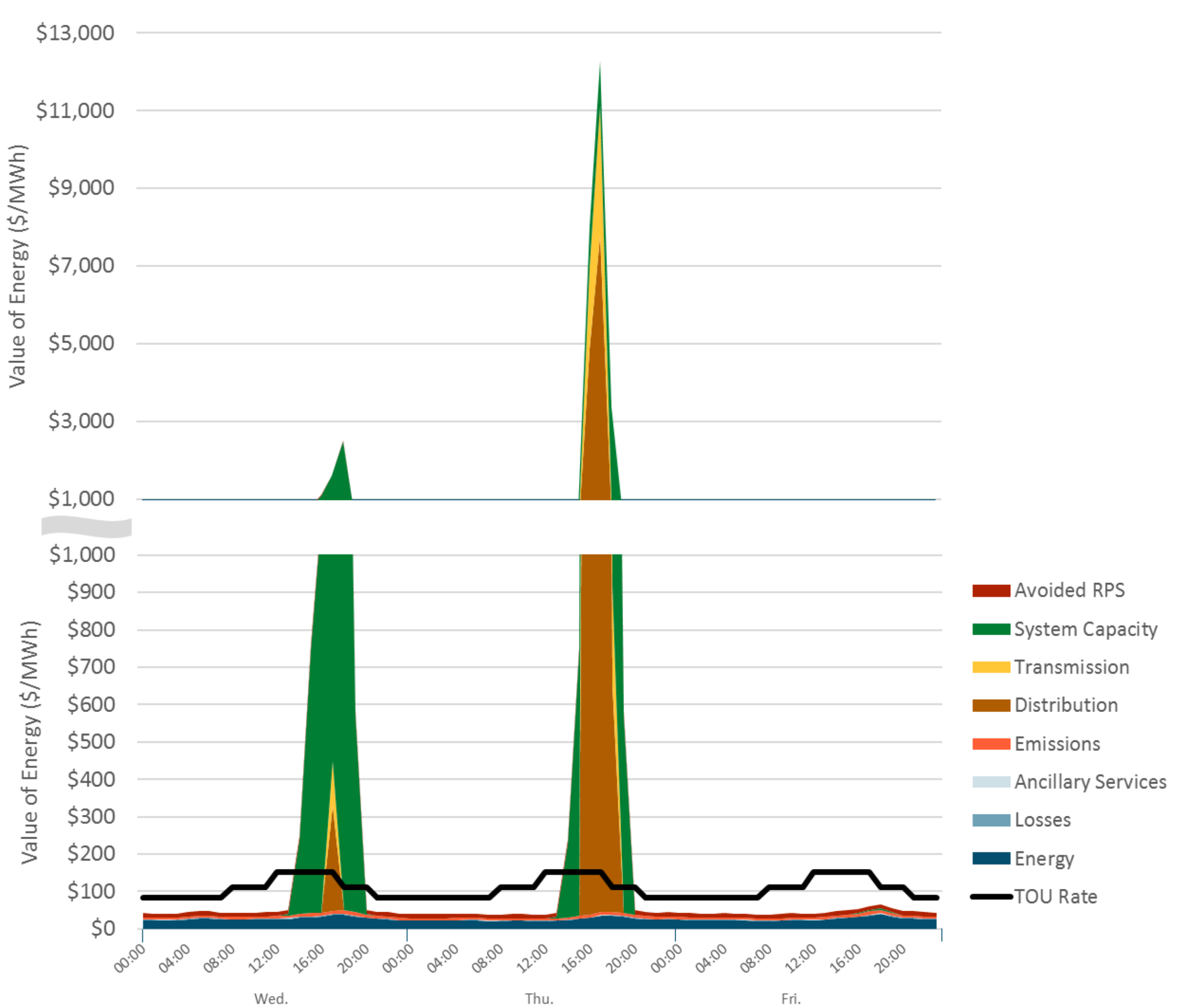
Pacific Local Time, Hour Ending; Climate zone 9: Burbank Glendale

Source: EPRI

Modifying TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening is under active consideration in the CPUC Residential Rate Reform Proceeding. Shifting the TOU period to later in the day will capture more of the high system marginal costs hours (e.g., hour ending (HE) 19 and HE 20 in August and September) that fall outside the current on-peak TOU period. SCE has also proposed a super off-peak period in the winter between HE 9 and HE 16 when excess renewable generation is most likely to occur.

Broad TOU rate periods, however, do not harness the potential for highly flexible resources like V2G and energy storage to support the grid during those specific hours with the highest marginal costs. Figure F-4 shows an example PG&E TOU rate (E19S) compared to the 2016 CPUC avoided costs in Fresno for three summer days. On the first day, high system capacity value is concentrated in the three hours between 5 and 8 PM, but the TOU rate provides an equal incentive for AES to discharge beginning at noon. The next day, local transmission and distribution capacity costs drive a significantly higher value concentrated between 4 and 6 PM. Focusing V2G discharge in just those two hours based on local system conditions would maximize the value to the grid. For the last day, the difference between on- and off-peak marginal costs are relatively small. Charging PEVs off-peak and discharging on-peak reduces the customer bill, but provides limited value to the grid on this particular day.

Figure F-4: Three-day Snapshot of PG&E TOU Rates and CPUC Avoided Costs in 2016



Climate Zone 13 – Fresno and PG&E E19S Rate

Source: EPRI

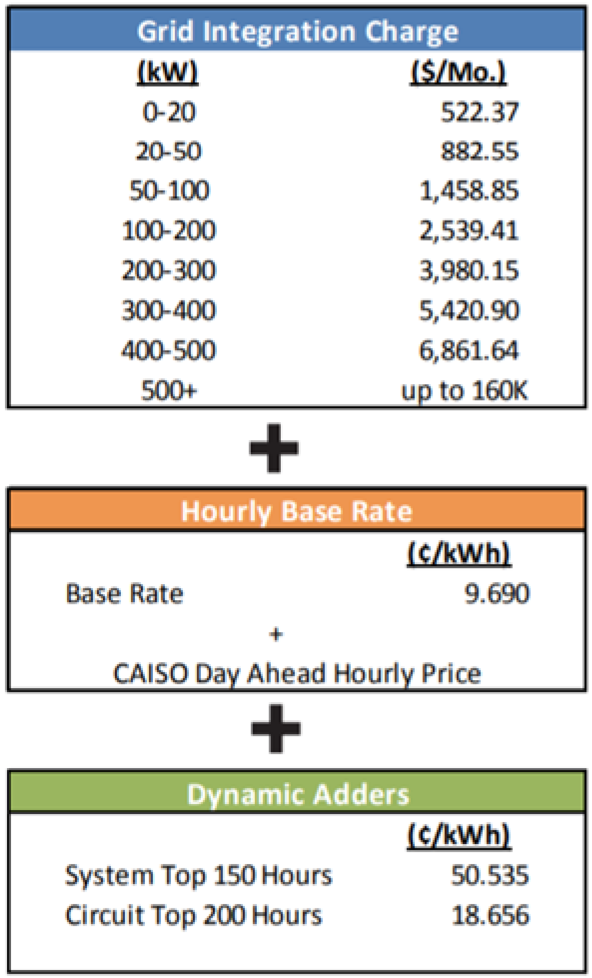
SDG&E Grid Integration Rate

- The GIR (Grid Integration Rate) consists of an hourly base rate plus the California ISO Day-Ahead hourly price
- There are also two dynamic capacity adders—one for the top 150 System hours, and the other for the top 200 Circuit hours

- GIR rate was proposed as part of SDG&E's SB350 Transportation Electrification[76]

Figure F-5: Commercial DIR

Diagram 5-4: Commercial GIR[24]



Grid Integration Charge	
(kW)	**($/Mo.)**
0-20	522.37
20-50	882.55
50-100	1,458.85
100-200	2,539.41
200-300	3,980.15
300-400	5,420.90
400-500	6,861.64
500+	up to 160K

Hourly Base Rate	
	(¢/kWh)
Base Rate	9.690
+	
CAISO Day Ahead Hourly Price	

Dynamic Adders	
	(¢/kWh)
System Top 150 Hours	50.535
Circuit Top 200 Hours	18.656

Source: EPRI

An analysis performed for the SGIP evaluation of energy storage is also instructive for the value of more dynamic rates for V2G.

- Six customers from SDG&E were selected, encompassing a variety of building types and battery sizes
- AES systems were dispatched in price taker optimization model. Resulting utility avoided costs, customer bill savings, and CO2 emission savings were quantified

[76] *Source: https://www.sdge.com/sites/default/files/regulatory/Direct percent20Testimony percent20Chapter percent205 percent20- percent20Rate percent20Design.pdf*

- GIR pilot rate modeled against existing rates
- VGI and TOU-DR-E3 rates were also analyzed, with similar results

Figure F-6: Customer Sample

Summary **CUSTOMER SAMPLE SUMMARY**

RTE	Customer IDs	Existing Rate	kW Size	Type	Online Date	Effective kW
84%	SD-SGIP-2014-0684	ALTOU_CPP_Hybrid	400	Industrial	5/1/2016 0:00	268
91%	SD-SGIP-2013-0537	ALTOU_CPP_hybrid	60	Mining	2/1/2016 0:00	55
84%	SD-SGIP-2013-0555	ALTOU	30	Food/Liquor	1/1/2016 0:00	30
81%	SD-SGIP-2013-0557	ALTOU	30	Food/Liquor	1/1/2016 0:00	30
84%	SD-SGIP-2015-0758	ALTOU	2000	Industrial	5/1/2016 0:00	1339
81%	SD-SGIP-2015-0757	ALTOUCP2	1600	Industrial	5/1/2016 0:00	1071

Source: SDG&E

Operating under the GIR rate tends to improve the $/kW of energy storage utility avoided costs over the existing rate.

Across the sample, the GIR rate has average $/kW savings of $14.80/kW versus $5.83/kW for the existing rate.

Figure F-7: $/kW Avoided Costs

Source: E3

Figure F-8: 2016 Avoided costs and SDG&E GIR

2016 Avoided Costs

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.087	0.063	0.031	0.040	0.049	0.072	0.069	0.059	0.044	0.044	0.039	0.047
1	0.073	0.054	0.030	0.042	0.051	0.069	0.066	0.060	0.043	0.043	0.038	0.045
2	0.059	0.047	0.030	0.040	0.050	0.061	0.059	0.056	0.043	0.042	0.038	0.044
3	0.051	0.042	0.031	0.037	0.049	0.052	0.054	0.051	0.044	0.044	0.038	0.044
4	0.049	0.040	0.034	0.038	0.048	0.043	0.051	0.048	0.046	0.047	0.040	0.045
5	0.050	0.039	0.040	0.042	0.047	0.042	0.048	0.046	0.049	0.054	0.045	0.050
6	0.053	0.043	0.044	0.041	0.040	0.040	0.043	0.046	0.048	0.058	0.051	0.056
7	0.052	0.042	0.036	0.016	0.010	0.030	0.041	0.043	0.043	0.047	0.046	0.058
8	0.044	0.036	0.020	(0.010)	(0.001)	0.019	0.039	0.043	0.039	0.039	0.038	0.050
9	0.041	0.032	(0.001)	(0.017)	(0.006)	0.017	0.034	0.044	0.039	0.035	0.030	0.044
10	0.039	0.030	(0.002)	(0.020)	(0.010)	0.022	0.038	0.046	0.047	0.032	0.027	0.039
11	0.038	0.027	(0.007)	(0.018)	(0.008)	0.029	0.043	0.048	0.052	0.038	0.029	0.038
12	0.037	0.026	(0.008)	(0.019)	(0.008)	0.032	0.046	0.051	0.058	0.042	0.028	0.035
13	0.037	0.027	(0.006)	(0.017)	(0.008)	0.037	0.053	0.058	0.104	0.078	0.035	0.037
14	0.039	0.033	0.001	(0.011)	(0.003)	0.043	0.058	0.069	0.130	0.099	0.038	0.042
15	0.041	0.036	0.010	0.003	0.006	0.049	0.065	0.087	0.166	0.125	0.045	0.048
16	0.047	0.040	0.037	0.021	0.020	0.056	0.064	0.085	0.162	0.114	0.057	0.058
17	0.062	0.050	0.043	0.042	0.043	0.062	0.068	0.083	0.132	0.108	0.071	0.071
18	0.061	0.056	0.051	0.051	0.048	0.066	0.071	0.073	0.087	0.079	0.062	0.068
19	0.065	0.050	0.047	0.054	0.057	0.062	0.064	0.064	0.079	0.066	0.056	0.064
20	0.075	0.047	0.042	0.045	0.048	0.053	0.058	0.056	0.069	0.059	0.053	0.061
21	0.091	0.052	0.039	0.041	0.041	0.047	0.059	0.051	0.052	0.052	0.049	0.056
22	0.108	0.061	0.035	0.037	0.038	0.052	0.064	0.048	0.048	0.048	0.045	0.052
23	0.107	0.062	0.033	0.035	0.044	0.065	0.069	0.050	0.045	0.045	0.042	0.049

Showing TOU periods adopted in SDG&E Revenue Allocation and Rate Design Proceeding D. 17-08-012 (A. 15-01-012)

SDG&E GIR*

Month

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.187	0.171	0.128	0.165	0.148	0.187	0.156	0.173	0.124	0.125	0.120	0.127
1	0.169	0.169	0.111	0.163	0.147	0.186	0.156	0.173	0.124	0.124	0.119	0.126
2	0.169	0.151	0.111	0.163	0.147	0.184	0.155	0.172	0.124	0.123	0.119	0.125
3	0.168	0.151	0.112	0.165	0.148	0.185	0.139	0.172	0.124	0.125	0.119	0.125
4	0.137	0.152	0.115	0.119	0.150	0.137	0.139	0.158	0.127	0.128	0.121	0.126
5	0.140	0.120	0.120	0.123	0.153	0.139	0.140	0.127	0.130	0.150	0.126	0.131
6	0.145	0.124	0.124	0.122	0.150	0.121	0.140	0.127	0.129	0.153	0.132	0.137
7	0.146	0.123	0.117	0.113	0.130	0.120	0.122	0.124	0.124	0.144	0.127	0.139
8	0.141	0.117	0.110	0.106	0.112	0.120	0.123	0.124	0.120	0.120	0.119	0.131
9	0.122	0.114	0.108	0.104	0.112	0.121	0.125	0.125	0.120	0.119	0.113	0.125
10	0.119	0.112	0.107	0.105	0.113	0.123	0.127	0.127	0.135	0.120	0.112	0.120
11	0.119	0.112	0.107	0.105	0.113	0.125	0.130	0.129	0.137	0.122	0.113	0.118
12	0.118	0.112	0.107	0.105	0.113	0.127	0.132	0.131	0.139	0.135	0.114	0.116
13	0.118	0.113	0.113	0.106	0.113	0.129	0.135	0.146	0.191	0.173	0.116	0.118
14	0.120	0.114	0.114	0.109	0.114	0.134	0.139	0.162	0.231	0.181	0.119	0.122
15	0.122	0.117	0.116	0.111	0.116	0.136	0.168	0.190	0.253	0.227	0.126	0.129
16	0.128	0.121	0.121	0.115	0.118	0.138	0.144	0.198	0.252	0.206	0.138	0.139
17	0.143	0.131	0.129	0.123	0.124	0.142	0.148	0.180	0.241	0.196	0.151	0.152
18	0.157	0.137	0.132	0.132	0.129	0.146	0.152	0.158	0.175	0.165	0.142	0.148
19	0.151	0.131	0.128	0.135	0.138	0.143	0.144	0.145	0.167	0.154	0.137	0.145
20	0.165	0.128	0.123	0.126	0.129	0.134	0.153	0.137	0.160	0.148	0.134	0.142
21	0.194	0.158	0.120	0.122	0.122	0.144	0.147	0.132	0.144	0.133	0.130	0.137
22	0.208	0.174	0.116	0.118	0.135	0.175	0.160	0.129	0.128	0.129	0.126	0.133
23	0.205	0.171	0.114	0.149	0.150	0.189	0.158	0.159	0.126	0.126	0.123	0.130

*Calculated using 2016 CAISO and DER avoided cost data

Source: EPRI

Summary

Previous sections have described a variety of approaches to assess value of V2G capable vehicles to the grid through a variety of mechanisms. These sections summarized how to translate this macro or per-vehicle value into program definitions and verify them through pilot implementation so the technology and market acceptance of a variety of approaches can be evaluated for effectiveness in terms of technology performance and customer engagement.

APPENDIX G: Program Fact Sheet

The Issue: Plug-in Electric Vehicles (PEVs) with integrated Vehicle to Grid (V2G) systems have the potential to simultaneously improve air quality, reduce vehicle operational costs and have the potential to reduce grid stress and increase grid reliability and stability. State of California PEV presence is approximately at 400,000 vehicles and is projected to be over 1.5 Million vehicles in 2023. If the future PEVs through 2023 (estimated 1M) are V2G capable with ability to provide 6.6kW average charging and discharging power will constitute 6.6GW of potentially dispatchable generation and load capacity for ancillary services and demand side load management. This magnitude of capacity from V2G and the low capital cost to utilities for implementation enhances the perception of V2G by the CPUC to be a viable low-cost energy resource. CPUC Rulemaking 10-12-007[77], the California Storage Mandate' requires IOUs to procure 1.3GW of storage; including the provision that Vehicle to Grid (V2G) technologies are an acceptable procurable energy storage resource to meet the mandate requirements. Additionally, compliance to CPUC Rule 21 for grid interconnection of DER systems will enable V2G as a Distributed Energy Resource to participate in DERP, DRAM, and DRMS energy market and distribution capacity programs.

The challenges for V2G implementation and value acquisition are: inconsistent V2G system communication approaches, lack of situational awareness of the PEVs relative to grid state, fragmented V2G standards for interoperability, interconnection authorization for PEVs, and regulatory inclusion of V2G resources into applicable distribution and ISO grid services programs. In addition, lack of advancement for on- or off-vehicle V2G systems from OEMs is because OEMs do not see the value to end customers. This prevents any realistic assessment of PEVs as a Distributed Energy Resource (DER) that provides a path to volume production from the OEMs.

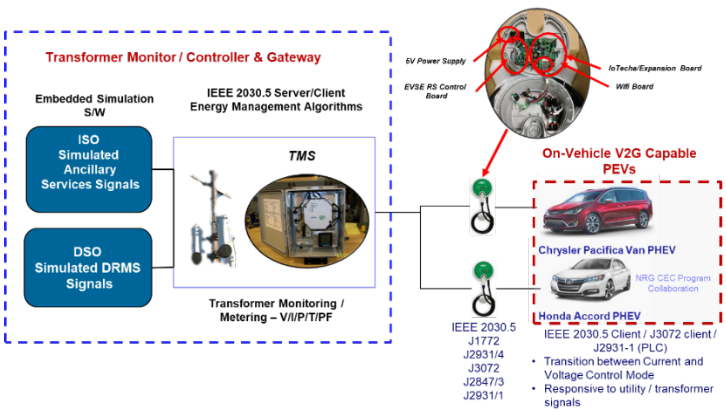
Project Description: This project is the development and verification testing of an integrated monitoring and communications control system that enables on-vehicle V2G as a dispatchable distributed resource to maintain grid stability and reliability from the residential transformer level. The project team involves EPRI, Kitu Systems, FCA (Chrysler), Honda, AeroVironment, Energy and Environment Economics (E3), University of Delaware, and University California at San Diego (UCSD). The premise is the application of standards based V2G communications protocols and specifications (J2931/1, J2931/4, J2847/2, J2847/3 J3072, J1772, IEEE2030.5).

The system architecture includes an innovative development and implementation by EPRI of a Transformer Management Unit (TMU) that monitors the transformer operating status and local grid conditions; and incorporates the IEEE2030.5 server/client software and DER functions to receive and respond to ISO and DRMS generation/load capacity and management signals. Kitu Systems provided the IEEE2030.5 server/client operating system software. The TMU is the

[77] 'Decision Adopting Energy Storage Procurement Framework and Design Program', CPUC, R 10-12-007, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K929/78929853.pdf

controller for the multiple V2G vehicles connected to the transformer circuit and monitors each vehicle arrival time, SOC, time charge is needed, and customer SOC min/max constraints. Algorithms are developed to simultaneously control the charging/discharging cycles of each vehicle to minimize stress to the transformer and offset the ramping effects from the distribution system for over/under generation of renewables, as well to synchronize V2G with residential solar generation.

Figure G-2: V2G System Architecture Overview



Source: EPRI

The EVSE developed by AeroVironment incorporates the J2931/4 compliant PLC communications module and contains the J3072 server for authentication and authorization of the on-vehicle inverter to be grid interconnected for reverse power flow. There are two versions of the on-vehicle communications module, one developed by EPRI for the Chrysler Pacifica PHEV and one by University of Delaware for the Honda Accord PHEV. Each have the J2847/3 implementation of the IEEE2030.5 DER function set and the J3072 client software. Chrysler and Honda have integrated bidirectional charge converters with integrated software for CAN to J2847/3 communications.

An PEV Simulator has been developed to perform validation testing of the TMU control algorithms with up to eight variable model PEVs/PHEVs simultaneously. The simulation testing incorporates residential seasonal load and behind the meter solar generation data profiles, transformer constraints, PEV charge/discharge capacities, varied PEV arrival times, and driver preferences for min SOC and time charge is needed or departure time. An ISO/DSO simulator was developed by EPRI to provide ancillary services and DRMS signals.

The field demonstration is being conducted at UCSD utilizing the Nuvve hosted on campus charge site. Modifications to the charge site will be to incorporate the TMU, two AeroVironment upgraded dual port EVSEs, 75KVA transformer, 400A power panel, and disconnect. 12 kW solar generation capacity will be routed to the charge site. Three Chrysler Pacifica PHEVs and one Honda Accord PHEV with V2G inverter and communications modifications will be allotted to this field demonstration.

EPRI and E3 are coordinating the cost effectiveness, value/benefit and circuit impact analysis for V2G. Data modeling will utilize the EPRI Storage Value Estimation Tool (VET) and the E3 CPUC

Cost Effectiveness Assessment model to estimate the cost effectiveness and value of V2G. Comparative analysis to previous V1G related data will be included. EPRI is developing a distribution circuit hotspot profile to assess the value of V2G to mitigate or alleviate feeder and transformer stress factors. The potential of V2G to extend transformer life cycle, reduce GHG emissions, enhance usage of solar, and benefit ratepayers are to be identified as an outcome of this project.

Anticipated Benefits for California

- Leverage installed base of V2G capable PEVs to enable higher penetration of distributed PV.
- Mitigate distribution system stress through monitoring and control of locational V2G dispatch
- Inform key stakeholders: IOUs, PEV manufacturers, participating customers and regulators of the potential, and the viable mechanisms, to engage PEVs with V2G technology.

Project Specifics

Contractor	**Electric Power Research Institute (EPRI), Inc.**
Partners	Clean Fuel Connection, Inc., Grid2Home, Inc., AeroVironment, Inc., Energy and Environment Economics (E3)
Amount	$1,499,977
Co Funding	$795,754 from EPRI and Proposal Team
Term	August 2015 to June 2018

APPENDIX H: EPIC Annual Report

Principal Investigator: Sunil Chhaya PhD, Electric Power Research Institute

Title: Distribution System Aware Vehicle to Grid Services for Improved System Stability and Reliability

The Issue:

PEVs are steadily gaining traction and the major automakers are progressively advocating PEVs as the top of the list for new vehicles. Global plug-in electric vehicles sales have continued to register impressive figures, with a 68 percent jump in 2015 and a 42 percent rise in 2016, attaining a sales figure of 773,600 vehicles in 2016. California has almost 50 percent of total US PEVs sold (260,000 of 542,000 through end 2016) and is targeting 1.5 M PEVs in 2025.

However, utilities are concerned that large scale deployment of electric vehicles could feasibly create load imbalance and stability issues for the power grids. The counter balance to these issues is the potential to use PEV battery energy storage as a resource to sustain, and potentially improve, stability and reliability of the grid.

PEVs are being produced with ever larger capacity high-density battery energy systems (60kWh to 95kWh), which with vehicle to grid (V2G) technology could provide a viable distributed energy resource (DER) to the utilities. PEVs with bidirectional inverters will enable reverse power flow from the PEV battery to the grid. Studies indicate that PEVs are on the road an average of 5 percent to 10 percent of the day meaning the PEV is parked approximately 20 hours of the day, allowing significant availability of the PEV for use as an energy storage resource by the utilities. An imperative for using the vehicle battery for an energy storage application is being sure the customer has a full battery charge when needed for transportation purposes.

The approach to a solution is the development and verification of end to end communications from the DSO/ISO to the PEV for integrating the vehicle battery system as a distributed energy resource. It is the ability to provide functionality to control PEV battery charging/discharging for real time response to grid load balancing and instability conditions (i.e. duck curve), within customer applied constraints (min SOC, time charge is needed, etc.).

Two primary needs V2G technology can address; balancing of PV generation at the local distribution level to mitigate the Duck Curve affects and impacts at the transmission level, and to mitigate distribution transformer impacts caused by growing clusters of PEVs. V2G can enhance the capacity value of distributed PV and create value from distribution asset upgrade deferral.

There is also the need for uniformity in connected technologies from a diversity of manufacturers for smart grid communications, and compliance to CPUC Rule 21 "Generating Facilities Interconnection". The equipment must meet specific safety and electrical standards. Uniformity is to be addressed through implementation, interoperability, and verification of open standards-based communications protocols (IEEE2030.5 and SAE Standard J3072, J2847/3, J2931/1, J2931/4).

Most significantly is the Rule 21 requirement the on-vehicle inverter and related power processing subsystems comply to IEEE 1547 which is the Standard for interconnecting Distributed Resources with Electrical Power Systems, and to UL1741 safety standard for Inverters, Converters, Controllers and Interconnection Systems Engineered for use with Distributed Energy Resources.

There are two challenges for V2G PEVs to comply. First is automakers self-certify their vehicles and do not submit their vehicles to 3rd party testing for safety certifications. Automakers also do not certify to UL standards. They certify the vehicles to Society of Automotive Engineers (SAE) and Federal Motor Vehicle Safety Standards (FMVSS) requirements. Second challenge is that Rule 21 assumes that all equipment is fixed at the site and all equipment certifications are identified in the Generator Interconnection Agreement between the applicant and the utility or energy service provider, which is required before the DER is activated. The PEV roams from site to site and must be certified with that site to engage in generating power to the grid.

SAE J3072 "Interconnection Requirements for On-Board Utility Interactive Inverter Systems" addresses the first challenge by incorporating the certification and verification testing required by UL 1741 and IEEE1547.

The second challenge requires an authentication process be established to track the vehicle inverter models that are J3072 compliant and upon plug in of the vehicle the system authenticates the inverter certification and authorizes the vehicle to discharge power to the grid. It is intended, as a part of this project, to implement and verify this requirement for evaluation with SDG&E and the CPUC. J3072 is being discussed with the CPUC Smart Inverter Working Group for evaluation and consideration to be an authorized provision within the Rule 21 requirements for certification and permitting.

Project Innovation:

A key innovation is the approach to develop and integrate the control for V2G at the local distribution circuit level, at the transformer. The project is developing a transformer monitoring and management system with the communications processing and interfaces for DSO/ISO signaling response and the control algorithms for aggregation of V2G grid services with multiple connected PEVs.

This is to optimize the V2G strategy to mitigate impacts at the distribution circuit level and upstream to the sub feeder, feeder, and transmission levels. There is as well, inherent enhancement to PV capacity values from integrating V2G energy storage with the proliferation of distributed PV installations throughout the edges of the grid, at the local transformer level.

Monitoring at the transformer level with control of V2G provides enhanced local situational awareness and real-time responsiveness to distribution grid conditions. The Transformer Monitoring and Management System will have awareness of load, power, temperature, current, voltage, frequency, and PEV customer constraints – information to be utilized to determine need for V2G resource. Provides a potentially significant solution for integration of a viable energy efficient energy storage technology into a decentralized grid structure, and with the ability to operate as a unified DER aggregation system.

The primary enabler, which is also innovative, for PEV V2G market development and implementation is SAE J3072. This project will be the first to integrate the use of J3072 for authorizing and permitting on-vehicle inverters to be interconnected to the grid. As stated earlier, J3072 incorporates the certification and verification testing required by UL 1741 and IEEE1547. It provides for self-certification by the automakers for authorization to discharge power from the vehicle to the grid.

Energy Commission funding for this project is providing a critical platform to develop, demonstrate, and qualify the value of V2G grid services to the IOUs, the ratepayers, the automakers, and the PEV customers. It is a platform that is intended to provide a means for uniformity of V2G communications through the conformity with open SAE and IEEE standards; evaluation and verification of a more dynamic value strategy for V2G utilization beyond the limited ancillary services and frequency regulation markets; and the opportunity to determine the V2G value properties that might influence further development and investment in a directional path toward market deployment.

This project further advances a key statewide priority articulated in CPUC's roadmap for VGI development and implementation; and will be a major milestone in the integration of PEVs as a viable grid resource. It also addresses the concerns addressed in Rule 21 on the control of Distributed Energy Resources and how they can benefit the grid.

Project Benefits:

The cost and benefit assessment/analyses is in the preliminary stages of work development. Previous related studies and assessments provide indication of V2G primary value to the utility and the ratepayer.

For the California Electric Transportation Coalition (CalETC), E3 performed a detailed analysis of PEV charging impacts collectively for the California IOU's and SMUD, which provided detailed distribution system data for over 80,000 feeders and substations. Matching PEV clusters to individual circuit, feeder and substation locations the project team calculated the incremental load and distribution upgrade costs driven specifically by PEV charging at each location from 2014 through 2030. The increase in the utilization of the existing feeders and substations with the addition of PEV load. Analysis showed that PEVs can provide a net ratepayer benefit of ~$2,500 per vehicle and a statewide economic benefit of over $5,000 per vehicle. Using TOU rates to shift charging loads off-peak reduces distribution upgrade costs by over 60 percent. Further analysis of a dynamic hourly VGI rate shows that it can reduce present value of charging costs per vehicle under 40 percent RPS scenarios from around $1,400 to under $600 - a net benefit of $850 per PEV.

The benefits described above are consistent with other studies that have been used to support California's ambitious PEV adoption goals. These benefits, however, can be achieved with managed charging alone (V1G). The crucial question the project team will answer with this project is: do the additional benefits of V2G capability justify the associated costs for ratepayers, utilities and the state as a whole?

While existing studies of the value of V2G rely predominately on ISO frequency regulation markets, these markets are small and their revenue potential for PEVs is likely to decline. Furthermore, the transactional barriers for retail loads such as PEVs to participate in California ISO markets are significant. Olivine has documented substantial information, metering, billing and settlement costs for DR and PEV pilots, which have been a severe sticking point in the LA Air Force Base demonstration of V2G.

The value for V2G must therefore be demonstrated outside the frequency regulation market to represent a sustainable long-term net benefit for utilities and ratepayers. This project will demonstrate how a low cost, open communication platform can employ PEV V2G services to provide local distribution system and reliability benefits.

One clear benefit is that V2G could be employed to increase the capacity value of distributed PV. To appropriately weight the value of distributed energy resources in reducing distribution capacity investment costs a "Peak Capacity Allocation Factor" must be applied. As the amount of PV on a distribution feeder increases, or as peak load shifts to later in the evening, the capacity value of PV decreases. With increasing penetrations of PV, its marginal capacity value will decline from ~0.5 kW per KW of PV today to less than 0.1 kW. V2G capability of PEVs can counteract this effect, providing a dispatchable capacity resource that can reliably reduce peak loads. In capacity constrained areas such as the LA basin, the local capacity value can be over $200/kW-Yr. V2G could increase the hosting capacity value of PV at higher penetrations by $190/kW-Yr. If 20 percent of California's goal for 1.5 million PEVs could provide V2G capability (at 6.6 kW per vehicle) in capacity constrained urban areas, they could provide roughly 2,000 MW of capacity at a value of over $350 million per year.

With distribution system modeling, the project team will quantify local distribution system and reliability benefits from V2G. EPRI is currently working actively with Sacramento Municipal Utility District (SMUD) to create such analysis. This is crucial research as such benefits have been discussed in concept for some time but have not yet translated into discrete avoided cost benefits that can be used to value distributed resources such as V2G. PEVs are expected to cluster in urban areas and correlate strongly with PV ownership. V2G capability can potentially help avoid or defer distribution system investments needed to integrate high penetrations of PV.
There are four major milestones for this project

1. The completion and verification of the V2G communications technology development, and hardware integration with the Transformer Monitoring and Management System, EVSE and PEV – verification of the interoperability and unified functionality of the V2G applied communications standards.
2. The implementation of J3072 and the IOU/CPUC evaluation to make it the protocol for authorizing and permitting V2G on-vehicle inverters for grid interconnection.

3. Completion of the V2G cost and benefit assessment/analyses qualifying the values of V2G for providing a viable energy storage resource for grid services.
4. Completion of the Technology Transfer process with expectation to utilize results of the cost and benefit assessment to set framework for next steps toward V2G commercialization.

Regarding Milestone 3 above the objective is to quantify costs and benefits of V2G charging from the customer, utility and societal perspective. This is the most critical effort so for this milestone the following is to be accomplished.

- Evaluate monitoring, control and analytic capabilities
- Perform OpenDSS modeling of test feeders
- Quantify local distribution benefits
- Develop and document enhanced avoided cost framework
- Perform cost/benefit analysis

Next steps for this technology is further development and integration of the Rule 21 critical functionalities and communications, present and being determined, to further the embodiment of PEVs to be more directly interactive with other distributed energy resources.