New York State Energy Research and Development Authority

Electric Transportation Energy Storage System Feasibility Study

Final Report

May 2011

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ELECTRIC TRANSPORTATION ENERGY STORAGE SYSTEM

FEASIBILITY STUDY

Final Report

Prepared for the

NEW YORK STATE
ENERGY RESEARCH AND
DEVELOPMENT AUTHORITY
Albany, NY

www.nyserda.org

Frank S. Ralbovsky

Senior Project Manager

Jason H. Doling

Project Manager

Prepared by:

AEYCH LLC
Endicott, NY

Hank McGlynn

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ABSTRACT

The Electric Transportation Energy Storage System (ETESS) is a new concept that integrates control logic for intelligently managing the charging of groups of plug-in electric vehicles with a small grid-connected electricity storage system.

Plug-in Electric Vehicles (PEVs) are coming and are forecast to become a significant share of the transportation sector in the future. The primary location for charging for most vehicles will be at a "home" location. Although many PEVs, particularly the pure battery electric vehicles, will need access to charge stations at other locations – at work, at shopping malls, in public parking garages, on city streets … everywhere, PEV charging loads will vary significantly during the day at these "park and charge" facilities. If the charging facility needs to keep its peak power demand below a power limit, it will need to actively manage the power allocation of each of the vehicles at the facility.

One challenge is to create optimization algorithms to allocate the available facility power to each PEV to keep the facility within its power constraints while minimizing PEV customer disappointment. This is called **intelligent Power and Energy Management (iPEM)** logic. While the iPEM logic provides the capability to control the total facility power demand, it cannot add power, and this increases the risk that some vehicles will not get their requested energy transfer. Still, if a grid-connected energy storage system is placed within the facility, the iPEM algorithms can now take advantage of the energy storage capability to further improve the optimization. This integrated system of iPEM logic and energy storage is called the **Electric Transportation Energy Storage System (ETESS).**

Community Energy Storage (CES) is a new concept for grid storage that was developed by American Electric Power. A CES unit has a power of 25 kW with up to three hours of storage at rated power. It connects to the 240 volt secondary of the pad mounted transformer serving a group of homes. They are managed as a fleet by the utility to help manage the peak loads on the distribution feeder. In 2010 the Electric Power Research Institute (EPRI) expanded on the CES concept to include units at power levels from 25 kW to 75 kW on single phase circuits and up to 200 kW on three phase circuits. They call it Distributed Energy Storage Systems (DESS) – Utility Padmount. The smaller CES-size units could be deployed in residential applications and the larger 75 kW to 200 kW DESS units could be deployed in commercial and industrial applications.

ETESS can also be thought of as just another DESS application, except it is connected to a group of charge stations at a parking facility rather than to homes or businesses**.** ETESS units can also serve the grid. They are individually capable of voltage and VAR support along a feeder and can be managed as a fleet to provide frequency regulation or peak load management.

The objective of this project was to conduct a feasibility study of the ETESS concept. This report presents the results of this study.

Keywords: Electric Vehicle, EV, Plug-in Hybrid Electric Vehicle, PHEV, Charge Station, Electric Vehicle Supply Equipment, EVSE, Energy Management System, EMS, Electricity Storage System, Energy Storage System, Distributed Energy Resource, Community Energy Storage, CES, Distributed Energy Storage System, DESS, Electric Transportation, ETESS, iPEM, AEYCH

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The author also thanks others that participated in the webinars.

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List of Acronyms

An “X” or “EQn” in the “Sim” column designates an acronym used in chapters 8 – 12, which is not necessarily a standard term used in the industry. “EQn” means that the term is defined by an equation in chapter “n” of the report.

Acronym	Sim	Definition
A		Amperes, Amps (measure of current)
AC		Alternating Current
AEP		American Electric Power
AES		AES Energy Storage, LLC
AS		Ancillary Service
AvDelEX	EQ10	Relative Gap in Energy Transfer to Request (all PEVs)
AvDX	EQ10	Average Disappointment Index – a new metric
BEV		Battery Electric Vehicle
BMS		Battery Management System
CAES		Compressed Air Energy Storage
CES		Community Energy Storage
CF	EQ10	Capacity Factor
CP		Control Pilot signal in an EVSE
CS		Charge Station
CSN	X	A specific Charge Station number
CSocc	X	Quantity of Charge Stations occupied at a specific time
csQTY	X	Total quantity of charge stations at the charging location
CSU	X	Charge Station Utilization Matrix
CSuse	X	Quantity of Charge Stations providing power at a time
DC		Direct Current
DESS		Distributed Energy Storage System- Utility Padmount
DF	EQ10	Disappointment Factor – a new metric
DM		Demand Management
DTE		Detroit Edison utility
DUR	X	Actual duration of a charging session (TOD – TOA)
DX	EQ10	Disappointment Index – a new metric
EA		Enhanced Aggregation
EBAT	EQ8	Battery Energy Level
EDUR	X	Estimated Duration of charging session (ETOD – TOA)
EFF	X	Actual efficiency of a specific PEV’s charger
EffNom	X	Nominal Efficiency of all PEV chargers
EGAP	EQ10	Energy Gap (kWh) – target value less actual energy
EMS		Energy Management System
EPRI		Electric Power Research Institute
ETEMS		Electric Transportation Energy Management System
ETESS		Electric Transportation Energy Storage System
ETOD	X	Estimated Time of Departure – input by driver at TOA
ETTG	X	Estimated Time to Go before disconnect – (ETOD-Time)
EV		Electric Vehicle
EVSE		Electric Vehicle Supply Equipment
EX	EQ11	Composite ETESS Index – a new metric

EXACT	EQ10	Actual Energy Transfer (kWh) made since start
EXGAP	EQ10	Energy Transfer Gap is actual less requested at start
EXMAX	EQ10	Energy transfer if PEV used rated power for duration of stay
EXREF	EQ10	Requested Transfer adjusted for early departure (Reference)
EXRQD	EQ8	Remaining Requested Transfer at any time in session
EXRQD1	EQ8	Requested Energy Transfer at the start (TOA)
GEN		Generator
GFCI		Ground Fault Circuit Interrupter
GPL	X	Grid Power Limit
GX	EQ11	Grid Power Exceeded Metric
HAN		Home Area Network
HEV		Hybrid Electric Vehicle
IAT	EQ8	Interarrival Time between arriving PEVs
ICE		Internal Combustion Engine
iPEM		Intelligent Power and Energy Management
IRR		Internal Rate of Return
ISO		Independent System Operator
kW		Kilowatts (power measurement)
kWh		Kilowatt-Hours (energy measure)
LBMP		Location Based Marginal Pricing
MIX	X	A power allocation strategy
MW		Megawatts (power measurement)
MWh		Megawatt-Hour (energy measurement)
NaMH		Sodium Metal Halide Battery
NaS		Sodium Sulfur Battery
NEMA		National Electrical Manufacturers Association
NGK		NGK Insulator (NaS battery manufacturer in Japan)
NLT		Not Later Than
NYISO		New York Independent System Operator
NYSERDA		New York State Energy Research and Development Authority
OBC	X	On-board charger
OIR		Order Initiating Rulemaking
PAF	EQ10	Power Allocation Factor
PAV	EQ8	Average Power to complete transfer in remaining time (ETTG)
PAV1	EQ8	Average Power Required at connection (TOA)
PCMD	X	Power Command - power authorization for a specific PEV
PDEL	X	Power Delivered (power used by vehicle at a specific time)
PDF	X	Probability Distribution Function
PEV		Plug-in Electric Vehicle
PGL	X	Power - Grid Limit
PHEV		Plug-in Hybrid Electric Vehicle
PHS		Pumped Hydroelectric Storage
PLC		Power Line Carrier communications
PMAX	X	Power Rating of On-Board Charger; power allocation strategy
PowerETESS	X	Power demanded by ETESS
PowerGRID	X	Power demand from Grid
PowerPEV	X	Aggregate power demanded by PEVs
PWM		Pulse Width Modulation

RF		Radio Frequency transmission
RMS		Root Mean Square
RTO		Regional Transmission Organization
Rx		Receive Message
SAE		SAE International
SCP	X	Simulation Control Panel
SLACK	X	Slack Time if charging is done at rated power of charger
SOC		State of Charge of battery (reference to useable capacity)
SOC1	X	State of Charge at start
SOC2	X	State of Charge Target at disconnect
TLATE	X	Latest Time to Start Charging at rated power of charger
TMIN	EQ8	Minimum time remaining to charge at rated power
TMIN1	EQ8	Minimum time to charge at rated power at the start
TOA	X	Time of Arrival (actually the time of connection)
TOD	X	Time of Departure (actually the time of disconnect)
TOU		Time of Use pricing
Tx		Transmit Message
UCAP	X	Useable Battery Capacity – less than nameplate capacity
UF	EQ8	Utilization Factor – a measure of system stress
UF1	EQ8	Utilization Factor at the start (TOA)
UFREF	EQ10	Utilization Factor adjusted for early departure (Reference)
URN	X	Uniform Random Number
UTC		Coordinated Universal Time
V		Volts
V1G		Vehicle to Grid one way - vary charging for demand response
V2G		Vehicle to Grid - bidirectional power transfer capability
V2H		Vehicle to Home power transfer - (backup genset - islanded)
V2L		Vehicle to Load power transfer (exportable power off grid)
V2V		Vehicle to Vehicle power transfer (remote charging)
VA		Volt Amperes (measure of real and reactive power)
VAC		Volts Alternating Current
VAR		Volt-Amps Reactive - measure of reactive power
VBA	X	Visual Basic for Applications
VN	X	An assigned vehicle number
vQTY	X	Total quantity of vehicles in a single pass of a simulation
VvDF	EQ10	Virtual Vehicle Disappointment Function – a new metric
VvDX	EQ10	Virtual Vehicle Disappointment Index – a new metric
VvUF	EQ10	Virtual Vehicle Utilization Factor – a new metric
W		Watts (measure of power)
XFMR		Transformer
XFR		Transfer

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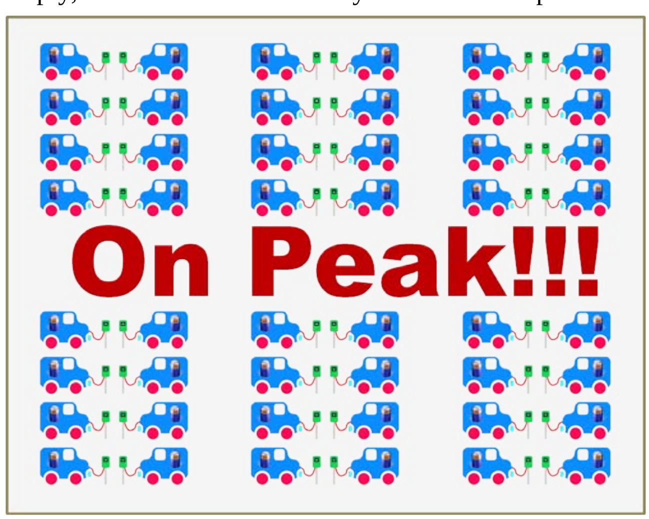
Executive Summary

The Electric Transportation Energy Storage System (ETESS) is a new concept that integrates control logic for intelligently managing the charging of groups of plug-in electric vehicles with a small grid-connected electricity storage system.

The Problem

Plug-in Electric Vehicles (PEVs) are coming and are forecast to become a significant share of the transportation sector in the future. The primary location for charging for most vehicles will be at a "home" location. Many PEVs, particularly battery electric vehicles, will need access to charge stations at other locations – at work, at shopping malls, in public parking garages, on city streets … everywhere.

PEV charging loads will vary significantly during the day at these "park and charge" facilities. There will be times when all of the charge stations are empty, and other times when they will all be occupied and in use. It is possible, but not very likely, that every charge station will be occupied by a PEV capable of drawing the rated power of each charge station at the same time. This could be a problem if the electric power infrastructure serving the facility or within the facility itself are not be sized to allow it. The facility may also have economic considerations, such as the peak monthly demand charge or demand response commitments.



Some charging facilities can take a laissez-faire approach. Their infrastructure may be capable of operating at full PEV charging capacity, the PEV loads may be small relative to the total facility power demand, or they just may not care about the peak loads. If the charging facility needs to keep its peak power demand below a power limit, it will need to actively manage the power allocation of each of the vehicles at the facility.

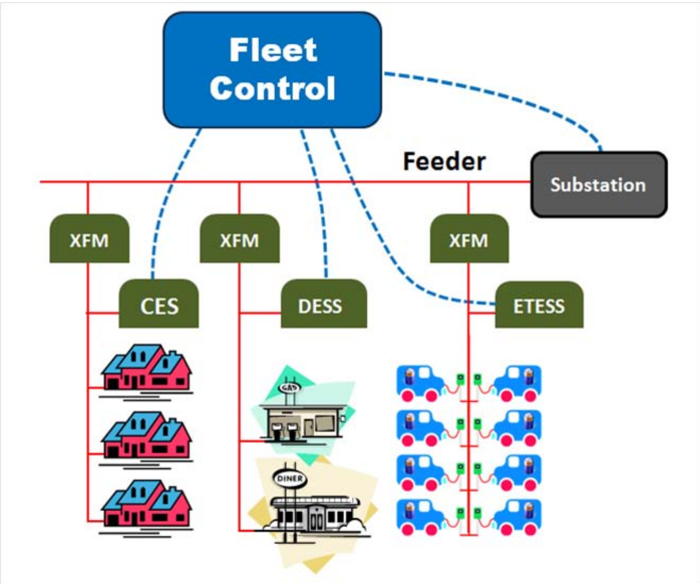
A Solution

SAE J2847-1 defines a communication capability called "Optimized Energy Transfer" that will allow a facility Energy Management System (EMS) to communicate with a PEV during a charging session and coordinate the power demanded by the PEV during the energy transfer. The challenge is to create optimization algorithms that accept an energy transfer request and an estimated departure time from each PEV, and then allocates the available facility power to each PEV to keep the facility within its power constraints while minimizing any PEV customer disappointments. This is called **intelligent Power and Energy Management (iPEM)** logic. A facility EMS with iPEM logic is called an **Electric Transportation Energy Management System (ETEMS).**

The iPEM logic provides the capability to control the total facility power demand. It can increase or decrease the rate of charging for each of the connected vehicles to control the aggregate facility power. It cannot add power, and this increases the risk that some vehicles will not get their requested energy transfer. Still, if a grid-connected, energy storage system is placed within the facility, the iPEM algorithms can now take advantage of the energy storage capability to further improve the optimization. The iPEM logic can now add power. This integrated system of iPEM logic and energy storage is called the **Electric Transportation Energy Storage System (ETESS).**

An New Opportunity

A new concept for grid energy storage is emerging. It is called **Community Energy Storage (CES)** by American Electric Power and **Distributed Energy Storage System (DESS)** by the Electric Power Research Institute (EPRI). These are small storage units that are collocated with the transformers that serve groups of homes or businesses. These units can act autonomously to control real and reactive power along a distribution feeder and they can also be aggregated as a fleet to form a large virtual storage system to serve the larger needs of the grid – for the feeder, the substation, or the control area. EPRI defined functional requirements for these units in 2010. The power levels range from 25 kW to 75 kW for single phase units and up to 200 kW for three phase units. The units should have between two to four hours of storage at rated power. The smaller CES-size units could be deployed in residential applications and the larger 75 kW to 200 kW DESS units could be deployed in commercial and industrial applications.



ETESS could be used exclusively for managing PEV charging loads within a facility. Nevertheless, it is also possible that an ETESS unit could support the needs of the grid outside of the facility as a Distributed Energy Storage System (DESS). ETESS can be thought of as just another DESS application, except it is connected to a group of charge stations at a parking facility rather than to homes or businesses. This additional role then becomes a key driver of the system architecture. An ETESS unit could be placed at a parking facility with only a few PEV charger stations and serve only as a DESS. The iPEM capability could be called on later as more charge stations are placed at the facility.

System Architecture

A simplified block diagram of an ETESS unit is shown in Figure ES-1. The ETESS unit connects to a single phase 240 VAC transformer and feeds a group of charge stations. The diagram only shows three vehicle,s but there would normally be many more. The bidirectional converter connects to the AC power line. It converts AC power to DC power to charge the battery and acts as an inverter to convert battery power to 240 AC power. The diagram also shows that renewable energy sources can connect to the DC-Link using DC to DC converters. This is another potential benefit of having an ETESS unit at a charging facility. The ETESS unit communicates with the utility or another higher level control using the Hub Communications link. This can be any type of communication system and will be site dependent. The ETESS unit communicates with each charge station at the site. This will also be installation dependent, and can use power line carrier communications, optical fiber, cable, or wireless. The control system manages the power conversion, battery, and other unit functions. It also implements the iPEM logic.

ETESS must meet the functional requirements of the EPRI specification for DESS units. ETESS is a DESS. Two sizes of ETESS are proposed: a basic 75 kW single phase unit and an optional 150 kW three phase unit, each with three hours of storage. Both must operate from a 240 VAC transformer to be compatible with AC Level 2 charge stations.

The 75 kW size was selected because it is the largest of the single phase DESS units and a parking facility should be capable of hosting a larger unit without becoming obtrusive. This is a primary consideration for residential applications of CES and DESS. The three phase unit was scaled at twice the capacity of the single phase unit. This is all rather arbitrary and not related to the capacity needed only to support the PEVs – it is large because it can be large and not blight the neighborhood.

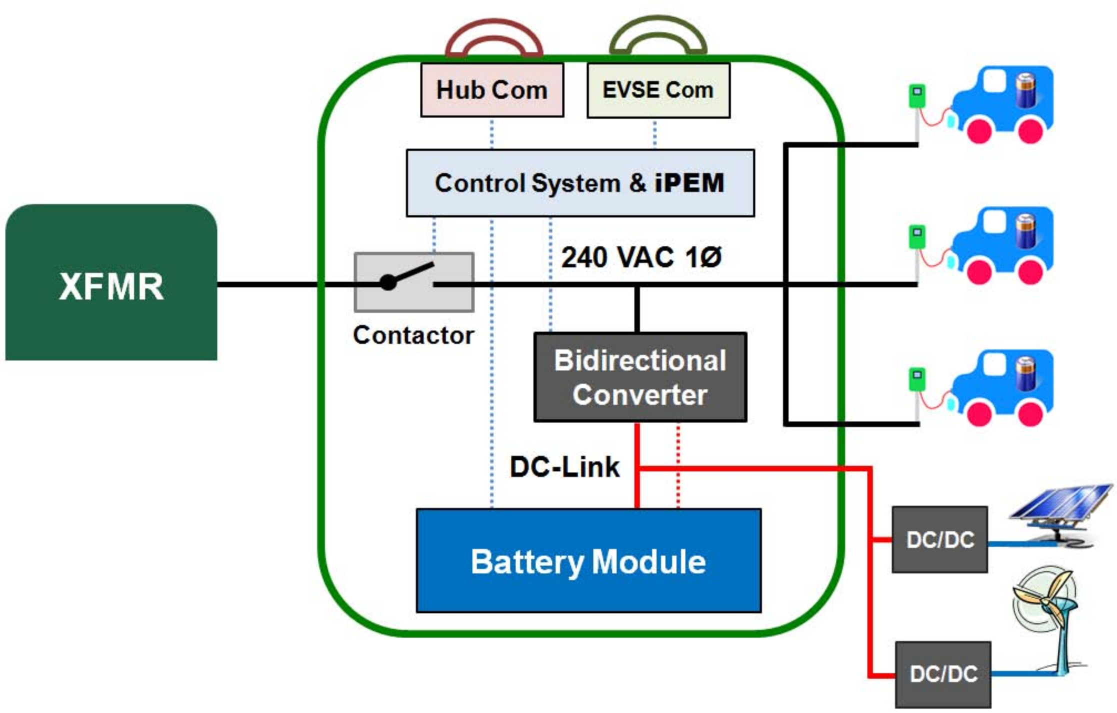


Figure ES-1 is a simplified block diagram of an ETESS unit.

ETESS at Work

ETESS can use its stored energy to maintain the total power demand of a charging facility below a grid power limit while satisfying the aggregate power demand of the PEVs. This is illustrated in Figure ES-2, which was generated by a multivehicle charging simulation that was developed as part of this project. This simulation example uses 18 AC Level 2 charge stations. The dashed line shows two overlapping grid power limits: a flat limit at approximately 70 kW that represents an infrastructure limit and a demand response notch from 2:00 p.m. to 6:00 pm where the facility is expected to stay below 42 kW.

The gray line shows the grid power demand without ETESS or ETEMS. The aggregate power of the PEVs and the grid power are the same. The vehicles connect and immediately start charging at the rated power of their on-board chargers and continue until the desired energy transfer is completed. The grid limits are exceeded and one of the highest peaks occurs during the demand response window.

When ETESS is engaged for the same scenario, the blue line shows the grid power demand and the red line shows the aggregate vehicle power. The blue line covers the red line when ETESS is not charging or discharging, because then the grid power must equal the PEV power. The peaks outside of the demand response window were entirely protected by iPEM logic within the ETESS unit without the need for any stored energy. During the demand response window, the aggregate vehicle power needed to exceed the grid power limit, but the ETESS provided power and energy to compensate. When the demand response window ended, ETESS recharged and the grid power exceeded the PEV power at the point, but stayed under the facility limit. All of the limits were protected and no vehicles were disappointed. This is ETESS at work.

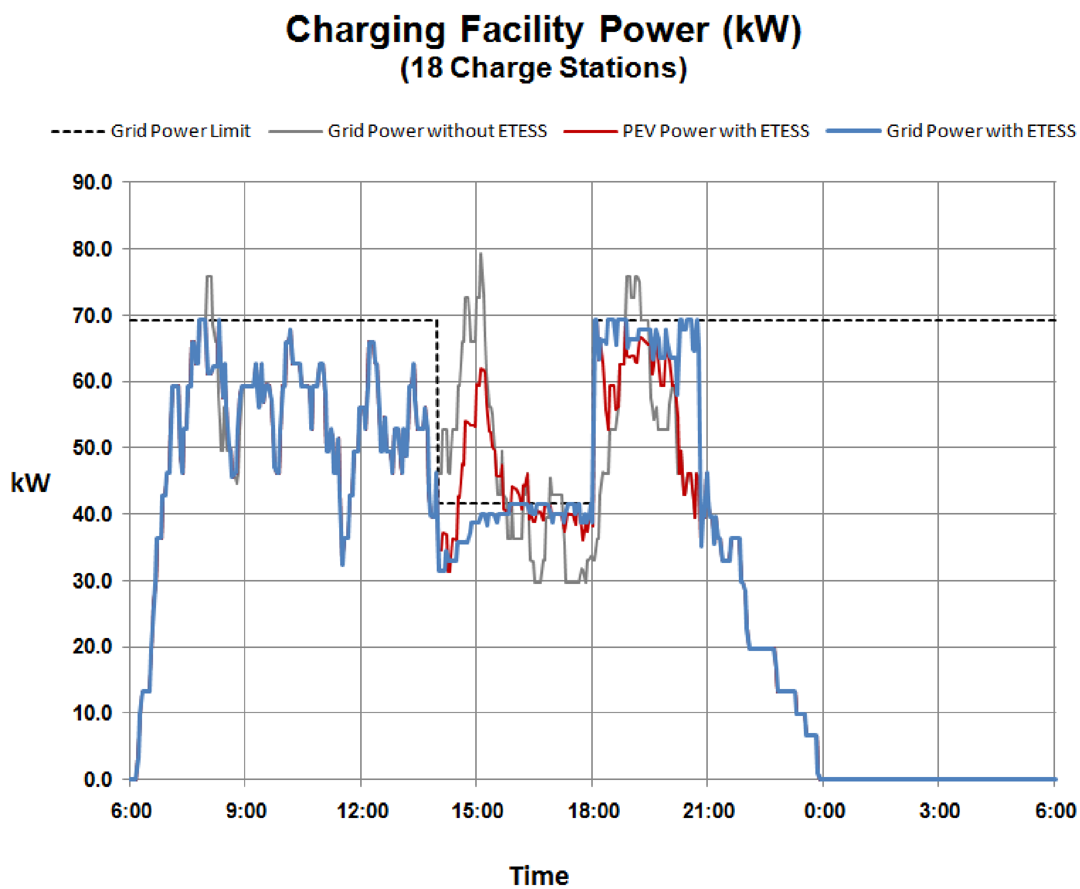


Figure ES-2 shows the impact that ETESS can have on grid power.

Business Issues

Several business models and associated economic cases were developed and evaluated. Models ranged from a base case of uncontrolled charging at a parking site, to the use of a simple onsite energy management system to control the charging of the vehicles (an ETEMS with iPEM logic), to a full ETESS that both manages the vehicles and provides ancillary services to the grid.

Tariffs for commercial businesses generally include a charge for energy and a charge for the peak monthly demand. This demand charge is based on the highest 15 or 30 minute average power drawn at any time during the month. The peak demand charge can be a significant portion of the monthly utility bill. One utility in New York State charges over $15 per kW. Reducing the monthly peak demand of a commercial charging facility by only 10 kW saves the business $1800 per year.

A simple ETEMS system with its iPEM logic should be part of any installation with ten or more charge stations. It is only a small additional cost over that of the basic charge station installation and it provides outstanding capability to manage the peak power demands of the facility. The risk of PEV customer disappointment rises as the target limit becomes more aggressive. Still, even a small amount of time shifting can clip higher peaks with minimal customer impact and generate savings in peak demand charges.

ETESS incorporates the same iPEM logic as ETEMS and is equally effective at holding the aggregate PEV demand below a target limit. Nevertheless, it can use its stored energy to offset some of the aggregated PEV power demand on the grid. This results in less PEV customer disappointment for an ETESS than an ETEMS for the same grid limit.

The business case for installing an ETESS unit behind the meter and using it only for lowering the risk of disappointment of PEV customers is not compelling. Some PEV customers may be willing to pay a higher fee during peak periods to avoid any curtailment, but not at other times. And others may accept the risk of a possible curtailment and not be willing to pay a higher fee to avoid it. Both of these situations could be accommodated with a simple ETEMS.

The business case improves for behind the meter ETESS units if they can be aggregated with many others and used to provide load following or ancillary services for the grid. This reduces the effectiveness of the unit for peak demand management, but it creates opportunity for additional revenue.

The ETESS unit could be installed outside the charging facility by a distribution utility. The primary justification must be as a DESS. Still, the utility could also use the ETESS to manage the loads within the charging facility and take advantage of its PEV demand management capability. Some adjustments would need to be made in the demand charge tariffs for the parking facility operator, because the utility can now control the monthly peak demand of the facility and may even want to use the PEVs to cause a peak load. The business case is still very challenging for the utility ETESS.

There are regulatory issues in restructured electricity markets that must be worked to make a viable business case for a utility owned CES, DESS, or ETESS. The traditional view of using an ISO/RTO to schedule generation assets or large blocks of demand may not be the right approach in a Smart Grid with small, highly distributed renewable energy sources, storage units, and PEV loads. The distribution utility may be better placed to control the PEV loads and other loads along the feeder as part of a tiered or even autonomous control concept. CES, DESS, and ETESS can facilitate this distributed control approach. In this model, the cost of the units could be recovered as part of the rate base of the distribution utility. The ISO/RTO would deal with larger system effects over the control area that must be handled at the front end by large generation, bulk storage, or concentrated loads.

Summary

ETESS works. Its embedded iPEM logic can effectively manage the aggregated power demanded by the PEVs. Its stored energy helps greatly with minimizing PEV customer disappointment while managing to grid power limits. Its stored energy can also be used to provide voltage support, load following, or other services for the grid.

Future PEVs will provide the communication capability and control modes that will allow iPEM logic to coordinate the charging session and limit PEV power consumption. Much work needs to be done to create iPEM algorithms and validate metrics to be used for optimization, but it is all technically feasible.

ETESS is a DESS variant. Several projects are underway to design and demonstrate DESS units over the next few years. There will certainly be many technical issues to overcome in the detailed design, implementation, testing of a DESS. This is true of any new product development project, but it can and will be done.

The tough issues are primarily business issues. It always comes down to the money. The key question is whether ETESS can ever be economically viable. It comes down to the value that ETESS can deliver to the owner as measured by revenue or cost avoidance and the life cycle cost of the unit. It is all about the return on investment.

ETESS provides capability well beyond that provided by ETEMS, but it also suffers from the same market issues of all battery storage systems for the grid. The batteries are too expensive and the current market prices for load following and ancillary services are too low to make a compelling business case for storage at this time.

1 *Introduction*

AEYCH LLC is exploring a new system concept that integrates grid-connected electricity storage with control logic that intelligently manages the charging of groups of plug-in electric vehicles. This system supports the electric power grid and also optimizes energy transfer to the connected vehicles. It helps mitigate the potential adverse impact that a widely available, public charging infrastructure for electric transportation could have on the electric power grid. The concept is known as ETESS – the Electric Transportation Energy Storage System.

What? They are charging during the day!

Everybody's talking about them – electric vehicles and plug-in hybrid electric vehicles, collectively known as plug-in electric vehicles (PEVs). Forecasts vary widely about the timing and the share of the market that PEVs will achieve, but a key factor in the growth projections of PEVs is the availability of a robust public charging infrastructure.

Most forecasts of the impact of PEVs on the grid are based on PEVs starting to charge late in the evening in the family garage and then finishing by early morning. This will be true for most of the earlier adopters. This new load will be good for the utilities because it will help fill the nighttime valley – leveling the load factor. Forecasts also show that large numbers of PEVs can be deployed before any additional power capacity is needed. This new nighttime load can absorb renewable energy from wind farms. This is all good news for the electric power industry, if it is true.

This may not be completely true, particularly in large cities. Many vehicles may not have access to public or private charging stations in the evening. Some urban PEV owners may only be able to charge while at work. And a suburban PEV owner may still want to "top the tank" for the trip home while at work or at the shopping center. This is a very significant consideration for pure (battery) electric vehicles (BEVs) that, unlike plug-in hybrid electric vehicles, depend exclusively on stored electricity to get home.

For PEVs to really flourish, public charge stations must be ubiquitous. They will need to be on city streets, in parking garages, at airports, at malls, at sports venues, at business parking lots – everywhere! Many vehicles may be charging during the day and at peak times and this could be a problem for the grid. A significant daytime PEV load could require the addition of new generation and transmission capacity. Even if the regional loads are manageable, concentrated PEV charging could have local impact on substations, distribution feeders, and distribution transformers.

The power flow at a PEV charging location is shown in Figure 1 for a typical day. This location has 18 AC Level 2 charge stations. The vehicles arrive and depart at random times. They just plug in and charge at the rated power of their on-board charger until the desired energy transfer is completed. This is one day and the pattern will change each day based on the variation in arrival times, length of stay, required energy transfer, and vehicle characteristics.

The chart also shows a dashed line that represents a grid power limit. This is actually two overlapping limits. In this example the AC Level 2 charge stations are individually rated at 7.7 kW – 100% load for 18 charge stations would be 139 kW. The flat limit at approximately 70 kW represents 50% of total capacity. This could be a utility infrastructure limit or a facility target level for the monthly peak demand charge. There is also a demand response notch from 2:00 p.m. to 6:00 p.m. where the facility needs to stay below 42 kW (30% of capacity). In this example, the highest peak is actually during the demand response period.

In this example, if the utility and facility infrastructure is sized for the 139 kW peak capacity, and it is acceptable to the facility owner to pay a peak demand charge every month based on hitting a single 139 kW peak during the month, and the there will never be a need to reduce power during a demand response event, then this unconstrained charging behavior may be perfectly acceptable to the charging facility operator and the utility that serves the facility. Otherwise, there may be a need to control the aggregate PEV demand on the grid. The objective is to meet facility level power constraints and at the same time minimize any disappointment of PEV customers. This is the ETESS concept.

ETESS provides two integrated methods for achieving this objective. One method is to communicate with the PEVs and use intelligent software to manage the timing and power levels of each PEV charging session. The other method is to use its stored energy to supplement the grid during peaks.

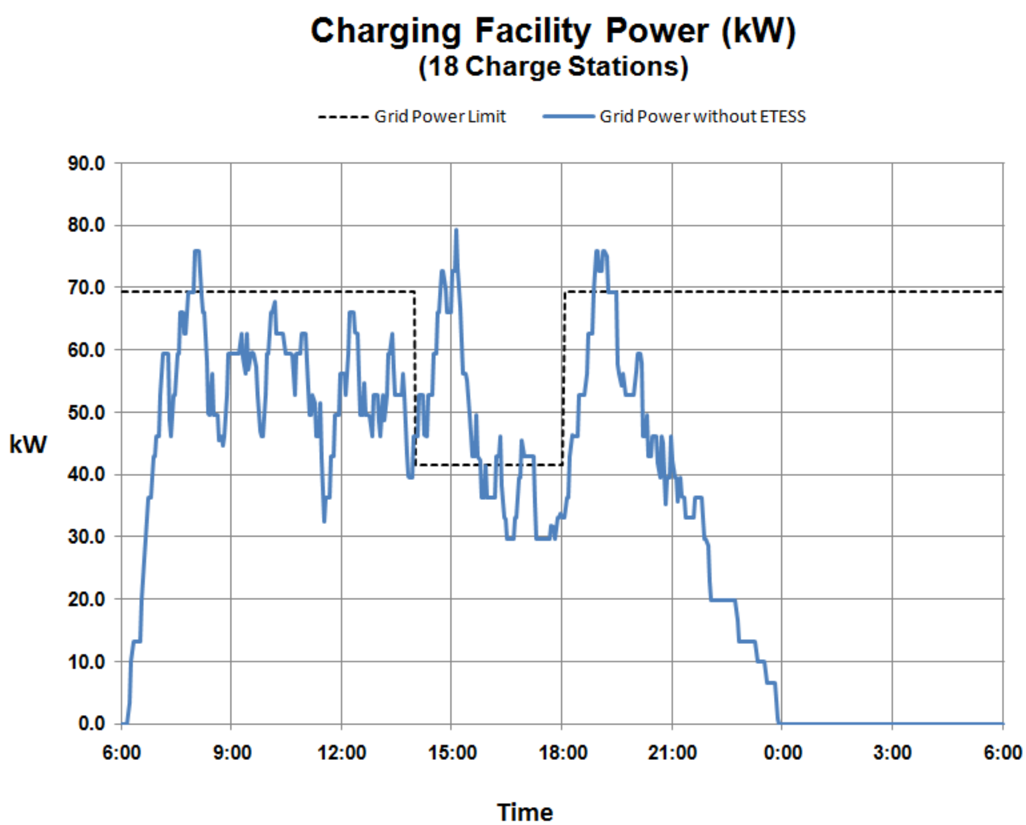


Figure 1 shows the power flow at a PEV charging location during a typical day.

Intelligent Control of PEV Charging

There is significant amount of ongoing activity in the smart grid and electric transportation communities to develop a means for a utility to control or influence the charging of PEVs anywhere in the grid. Most of the effort has been directed toward how to provide rate incentives to encourage PEVs to charge at off-peak times. Figure 2 shows a very simplified view of the world of electric power and electric vehicles. Utility in this chart means all of the relevant players in the electric power industry. It includes the distribution utility, the system operator, energy service companies, independent ancillary service aggregators, and others. The "utility world" ends at the meter.

The definition of facility is also broadly defined. It means everything from the meter to the PEV. It can be a residential property. It can be a commercial property with public access to charge stations. It can be a factory with employee access to charge stations. It might even be a group of charge stations along a street. There will always be a meter, a distribution panel, and an EVSE (Electric Vehicle Supply Equipment). Some facility may have an energy management system (EMS)

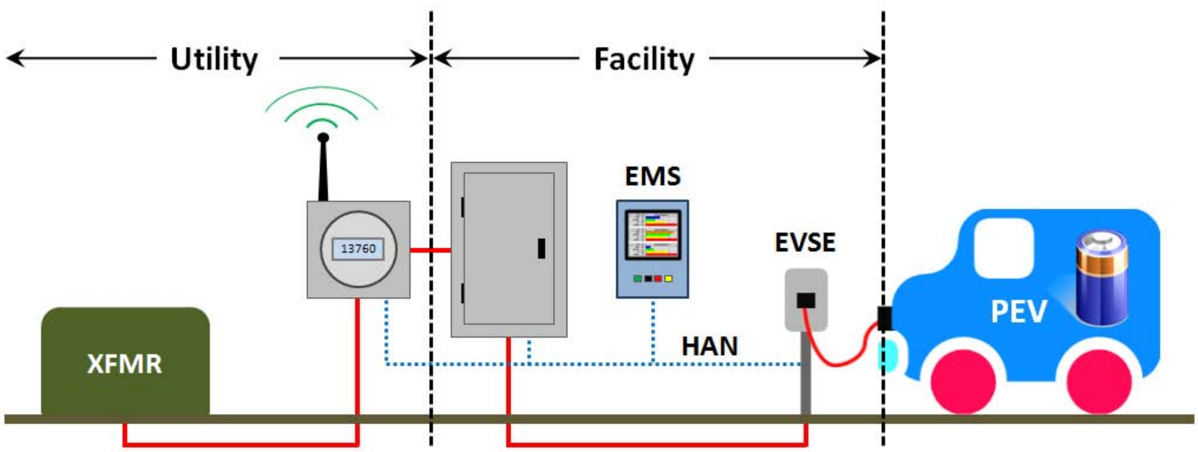


Figure 2 shows the infrastructure for charging a PEV.

While rate incentive programs can be useful for charging at home, they will not be that useful at public sites. A PEV driver that plugs-in to charge at a public site during an afternoon peak is not going to worry about a utility rate program – when charging at home yes, but not when the juice is needed in the afternoon. And a parking facility operator may not want a charge station occupied and not being used – it is a valuable asset. While a time of use or rate based program might be acceptable for an overnight stay at a public site, there are other ways to directly manage the charging vehicles at a parking site that can be more effective.

SAE J2847-1 defines a communication capability called "Optimized Energy Transfer" that allows a utility or a facility EMS to dynamically manage the charging session of a PEV. Algorithms for **intelligent Power and Energy Management (iPEM)** can be developed to allocate power to each of the PEVs charging at a facility to maintain the total power demand of the facility within limits and also minimize any disappointment to the PEV drivers. The iPEM logic can be used in an EMS at the charging facility that we will call **ETEMS** (the **Electric Transportation Energy Management System**). When combined with ETESS the algorithms can now take advantage of the energy storage capability of the ETESS unit to further improve the optimization.

Placing Electricity Storage with the Vehicles

If an energy storage system is placed at a PEV charging facility, it can enhance the capability of the iPEM logic. The iPEM logic can manage vehicle loads and also draw on stored energy, as needed, to reduce risk of not completing the requested energy transfer of each PEV, but this use is all internally focused. It is also possible that the storage unit could support the needs of the grid outside of the facility.

Community Energy Storage (CES) is a new concept for grid storage that was developed by American Electric Power (AEP). A CES unit has a power of 25 kW, with up to three hours of storage at rated power. It connects to the 240 volt secondary of the pad mounted transformer serving a group of homes. They are managed as a fleet by the utility to help manage the peak loads on the distribution feeder. In 2010 the Electric Power Research Institute (EPRI) expanded on the CES concept to include units at power levels from 25 kW to 75 kW on single phase circuits and up to 200 kW on three phase circuits. They call it Distributed Energy Storage Systems (DESS) – Utility Padmount. The smaller CES-size units could be deployed in residential applications and the larger 75 kW to 200 kW DESS units could be deployed in commercial and industrial applications.

ETESS, the **Electric Transportation Energy Storage System,** can be thought of as just another DESS application, except it is connected to a group of charge stations at a parking facility rather than to homes or businesses. There are many business issues to be explored, such as who can own and operate an ETESS. Should it be a utility asset or a charging facility asset? If it is only used within a facility for managing vehicle loads that may favor one approach, but if many ETESS units need to be aggregated to provide ancillary services for the grid, the business issues become more complex.

Two sizes of ETESS are proposed: a 75 kW single phase unit and a 150 kW three phase unit, each with three hours of storage. This level of power and energy may be more than is needed for use solely with the vehicles, but any excess capacity would be available for external grid applications. ETESS should be sized at the high end of the DESS range, primarily because it can be placed at commercial business locations and not be out of place. Fewer units are needed to reach a target aggregated capacity. CES, DESS, and ETESS can all serve the grid as shown in Figure 3.

Voltage	Phases	Power	Energy
240VAC	1ϕ	75kW	225kWh
240VAC	3ϕ	150kW	450kWh

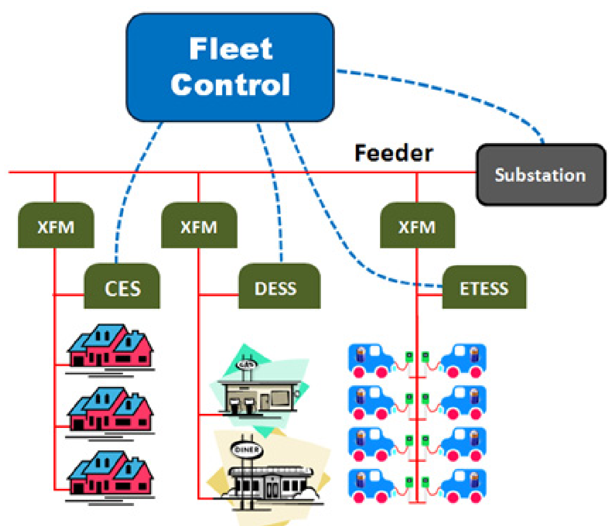


Figure 3 shows a fleet of CES, DESS, and ETESS units serving the grid.

ETESS at Work

The impact of ETESS on managing power to a grid power limit is illustrated in Figure 4 for the same scenario shown earlier. The gray curve is power demand from the original day. The blue line shows the grid power demand, and the red line shows the aggregate vehicle power. The blue line covers the red line when ETESS is not charging or discharging, because then the grid power must equal the PEV power. The peaks outside of the demand response window were entirely protected by iPEM logic within the ETESS unit without the need for any stored energy. During the demand response window, the aggregate vehicle power needed to exceed the grid power limit, but the ETESS provided power and energy to compensate. When the demand response window ended, ETESS recharged and the grid power exceeded the PEV power at the point, but stayed under the facility limit. All of the limits were protected and no vehicles were disappointed. This is ETESS at work.

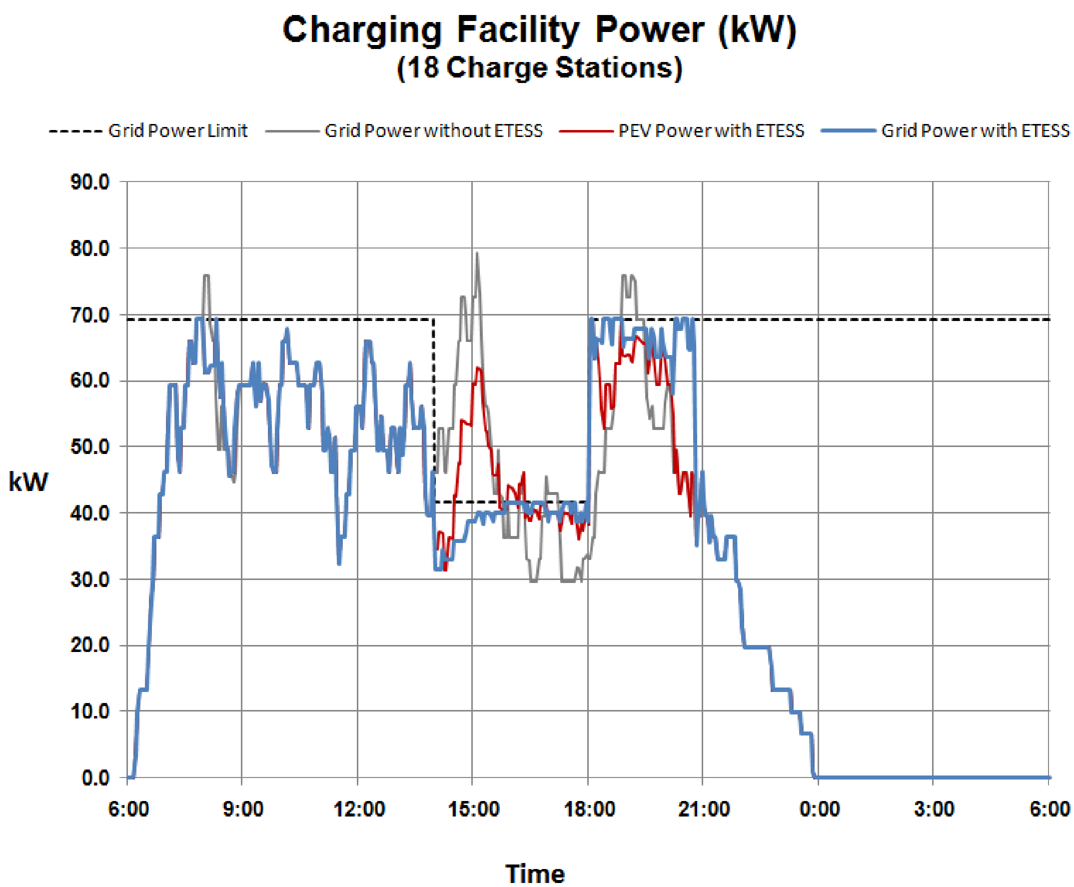


Figure 4 shows the impact that ETESS can have on grid power.

The ETESS Project

The objective of this project was to conduct a feasibility study of the ETESS concept. This report presents the results of this study. This project was supported by the New York State Research and Development Authority (NYSERDA), although the opinions expressed in this report do not necessarily reflect those of NYSERDA or the State of New York.

AEYCH LLC elected to follow an approach similar to that used by EPRI for the CES and DESS projects. Several webinars were conducted where interested stakeholders from government, industry, and academia could review progress and help shape the system concept. This project began in April 2010. Webinars were conducted in June, August, and September of 2010. Over 30 people from both the electric power and electric transportation communities participated in one or more of the sessions and provided valuable advice and counsel either during the session or in follow-up discussions.

One of the major activities conducted in support of this project was the creation of a simulation that could be used to evaluate the impact that a group of charging PEVs could have on the facility power demand. Developing a simulation of the scope and complexity as the one actually created was not a planned task for this project and most of the work on it was conducted as a separate, but related, activity. It proved to be an essential tool for assessing the capability of ETESS and the potential of iPEM logic. While the development of actual iPEM algorithms also was not an objective of this project, the simulation did allow the evaluation of some preliminary algorithms.

An Overview of the Report

This report is divided into two parts. Part I is the core ETESS Feasibility Study. This Introduction along with Part I form a complete report. The reader does not have to go beyond Part I to understand and appreciate ETESS.

Part II provides a detailed technical discussion of a simulation of multivehicle charging that was used to evaluate both preliminary iPEM logic and ETESS. While this part does show many equations, it is not necessary that the reader follow the mathematical detail to appreciate some of the results. There are many charts that show the performance of iPEM and ETESS that can be appreciated without delving into the math. **Do not let the equations intimidate you – they can be skipped.**

The contents of each chapter are reviewed in more detail below.

The Chapters of Part I - The ETESS Feasibility Study

Chapter 2, "Grid-Connected Electricity Storage," begins with a review of some fundamentals about the electric power grid - the need to balance supply and demand for power every second of the day and how this is managed. Next, a brief overview of bulk electricity storage, flywheels, and substation-scale battery storage systems is provided. Then an exciting new concept for grid storage that has emerged over the last few years is discussed. American Electric Power, a pathfinder for this new concept, calls it Community Energy Storage (CES). The Electric Power Research Institute (EPRI) recently extended the CES concept to a wider power range, calling it a Distributed Energy Storage System (DESS) -Utility Padmount. It is important to understand CES and DESS, because ETESS can be viewed as just another application of the same grid-connected electricity storage concept.

Chapter 3, "Electrification of Transportation," reviews certain aspects of electric vehicles and the associated infrastructure for charging electric vehicles that are directly relevant to understanding the purpose and operation of ETESS. The chapter begins with a discussion of the different types of plug-in electric vehicles (PEVs). Next, some fundamentals of PEV charging are reviewed; including the different SAE J1772™ levels of AC and DC charging, the role of the EVSE (Electric Vehicle Supply Equipment) and its control pilot signal, and the public access charge station. The implications of AC Level 2 "Park and Charge" versus high power DC "Charge and Go" on ETESS are discussed. Digital communications between the PEV, the EVSE, a facility Energy Management System, and the utility are reviewed. The use of the SAE J2847-1 defined Optimized Energy Transfer use case messages to control the aggregate power demanded by a group of charging PEVs is discussed - this is a core capability needed for ETESS.

Chapter 4, “Intelligent Power and Energy Management,” discusses the fundamentals of how power can be allocated to each of the vehicles charging at a facility during the day to maintain the total power demand of the facility within limits, and also to minimize any disappointment to the PEV drivers. These iPEM algorithms are a core capability of ETESS, but they can also be used without energy storage in an Electric Transportation Energy Management System (ETEMS). The chapter begins with a brief discussion of the concept of measuring customer disappointment – this topic is discussed in much more detail in Chapter 10. Then some basic strategies for power allocation (such as Start Max, Delay Max, and Average) are reviewed. Examples of unconstrained charging and managed charging with both hard and soft limits are provided. The development and demonstration of actual iPEM algorithms was beyond the scope of this project, but some simple algorithms were developed and used in a simulation of ETESS that will be discussed in Part II.

Chapter 5, “The ETESS Concept,” provides an overview of the Electric Transportation Energy Storage System. The chapter begins by showing that ETESS can be thought of as an extension of an energy management system with iPEM software (ETEMS) – just add storage. Then it shows that ETESS can also be thought of as a just another CES or DESS application – but with some additional capability provided by the iPEM software. The system architecture and power and energy sizing are also discussed.

Chapter 6, “Business Issues,” discusses some of the business issues associated with both energy storage and PEV charging and how they relate to ETESS. The chapter begins with a general discussion of the benefits and market potential for energy storage, because ETESS can be viewed as a distributed energy storage system. This raises questions regarding whether the units can or should be owned and operated by a distribution utility, an independent power producer, or a commercial customer of the utility. Electricity Storage can be deployed on either side of the meter, but the opportunities to generate income or avoid costs can be very different. Also, electricity storage deployed on the utility side of the meter can have different business models depending on the degree of restructuring of the electric power industry in the state. Other issues are discussed including: reselling electricity versus proving access to a charge station, AC versus DC charging, and the implications of roaming. The chapter ends with a discussion of several business models and the associated economic cases.

Chapter 7, “ETESS Feasibility Study Summary,” wraps up Part I.

The Chapters of Part II – Simulation Design and Results

Chapter 8, “A Multivehicle Charging Simulation,” describes the fundamental capabilities and the theory of operation of this tool**.** This chapter sets the stage for the remaining chapters that show results from the simulation. The terminology and concepts introduced in this chapter are central to understanding iPEM and ETESS. The chapter begins with an overview of the simulation. Next, the charging of an individual PEV is described, including discussions of battery and time terminology, the charging model, vehicle communication, and concepts of utilization factor and average power. Then, the concepts behind creating the random arrival of vehicles during each day of simulation for different scenarios of locations and vehicles are discussed. The chapter ends with a discussion of how the aggregated power from all of the vehicles and ETESS impact the grid.

Chapter 9, “Charge Station Metrics,” begins the discussion of simulation metrics. Subsequent chapters will build on the methods introduced in this chapter. Metrics for describing the process of how vehicles come and go throughout the day at a charging facility are developed. How many charge stations are occupied at any time and how many of the occupied charge stations are actually being used? The chapter begins with examples of time plots for the number of charge station occupied and in use (drawing power) during a simulated day. The timeline is transformed into a histogram and cumulative distribution. The value of Monte Carlo simulation to smooth the pass-to-pass variations is demonstrated. Then, the cumulative distribution is used to look at the effects of charging strategy (maximum versus average), vehicle scenario, and location scenario. Finally the use of summary metrics, such as the percent of charge stations occupied over the day, is introduced.

Chapter 10, “Measuring PEV Customer Disappointment,” introduces metrics for assessing the performance of vehicle charging. New concepts for measuring disappointment of individual vehicle drivers as well as the aggregate disappointment for all of the vehicles that charge during the day are developed in this chapter. Concepts for intelligent Power and Energy Management were briefly discussed in Chapter 4, but in this chapter some preliminary algorithms for allocating power to stay within facility power limits are explored using the ETESS simulation and the new disappointment metrics are used to assess performance.

Chapter 11, “System Performance Metrics**,”** develops metrics for evaluating the performance of iPEM logic and ETESS units for managing grid power. These include a Grid Power Exceeded Metric (GX) and a Monthly Peak Demand value. These are compared for several scenarios. Metrics are also developed to assess the stress on the ETESS unit during operations. ETESS configurations are then compared using the ETESS metrics and GX for several scenarios.

Chapter 12, “Simulation Summary” wraps up Part II.

Part I - The ETESS Feasibility Study

CHAPTERS

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2 *Grid-Connected Electricity Storage*

An exciting new concept for grid storage emerged over the last few years. It has not yet been demonstrated, but several demonstration projects were launched in 2010 with support of federal stimulus grants. American Electric Power (AEP) is a pathfinder for this new concept, calling it Community Energy Storage (CES). The Electric Power Research Institute (EPRI) recently extended the CES concept to a wider power range, calling it a Distributed Energy Storage System (DESS) - Utility Padmount. Energy storage has traditionally been considered to be power generation, far from the load centers at the start of the grid. The CES and DESS units are very small units that are collocated with the load centers at the "tips" of the grid. This offers some unique capabilities where individual units along a distribution feeder can act autonomously and also be aggregated as a fleet to form a large virtual storage system to serve the needs of the grid.

Some Fundamentals about the Grid

It is about power, not energy

It is important to understand and appreciate the difference between power and energy. Power is the rate of change of energy and it cannot be stored. Electric utilities are in the power business, not the energy business. It is the electric power industry not the electric energy industry. The entire purpose of the system for power generation, transmission, distribution, and demand management at the end user is always to match the supply and demand for power, every second of the day and every day of the year. It is really all about kilowatts and not kilowatt-hours. Exxon is in energy business. It provides gasoline for vehicles and gasoline contains chemical energy. Unlike the chemical energy of gasoline, which is static, electricity is energy in motion – power.

Balancing the supply and demand for power

The power grid is a massive machine that converts fossil fuels, nuclear energy, and renewable energy into electric power and then transmits the power to the loads. If the power generation and consumption are in perfect balance, the grid maintains a target frequency of 60 cycles per second (Hertz). Because the many spinning generators on the grid do not have isochronous governors (by design), if the load increases all the generators slow down, or droop. As the grid frequency drops, the load reduces automatically, and the system stabilizes at a reduced frequency. This is called primary frequency regulation or governor response. Without this inherent stability created by the rotating machines and passive loads, the grid would be extremely difficult to control. Because the frequency doesn't "run away" there is time to add generation to return the frequency back to the target. The reverse happens if the load decreases.

This balancing act is a complex process based on forecasting loads and scheduling generation to meet these forecasts. Generators are scheduled to provide a specific power output for each hour of the day one day ahead. These schedules are then adjusted one hour ahead to adjust for variances in the day ahead load forecasts. Real time changes to the generation schedules are also made on five minute intervals. Every hour of the day some generators are scheduled to be automatically controlled by grid computer systems to increase or decrease their power output in seconds to help match power supply and demand and hold grid frequency - this is called frequency regulation. Most of the grid rebalancing is done by real time, dispatching of additional scheduled generation with an objective of maintain the scheduled frequency regulation generators at a zero net energy delivery. Governor response keeps the grid stable, the generators scheduled to provide frequency regulation respond within seconds to return frequency to target, and then real time dispatch of generation is done to anticipate load shifts and return the regulation assets to net energy neutral.

Figure 5 shows a 30 minute segment of the day as load is ramping up and how the day ahead, hour ahead, and real time dispatch, and frequency regulation all work together to match generation to the load. The vertical axis is the power in megawatts and is not to scale. The Day Ahead schedule would pick up most of the power requirement and the regulation would only be a small percent of the total load. In the first five minutes of the segment, the day ahead schedule did not schedule enough generation, but the hour ahead schedule is asking for more generation than is needed. Real time dispatch curtails some of the scheduled generation, but not enough. Generators providing frequency regulation services cut back to match the load.

The discussion so far has been about increasing or decreasing generation to match supply and demand for power. The markets and systems are set up to do this. The legacy systems are not set up to dynamically control loads. Load control has generally been through rolling blackouts, curtailments, or other scheduled reductions during emergencies. It is not typical for a utility to request a customer to increase its load. The Smart Grid will provide the potential to dynamically adjust certain loads. This active demand management will provide a new capability to match supply and demand. Increasing and decreasing loads is equivalent to increasing and decreasing generation. Actively managing the timing and power levels for charging many thousands of electric vehicles can be an outstanding source for demand management for the grid in the future.

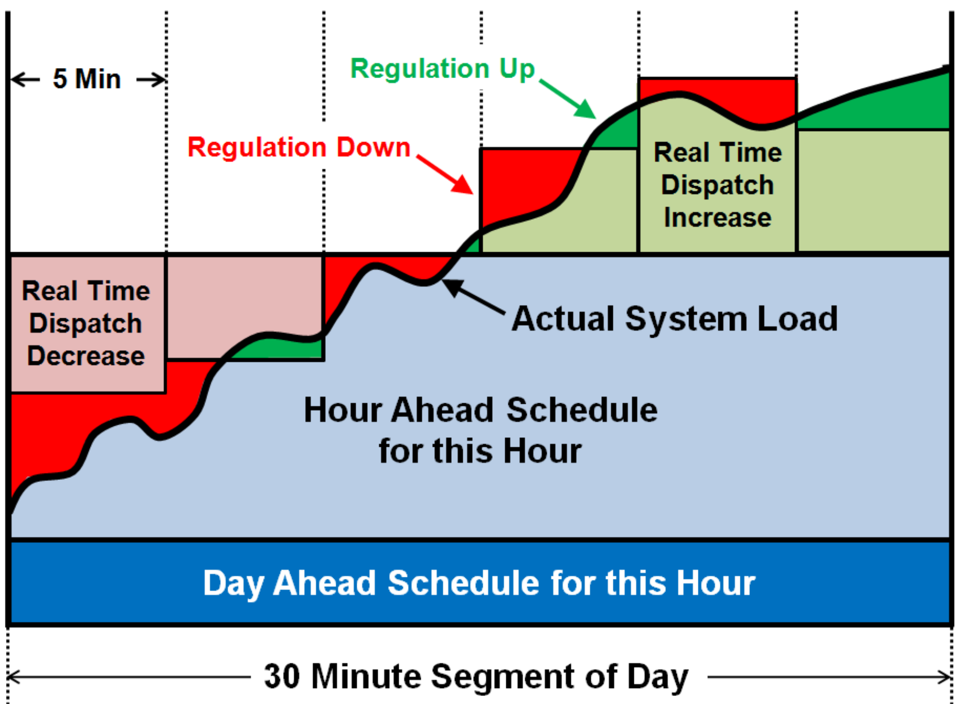

Figure 5 is an example of power scheduling for the grid.

Electricity Storage combines generation and demand management in one unit. Unlike generation and demand management that can only vary about a nominal power level, a storage system can sit at zero output or demand until needed. A storage system can provide a unique capability during ramp ups or ramp downs. During a ramp up the total scheduled generation is generally lower than needed at the end of the hour, and as new generators come on-line for the next hour there is too much power at the start. A storage system can be paid to provide power at the end of the hour and then paid to charge up at the beginning of the next hour. Paid to charge and discharge! Paying a storage unit to charge may be lower cost than paying a scheduled generator not to generate. This would be part of the real time economic dispatch market. Storage systems are also fully capable of providing frequency regulation in the ancillary services market.

Volts, VARs, and Power Factor

Most of the power in the grid is transmitted in alternating current (AC) circuits. The voltage and electric current in the circuit change at a frequency of 60 Hertz. In a circuit with only a resistive load, the current and the voltage remain exactly in phase and the power is equal to product of the current in Amperes and the voltage. This is Real (or True) Power and is measured in Watts (W).

Unfortunately, the loads on the grid are not purely resistive. Electric motors operate by creating magnetic fields and this inductive load causes the current to lag the voltage. In a pure inductive load the current lags the voltage by a phase angle of 90 degrees. The grid is dominated by inductive loads caused by the magnetic fields in the wires of the transmission and distribution system as well as the many motors. The reverse is true for a capacitive load. When a current is flowing into a capacitor to charge it the voltage lags the current – or equivalently the current leads the voltage. Current leads voltage by a phase angle of 90 degrees with a pure capacitive load. Inductors and Capacitors are both considered to be Reactance or reactive loads. These relationships are illustrated in Figure 6

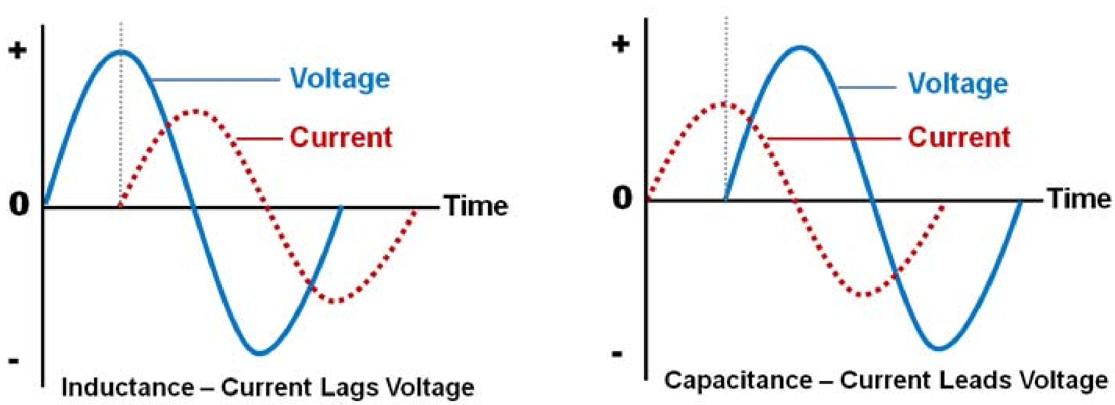

Figure 6 shows the effect of inductance and capacitance on voltage and current.

Apparent Power is the product of voltage and current at any instant. It is measured in Volt-Amps. Many electric machines are rated in Volt-Amps and not in Watts. Power Factor is defined as the ratio of Real Power to Apparent Power. A Power Factor of 1.0 is ideal. Real Power is equal to the product of Apparent Power and the Cosine of the Phase Angle between voltage and current. Reactive Power is measured in Volt-Amps-Reactive (VAR). These relationships are diagrammed in Figure 7 Electric utilities work to compensate for the reactance in the grid.

A storage system with a bidirectional converter can deal with power in four quadrants. As shown in Figure 7, the horizontal axis can represent charging or discharging. The converter can control the phase angle of how current is sourced or used relative to the grid voltage. This allows an inverter based system to provide VAR support or Power Factor Correction.

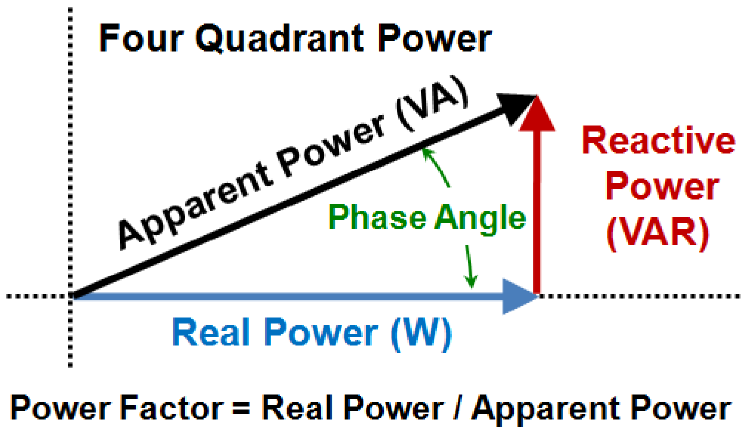

Figure 7 shows the relationship of Apparent Power, Real Power, and Reactive Power.

A Brief Overview of Electricity Storage

This section provides a brief overview of electricity storage. For more information on electricity storage visit the websites of the Electricity Storage Association (www.electricitystorage.org) and the Department of Energy, Office of Electricity Delivery and Energy Reliability (www.oe.energy.gov/storage). The IEEE Power and Energy Society Magazine devoted the July/August 2009 issue to Electricity Storage and is an excellent source – a key article by Brad Roberts is available on the ESA website.(Roberts 2009) KEMA (www.kema.com/StorageFuture) released a booklet in 2009 that also provides an excellent and timely overview of the potential of electricity storage for the grid.

Bulk Storage and Flywheels

Over 2.5 percent (22,000 MW) of the power generation capacity of the grid is actually provided today by a form of electricity storage known as Pumped Hydroelectric Storage (PHS). There are 40 PHS plants in operation in the United States. A water reservoir is built on a hilltop and used for a normal hydroelectric power plant when the grid needs more power. The reservoir must be refilled by pumping water back up the hill and this provides an extra off-peak load for wind turbines or nuclear plants. This is not as efficient as just using the primary generation source to serve the load because of the round trip efficiency losses, but it does allow the power to be applied when needed. PHS can be more cost effective than the avoided cost of building and operating the last fossil fuel generator needed to be brought online to only serve peak loads.

No other form of energy storage can compete with PHS for bulk storage. For example, the PHS facility at Raccoon Mountain, Tennessee, can generate 1600 MW for 22 hours. Power is established by the vertical drop and number of water turbines (for discharge) or pumps for storing energy. Duration is determined by the volume of the reservoirs. While the cost per kWh is the lowest of any form of storage, the total capital cost and complexity is high because these are massive civil engineering projects. Even so, the cost per unit of capacity is still very competitive, with most other forms of electricity storage at about $1500 per kW.

Compressed Air Energy Storage (CAES) is another form of bulk storage. Excess power from the grid is used to compress air in a sealed underground cavern and the energy is stored thermodynamically in the compressed air. When power is needed, the compressed air is then fed into a gas turbine power plant. Normally two thirds of the power of a gas turbine is used by the compressor stage of the unit. In this case all of the power is delivered to the electric generator.

Today there is only a single 110 MW CAES plant in the United States in Alabama. It can produce power for 26 hours. The first and only other CAES is in Germany and rated at 290 MW. A 150 MW plant is being constructed in New York and a 300 MW plant in California supported by Federal Stimulus grants. Other large CAES installations have been discussed in Ohio and Iowa but, as yet, have not been started. CAES is receiving a lot of interest for firming up wind farms. CAES costs per kWh of energy and per kW of capacity are competitive with PHS, but are likely to be easier to construct than new PHS facilities.

Both PHS and CAES are proven, mature technologies and are ideal for bulk storage. These bulk storage facilities are very large and are located remote from load centers. They are properly considered to be generation assets for the grid.

Another form of mechanical storage is to convert power into kinetic energy by spinning a flywheel. Modern flywheels are very high speed rotors that are magnetically suspended in a vacuum. Beacon Power is building three 20 MW facilities dedicated to frequency regulation. Each of these facilities will be constructed using 200 100 kW - 25 kWh flywheels. Flywheels are very efficient at power cycling, but are not useful for energy applications. At rated power the flywheel can deliver power for only 15 minutes. Flywheels are a proven technology and well suited to providing frequency regulation for many years. Today capital costs are high at approximately $2500 per kW. Because of the specialized application and operation as an independent power producer in restructured markets, these are considered to be generation assets.

Battery Storage

Lead acid batteries have been used behind the meter for uninterruptable power supplies (UPS) for many years and the UPS market is enormous. Still, the UPS duty cycle and installation environment is very benign in comparison to that required for grid storage and for electric drive vehicles. There are very few commercial installations of battery systems in the grid. There have been several successful demonstrations over the past decade by utilities with support of the U.S. Department of Energy, the New York State Energy Research and Development Authority (NYSERDA), and the California Energy Commission.

Today, Sodium Sulfur (NaS) is the most widely deployed battery technology for grid applications. The battery modules are only produced by NGK Insulators in Japan. There are over 300 MW installed globally, with most applications in Japan. The largest installation in Japan is 34 MW at the Rokkasho wind farm. American Electric Power has been a leader in the United States in successfully deploying these systems and has 11 MW installed in five locations. A typical AEP installation is two MW. The NaS battery is capable of delivering rated power for six hours. General Electric is completing a factory in Schenectady, New

York, to produce an advanced Sodium Metal Halide battery that will be very competitive with NGK's battery.

Other technologies are moving from demonstrations to larger applications with support of federal stimulus grants. Flow batteries, such as Zinc-Bromine, are very good for energy applications. Primus Power will be building a 25 MW - 75 MWh facility. Lithium Ion batteries that are a core technology in electric vehicles are also being deployed in grid applications at substation scale. A123 Systems is working with Southern California Edison to field an 8 MW - 32 MWh Li-Ion facility at Tehachapi, California, for wind firming. AES and A123 Systems are installing an 8 MW – 20 MWH facility in Johnson City, New York.

Most demonstrations of battery storage for the grid have been systems of at least one megawatt in size, connecting to the grid at distribution voltages of 4 kV to 34 kV. System operators will not deal with generation sources less than one or two megawatts. In 2009 a new concept started to emerge at AEP - a concept based on aggregating many small 25 kW storage units to create a virtual storage system with a capacity greater than one megawatt. They called this concept Community Energy Storage.

Community Energy Storage – a New Concept Emerges

Community Energy Storage (CES) is a new concept for grid storage that was developed by American Electric Power. The original AEP concept is for a small 25kW unit with either one, two, or three hours of storage at rated power. The unit connects to the grid downstream of the final distribution transformer on the utility side of the meter, and operates at 240 VAC single phase. They are assets of the distribution utility. These units are distributed along a feeder on different phases as needed. They are individually and collectively capable of voltage and VAR support. The utility aggregates these distributed units to serve the grid. They can provide frequency regulation and peak load management. During power failures the units can disconnect from the grid and be islanded to provide power to the residences served by the transformer, and improve power quality. These small units are based on electric vehicle Li-ion batteries and may even be able to use recycled vehicle batteries to reduce acquisition cost of the CES in the future. With support from federal stimulus grants, AEP will be demonstrating a distributed two MW storage system in Ohio that will use 80 25 kW CES units and DTE Energy will be demonstrating a 500 kW system in Michigan that uses 20 25 kW CES units with two hours of storage. First installations will be in mid 2011.

During 2009 Dr. Ali Nourai and Mr. Tom Walker of AEP worked with EPRI to establish a process for securing broad industry participation in a review of two AEP CES specifications: One for the CES unit(AEP CES Unit 2009) and another for the CES Control Hub (AEP CES Hub 2009) that serves to aggregate the many CES units in the system. They conducted a series of web meetings and working group meetings with broad participation to further develop the technical specifications. Both the CES unit and

CES Hub specifications are open source and publically available at the AEP website (www.aeptechcentral.com/CES/).

Figure 8 shows a simplified functional block diagram of a Community Energy Storage unit. This does not show all of the elements that could comprise a CES unit. There will be measurement devices to sense currents and voltages throughout the unit and a significant amount of mechanical hardware. The CES unit connects with a distribution transformer on a single phase at 240 VAC. The contactor is normally closed, but can be opened during a power failure to allow the CES unit to island and provide power to the connected residences. The bidirectional converter converts AC power to DC to charge the batteries and converts DC power to AC to supply power to the grid. The converter can operate in all four quadrants to provide power factor correction and VAR support. It operates as a current source when connected to the grid and as a voltage source when islanded. The unit communicates with the Hub controller and also with the Home Area Networks (HAN) for the connected residences. These will vary by utility.

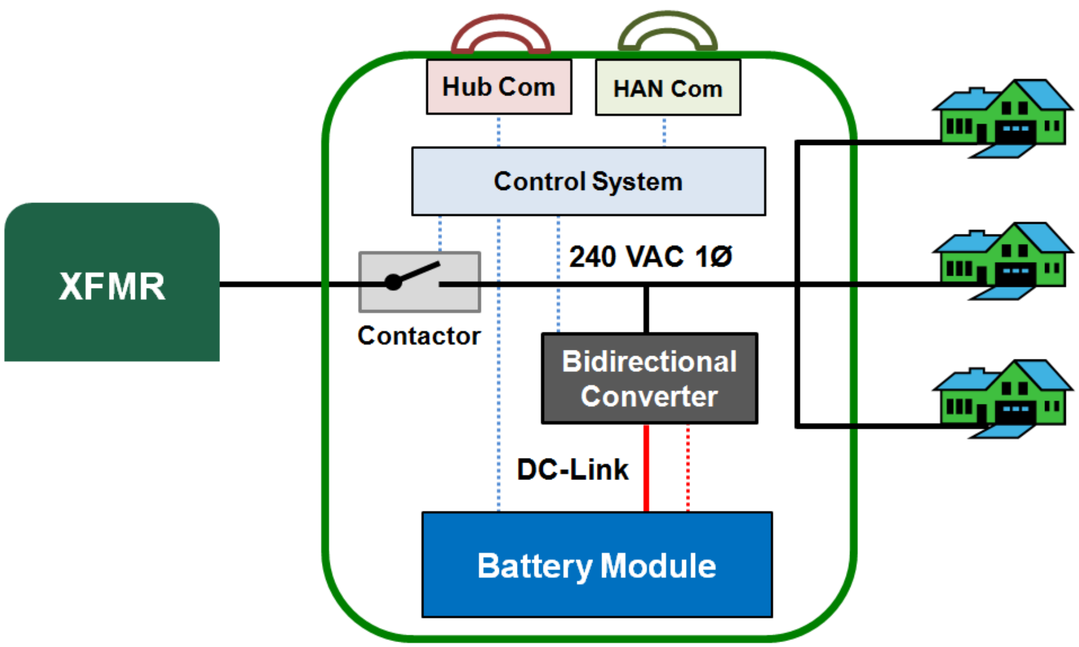

Figure 8 is a block diagram of a Community Energy Storage Unit

The AEP CES unit was sized for 25 kW, although some other utilities would prefer a 50 kW unit for residential applications. Although the CES unit specification allowed for units with one hour of storage, three hours was preferred for the application. Cost of storage and volume constraints were limiting factors. The DTE Energy demonstration units will provide two hours of storage.

CES has several advantages over a substation scale storage system. Because of the small size and the need for large numbers of them, it is more likely to become a standard product that will result in lower costs. A failure of a single unit has much less impact to the grid. It is easier to install and maintain because it is only a 240 VAC system. It uses electric vehicle battery technology, which will also drive costs because of the anticipated vehicle production volume. The vehicle batteries are compact, reliable, efficient, and operate in a demanding environment – all essential for deployment alongside transformers.

Distributed Energy Storage System – Utility Padmount

In 2010, EPRI conducted a project to establish functional requirements involving electricity storage systems for the grid in several applications. Unlike the AEP-EPRI project in 2009 that sought to develop a technical specification for the CES product, the 2010 EPRI project was aimed at establishing higher level functional requirements and remaining technology neutral. This project followed a similar protocol of webinars and working group meetings with broad industry participation. One task of this project was to look at small pad mounted storage systems, such as CES. Mr. Tom Walker of AEP was the leader for this working group.

EPRI expanded the CES concept to include units at power levels from 25 kW to 75 kW on single phase and up to 200 kW on three phase circuits. The units operate on the secondary of the distribution transformer at up to 480 VAC three phase. The units have between two to four hours of storage at rated power. EPRI calls these units Distributed Energy Storage Systems (DESS) – Utility Padmount. The requirements are documented in an EPRI report ("Functional Requirements for Electric Energy Storage Applications on the Power System Grid. EPRI, Palo Alto, CA, 2010, 1020075) (EPRI 2010).

The CES application is included within the DESS scope. Both names are used in Figure 9, which shows CES and DESS units serving the grid. The smaller size 25 kW to 50 kW CES (DESS) units are deployed in residential applications and fit the AEP CES technical requirements. The larger 75 kW to 200 kW DESS units are deployed in commercial and industrial applications. The fleet control may go by different names and be operated by different entities. AEP refers to it as the CES Control Hub.

The use cases for the DESS are very similar to CES. Use cases are peak load management using substation/feeder real time load signals; voltage and VAR support; frequency regulation with aggregation to meet ISO/RTO minimum size requirements; participation in the capacity market; and provision of backup power for increased customer reliability (islanding). The EPRI DESS requirements are based on utility applications with the unit on the utility side of the meter. The same unit could be used on the customer side of the meter, but with different use cases. Behind the meter applications were not addressed by the EPRI project.

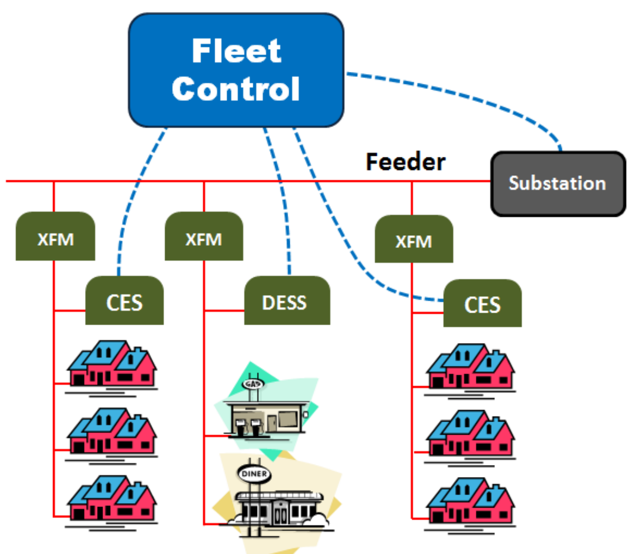

Figure 9 shows CES and DESS units serving the grid.

Managing a CES Fleet

It is becoming more challenging to regulate voltage and reactive power along a distribution feeder. In the ideal situation the utility uses a switched tapped transformer to set the voltage at the start of the feeder at the distribution substation. The voltage is set higher at the substation and it drops off toward the end. Capacitor banks are placed along the feeder to correct power factor. Things get more complicated if power is injected along the feeder by PV arrays or other distributed generation. Some dynamic loads can cause voltage and reactive power problems along the feeder. It is very difficult to control this from only the substation. Dynamic reactive devices can be added – but a storage system with a four quadrant converter also provides this capability. By distributing storage systems along each phase of a feeder, this gives the capability to control the real and reactive power along the feeder. Longer term balancing can be done by central command. Short term voltage support can be done autonomously.

In Figure 10 groups of CES units are distributed by zone and phase on the substation feeders. A group is one or more CES units. A group, or even an individual unit, can be commanded by the fleet aggregation control (the CES Hub) to provide or absorb real and/or reactive power. Group X1A can be sourcing real

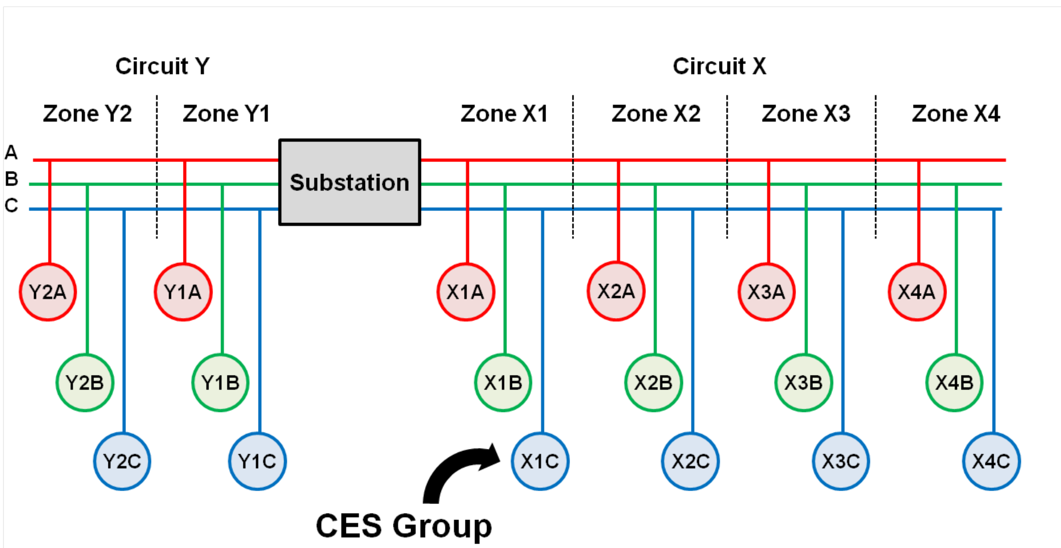

Figure 10 shows how CES units can be allocated along a distribution feeder circuit.

power, and Group X4A can be absorbing reactive power at the same time. This provides almost unlimited capability to manage the power quality along the feeder. This is a capability that cannot be achieved with a larger storage system at the substation.

Chapter Summary

There is a new concept for grid energy storage called Community Energy Storage (CES) by AEP and Distributed Energy Storage System (DESS) by EPRI. Small storage units are collocated with the transformers that serve groups of homes or businesses. These units can act autonomously to control real and reactive power along a distribution feeder, and they can also be aggregated as a fleet to form a large virtual storage system to serve the larger needs of the grid – for the feeder, the substation, or the control area.

3 *Electrification of Transportation*

Everybody's talking about them – plug-in hybrid electric vehicles and electric vehicles, collectively known as plug-in electric vehicles (PEVs). The prevailing view is that PEVs will charge at night and that large numbers of PEVs can be deployed before any additional generating capacity is required for the power grid. Still in large cities this may not be completely true. Many electric vehicle owners will want to "top the tank" during the day to alleviate "range anxiety" and many prospective PEV buyers may have access to public charge stations only during the day. This new daytime load could require the addition of new generation, transmission, and distribution capacity. This potential adverse impact can be mitigated by communicating with the vehicles to optimize the charging.

This section will review certain aspects of electric vehicles and the associated infrastructure for charging electric vehicles that are directly relevant to understanding the purpose and operation of ETESS. This report will not attempt to provide a comprehensive review of the topics. There is a wealth of public information available. One excellent source of information is the Electrification Roadmap produced by the Electrification Coalition (Electrification Coalition 2009). This was published in November 2009 and provides an excellent overview of the vehicles, the charging infrastructure, and the many issues that could impact the successful deployment of the vehicles. The document is available on the coalition website (www.electrificationcoalition.org).

Types of Plug-in Electric Vehicles

There are two fundamental types of plug-in electric vehicles (PEVs): pure electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs). The pure electric vehicles are sometimes called battery electric vehicles (BEVs), and that term will be used in this report. A regular hybrid electric vehicle (HEV) cannot be plugged in to recharge its battery and therefore is not a PEV. Figure 11 shows the key differences between the BEV, PHEV, and HEV. To keep the comparison simple in this report, a series drive configuration is used for both the HEV and PHEV.

The BEV is a very simple machine. The complete drive system includes the battery, electronics, and traction motor. The BEV requires a larger battery than an equivalent size PHEV because it is the only source of energy. It must be plugged in to recharge the battery and when the battery is empty the vehicle stops. It is capable of recovering some energy during regenerative braking, but it is always operating in a "Charge Depleting" mode. The PHEV and HEV are more complex vehicles than a BEV because an internal combustion engine, fuel system, generator, and generator electronics must be added to the BEV configuration.

An HEV is just a new concept for an energy saving vehicle transmission. It requires the same infrastructure as a regular gasoline powered vehicle, but provides improved fuel economy because of the efficiencies of the new powertrain. The battery is only used to provide energy for acceleration and to recover energy during deceleration using regenerative braking. An HEV always operates in a "Charge Sustaining" mode and tries to hold the battery state of charge near the center of its range. The HEV does not have a battery charger.

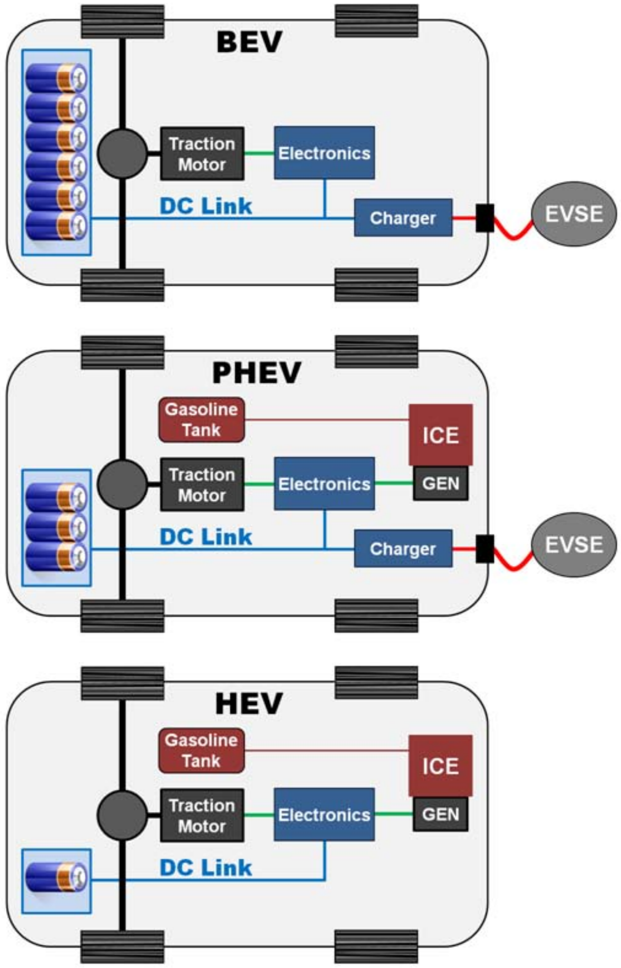

Figure 11 shows the primary differences between a BEV, PHEV, and HEV.

The PHEV is a combination of a BEV and an HEV. It is an HEV that can be plugged in to recharge the battery. The battery will be larger than that of an equivalent size HEV and smaller than that of an equivalent size BEV. The battery is fully charged at the start, unlike an HEV, which likes to maintain the battery half full. It starts operation in a charge depleting mode as an electric vehicle until the battery reaches the state of charge level maintained for HEV operation, and then the vehicle operates like an HEV. For many users the typical daily drive cycle may be very short, and it may be possible to operate the PHEV as a BEV most of the time.

Because a BEV stops dead when the battery is empty, BEV drivers often have "range anxiety" and charge early and often and will not let the battery state of charge get too low before recharging. Range anxiety is the same feeling that you get when the fuel gauge is reading empty and you are on a strange deserted highway and cannot find a gas station.

As long as the fuel tank is filled on a PHEV, the battery can always be taken to the end of the charge depleting mode so there is no range anxiety. The behavior of PHEV drivers regarding opportunity charging at public charging facilities is likely to be very different than that of BEV drivers – as measured by the state of charge of the battery at connection, the sensitivity to charging prices, and the degree of disappointment if the expected charge is not fully delivered by disconnect.

Some Fundamentals about Charging

There are two ways to charge the vehicle. The most common will be to directly connect the vehicle to a source of AC power and use the vehicle's on-board charger to manage the charging session. This is called AC charging. The other approach will be to use an external charger that directly couples to the vehicle traction battery and uses high levels of direct current to charge the battery – not unlike jump-starting a car, but under much tighter control between the vehicle and the external charger. This is called DC charging. The SAE has defined three levels of AC and three levels of DC charging.

SAE J1772™ and the Levels of Charging

SAE Recommended Practice J1772™ defines the conductive charge coupler and the electrical interfaces between the vehicle and the Electric Vehicle Supply Equipment (EVSE) for both AC and DC charging. This practice was first issued in October 1996 with the most recent prior version dated November 2001. The latest release was made in January 2010 and it "redefines AC Level 1 and AC Level 2 charge levels and specifies a new conductive charge coupler and electrical interfaces for AC Level 1 and AC Level 2 charging." The new charge coupler replaces an earlier design used in vehicles, such as the General Motors EV1. This new connector will be used for AC Level 1, AC Level 2, and DC Level 1 charging.

As of March 2011 the SAE is still working to define the coupler and interfaces for DC charging. The SAE will be defining three levels of DC charging in future releases of J1772™: DC Level 1, DC Level 2, and DC Level 3. Table 1 shows the power levels for each type.

Charging Levels SAE J1772™	Limits		
	Voltage	Current	Power
AC Charging (On-Board Charger)			
AC Level 1 (N5-15R)	120 V_{AC}	12 A_{RMS}	1.4 kW
AC Level 1 (N5-20R)	120 V_{AC}	16 A_{RMS}	1.9 kW
AC Level 2 (Old)	240 V_{AC}	32 A_{RMS}	7.7 kW
AC Level 2 (New)	240 V_{AC}	80 A_{RMS}	19.2 kW
AC Level 3	TBD	TBD	TBD
DC Charging (Off-Board Charger)			
DC Level 1	450 V_{DC}	80 A	19.2 kW
DC Level 2	450 V_{DC}	200 A	90 kW
DC Level 3	600 V_{DC}	400 A	240 kW

A new and different coupler will be needed for DC Level 2 charging. The pins on the AC coupler are not large enough for the higher currents needed for DC Level 2 and DC Level 3. One approach is to create a coupler that is unique for DC Level 2 charging. This would require a vehicle to have two couplers.

Another approach is to create a single hybrid coupler that can connect with the baseline AC coupler, but carry separate pins for higher power DC connections. The current levels for DC Level 3 charging would require a larger shell and could not be combined with the AC coupler in a hybrid design. As of March 2011, the SAE is evaluating the different options for DC Level 2 charging. The selected couplers will be defined in a future release of J1772^{TM}.

Electric Vehicle Supply Equipment and the Control Pilot

A PEV cannot directly connect to the power system. It must connect through Electric Vehicle Supply Equipment (EVSE) that meets the requirements of SAE J1772^{TM}. The EVSE provides safety interlocks and ground fault protection. It also provides a signal to the PEV (called the Control Pilot) that performs several functions. One function is to define the maximum allowable current that an on-board charger is allowed to draw during AC Charging. It uses a 1000 Hertz pulse width modulated (PWM) signal to communicate this information to the PEV. For duty cycles of 10% to 85%, the maximum allowable charging current must be limited to 0.6 times the percent duty cycle. And for duty cycles of 85% to 96%, it is set to 2.5 times the difference between the percent duty cycle and 64%. The EVSE normally sets the control pilot to limit the vehicle charger to draw a maximum current of 80% of the branch circuit capacity. For example, on a 40A branch circuit the maximum AC charger current should be limited to 32A (a power level of 7.7 kW on a 240 VAC circuit). The EVSE would set its control pilot duty cycle to 53.3% to communicate this to the PEV's on-board charger.

The relationship between the PEV and EVSE are shown in Figure 12 for AC Level 1, AC Level 2 and DC charging. In AC Level 1 the cord set is the EVSE. In other levels it is a part of the facility infrastructure.

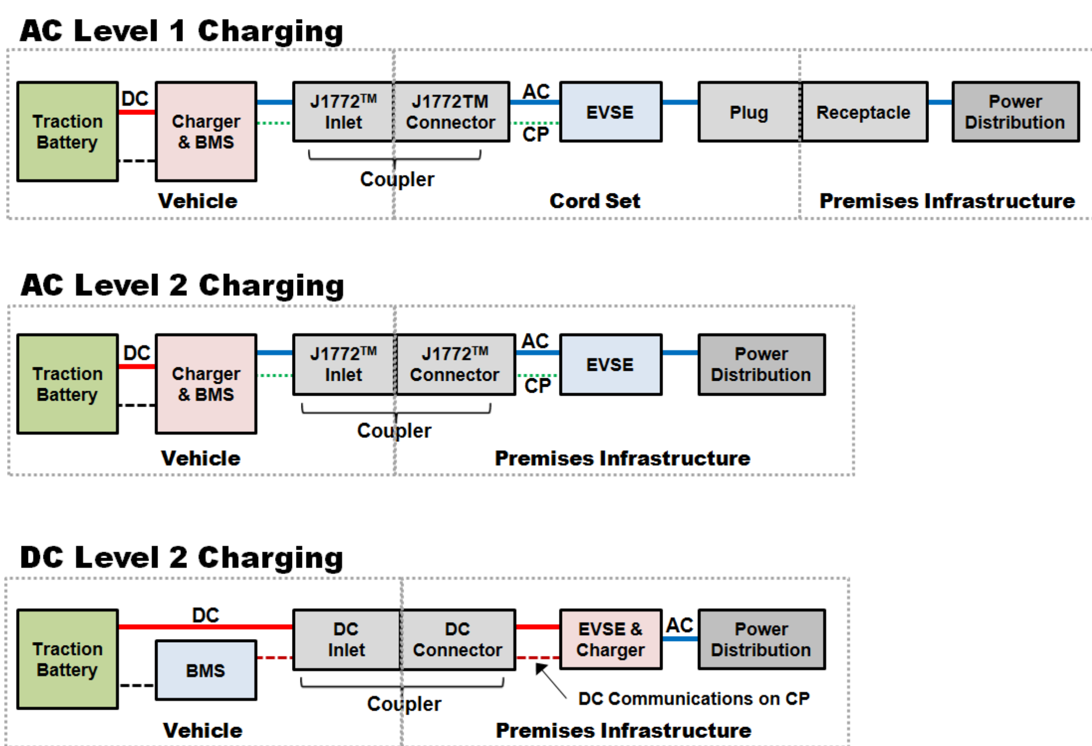

Figure 12 shows the relationship of the PEV and EVSE for several charging levels.

Digital communications are not required for basic AC Charging. The EVSE enables the PEV to charge by turning on its control pilot and using it to communicate the facility limits to the PEV's on-board charger. It could do this as soon as the PEV is connected and rely on the PEV to manage the time to start and end charging - the PEV does not have to immediately start the energy transfer. Alternatively, the EVSE doesn't have to activate the PWM signal at connection and it may be programmed to "wake up" the PEV to start a charging session. It is allowable for the EVSE to establish a lower maximum power level than that of the branch circuit and this could be done dynamically in an intelligent EVSE. For example, a facility energy management system may want a vehicle with a 6 kW (25A) on-board charger on a 40A branch circuit (with a normal 32A limit) to charge at 3 kW. It would set a 12.5A current limit by setting a 20.8% duty cycle on the control pilot. Even with no digital communication between a PEV and EVSE, the EVSE could communicate with a facility EMS or even directly with a utility to take advantage of special rate programs to encourage off-peak charging.

For DC charging, the EVSE is the off-board charger and digital communications are required between the PEV and the EVSE. The EVSE sets the control pilot PWM to a duty cycle of five percent to advise the PEV that digital communications are required. If communication cannot be established the DC charging cannot happen. This data link is required to perform the same very tight communications that normally occurs between the on-board charger and the battery management system within the PEV. It also includes all of the messages needed to control the safety of the connection and charging process. These are point to point messages that only have to go between the EVSE (charger) and the PEV. SAE J2847-2 defines the messages required to control DC charging.

Park and Charge

Many PEV users will charge their vehicles off-peak overnight to take advantage of lower rates. It is also very convenient because most vehicles will be idle then. It may also be convenient for owners to recharge while they are at work. Some users may elect to recharge at other venues where the PEV could be parked for several hours. These are all "park and charge" scenarios and AC charging using the PEV's on-board charger is an ideal solution.

Most PEV models will have an on-board battery charger. The charger accepts alternating current (AC) power from the grid and converts it to direct current (DC) power to charge the vehicle's traction battery. This is referred to as "AC Charging." The sequencing and levels of voltage and current applied to the battery are controlled entirely by the on-board charger. The power rating of the on-board charger is determined by the vehicle manufacturer by trading off charging time versus cost, size, and weight of the charger and the available infrastructure.

AC Level 1 Charging

AC Level 1 can be performed at two power levels depending on the capacity of the branch circuit and the custom cord set. Vehicle manufacturers will provide one of two types of special cord sets with each vehicle: one that will allow the vehicle to plug into a standard 120V/15A NEMA 5-15R receptacle and charge at 1.44 kW or the other, which uses a 120V/20A NEMA 5-20R receptacle and charges at 1.92 kW. This type of charging is referred to as AC Level 1 Charging. AC Level 1 charging may be acceptable for a PHEV or in an emergency for a BEV, but it will be a very long charging cycle for a large BEV battery. This cord set also includes the safety and control circuits of an EVSE. It actually is an EVSE. Even if the vehicle charger is capable of using 6.6 kW, it will only draw up to either 1.44 kW or 1.92 kW when using one of the AC Level 1 cord sets.

AC Level 2 Charging

This level of charging uses a facility-mounted EVSE connected to a single phase 240 volt branch circuit. Until the January 2010 release of SAE J1772™ the maximum current was limited to 32A on a 40A branch circuit (7.7kW). This was extended to 80A (19.2 kW) to accommodate high battery capacity vehicles, such as the Tesla Roadster, but it is not likely that many vehicles will go to that level of on-board charger. Many of the vehicles will only have 3.3 kW on-board chargers with future plans to get to 6.6 kW. It is more likely that external DC chargers will be used beyond the 7.7 kW level.

DC Level 1 Charging

Even though AC Level 2 could go to 80A and 19.2 kW, it is not likely that many PEV models will ever provide on-board chargers capable of operating at that power level, or even beyond the old limit of 32A and 7.7 kW. It is not a cost effective trade for the vehicle manufacturer. For higher power levels it is much more cost effective to use DC charging. DC Level 1 charging is a more cost effective way to get to a 19.2 kW level than using AC Level 2, at least for the vehicle manufacturer.

Charge and Go

Some PEV users will want to recharge very quickly. A BEV with a 25 kWh battery that plugs in with a state of charge (SOC) of 20% and leaves with a SOC of 80% needs 15 kWh of energy. With a 3.3 kW on-board charger this would take over five hours at 85% efficiency using an AC Level 2 EVSE. The same energy transfer would take only 20 minutes, using a 50 kW DC Level 2 charger. If it could be done at DC Level 3 at 200 kW, it would only take five minutes. That's fast charging! There is the potential to take some life out of the battery and these chargers are very expensive, but this moves to the gas station model. As battery technology improves and costs decrease, it could be that high power charging becomes the norm. There is not much point worrying about time of use or special rates when you are surging 200 kW into the battery.

The Good, the Bad, and the Ugly

Electric utilities want to encourage the adoption of electric vehicles - not because they want to reduce our dependence on foreign oil or reduce greenhouse gas emissions, even though these are noble causes. They like making money and PEVs represent a potential huge growth market; and because most vehicles are parked at night, this could be a great off-peak load for the utilities. Because the generation and transmission capacity of the grid is sized by the occasional peak, there is a significant amount of idle capacity most of the time. If this otherwise idle capacity could be dispatched in the evening to charge PEVs, this levels the load factor and improves the economics for everyone - a **good** deal for all. The utilities want to offer special rates for PEV charging to encourage people to buy them.

The peak demand generally occurs between 4:00 p.m. to 8:00 p.m. - when people are arriving home from work, meals are being prepared, and air conditioners are running. This is also when many PEVs will get plugged in to charge. This would be **bad** if the vehicles actually started charging then. The utilities want PEVs to happen, but they also want them to wait until later in the evening to start charging. The utilities want to be able to offer programs that offer attractive rates for PEVs but in ways to encourage the owners to charge at the right times.

Utilities do not expect to see a nice uniform distribution of PEVs around the grid. Based on consumer behavior in purchasing HEVs, the utilities expect that clustering is more likely to happen. They will be more likely to happen in certain neighborhoods and maybe even in a cluster of homes served by a single transformer. This could get **ugly** if all of the vehicles switch on at midnight and blow the transformer. A larger transformer could potentially resolve the problem. Another way is to stagger the start times –

something that a simple time of use rate schedule may actually make worse. Here the utilities may want to control the charging schedules of specific vehicles to spread them out.

It was the excitement of utilities about encouraging the adaptation of PEVs, but also wanting to encourage off-peak charging and protect the grid infrastructure that drove the need for the electric utilities, to be able to communicate with PEVs.

Public Charge Stations

At the very lowest level of the public charging infrastructure there is the charge station. It is an EVSE. This unit provides a cable and connector plug that inserts into the vehicle's charging receptacle. It also provides a display and user interface. A functional diagram of a typical charge station is shown in Figure 13. This charge station is set up for SAE J1772™ Level 2 charging and is nothing more than a direct path of single phase 240 VAC power from the branch circuit to the vehicle connector plug. A ground-fault circuit interrupter (GFCI) device is provided for safety. The charge station uses the control pilot to set the maximum allowable power level. The PEV on-board charger will draw power up to the lower of its charger capacity or the limit established by the control pilot.

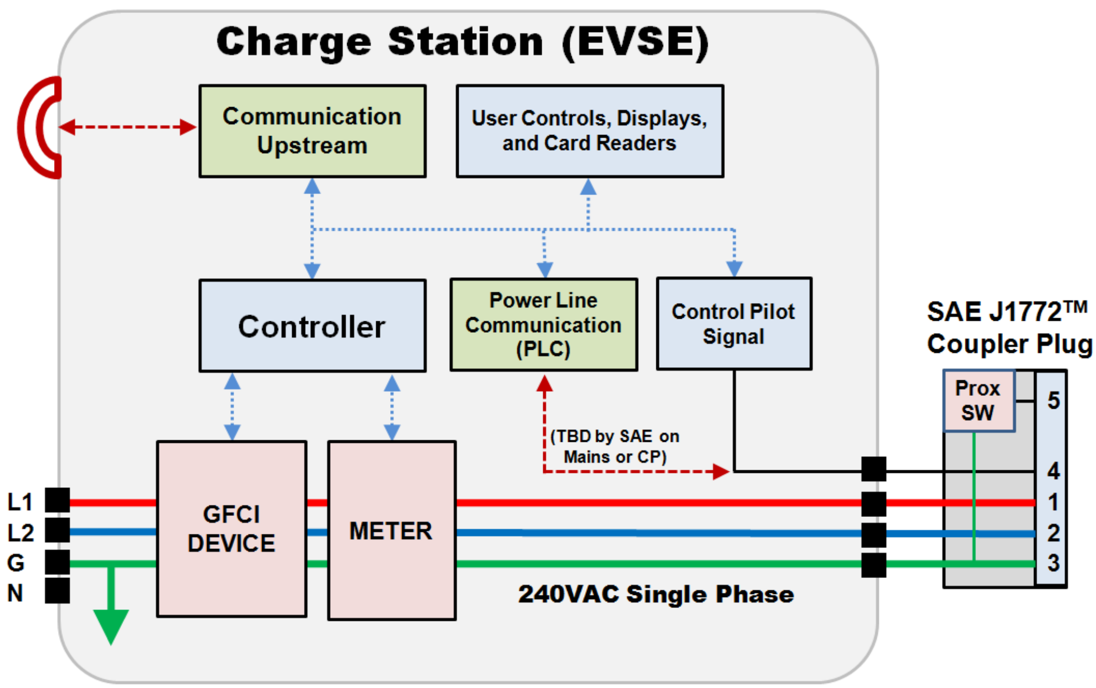

Figure 13 is a block diagram of a typical public charge station.

A revenue grade meter may be needed either in the charge station or in the parking facility for the branch circuit that serves the charge station. For commercial charging it is not clear what service will actually be provided. If energy is the product, a revenue grade meter will be needed. Still, if access to charging is the product, the exact energy transfer is less important than the time connected and the peak power used, and non-revenue grade equipment might be acceptable for measuring power flow.

For most commercial applications there will need to be some communication between the charge station and upstream business systems to allow for payment. This will be needed even if the PEV is not capable of any digital communications. The specific communication system could be location specific. An RF link is shown in the figure but it could easily be wired Ethernet, optical fiber, or power line communications (PLC) on the branch circuit – there are many viable options. An energy management system at the site could take information entered on a charge station keypad (such as the required energy transfer and the estimated time of return) and use this to manage the session by just using the control pilot. This is not an elegant solution for controlling the charging of many vehicles at a public park and charge location, but it can be done.

A more effective approach for conducting the charging session is to establish digital communications between the charge station and the PEV. This could allow information to be provided from the PEV and not need to be entered directly into the charge station. It also allows the PEV to share more detailed information with the charge station to allow more effective energy management across the site. The charge station will serve primarily as a bidirectional relay between the PEV and upstream energy management systems and business systems. These upstream systems could belong to the parking facility or they could even be at a utility.

Digital Communication with the PEV

The SAE is creating four families of documents to define PEV communications: J2836™, J2847, J2931, and J2953. Each family has several "dash" numbers. The J2836™ series defines uses cases and the J2847 series defines the messages needed to implement each of the use cases. Each of these two series has five documents: Dash 1 is for Utility Programs; Dash 2 is for communication with the off-board charger for DC charging; Dash 3 is for Reverse Energy Flow for Vehicle to Grid (V2G), Vehicle to Home (V2H), Vehicle to Load (V2L), and Vehicle to Vehicle (V2V); Dash 4 is for Diagnostics; and Dash 5 is for Customer Interface. The J2931 series defines the actual communication protocols used to transmit the J2847 messages. J2953 will deal with interoperability of the PEV with the EVSE.

Power Line Carrier Communications

The SAE selected Power Line Carrier (PLC) as the physical medium for communication between the PEV and the EVSE and they may decide to use two separate PLC channels. One channel will be used for the J2847-2 messages that are required for DC charging. The timing of these messages is critical and they only need to go between the PEV and the off-board charger (EVSE). It has been decided to send these messages on top of the control pilot circuit. As of March 2011, the SAE has not yet decided what specific PLC technology to use over the control pilot. A simple point to point message protocol can be used, but this has not yet been decided or defined.

The other channel will be used for other digital communications, such as the J2847-1 messages needed to support utility programs. At this time, the decision has not been made on whether to use the control pilot circuit or the mains (AC or DC power circuits), and which PLC technology to use for the J2847-1 messages. The PEV only connects to the EVSE and therefore all information coming from or going to the PEV must route through the EVSE. It is very likely that any facility network beyond the EVSE will use a different communication medium and this will require the EVSE to at least "bridge" the messages. Nevertheless, it is also possible that the exact formats and protocols used to transmit and receive the messages by the PEV may not be compatible with the message formats and protocols used by the external network. In this case the EVSE will need to actively translate the message streams.

Use Cases for Utility Programs

J2836-1™ defines five use cases for utility programs: Time of Use (U1), Direct Load Control (U2), Real Time Pricing (U3), Critical Peak Pricing (U4), and Optimized Energy Transfer (U5). Time of Use, Real Time Pricing, and Critical Peak Pricing programs are all associated with encouraging PEVs to charge at a time preferred by the utility. Direct Load Control is a demand response program and not a demand management program. It allows the utility to interrupt charging during an emergency.

Optimized Energy Transfer (U5) is the most powerful use case. This is the only case that allows the utility to engage in real time with the PEV while it is charging to actively adjust the power draw of the PEV, up or down. This allows for demand dispatch and management. This mode can be used by a utility to stagger the start of charging and adjust power draw during charging for each of the vehicles connected to the same transformer in a cul-de-sac. It can also be used by an energy management system in a public parking facility to actively manage the charging of all of the vehicles at the site.

Optimized Energy Transfer

Table 2 shows some of the messages required by SAE J2847-1 to implement Optimized Energy Transfer (U5). The EVSE could be in private premises or it could be a public charge station. The EVSE is never optional, but it may not need to be used for communications and can serve as a pass through for messages between the PEV and EMS. The column labeled EMS represents where the control logic is originating. The EMS could be operated by a utility and used to control PEVs in a cul-de-sac, or it could be privately owned, used to control all of the PEVs at a public parking facility. The table identified that entity transmits the message (Tx), and which receives the message (Rx).

Table 2 shows essential messages for optimized energy transfer.

Essential Messages for Optimized Energy Transfer (SAE J2847/1)					
Message	Units	Rate	PEV	EMS	EVSE (Optional)
Time Charge is Needed	UTC	Start	Tx	Rx	Keypad Entry & Tx
Energy Request	kWh	XFR	Tx	Rx	Keypad Entry & Tx
Power Request	kW	XFR	Tx	Rx	Keypad Entry & Tx
Time at Connection	UTC	Start	Rx	Tx	
Energy Available	kWh	XFR	Rx	Tx	
Power Available	kW	XFR	Rx	Tx	Rx & Set Control Pilot

The EMS needs to know the time the charge is needed, the requested amount of energy to transfer by that time, and the requested power level to use for the transfer. If the PEV does not have digital communication, this information could be entered into a keypad on the EVSE. The requested power should normally be the maximum power rating of the on-board charger. The EMS will send the PEV the time of connection, the energy available, and the power available. The connection time is needed to align the EMS and PEV time reference because this event is directly visible to the EVSE and the PEV. If the PEV does not have digital communications, the EVSE can use the control pilot to signal the maximum power available.

When digital communication is available with the PEV, the information will be updated on a regular basis throughout the energy transfer. The PEV can compute the state of charge (SOC) of its battery. Taking into account the target state of charge, battery capacity, charging efficiencies, and hotel loads, it is easy to compute the remaining energy transfer required. This is not the net energy delivered to the battery but the actual energy drawn by the PEV from the grid. The vehicle should always present its maximum power capability and not try to send an average power requirement based on the energy required over the time to go. This could conflict with EMS algorithms. The requested power request should only be dropped if the PEV needs to reduce the power level to protect the battery.

The EMS will use the power available to control charging. It can set this from zero to the maximum allowed by the charge station. The EMS can authorize more power than requested by the PEV, because the PEV will not draw more than it is capable of using.

For this system to work it only requires the PEV to tell the EMS how much remaining energy transfer is needed until the estimated time of departure and for the EMS to set the maximum power that the PEV is allowed to draw at that time. The PEV sends the Energy Request and the EMS authorizes the Power Available continuously during the session.

For many applications this may not need to be very dynamic. It could be used by a utility to simply stagger start times for a few vehicles in a cul-de-sac and let them charge at max rates. At a public site with many vehicles coming and going during the day, the control could be much more dynamic.

Power Management for Park and Charge Locations

Forecasts vary widely about the timing and the share of the market that PEVs will achieve, but a key factor in the growth projections of PEVs is the availability of a robust public charging infrastructure. Most forecasts of the impact of PEVs on the grid are based on PEVs starting to charge late in the evening in the family garage and then finishing by early morning. And this will be true for most of the earlier adopters. This new load will be good for the utilities because it will help fill the nighttime valley – leveling the load factor. Forecasts also show that large numbers of PEVs can be deployed before any additional power capacity is needed, and this new nighttime load can absorb renewable energy from wind farms. This is all good news for the electric power industry, if it is true.

Still this may not be completely true, particularly in large cities. Many vehicles may not have access to public or private charging stations in the evening. Some urban PEV owners may only be able to charge while at work, and a suburban PEV owner may still want to "top the tank" for the trip home while at work or at the shopping center. This is a very significant consideration for pure (battery) electric vehicles that, unlike plug-in hybrid electric vehicles, depend exclusively on stored electricity to get home.

For PEVs to really flourish, public charge stations must be ubiquitous. They will need to be on city streets, in parking garages, at airports, at malls, at sports venues, at business parking lots – everywhere! And many vehicles may be charging during the day and at peak times and this could be a problem for the grid. A significant daytime PEV load could require the addition of new generation and transmission capacity. Even if the regional loads are manageable, concentrated PEV charging could have local impact on substations, distribution feeders, and distribution transformers.

A park and charge facility with twelve charge stations is shown in Figure 14. Each charge station is connected to the distribution panel by a 240 VAC 40A branch circuit. This panel is fed by a dedicated 50 kW transformer. The maximum allowed charge rate for any charge station in this site is 7.7 kW. If all twelve vehicles attempted to charge at that rate it would require over 90 kW – not very good for a 50 kW rated transformer. It is clear that all of the vehicles can not be allowed to charge at the maximum rate at the same time. This could be solved by using a 100 kW transformer, but there may still be other reasons to limit peak power.

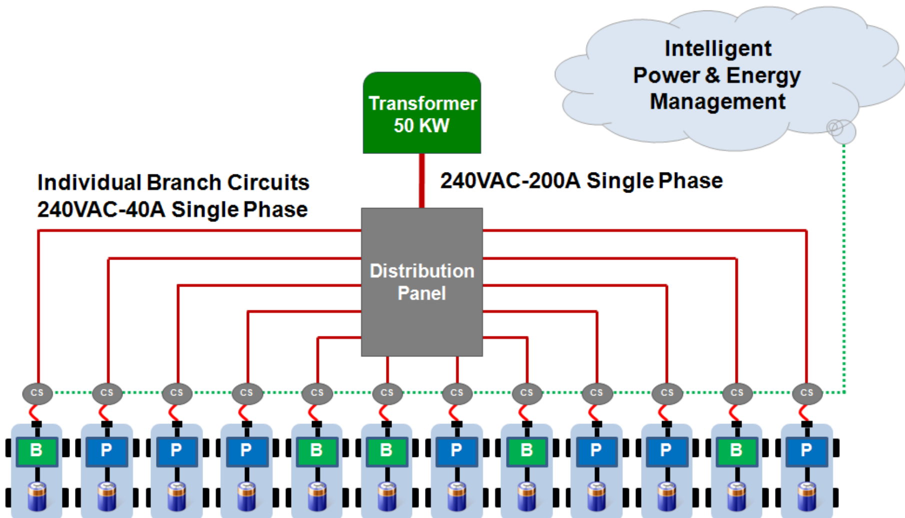

Figure 14 shows a PEV parking facility with 12 charge stations.

Assume these charge stations are at a shopping mall that is open from nine in the morning until nine at night. Morning mall walkers may come in at six. Restaurants may stay open until midnight, and during the afternoon peak period there is some probability that the utility may not want to allow more than 30 kW through the circuit to the transformer. Vehicles arrive and queue up for spaces with a probability that varies during the day, and they stay for various durations. The types of vehicle also vary by maximum charge rate, battery capacity, state of charge, and amount of energy requested. If a BEV does not get the juice it needs, it may not be able to get home. PHEVs operate just like regular HEVs when the battery is low, so topping the tank is not as critical, but people do not plug-in at a commercial charging station unless they specifically want to charge up. Otherwise they would park in another non-charging spot. They might be disappointed to return to their vehicles after four hours and find that theirs was not charged up, and this is just one scenario!

In this example, the transformer rating establishes the maximum power. The limit could easily be a result of a utility demand response cutback to the facility or just the need to keep the peak 15 minute demand below a threshold for the purpose of managing the facility demand charges.

It is clear that you cannot let each connected PEV draw whatever power it wants whenever it wants and stay within facility limits. The J2847-1 Optimized Energy Transfer capability built into the PEV provides a means to dynamically control the time of charging and the power allocation of each vehicle. The challenge is to create an optimization algorithm that accepts the energy request and estimated departure time from each vehicle and then allocates the available power to each connected vehicle to stay within facility power constraints and also minimize customer disappointments. We call these algorithms **iPEM** for **intelligent Power and Energy Management**.

Electric Transportation Energy Management System

One way to manage the allocation and optimization of power for a group of charge stations and their connected PEVs is to put communication and computation capability into the distribution panel and execute the **iPEM** logic in this "smart" panel. This smart distribution panel will be called an **Electric Transportation Energy Management System (ETEMS).** A functional diagram of ETEMS is shown in Figure 15.

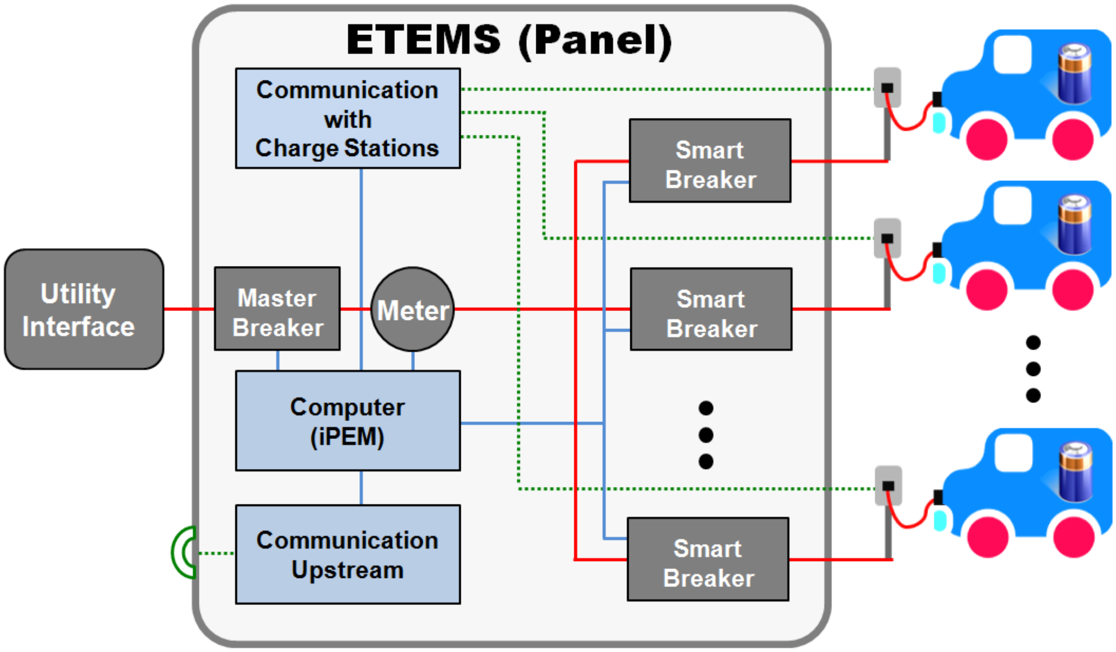

Figure 15 is a block diagram of an ETEMS panel.

The PEVs will communicate with the charge stations using Power Line Communications (PLC). As discussed previously, the SAE is currently defining the specific PLC technology to be used. The communication link between the ETEMS panel and the charge stations for SAE J2847-1 messages could be PLC, a separate Ethernet cable, an optical fiber, or a radio link. ETEMS communication will need to be modular to accommodate local requirements for the parking site. These links are shown by the dotted green lines. This is the equivalent of a Home Area Network (HAN) in a private residence and it could use a HAN protocol, such as Smart Energy 2, to encode the messages. The SAE J2847-1 Optimized Energy Transfer (U5) messages will be used to manage the charging session of each connected vehicle.

The ETEMS panel can also communicate with upstream systems. This could be with a utility smart meter or a higher tier energy management system for an entire site. These also could be a radio link (as shown) or by cable or fiber. This will also be location dependent and the ETEMS must be modular to accommodate differences. It is not anticipated that messages required to control charging of PEVs will be routed to a higher tier. These will be handled by the ETEMS panel. This link will be used for ETEMS to receive power limits and allocations from the next tier. ETEMS could use preset limits to protect the immediate power infrastructure, but any additional limit reductions would need to come as an allocation of a total facility limit or a utility demand response limit.

The meter is for control purposes and does not need to be a revenue grade instrument. ETEMS needs to know the total power draw. This panel shows a dedicated 240 VAC 40A single phase breaker and circuit to each charge station and does not use a shared higher power breaker and circuit to multiple charge stations. Each charge station has its own internal GFCI breaker so it may not be necessary to wire each charge station individually. Although this is less forgiving if an ETEMS needs to override a single charge station failure and the other connected charge stations are also shutdown.

The computer in the ETEMS panel implements the iPEM alogrithms for managing the power allocation to the connected vehicles. It is expected that the ETEMS panel and iPEM algorithms would deal with a group of ten to twenty charge stations. At 100% utilitzation at the rated limit of 7.7 kW per charge station, twenty stations could draw over 150kW, but not all charge stations will be occupied and charging at the same time and many vehicles will draw less than 7.7kW. At a 50% derate, the maximum allowable power could be limited by iPEM logic to 75kW and a 75kW transformer could be used. A 50 kW transformer could feed up to twelve AC Level 2 charge stations at a 50% derate.

Multiple Tiers of Power Management

It is a very complex and specialized problem to manage the power and energy flows within a large public charging site. A shopping mall will have very different user characteristics than a factory parking lot or an apartment building. The optimization and allocation logic needs to be tiered to reflect the infrastructure. This approach is illustrated in Figure 16.

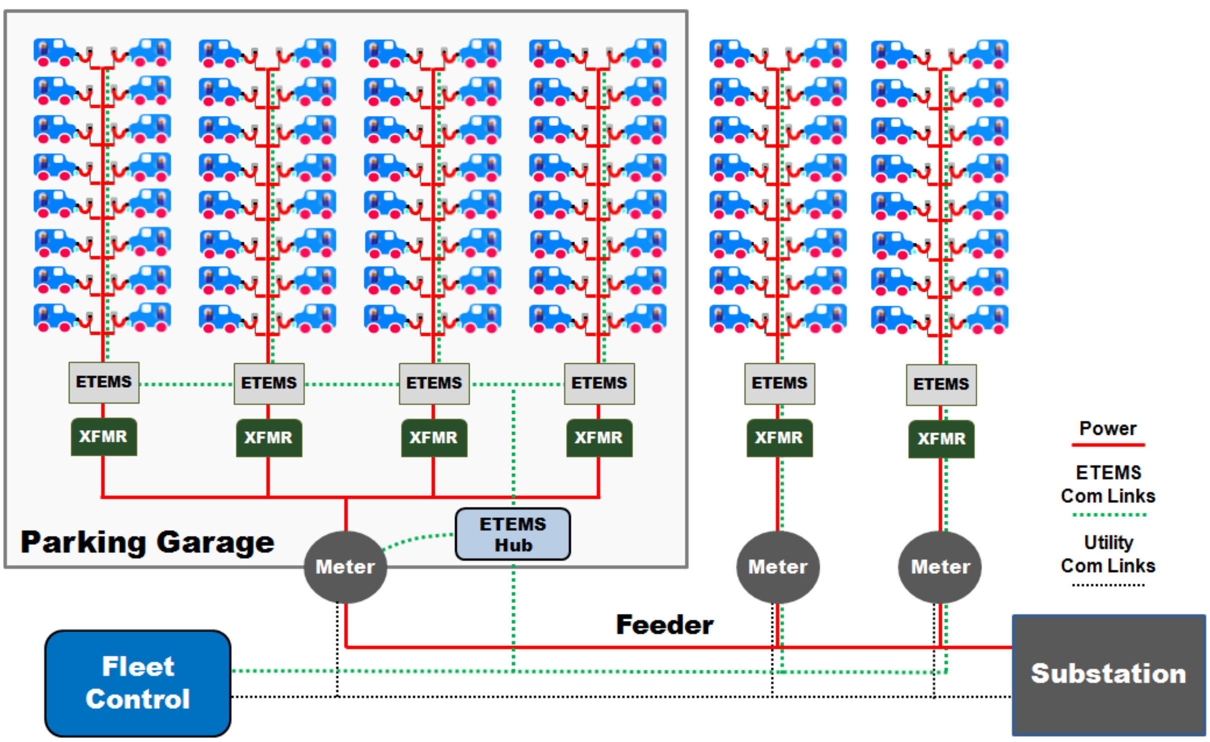

Figure 16 shows multiple tiers of control for vehicle charging.

Each group of sixteen charge stations is served by an ETEMS panel. The iPEM logic in the ETEMS panel manages the charging sessions of that group of PEVs, keeping power below the transformer limit or any lower limit passed to it from a higher tier control.

Within the parking garage an ETEMS Hub manages power allocation between the four groups of charge stations. The ETEMS Hub does not need to be a standalone system; it could just be software within a facility EMS or even as separate software running in one of the ETEMS panels. It does not make sense to allocate an equal reduction to each ETEMS when the facility must reduce power to meet a utility demand response command. The ETEMS Hub allocates power to each ETEMS based on the aggregate power requirements and disappointment metrics of each group. The objective is to meet facility requirements and also minimize disappointment across all the PEVs at the site.

The Fleet Control could be operated by an electric utility or by a private operator. It will depend on the electricity market structure for the region. The dotted black lines show communication links between a utility and its meter. The utility would use this link to allocate demand response limits to the parking garage and the two individual groups of charge stations. Messages between the meter and the ETEMS Hub or panels would use the ETEMS network. The dotted green lines show the ETEMS network. If the fleet control is owned by a parking facility operator it could not communicate via the meter and would use its own network to connect with each ETEMS – this is shown by the dotted green line.

The iPEM control logic needed to manage a specific group of charge stations does not need to reside in a computer in an ETEMS distribution panel. A central computer at the site, or even offsite could be used. The Fleet Control could directly control all of the PEVs. All of the real time information from each PEV could be uploaded and the central system could send commands back to each PEV. But executing iPEM algorithms for each group of charge stations in large service area could become a central computer throughput and communication bandwidth problem. A distributed computation, multi-tiered approach could be much easier and lower cost to implement.

For this system to work, any PEV that uses this facility must agree to allow the EMS to control the charging, using SAE J2847-1 Optimized Energy Transfer. This needs to be a condition for parking at the location and using the charger. ETEMS should have the capability to engage this mode by default as long as the PEV has indicated that it is ready to receive energy. ETEMS can enforce this by using the control pilot in the charge station (EVSE) to override any other behavior by a PEV.

Chapter Summary

The PEVs are coming and will hopefully become a large share of the global light duty fleet. While most of the PEVs will charge at night at off-peak times, many vehicles will park and charge during the day and potentially during peak periods.

This could become a potential problem at public parking locations. PEVs do not plug in during the day to not charge. Also idle, but occupied, charge stations are not a good use of valuable assets. An uncontrolled load could result in excessive power demand charges for the facility and could also adversely impact the local infrastructure, the distribution feeder, and even the control area. The aggregate loads at the facility need to be managed to stay within system constraints and at the same time minimize any disappointment to the PEV drivers.

Most PEVs will have digital communications capability to allow them to participate in electric utility incentive programs. Several use cases for these utility programs are defined by SAE J2836-1™ and the messages to implement them are defined in SAE J2847-1. One of them, Optimized Energy Transfer, provides the capability for an Electric Transportation Energy Management System (ETEMS) to directly manage the maximum power consumption of a PEV. This will be an essential capability for large park and charge facilities.

4 *Intelligent Power and Energy Management*

An Electric Transportation Energy Management System (ETEMS) that serves a park and charge facility must be capable of intelligent Power and Energy Management (iPEM). If a facility must stay within its power constraints, each connected vehicle at the site cannot be allowed to draw whatever power it wants whenever it wants. The challenge is to create an optimization algorithm that accepts an energy transfer request and an estimated departure time from each vehicle and then allocates the available power to each vehicle to stay within any firm infrastructure power constraints while minimizing customer disappointments. The vehicle operators are the most obvious customers and any driver will be disappointed if the requested energy is not delivered during the connection time. still, the electric utility, the facility owner, and any charge facility operator are also potential customers of the ETEMS. Even if the total power consumption is maintained below firm infrastructure limits, it could still exceed an economic target, such as a utility demand response target or a facility peak demand objective. The algorithms must balance both vehicle and grid disappointments.

Fundamentals of Power Allocation

The chart in Figure 17 shows an example of unconstrained and managed power allocation for six vehicles charging during a four hour interval. In the managed situation (shown by the red line) the ETEMS is seeking to maintain a power demand of not more than 8 kW and it has been successful. It has a total energy capacity of 32 kWh at the 8 kW limit and it has effectively allocated 31 kWh – 97% of the capacity. The power demand for the unconstrained situation is shown in blue for the same 31 kWh. There is clearly value in managing the demand. The details of this example will be explained later.

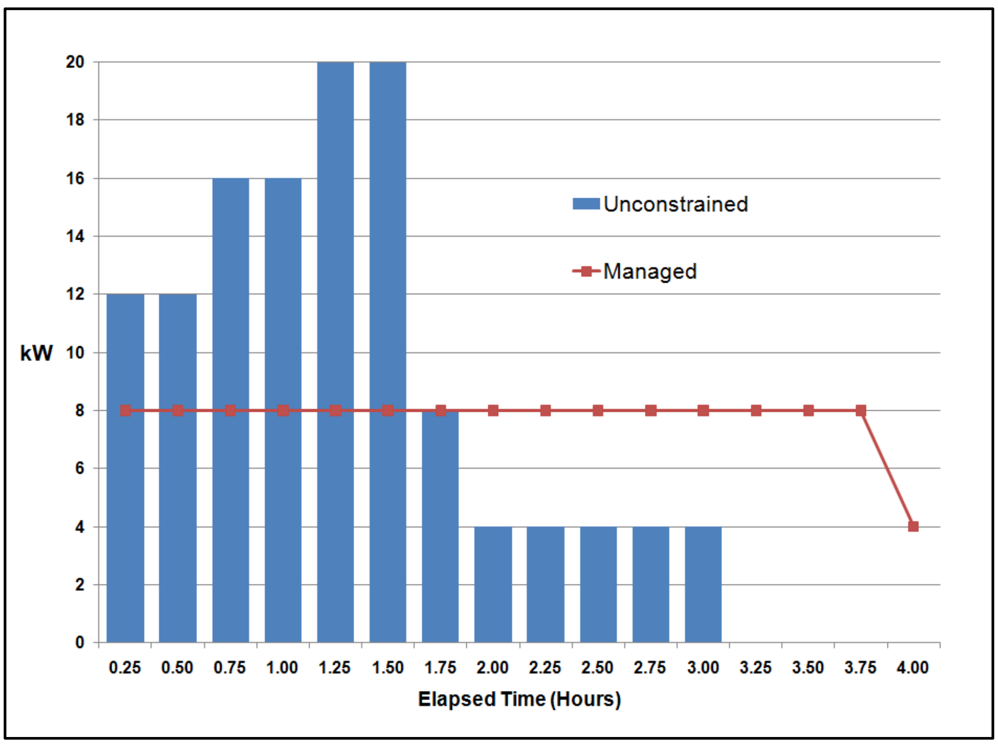

Figure 17 illustrates the benefits of managed charging

In this example it was feasible to allocate the power to stay within a facility limit and fully satisfy the energy requirements of all of the vehicles. In other scenarios the vehicles may request more power and energy than can be allocated without exceeding the total power limit at some point. In that case someone will be disappointed.

If the system power limit is only a target and not a hard limit, ETEMS will still be effective at minimizing the peaks. If the limit is a hard limit, then vehicles will be disappointed and the system needs to work to minimize customer disappointment. In other cases the limit has economic consequences and the disappointment must include metrics for the vehicles and the facility. A key problem for any optimization algorithm is defining a metric that can be minimized. This is not always obvious.

The example in Table 3 shows four vehicles charging for exactly one hour. Three vehicles want 2 kWh of energy and one vehicle wants 6 kWh. The system has only 6 kW of power to allocate to these four vehicles during that hour. Four strategies are shown: allocate power to those vehicles with the lowest requirements first; allocate power to those vehicles with the highest power first; allocate a power proportional to the ratio of available and required power; and allocate an equal share to each vehicle. These are not necessarily actual or viable strategies but do illustrate the issues associated with disappointment metrics.

Table 3 illustrates the how metrics can drive power allocation strategy.

What is Disappointment?					
Vehicle Number	Energy Request	Strategy			
		Lower	Higher	Ratio	Equal
V1	2.0	2.0	0.0	1.0	1.5
V2	2.0	2.0	0.0	1.0	1.5
V3	2.0	2.0	0.0	1.0	1.5
V4	6.0	0.0	6.0	3.0	1.5
Total	12.0	6.0	6.0	6.0	6.0
		Metrics			
PEVs with Miss		25%	75%	100%	100%
Greatest PEV Miss		6 kWh	2 kWh	3 kWh	4.5 kWh
Greatest PEV %Miss		100%	100%	50%	75%
Average Miss		6.0	2.0	1.5	1.5
RMS Miss		6.0	1.2	0.9	1.2

You can get different answers depending on what is measured. The Lower strategy is best if you try to minimize the number of vehicles that have any miss. The Higher strategy is best if the objective is to minimize the largest miss to any PEV. The Ratio strategy is best for minimizing the greatest percent miss to any vehicle and well as the RMS miss. Both the Ratio and Equal strategies are best for minimizing the average miss. You get what you measure.

The above example was only concerned with the absolute or relative miss in energy transfer, but there are other factors that impact customer disappointment. Disappointment is based on human perception and behavior. How long the vehicle was parked and how much power it demanded of the total system will also impact disappointment. Figure 18 illustrates how these other factors can influence disappointment.

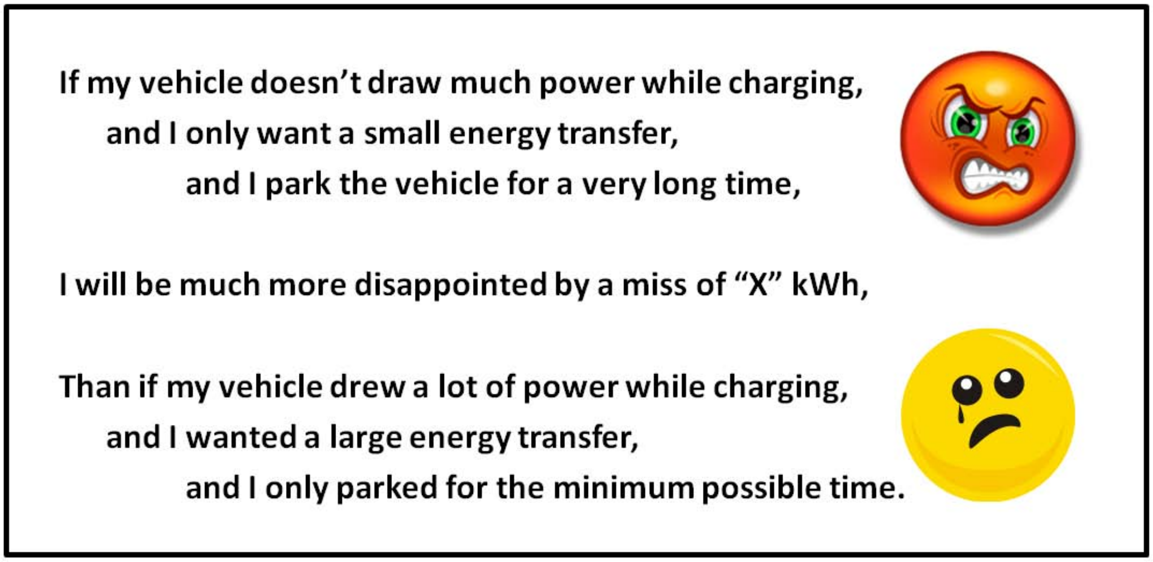

Figure 18 illustrates that disappointment is not also just a simple measurement.

Some Basic Strategies for Power Allocation

Some basic strategies that an ETEMS can use to allocate power are shown in Figure 19. An unconstrained PEV would normally charge at the maximum power level of its on-board charger until the target state of charge of the battery was reached. This is a **Start Max Strategy** and should be a normal default approach used by an ETEMS. This is the lowest risk strategy for not disappointing a PEV customer. The only way to be "disappointed" is if the owner disconnects before charging is complete, and this shortfall would not be counted as an energy transfer miss by the ETEMS because it is an impossible situation. The ETEMS can only measure success by comparing the measureable energy transfer made against the initially requested energy transfer. It is all about the energy transfer requested at connection and actual energy delivered, by disconnect and not the final state of charge of the vehicle battery.

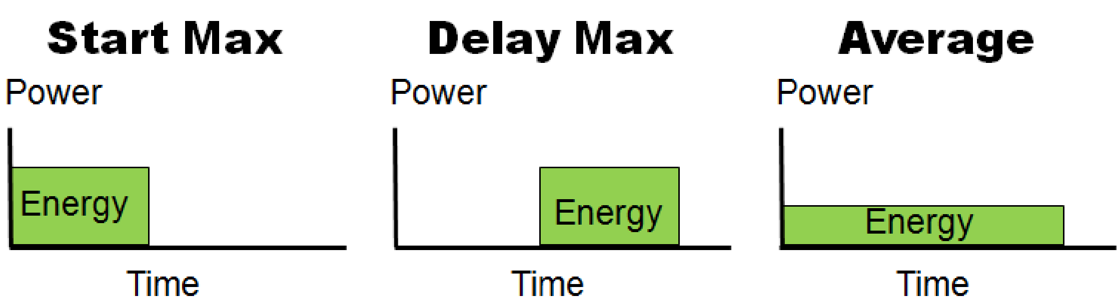

Figure 19 shows basic power allocation strategies.

If the energy management system for the parking site knew that the PEV only needed 50% of the available time, it could hold off and schedule the vehicle to start later at its maximum power. This is a **Delay Max Strategy**. It may not be desired to push this start time to the limit to allow for a potential earlier than planned disconnect. The Delay Max Strategy could be useful if a vehicle arrived during a peak and was planning to depart long enough after the peak to delay the start.

Another alternative would be to compute an average power and authorize the vehicle to charge at the lower level – an **Average Power Strategy**. Again, it might be better to use 110% of the average or average over a shorter interval to allow some margin for an earlier than planned departure.

An ETEMS could combine these three simple strategies during the entire day to avoid a peak and yet satisfy all of the vehicles. It needs to consider all of the individual infrastructure constraints as well as the total facility power demand.

The consequences of unconstrained charging

Figure 20 shows what would happen if each vehicle just plugged in and drew whatever power it wanted. Six vehicles are charging during a four hour interval. They all have on-board chargers that draw 4 kW. The black bar shows the duration of each session. In this example the estimated and actual duration are the same. The next row for each vehicle shows the allocated power, and the third row shows the remaining required energy transfer. The facility is trying to maintain a target total demand of not more than 8 kW.

Vehicles V1, V2, and V3 all start charging at the beginning of the session and draw 12 kW, exceeding the target limit by 50%. After 30 minutes, V4 arrives and the site power rises to 16 kW, 100% over the target. When V5 arrives after 60 minutes the total power rises to 20 kW, 150% over the limit. After 90 minutes the total vehicle demand falls at or below the 8 kW level for the balance of the scenario. No power is used during the last 60 minutes. It is clearly inefficient to let the vehicles charge without any oversight.

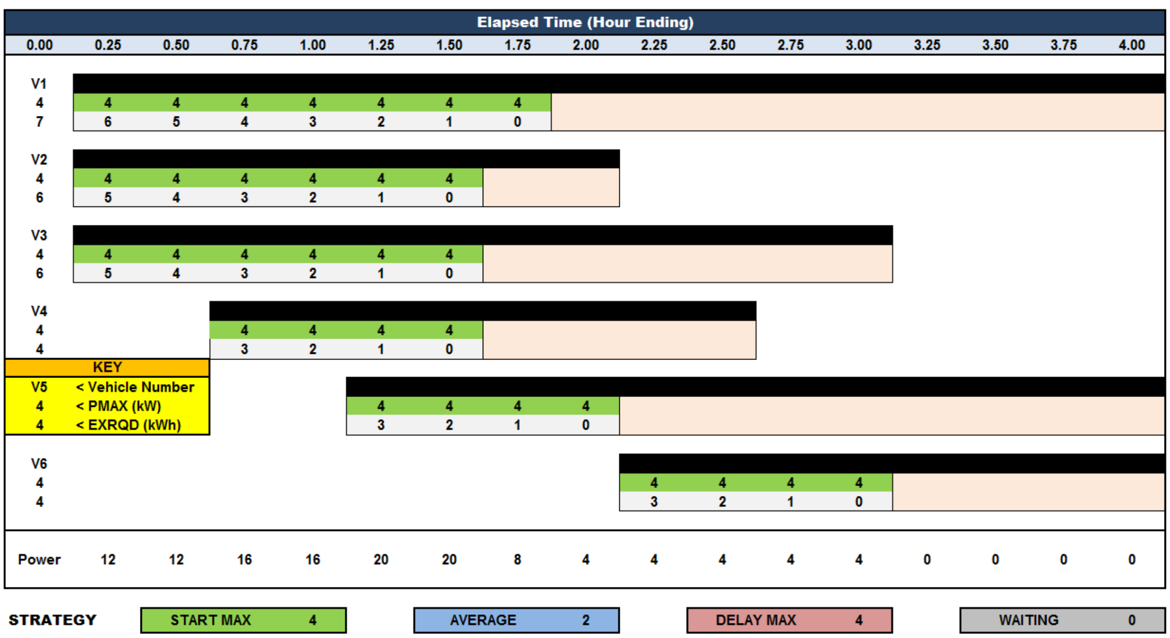

Figure 20 shows the consequences of allowing each vehicle to charge with no allocation constraints.

A simple example of power management

This next sequence shows how an ETEMS could use some basic strategies to improve on the site total power management. The system does not know when vehicles will be arriving. It seeks to maintain the limit and move the riskiest jobs forward when it can. This is a simple example of how power can be allocated to stay within limits.

At the start shown in Figure 21, V1, V2, and V3 plug in to charge. Because V1 has four hours to take on 7 kWh, it is set up with a Delay Max Strategy and will be allowed to start charging two hours into the session. It is hedging and not using the last 15 minutes of the estimated duration. This will help if the driver returns a bit early. V2 and V3 begin with a Start Max Strategy. This plan holds the power to 8 kW or less for the day, as it is known to the ETEMS.

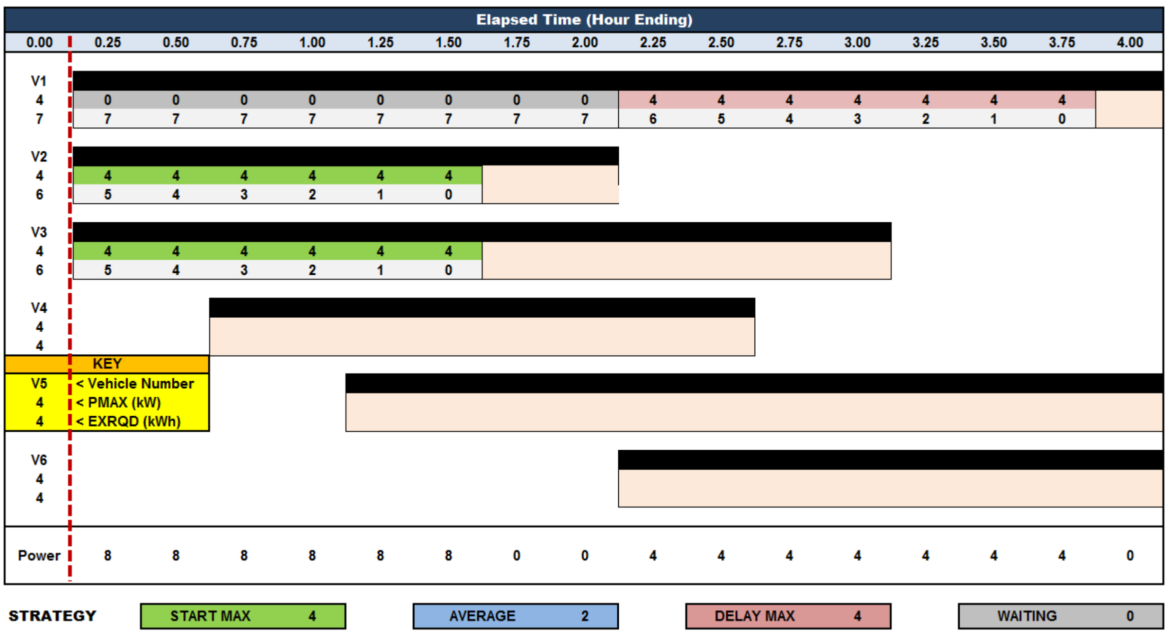

Figure 21 shows V1, V2, and V3 arriving at the start of the session.

After 30 minutes, V4 arrives and this forces a change in strategy. This is shown in Figure 22. V1 continues with the Delay Max Strategy. V2 and V3 switch to an Average Strategy. V4 starts with an Average Strategy. This starts with an average of the remaining power over the remaining intervals, less the last interval. These are then adjusted up or down to take the power to the limit with priority to the lower stress vehicles. Total power is maintained at or below 8 kW. The power should never be allowed to go below the limit if any of the vehicles are below their rated power (PMAX).

When V5 arrives at 60 minutes, it is set to a Delay Max Strategy. This is shown in Figure 23. Because V2 is finishing, additional power is allocated to V3 and V4 after 90 minutes. Power is held at 8 kW across the known vehicle demand.

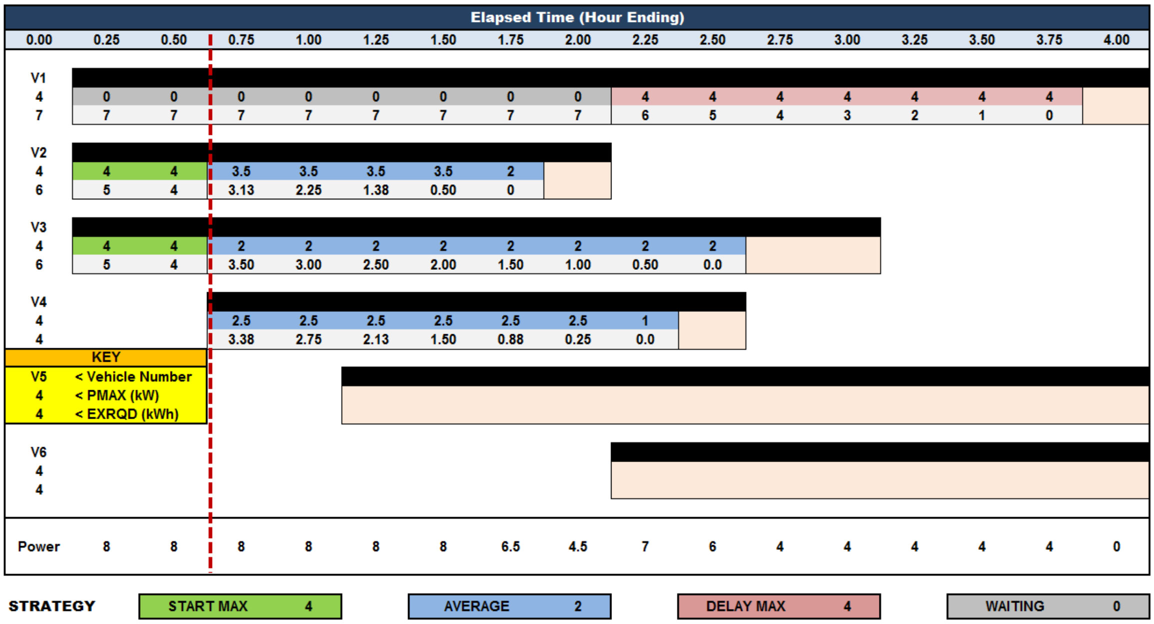

Figure 22 shows V4 arriving after 30 minutes.

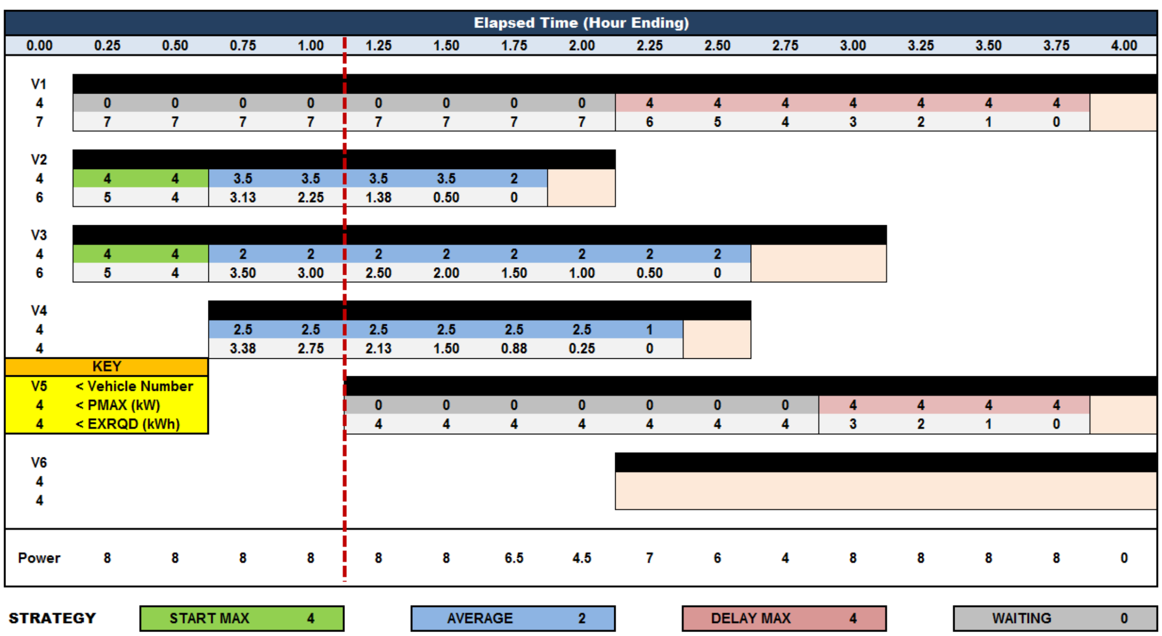

Figure 23 shows V5 arriving after 60 minutes.

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After 90 minutes, the EMS makes adjustments in the 30 minute look ahead. It switches V1 to an Average Strategy. This reduces risk to V1 by starting early and brings the power demand up to 8 kW. This is shown in Figure 24.

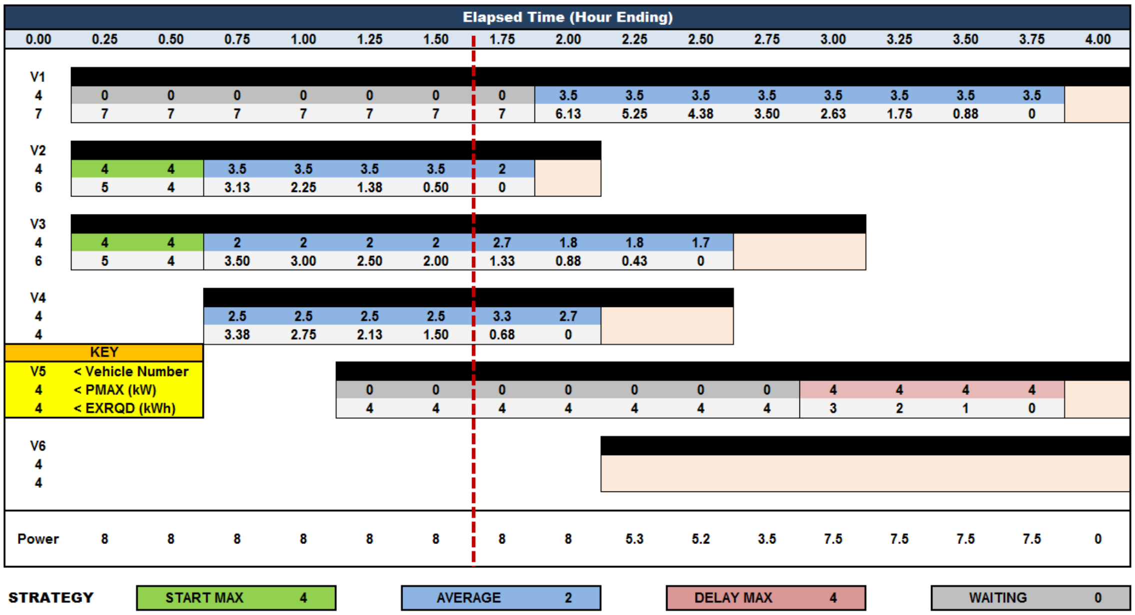

Figure 24 shows power rescheduling after 90 minutes.

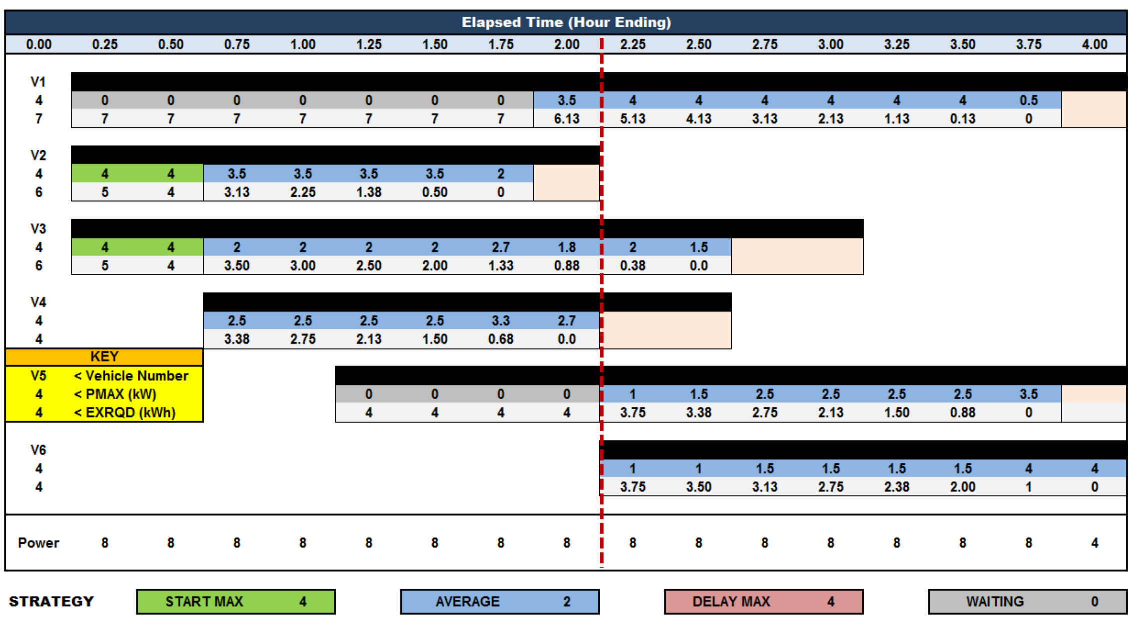

Figure 25 shows V6 arriving after two hours and the final sequencing.

V6 arrives after two hours and sets up the final sequence as shown in Figure 26. V5 switches from Delay Max Strategy to Average Strategy. V1 is set to 4 kW to minimize risk because it was held off the longest. V3 is next in priority and gets a bump over the last schedule. V5 has a slight priority over V6 because of the delayed start. When V3 completes at 2.5 hours, the 4 kW of available power after V1 is allotted 4 kW is shared between V5 and V6 with a slight priority to V5. The power is held at 8 kW for the entire session and drops to 4 kW during the final 15 minutes.

Six vehicles arrive and depart over the four hour session. The vehicles required a total energy transfer of 31 kWh. The total available power allocation during any of the 15 minute segments was 8 kW, which would transfer 32 kWh of energy if perfectly allocated. In this scenario 97% of the available energy was transferred, the system operated at full capacity 94% of the time, and all of the vehicle energy transfer requirements were achieved.

In comparison to the earlier unconstrained example, this example shows the value of the EMS managing the power allocation to protect the facility power demand, but it does increases the risk of a miss. This comparison was illustrated in the chart in Figure 17. This was a difficult problem to solve, but not impossible. The art comes in dealing with the impossible situations.

Making the best with impossible scenarios

If a firm facility power limit is imposed, some vehicles will not get all of the requested energy transfer and the objective is to minimize disappointment. This is shown by the example in Figure 26. In this scenario the energy request for V1 has been increased from 7 kWh to 10 kWh and for V6 it has been raised from 4 kWh to 6 kWh. This raises the total energy requested from 31 kWh to 36 kWh. At a maximum power of 8 kW only 32 kWh can be transferred and the vehicles will miss by 4 kWh. V1 misses by 2 kWh (20%), V4 misses by 0.5 kWh (12.5%), and V6 misses by 1.5 kWh (25%). The ETEMS is allocating the miss based on the relative stress the vehicles place on the system. It is not until after V6 arrives, after two hours, that any miss can be forecast by the ETEMS, V2 is complete, and V3, and V4 are allowed to complete their energy transfers.

Elapsed Time (Hour Ending)																
0.00	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00
V1																
4	0	0	0	0	0	2	3	4	4	4	4	3	2.5	2.5	2	1
10	10	10	10	10	10	9.5	8.75	7.75	6.75	5.75	4.75	4.00	3.38	2.75	2.25	2.00
V2																
4	4	4	3.5	3.5	3.5	2	2	1.5								
6	5	4	3.13	2.25	1.38	0.88	0.38	0.00								
V3																
4	4	4	2	2	2	2	1	1	2	1.5	1.5	1				
6	5	4	3.50	3.00	2.50	2.00	1.75	1.50	1.00	0.63	0.25	0.00				
V4																
4			2.5	2.5	2.5	2	2	1.5	2	1						
4			3.38	2.75	2.13	1.63	1.13	0.75	0.25	0.00						
KEY																
V5	< Vehicle Number															
4	< PMAX (kW)				0	0	0	0	0	0	0	0	3.5	3.5	3.5	3.5
4	< EXRQD (kWh)				4	4	4	4	4.00	4.00	4.00	4.00	3.13	2.25	1.38	0.50
V6																
4									0	1.5	2.5	4	2	2	2.5	3.5
6									6.00	5.63	5.00	4.00	3.50	3.00	2.375	1.5
Power	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8

STRATEGY	START MAX	4	AVERAGE	2	DELAY MAX	4	WAITING	0

Figure 26 shows a scenario with a firm power limit.

If the facility limit is a target and not a hard limit the objective would be to minimize the highest 15 minute peak. This example is shown in Figure 27. This is the same scenario as before. ETEMS is able to allocate power and meet all constraints until V6 arrives after two hours. It is only at that time that ETEMS has 20 kWh of energy to allocate over two hours to the remaining five vehicles. The best that it can do is to keep the 15 minute peak at or below 10 kW and it is able to accomplish this objective. Again, it is not possible to hold a limit of 9 kW over the four hours because it doesn't recognize a problem until after V6 arrives. A smarter ETEMS might have anticipated at least one vehicle arriving after V2 and V4 departed and used it for planning. This would have resulted in an earlier step up and maybe the ETEMS could have held the peak at 9.5 kW rather than 10 kW.

Elapsed Time (Hour Ending)

0.00	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00
V1																
4	0	0	0	0	0	4	3	3	4	4	4	4	4	4	4	2
10	10	10	10	10	10	9	8.25	7.50	6.50	5.50	4.50	3.50	2.50	1.50	0.50	0.00
V2																
4	4	4	4	4	4	2	2	0								
6	5	4	3.00	2.00	1.00	0.50	0.00	0.00								
V3																
4	4	4	4	4	2	0	0	1	0	3	2	0				
6	5	4	3.00	2.00	1.50	1.50	1.50	1.25	1.25	0.50	0.00	0.00				
V4																
4			0	0	2	2	3	4	4	1						
4			4.00	4.00	3.50	3.00	2.25	1.25	0.25	0.00						
KEY																
V5 < Vehicle Number																
4 < PMAX (kW)					0	0	0	0	0	0	0	2	2	4	4	4
4 < EXRQD (kWh)					4	4	4	4	4.00	4.00	4.00	3.50	3.00	2.00	1.00	0.00
V6																
4									2	2	4	4	4	2	2	4
6									5.50	5.00	4.00	3.00	2.00	1.50	1	0
Power	8	8	8	8	8	8	8	8	10	10	10	10	10	10	10	10

STRATEGY	START MAX	4	AVERAGE	2	DELAY MAX	4	WAITING	0

Figure 27 shows a scenario with a soft power limit.

Chapter Summary

If each PEV is allowed to arrive at public facility, plug-in, and start charging at the rated power of its on-board charger until it is done, this will create a problem for any facility that cannot allow unrestricted power. For any facility that must maintain the total power demanded by a group of vehicles below an infrastructure or economic limit, active management will be required. An Electric Transportation Energy Management Systems (ETEMS) using intelligent Power and Energy Management (iPEM) algorithms is needed to allocate power to protect infrastructure limits and also minimize customer disappointment. This chapter demonstrated the concept of iPEM.

While the development and demonstration of actual iPEM algorithms was beyond the scope of this project, some simple algorithms and disappointment measures were developed and used in a simulation of ETESS. The simulation design will be discussed later.

5 *The ETESS Concept*

ETESS (the Electric Transportation Energy Storage System) integrates control logic for intelligently allocating power among group of charging PEVs with a small, grid-connected, electricity storage system. ETESS can serve the electric transportation community by intelligently allocating stored energy and managing vehicle charging to minimize customer disappointment. ETESS can also serve the electric power grid as a Distributed Energy Storage System.

Energy Storage to the Rescue

The Electric Transportation Energy Management System (ETEMS), using intelligent Power and Energy Management (iPEM) logic, might prioritize meeting facility power limits at the expense of individual PEV customer disappointment. This was shown by example in Figure 26 in the previous chapter. Still, if an energy storage system could be integrated with ETEMS, it may be possible to hold the facility limits and not disappoint the PEV customers.

Figure 28 shows how energy storage can be integrated with an ETEMS panel. This is the Electric Transportation Energy Storage System (ETESS). The ETESS unit will be significantly larger than a simple ETEMS panel. The ETESS system can perform everything that the ETEMS system could perform, but it adds new capability with the energy storage. Energy storage can be used to help minimize PEV customer disappointment. The iPEM algorithms have a new capability for allocating power while protecting a facility limit.

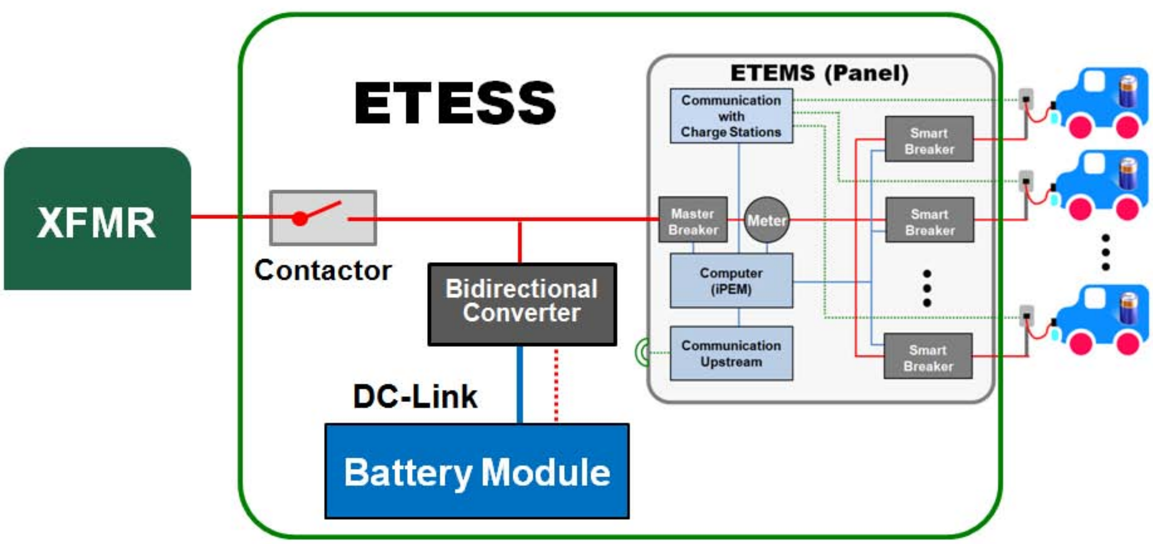

Figure 28 integrates an energy storage system with ETEMS to create ETESS.

There are many ways to set up this improved logic. The system could start with the soft power limit approach from Figure 27 and just added 2kW of power for the last two hours to hold the grid draw at 8kW. This is a reactive approach where iPEM works to minimize the total vehicle power during any 15 minute interval and then ETESS supplements the grid.

In the example in Figure 29, the stored energy is applied earlier. This reduces risk associated with potential vehicle arrivals after V6. In the example the system is trying to maintain the total power draw below 10kW and hold the grid at 8kW. The system draws 8kW during the last 15 minutes to partially recharge. This recharge might not be possible if other vehicles arrived after V6 and it could be delayed or done at a reduced rate over a longer period. For this type of proactive strategy the control logic must be well integrated with the iPEM algorithms.

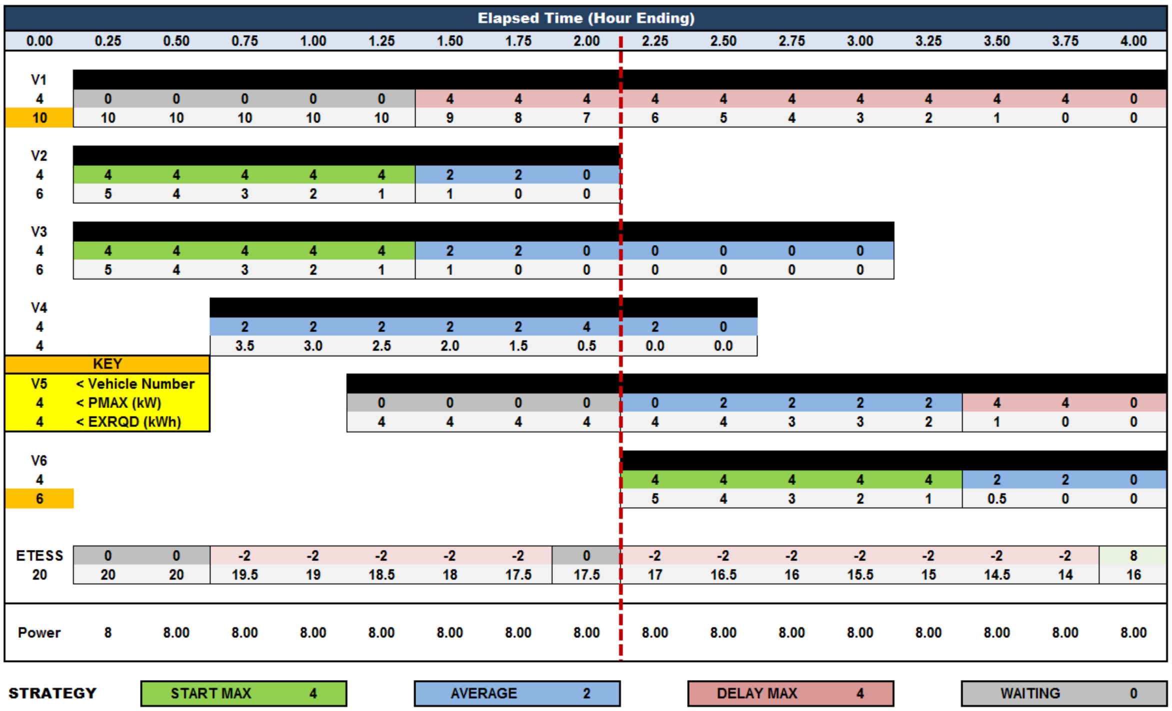

Figure 29 shows how energy storage can help with facility power limits.

Commercial facilities pay a monthly demand charge based on the highest 15 or 30 minute average power demand (kW) during the month. The specific averaging interval varies by utility. The iPEM software in ETEMS can do this without calling on stored energy, but the use of stored energy might allow working to a lower monthly peak. The availability of ETEMS at a charging facility could allow the facility to work with a demand aggregator to offer demand response or demand dispatch to the grid. This capability could also be improved by using ETESS. These and other business issues associated with ETESS will be discussed in much more detail in the next chapter.

A Convenient Place for Grid Storage

In Chapter 2 we discussed the benefits of grid connected energy storage and in particular a new concept for grid energy storage called Community Energy Storage (CES) by AEP and Distributed Energy Storage System (DESS) by EPRI. The AEP CES unit is an energy storage system with a 25kW four quadrant inverter and one to three hours of storage. It operates on a single phase of 240VAC power. The AEP CES is planned to be deployed in residential neighborhoods collocated with the distribution transformers. EPRI established requirements for a family of DESS units have power ratings from 25kW to 200kW with between two and four hours of usable storage; single phase units range from 25kW to 75kW and three phase units range up to 200kW. The single phase 25kW to 50kW units would be located in residential areas and the 75kW to 200kW units would be located at commercial and industrial locations. The AEP CES fits within the DESS family. In this report we use the term CES for the residential units and the term DESS for the commercial units.

Figure 30 shows the major elements of a DESS unit and an ETESS unit. The changes for ETESS are shown in red. The primary change is the addition of intelligent Power and Energy Management (iPEM) logic to the control system. While the EVSE and HAN communication links are shown as different, these links will be different across DESS and ETESS locations, so both units need flexibility. For the purpose of grid-connected storage ETESS and DESS are functionally identical.

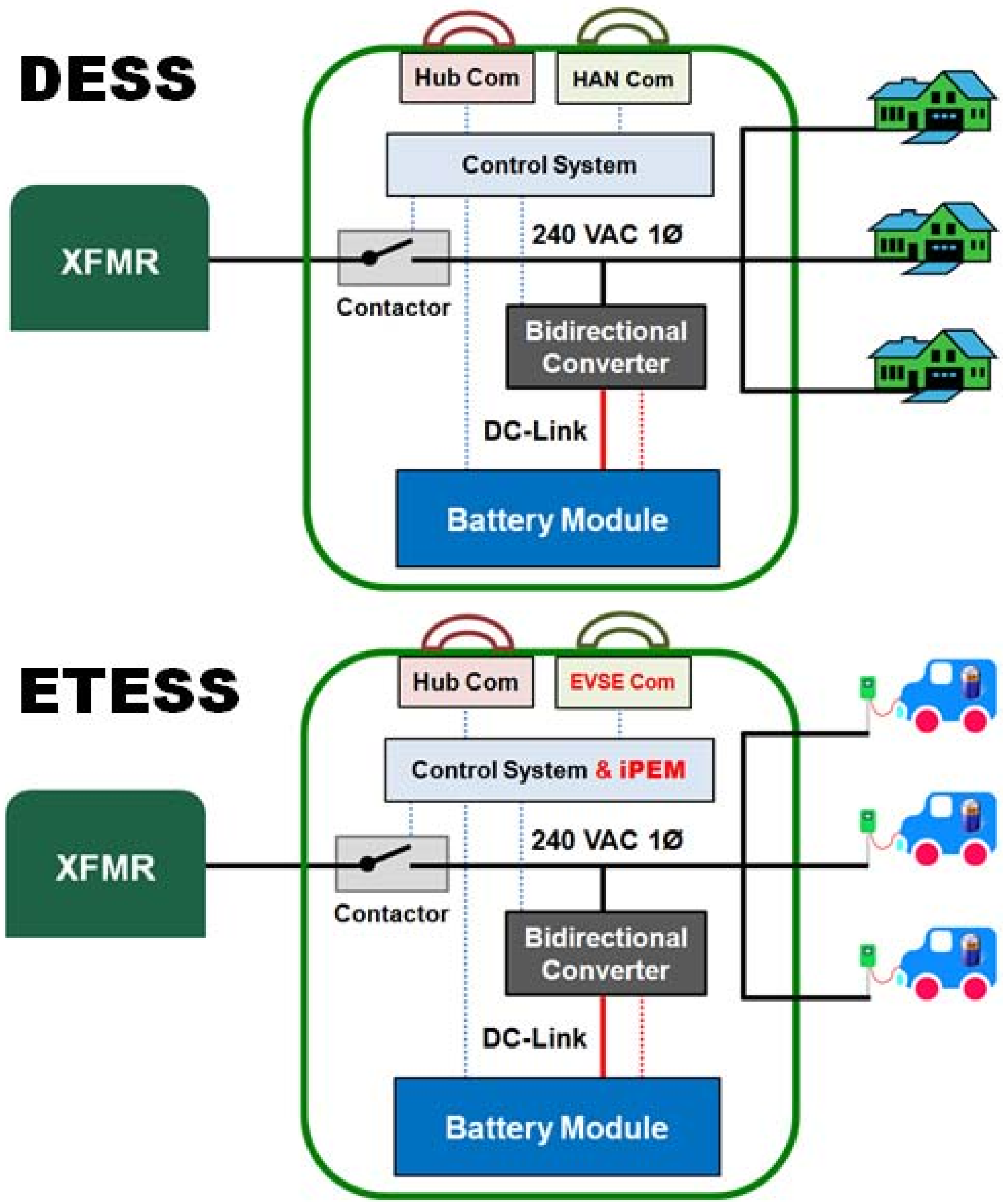

Figure 30 shows how ETESS is derived from DESS.

ETESS will be used at commercial and industrial locations where electric vehicles will be charging. It is just a DESS with additional software and could be sized for the 75kW to 200kW DESS range. If it makes business sense for a utility to place DESS units near commercial and industrial facilities, the utility could decide to place ETESS units there instead of the pure DESS unit if these same facilities planned to install PEV charging stations. ETESS may be a way for a utility to justify placing DESS units.

ETESS is a DESS and can be aggregated and controlled as a fleet just as was described in Chapter 2. Figure 31 shows CES, DES, and. ETESS all supporting the grid. The utility can manage the ETESS units to help with peak loads on the distribution feeder. Everything that DESS can do for a utility, ETESS can also do.

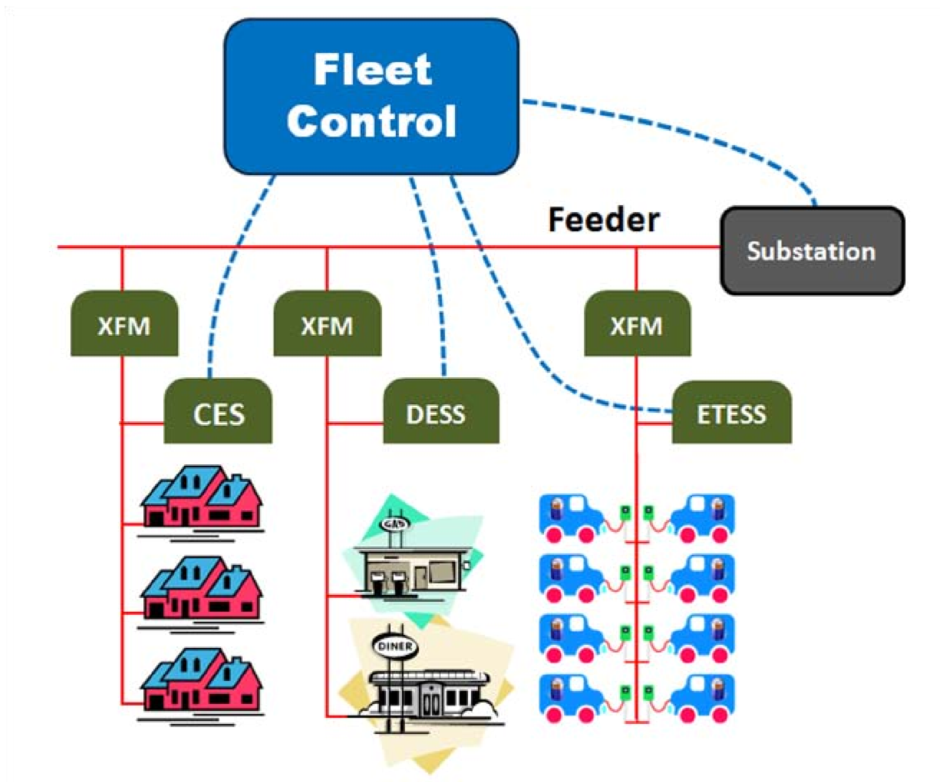

Figure 31 shows CES, DESS, and ETESS serving the grid.

ETESS Architecture

The Baseline ETESS is defined as a 75kW unit with three hours of usable storage. It operates on a single phase of 240VAC power. It must conform to the EPRI DESS functional requirements. Each ETESS unit can connect to up to 18 charge stations.

An optional 150kW three phase ETESS with three hours of storage is also proposed. The most common three phase transformers produce 480VAC which is not usable for PEV charging; although 240VAC three phase transformers are available to support this ETESS configuration. This ETESS could support a larger group of PEVs with up to 12 charge stations on each phase for a total of 36 PEVs.

The energy storage can only source or absorb real and reactive power equally for each phase through the converter. Nevertheless, the iPEM logic in the three phase unit is capable of balancing the real power demand on each phase. A single three phase unit may be more cost effective than using two single phase units, but it is less flexible than using the single phase units with the ability to perform voltage support on each phase. These two units are shown in Figure 32.

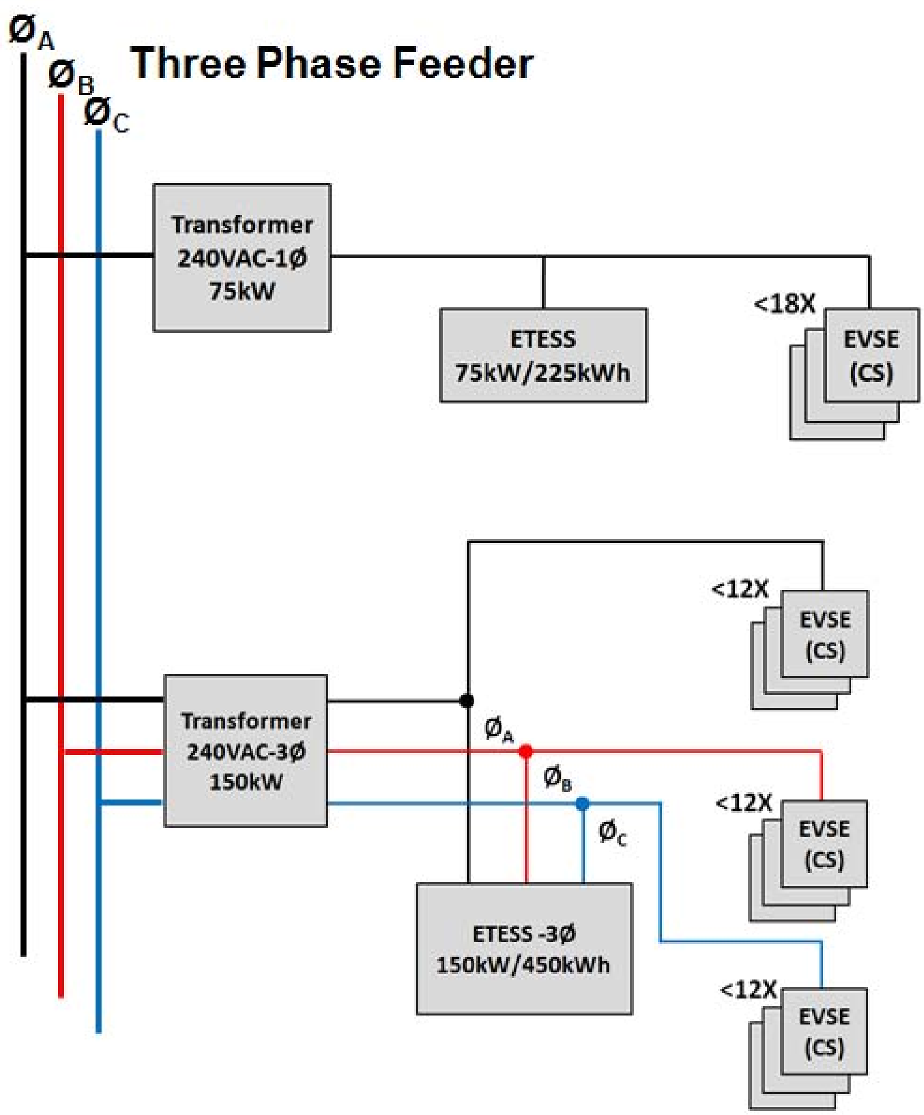

Figure 32 shows two ETESS configurations.

If the primary purpose for installing ETESS at a commercial location is to directly serve as a DESS, it makes sense to deploy the larger 75K-1Ø or 150K-3Ø units. This would be lower cost than deploying a larger quantity of smaller 25kW-1Ø CES-like units. Still, a smaller 25kW-1Ø ETESS unit might be appropriate for use behind the meter for facility peak load management, where much of the value comes from the iPEM algorithms managing the vehicle loads. The relationship of the ETESS power rating to the number of vehicles charging will be discussed next.

ETESS Power Rating and Charge Stations Served

One way to establish the power rating for the ETESS unit is to determine the number of charge stations that can be supported during islanding after a power failure or during a demand response curtailment event. Figure 33 shows the relationship of the ETESS power rating to the number of charge stations that can be supported without grid power. The left y-axis shows the number of active charge stations that can be supported. The x-axis shows the average power for all charge stations as a percent of the charge station maximum rating. The right y-axis is used with the dotted green line and shows the actual power in kW that corresponds to the percent of charge station maximum rating (100% = 7.7kW).

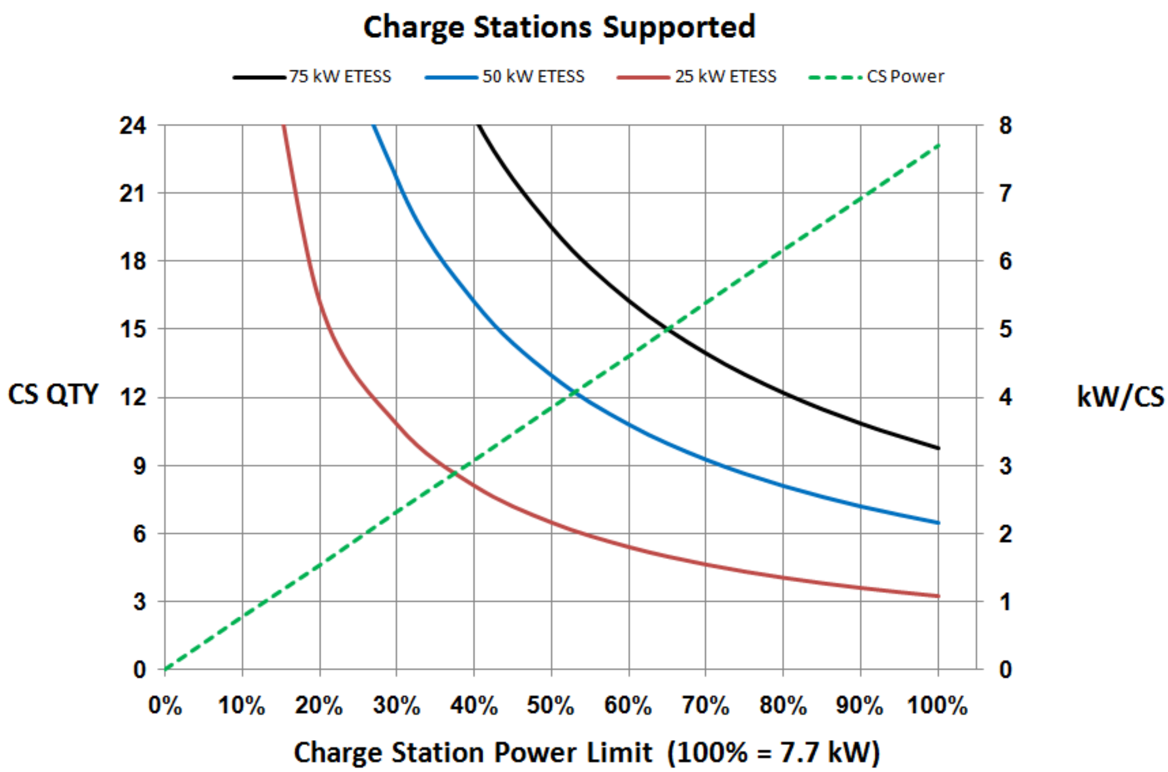

Figure 33 shows how charge station quantity is impacted by ETESS configuration.

It is assumed that most park and charge locations will use AC Level 2 charge stations limited to 32A (7.7kW). If it is required to be able to provide 7.7 kW to each vehicle, a 25 kW ETESS could support three charge stations, a 50 kW unit could support six charge stations, and a 75 kW unit could support nine charge stations. At a 50% level a 25 kW ETESS could support six charge stations, a 50 kW unit could support thirteen charge stations, and a 75 kW unit could support nineteen. A 25 kW ETESS unit could support eighteen charge stations at an average power consumption of 1.4 kW (AC Level 1).

The baseline ETESS power rating of 75kW is based on having 50% of the maximum power of 7.7kW available for 18 charge stations during islanded operation. This is for an ETESS that will be used primarily for providing ancillary services to the grid. The objective would be to reserve 25kW for use within the facility to be used by iPEM algorithms to manage vehicle load. This leaves 50kW free to provide grid ancillary services. A smaller 25kW ETESS unit could be used for those applications that only manage behind the meter facility loads.

Chapter Summary

ETESS, the Electric Transportation Energy Storage System, combines algorithms for managing the charging of a group of electric vehicles (iPEM) with a small grid-connected electricity storage system (DESS). You can start with a DESS unit and add iPEM software to make an ETESS. You can also think of it conceptually as starting with a distribution panel that includes an iPEM processor (ETEMS) and then add electricity storage. The availability of stored energy gives new possibilities for the iPEM software for minimizing PEV customer disappointment while maintaining facility power limits.

ETESS is technically feasible. It is a relatively simple system concept. There will certainly be many technical issues to overcome in the detailed design, implementation, testing, and deployment of ETESS. This is true of any new product development project, but it can be done.

The key question is whether ETESS can ever be economically viable. It comes down to the value that ETESS can deliver to the owner as measured by revenue or cost avoidance and the life cycle cost of the unit. It is all about the return on investment. Even some “technical” issues, such as battery life, in the end are really just business issues, a question of acquisition cost and maintenance cost. The business issues will be discussed in the next chapter.

6 *Business Issues*

The Electric Transportation Energy Storage System (ETESS) is a grid-connected electricity storage system. It is just a Distributed Energy Storage System (DESS) with some additional software for controlling plug-in electric vehicle (PEV) loads. Still, there are underlying business issues with grid storage, and with DESS in particular, that directly impact the business model for ETESS. ETESS is also part of the public charging infrastructure for PEVs, and there are many business issues associated with public charging that could also impact the viability of ETESS. This chapter will discuss some of the business issues associated with both energy storage and PEV charging and how they relate to ETESS.

The Business of ETESS

ETESS combines two capabilities in a single unit. One purpose of ETESS is to directly use its energy storage capacity to provide services to the grid. It is a grid-connected energy storage system and can perform all of the functions of a DESS unit. ETESS can serve this need even if no charge stations are connected to it. ETESS units could be placed at commercial business locations that only plan to install one or two charge stations in the beginning, but have plans to add more in the future as the need grows. The ability to serve the grid as a DESS is there immediately and power management for the site can be called on later in the life of the unit.

The other purpose of ETESS is to intelligently manage the total power demanded by a group of connected PEVs. The objective is to control the aggregate power demanded by the group of vehicles in order to meet total facility power demand constraints and economic commitments while also minimizing any disappointment to the vehicle drivers for missed energy transfer. It performs this purpose primarily with its intelligent Power and Energy Management (iPEM) software, but it can also draw upon its stored energy to help satisfy this objective.

These two purposes have synergy. If a utility needs to reduce the load on a feeder, an ETESS unit can be called upon to provide this service. ETESS can do this by either directly providing power to the grid or by reducing the power demanded by the vehicles. If the facility itself needs to keep its total power demand from the grid below a target, ETESS to either reduce vehicle loads or directly provide power to compensate for the vehicle loads.

While the technical capability to perform these functions in the future is relatively clear, the business models are much more complex. Should ETESS be a utility asset or a facility asset? If it is a facility asset, can it provide voltage support and other ancillary services directly to the grid? If it is a utility asset, what are the business implications of managing the PEV loads within the parking facility? Can a distribution utility even operate a storage unit or does it need to belong to an independent power producer? The answers to these questions today could be very different based on the degree of restructuring of the electric power industry in each state. Current regulations and business models for storage systems may need to change to take advantage of new technologies in the smart grid.

A PEV driver receives value from a charge station by connecting the PEV to it and transferring the desired energy to the vehicle battery. The least risk for a PEV driver is for the transfer to start immediately after connecting and to happen at the full rating of the on-board charger. ETESS increases the risk of disappointment in comparison to unconstrained charging. The business case for the basic charge station infrastructure must be a direct result of the charging services provided to each vehicle. Still, the ETESS value must come from the other direction, from the grid. There may be some opportunity to recover some of the cost of ETESS from the provision of charging services, but this will be limited by the overall affordability of public charging.

ETESS is intended to be deployed at "park and charge" locations served by AC Level 2 charge stations. There is no value in trying to manage individual PEV demand for high power DC charging. You do not plug in at 50kW charger and expect to wait an hour for a 20 minute charge to start. For these chargers it is essential that the transfer always starts immediately and at full power. This is bad for ETESS. This type of "charge and go" facility may need an energy storage system to help level the facility demand on the grid, but it is not this type of ETESS –it is an ETESS-DC and a topic beyond this report. The key issue for ETESS is what type of charging infrastructure is likely to predominate in the long term –or will both coexist for public charging.

Benefits and Market Potential of Energy Storage

The U.S. Department of Energy (DOE), operating through its Office of Electricity Delivery and Energy Reliability, has been a champion of advanced energy storage technology for many years. Over the past decade Sandia National Laboratories (SNL), in support of the Office of Electricity, has commissioned many activities to define the benefits and market potential for electricity storage.

A SNL report released in February 2010 titled "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide" is an outstanding source of information on the business of electricity storage.(Eyer and Corey 2010) This study was conducted by Mr. Jim Eyer of Distributed Utility Associates (DUA) and Mr. Garth Corey of KTech. It builds on work performed in 2004 by Mr. Eyer, Mr. Joseph Iannucci (also from DUA), and Mr. Corey (then with DOE SNL) titled "Energy Storage Benefits and Market Analysis Handbook."(Eyer, Iannucci and Corey 2004)

Ms. Susan Schoenung of Longitude 122 West has also worked with SNL in this area working both independently and in association with DUA. One such report released in 2008 by Schoenung and Eyer is titled "Benefit/Cost Framework for Evaluating Modular Energy Storage."(Schoenung and Eyer 2008) One of the earliest joint reports was by Ms. Schoenung and Mr. Iannucci from 2000 titled "Energy Storage Concepts for a Restructured Electric Utility Industry." (Iannucci and Schoenung 2000)

Mr. Eyer, working with Mr. Ruben Brown of the E Cubed Company, performed a similar investigation for NYSERDA. This 2007 report is titled "Guide to Estimating Benefits and Market Potential for Electricity Storage in New York (with Emphasis on New York City)." (Eyer, Brown and Norris 2007)

This body of work serves as an excellent resource for anyone that is interested in the benefits and economics of electricity storage. The February 2010 guide was used extensively during this project. This guide provides a comprehensive review of 17 applications for electric energy storage. These 17 applications are aggregated into five categories: Electricity Supply, Ancillary Services, Grid System, End User, and Renewables Integration. The applications and categories are not mutually exclusive and a storage unit may be able to serve multiple purposes, and some even at the same time. The report is technology neutral, but applications may favor a certain technology and scale of storage. ETESS is most suited for the two categories of Ancillary Services and End User. It might also have some value for Transmission and Distribution Upgrade Deferral, which is part of the Grid System category.

The Ancillary Services category includes Load Following, Voltage Support, Area Regulation, and Electric Supply Reserve Capacity. Load following is not traditionally thought of as an ancillary service and usually part of the real time energy market. These are the same functional capabilities that are specified by EPRI for a DESS unit: peak load management, voltage regulation/reactive power support, frequency regulation, and capacity market. The terms are slightly different but the intended purpose is similar.   ETESS is a DESS and needs to be able to engage in these applications.

The End Use category includes Time-of-use (TOU) Energy Cost Management, Demand Charge Management, Electricity Service Reliability, and Electric Service Power Quality applications. The focus of the guide is primarily measured by the savings that accrue through time shifting power and energy against the utility demand and energy rate structures. The SNL guide does not include benefits for demand management or demand response. Still, if an aggregated ETESS fleet is providing load following to the system operator it cannot offer demand management to the system operator at the same time.

It is difficult to make a business case for any battery storage systems today because of the high cost of the batteries and the fragmentation of the benefits. A system must participate in multiple revenue streams to be viable. This approach will be followed with ETESS.

There could be some benefit that accrues by just using ETESS to avoid peak power spikes at a facility, but this is not likely to be enough to justify the storage unit. Much of this can be accomplished by using iPEM software alone in an ETEMS panel without drawing on the storage capacity of an ETESS unit. The PEV disappointment level might be higher, but the facility demand could be clamped. TOU energy charges could just be passed on to the PEVs – this may be much more cost effective than using energy storage to shift the costs. PEV drivers that charge at off-peak times may not see value paying a price premium to pay for equipment that only benefits those drivers that charge during the peaks.

Most, if not all, of the ETESS value must come from being paid to directly serve the distribution feeder to which it is connected. ETESS exists to serve the grid. Part of this capability to serve the grid comes from its ability to manage the charging loads of the connected vehicles. Without the vehicles it is a DESS, not an ETESS - a valuable grid asset, but not an ETESS.

Some Business Models for AC Level 2 Public Charging

ETESS can be viewed as adistributed energy storage system capable of serving the grid. This raises questions whether the units can or should be owned and operated by a distribution utility, an independent power producer, or a commercial customer of the utility. Electricity Storage can be deployed on either side of the meter, but the opportunities to generate income or avoid costs can be very different. Also, electricity storage deployed on the utility side of the meter can have different business models, depending on the degree of restructuring of the electric power industry in the state**.**

ETESS can also be viewed as an energy management system for a facility. The use of ETESS behind the meter to manage facility demand is clear. Still if ETESS is deployed on the utility side of the meter, its use for demand management within a customer facility becomes more problematic.

Five basic business models will be discussed. They are the Uncontrolled Charging Model, the Centrally Controlled Charging Model, the ETEMS (Electric Transportation Energy Management System) Model, the Facility ETESS Model, and the Utility ETESS Model.

The Uncontrolled Charging Model is shown in Figure 34. This model assumes that there will be no communication with the PEV beyond the charge station. The PEV will draw whatever power it requires up to the level authorized by the charge station (EVSE) control pilot. This is not a useful business model, but it represents what can happen without any active management of a parking location.

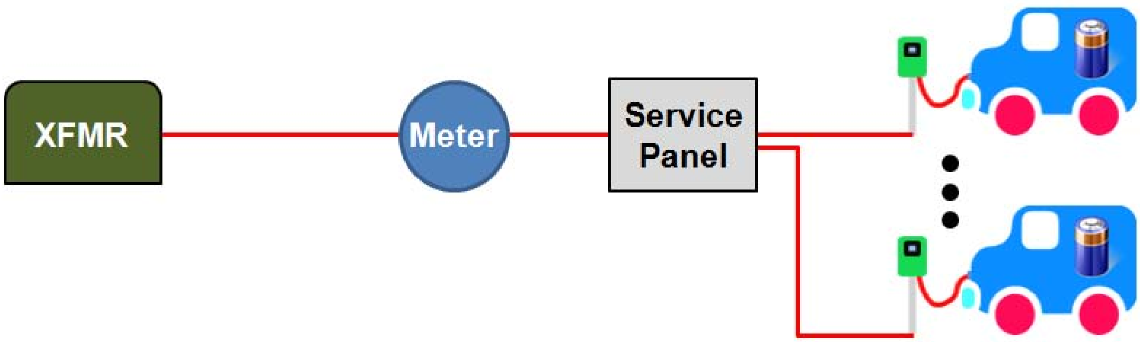

Figure 34 is the Uncontrolled Charging Model.

The next model, shown in Figure 35, is the Centrally Controlled Charging Model. The baseline approach for this model is to allow the vehicles to directly interact with the distribution utility serving the site. The service panel could include a network controller to translate message protocols between the utility meter and the charge stations.

An option is to use an aggregator to manage the vehicles across the area. The aggregator may also have to manage the facility loads as part of any aggregation agreement with the facility owners and vehicle owners. The utility interface for the aggregator would be with an ISO/RTO (Independent System Operator and Regional Transmission Organization) in restructured areas. The ISO would provide demand dispatch to the aggregator that would independently control the PEV loads.

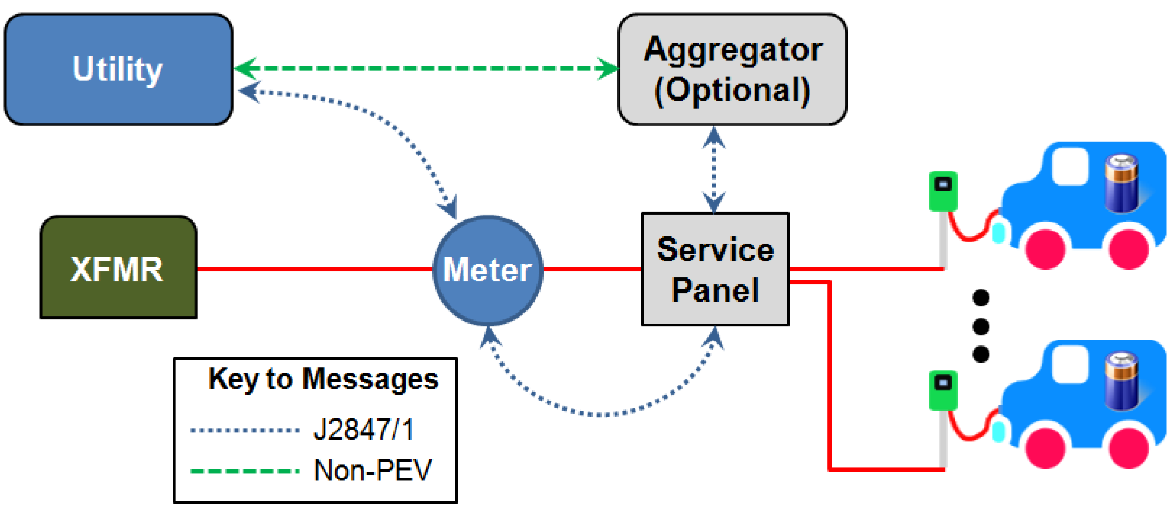

Figure 35 is a block diagram of the Centrally Controlled Charging Model.

The third option is to provide local control in the distribution panel serving the charge stations. This ETEMS Model is shown in Figure 36   In this case the vehicles are not visible to either an aggregator or a utility for the purposes of directly managing the charging of the vehicles. The aggregator interacts only with the facility. This offloads the requirement to tightly manage the vehicles from the aggregator. This could be done in the central software, but there are advantages using distributed control.

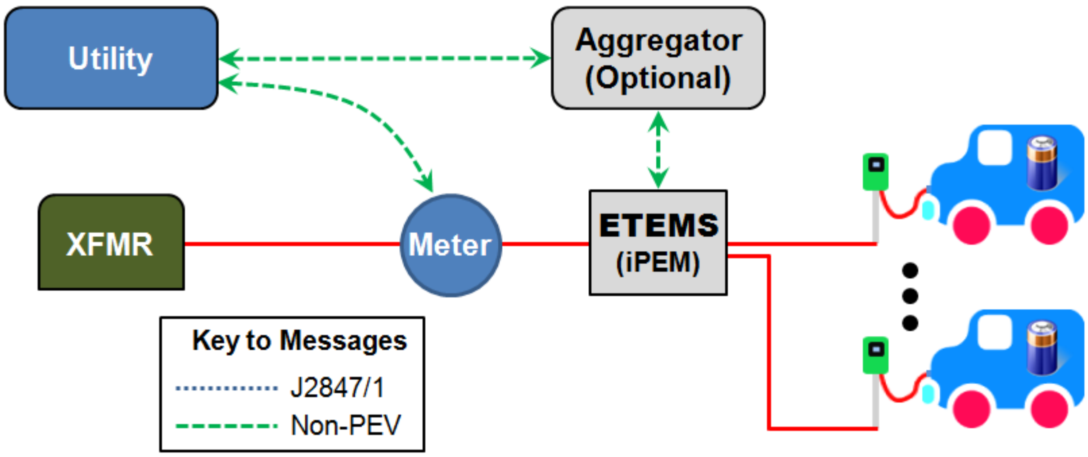

Figure 36 shows the ETEMS Model.

The ETESS model, shown in Figure 37, adds energy storage. The utility link is only for demand management. When there is no aggregation, the system only services the facility. Fleet management is required to deploy storage for ancillary services – either by the utility or a 3rd party aggregator.

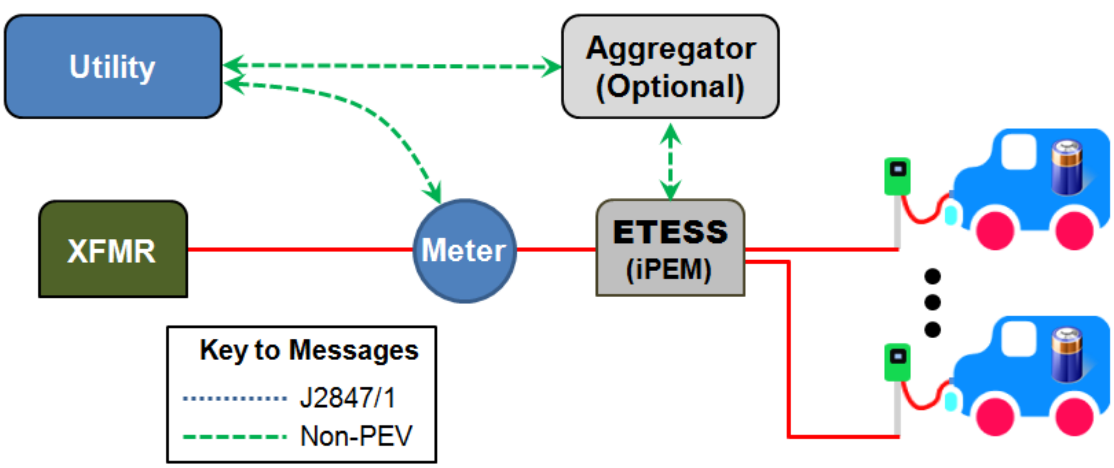

Figure 37 shows the ETESS Model.

In the fifth model a distribution utility owns ETESS and provides fleet management as a service for the facility and possibly the vehicles. This is shown in Figure 38. The storage is directly used for the grid as a DESS. The local demand management offloads the central computer and can deal with local shifting for the vehicles. For parking along a street and at public sites, the utility local management might be preferred to a behind the meter approach.

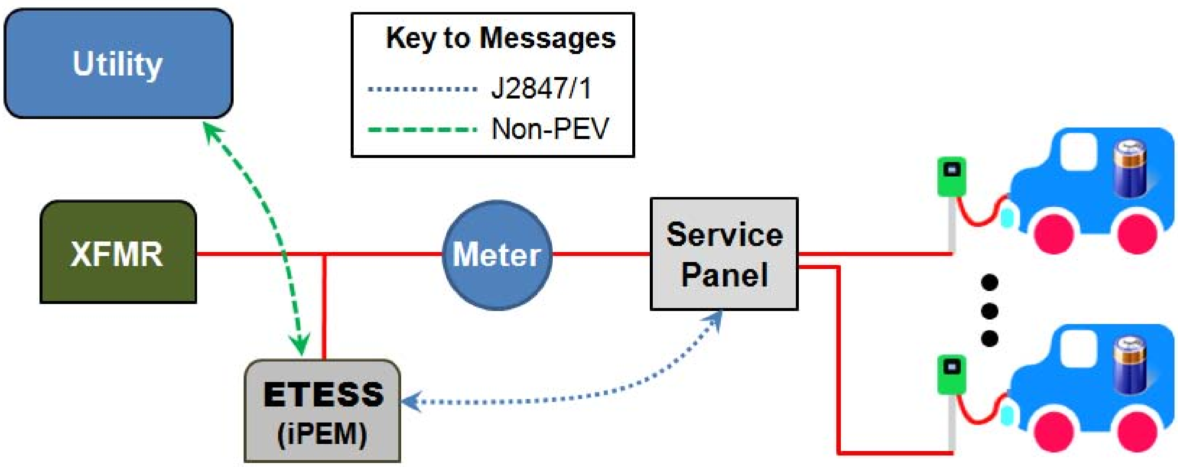

Figure 38 shows ETESS operated by a distribution utility.

The Case for Uncontrolled Charging

In the Uncontrolled Charging Model, there is no communication with the vehicle, and the power drawn by the vehicle during charging is only limited by the control pilot signal of the charge station (EVSE). This approach may be fine for a business that only provides a few charge stations and the total demand is low with respect to the building demand. At an industrial location that consumes a significant amount of power this approach might still be usable even with a large number of chargers. It is just a question of how much influence the charging vehicles can have on the overall facility demand and TOU energy prices. This could be partially mitigated by setting the control pilot on the charge stations to 3.3 kW to reduce the potential power draw. This is the capacity of the onboard charger for the Nissan Leaf and Chevy Volt. Vehicles with higher power chargers would just need longer to complete the desired energy transfer.

The Case for Central Control

This is the core concept for managing end user demand in the Smart Grid. The communication capabilities defined by SAE J2847-1 and use cases in SAE J2836-1™ are all intended to support this mode of control. Four of the five use cases would be used by a utility to provide incentives for charging at off-peak times or provide an ability to interrupt charging at critical times. The Optimized Energy Transfer (U5) use case, which is the one used by ETESS, is now gaining more attention in the Smart Grid community. The term "Demand Dispatch" is being used for this capability because the load is adjustable and not just available for curtailment. Demand Response is the term often used to describe the ability to remotely disconnect loads during emergencies.

The ISO/RTO Council working with KEMA and Taratec produced a report in March 2010 titled "Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems (IRC, KEMA, and Taratec

2010). This report is a timely and excellent review of the potential for actively using PEVs to serve the grid. The concept of using an aggregator to manage a distributed fleet of PEVs and bid services to the ISO/RTO is discussed in detail. The ISO/RTO is not interested in directly dealing with the PEVs. They would work with the aggregator just as they work with energy and ancillary service providers today and would expect to deal in blocks of one or two megawatts. The aggregator would respond to commands from the ISO/RTO and then in turn manage its fleet of vehicles. The aggregator would be accountable for enrolling the PEVs and ensuring adequate capacity to meet its commitments to the ISO/RTO.

The report discussed the use of PEV fleets to support current ISO/RTO products such as Scheduled Energy, Regulation, Reserves, Emergency Load Curtailment, and Balancing Energy. It also introduced two new capabilities: Enhanced Aggregation (EA) and Dynamic Pricing. Dynamic Pricing is one of the use cases already defined for PEVs. Enhanced Aggregation takes advantage of knowing the location of the PEVs on the grid to modulate power more precisely at specific locations.

The concept of Demand Dispatch was also discussed in depth in an article in the May/June 2010 IEEE Power & Energy Magazine titled "Demand Dispatch: Using Real-Time Control of Demand to Help Balance Generation and Load" (Brooks, et al. 2010). This raised many of the same concepts as in the ISO/RTO Council report.

This recent activity is encouraging for two reasons. The value of actively managing the rate of charging of large numbers of PEVs to provide services to the grid is being embraced by the industry. The concept of functionally aggregating resources to provide services is also gaining acceptance. Aggregation is central to the concept of CES, DESS, and ETESS. If the system operators are willing to deal with distributed PEVs on a distribution utility infrastructure, they can also deal with 3rd party storage units.

The concept of central control works fine when the vehicles are at the home premises, but it gets much more complex with commercial parking facilities. It is possible that there could be several aggregators that sign up PEVs, just as several energy providers may serve a given utility area. This is not a problem if the facility does not need to manage its own total demand, but if the facility does need to manage its total demand this will be very difficult to do if more than one aggregator is engaged. How do the multiple aggregators meet their obligation to the ISO/RTO and also coordinate to manage a facility demand?

It is much cleaner if there is one aggregator per facility and the aggregator works through the facility and not with individual PEVs. Control could still be provided centrally by the aggregator for all of the vehicles in each facility. It is not possible for an aggregator to manage vehicles in a facility without the cooperation of the facility. The facility does not need to provide any visibility of the PEV to anyone outside the facility.

The Case for Local Control – ETEMS

Unless the facility has no constraints on infrastructure, peak demand charges, or time of use charges, some form of energy management will be needed. While electric utilities talk about their incentive programs for PEVs, these are primarily set up to encourage off-peak charging in private garages. It is easier for a utility to hold the facility accountable for controlling demand than to try to independently manage the vehicles within the parking facility. If the PEV driver pays the facility to park and charge and the utility independently cuts back the charging, this could create PEV customer disappointment and also result lost income for the facility. This could be a problem. This might be fine if the utility owned and operated the charge stations, but that may not be allowed in some states and will certainly not be the general case.

As discussed earlier, it may be easier to aggregate PEV charging facilities than to try to aggregate individual PEVs for the purpose of demand dispatch. Enrollment should be a condition of parking for simple demand management. This is not harmful to PEV battery life and the facility needs the flexibility to manage its total power demand. If a facility is participating in ancillary services with an aggregator, the facility owner might offer more attractive charging rates to encourage PEVs to park and charge.

The use of an on-site ETEMS computer to manage the site demand will reduce the communication bandwidth and computational demands for the central computer of the aggregator. ETEMS does not have the storage capability of ETEMS, but it can provide all that is needed for demand dispatch.

The Case for a Facility-Owned ETESS

An ETESS unit can perform all of the demand management for a parking location that can be done by ETEMS. It is an ETEMS with energy storage. It is more capable than ETEMS because of its ability to use the stored energy to serve the vehicles when the facility demand constraints would be otherwise exceeded. Tt is not clear that PEV drivers would be willing to pay more for service because of the capability for the energy shifting. The value of ETESS over ETEMS for time shifting may be minimal.

The value of the storage must come primarily from providing services to the grid. This capability can be leveraged by an aggregator to offer a broader capability than is available with only demand dispatch of PEVs. Now there is full reverse flow from the ETESS unit. The ETESS bidirectional converter can also be designed to provide VAR support.

We have shown that ETESS can be considered to be another application of distributed storage for the grid. It is only a DESS unit with some additional software for managing PEV charging. The ISO/RTO Council report clearly accepted the premise that PEVs could be aggregated from across a distribution utility grid to provide ancillary services to the system operator. It follows that they will likely allow ETESS units to be aggregated for the same purpose.

This could be a problem in areas of the country that have vertically integrated utilities. It is not clear that utilities in these areas would allow and pay behind the meter storage units to provide ancillary services.

The Case for a Utility-Owned ETESS

In electricity markets that have not been restructured, a vertically integrated electric utility could purchase, install, and operate ETESS - at least for the purpose of providing services to their own distribution grid. Its use for frequency regulation, voltage support, spinning reserve, and load following would not have to be bid as a market service and the cost of the ETESS units could be built into the rate base. It still needs to be justified to the state public utility regulators versus other alternative solutions. Recovery of investment would follow the same regulatory approvals as other capital equipment.

In a state that has restructured, such as New York, only an independent power producer can purchase, install, and operate energy storage. There are regulatory issues that must be resolved for electricity storage systems to be operated by a distribution utility. Today storage systems are considered to be generation assets and current regulations prohibit a distribution utility from generating energy. This is reserved for independent power producers. The system operator (ISO/RTO) purchases ancillary services from the independent power producers. Also the system operator does not want to deal with small sources – it will generally only deal with bids of at least one or two megawatts, depending on the system operator.

While an independent power producer could aggregate many DESS systems to reach a two megawatt capacity, there are problems with this approach. Unlike a centralized storage system connecting to the transmission grid, the DESS units are all over the distribution grid, and this could create problems for the distribution utility if it is not part of the process and possibly providing operational control. It may be possible for an operator of many parking facilities to aggregate its ETESS units to be able to bid ancillary services to the grid as an IPP, but this is not allowed today.

Many of the benefits of DESS derive from being distributed along a feeder with the loads. It could make sense for DESS units to be owned and operated by the distribution utilities because of the very close association with the distribution infrastructure. The regulations need to change to make DESS economically viable in restructured market. One approach is to allow recovery in the rate base for distribution services and remove a portion of the ancillary services from the competitive market. Another approach is to allow the distribution utilities to compete for ancillary services by aggregating a fleet of DESS units.

Once you accept that ETESS is a DESS and that DESS can be owned and operated by a distribution utility and that a viable business case can be made for DESS, that does not end the concern over the viability of ETESS. The next key issue is whether a utility can use the iPEM software to actively manage the vehicle charging loads in a parking facility served by the ETESS unit. This would require a business agreement between the utility and the facility, and possibly the vehicle owners, although this could be a condition for using the charge station. It is in the interest of both the utility and the facility to manage the peak loads and it should not matter whether the software is inside or outside the parking facility. The two parties could pursue separate solutions with the utility installing pure DESS units to serve their grid needs and the parking facilities using ETEMS for demand management. This loses the advantage of integrated algorithms provided by using a single ETESS.

The Business of Public Charging

Most PHEV owners will not need access to a public charge station. They may want access but most will not need access. A PHEV never needs to charge. It could operate as an HEV all the time and never plug in to charge the battery. This would be a bad investment decision, versus buying a lower cost regular HEV, but it is possible. Most PHEV owners will want to take advantage of the PHEV all-electric capability for short trips. Even BEV owners may be able to accomplish many of their daily trips without needing to recharge until returning home for the night. The primary location for charging privately owned PEVs will be the home garage at night using an AC Level 1 or AC Level 2 EVSE. The cost of the home base charger (EVSE) is part of the cost benefit justification for the PHEV itself.

Most fleet vehicles will also be able to recharge using private EVSE. These would be installed and justified as part of the fleet purchase. The charge stations could be centralized (and may benefit from having an ETESS at the site) or be distributed in the fleet service area. This charging infrastructure is part of the business of operating the fleet.

So who needs public charging?

Unlike a PHEV that never needs a charge other than at home base, most BEVs will need access to public charging or the value of the BEV will be very restricted. Some potential PHEV and BEV owners may not have access to private charging and may need access to public charging to even consider purchasing the vehicle. A robust public charging infrastructure will be needed or the anticipated large fleets of PEVs, particularly BEVs, will not happen.

Some charge stations will be installed for other than direct business purposes. They can be part of establishing a green image by businesses or government entities in seeking to encourage the sales of PEVs.

Being PEV friendly may be good for business. A business could provide an employee with a personal spot with a charge station as a perquisite. The business case for the installation and operation may not be directly relevant and it is part of a larger business purpose. Even here, as long as there are groups of charge stations, an ETESS could be used at these locations.

Because a PHEV never needs to charge to return home, many drivers may elect not to use public charging unless the rates are very favorable. Although some drivers may just want to plug-in just to show off even if it is not cost effective. It could be very difficult to build a self sustaining business case for even installing public charge stations if only for PHEVs. There could be intangible or indirect benefits that accrue to the provider of public charge stations, but it could be a real problem to try to monetize their installation.

As the number of PEVs grows the ability of a business to provide free access to charge stations and maybe even free energy will change. While it might be fine to have one or two spots in a lot with 100 spots as green advertizing, it is not likely that when 90 of the 100 spots need to have charge stations, that the business will not try to monetize the use. It is not like a cinema complex that provides free or inexpensive soft drinks. Eventually the installation, operation, and maintenance of the charge station infrastructure will need to make sound business sense.

Reselling Electricity or Providing Access?

It is not as simple as putting in charge stations and selling electricity. In almost every state it is not legal to resell electricity. Only regulated electric utilities can sell electricity. For a home charger the electricity comes from the regulated utility. This is true for chargers that serve a private fleet. For an employer or business that provides free access, this is fine also – no resale is taking place, but if you charge a PEV to fill up by the kilowatt-hour this is a resale of electricity, and this is not allowed.

Of course it is not as clear as selling electricity. Connecting to a charger is getting access to power as well as occupying a parking spot. A charge station operator can always sell access by the hour and not charge for the energy.

The California Public Utility Commission issued an Order Instituting Rulemaking (R.09-08-009) on August 24, 2009 to consider alternative-fueled vehicle tariffs, infrastructure, and policies to support California's green house gas emissions reductions goals, (California Public Utilities Commission 2009). This is a very impressive OIR. The comments received from the utilities, charge station manufacturers, and others in response to the questions asked in the OIR are enlightening. There were comments and comments on comments.

A key question to be decided was whether a third party can buy electricity from a regulated utility and then resell it to someone else as an unregulated transaction. The major California investor-owned utilities all took different positions on the resale of electricity. In August 2010, California PUC ruled that the supply of electricity to PEVs would not be regulated by the PUC. This was the position advocated by charge station manufacturers and one of the utilities. There were good arguments for each option and all were well intended to promote PEV adoption in the State of California.

If utilities owned and operated charge stations there were concerns that these could be absorbed into a rate base spread to all power users and they would derive an unfair advantage over third parties. The argument also surfaced that spreading chargers over the rate base would be subsidizing affluent purchasers of PEVs by less affluent rate payers. The counter is that this at least makes the infrastructure affordable.

Regulating sales creates a potential problem for a parking facility that installs the charge stations. These charge stations are not cheap, particularly ones that are commercial grade. There needs to be some markup over energy cost to pay for the infrastructure. The charge station transfers power to the PEV but the facility also provides access to that power, and it could be argued that the energy is free and the PEV is paying for access to the power. They are selling access and not energy.

This debate will occur in many states because in most states only a regulated utility can sell electricity. Each state commission will need to decide the same issue, although California may be precedent-setting.

AC versus DC Charging

BEVs are very different. When the juice is gone the vehicle stops. It does not just keep rolling along as does a PHEV. The BEV batteries are much larger and while on-board AC chargers will be adequate for most, the very long range vehicles will benefit from DC charging, even at home. While a PHEV might be able to do very well by charging only at home base once a day, this will not work for most BEVs. Even if the daily use cycle never exceeds the battery range, the fact that an unforeseen problem could cause the battery to drain will work against most people buying a BEV unless there is a visible public infrastructure.

A key issue is which type of infrastructure is needed for BEVs. BEVs can use AC Level 2 when they park and charge. This will be useful at work, shopping malls, and other locations where the vehicle is normally parked for a few hours or more. They can also benefit greatly from high power DC charging. The availability of high power DC charging could reduce the need for public long-stay AC charging. In the long term, if battery technology advances to where DC charging can be routinely done at over 100kW, and DC charging becomes readily available, the need for public AC charging could be minimized. This is closer to the gas station model for refueling.

It is also not clear why any PHEV driver would ever use a high power DC charger and not just drive home as an HEV. This risks battery life for an unnecessary recharge. If PHEVs are ever going to charge other than at home base, they will most likely use AC charge stations.

What is a Kilowatt-Hour Worth?

One key benchmark is the cost per mile. This is one way to compare a PEV with a conventional vehicle. A gasoline-powered vehicle that gets 30 miles per gallon will spend $0.13 per mile with fuel at $3.99[9] per gallon. This sets an upper limit on the affordability for opportunity charging.

A PEV that consumes 250 Watt-hours of stored energy per mile will get 3.4 miles per kWh of energy transfer with an overall conversion efficiency of 85%. To spend no more than $0.13 per mile for the PEV, the energy transfer can cost no more than $0.44 per kWh ($0.13/mi * 3.4mi/kWh).

Charging at home at a cost of $0.10 per kWh is only $.03 per mile – this is only 22% of the cost of using a conventional vehicle. In an emergency, the BEV driver would not hesitate to pay even $0.44 and be at parity with a gasoline vehicle, but even a BEV driver might struggle with that level for routine charging at a public site. That leaves a maximum of $0.25 to $0.35 per kWh over the cost of energy, depending on the region, to cover the installation and use of the charge station infrastructure.

Implications of Roaming

Cars have always roamed - it is the purpose of a vehicle – but the term has never been used with conventional vehicles. The term roaming comes from world of wireless communication, and it is now being used to describe PEVs plugging in to charge at other than the home premises. There are several tiers of capabilities associated with concept of roaming. Some of these will potentially conflict with the fundamental operation of ETESS and iPEM software.

All roaming concepts assume that a PEV is registered with the utility or energy services company (ESCO) that serves the residence where the vehicle will primarily be charging. At the most basic level, if the PEV connects to an EVSE at another residence or at a public charge station, the full costs of the charging session plus any handling fees would appear on the electric bill for the home residence. This would be just another credit arrangement – an electronic version of today's pay at the pump with a credit card. This is not a trivial problem because there are thousands of electric utilities in the U.S. that have to establish systems to support these financial transactions. An alternative is to use a credit card at public charge stations to pay at the time of charging and at another private residence just give the home owner a few dollars.

The next level of complication comes with trying to have a roaming rate plan – much like wireless phone plans. The PEV owner might like to get the same preferred rates at public charging facilities or another private residence, as at home. This may be very feasible within a utility service area for charging at another private residence. It may also work well if the PEV is registered with an ESCO at home and the ESCO maintains a network of charge stations. This gets more complex when public charge stations are independently operated. Here, the ESCO still might only charge the PEV customer the negotiated rate and then pay a negotiated or prevailing market rate to the charge station operator. The ESCO might absorb any loss on a single transaction as part of the package deal.

These two levels of roaming – first billing and then preferred rates – have no impact on ETESS. The complication comes with the concept of aggregation for the purpose of providing ancillary services to the grid. At the next level, an aggregator controls the timing and the rate of charging of each vehicle. When vehicles become capable of reverse flow, the aggregator then gets an expanded range of operability- this is called Vehicle to Grid (V2G). The active management of only charging is often called V1G. For some visions of how this can be implemented, this creates a direct conflict with ETESS. In other ways they can be very synergistic.

One of the concepts being discussed is that an aggregator would sign up thousands of PEVs to participate in demand response (V1G) or full bidirectional service (V2G). The aggregator would bid an ancillary service, such as frequency regulation, in a one-or-two megawatt block. The aggregator would then manage the charging or reverse flow of a large fleet of vehicles to perform the service. The vehicle owner would receive some compensation for participating in the program. This is a random aggregation scheme that does not give much consideration to the parking facility and local utility infrastructure. This might be acceptable for vehicles located at the primary residences or certain public sites, but could become a problem for commercial businesses.

A business will generally have demand and energy charges and may also be enrolled in demand response or other utility programs as a facility. The utility infrastructure is designed to support the facility. The facility needs to be accountable for managing its own loads and working with the distribution utility. If all of the vehicles in the facility were registered with the same aggregator, it is possible that the facility owner could hold the aggregator accountable for also managing the facility demand – the aggregator could implement iPEM on site, remotely, or even install an ETESS unit. It becomes much more complex if there are several aggregators, and vehicles from each aggregator are charging at the facility. It will be difficult, if not impossible, to get multiple aggregators to jointly manage the facility demand and also independently provide ancillary services. It makes sense that any V1G or V2G be performed at the facility level and then aggregated by facility.

Fortunately a parking facility has ultimate control over the vehicle communications. All communications route through the charge station and the facility energy management system. The parking facility does not have to allow a PEV to participate in any aggregation program or even a billing program outside the facility. As discussed earlier, the expectation would be that any vehicle using the public facility would agree to allow active management of charging as a condition of parking. This does no harm to the battery and is required to manage the facility. Reverse flow would require some level of compensation but this could also be worked out with the facility as a credit during the session.

Facilities do not roam. The relationship of the facility to the transformers, feeders, and substations is fixed. The PEV loads must be managed at a facility level and ETESS does this for the facility. Vehicles with reverse flow capability expand the energy capacity of the ETESS units at the facility and can participate in providing ancillary services to the grid along with ETESS.

Assessment of Business Cases

Business cases were developed for several of the business models discussed earlier to evaluate the benefits and economic returns of each. Six business cases were developed. The Base Case is for a commercial parking location with no energy management system – this is the Uncontrolled Charging Model shown in Figure 34. The next two cases are based on the use of an on-site energy management system – the ETEMS (Electric Transportation Energy Management System) Model shown in Figure 36 . In one ETEMS case all of the benefit is accrued through behind-the-meter savings to the facility. The other ETEMS case aggregates control of the vehicles to provide demand dispatch for the grid. The last three cases are based on ETESS. One ETESS case uses the system only to provide behind-the-meter management of power and energy within the parking facility – this model was shown in Figure 37. The next ETESS case builds on this and offers ancillary services that do not conflict with peak management. The final case only uses ETESS to provide ancillary services. This last business case could be either of the two ETESS models shown in Figure 37 and Figure 38.

A ten year model was created for each business case. These were intended to be approximate models and therefore everything was based on a year end point of reference for all financial measures. The primary assessment metric was the Internal Rate of Return (IRR). Everything was based on after-tax cash flow at a 50 percent tax rate. A key assumption was that the charging facilities are being added to a profitable existing business, such as a parking garage, movie complex, or shopping mall, and that pretax profits of the core business are large enough to absorb accelerated depreciation of the charging equipment. This provides a better cash flow in the early years than might be the case in a start up business. All models build on the base case so it is important to understand it.

Base Case – Uncontrolled Charging Model

The base case is a facility that installs 18 AC Level 2 commercial grade charge stations. There is nothing magic about the use of 18 charge stations, but it is a reasonable quantity for ETEMS and ETESS systems to control at the first tier. If the number of charge stations at a site is very low, the ability to manage the allocation of power between vehicles at the site becomes limited. As the number of charge stations gets larger, the complexity of the cross vehicle allocation algorithms grows, and this could favor tiers of software. This was discussed earlier where higher tier logic would manage the aggregation across groups.

The business case assumes an average installed cost of a commercial charge station to be $4000. This includes the charge stations, mounting equipment, signs, site engineering, permits, inspections, wiring, circuit panels, communication equipment, billing systems, and installation labor and materials – everything.

This is the total cost to open and operate a group of charging stations at a business that has the available parking spots. This cost is adjustable in the model. The fee structure for using the basic charge station is adjustable to maintain a target IRR as charge station utilization and installed cost varies. It was also assumed that annual maintenance would be two percent of the installed cost - $80 per charge station per year. This is for all equipment at the site that was part of the installation. A transaction cost of five percent of non-energy access charges was also assumed. This would cover costs of credit transactions and other services both on and off-site.

The business case splits customer access and energy charges. The access charge is per hour and unrelated to the amount of energy transferred. A value of $0.40 per hour is used as the baseline fee. It was also assumed that the average occupancy of charge stations over 24 hours would be 50 percent. It is actually the product of the access fee and the rate of utilization that is most important because it directly drives the revenue in the business case.

The customer also pays for energy, but this is an exact pass through in the model. The cost of energy to the facility per kWh at the time of transfer is the exact amount billed to the customer. This business case is driven entirely by access charges. The model assumes that the energy costs include all costs except the monthly demand charge, which will be recovered through the access charge. The models used an off-peak rate of $0.10 per kWh and a peak rate of $0.30 per kWh. The peak was assumed to be for six hours on five days per week – 1560 hours per year.

The Internal Rate of Return (IRR) for the base case was 15.5 percent. In fact the access fee was selected to make the Base Case IRR approximately 15 percent. The total cost of the installed system was $72,000. The base case is primarily governed by three factors: the product of the access fee and the occupancy rate, the cost per charge station, and the utility monthly demand charge rate. The IRR of the Base Case is shown in Figure 39 as a function of the product of the access fee and the occupancy rate for three values of charge station cost. The nominal case is a value of $4000 per charge station, an occupancy rate of 50%, and an

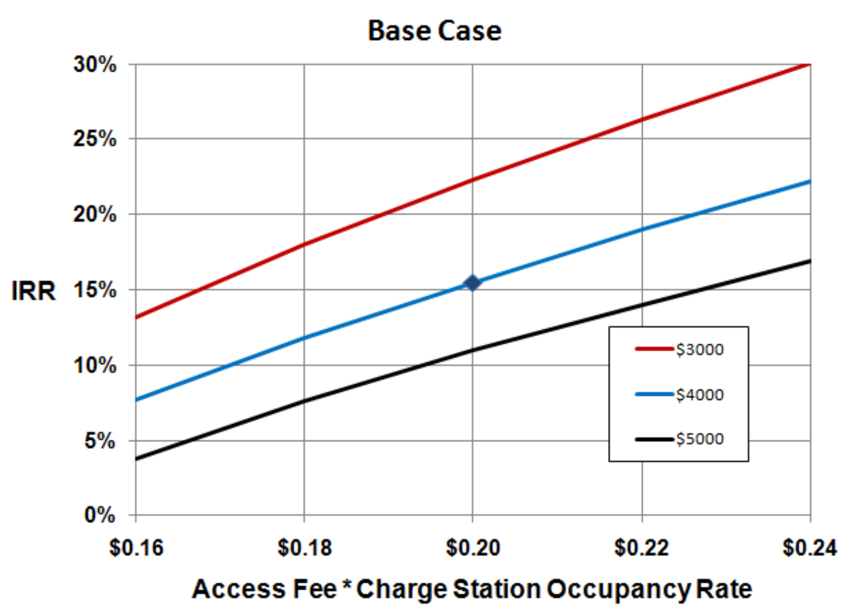

Figure 39 shows the IRR of the Base Case

access fee of $0.40 per hour (a weighted fee of $0.20 for all of the hours in the year). The access fee can be directly adjusted to compensate for utilization. If the utilization dropped to 40 percent, an access fee of $0.50 would compensate. The issue is what impact the access fee has on the cost to the vehicle owner.

One way to assess affordability is to compare the cost per mile for recharging a PEV versus the cost per mile of a gasoline vehicle. A gasoline powered car that gets 30 miles per gallon, using gasoline that costs $4.00 per gallon, would have an operating cost of $0.133 per mile. A PEV that gets four miles to the kWh (250 Watt-hours per Mile) would refuel at a rate of 300 Watt-Hour per mile to allow for charger efficiency. Charging at home at a cost of $0.10 per kWh would result in a rate of $0.03 per mile. This was discussed earlier, but now the cost of charge stations must be recovered at a commercial site.

The model assumes average on-board charger power of 5.0 kW – a 50 percent mix of 3.3 kW and 6.6 kW chargers. It was assumed that the average vehicle would need to use 70 percent of the connection time to complete the required energy transfer at its rated power – a slack time of 30 percent. This results in an average power consumption per hour of occupancy of 3.5 kW. With an access fee of $0.40 per hour and an average power consumption of 3.5 kW per hour of connection, this is a rate of $0.114 per kWh. At an off-peak base cost of $0.10 this will result in an equivalent cost of $0.214 per kWh, which is a cost of $0.064 per mile. This is illustrated in Figure 40. Charging at peak times approaches the gasoline vehicle costs. This is also true if the vehicle only needs a small portion of the connection time to complete the transfer.

Commercial facilities pay a monthly amount based on the peak power consumed at any single time during the month. This is an average over either 15 minutes or 30 minutes, depending on the utility. If the demand charge is $12 per kW, a facility that draws a peak of 50 kW would pay a $600 demand charge during that month. If a facility were unused except for one hour per month, when a maintenance person would turn on everything at once at 50 kW for one hour – the $600 demand charge would apply and an energy bill might be $5.00 at a rate of $0.10 per kWh.

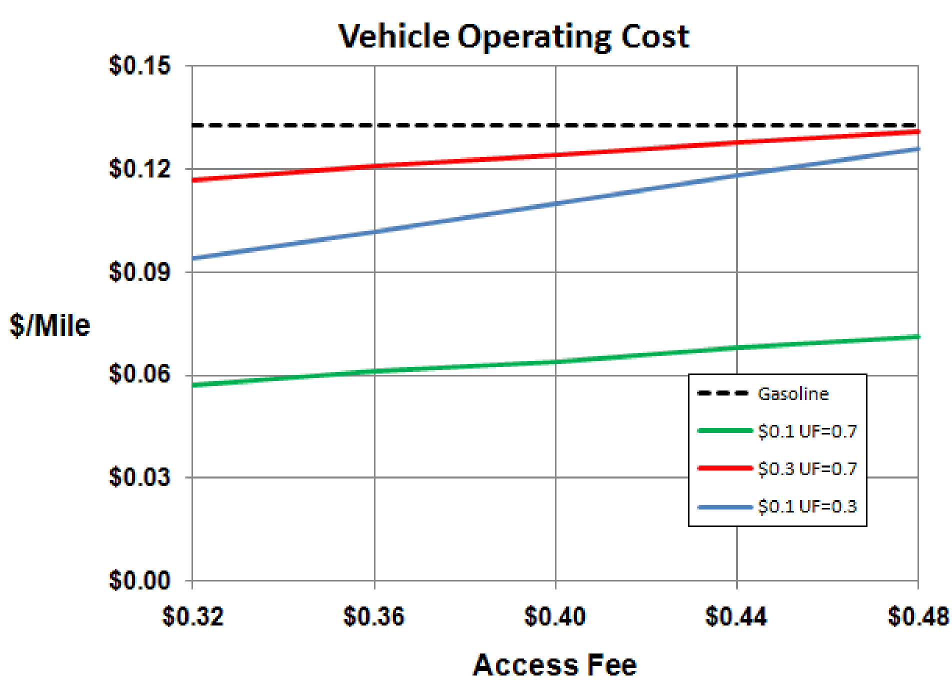

Figure 40 shows how Cost per Mile varies with Access Fees.

The absolute worst case for a parking facility would be if every charge station were occupied for a 15 minute interval with vehicles with on-board chargers capable of drawing 7.7 kW, and all were charging. This would be 139 kW for 18 charge stations. Even with no control this is not likely to happen, but the peak will significantly exceed the average. In the Base Case it was assumed that 90 percent of the charge stations would be occupied during a monthly peak and drawing an average of 5.0 kW – 81 kW total. At $12.00 per kW per month that is an annual cost of almost $12,000 - a great target for an ETEMS system.

ETEMS Business Case – Peak Management

The ETEMS system consists of a computer connected to the network that goes to each of the charge stations. It also has the iPEM software to manage the PEV charging sessions. It was assumed that the computer would cost $3,000 and the software would cost $1,500. The software would have an annual maintenance cost of 20 percent.

There are no additional top line revenues for this system. Its sole purpose is to manage the peak demand of the vehicles to keep the monthly peak charge below a target. It only has to shift, reduce, or curtail PEV loads to keep the facility monthly peak average demand below the target. The model assumes a nominal value of 12 percent below the expected peak of 81 kW – a reduction of 9.7 kW. This establishes a target limit of 71 kW. The system would actually work to the target. The annual value at $12.00 per kW is worth $1400 per year in savings. This is strongly influenced by the demand price and the target reduction from peak. While the model assumed a peak of 81, it could go well above that if 18 vehicles came in at the same time with 6.6 kW chargers – 118.8 kW. If ETEMS clips the 15 minute peak at 70 kW, that would be worth $6884 over the year.

Figure 41 shows the impact on IRR of demand price for both the Base Case and the ETESS Peak

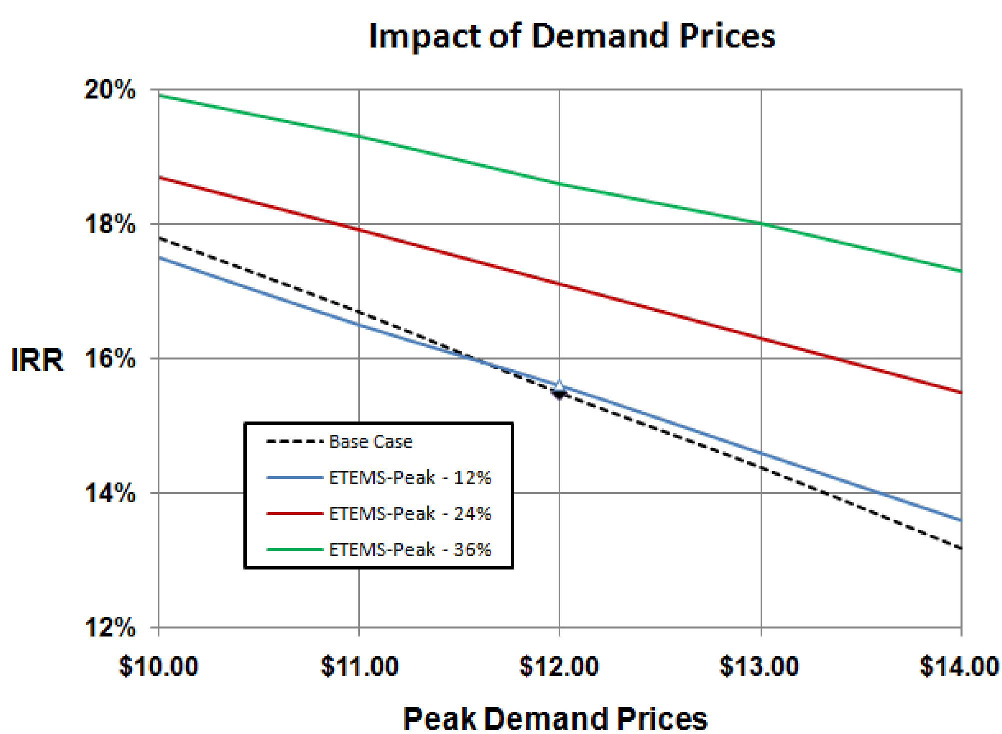

Figure 41 shows the Impact of Demand Prices on IRR.

Management Case.   The peak demand is a drag on access revenue - as the price goes up the IRR goes down. Because of the extra equipment for the ETEMS case, the IRR becomes lower than the Base Case at lower demand charge rates (for the 12 percent reduction model). As the level of reduction of the peak increases, the IRR of the ETEMS model is clearly superior to an unmanaged charging location. The 12 percent savings was selected to match the behind the meter ETESS Case to the Base Case. The 36 percent reduction is not unreasonable.

ETEMS Business Case – Demand Dispatch

In this case the ETEMS iPEM logic aggregates demand within the facility to provide a demand dispatch capability for the grid. The individual ETEMS units are controlled by an upstream aggregator that combines facilities to be able to bid ancillary services to the system operator. In the model it is assumed that ETEMS cannot simultaneously manage the facility peak monthly demand and respond to commands to increase or decrease loads on the grid. This is conservative. There is some potential synergy because it is more likely that the grid will call for demand reduction at peaks, and this will prevent a monthly peak from happening during grid peaks. Still, it is possible that the system asks for increased load when the grid is lightly loaded and this could drive a monthly peak.

The model is based on providing demand reduction from peak power to average power for the connected vehicles. During the six peak hours on each weekday, the peak power is reduced by 67 percent of the slack. For 81 kW of vehicles at a Utilization Factor of 0.7, this would be a reduction of 16 kW. During off peak and during the times when vehicles are charging (50 percent of all hours less the peak hours), a value of 50 percent of this power was used. During off peak this could be calls for increased load as well as reduction. The 50 percent factor also accounts for reduced price for the service at off peak times.

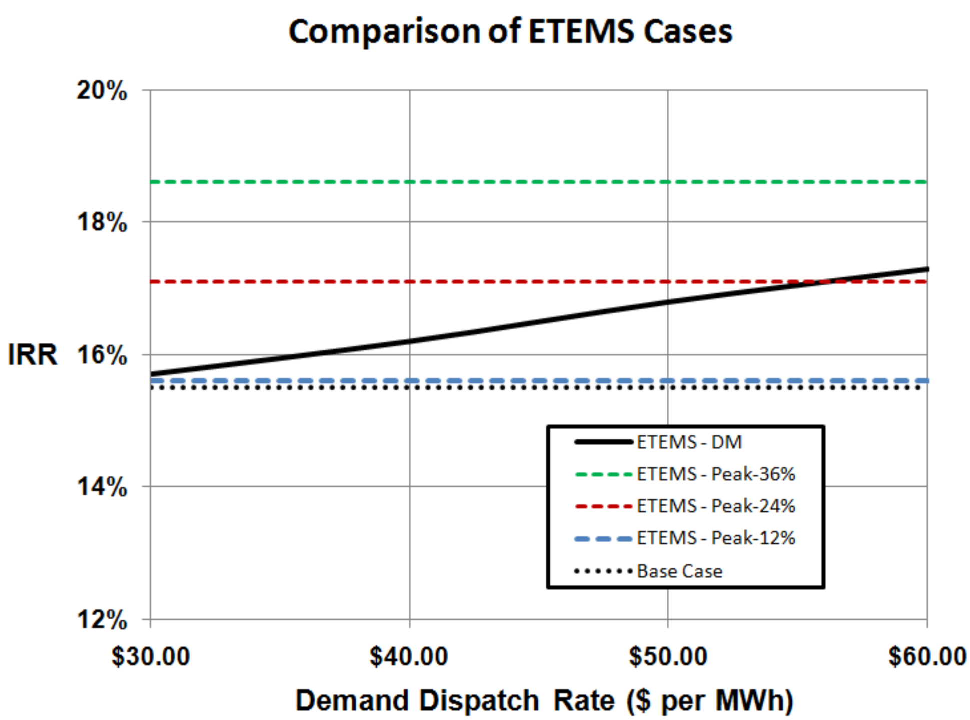

Figure 42 shows a comparison of the two ETEMS Cases.

The primary variable is the price for these services. This could be part of the real time energy market. This varies widely. On February 4, 2011, the NYISO LBMP (Location Based Marginal Pricing) varied from paying someone to not generate power $71 per MWh to paying $742 per MWh. The Middle 60% varied from $33 to $61 and the median value was $41. A nominal value of $40 per MWh ($0.04 per kWh) was used for the model. Reducing the charging of vehicles is the equivalent of generating power.

The two ETESS cases are compared in Figure 42. The peak management cases do not vary with the demand dispatch price and vary only with the percent reduction in the peak. The nominal value is 12 percent, but it is possible to do as well as 36 percent, and maybe beyond. The demand dispatch model varies strongly with the price, as expected. It is better than the 12 percent peak management model, but not as good as the 36 percent peak model. Some peak shaving may be possible even while offering demand response. These are additive.

The models clearly show that there is great benefit installing a power and energy management system such as ETEMS at any site associated with charging electric vehicles. It can pay by managing peak charges for the facility and it offers the possibility to engage in demand dispatch or demand response programs along with a facility level aggregator.

ETESS Business Case – Peak Management

The business case for ETESS is not as clear as that for ETEMS and iPEM software. This is true for all battery-based grid storage systems. Battery storage is currently very expensive and it is difficult to create a compelling business case.

The cost (purchase price) model for the ETESS unit is based on a fixed cost of $10,000 for the basic inverter and the balance of the system. A variable cost of $200 per kW of power rating is added for the inverter. A variable cost of $300 per kWh is added for the nameplate capacity of the complete energy storage system. Usable capacity is assumed to be 80 percent of the nameplate capacity. The installation cost is assumed to be 10 percent of the total equipment cost. This is a very challenging future cost model. The ETEMS equipment and software is not included here because it is already counted in the buildup to a total system cost:

$$ETESS\ Cost = 1.1 * \left(\$10{,}000 + Power * \left(\$200 * StorageHours * \frac{\$300}{0.8} \right) \right)$$

For a 25 kW system with three hours of usable storage (75 kWh), the installed ETESS cost is $47,438 and $51,938 with the included ETEMS hardware and software. This is $2000 per kW of power capacity or $700 per usable kWh of storage capacity. The cost of $300 per kWh for a storage system is consistent with future cost targets for PEV energy storage systems. In 2010 vehicle storage systems cost $800 to $1200 per kWh of nameplate storage. A 25kW unit with 75kWh of usable storage would cost over $100,000 today. Annual maintenance in the model is set to two percent of the ETESS cost.

For use behind the meter, it was assumed that the availability of energy storage would improve peak management by 24 percent of the peak. This takes the basic ETEMS from the 12 percent level to the 36 percent level. This follows the same model as the ETEMS peak management case. The availability of storage also allows for energy arbitrage. The PEV customer will pay the peak rate even though much of the energy may be transferred from the ETESS battery. This model assumes one energy cycle per workday and benefits from the rate differential at the time the vehicles are charged. The energy cost savings accrues to the facility and the vehicle owner pays the peak rates.

This model reduces the IRR of the ETEMS peak management business case from 15.6 percent to 11.1 percent for an additional investment of over $50K. The system cost has to drop from $50K to $25K or the peak energy price has to be $0.65 to match the IRR of the ETEMS system. The on-site storage may be able to help with integration of onsite renewable energy sources, but the economic value for only peak limiting and energy shifting appears marginal.

ETESS Business Cases – Ancillary Services Models

Two models provide ancillary services. One builds on the ETESS peak management business case that was just discussed. It uses the ETESS unit off-peak to provide ancillary services. This builds on the ETEMS peak management business case. The power handling for the grid should not be counted against facility peaks if the system is being commanded to absorb power. With a 50 percent share of the off-peak hours at a price of $40 per MWh, the IRR has improved to 13.6 percent versus the pure behind the meter ETESS model at 11.1 percent.

The second model only provides ancillary services. At 75 percent utilization and a price of $40 per MWh, the IRR is only 10.1 percent. The annual revenue from ancillary services is $6570 ($263 per kW). This is not a compelling business case with prices in this range. At $90 per MWh the IRR gets back to 16.2 percent.

All of the ETESS business cases are compared in Figure 43 for different ancillary services rates. The base case and the ETEMS cases are shown for reference. This chart also shows a DESS unit – an ETESS without charge stations. It is even more sensitive to the price of services because of the loss of access fee revenues.

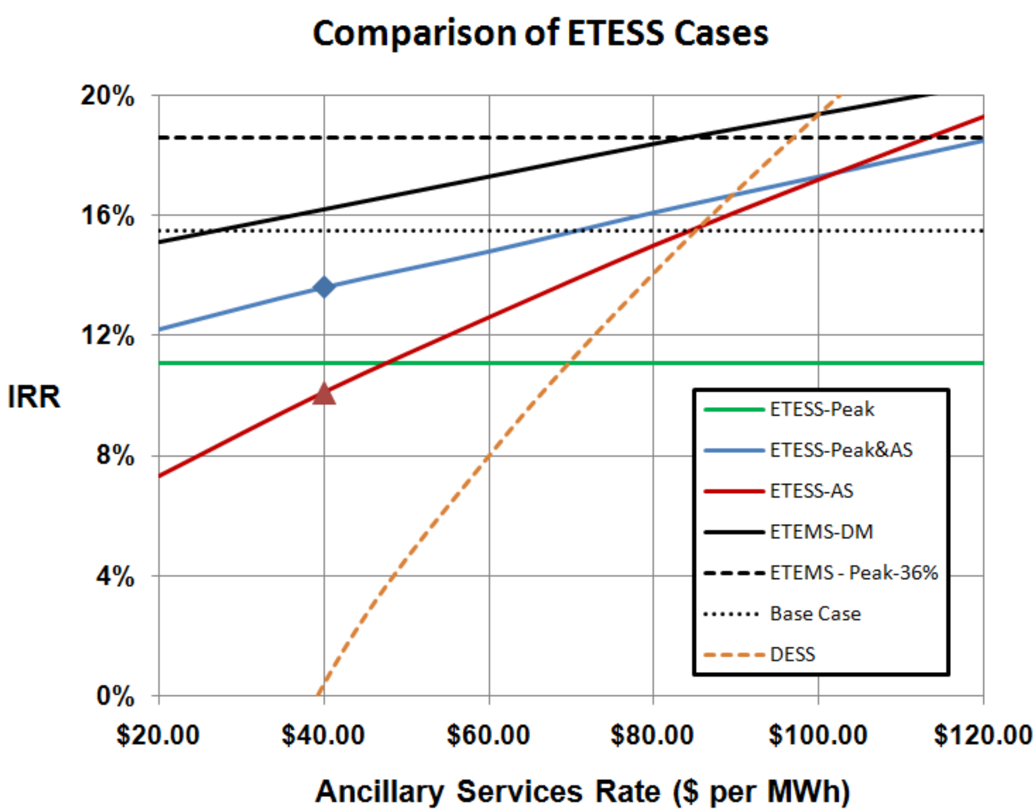

Figure 43 shows a comparison of ETESS business cases.

Prices for Load Following (Peak Management) follow the real time energy market. They vary by year, month, time of day, and location. The price of natural gas is a big driver, and natural gas prices are relatively low at this time. On April 20, 2011, the NYISO energy prices ranged from $30 to $40 on their reference bus during the day. In the New York City zone the Location Based Marginal Prices varied from $29.60 to $64.10 in the Hour Ahead Market. Energy injected directly into the New York City zone may have a higher value at certain times than energy injected elsewhere into the system because of transmission losses and congestion costs. A storage system in NY would benefit from the higher rate for sourcing power, although it would pay this higher price to recharge at that time.

The rates for frequency response services today do not reflect the value of the rapid response that can be provided by energy storage systems versus a gas turbine generator. This is being addressed by the Federal Energy Regulatory Commission (FERC) as a Notice of Proposed Rulemaking filed on February 17, 2011 and should result improved rates for battery systems.

Chapter Summary

This chapter discussed many of the business issues associated with the Electric Transportation Energy Storage System (ETESS). ETESS brings together electricity storage for the grid with algorithms to manage the charging sessions of groups of plug-in electric vehicles. It can benefit from serving both worlds but that also raises concerns. Several business models and associated economic cases were developed and evaluated. Models range from uncontrolled charging at a parking site, to the use of a simple on-site energy management system (ETEMS) to control the charging of the vehicles, to a full ETESS that both manages the vehicles and provides ancillary services to the grid.

The simple ETEMS system with iPEM logic should be part of any installation with ten or more charge stations. It is a small additional cost to that of the charge station installation and it provides outstanding capability to manage the peak power demands at the facility.

ETESS provides capability well beyond that provided by ETEMS, but it also suffers from the same market issues of all battery storage systems for the grid. The batteries are too expensive and the current market prices for load following and ancillary services are too low to make a compelling business case for storage without government subsidies. There are lower cost alternatives to storage systems at the system level.

The distributed CES, DESS, and ETESS units can offer unique capability because of their location on the feeders with the loads. The ability to source or absorb real and reactive power on the feeder is a unique capability. As more variable loads, such as PEVs, and distributed renewable energy sources pop up all over the grid, this network of small distributed storage units may start to develop a unique value. The value may need to be recognized by the distribution utility and not be part of the ISO/RTO market. The ongoing demonstration projects of CES will need to be closely followed. The success of ETESS is directly linked to the success of CES.

7 ETESS Feasibility Study Summary

The objective of this project was to explore the feasibility of a new system concept that integrates grid-connected electricity storage with control logic that intelligently manages the charging of groups of plug-in electric vehicles. It is called ETESS – the Electric Transportation Energy Storage System.

The Problem

Plug-in Electric Vehicles (PEVs) are coming and are forecast to become a significant share of the transportation sector in the future. The primary location for charging for most vehicles will be at a “home” location. Many PEVs, particularly BEVs, will need access to charge stations at other locations – at work, at shopping malls, in public parking garages, on city streets … everywhere.

PEV charging loads will vary significantly during the day at these “park and charge” facilities. There will be times when all of the charge stations are empty and other times when they will all be occupied and in use. It is possible, but not very likely, that every charge station will be occupied by a PEV capable of drawing the rated power of each charge station at the same time. A road rally of Tesla Roadsters arrives! This could be a problem if the electric power infrastructure serving the facility or within the facility itself are not be sized to allow it. The facility may also have economic considerations, such as the peak monthly demand charge, or demand response commitments.

Some charging facilities can take a laissez-faire approach. Their infrastructure may be capable of operating at full PEV charging capacity, the PEV loads may be small relative to the total facility power demand, or they may just not care about the peak loads, but if the charging facility needs to keep its peak power demand below a power limit, it will need to actively manage the power allocation of each of the vehicles at the facility.

A Solution

SAE J2847-1 defines a communication capability called “Optimized Energy Transfer” that will allow a facility Energy Management System (EMS) to communicate with a PEV during a charging session and coordinate the power demanded by the PEV during the energy transfer. The challenge is to create optimization algorithms that accept an energy transfer request and an estimated departure time from each PEV and then allocates the available facility power to each PEV to keep the facility within its power constraints while minimizing any PEV customer disappointments. This is called **intelligent Power and Energy Management (iPEM)** logic. A facility EMS with iPEM logic is called an **Electric Transportation Energy Management System (ETEMS).**

The iPEM logic provides the capability to control the total facility power demand. It can increase or decrease the rate of charging for each of the connected vehicles to control the aggregate facility power, but it cannot add power, and this increases the risk that some vehicles will not get their requested energy transfer. Nevertheless, if a grid-connected, energy storage system is placed within the facility, the iPEM algorithms can now take advantage of the energy storage capability to further improve the optimization. The iPEM logic can now add power. This integrated system of iPEM logic and energy storage is called the **Electric Transportation Energy Storage System (ETESS).**

A New Opportunity

A new concept for grid energy storage is emerging. It is called **Community Energy Storage (CES)** by American Electric Power and **Distributed Energy Storage System (DESS)** by EPRI. These are small storage units that are collocated with the transformers that serve groups of homes or businesses. These units can act autonomously to control real and reactive power along a distribution feeder and they can also be aggregated as a fleet to form a large virtual storage system to serve the larger needs of the grid – for the feeder, the substation, or the control area. EPRI defined functional requirements for these units in 2010. The power levels range from 25 kW to 75 kW for single phase units and up to 200 kW for three phase units. The units should have between two-to-four hours of storage at rated power.

ETESS could be used exclusively for managing PEV charging loads within a facility. Nevertheless, it is also possible that an ETESS unit could support the needs of the grid outside of the facility as a Distributed Energy Storage System (DESS). ETESS can be thought of as just another DESS application, except it is connected to a group of charge stations at a parking facility rather than to homes or businesses. This additional role then becomes a key driver of the system architecture. An ETESS unit could be placed at a parking facility with only a few PEV charge stations and only serve as a DESS. The iPEM capability could be called on later as more charge stations are placed at the facility.

The System Architecture

ETESS must meet the functional requirements of the EPRI specification for DESS units. ETESS is a DESS. Two sizes of ETESS are proposed: a basic 75 kW single phase unit and an optional 150 kW three phase unit, each with three hours of storage. Both must operate from a 240 VAC transformer to be compatible with AC Level 2 charge stations.

The 75 kW size was selected because it is the largest of the single phase DESS units, and a parking facility should be capable of hosting a larger unit without becoming obtrusive. This is a primary consideration for residential applications of CES and DESS. The three phase unit was scaled at twice the capacity of the single phase unit. This is all rather arbitrary and not related to the capacity needed to only support the PEVs – it is large because it can be large and not blight the neighborhood.

Business Issues

A simple ETEMS system with its iPEM logic should be part of any installation with ten or more charge stations. It is only a small additional cost over that of the basic charge station installation and it provides outstanding capability to manage the peak power demands of the facility. The risk of PEV customer disappointment rises as the target limit becomes more aggressive. Still, even a small amount of time shifting can clip higher peaks with minimal customer impact and generate savings in peak demand charges.

ETESS incorporates the same iPEM logic as ETEMS and is equally effective at holding the aggregate PEV demand below a target limit. Still, it can use its stored energy to offset some of the aggregated PEV power demand on the grid. This results in less PEV customer disappointment for an ETESS than an ETEMS for the same grid limit. Nevertheless, the business case for installing an ETESS unit behind the meter and using it only for lowering the risk of disappointment of PEV customers is not compelling. Some PEV customers may be willing to pay a higher fee during peak periods to avoid any curtailment, but not at other times. Others may accept the risk of a possible curtailment and not be willing to pay a higher fee to avoid it. Both of these situations could be accommodated with a simple ETEMS.

The business case improves for behind the meter ETESS units if they can be aggregated with many others and used to provide load following or ancillary services for the grid. This reduces the effectiveness of the unit for peak demand management, but it creates opportunity for additional revenue.

The ETESS unit could be installed outside the charging facility by a distribution utility. The primary justification must be as a DESS. Nevertheless, the utility could also use the ETESS to manage the loads within the charging facility and take advantage of its PEV demand management capability. Some adjustments would need to be made in the demand charge tariffs for the parking facility operator, because the utility can now control the monthly peak demand of the facility and may even want to use the PEVs to cause a peak load. The business case is still very challenging for the utility ETESS.

There are regulatory issues in restructured electricity markets that must be worked to make a viable business case for a utility-owned CES, DESS, or ETESS. The traditional view of using an ISO/RTO to schedule generation assets or large blocks of demand may not be the right approach in a Smart Grid with small, highly distributed renewable energy sources, storage units, and PEV loads. The distribution utility may be better placed to control the PEV loads and other loads along the feeder as part of a tiered or even autonomous control concept. CES, DESS, and ETESS can facilitate this distributed control approach. In this model the cost of the units could be recovered as part of the rate base of the distribution utility. The ISO/RTO would deal with larger system effects over the control area that must be handled at the front end by large generation, bulk storage, or concentrated loads.

Summary

ETESS works. Its embedded iPEM logic can effectively manage the aggregated power demanded by the PEVs. Its stored energy helps greatly with minimizing PEV customer disappointment while managing to grid power limits. Its stored energy can also be used to provide voltage support, load following, or other services for the grid.

Future PEVs will provide the communication capability and control modes that will allow iPEM logic to coordinate the charging session and limit PEV power consumption. Much work needs to be done to create iPEM algorithms and validate metrics to be used for optimization, but it is all technically feasible.

ETESS is a DESS variant. Several projects are underway to design and demonstrate DESS units over the next few years. There will certainly be many technical issues to overcome in the detailed design, implementation, testing of a DESS. This is true of any new product development project, but it can and will be done.

The tough issues are primarily business issues. It always comes down to the money. The key question is whether ETESS can ever be economically viable. It comes down to the value that ETESS can deliver to the owner as measured by revenue or cost avoidance and the life cycle cost of the unit. It is all about the return on investment.

ETESS provides capability well beyond that provided by ETEMS, but it also suffers from the same market issues of all battery storage systems for the grid. The batteries are too expensive and the current market prices for load following and ancillary services are too low to make a compelling business case for storage at this time.

Part II - Simulation Design and Results

CHAPTERS

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8 *A Multivehicle Charging Simulation*

A simulation was developed to allow evaluation of an ETESS unit for managing the charging sessions of a group of vehicles. The primary focus was on the management of vehicle charging and the use of ETESS stored energy to mitigate facility demand constraints. It does not simulate dispatch of energy to the grid for load following, voltage support, or frequency regulation. The objective was to assess availability of excess power and energy for grid support after dealing with the requirements of vehicle demand management.

Overview of the Simulation

The simulation was implemented using Visual Basic for Applications (VBA) in Microsoft Excel 2007. Consideration was given to just doing it in Visual Basic as a standalone application, but the advantage of using Excel VBA was the ability to use the worksheets for visualization displays, for data display, and for charting. This simulation does not use any functions or cell equations within any worksheet. All of the logic is implemented within the VBA program. The user interacts directly with Windows Forms that are generated by the VBA program

The purpose of the simulation is to understand the interaction between groups of vehicles, the ETESS unit, and the grid. It was designed to allow the evaluation of algorithms to allocate power among the vehicles as well as use ETESS storage to manage total grid loads and minimize disappointment of the vehicle operators. Each pass of the simulation starts at 6:00 AM and runs for 24 hours. It can simulate different parking scenarios (such as a shopping mall, city garage, and factory) and mixes of PHEV and BEV vehicle types. These and other factors are defined by stochastic models. The simulation allows for different ETESS configurations to be evaluated. It also allows for different types and levels of facility power demand restrictions to be simulated. There are several different control strategies for power allocation to the vehicles, and for managing the discharging and charging of ETESS batteries.

The simulation can operate in three modes. There is a time lapse visualization mode for a single pass where the coming and going of vehicles can be watched on the screen. This mode is good for getting a feel for the simulation, but the single pass without visualization mode is a much faster way to get to the results. The results for each pass are displayed in tables and charts in the workbook for all modes. The Monte Carlo mode executes 2,000 passes and generates results for the combined passes. It also saves results for the one of the 2,000 passes to use as a point of reference. It takes less than 30 seconds to run 2,000 passes.

The simulation mode is selected using the Simulation Control Panel (SCP). A screen image is shown in Figure 44. The mode selection page is shown in the figure. The other pages will be described later in this chapter. A page is selected by clicking the tab at the top. There are three option buttons to select the simulation mode – only one mode can be selected.

Option buttons are provided to select the time for the visual display mode. The default is to simulate 24 hours in approximately 30 seconds. This display speed is too fast to study the details of a simulation pass, but very good for getting a feel for the overall flow of the day. The 24 hour day can be run as slowly as eight minutes – painfully slow.

The simulation is capable of running a single pass and then repeating the exact same randomly generated location and vehicle scenario over and over with different control strategies, ETESS configurations, and grid limits. The mode selection page has a check box to designate that a single pass should be repeated. The first pass generated after this box is checked will be randomly generated using the selection choices made on the Location and Vehicles pages. After this single pass is executed, either with or without visualization, the simulation will return to the SCP. The selection options on the Location and Vehicle pages are now locked out. This locks the exact placement and starting configuration of each vehicle in the first simulation, and not just the set up options. It is an exact repeat of that day. Changes can be made to the other selection pages on the SCP and the next simulation pass can be run to evaluate different control strategies, grid power limits, and ETESS configurations.

The SCP has three command buttons along the bottom: Simulate, Reset, and Exit. These are not part of the selection pages and are always visible on the SCP. Simulate starts the simulation that has just been set up. When a single pass or a Monte Carlo run has been completed and the SCP appears again, the selections are all remembered. Clicking the Reset button returns all selections to their default values. Exit terminates the simulation, but does not leave the Excel program.

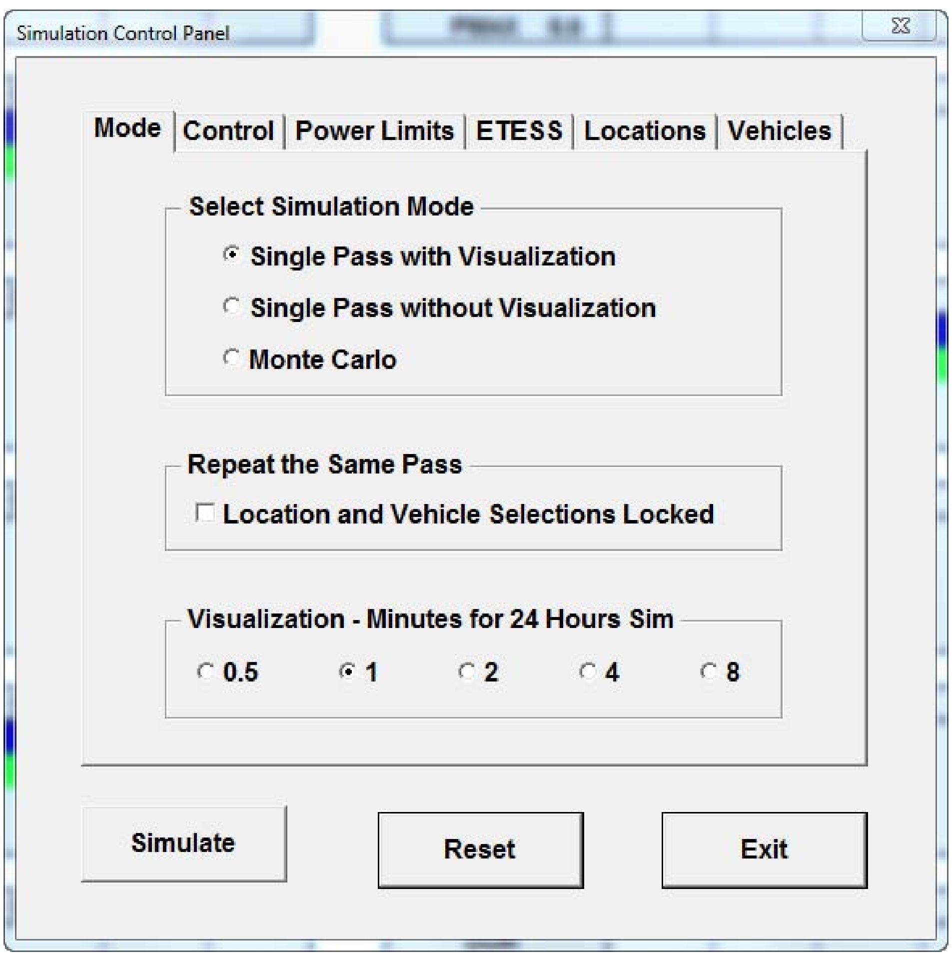


Figure 44 shows the Mode Page of the Simulation Control Panel.

The overall flow of the simulation is shown in the flow diagram in Figure 45. When the simulation is first started, it goes through a complete initialization and then brings up the Simulation Control Panel. This flow chart only shows the Simulate command button paths out of the SCP block – the Reset and Exit paths are not shown. If a Monte Carlo simulation is selected, the next step is Monte Carlo initialization followed by the generation of the Stochastic Model for the Day and then on to the Pass Initialization for the non-stochastic parameters. The single pass mode skips the Monte Carlo initialization block. In the repeat pass mode, the stochastic day block is skipped after the first pass.

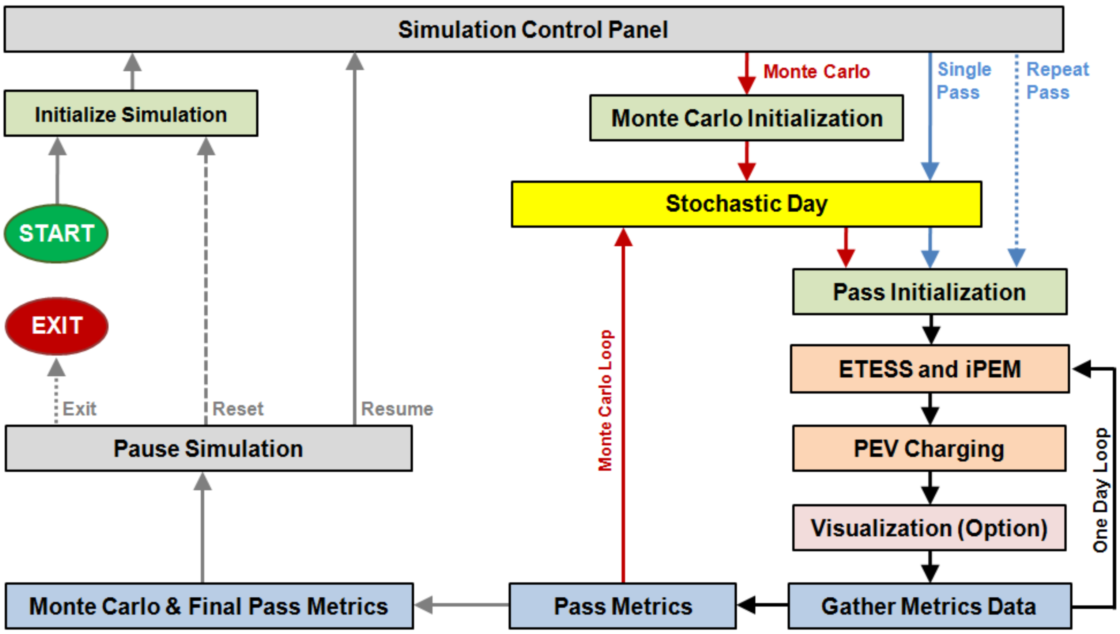


Figure 45 shows the flow of control in the simulation.

Next control passes to the core simulation loop for a single pass through a 24 hour day. The simulation uses a three minute time step interval and loops through 480 intervals to complete the day loop. Each step starts with the allocation of power to each of the vehicles that are charging and setting the rate of ETESS charging or discharging. This is done in the first block labeled “ETESS and iPEM.” This is not a subroutine name but a functional description of what happens first in the core loop. “PEV Charging” is the next functional block in the core loop. Each connected vehicle charges at the authorized power level during that interval and updates its energy request. These updated requests are then used in the next iteration by the iPEM software. Next visualization displays are updated if that option has been selected. The last functional block of the core loop is the gathering of metrics data for that time interval. Control loops back to the ETESS block until the 24 hour day is completed.

After the day is completed, “Pass Metrics” are computed. This is a minimal set that must be processed before another Monte Carlo pass is executed and the pass data is lost. If this is one pass from a Monte Carlo run control goes back to generating another stochastic day, and this continues until 2000 days have been run. After a single pass run or at the end of a Monte Carlo run, control goes to final processing of single pass metrics and the Monte Carlo data. All of the data is now written to worksheets in the Excel workbook. Charts in the Excel workbook are generated from the data written to these worksheets. These are the primary means for evaluating results of each simulation. The various charts and data tables will be described in more detail later in the report.

The simulation then pauses and another Windows Form is displayed (Figure 46). It is labeled "Pause Simulation for Review of Worksheets." Option buttons are presented to select Resume, Reset, or Exit. When the "OK" command button is clicked the selected action is taken. Resume returns directly to the Simulation Control Panel and the last selections are remembered. Reset and Exit perform the same as those buttons on the SCP. This little display is very important because the simulation must continue to execute in the background or it would not be possible to remember the last selections or repeat a single pass. While in the pause state, the various pages of charts and tables of data can be reviewed and the Pause window moved around on a worksheet to not block a view of data. When the user is ready to move on, the appropriate button is clicked.

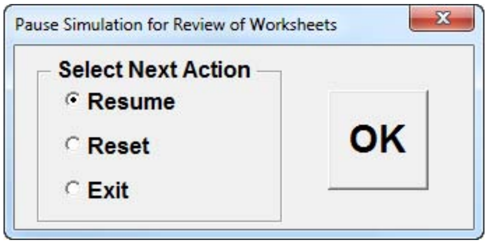


Figure 46 shows the Pause Display.

A screen image of the visualization worksheet is shown in Figure 47. On the right side are three columns and six rows of charge station displays. Each charge station display lists the charge station number and the sequence number of the vehicle that is currently connected to it. Numerical data is provided for the actual duration of the session, the requested energy transfer at the time of connection, the Utilization Factor at the time of connection (which will be described later in the report), and the maximum power of the vehicle's onboard charger. Four progress bars are also shown. The top bar shows the percent of time (duration) that has gone by. The next bar is the percent of the required energy transfer; then the Utilization Factor at that exact time. The last bar is the percent of maximum power that is being used by the vehicle.

The block in the top left corner shows the selection choices. Below that are four vertical tapes. Three show power flow for the Grid, ETESS, and the aggregate of all PEVs. One is for the SOC of ETESS. Across the bottom are data tables and bar displays for metrics data. This is a very colorful and busy dashboard.

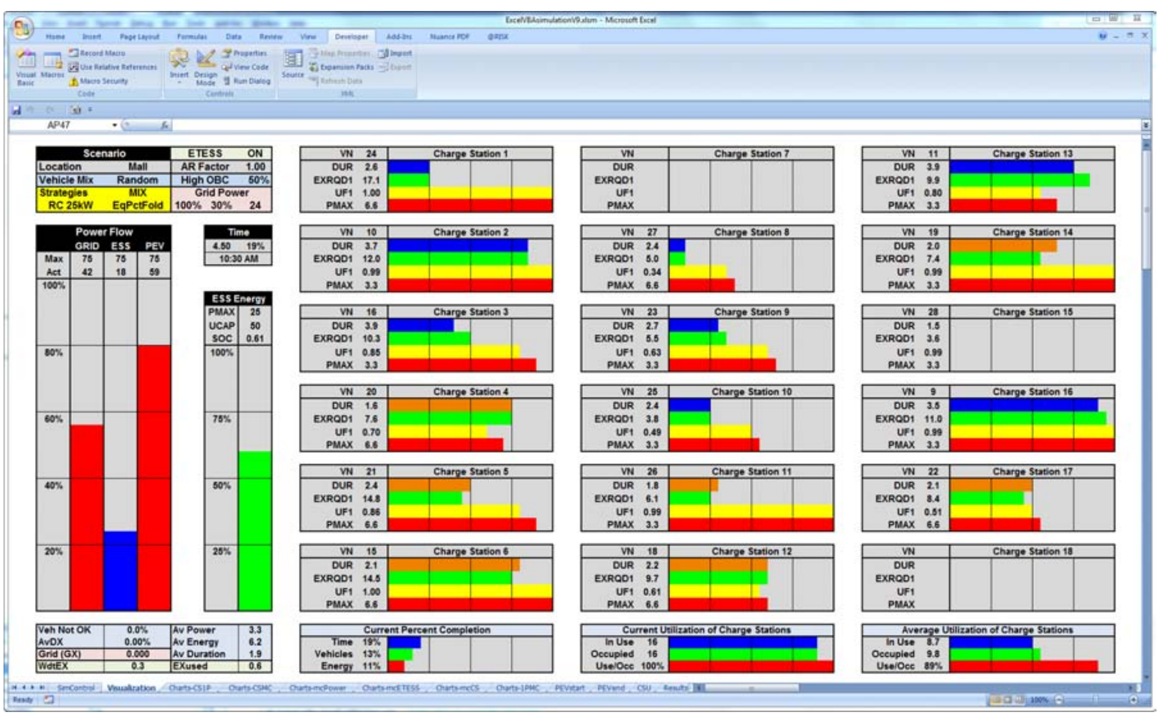


Figure 47 shows the visualization display.

PEV Charging using Optimized Energy Transfer

This section reviews the design considerations for simulating the charging of a single PEV using SAE J2847-1 Optimized Energy Transfer. This section begins with a discussion of some essential battery terminology, followed by a discussion of the time events associated with a charging session. Next a simplified model for the actual charging of the vehicle battery is presented. Then communication between the PEV and ETESS to manage the energy transfer will be discussed. The concepts of Utilization Factor and average power are then introduced..

Vehicle Battery Terminology

In this report the State of Charge (**SOC**) is the fraction of battery capacity that is available and ranges from zero to one. The absolute SOC is measured across the total battery capacity. The relative SOC is across the Usable Capacity (**UCAP)**. The relative SOC is used in this report. An SOC of zero means that there is no usable energy left and an SOC of one means that the battery is full. **SOC1** is the SOC at the time of arrival at the charge station and **SOC2** is the target SOC. The actual energy state of the battery (**EBAT**) is defined as the product of SOC and UCAP (**EBAT = SOC * UCAP**). These relationships are all shown in Figure 48.

A battery has a total (nameplate) energy capacity, but this may not all be available for propulsion. It may not be desirable to drain the battery completely without causing damage. Similarly it may not be desirable to charge it completely either. In this report the UCAP of a PHEV battery is defined as the energy storage (kWh) associated with its charge depleting mode of operation. Energy storage associated with the charge sustaining (HEV) mode is excluded along with potential protected zones at either end of the battery.

The UCAP for a BEV is defined as that associated with the full range of the vehicle with no reserve, although protected zones at either end of the battery are excluded. A BEV is allowed to operate across the full usable capacity – although range anxiety would normally limit operation to a SOC based on UCAP to no lower than 20%. In this report a vehicle's electric range is measured against the UCAP. PEVs consume 200 to 300 Watt-hours per mile. A good rule of thumb is four miles per kWh or 250 Watts per mile. A BEV with a 100 mile range needs a UCAP of 25kWh.

The definition of UCAP and SOC may not be industry standard definitions, but they are useful for this simulation, which is only concerned with charging. The entire purpose is to allow for the random assignment of a required energy transfer for each vehicle as it arrives at a charge station.

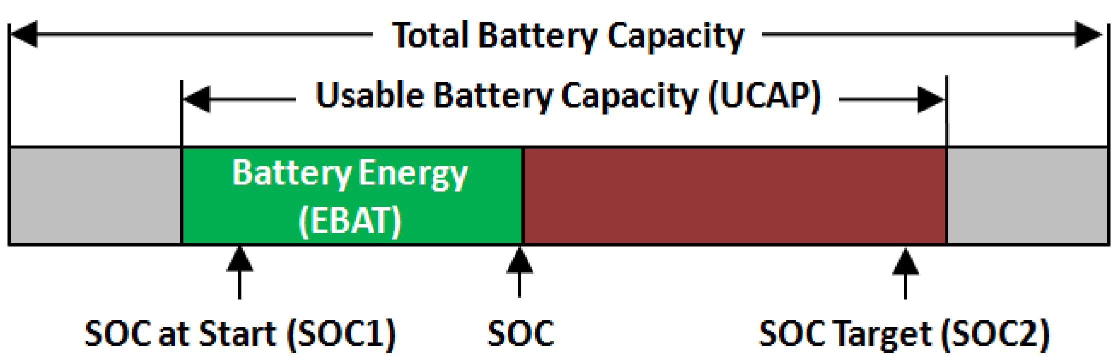


Figure 48 illustrates battery terminology.

It is About Time

There are several time measures used to manage and measure performance of vehicle charging. Figure 49 defines terminology used in this report. Certain time information is known to the PEV and ETESS at connection. The Time of Arrival (**TOA**) is the time that connection is made. Either the PEV or a data entry at the charge station provides the Estimated Time of Departure (**ETOD**) to ETESS. The Estimated Duration (**EDUR**) of the charging session is computed as the difference between ETOD and TOA. The figure shows all of the information known at connection by ETESS and the PEV in black.

Neither the PEV nor ETESS can know the actual Time of Departure (**TOD**) before it happens. TOD is the time that the PEV disconnects from the charge station. It is measureable when it happens, and is useful for performance measurements. The actual Duration (**DUR**) is computed as the difference between the TOD and TOA. Information that becomes known only at TOD is shown in red.

The ETESS and PEV clocks are synchronized at connection and can always measure the current time (**TIME**). The ETESS and PEV must always work with what is known at connection and at the current time for controlling the charging session. Information known or computed at the current time is shown in blue.

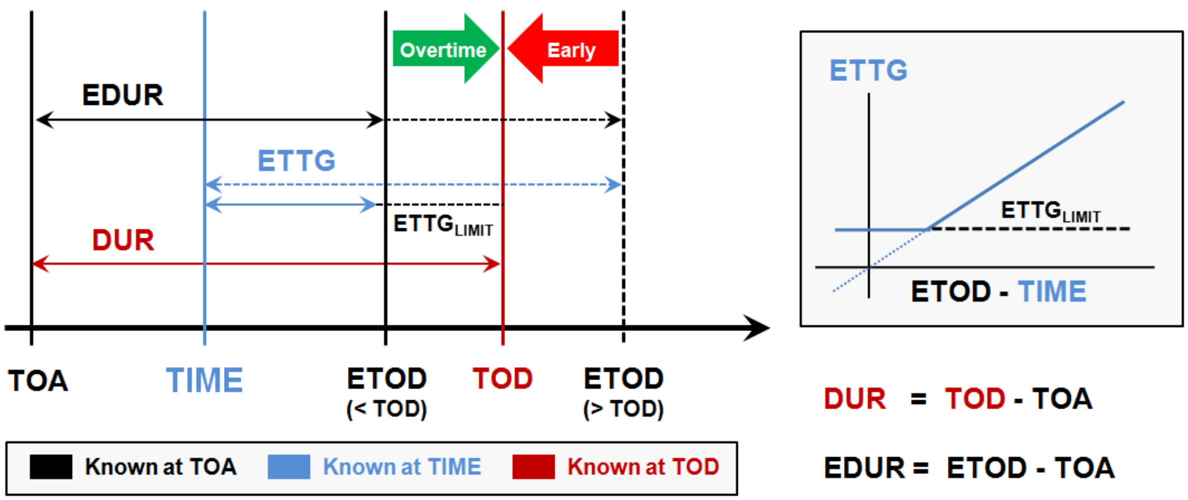


Figure 49 illustrates time terminology associated with vehicle charging.

The Estimated Time to Go (**ETTG**) is a key parameter that ETESS uses to manage charging. It is usually defined as the difference between the ETOD and TIME, but ETTG cannot always simply be set to that for two reasons. If the driver returns and disconnects after the ETOD, the ETTG will become negative and this is bad for algorithms that use ETTG. Also ETTG is often used in the denominator of calculations and it cannot be allowed to go to zero either. A minimum positive value for ETTG ($\mathbf{ETTG_{LIMIT}}$) must be set. This ETTG limiting function is also shown in the figure. Any charging after the ETOD is considered to be Overtime.

The vehicle could also disconnect before the ETOD – an early departure. This is not good for charging because some energy transfer may have been scheduled to occur between the actual return and the expected time of departure. Because the driver will know about the early disconnect, there will be some allowance made for missed charging. Early departure is an issue for establishing performance measures, but of no use for managing the charging because it is unknowable to ETESS or the PEV in advance of disconnect.

Vehicle Charging Model

The purpose of the ETESS simulation is to understand the interaction between groups of vehicles, the ETESS unit, and the grid over a 24 hour cycle. It was designed to allow the evaluation of algorithms to allocate power among the vehicles as well as use ETESS storage to manage total grid loads and minimize disappointment to the vehicle operators. The update interval of power authorizations will be in the order of several minutes at the fastest. It was not intended or necessary to model the more complex interactions that occur between a vehicle's on-board charger, battery, and other vehicle systems, which would need accurate physical models. Because of the number of assumptions in the overall simulation, it was decided that there would be no benefit to trying to model ramp-ups and ramp-downs or conditioning. The extra fidelity would be lost in the variability of the stochastic modeling of times of arrival, durations of stay, efficiencies, and the many other parameters.

The model assumes that the vehicle charger will draw power at level authorized by ETESS (**PCMD**) until charging is completed, but never more than its rated power. ETESS will not authorize a power level greater than the rating of the on-board charger. ETESS will update PCMD authorizations at control intervals and the PEV is expected to draw the authorized power level until it is updated or charging is completed. The interval between ETESS power updates will not be less than three minutes and could be as long as fifteen minutes. This simulation uses a three minute interval. The PEV considers charging to be completed when the SOC reaches the SOC2 target or the battery energy (EBAT) reaches the capacity of the battery (UCAP).

Not all of the power delivered to the vehicle (**PDEL**) can be usefully converted into stored energy in the battery. Effective power is lost two ways. Some of the losses are directly proportional to PDEL and others are just a steady parasitic loss. The on-board charger has an overall efficiency for converting AC current to DC current that is proportional to the power level. It also consumes power in much of its internal electronics that is a fixed level as long it is operating. The battery itself is not perfect in converting the power on the DC Link into stored energy. The electrochemistry is not perfect. Energy is lost in heating of the battery. Active cooling systems result in parasitic losses. The battery management system, communication systems, and vehicle computers also drain power.

The proportional losses can be modeled by multiplying PDEL by an overall conversion efficiency (**EFF**) factor and the steady (parasitic) losses can be modeled by subtracting a steady power (**Veh12vLoad**). It is often called a vehicle 12V load, but it really represents all non-proportional losses. The energy level of the battery (EBAT) at time (t) is defined by

$$\mathrm{EBAT(t) = UCAP * SOC1} + \int_{\mathrm{TOA}}^{t} \mathrm{(PDEL(t) * EFF - Veh12vLoad)\, dt}$$

If EBAT is known, by definition the state of charge is

$$SOC = \frac{EBAT}{UCAP}$$

The vehicle would use its battery management system to compute SOC and then carry out a calculation such as the one below to define the remaining energy transfer required (EXRQD). It is assumed that the vehicle accurately knows its parasitic load - although a nominal Veh12vLoad could be used.

$$EXRQD = (SOC2 - SOC) * \frac{UCAP}{EffNom} + Veh12vLoad * ETTG$$

ETESS transmits an authorized PCMD for each update interval to the PEV. The vehicle charges at that level (PDEL) and periodically sends an updated EXRQD to the ETESS unit. In the simulation this is done every three minutes. ETESS used the EXRQD and other information to compute the next PCMD. How PCMD is defined by ETESS will be discussed later.

Vehicle Communication

The PEV and ETESS will use SAE J2847-1 Optimized Energy Transfer messages to control charging. The required messages were shown in Table 2 in Chapter 3. This is all illustrated in Figure 50. At the time of connection the PEV transmits to the ETESS the time charge is needed, the total energy transfer that is needed, and the requested power. It is assumed that the time charge needed will be the Estimated Time of Departure (ETOD) and that the PEV will not add a contingency buffer. It is possible that a driver will return later than the programmed time of disconnect, but the system allows for this as discussed earlier – TOD and ETOD will generally be different.

It is assumed that ETESS will know the rated power of the on-board charger (**PMAX**). The PEV should always request that the rated power (**PMAX**) of its on-board charger be authorized by ETESS until charging is completed. If communication is not available, ETESS can measure the unrestricted power draw of the PEV by authorizing charging at 7.7kW at the start for a short period, and measuring the power drawn by the PEV. It is important in SAE J2847-1 Optimized Energy Transfer that the PEV does not independently try to charge at a lower power level than its on-board charger rating, except as needed for battery conditioning, and it will never request a lower level than PMAX. A real PEV may use a lower maximum level below the charger rating, but for the purpose of the simulation PMAX will be used. PMAX is intended to represent the maximum steady power that a PEV will draw during the session if authorized to charge at 7.7kW.

The Requested Energy Transfer is computed by the PEV and provided to ETESS at the TOA (**EXRQD1**) and at regular intervals throughout the energy transfer (**EXRQD**). At connection the required transfer is defined as

$$\boldsymbol{EXRQD1} = (\boldsymbol{SOC2} - \boldsymbol{SOC1}) * \frac{\boldsymbol{UCAP}}{\boldsymbol{EffNom}} + \boldsymbol{Veh12vLoad} * \boldsymbol{EDUR}$$

An actual PEV could use a nominal efficiency and load for the calculation of EXRQD or it could use estimated values. The PEV must also calculate the value for SOC. For this simulation a nominal efficiency (EffNom) is used for the EXRQD calculations and a stochastic variation is allowed about the nominal to define EFF for the actual conversion efficiency of each PEV.

ETESS provides the PEV with the time of connection (TOA), the energy available, and the power available at connection. TOA is useful for time synchronization so the PEV and ETESS have the same basic for assessing time to go in respective calculations. Energy available may be useful at the start where this could be used with the driver to plan the session. It is not used in the simulation. This simulation does not provide for “negotiations” with the driver or PEV computer about taking less than the desired energy transfer.

The entire purpose of the iPEM algorithms within ETESS is to accept an EXRQD message from each of the connected vehicles and then to provide a PCMD authorization to each vehicle. This is how it will manage the charging sessions. The PEVs draw the authorized power for the interval, charge their batteries and then update and transmit EXRQD to ETESS to be used for power allocation in the next control interval. The concepts behind the allocation algorithms were reviewed in Chapter 4.

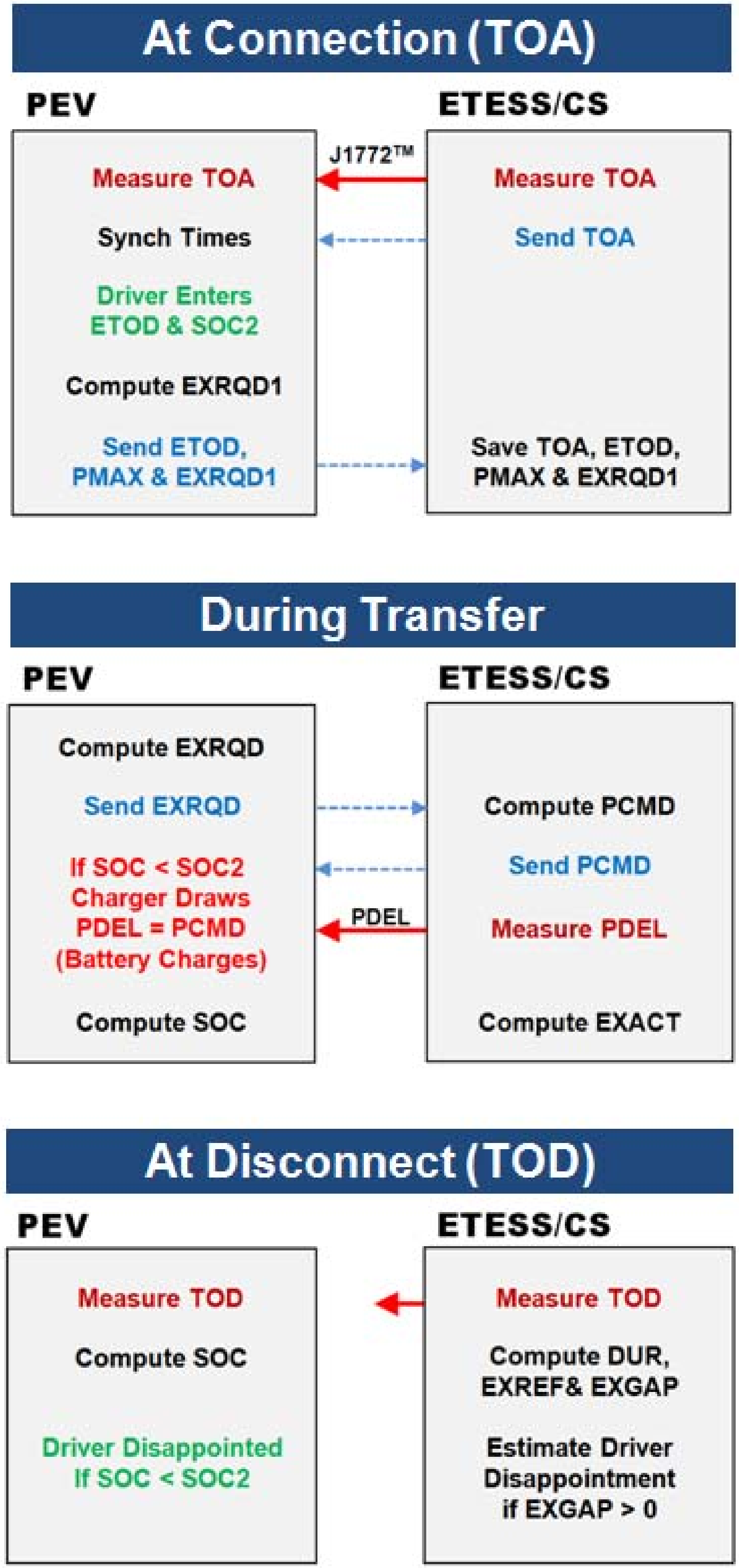


Figure 50 shows measurements, communications, and computation during a charging session.

Utilization Factor and Average Power

One measure of the risk of not completing the required energy transfer is the amount of slack time there would be if charging was done at the rated capacity of the onboard charger (PMAX). Since neither the PEV nor ETESS know when the actual disconnect will occur, everything must be based on the estimated time of departure (ETOD). Performance metrics can be adjusted after the TOD to account for an early departure. At any point during a charging session the minimum time (**TMIN**) to complete remaining required energy transfer (EXRQD) is

$$TMIN = \frac{EXRQD}{PMAX} \qquad TMIN1 = \frac{EXRQD1}{EDUR}$$

The difference between the estimated time to go and the minimum time to complete is the available slack time (**SLACK**).

$$SLACK = ETTG - TMIN$$

The latest start time (**TLATE**) is the difference between the estimated time of departure (ETOD) and TMIN.

The Utilization Factor (**UF**) is defined as the ratio of the required time to complete charging over the remaining time.

$$UF = \frac{TMIN}{ETTG} \qquad UF1 = \frac{TMIN1}{EDUR}$$

UF is a measure of risk. When it is greater than one, it is not possible to complete charging successfully. The values at the time of arrival (TOA) use the estimated duration (EDUR) in place of ETTG and are denoted as **TMIN1** and **UF1**. The values at TOA are useful for power allocation because they define the risk at the start for a PEV. Both UF and UF1 are useful. These relationships are illustrated in Figure 51.

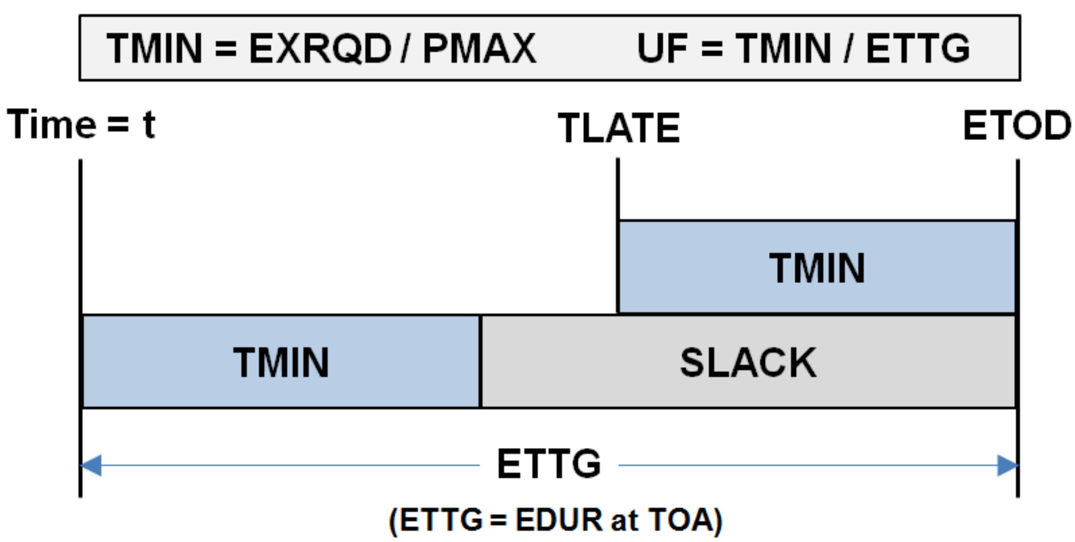


Figure 51 shows the relationships of TMIN, SLACK, and TLATE.

Average Power (PAV) is the power level that will complete the required energy transfer (EXRQD) in the estimated time to go (ETTG). It is defined as

$$PAV = \frac{EXRQD}{ETTG}$$

The Average Power at the TOA (PAV1) is based on the estimated duration (EDUR) and the total required energy transfer (EXRQD1). It is defined as

$$PAV1 = \frac{EXRQD1}{EDUR}$$

Utilization Factor can also be defined as the ratio of average to maximum power

$$UF = \frac{TMIN}{ETTG} = \frac{EXRQD}{PMAX * ETTG} = \frac{PAV}{PMAX}$$

At TOA the same relationships hold for computing UF1, TMIN1, and PAV1 with EDUR used in place of ETTG. As discussed in Chapter 4 the use of average power is one basic strategy for allocation of power.

From One Vehicle to a Group of Vehicles

The simulation dynamics for the vehicle are very simple. At the start of each three minute simulation interval, the amount of remaining energy transfer (EXRQD) for each PEV is provided to the functional block that represents ETESS and its iPEM software. This simulation function does its thing and provides a power authorization (PCMD) to each vehicle. The authorization will never exceed the PMAX for that vehicle. The vehicle charges at the authorized power level until it reaches the target SOC or the interval ends. It updates the EXRQD for the next interval. While at the core of the simulation is the charging of an individual PEV, the primary objective was dealing with the group of PEVs and the interaction with ETESS and power limitations of the facility and the grid.

The concepts of UF, TMIN, and PAV are more relevant to the ETESS logic than to each PEV. These can be computed by ETESS and used to help with power allocation. Some of the fundamentals of power allocation were discussed in Chapter 4. It was not an objective of this project to develop and evaluate the iPEM algorithms for optimal power allocation, but preliminarily some concepts were evaluated using the simulation.

Just Another Stochastic Day

The simulation is capable of creating charging sessions for various location scenarios and vehicle scenarios. Each pass of the simulation is for a 24 hour period that begins at 6:00 AM. The simulation has a Monte Carlo mode where thousands of passes can be executed with randomly generated arrivals and departures of different vehicle types with different needs for energy transfer. This section describes some of the methods used to create each stochastic day.

The simulation day is established by allowing a vehicle to arrive and be placed into an empty charge station at the location. The duration of a stay is defined for that vehicle based on a probability model for that time of day for that location. A vehicle number is assigned (VN) and a charge station number (CSN), time of arrival (TOA), and a time of departure (TOD) are associated with that vehicle. When the next vehicle arrives, a test for an open charge station is conducted again, and if one is available the next vehicle number is assigned. If a charge station is not available when a vehicle arrives, it waits briefly and if a space does not open up, it departs to find another place to charge. The loading process continues until the day is completed. This loading process is done before the simulation executes the day.

This is illustrated in Figure 52. The simulation actually builds a matrix of charge station occupancy similar to this figure, which is used to manage execution of the simulation. Also, an array is created that defines the complete state of each vehicle at the start, during transfer, and at completion. All of the information to create the charge station occupancy matrix is contained in the vehicle state array. That is where VN, CSN, TOA, and TOD are stored as well as all other information about each vehicle.

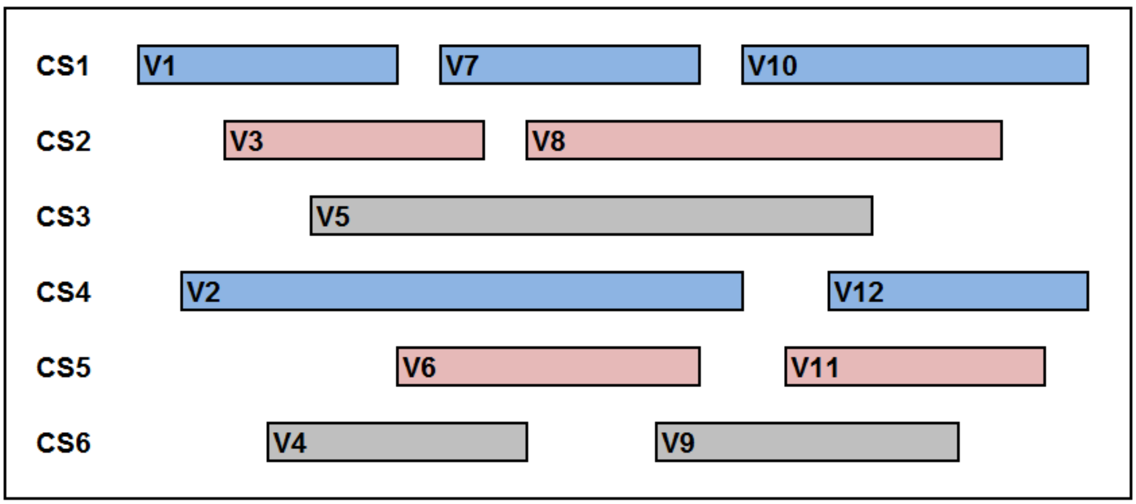


Figure 52 is an example of loading vehicles into charge stations.

After all of the vehicles are assigned and placed, the other random details can be defined. The estimated time of departure (ETOD) comes from a scenario based probability model. The vehicle battery capacity (UCAP), onboard charger power (PMAX) and charger efficiency (EFF) are defined next, based on a vehicle mix probability model. Finally the state of charge at connection (SOC1) and the target state of charge (SOC2) are defined. This information fully describes the set up for a pass. Once this is saved, the same exact randomly generated day can be repeated over and over by rebuilding and reinitializing with the set of VN, CSN, TOA, TOD, ETOD, UCAP, PMAX, EFF, SOC1, and SOC2. There are many variables that need to be initialized, but this set completely defines a pass. The details behind of some of the probabilistic models will be discussed next.

The Arrival Process

This is a queuing problem where vehicles arrive, are served, and depart. The Poisson arrival process is a key model for simulating the random arrival of customers in a queue. (Banks, et al. 2010) The model produces a random interarrival time (IAT) for the next arrival based on an arrival rate (λ) and a uniform random number (URN).

$$IAT = -\frac{1}{\lambda} * log(URN)$$

For the simulation it was desired to maintain a constant arrival rate per charge station (λ_{CS}). The location arrival rate (λ) equals the product of the charge station quantity and the charge station arrival rate (λ_{CS}). The arrival rate per charge station is defined for each location scenario and can vary during the day. For example the arrival rate might be high in the morning and very low in the late evening. This is all part of the design of a location scenario.

Excel Visual Basic provides a random number generation function that provides a random number between zero, and one each time it is called. This is used extensively in the simulation.

Establishing the Time of Departure

The duration of the stay for each vehicle (DUR) can be defined using either a triangular or rectangular probability distribution function. The choice of distribution function is based on the selected location scenario. Both of these distributions have a defined minimum and maximum duration. The triangular distribution also has a nominal distribution (the Mode). The simulation uses the nominal distribution value to determine whether to use a triangular or rectangular distribution – if the value provided for the nominal duration is outside the min-max range it uses a rectangular probability function. The values for the minimum, nominal, and maximum duration can be changed during the day based on the location scenario. This is shown in Figure 53.

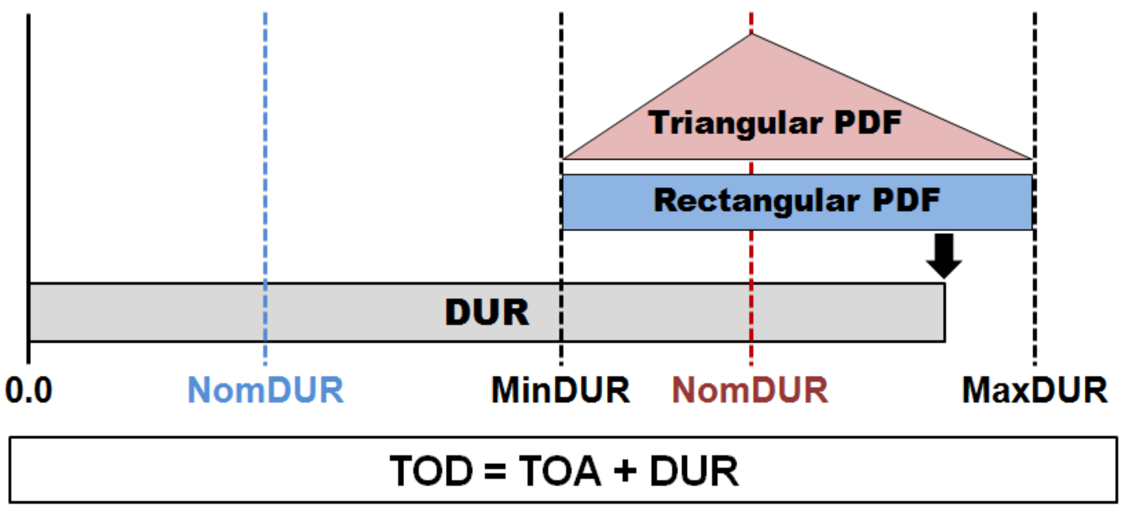


Figure 53 shows probability functions for duration.

The scenario builder also allows for a "not later than" time to be defined for the time of departure (TODnlt) and also a probability that a vehicle will stay until the end of the simulation (PrEnd). These values can also be changed through the day to shape the day. The default is a TODnlt of 24 hours and a PrEnd of zero. PrEnd is useful in the evening when some vehicles may plan to park and charge all night and others only plan to stay for a few hours.

Establishing the Estimated Time of Departure

During the placement of vehicles it is critical that the actual arrival and departure times be established first. Still, the power management during the simulation is all based on the estimated time of departure. This models the variability of when a driver tells the system that he will return versus when he actually returns. The variation can be biased based on the type of location. If there is a penalty for returning late, the estimated times might be biased to be longer. This is like putting enough coins in the parking meter for one hour and returning after 45 minutes. If there is no penalty, but the driver wants to game the system by returning later than indicated the bias might be on the early side. Even without a bias the driver can only estimate, with a certain accuracy, the actual time of disconnect.

The method for computing estimated duration (EDUR) and estimated time of departure (ETOD) is the shown in Figure 54. For each location scenario a minimum, nominal, and maximum variance of EDUR from the duration (DUR) is defined. This can be changed as a function of the time of day in each scenario. As with the probability distributions for DUR if the nominal is outside the min-max range, a rectangular probability distribution is used. The estimated duration variance (EVAR) is added to the DUR to get EDUR. ETOD is the time of arrival (TOA) plus EDUR.

In the real world, the driver directly enters the ETOD, and this is then used to control the power allocation by ETESS. A driver will most likely leave earlier or later than the ETOD, and the actual TOD is then established. This must work in reverse in setting up the simulation. Only the actual TOD of vehicles is relevant for placing a newly arrived vehicle at an empty charge station, so it is defined first and we work backwards to defining the ETOD. ETOD is still used by ETESS and the TOD is only used after disconnect for metrics.

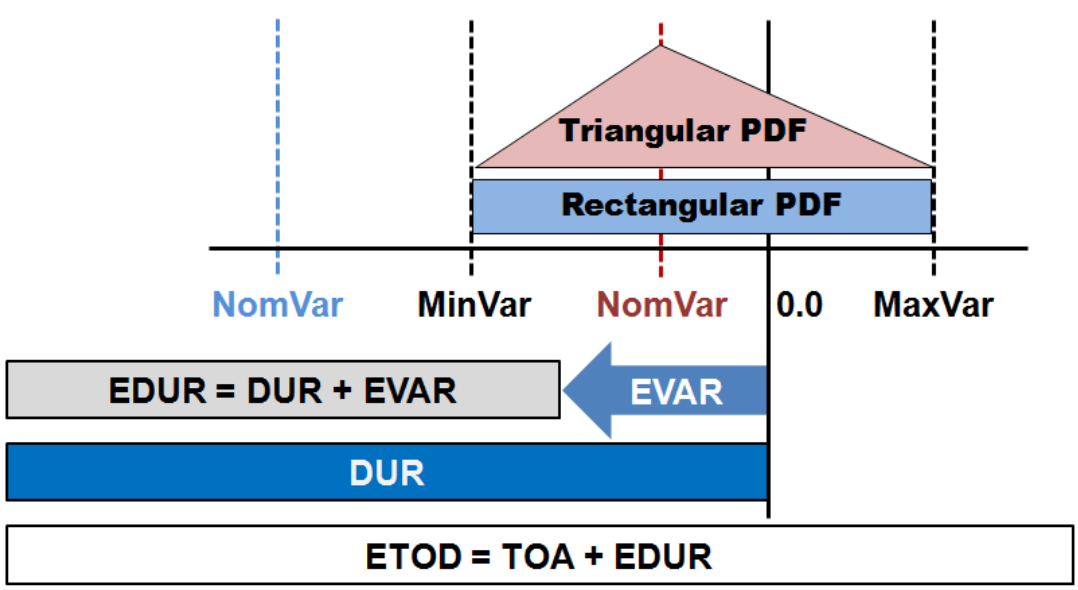


Figure 54 shows the approach for defining estimated time of departure.

Defining the Vehicle Characteristics

The simulation uses five generic vehicles: two are PHEVs and three are BEVs. The PHEVs have a 20 mile (PHEV20) or a 40 mile (PHEV40) electric drive range. The BEVs have a 60 (BEV60), 80 (BEV80), or 100 (BEV100) mile range. A vehicle can have either a 3.3kW or a 6.6kW on-board charger.

The simulation allows one of ten vehicle scenarios to be selected. Each vehicle scenario is a mix of these five vehicle types. The primary difference is the usable capacity of their battery (UCAP). Also the stochastic model for determining state of charge at TOA will use a different model for a PHEV versus a BEV – this will be discussed later. After each vehicle is placed in the simulation, the appropriate probability distribution for the selected vehicle scenario is used to determine the vehicle type. This is shown in Table 4.

The simulation also allows a probability to be defined that a vehicle will have a 6.6kW rather than a 3.3kW on-board charger. The size of the charger is determined using this distribution. The efficiency of the charger (EFF) is defined using a triangular distribution (0.85, 0.90, 0.92) and EFFNOM is set to 0.90. The Veh12VLoad is 150 Watts (0.150kW).

For the same set of vehicle arrivals and departures, the vehicle scenario can go from all PHEV20s with 3.3kW chargers to all BEV100s with 6.6kW chargers.

A more precise model could have been used by including specific vehicle models, but this provides a reasonable mix of the types that might use an AC Level 2 charge station.

A uniform random number is selected, and based on the selected scenario the vehicle type is easily defined. In the Random Scenario a URN between 0.4 and 0.6 designates a BEV60 with a UCAP of 15kWh. If the probability of a vehicle having a high power charger is set to 0.6, then a URN between 0.6 and 1.0 will result in a 3.3kW charger being assigned to the vehicle.

Table 4 shows the ten vehicle scenarios.

Vehicle Class	**PHEV**		**BEV**			**UCAP Expected Value**
Vehicle Type	PHEV20	PHEV40	BEV60	BEV80	BEV100	
UCAP (kWh)	5	10	15	20	25	
Scenario	**Mix Probability for Scenario**					
PHEV20 ONLY	100%					5.0
PHEV RANDOM	50%	50%				7.5
PHEV40 ONLY		100%				10.0
SKEW PHEV	30%	25%	20%	15%	10%	12.5
RANDOM	20%	20%	20%	20%	20%	15.0
BEV60 ONLY			100%			15.0
SKEW BEV	10%	15%	20%	25%	30%	17.5
BEV RANDOM			33%	33%	33%	20.0
BEV80 ONLY				100%		20.0
BEV100 ONLY					100%	25.0

Defining the State of Charge at Connection

A key vehicle parameter for the simulation is the State of Charge at the Time of Arrival (SOC1). This is a key element in determining the amount of energy required to be transferred to the vehicle during the charging session, particularly if you assume that the driver is always interested in filling the battery, even if it is not technically feasible in the available time. SOC1 will clearly be a stochastic variable, but what factors will influence the probability distribution?

The decision by a PEV driver to stop to recharge the battery is complex and related to both physical and behavioral factors. For a BEV the remaining range at any given time is absolute and the decision about when, where, and how long to recharge is critical. This is based largely on being able to reach the charge station with a reasonable reserve, and being able to take on enough energy at the charge station to get to the next charge station (or home base).

The simulation must take the perspective of the charge station and not the vehicle and driver. The issue is what is the likely state of charge for a vehicle that arrives at a charge station, and not when does a driver seek out a charge station. In the simulation it is a fact that the vehicle has arrived to be charged. The probability distribution for SOC1 is about the state of the vehicles that have connected, not those that could or should connect.

For example, two BEVs drive to a movie complex and only one elects to recharge during a three hour stay. The SOC1 of the BEV that plugged in to recharge could be higher than that of the BEV that elected not to recharge. The driver of the vehicle that recharged may have needed the energy to get home and the other did not. It could also be that the driver that recharged was just very conservative and recharges at every opportunity, even if the battery is 90% full. It could also be that the BEV that did not recharge did not have enough energy to get home, but the driver planned to recharge at another location after the movie where the prices were lower. All that the charge station knows is that a vehicle appeared and has a certain SOC1.

The type of charge station will influence the decision to stop and recharge. For charge stations at work, a BEV will arrive with a SOC1 based on the commute distance and the usable capacity of the battery (UCAP). If it is filled during the day, it should have enough energy to get home. For a specific work location and set of commuters with assigned charge stations, this pattern would be very repeatable because the distances from home to work could be defined for each vehicle with some slight variations. The commute distance may not be a completely independent variable because the choice of buying a BEV versus a PHEV could be heavily influenced by the planned commuting distance.

The duration of charging could be either an independent or a dependent variable. For a reserved charging spot at work, the PEV might be at the spot for nine hours even if it could be refueled in only one hour. This may also be true at a movie complex, where the vehicles would plug in for two to three hours and would draw what is needed during that time. In other cases the owner may plan to stay "long enough" to fill the battery. If the driver or the PEV "tells" the charge station at plug-in that that the planned departure will be in three hours, the charge station cannot know whether this is intended to be "long enough to charge to full" or "give me as much as you can while I'm here."

Is it more likely that a PHEV will start charging at a lower SOC1 than a BEV? This is likely to be true. With a PHEV there will be no "range anxiety" because the vehicle will continue to operate in a charge sustaining mode with the full capability of a regular HEV after the battery capacity allocated to charge depleting operations has been consumed. It would not be unreasonable for a PHEV to arrive with an SOC1 of zero. For the purposes of the simulation the usable capacity (UCAP) for a PHEV is set to reflect 100% of the charge depleting capability. For a BEV it is likely that the driver will always allow a reserve and never let the SOC go below a minimum threshold, except in an emergency. For the simulation, the threshold has been set to 20% - although UCAP for a BEV battery is still based on the full 0% to 100% charge depleting SOC range. This establishes a lower limit for probability distribution of SOC1 of 0% for a PHEV and 20% for a BEV.

What about the upper limit of SOC1? The physical upper limit for SOC is 100%, but it is not likely that anyone would plug-in and start charging if the vehicle battery is full. This could be modeled using a highly skewed probability distribution that ends at 100% or it could be modeled by setting a hard upper limit for the SOC1 distribution. It is likely that the vehicle has to drive some minimum distance to get to a charge station from the last charge station. One approach is to set a minimum distance such as four miles (1.0 kWh) that will result in a variable upper SOC1 limit based on the UCAP. Another approach is to set a maximum SOC1 level and assume that the driver would not stop to charge if the battery was not depleted by a certain percent of capacity.

While the lower limit of SOC1 range is set at empty for a PHEV and a relatively “hard” minimum reserve of 20% for a BEV, the upper threshold is more subjective. For this simulation it is assumed that a BEV would make more use of opportunity charging than a PHEV and some might actually start charging even at a high SOC1 threshold of 90%. For this simulation it is assumed that a PHEV would not charge at a public location unless it was closer to empty. With no range anxiety there would be no strong incentive for opportunity charging at short intervals to keep the battery full. An upper limit of 50% was selected for the PHEV SOC1 distribution.

The shape of the distribution is also significant. One approach is to use a uniform distribution across the range. Another approach is to use a triangular distribution with the same minimum and maximum as above, but with a mode value specified. For the BEV distribution a mode of 0.6 was selected and a value of 0.1 was selected for the PHEV. These distributions are shown in Figure 55.

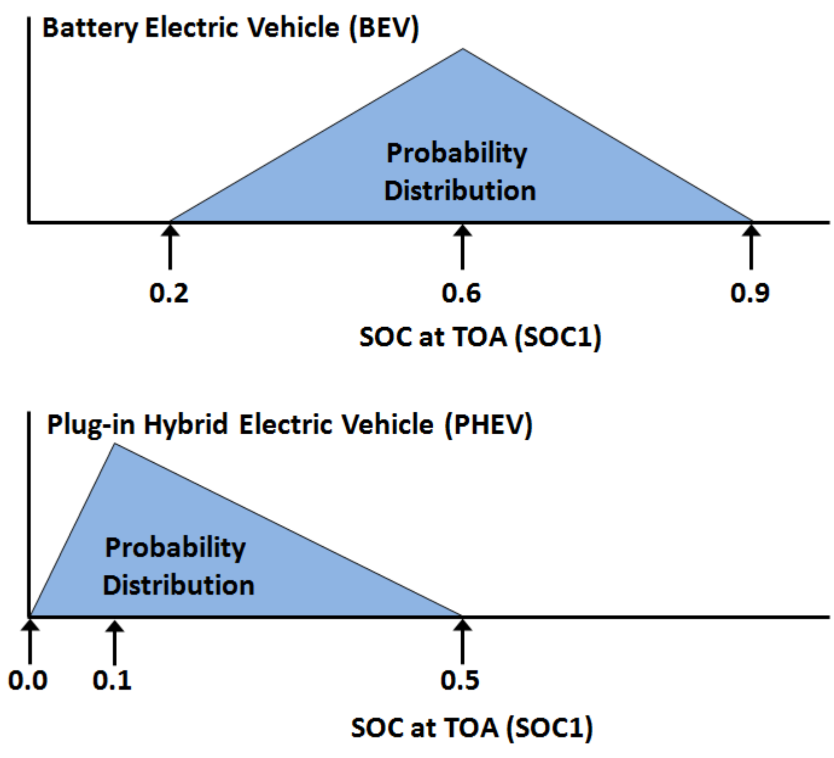


Figure 55 shows probability distributions for battery SOC at connection.

Keeping the Problem Feasible

Usually the objective of charging is to fill the battery – to take state-of-charge at disconnect (SOC2), to one. Even if this is not possible to accomplish in the planned time at the rated power of the charger, this may still be the objective. In the impossible situation, the driver would most likely be happy as long as the vehicle was able to charge at its rated capacity for the entire session. The ETESS system can easily detect this situation because the Utilization Factor at connection (UF1) would be well above 1.0 and performance metrics could be adjusted to not count the excess energy request against the system.

For the simulation it was decided to keep SOC2 = 1.0 as the target for all vehicles and to adjust the SOC1 upward, if needed, to make the charging situation at least minimally feasible for every vehicle. Feasible means that UF1 cannot be greater than 1.0 and this leads to the maximum possible change in SOC over the expected duration (ΔSOC) to be

$$\Delta SOC = \frac{(PMAX * EFF - Veh12VLoad) * EDUR}{UCAP}$$

The minimum value for SOC1 (with SOC2 = 1.0) is then

$$MinSOC1 = 1 - \Delta SOC$$

If the SOC1 defined by the probability distribution is achievable (UF1 < 1.0) it will be greater than the MinSOC1 value. Otherwise it will be lower and the MinSOC1 should be used for SOC1. This is illustrated in Figure 56. Case 1 has a MinSOC1 below the value defined by the distribution and SOC1 does not need to be adjusted. In Case 2 the vehicle could never reach SOC2 = 1.0 and SOC1 needs to be shifted to the MinSOC1 value (1.0 – ΔSOC) to be feasible.

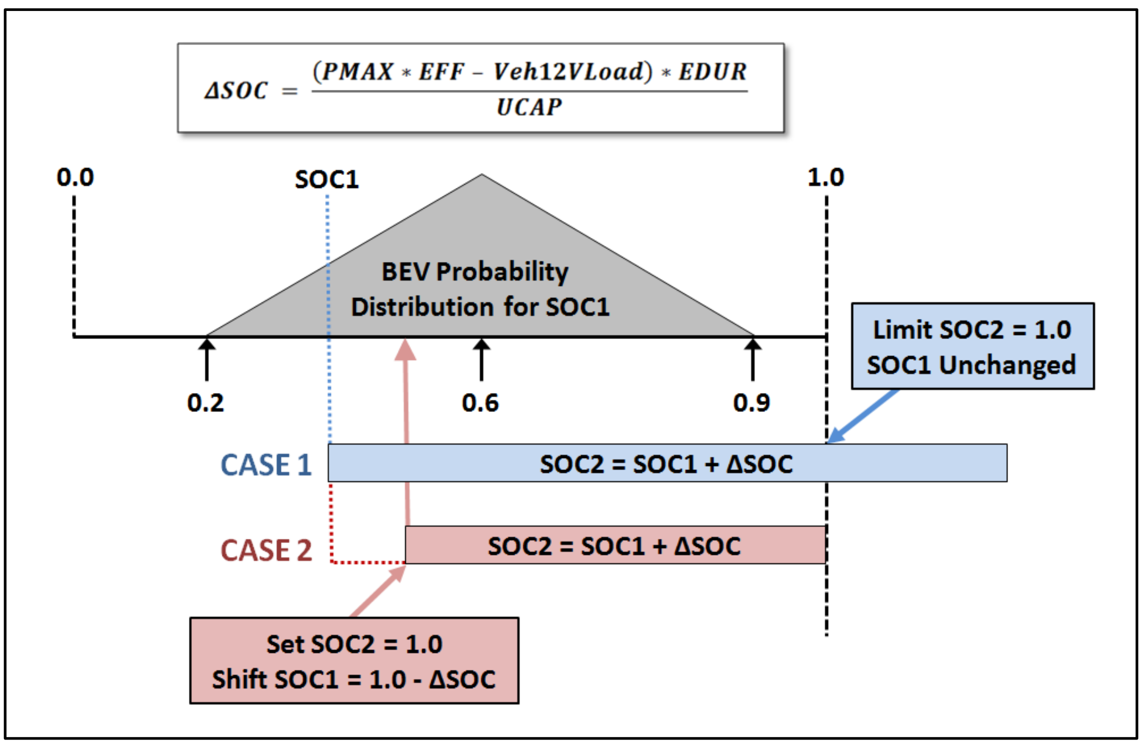


Figure 56 shows how SOC1 is adjusted to maintain a feasible solution.

Selecting the Location and Vehicle Scenarios

Two pages of the Simulation Control Panel shown in Figure 44 are used to set up the scenarios for the stochastic parts of the simulation: the "Locations" page and the "Vehicles" page. The content of the Vehicles page is shown in Figure 57 Figure 58. There are ten possible probabilistic mixes of PHEVs and BEVS that can be selected. These are described in Table 4. The percent of high power on-board chargers is selectable from none to 100% in increments of 25%. A vehicle only gets either a 3.3kW or a 6.6kW charger.

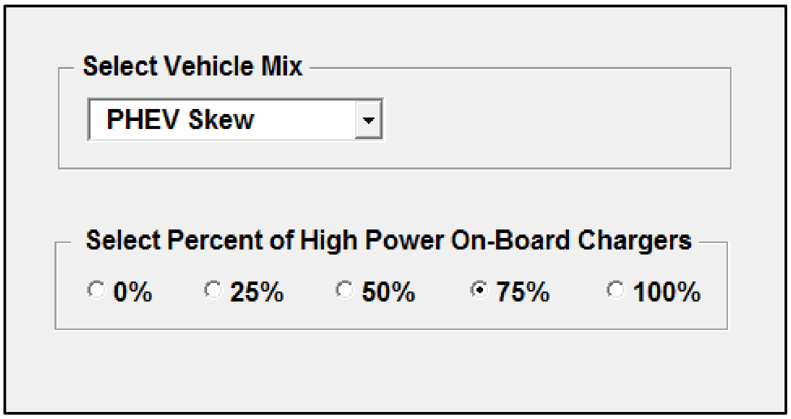


Figure 57 shows contents of the Vehicles Page of the Simulation Control Panel.

The content of the Locations page is shown in Figure 58. On this page the number of charge stations, the location scenario, and the arrival rate multiplier are selected. The number of charge stations is a primary driver for total power consumption. The limitation to a maximum of 18 charge stations was largely made to accommodate visualization display constraints, but this is a reasonable limit for ETESS sizing as well.

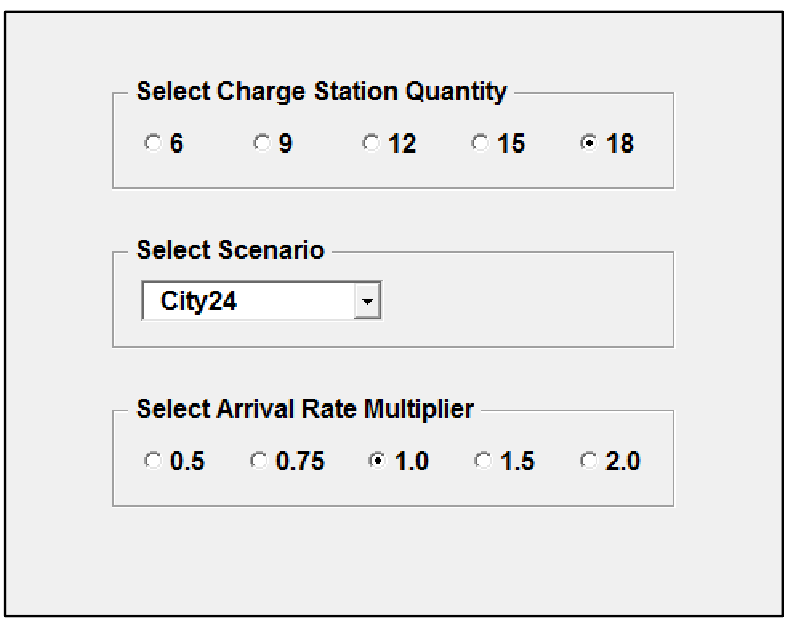


Figure 58 shows contents of the Locations Page of the Simulation Control Panel

A location scenario defines a venue such as a cinema complex, shopping mall, city garage, or employee parking at an industry for day of the week and time of the year. There are five scenarios: High Stress, Mall, Movie, Work, and City 24. The parameters that govern these scenarios are provided in Table 5. These are only approximate scenarios and calibrated scenarios can be used when real user data becomes available.

Each location scenario is defined by nine parameters, each of which can be changed at any time interval of the simulation. Only the most recently defined value for a parameter is used. These parameters govern the arrival rate for vehicles per charge station at a given time, the probability distribution that governs for duration of the stay for an arriving vehicle, the probability distribution for the variance in actual versus estimated duration, a time that an arriving vehicle must depart, and a probability that an arriving vehicle must stay until 6:00 AM Duration and variance in estimated and actual duration can use either a uniform (rectangular) or a triangular probability density function.

Table 5 shows Location Scenario Properties.

Location Scenarios									
Time	AR	DUR					EDUR		
of Change	PerCS	Min	Nom	Max	TOD-NLT	PrEnd	Min	Nom	Max
High Stress									
6:00 AM	0.5	1.0	0.0	3.0	2:00 AM	0.0	-0.25	0.00	0.50
12:00 AM	0.0								
Movie									
6:00 AM	0.0	2.0	2.5	3.5	6:00 AM	0.0	-0.25	0.00	0.50
9:30 AM	0.3								
11:00 PM	0.0								
Mall									
6:00 AM	0.5	1.0	2.0	4.0	12:00 AM	0.0	-0.50	0.00	0.50
10:00 PM	0.0								
Work									
6:00 AM	0.7	8.0	8.5	9.5	6:00 AM	0.0	-0.50	0.00	0.50
8:00 AM	0.0								
10:00 AM	0.2	2.0	0.0	4.0	4:00 PM				
2:00 PM	0.0								
4:00 PM	0.5	8.0	8.5	9.5	2:00 AM				
6:00 PM	0.0								
City24									
6:00 AM	0.5	1.0	2.0	4.0	1:00 AM	0.0	-0.25	0.00	0.25
6:00 PM						0.5			
8:00 PM						0.0			
10:00 PM	0.0								

Vehicle State Variables

The simulation saves all of the state variables for each vehicle in a two dimensional array (PEV). Many are defined during the set up of the Stochastic Day. Other are initialized at the start of each pass and then updated during the simulation. All of the variables listed in Table 6 have been defined in this chapter. Additional state variables will be defined in later chapters.

Table 6 lists the vehicle state variables defined in this chapter.

Vehicle State Variables (PEV Array)	
Name	**Description**
The Stochastic Day	
Load the Charge Stations	
VN	Vehicle Number
CSN	Charge Station Number
TOA	Time of Arrival
TOD	Time of Departure
DUR	Duration
Establish Estimated Time of Departure	
ETOD	Estimated Time of Departure
EDUR	Estimated Duration
Assign a Vehicle Model	
PMAX	Power Rating of On-Board Charger
UCAP	Usable Battery Capacity
EFF	Charger Efficiency
BEV	BEV = 1, PHEV = 0
Define Initial and Target State of Charge	
SOC1	State of Charge at TOA
SOC2	State of Charge Target
Initialization of a Defined Pass	
Initialize and Update during Simulation	
SOC	Actual State of Charge
EBAT	Battery Energy Level
EXRQD	Energy Transfer Required for ETTG
UF	Utilization Factor
PAV	Average Power Required over ETTG
TMIN	Minimium Time to Charge
SLACK	Slack Time at PMAX
TLATE	Latest Time to Start Charging at PMAX
Save TOA values	
EXRQD1	EXRQD at TOA
UF1	UF at TOA
PAV1	PAV at TOA
TMIN1	TMIN at TOA
Other State Variables	
Power Allocation and Use	
PCMD	Power Commanded by ETESS
PDEL	Power Used by Vehicle

System Selections

A fundamental purpose of the simulation is to provide a platform for assessing the impact of groups of charging PEVs on the total power demanded by the facility, and how ETESS and iPEM logic can manage that demand. Much of the earlier discussion was about the charging of the individual vehicle and metrics for disappointment if the full expected transfer was not completed by disconnect. Then the process for constructing a scenario for a mix of vehicles at a specific location was discussed – the stochastic day. Now the discussion must turn to the collective PEVs, the facility power, and ETESS.

The simulation must allow limits to be defined for grid power. It must allow different control strategies to be evaluated both with and without ETESS units. It must allow different ETESS configurations to be assessed. The simulation allows an exact vehicle scenario – not just the selections – to be repeated for a single pass with different options for ETESS configuration, grid power limits, and control strategy. This allows for a quick side-by-side assessment of different options. This is not relevant to a Monte Carlo simulation, where only the location and vehicle selections need to be retained between comparison runs with different ETESS, grid limit, or control strategies.

ETESS Selections

The “ETESS” page is shown in Figure 59. ETESS can be made available or it does not need to be used in the simulation. The ETESS power can be 25kW, 50kW, 75kW, or unlimited. Unlimited actual sets a limit of 150kW that exceeds the power capacity of 18 charge stations (139kW). The available energy can be one, two, or three hours or unlimited. Unlimited actually sets 24 hours - a value is needed for the simulation.

The objective is to set what is available for use by the vehicles. If a 75kW ETESS unit needs to reserve 50kW for ancillary services, a 25kW level would be set for use with the vehicles. Normally the ETESS unit would be charged by 6:00 a.m. and the SOC would be 100%, although the simulation allows lower settings to be used.

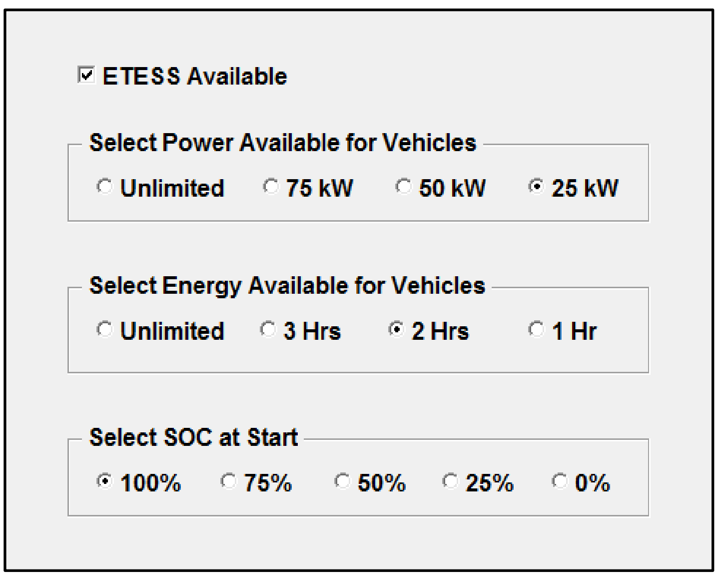


Figure 59 shows the Contents of the ETESS Page of the Simulation Control Panel.

Power Limits Selections

The "Power Limits" Page is shown in Figure 60. The Facility Power Limit applies for the full 24 hours. The limit is set based on charge station capacity of 7.7kW. This does not derate each charge station but it allows the limits to scale with the number of charge stations. At 40% this sets the facility limit to 55.4kW.

A demand response power limit can also be set. If selected, this can be 20%, 30%, or 40% of the capacity. The window can be two, four, eight, or 24 hours. If a 24 hour limit is selected this actually becomes the facility limit, which can now go as low as 20%.

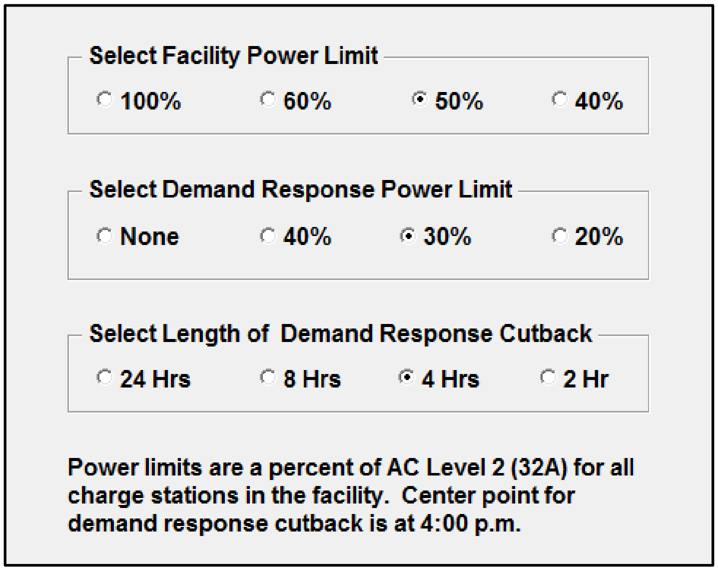


Figure 60 shows Contents of the Power Limits Page of the Simulation Control Panel.

Control Strategy Selections

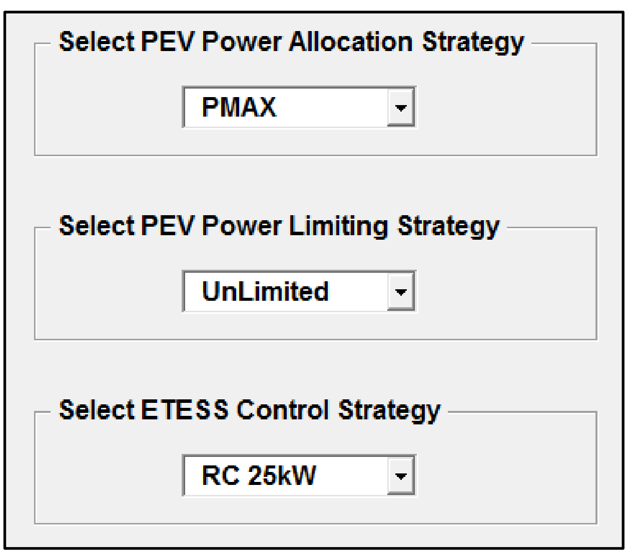


Figure 61 shows the content of the Control Page of the Simulation Control Panel.

The content of the "Control" Page is shown in Figure 61. The strategy for controlling the PEV initial power allocation is selected from one Combo Box. Another Combo Box is used to select a PEV power limiting strategy. The strategy for managing the charging of the ETESS unit is selected from another Combo Box.

There are only two ETESS control strategies at the present time. In this simulation the ETESS unit recharges whenever the collective power drawn by all of the vehicles is less than the grid limit. It will draw the amount of power available up to the lower of the limit or the ETESS limit. In one mode, the charging is limited to 25kW. In the other, it uses the selected power rating. This can result in a large power swing when the demand response cutback window ends. It may be more desirable to use a lower ramp rate. This could also be a function of the cost of energy. Other control strategies can be added for evaluation.

The PEV Power Allocation Strategy is used to allocate power to each connected PEV at the start of each control interval (the simulation three minute iteration intervals). There are four strategies. The "PMAX" strategy allows the vehicle to charge at the rating of its on board charger. The "PAV @ TOA" strategy applies the average power (PAV) computed at the time of connection (TOA). The "1.1 * PAV" strategy takes a multiple of 1.1 times the average power (PAV) needed complete charging in the estimated time remaining to disconnect (ETTG). The "MIX" strategy is a mixed allocation of PMAX, 1.1 * PAV, and delayed start based on Utilization Factor, but only if all connected vehicles cannot charge at PMAX and stay within a grid limit – it reverts to PMAX if they can stay within limits.

There are five PEV Power Limiting Strategy choices. These are used after ETESS power is applied. The "Unlimited" strategy does not enforce a grid limit. The other four strategies reduce PCMD of the connected vehicles to stay within a grid limit. These will be discussed in a subsequent chapter.

It was not an objective of this project to develop and demonstrate the algorithms for intelligent power and energy management (iPEM) of the vehicles. These are rough models. The primary use was to look at the benefit of ETESS with unconstrained charging, and with proportional limiting. This simulation tool will allow more sophisticated iPEM logic be designed and evaluated in the future.

Facility Power Flows

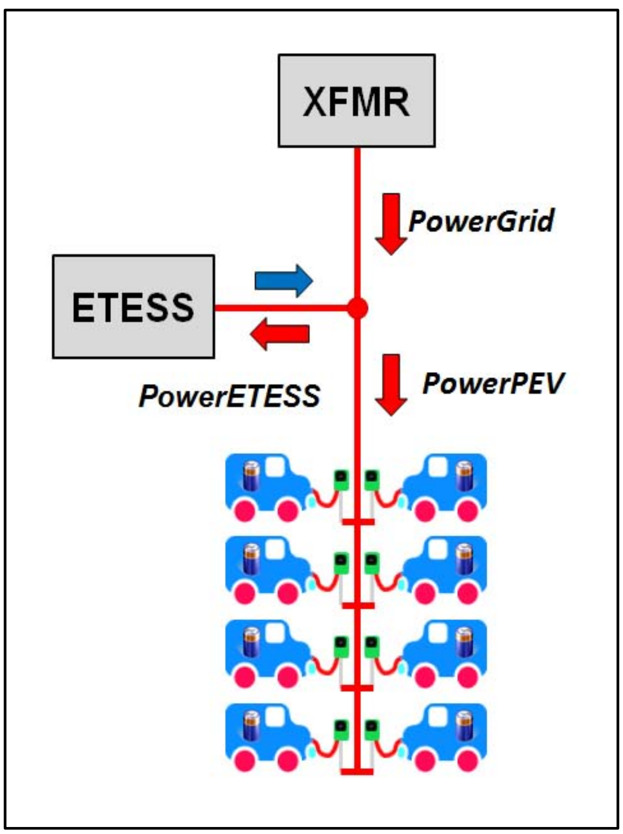


Figure 62 shows the facility power flows.

Figure 62 defines the power flows at the charging facility. The positive flows are denoted by the red arrows and negative flows by the blue arrows. The ETESS unit is capable of drawing power when charging its battery and sourcing power when discharging its battery. The net power flow of the ETESS unit is called PowerETESS. The power either drawn by or sourced by the ETESS unit is controllable. In this simulation ETESS is not used to provide power to the grid. It only deals with that portion of ETESS power and energy that is reserved for power management within the facility. When the full capability of ETESS is used it is possible to drive net power to the grid.

The sum of all of the power consumed by the vehicles at charge stations at any time is called PowerPEV. It is defined as

$$\text{PowerPEV} = \sum_{i=CS1}^{csQTY} \text{PEDL(i)}$$

The purpose of the intelligent power and energy management (iPEM) software is to limit PowerPEV. The individual vehicles, and therefore the aggregate load, are controllable.

The power from the grid is called PowerGrid. It is not independently controllable. It is the result of balancing the power flows. The fundamental power balance is defined by:

$$PowerGrid = PowerETESS + PowerPEV$$

PowerGrid, PowerPEV, and PowerETESS along with the state of charge of ETESS are key measures of total system performance.

The Prime Objective

The entire purpose of this simulation is to assess the impact of both ETESS and iPEM algorithms on controlling PowerGrid – to work to keep it below a limit. Unless there is some limit, the vehicles will just draw whatever power their on-board chargers require and the PowerGrid will follow the group demand. The simulation will allow this behavior to be assessed for different location and vehicle scenarios, and that has value, but that was not the objective of this project.

If there is a “hard” limit to protect and ETESS is not available, the iPEM algorithms can allocate power to the group of PEVs to maintain PowerGrid below the limit. This may result in certain PEVs not receiving the request energy transfer, and some PEV customers will be disappointed. A well designed iPEM algorithm will seek to minimize the disappointment. Of course, that requires a measure of disappointment that can be compared across competing vehicles – it is not as simple as a projected shortfall in energy delivery. This will be discussed later in the report.

ETESS can help even without iPEM logic. If the vehicles just charge at their own rate ETESS can provide power and energy to hold PowerGrid below the limit. This works as long as the ETESS unit has energy available. The iPEM logic can work with ETESS to spread the demand to clip power surges and extend ETESS capability.

A key part of the simulation was the development of metrics to be used to assess the performance of ETESS and iPEM in managing PEV loads. Many of these metrics will be discussed in the next chapters. Some are standard measures. Others were created specifically for this project.

Chapter Summary

This chapter reviewed the design of the ETESS simulation. The terminology and fundamentals of charging a single PEV were presented. Then the approach to randomly setting up each day of a simulation to a selected vehicle and location scenario was described. Then the approach to selecting ETESS, grid power limits, and control options was described. Then the critical power balance of grid, ETESS, and aggregate PEV power was presented.

9 *Charge Station Metrics*

One of the key measures for a selected scenario is how the vehicles come and go throughout the day. How many charge stations are occupied at any time and how many of the occupied charge stations are actually being used? The time of arrival of vehicles and the duration of stay of each vehicle are randomly determined for each simulation based entirely on the location selections. The use of occupied charge stations also depends on the amount of energy to be transferred and the specific power allocation approach being used. This chapter describes these metrics. This is a good place to begin the discussion of simulation metrics.

Measuring Charge Station Utilization

Charge StationUtilization can be measured two ways. One is whether a charge station is "Occupied" – that a PEV is connected. The other is that the charge station is "In Use" – that the PEV is actually drawing power. These two metrics are tracked in the ETESS simulation. The occupancy measures are driven entirely by the choice of location scenario, the number of charge stations, and the arrival rate multiplier – all three of these are selected on the Locations Page of the Simulation Control Panel. These properties govern the stochastic process for assigning a TOA and TOD of each vehicle during each pass. The "In Use" metrics are also influenced by the selections on the Vehicles Page and the Control strategy.

When the simulation is setting up a new day, vehicles are randomly assigned to charge stations based on the stochastic model for the location. The assignment of each vehicle to charge stations for each three minute time interval of the simulation is stored in a Charge Station Utilization (CSU) matrix. This process

IDENT	4748781																		
T\CS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	Time
54	5	10						3	7	12	13	8	11		14	9		4	8:42
55	5	10						3	7	12	13	8	11		14	9		4	8:45
56	5	10				15		3	7	12	13	8	11		14	9		4	8:48
57	5	10				15		3	7	12	13	8	11		14	9		4	8:51
58	5	10	16			15		3	7	12	13	8	11		14	9		4	8:54
59	5	10	16			15		3	7	12	13	8	11		14	9		4	8:57
60	5	10	16			15	17	3	7	12	13	8	11		14	9		4	9:00
61	5	10	16			15	17	3	7		13		11		14	9		4	9:03
62	5	10	16			15	17	3			13		11		14	9		4	9:06
63	5	10	16			15	17	3			13		11		14	9		4	9:09
64		10	16			15	17	3			13	18	11		14	9		4	9:12
65		10	16			15	17	3			13	18	11	19	14	9		4	9:15
66		10	16	20		15	17	3			13	18	11	19	14	9		4	9:18
67		10	16	20	21	15	17	3			13	18	11	19	14	9		4	9:21
68		10	16	20	21	15	17	3			13	18	11	19	14	9		4	9:24
69		10	16	20	21	15	17	3			13	18	11	19	14	9		4	9:27
70		10	16	20	21	15	17	3			13	18	11	19	14	9	22	4	9:30
71		10	16	20	21	15	17	3			13	18	11	19	14	9	22	4	9:33
72		10	16	20	21	15	17	3				18	11	19	14	9	22	4	9:36
73		10	16	20	21	15	17	3				18	11	19	14	9	22	4	9:39
74		10	16	20	21	15	17	3	23			18	11	19	14	9	22	4	9:42
75		10	16	20	21	15	17	3	23			18	11	19	14	9	22	4	9:45
76	24	10	16	20	21	15	17	3	23			18	11	19	14	9	22	4	9:48

Figure 63 shows the Charge Station Utilization (CSU) Matrix.

was described in Chapter 8. This matrix is the master control for the simulation – it is the day plan. The CSU Matrix is stored within the VBA program, but a copy is printed to a worksheet. A portion of a sample CSU worksheet is shown in Figure 63. Each row represents a specific three minute time slot. Each column represents a specific charge station at the location. The number of columns in the matrix varies with the number of charge stations selected for the simulation. This simulation pass uses 18 charge stations.

Vehicle numbers are assigned in sequence as each vehicle finds an open charge station. There must always be at least one three-minute gap between vehicles. A transition from a blank cell to a numbered cell represents an arrival and the reverse is a departure. Vehicle 15 loads into charge station 6 at simulation time interval 56 (8:48 a.m.). Vehicle 16 arrives at 8:54 and parks at charge station 3. Vehicle 5 disconnects after time interval 63 is completed. This is how the loading process proceeds.

During each time interval the number of occupied charge stations (CSocc) can be easily computed using the CSU matrix. Figure 64 shows a plot of CSocc versus time for three passes of a simulation at a shopping mall with 18 charge stations. The mall scenario model does not allow any vehicle to stay after midnight. The buildup occurs quickly during the first few hours in each pass. The arrival rate in the scenario is set at zero after 10PM and that starts the drop in vehicles until all vehicles exit by midnight. From about 9:00 AM until about 10:00 PM the usage is steady. This will be shown more clearly in the mean values for a Monte Carlo simulation. There is significant variation in occupancy between these random runs at specific times. Run 1 reaches a mid-day minimum of seven charge stations at noon. It also shows a mid-morning and mid-afternoon peak at 18 stations. Run 3 holds more closely to a level of approximately 15 charge stations.

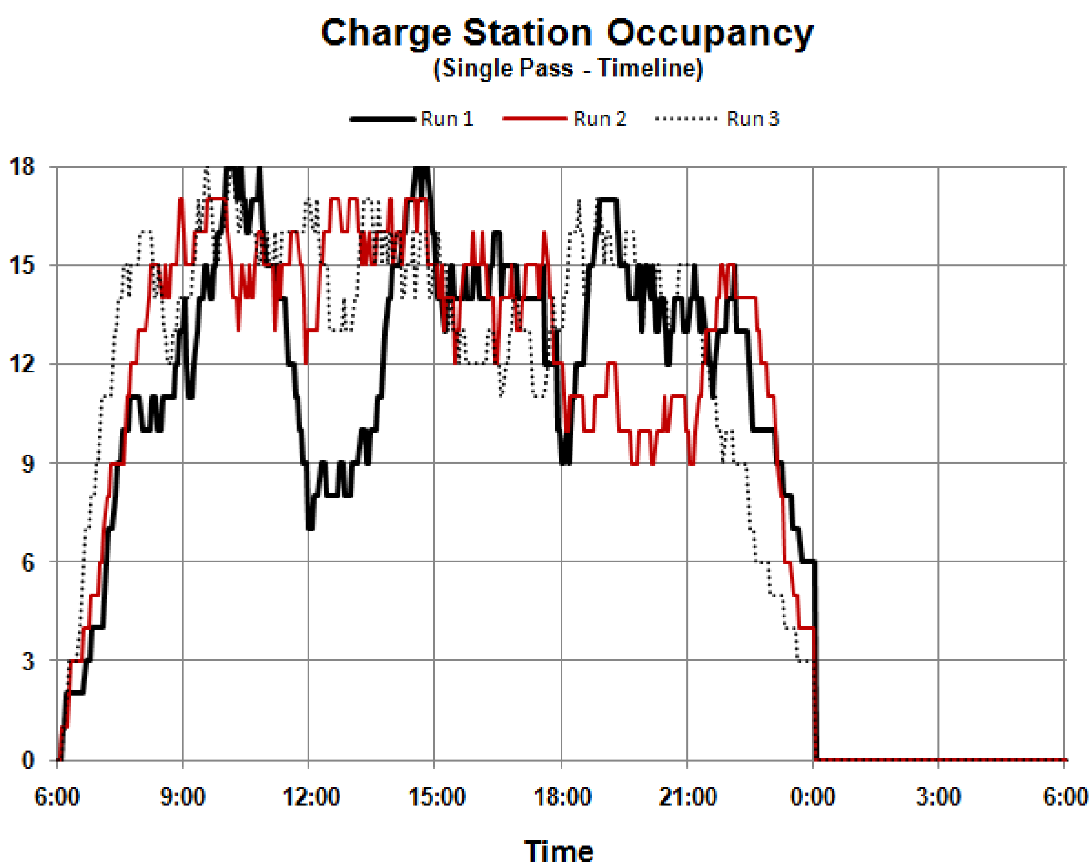


Figure 64 shows an example of charge station occupancy.

The other measure of utilization is charge station use (CSuse). Use means that energy transfer is actually happening during that time interval - that PDEL is greater than zero. CSuse can never exceed CSocc at any specific time interval. While CSocc is only driven by the parameters of the location scenario, CSuse is influenced by the amount of energy that must be transferred for each vehicle and the selected strategy for delivering power. The greatest gap and greatest variation between CSuse and CSocc will occur when vehicles stay a long time and only need to transfer a small amount of energy and charge at the maximum power rating. The gap can be as high as 18 charge stations, all occupied and none in use – not likely but possible. The smallest gap occurs when all vehicles charge at average power.

Figure 65 shows another example of Charge Station Utilization. This chart was created using the Repeat Pass mode of the simulation. A randomly generated pass using the PMAX charging strategy was repeated using the PAV charging strategy. Observe how much variation occurs between CSocc and CSuse when using a PMAX strategy versus the PAV charging strategy. This pass uses the shopping mall with a Random vehicle mix and a 50% probability of a high power on-board charger. The vehicle and charger selections have no impact on CSocc but do impact CSuse. These plots are useful for developing an understanding of the dynamics of multi-vehicle charging, but there are other methods that provide a different perspective and more meaningful metrics.

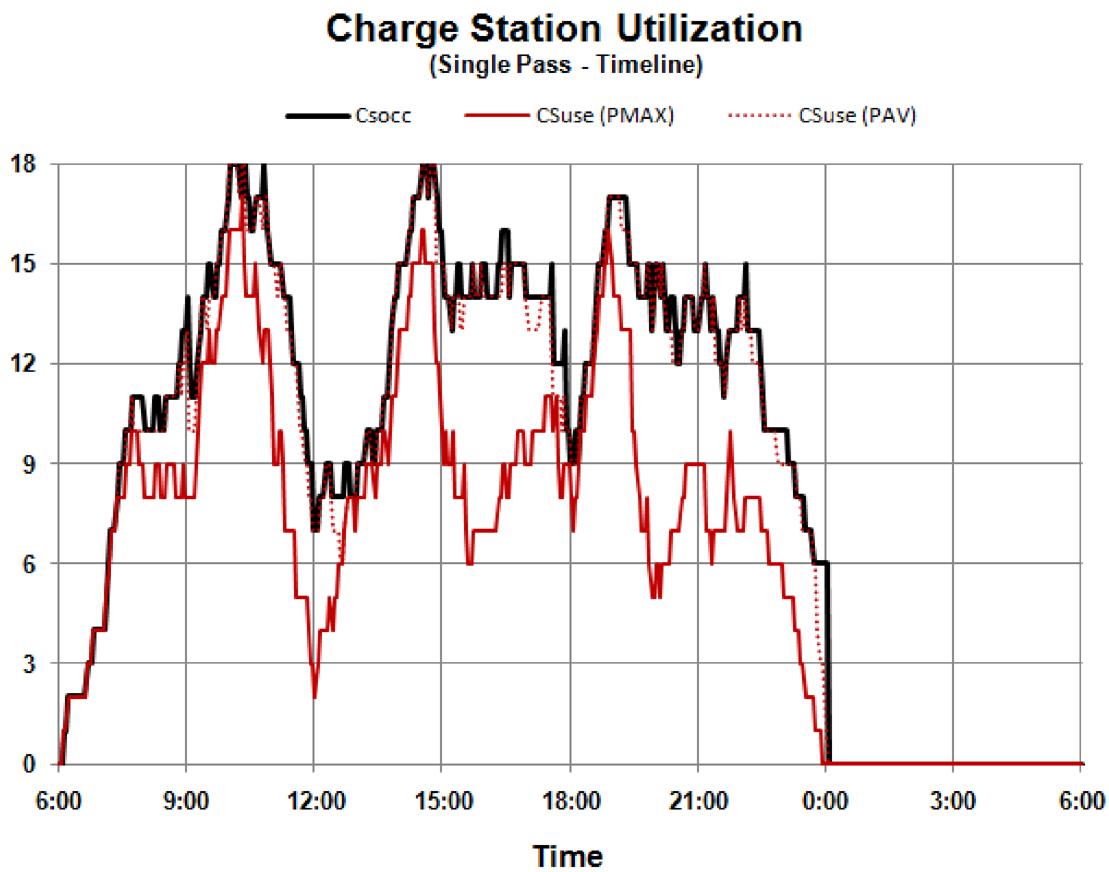
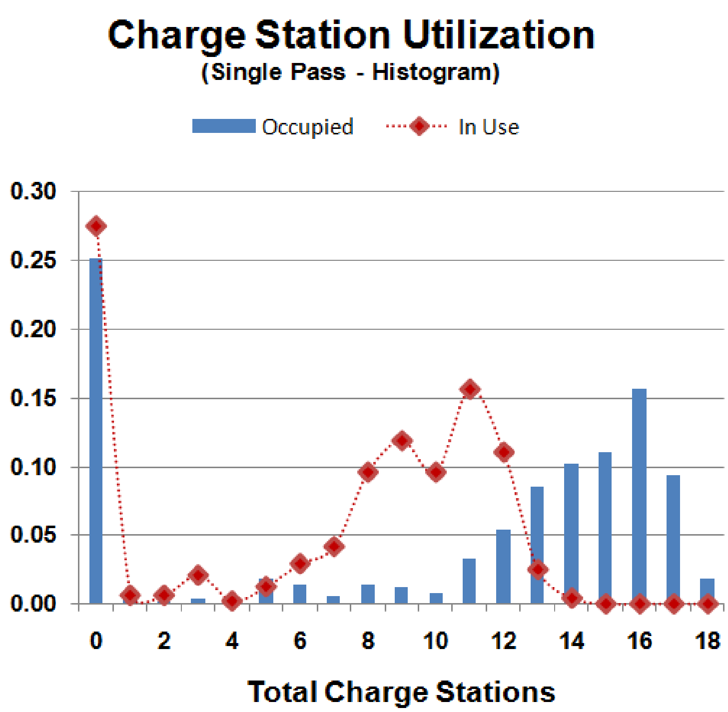


Figure 65 shows charge station occupancy and use (PMAX).

Histograms and Cumulative Probability Distributions

Another way to investigate a time series is to transform it into a histogram. This is very easy to do for Charge Station Utilization because the number of occupied charge stations (CSocc) and the number of in-use charge stations (CSuse) can only be an integer between 0 and 18. The 480 three minute time intervals of data are easily sorted into these nineteen buckets. Figure 66 is an example of a histogram.

The blue bars are for CSocc and the red line with markers is for CSuse. The height of a CSocc bar is the total number of time intervals with that exact number of charge stations being occupied divided by the total number of intervals in the 24 hour day (480). For 16 charge stations it is approximately 0.15 – this is the relative frequency that exactly 16 charge stations are occupied. The markers on the red line are established the same way for CSuse. Because no charge stations can be occupied from midnight to 6:00 AM for the Mall scenario, a CSocc and CSuse of zero must have a frequency of at least 25%. It is possible and even likely that CSuse will occur at a higher frequency than CSocc for the same exact number of charge stations as you move down the scale. This histogram is great for defining the most likely utilization. When charge stations are occupied (not zero) in this pass, the most likely number occupied is between twelve and seventeen, and the most likely number actually being used is between eight and twelve.



The next step is to create a cumulative distribution by adding the buckets moving from exactly 18 charge stations, eighteen being occupied or used, to zero. This provides the frequency that a given number of charge stations are occupied. It is easy to get this thinking reversed. A sample cumulative distribution is shown in Figure 67. This chart was constructed using the data from the histogram that was just shown. In this chart the CSuse number must always be less than or equal to the CSocc number. The chart shows that 75% of the time during the 24 hour day that at least one charge station is occupied. Approximately 60% of the time (14 hours) at least twelve charge stations are occupied and at least eight charge stations actually being used.

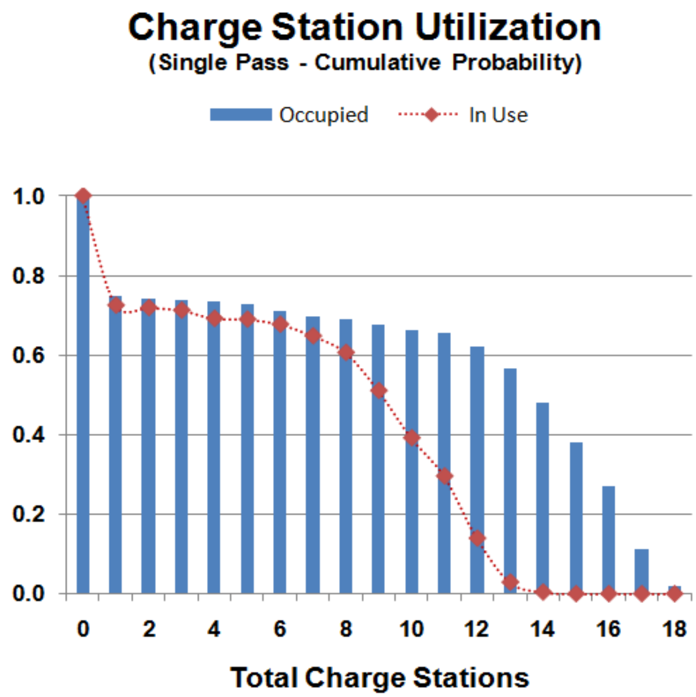


Figure 67 shows a cumulative distribution for CSocc and CSuse.

The y-axis of the cumulative distribution can be rescaled into hours by multiplying by 24. This is easier to interpret if the x-axis and y-axis are then flipped. This is shown in Figure 68. This is also difficult to interpret and it is easy to reverse the logic. This chart shows for up to nine hours of the day at least 15 charge stations were occupied. There is a cumulative total of nine hours' worth of three minute chunks during this day when 15, 16, 17, or 18 charge stations are occupied. For 15 cumulative hours of the day, 12 or more charge stations were occupied. It can also be interpreted that at least 12 charge stations were occupied for as long as 15 cumulative hours. Not consecutive time segments – but cumulative time. At least one charge station was occupied for almost 18 hours of the day.

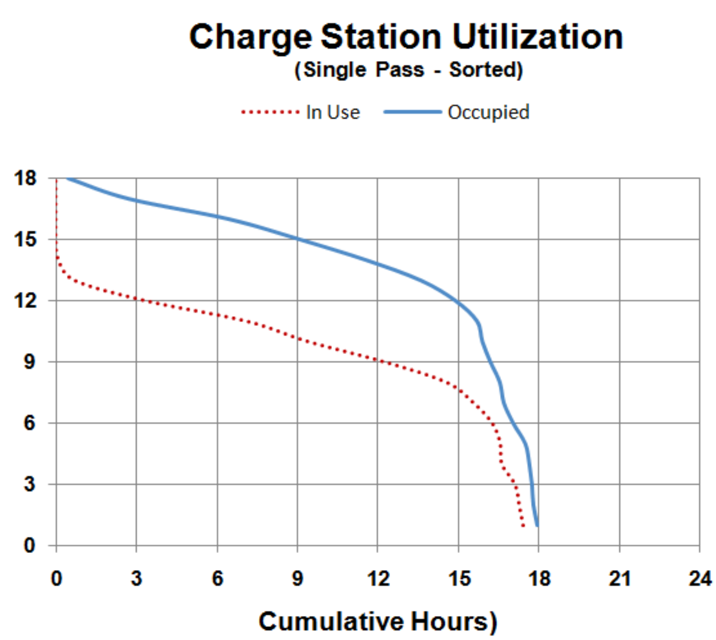


Figure 68 shows Charge Station Utilization versus cumulative hours.

The area under this curve is also important. It represents that total charge station occupancy hours. The total available charge station hours are the product of 18 charge stations and 24 hours – 432 charge station hours per day. The average occupancy is the ratio of the area under the blue curve to this number. The same can be done for 18 hours or any other cumulative hour. The same information is available in the cumulative distribution, but it is easier to interpret the time averages when charted this way.

A Monte Carlo Perspective

It is possible to measure and record the number of charge stations occupied (CSocc) at a specific time (say 10:00 AM) for each one of the 2,000 passes of a Monte Carlo simulation. The sum of these numbers divided by 2,000 is the average (or mean) occupancy at 10:00 AM This can be done for every one of the 480 three minute time intervals in the 24 hour day. The same procedure can be applied to CSuse. This results in the Monte Carlo average (or mean) value plots shown in Figure 69.

All of the random variation observed in the individual passes is smoothed out. There are central elements of the scenario that are not the result of a random process. The day always starts with no vehicles present at 6:00 a.m. for the shopping mall scenario used here. The vehicle arrival rate goes to zero at 10:00 p.m. and no vehicles are allowed to stay past midnight. That model is clearly visible in the mean value plots. The portion of the day between noon and 9:00 p.m. could be considered to be a stationary random process, but the start and end periods are clearly non-stationary.

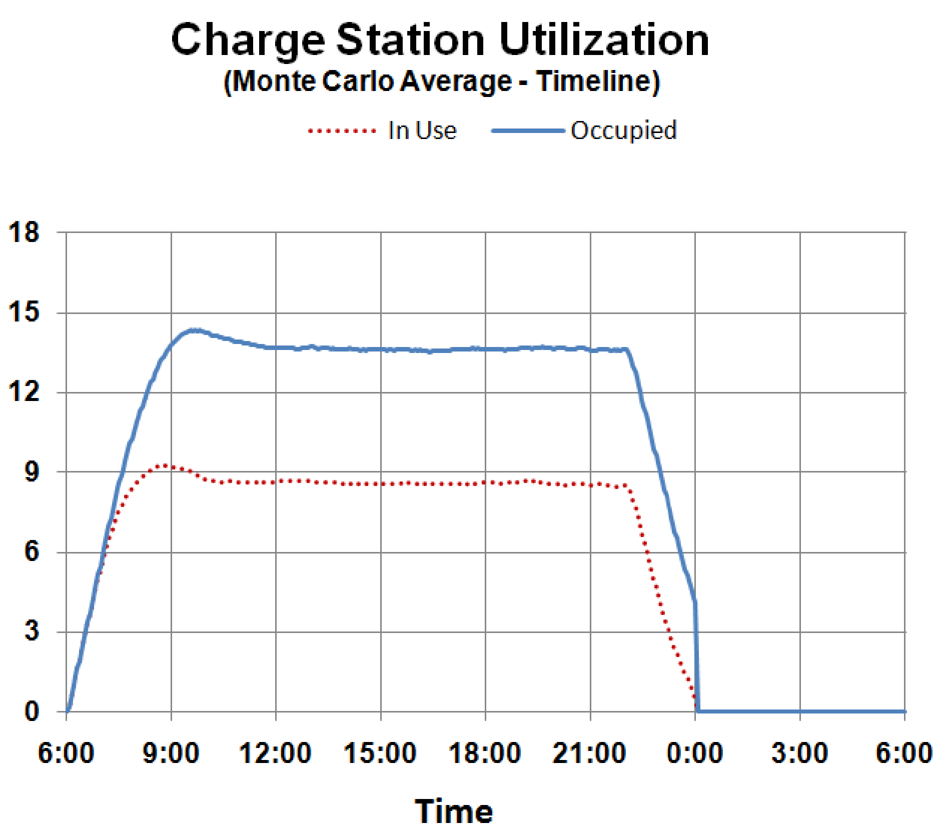


Figure 69 shows Monte Carlo simulation average values for CSocc and CSuse.

In the same way that the sum of CSocc values was taken at a specific time interval across an ensemble of passes, it is also possible to take the sum of the squares and record the largest and smallest values. The RMS value (which is useful for data that can go negative such as ETESS power) and the standard deviation (σ) for each data point are given by:

$$\mathrm{RMS}_X = \sqrt{\frac{\sum_{i=1}^{N} X_i^2}{N}} \qquad \sigma_X = \sqrt{\frac{\sum_{i=1}^{N} X_i^2}{N} - \left[\frac{\sum_{i=1}^{N} X_i}{N}\right]^2}$$

This expanded set of Monte Carlo statistics is shown in Figure 70 for CSuse. A single pass is also shown to give some perspective on the frequency content that is lost in the averaging. The chart shows the peak and minimum value of CSuse recorded at that exact time from any of the 2,000 passes. It shows both the average and RMS value, which track closely because all values of CSuse are non-negative. The standard deviation is also shown – this could have been placed as a band around the mean or RMS value. If CSuse resembled a normal distribution, then at 3:00PM on 68.3% (1σ) of the days between 7 and 11 charge station would be in use. Between five and 13 charge stations would be in use at that time for 95% (2σ) of the days, and 99.7% (3σ) of the days between three and 15 would be in use.

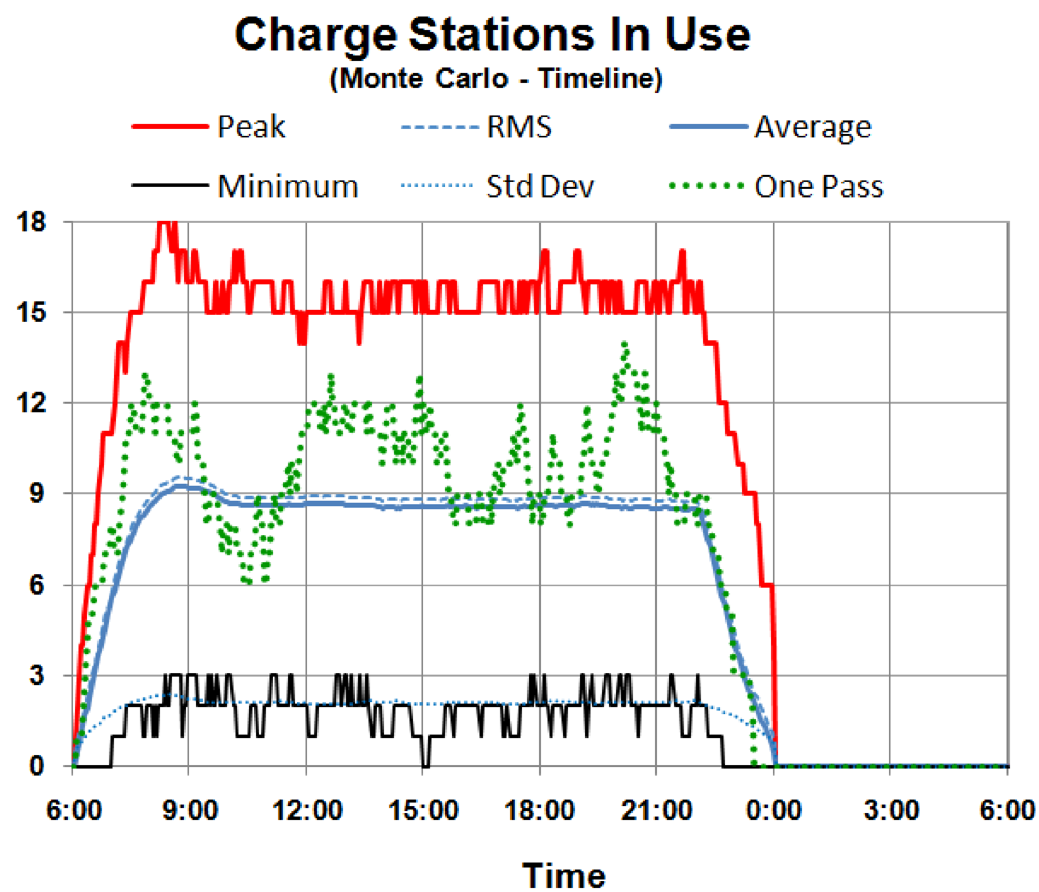


Figure 70 shows metrics from a Monte Carlo simulation for CSuse.

While averaging across a specific time interval for all passes of a Monte Carlo simulation provides some perspective, it also hides information. The ensemble metrics smooth the variation of the random process – the frequency content of the single pass is lost. In a future version of the simulation, frequency domain processing beyond the histograms and distribution functions (such as Fourier Transform) may be added. Single pass charts all show daily variations that are leveled in the average value of the Monte Carlo chart. The standard deviation shows that there will be variation, but the frequency content is lost. In a Monte Carlo simulation of a pure sine wave $A\sin(\omega t + \varnothing)$, where the phase angle ($\varnothing$) is a random variable, the Monte Carlo mean would be a flat line at zero and the RMS would be a flat line at $A/\sqrt{2}$. No indication of the perfect sine wave. This would be readily apparent in a single pass chart and a frequency domain chart would show a single bar of amplitude A at frequency ω.

It is useful to compare the charts that were produced for a single pass with those from the Monte Carlo simulation. The histogram (Figure 71) and cumulative distribution (Figure 72) are much smoother curves. They start to look like a probability density function and a cumulative probability distribution.

The assumption of a normal distribution was reasonable for CSuse when the spike at zero is eliminated. The CSocc chart would have assumed a more normal shape if the number of charge stations was not limited to 18. The time line for CSuse showed an average of approximately nine charge stations in use at 3:00 PM For this histogram if you ignored the spike at zero and notice that the values are higher on the left side of the CSuse plot than on the right side, the average value would be slightly less than eight charge stations in use, left of the peak (or Mode) value. The difference is because the histogram is also averaging the startup and shutdown parts of the day.

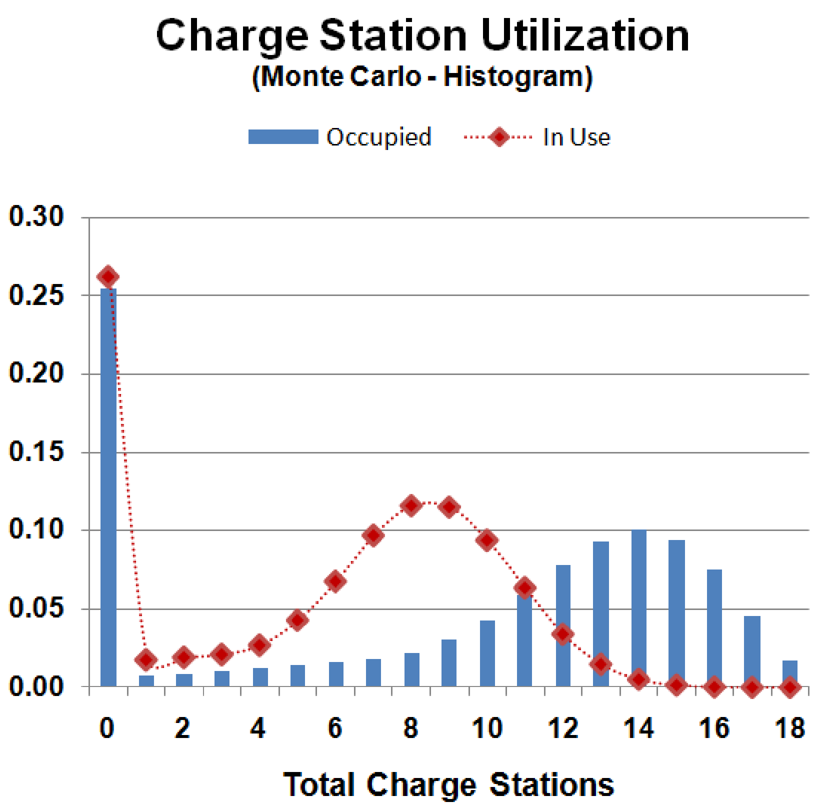


Figure 71 is a histogram from a Monte Carlo simulation.

The cumulative distributions are shown in Figure 72. The interpretation is that the likelihood, or probability, that at least ten charge stations are occupied is 0.6 or that the probability is 0.6 that ten or more charge stations are occupied. As mentioned earlier, it is easy to get the "at least" and "or more" expressions reversed. It helps to think that the probability of at least 18 being occupied must be very low, as would be the probability of having 18 or more occupied. The transposed version showing cumulative time on the x-axis is shown in Figure 73.

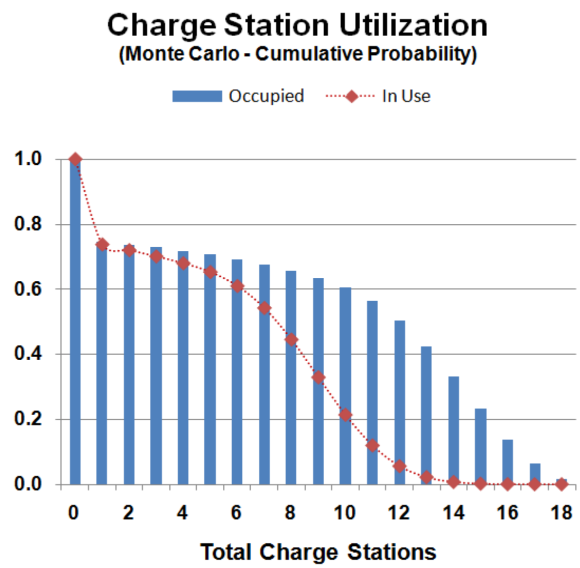


Figure 72 is a cumulative distribution for charge station occupancy and use.

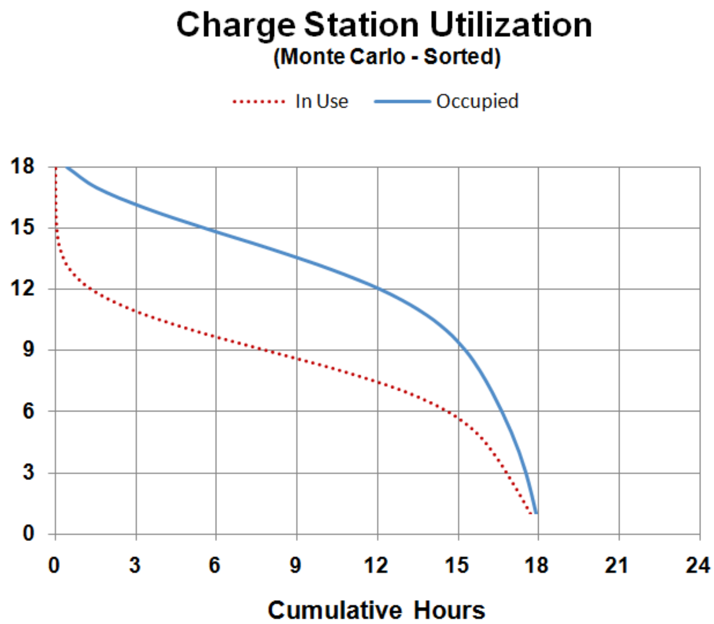


Figure 73 shows CSocc and CSuse versus cumulative hours for a Monte Carlo simulation.

Examples of Charge Station Utilization

For the remainder of this section, we will use only the cumulative probability distributions for charge stations occupied, and in use, to make some comparisons. The baseline scenario selection is for the "Mall" location with a "Random" vehicle mix and a 50% mix of 3.3kW and 6.6kW. The vehicles will all charge at the rated value of their on-board chargers from connection until completion of the energy transfer.

Figure 74 shows the first comparison of the effect of using average power (PAV1) for each PEV versus the maximum power (PMAX) of the charger. As expected the in-use and occupied time are almost identical when average power is used. As expected, when maximum power is used, many of the vehicles will complete charging earlier. The reason that the occupied and in-use probability curves are not identical is that power management is accomplished by using the estimated time of departure, and that will vary from the actual time of departure that is the basis for this chart. Some vehicles will complete early because the estimated time of departure was earlier than the actual time of departure and a higher power level was used.

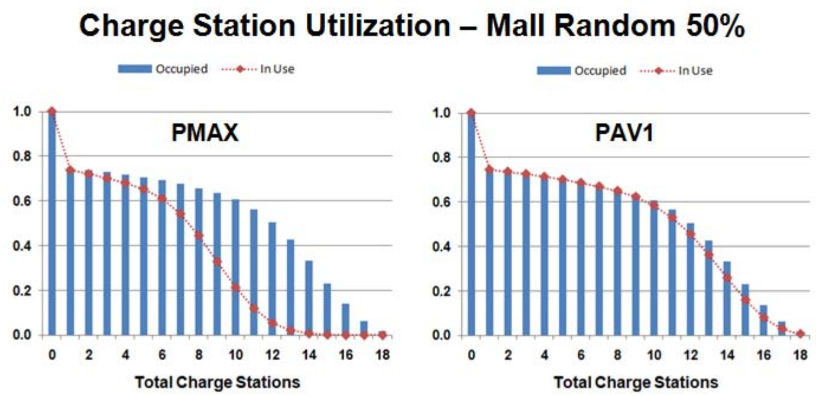


Figure 74 shows the impact of charge strategy.

The next example (Figure 75) shows the difference between a mix of vehicles skewed toward PHEVs, the random mix, and a mix skewed toward BEVs. The random mix is actually 60% BEVs. The occupied statistics are not impacted by vehicle mix. This only impacts the in-use metrics because the vehicles will have different battery capacities and this will result in greater energy transfer requirements as the number of larger BEVs increases. The in-use probability increases as the BEV mix increases. Eight or more charge stations are used 39% of the time with a PHEV skew, 42% for a random mix, and 50% for a BEV skew.

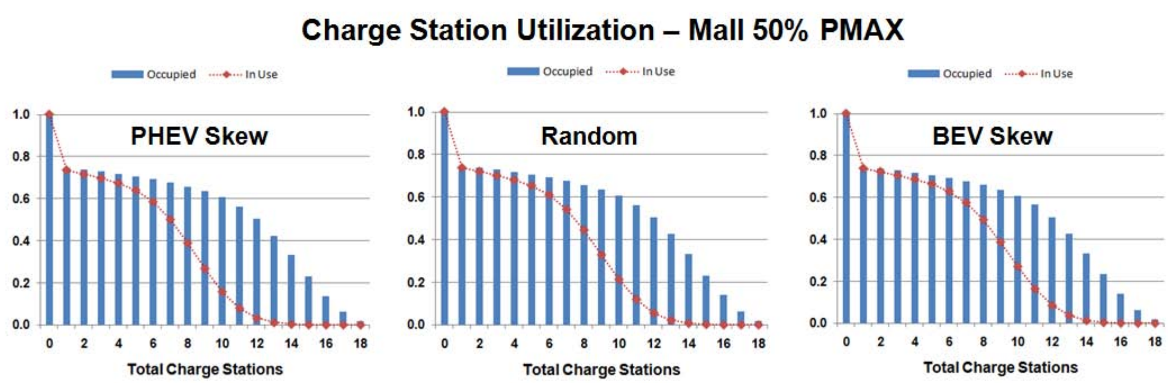


Figure 75 shows the impact of vehicle mix.

The example in Figure 76 shows the impact of changing the probability that a vehicle has a 6.6kW on board charger. The chart on the left shows all of the vehicles with 3.3kW chargers and the chart on the right shows all of the vehicles with 6.6kW chargers. The middle chart is the baseline 50% probability that has an expected value of 4.95kW in a Monte Carlo run. As expected, the in-use probability drops as the charger power increases. Because these are park and charge scenarios, the vehicle departure times are based on the scenario and not the time for completion of the energy transfer.

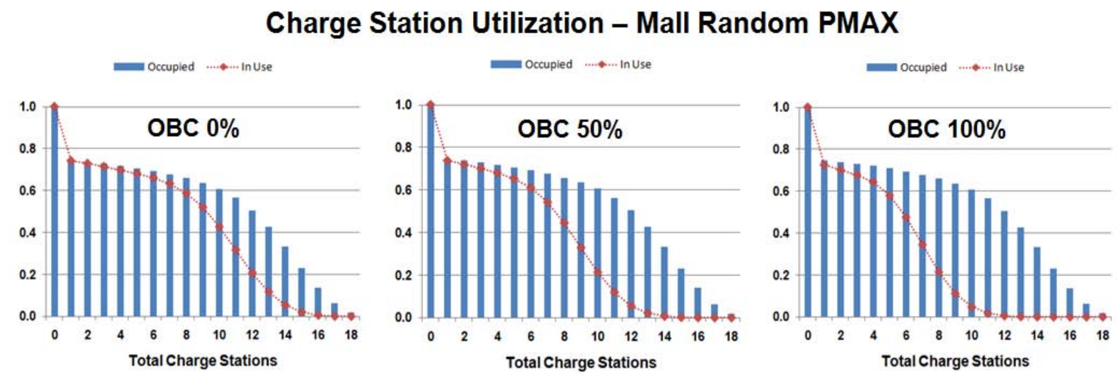


Figure 76 shows the impact of on-board charger selection.

The next example (Figure 77) shows the impact of arrival rate on the scenario. This does impact the metrics for the number of charge stations occupied. Each scenario has a basic arrival rate of vehicles per hour per charge station. This can change during the day to shape the scenario. To allow for fleet density the base rate can be varied from 0.5 times to 2.0 times. As the fleet density increases the occupancy and in-use measures both increase as expected. The average occupancy over 24 hours goes from 35% to 51% to 53% as the arrival rate multiplier goes from 0.5X to 1.0X to 2.0X, respectively. These occupancy statistics come from data tables in the simulation and were not derived from these charts.

The difference between the shopping mall scenario and several others are shown in the next set of figures. Figure 78 shows a work scenario which is a factory with two shifts and visitors. While it has a high occupancy the usage is low. Most of the vehicles stay for a shift but may only be charging for a small portion. The movie scenario is for a cinema complex. It has a similar pattern to a shopping mall except the durations are more clustered to a movie length. Average occupancy over 24 hours goes from 56% to 51% to 37%, respectively.

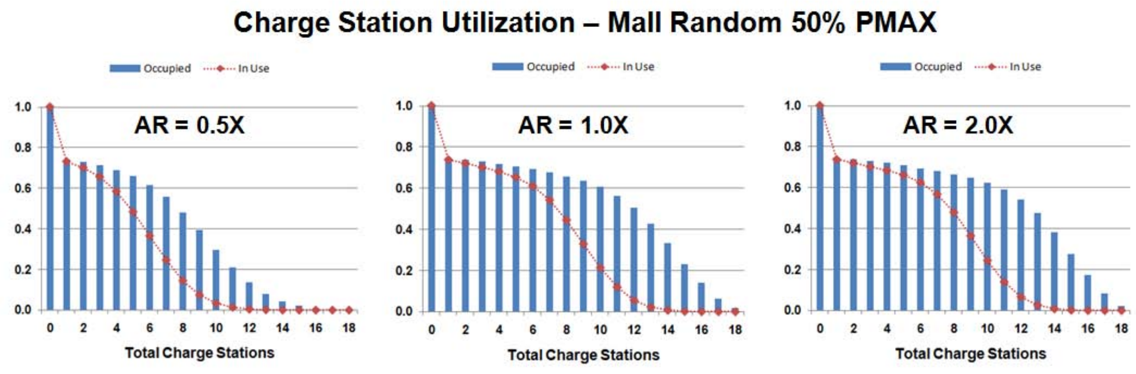


Figure 77 shows the impact of fleet density as defined by the arrival rate.

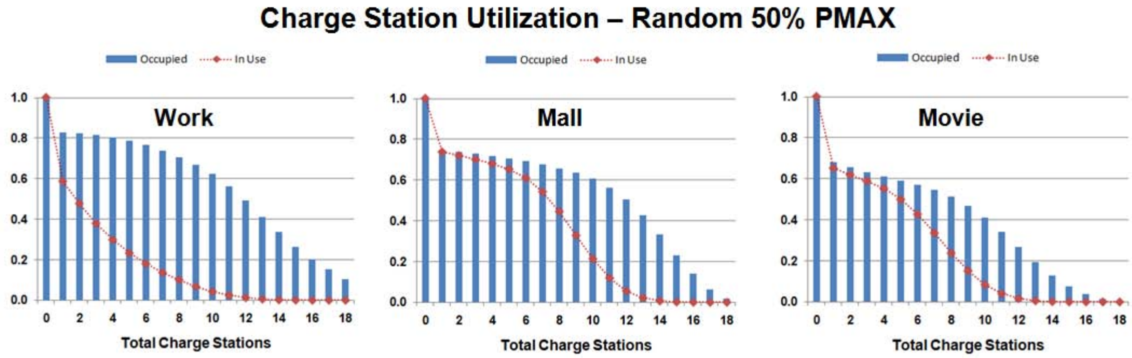


Figure 78 shows a work, mall, and movie scenario.

Figure 79 shows a city scenario where some vehicles will park overnight. It also shows a high stress scenario that was designed for a mix of shorter duration visits. Average occupancy goes from 61% to 51% to 49%, respectively.

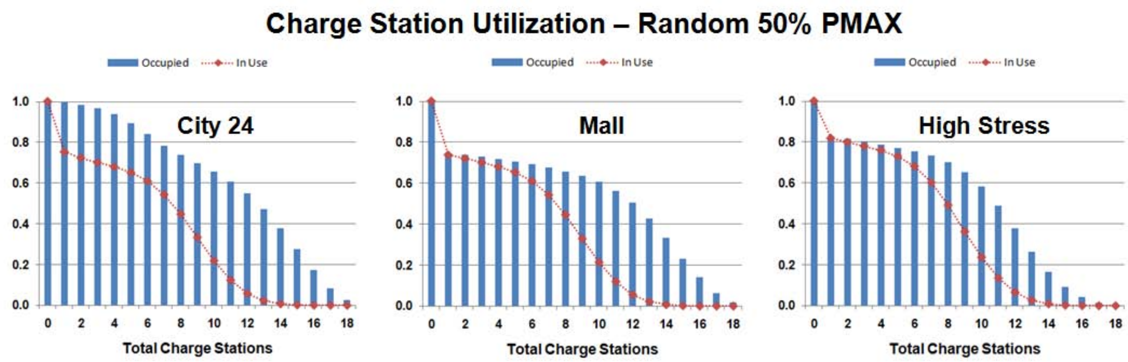


Figure 79 shows a City, Mall, and High Stress scenario.

The ability of a commercial park and charge station operator to recover the investment in the infrastructure will depend directly on the pattern of utilization. If prices are based on access time, the use to occupancy ratio is not relevant. Nevertheless, if charges are proportional to the energy transfer this will favor high use to occupancy situations with higher power onboard chargers. In many cases the location defines the length of stay and not the time needed to complete the desired energy transfer. Longer stay scenarios, such as work or overnight, are likely to have lower use to occupancy ratios. The arrival rates used with each scenario were selected by that author to provide a reasonable percent occupancy for a fully expanded deployment of charge stations. Lower rates would be expected in early years of PEV deployment.

From Charts to Individual Metrics

The histograms, cumulative probability distributions, and time series charts are useful for understanding patterns of usage, but sometimes just a simple number is needed. It is easier to say that this scenario has a 50% occupancy rate and that one only has a rate of 35%.

This opens up many possibilities. Should the rate be based on 24 hours or should it be based only on the hours of operation for the facility? The 24 hour statistics are useful for revenue models. The rate based on the time when at least one charge station is occupied is useful for assessing whether there are enough charge stations to meet the customer demand. For this purpose it also useful to look at the charts that plot the average and standard deviation for each interval of the simulation.

Table 1 shows summary data for each of the location scenarios that were discussed earlier. This is the source for some of the numbers that were provided. The table includes three mall scenarios with different arrival rate multipliers. The percent of occupied charge stations in use is provided for the PMAX and PAV1 charging strategy. As expected the use of average power drives the rate to 96% or better.

Table 7 shows Charge Station Occupancy Statistics.

Comparison of Scenaio Statistics (Monte Carlo Simulation)							
Location	**Mall**	**Mall**	**Mall**	**Movie**	**High Stress**	**Work**	**City24**
Arrival Rate Multiplier	**0.5**	**1.0**	**2.0**	**1.0**	**1.0**	**1.0**	**1.0**
Time One or More Charge Stations Occupied							
Hours	17.8	17.9	17.9	16.4	19.8	19.9	23.9
Percent of 24 Hours	74.1%	74.5%	74.6%	68.2%	82.7%	82.9%	99.5%
Average Number of Occupied Charge Stations							
Over 24 Hours	6.4	9.2	9.5	6.7	8.9	10.1	11.0
Over Occupied Hours	8.6	12.3	12.7	9.9	10.7	12.2	11.1
Percent of 18 Charge Stations Occupied							
Over 24 Hours	35.4%	51.0%	52.7%	37.4%	49.2%	56.2%	61.3%
Over Occupied Hours	47.8%	68.5%	70.7%	54.9%	59.5%	67.8%	61.6%
Standard Deviation (Charge Stations)							
Over 24 Hours	4.7	6.2	6.4	5.7	5.1	6.0	4.5
Over Occupied Hours	3.2	3.7	3.7	4.0	3.4	4.2	4.4
Percent of Occupied Charge Stations in Use							
For PMAX Strategy	63.4%	63.6%	63.5%	62.5%	73.4%	25.2%	53.4%
For PAV1 Strategy	96.4%	96.4%	96.4%	98.8%	98.3%	98.8%	98.3%

Chapter Summary

Metrics for charge station occupancy (CSocc) and use (CSuse) were presented for a baseline scenario of a shopping mall, with a Random vehicle mix, and 50% probability of a high power charger. Plots of CSocc and CSuse were shown for the 24 hour day. Histograms and cumulative probability distributions were shown for a single pass and a Monte Carlo simulation. Monte Carlo ensemble statistics for the mean, standard deviation, maximum and minimum values for each time interval were shown. The cumulative distributions were used to compare location, vehicle, and control strategy selections. The use of summary metrics for the same location scenarios was also discussed. This chapter provides more insight into the behavior of the PEVs in each scenario. It also introduced the charts and data to be used to evaluate other parameters, such as grid power.

10 *Measuring PEV Customer Disappointment*

One purpose of ETESS is to allocate power among vehicles charging at a facility to meet facility power constraints and also minimize disappointment of the vehicle drivers. You cannot control what you do not measure. However, disappointment is a human valuation. New concepts for measuring disappointment of individual vehicle drivers as well as the aggregate disappointment for all of the vehicles that charge during the day will be developed. Concepts for intelligent Power and Energy Management were briefly discussed in Chapter 4. In this chapter some preliminary algorithms for allocating power to stay within facility power limits will be explored using the ETESS simulation, and disappointment will be assessed using the new metrics.

Keeping Score and Reference Values

During the charging session it is important to measure whether the desired energy transfer was accomplished. The energy gap (**EGAP**) of the battery is directly related to the difference between the target state of charge (SOC2) and the final state of charge (SOC), and the usable battery capacity (UCAP) by

$$\boldsymbol{EGAP = (SOC2 - SOC) * UCAP}$$

This needs to be tracked throughout the energy transfer. Another way to define EXRQD during the energy transfer is

$$\boldsymbol{EXRQD = EGAP/EffNom + Veh12vLoad * ETTG}$$

These are measures internal to the PEV and not directly available to the ETESS unit. The ETESS unit and the iPEM algorithms do not have visibility into the SOC of the vehicle. This is optional information in SAE J2847-1 and cannot be relied on for iPEM or for performance measurement after disconnect.

ETESS needs to use information that it can measure. It can compute the actual energy transfer (**EXACT**) to the vehicle by integrating the delivered power during the connection as

$$\mathrm{EXACT} = \int_{toa}^{t} \mathrm{PDEL(t)dt}$$

The gap in energy transfer (versus the battery energy state) is

$$\boldsymbol{EXGAP = EXRQD1 - EXACT}$$

If a PEV disconnects earlier than the estimated time of departure (ETOD), some of the expected energy transfer may not be completed. The driver may “allow” for some miss in assessing satisfaction with the outcome of the session. This can be accomplished by reducing the transfer request at TOA (EXRQD1) by some power level times the difference between the ETOD and TOD. The issue is what power level is reasonable. If a PEV connects with a significant amount of slack time, the driver might not make any “allowance” for a miss – zero is the right power level. The ETESS could assume that it is allowable to start as late as possible and PMAX is a reasonable power level to use for the adjustment.

For DUR < EDUR, it was decided to use the average power required to complete the transfer.

$$PAV1 = EXRQD1/EDUR$$

$$EXREF = EXRQD1 – PAV1 * (EDUR – DUR)$$

$$EXREF = EXRQD1 * DUR/EDUR$$

And for DUR ≥ EDUR

$$EXREF = EXRQD1$$

The utilization factor at completion (UFREF) is then

$$UFREF = EXREF/(PMAX * DUR) = EXREF/EXMAX$$

The reference values are only available at disconnect for use in performance assessment. The iPEM algorithms must use the values at TOA (e.g. UF1) or at the current time (e.g. UF) during charging.The raw gap in energy transfer (**EXGAP**) at any time during the charging session is defined by

$$EXGAP = EXRQD1 – EXACT$$

After disconnect the final raw gap for performance metrics is

$$EXGAP = EXREF - EXACT$$

The relative gap (**ΔEX**) is defined as

$$\Delta EX = 1 – EXACT/EXREF = EXGAP/EXREF$$

Disappointment Factor

How a driver feels about a miss in required energy transfer is related to how much stress the requested energy transfer placed on the system during the session. The driver will be very sensitive to how much time was allowed. There will be a higher level of disappointment for lower utilization factors (UF). Also a vehicle with a PMAX of only 1.4 kW is less demanding on the system than one with a PMAX of 7.7 kW. This makes both UF and PMAX factors in assessing relative disappointment.

The objective was to create a Disappointment Factor (**DF**) that could be used both during and after a charging session to assess the potential for disappointment. Just as with other variables, the DF could have a value at the start, during the transfer, and a reference value for performance measurement. This is more art than science and at some point a real behavioral study will be required to create a model. Three different models were developed.

It was decided not to consider whether a vehicle was a BEV or a PHEV in computing DF at this time. There is an argument to be made to give preference to BEVs over PHEVs in any power allocation scheme. A PHEV can always get home if charging is not completed, but this may not be true for a BEV. Nevertheless, there is also an argument that this is not fair to PHEV owners. SAE J2847-1 includes Vehicle Type as an optional message for Optimized Energy Transfer to be used for this purpose. It can always be added to the calculation of DF or just used as a priority in an allocation algorithm.

Disappointment Factor - Method 1

The first approach assumes that disappointment is inversely proportional to the utilization factor. It is only relevant to use UF1 during a session and UFREF for post session assessment. It was decided to select a value of 1.0 for DF when UF1 is 1.0 and PMAX is 1.4 kW. This assumes that AC Level 1 at 1.4 kW is an entitlement and it is reasonable to charge for 100% of the duration at that level. The next fixed point was to assess that a driver would be half as disappointed with an equal miss if they were charging at 7.7 kW. This results in a Method 1 value for DF of

$$DF = \frac{1}{UF} - \frac{\frac{PMAX}{1.4} - 1}{9}$$

This is shown in Figure 80. The disappointment of a miss will be equal for a PEV with a PMAX of 7.7 kW that needs to use 67% of the available time (UF = 0.67) with that of a PEV that needs to use all of the available time at a PMAX of 1.4 kW. This method puts extreme weighting on the disappointment for low UF, and this may be too aggressive.

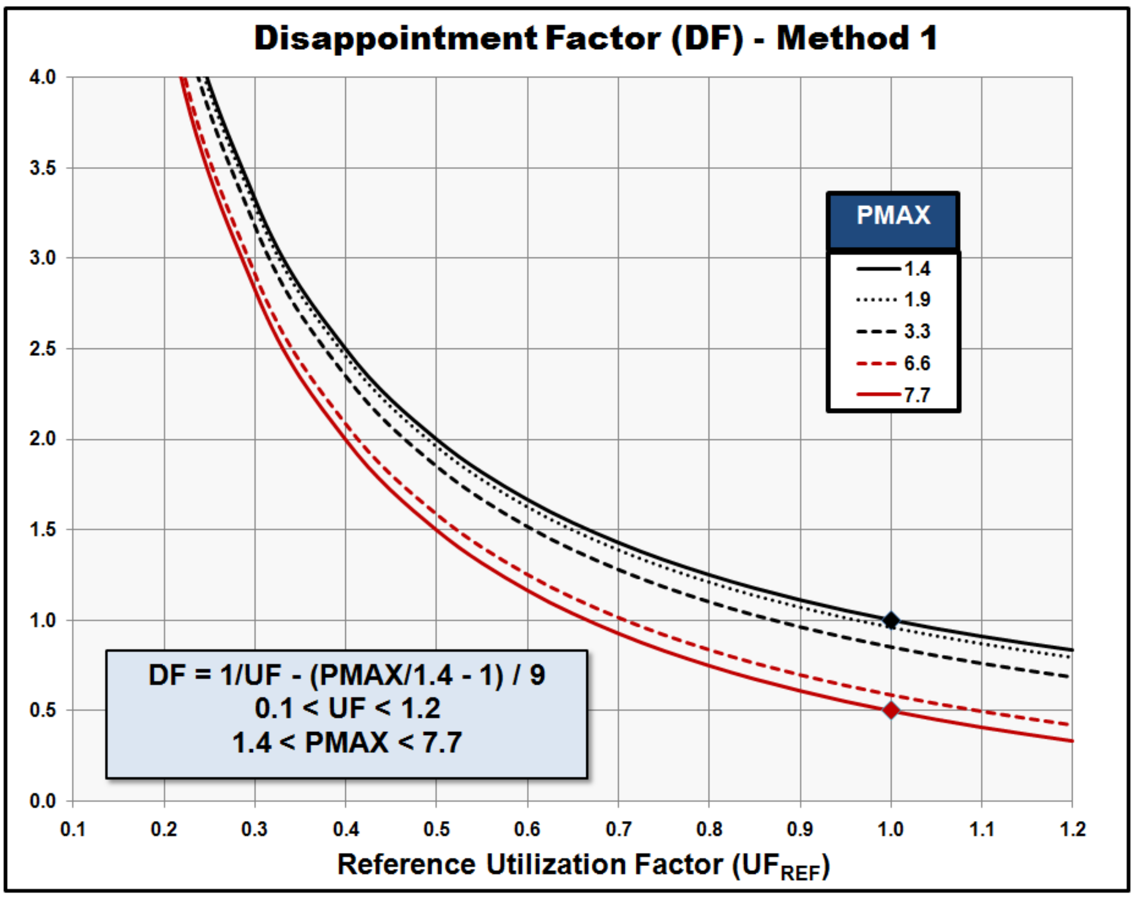


Figure 80 shows Method 1 for Disappointment Factor.

Disappointment Factor – Method 2

This was addressed by developing a second model that does not spike at low UF. In this method DF is defined by

$$DF = \left(2 - UF^2\right) * \frac{K1 - PMAX}{K2}$$

The value of DF was set to 1.0 at a PMAX of 1.4 kW and UF of 1.0 based on the same entitlement logic as for Method 1. The coefficients K1 and K2 are determined by selecting a value (X) for UF when PMAX is equal to 7.7 kW.

$$K2 = 6.3 * \frac{2 - X^2}{1 - X^2} \qquad K1 = K2 + 1.4$$

This is shown in Figure 81 where a value of 0.8 was selected for X. This model gave the desired roll off at very low UF. Although at very low UF it is likely that all customers will be equally unhappy with a miss of the same percent. A customer charging at 1.4 kW should be more disappointed than one charging at 7.7 kW, but this difference would be expected to be greater for a UF of 1.0 than for a UF of 0.1 – in this model that ratio is always 0.74 of the reference value at 1.4 kW.

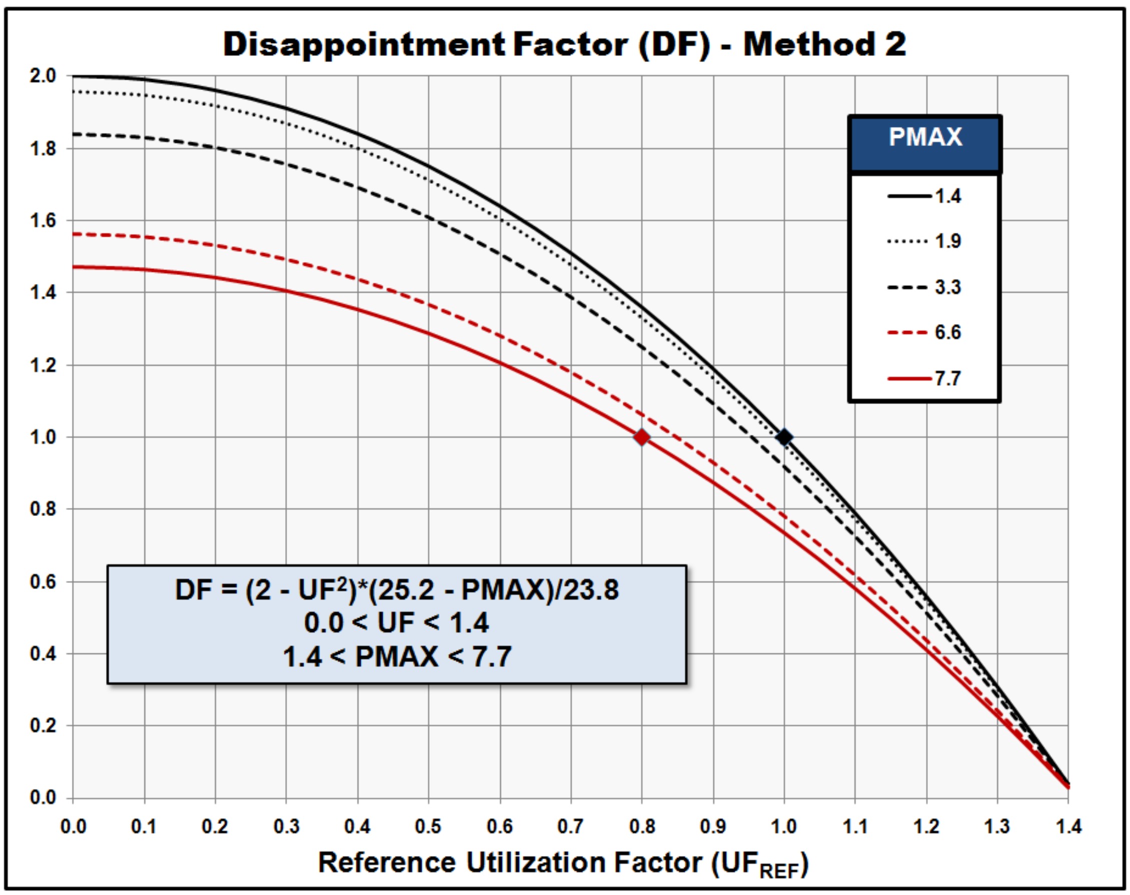


Figure 81 shows Method 2 for Disappointment Factor.

Disappointment Factor – Method 3

It is possible to directly combine UF and PMAX into a Capacity Factor defined as

$$CF = UF * \frac{PMAX}{7.7}$$

A charging session with a high CF places more absolute stress on the system and should be more forgiving of some miss in energy transfer. For this model we used a logistic function. The logistic function is often used in artificial intelligence for games(Mark 2009). The shaping constants were selected to allow the value to swing from three to one as CF ranged from zero to one. DF is defined by

$$DF = 3 - \frac{2}{1 + 1.5 * e^{-15*(CF-0.3)}}$$

This function is shown in Figure 82. Separate curves are shown for different values of PMAX versus UF. For a PMAX of 7.7 kW, UF and CF are the same and this is the basic function versus CF. This DF model achieves equal disappointment at very low values of UF for any power level. At UF approaching 1.0 there is clear differentiation between entitlement levels of 1.4kW and 1.9kW for AC Level 1 and the 6.6kW and 7.7kW AC Level 2 chargers. This model holds promise, and model coefficients could be fit in the future to better capture customer perceptions of disappointment. This DF model is now used in the simulation.

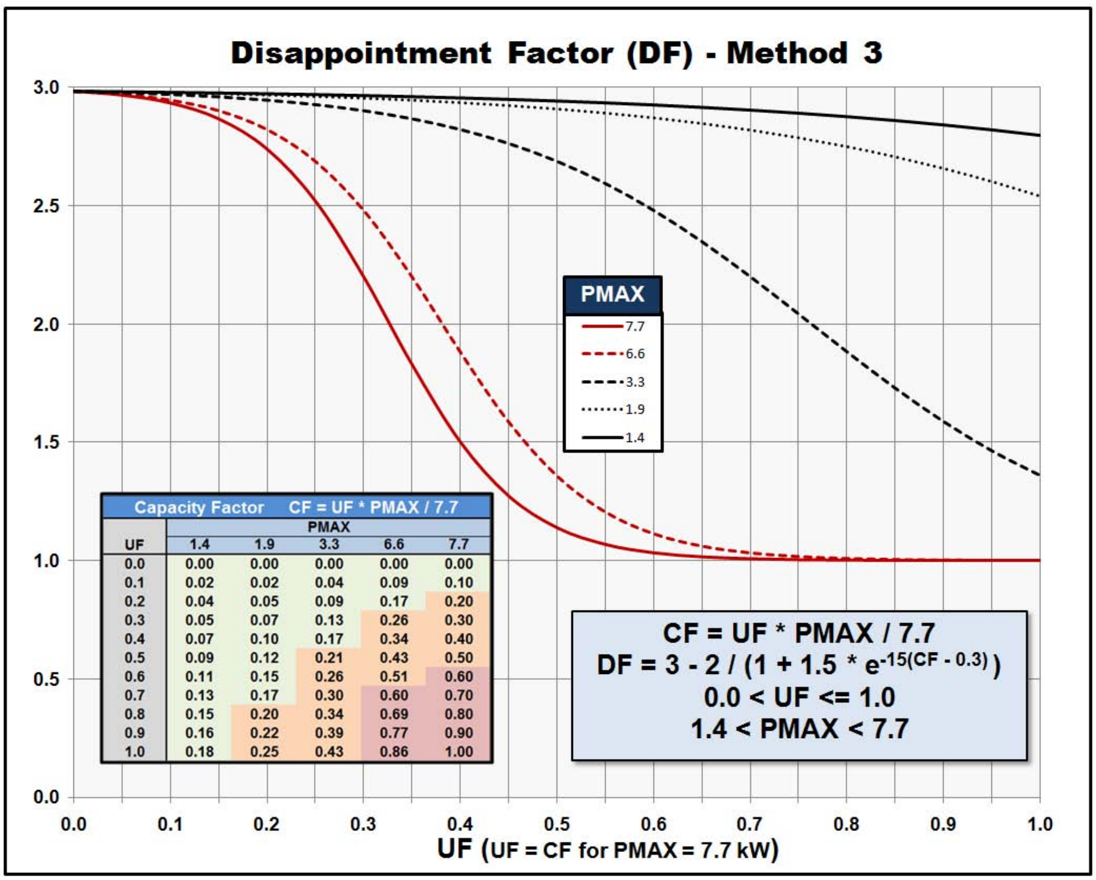


Figure 82 shows Method 3 for Disappointment Factor.

Disappointment Index

For two charging scenarios with equal disappointment factors (DF), the relative miss (ΔEX) is a more useful metric than the absolute miss (EXGAP). DF accounts for the relative complexity of the scenario. The next question is whether the disappointment is linear with ΔEX. Is the disappointment with a 10% miss two times that of a 5% miss? Sometimes Mean Square Error (MSE) is used.

A basic model for defining the weighted error (**WtdError**) is

$$\text{WTDError} = \text{A} * \left(1- \left(\frac{\boldsymbol{EXACT}}{\boldsymbol{EXREF}}\right)^{2} + \boldsymbol{B} * \left(1 - \frac{\boldsymbol{EXACT}}{\boldsymbol{EXREF}}\right)\right.$$

$$\boldsymbol{WtdError} = \boldsymbol{A} * \boldsymbol{\Delta EX}^{2} + \boldsymbol{B} * \boldsymbol{\Delta EX}$$

This model covers pure linear models when coefficient A is zero and pure quadratic models when coefficient B is zero. Figure 83 shows several versions. The models were built by establishing that a measured ΔEX of 5% would always have a weighted value of 5%. Then weighted values for a measured ΔEX of 10% were selected. A pure linear model results when 10% is selected (A = 0, B = 1). A pure MSE model results when 20% is selected (A=20, B=0). Values of 12.5% and 15% set up tilted quadratic models.

The Disappointment Index (**DX**) is defined by

$$\boldsymbol{DX} = \boldsymbol{DF} * \boldsymbol{WtdError}$$

The 12.5% weighting model was used for this report.

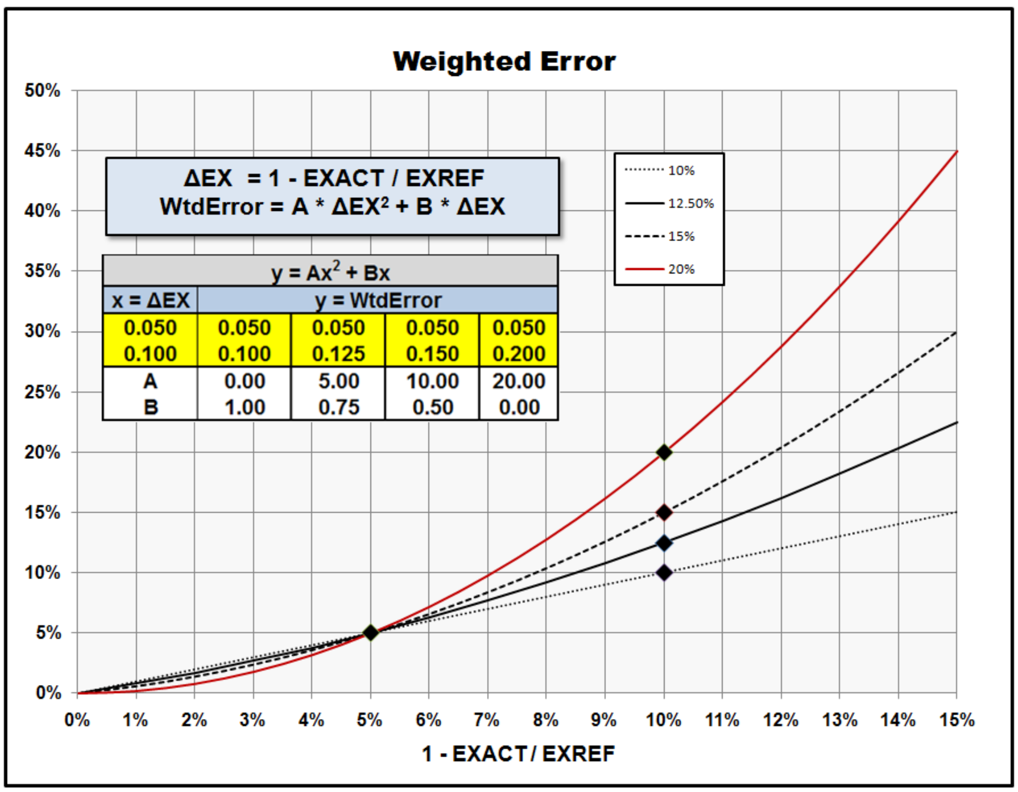


Figure 83 shows weighted error models.

A Charging Session Example

A charging example will be shown to illustrate the concept of customer disappointment. The example is based on four vehicles charging at a facility over a nine hour period. This will be explained first to show the flow of information and the dynamics of the session. Then metrics will be compared for a possible outcome from this charging session.

Figure 84 shows four vehicles charging. Two time bars are shown for each vehicle. The upper bar shows the condition at the time of arrival (TOA). The lower bar is the condition at the current time, which is indicated by the vertical red dotted line. The current time is three hours after the arrival of Vehicle V1 and V2. Vehicles V3 and V4 both arrive one hour after V1 and V2. The length of each bar indicates the time remaining before departure.

The blue segment at the start of each upper bar depicts the minimum time required to charge at PMAX at the TOA (TMIN1) – 1.5 hours for V1. The estimated duration (EDUR) is listed in the gray area of each top bar. The blue triangle over each upper bar shows the latest time that charging can start at PMAX and complete by the ETOD (TLATE1). The requested energy transfer at TOA (EXRQD1) is listed to the right of each upper bar. The utilization factor at the TOA is displayed above the upper time bar, which is 0.25 for V1. PMAX and the average power needed to complete charging over the estimated duration (PAV1) are listed below each upper bar. The values of all parameters at TOA are shown in blue text.

The red segment of the each lower bar is the minimum time to charge at PMAX at the current time (TMIN). The remaining requested energy transfer (EXRQD) is shown to the right and the estimated time to go (ETTG) is shown within the bar. Some of the labels are shown only once, and then the position must be used to know the meaning of each number. Below the lower bar, the utilization factors (UF) and average power (PAV) are listed. The red triangle shows the latest start point to complete the transfer using PMAX (TLATE).

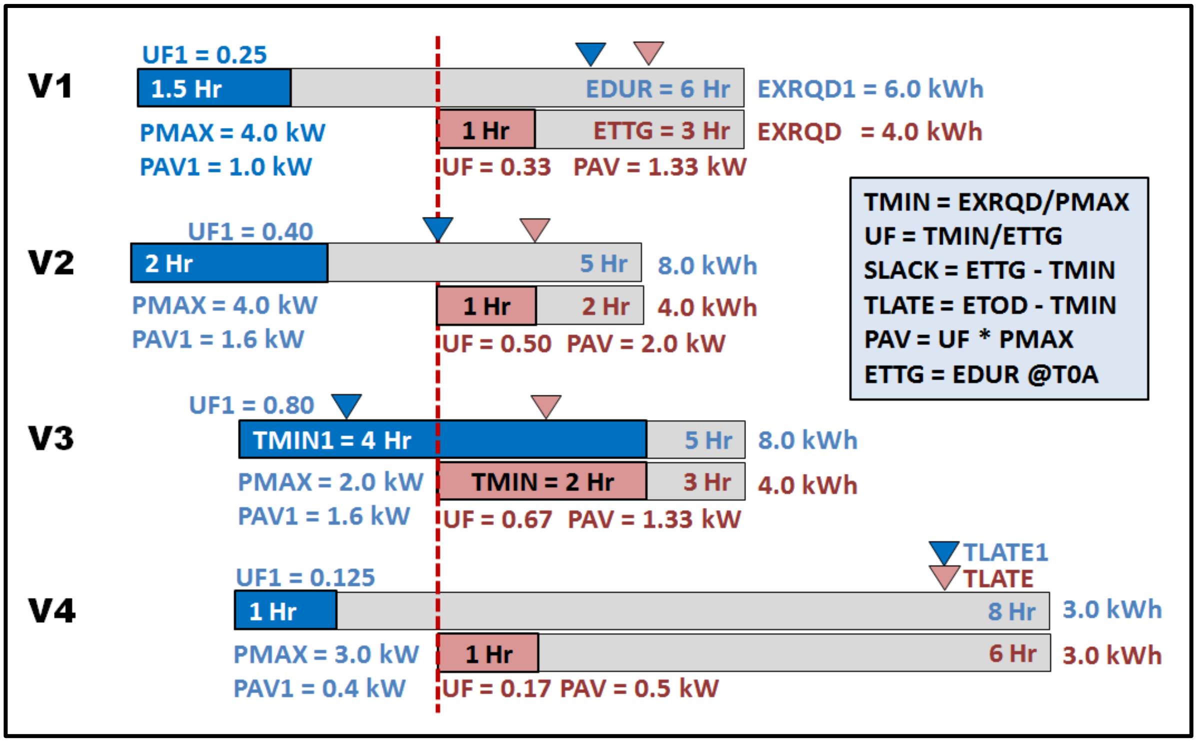


Figure 84 is an example of a charging session with four vehicles.

Vehicle V1 needs to transfer 6 kWh of energy in six hours and has a PMAX of 4.0 kWh. TMIN1 is 1.5 hours. The latest charging can start at PMAX is 4.5 hours after the TOA. It could charge for all six hours at 1.0 kW. After three hours, only 2.0 kWh of the 6.0 kWh have been transferred and 4.0 kWh must be transferred over the remaining three hours. At PMAX, it will take one hour to complete the transfer. The UF has increased from 0.25 to 0.33 – V1 has fallen behind. V2 has also fallen behind at the current time. It has moved 50% of the power in three of five hours. UF has increased from 0.4 to 0.5 and PAV has increased from 1.6 kW to 2.0 kW – a sign of falling behind. V3 needs to transfer 8.0 kWh over five hours. It has a PMAX of only 2.0 kWh. TMIN is 4.0 hours and UF1 is 0.8 – a relatively high UF1. After two hours it has moved 4.0 kWh with 4.0 kWh to go in the three remaining hours. The slack is holding and it is on target at PMAX to complete. UF is decreasing because V3 is running ahead. V4 is very low in its demand on the system. It only needs one hour at PMAX to move 3.0 kWh of energy over of eight hours. Still, after two hours it hasn't started, and UF is increasing.

This is a busy chart, but it is useful for getting a feel for the charging of multiple vehicles. It is clear that V4 is being managed using a Delay Max power allocation strategy. The power allocation for V3 is a Start Max strategy. V1 and V2 are being managed at a lower rate than even an Average strategy would suggest. During the first three hours V1 was at a PAV of 0.67 kW versus a PAV1 of 1.0 and V2 charged at PAV of 1.3 kW versus a PAV1 of 1.6 kW.

Table 8 shows possible results for the four vehicles. It lists PMAX, EDUR, EXRQD1, and UF1 as shown in Figure 84. The capacity factor, CF, is calculated as CF=UF1*PMAX/7.7 and is a measure of absolute stress on the system. While UF is a relative measure of stress for a specific vehicle, CF normalizes it to the charge station maximum power of 7.7 kW. The three methods for computing disappointment factor (DF) are shown. All are functions of PMAX and UF1.

Table 8 compares metrics of customer disappointment.

PEV Customer Disappointment				
Parameter	Vehicle			
	V1	V2	V3	V4
PMAX	4.0	4.0	2.0	3.0
EDUR	6.0	5.0	5.0	8.0
EXRQD1	6.0	8.0	8.0	3.0
UF1	0.25	0.40	0.80	0.13
CF	0.13	0.21	0.21	0.05
DF (M1)	3.79	2.29	1.20	7.87
DF (M2)	1.73	1.64	1.33	1.85
DF (M3)	2.90	2.71	2.71	2.97
EXGAP	0.8	0.6	1.0	0.3
ΔEX	13.3%	7.5%	12.5%	10.0%
DX (M1)	71.7%	19.4%	20.7%	98.4%
DX (M2)	32.6%	13.8%	22.8%	23.1%
DX (M3)	54.8%	22.9%	46.6%	37.1%

For discussion purposes an EXGAP is also shown for each vehicle. These are just selected for the example and cannot be deduced from the earlier figure. ∆EX is the relative miss shown as a percent. The disappoint index (DX) is shown for each of the DF methods. This is based on the weighted error model for a ∆EX of 10% equal to a weighted error (WtdError) of 12.5%.

On an absolute basis V3 has the largest EXGAP and V4 the smallest. The red color shows the worst and green shows the best for each measure. All of the DX measures show V2 to be the least disappointed. Method 1 shows V4 to be the most disappointed and the other two methods show V1 to be the most disappointed. The ranking of the second most disappointed is V1, V4, and V3 for the three methods, respectively. With the exception of the absolute miss, V2 is best overall. V1 ranks poorest in three of the five measures and is a close second in the other two.

The DX metrics are not normalized to each other, so it is not possible to compare the actual numbers between the methods. A 10% miss for V4 gives a 98.4%, 23.1%, and 37.1% result for each of the three methods – but it represents the same disappointment by that driver.

This was not an attempt to create a definitive metric. Doing that will require work with people to understand behavior and real field work. Method 3 was selected for the simulation.

Measures of Collective Disappointment

As discussed in this chapter, there are several measures that can be used to assess the disappointment of a driver for an incomplete energy transfer for a single vehicle. The most direct driver assessment will come from looking at the SOC on the battery gauge. ETESS can only reliably compare the requested and actual transfer and any gap (EXGAP). The relative gap is more useful than the absolute miss for comparisons (∆EX= EXGAP/EXREF). The Disappointment Factor (DF) is a way of adjusting the relative miss for driver perceptions based on the degree of stress that the PEV is placing on the total system – this is expressed in the Disappointment Index (DX).

If power delivery to a PEV is not constrained, and it is feasible to complete the requested energy transfer during the charging session, DX will always be zero. The ETESS simulation only allows feasible solutions. DX will only be non-zero when power delivery must be constrained in order to maintain the total power to all vehicles at the facility less than a grid power limit. Then it is possible that some PEVs may have a DX greater than zero.

DX is a weighted measure of customer disappointment for a single PEV. A value of zero for DX is, of course, the preferred outcome. DX is useful for comparing how each PEV did during the day against all others. And DF and projected DX can also be useful for power allocation algorithms. Nevertheless, a composite measure of disappointment for all of the vehicles charged during a day is also needed. It is needed to assess the performance of ETESS and iPEM logic in minimizing PEV customer disappointment while also dealing with grid power limits. There needs to be a collective DX metric for all vehicles that can be minimized.

One key metric is the percent of vehicles that successfully completed charging with a DX of zero (**PctVehOK**). This is a very rough measure, but it is a very useful metric. Is it better to fully satisfy 99% of the vehicles (DX = 0) and give no energy to one vehicle, or give every vehicle 99% of its requested energy transfer? By this measure, it is best to select a small number of vehicles to receive no energy transfer. This not the best metric for use in power allocation, but it is still a good measure to be used in association with other metrics.

Another basic metric is to define the relative gap in the transferred energy for all of the vehicles that charged during the day. It is defined as:

$$\mathbf{AvDelEX} = \frac{\sum_{\mathbf{vQTY}} \mathbf{EXGAP_i}}{\sum_{\mathbf{vQTY}} \mathbf{EXREF_i}}$$

This is total energy transfer missed by all of the vehicles relative to the total required energy transfer for all of the vehicles during the day (vQTY). It is not appropriate to take the average of averages for this metric.

Another composite metric is to create an average Disappointment Index (AvDX):

$$\boldsymbol{AvDX} = \frac{\sum_{i=1}^{vQTY} \boldsymbol{DX_i}}{\boldsymbol{vQTY}}$$

This is a simple average where the DX for each vehicle is considered to be of equal importance. Because disappointment is already a relative measure, this AvDX metric treats each vehicle equally.

Another way to create a composite metric for DX is to create a "Virtual Vehicle" and compute the DX for it. In this case the relative gap (ΔEX) for the "Virtual Vehicle" is the AvDelEX for all of the vehicles. This can be used in the equations for Disappointment Index (DX) to compute the Virtual Vehicle DX. This requires a Virtual Vehicle Disappointment Factor (VvDF), which is a function of the Utilization Factor and PMAX for the Virtual Vehicle.

$$\boldsymbol{VvUF} = \frac{\sum_{vQTY} \boldsymbol{EXREF_i}}{\sum_{vQTY} \boldsymbol{EXMAX_i}} \qquad \boldsymbol{VvPMAX} = \frac{\sum_{vQTY} \boldsymbol{EXMAX_i}}{\sum_{vQTY} \boldsymbol{DUR_i}}$$

$$\boldsymbol{VvDF} = \boldsymbol{Method}\ \mathbf{3}\ \boldsymbol{Function}(\boldsymbol{VvUF}, \boldsymbol{VvPMAX})$$

$$\boldsymbol{VvDX} = \mathbf{5} * \boldsymbol{VvDF} * \boldsymbol{AvDelEX} * (\boldsymbol{AvDelEX} + \mathbf{0.75})$$

The use of PctVehOK, AvDelEX, AvDX, and VvDX as measures of collective disappointment will be demonstrated by simulation for different scenarios.

Power Allocation and Grid Power Limits

When a PEV connects at a public access charge station, it would normally start charging at the power rating of its on board charger. The vehicle will charge until it has achieved the target energy transfer and then stop charging. This is the charging strategy that a PEV can take to minimize the risk of not completing the desired energy transfer before disconnect – any other approach that delays application of maximum power introduces some risk. As long as it is technically feasible to complete the transfer in the time available, it will be successful and EXGAP and DX will be zero for each PEV. The aggregate metrics for the entire facility for the 24 hour day will also be fully satisfactory. Still, the aggregate power demand for the parking facility can swing from zero to the extended power limit of all of the charge stations at their rated limit. If a road rally of Tesla Roadsters all stopped to charge at the same time, this could drive the facility to its capacity.

Some public access charging facilities may not have a need to control the aggregate power demanded by all of the PEVs at the site, and can allow all of the vehicles to charge at PMAX. The aggregate maximum PEV demand may be small relative to the total facility demand. There may be no economic incentive to control peak 15 or 30 minute demand charges and the facility may not participate in any demand management programs. The infrastructure may be sized to handle 7.7 kW on every charge station at the facility at any time during the day. This could be the case for a small group of charge stations at a large shopping mall or even for a larger number of employee spots at an industrial plant.   These locations would not need an energy management system (ETEMS or ETESS) to manage the aggregate PEV load.

There may be many other public access charging facilities that do need to be concerned about the aggregate charging demand.   The infrastructure may not be sized for 100% of the charge stations operating at their individual power rating. It may support a road rally of Chevy Volts or Nissan Leafs, but not all of the Tesla Roadsters. The facility may be concerned about keeping monthly peak demand below a threshold. The facility may be enrolled in a demand response or demand dispatch program and need to actively control its load profile. These facilities will want to hold the aggregate power below a grid power limit or target. These facilities will need an energy management system (ETEMS or ETESS) to manage the PEV loads.

Energy Transfer Profile

Figure 85 shows a possible maximum power profile for a charging facility. This assumes that any vehicle could draw its onboard charger rated power (PMAX) at any time during the actual duration (DUR) of its stay.   This is not the power capacity of the facility which is the product of the number of charge stations and the rated power of each. It reflects the pattern of usage for the location. The total power is the sum of the PMAX for each of the charge stations that are occupied at that time of day. If there is a power limit for the facility, the aggregate power demanded by the vehicles must be maintained at or below this limit.

The total area under the curve represents the maximum possible energy transfer for that location on that day. The area shown in red is the unavailable energy if the aggregate power consumed by the vehicles as always maintained below the grid power limit. The area shown in green is the available energy. The maximum energy transfer capability for any individual vehicle (EXMAX) is

$$\boldsymbol{EXMAX = PMAX * DUR}$$

Most vehicles will not need to draw this amount of energy during the session, but it is possible. The total area under the curve is the sum of EXMAX for all of the vehicles that charged during the day. The amount of energy required by all of the vehicles is the sum of EXREF for all of the vehicles.   The total amount of energy actually delivered to all vehicles during the day is the sum of EXACT for all of the vehicles.

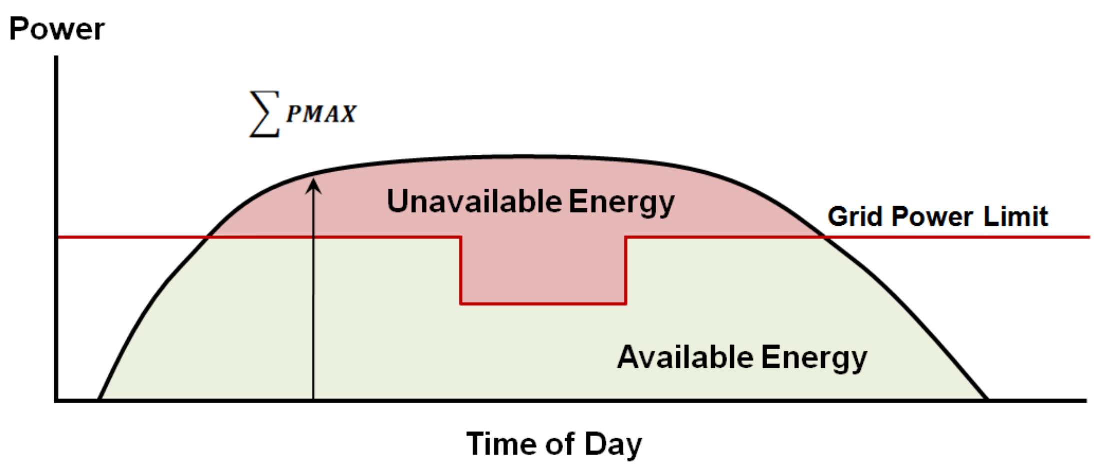


Figure 85 shows a daily power profile for a charging facility.

The ratios between some of these energy transfer measures are useful indicators. The ratio of available energy to the total energy is an indicator of the degree of challenge to vehicle charging imposed by the grid limit. The ratio of required energy to available energy is a measure of the stress for the specific charging requirements. The ratio of actual energy delivery to the requirement is a measure of success.

Figure 86 shows how these ratios vary with the grid power limit. This simulation was done using the mall location, with a random mix of vehicle types, and a 50% probability of a high power (6.6 kW) charger. The vehicles charged at PMAX, but were rolled back proportional to their PMAX to stay within the grid power limit. Control strategy will be discussed next. A flat power limit was used for 24 hours. The limit is established in the simulation as share of the maximum power rating of the facility, which is the product of the number of charge stations (csQTY) and the power rating of each charge station (7.7 kW). Even a level of 100% has some inherent discount because the maximum vehicle power is 6.6 kW in the simulation.

At 60% of capacity all of the vehicles charge perfectly, and there is no discounting of available to maximum energy. The required to available is about 60% - lots of margin. The available to maximum ratio drops as the lower grid limits are imposed – a lower percentage is a lower percent of facility capacity. As expected the required to available ratio rises and crosses 1.0 (to impossible) just below a 30% power level. There is some margin in the timing of power allocation and this is reflected in the actual to required ratio holding close to 1.0 through 40% and dropping to about 90% at the 30% power level. At 20% the energy transfer miss is very large because the required to/available ratio is over 1.3.

The available to maximum ratio is a function of the selected grid power limit, the location scenario selections, and probability of a high power vehicle charger. The required to available ratio is also impacted by the vehicle mix selection. The outcome (actual to required ratio) is then driven by the control strategy and the availability of an ETESS unit.

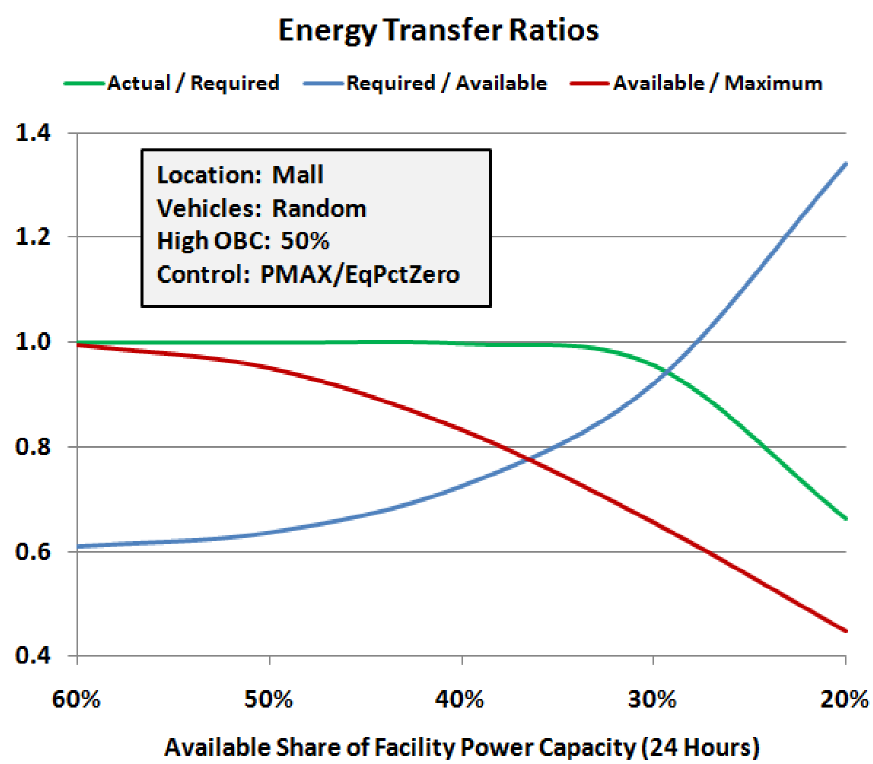


Figure 86 provides an example of Energy Transfer Ratios.

Initial Power Allocation

At the start of every three minute power allocation cycle, the intelligent Power and Energy Management (iPEM) logic allocates power (PCMD) to each connected vehicle. It does this in two stages. First, it allocates power without working to a firm grid power limit or the considering the availability of an ETESS unit. This is the initial power allocation. If there are no firm restrictions on grid power, these commands are sent to the connected vehicles. The ETESS simulation currently provides four methods for performing the initial power allocation.

The most basic PEV Power Allocation Strategy selection is "PMAX." At the start of each control interval every connected vehicle is authorized to use the rated power of its onboard charger (PCMD = PMAX). This mode is enabled by default if there is not any energy management system control at a facility. The charge station control pilot would be set to the branch circuit capacity and the vehicle will never exceed its charger rating even if the charge station control pilot allows it. This is enabled in J2847-1 Optimized Energy Transfer by authorizing a power equal to or greater than the PEV charger rating.

Another approach for allocating power is to compute the power needed to exactly transfer the required amount of energy by the estimated time of departure. This is the average power (PAV). PAV can be computed at the time of connection (TOA). The value may change during the session if there are differences in efficiency from what is used by the PEV to forecast the required transfer and the actual efficiency. The average power can also be updated during the session based on the remaining required transfer and the estimated time to go before disconnect (ETOD). To allow for some variation from the estimated and actual return of the driver, it is best to hedge somewhat. The ETESS simulation uses a strategy that uses 110% of the actual dynamic average. This is the "1.1 * PAV" strategy. There is also strategy that fixes the exact PAV at the time of arrival (PAV @TOA). This is used primarily as a benchmark for testing the simulation, and is not a useful control option.

In the discussion of intelligent Power and Energy Management in Chapter 4, a mixed strategy was shown where some vehicles start immediately at PMAX, others delay the start, and others use PAV. This is only exercised if the available grid power cannot support all of the connected vehicles at PMAX. The default is still to use PMAX for all vehicles if sufficient power is available. This type of approach is called the "MIX" strategy. If a vehicle's Utilization Factor (UF) is less than 0.6 and that vehicle has not started charging yet, PCMD is set to zero for that vehicle – it is a delayed start. The UF for that vehicle will increase as time goes by, and when UF goes beyond a value of 0.6, the mode will change. For any vehicle with a UF greater than 0.6 and less than 0.9, PCMD will be set to 1.1 times PAV. This is an initial allocation and there is no limiting of the average power. The reductions from PMAX are done in order of increasing UF until the total power is less than the grid limit or the last vehicle with UF less than 0.9 has been set to 1.1 times PAV.

If there are no power constraints, all of the allocation strategies will result in a PctVehOK of 100% and AvDelEX, AvDX, and VvDX of zero. Grid limits might be exceeded, but vehicles will not be disappointed. The ETESS simulation includes a PEV Power Limiting Strategy called "Unlimited" that allows this operation.

Power Limiting

If the total commanded power exceeds a grid power limit, the first action by the control system is to schedule the ETESS unit to provide power to offset or partially offset the excess over the grid power limit. If there is not a hard limit for the grid, no further action will be taken. This is the action taken when the "Unlimited" PEV Power Limiting Strategy is selected in the simulation.

Four algorithms were developed for the ETESS simulation to investigate the effects of holding a hard grid limit on vehicle disappointment metrics. These are applied after any available ETESS power and energy is allocated. The development of optimization algorithms needs continued work, but these illustrate the concept for managing power to a limit across a fleet of vehicles. The power limiting logic is used to reduce the power command of each vehicle to keep the commanded vehicle power below the available power.

One very simple algorithm for reducing the power level of all PEVs is to reduce all vehicles power allocation by the same percent. The scale factor is defined by

$$\boldsymbol{Scale\ Factor} = \frac{\boldsymbol{AvailablePower}}{\sum_{csQTY} \boldsymbol{PCMD_i}}$$

The available power is the grid power limit adjusted for any scheduled power provided by ETESS. If the Grid can support 60 kW and ETESS can schedule a discharge at 15 kW, the available power for the vehicles is 75 kW. If the aggregate of the initial vehicle power commands is 100 kW, the scale factor would be 75%. Each initial PCMD would be multiplied by the scale factor and then sent to each vehicle. This is an equal percent reduction.

The charge station control pilot cannot select a charging current level of less than six amperes, which is a power level of 1.44 kW on a 240VAC AC Level 2 charge station. While it might be possible to digitally command a lower power value, the efficiency of an onboard charger may be compromised below a minimum power level. There are losses associated with battery cooling system and other equipment that may not justify going below the threshold of 1.44 KW – which is also the AC Level 1 minimum level. The ETESS simulation uses a minimum power (PMIN) of 1.44 kW. If PAV is less than 1.44 kW during the initial allocation, the PCMD is set to 1.44 kW. Still, during power limiting, if the scale factor takes a vehicle below that level, the PCMD is set to zero. If the remaining power is not reallocated to other vehicles, this mode is called "EqPctZero." With a slightly more complicated algorithm, the residuals can be redistributed (or folded) to vehicles with a PCMD greater than PMIN. This mode is called "EqPctFold."

Another set of methods for power limiting is to try to minimize the aggregate disappointment (AvDX). This will be done based on a Power Allocation Factor that is defined as

$$\boldsymbol{PAF = 10 * DF * \Delta EX / EXRQD1}$$

This factor defines the relationship to how DX for any specific vehicle changes with incremental amounts of PCMD. For every Watt of additional power provided to a vehicle, that vehicle's DX during that interval will decrease proportional to the PAF. This is an approximate and not an exact relationship. It was developed by looking at the rate of change of the DX function with respect to commanded power.

One approach for using PAF is to sequentially apply power to vehicles in the order of decreasing PAF for all charging vehicles. Vehicles that are already at a PCMD = 0 following the initial allocation are not changed. Any vehicle at PMAX stays at PMAX until the first vehicle with PCMD less than PMAX is found. Then all vehicles are set to 1.1 * PAV until all of the available power has been allocated. This will partially override the MIX strategy. With the PMAX initial allocation strategy the vehicles are sorted by PAF and then power is allocated at each vehicle PMAX until it is all used. This may not be a good algorithm, but it was implemented. This is the "SeqPAF" strategy.

Another approach for PAF is to first scale power back by two times the scale factor used in the equal percent modes. Then the extra share of power reduction is added back to the vehicles. The additional power is allocated proportional to the weighted share of PAF. The weight for each vehicle is its PAF divided by the sum of PAF for all vehicles that do not have a PCMD already set to zero during initial allocation or during the rollback as a result of going below PMIN. This is the "WtdPAF" strategy.

All four limiting algorithms are reactive and do not consider future events. More effective solutions can be developed using more advanced techniques. The optimization of the iPEM logic was not an objective of this project. These are adequate for demonstrating the concept.

A Demonstration of Power Allocation and Limiting

The ETESS simulation was used to demonstrate how iPEM logic can be used to manage vehicle power allocation to stay within grid power constraints for a facility. This also allows the metrics for PEV disappointment to be compared. The baseline case for comparison uses the following selections: Mall location, Random vehicle mix, 50% probability of high power onboard charger, PMAX charging strategy, EqPctZero limiting strategy, and a 30% demand response limit for 24 hours. The 30% level is a very restrictive level, but this was selected because it produces a meaningful level of customer disappointment and the purpose of this section was to show disappointment metrics. The actual to required energy transfer ratios starts to roll off strongly at the 30% level as shown earlier in Figure 86.

An actual time history is shown, Figure 87, for a simulation that was repeated exactly using two control strategies. The first was run at PMAX without any limiting ("Unlimited" strategy). The second used PMAX for initial allocation and then rolls back using an equal percent reduction approach ("EqPctZero" strategy). The 30% power limit is shown as the flat line at 42 kW. The darker red line is the sum of the PMAX for all of the vehicles connected at the time. The black line is the unlimited PMAX. It follows the

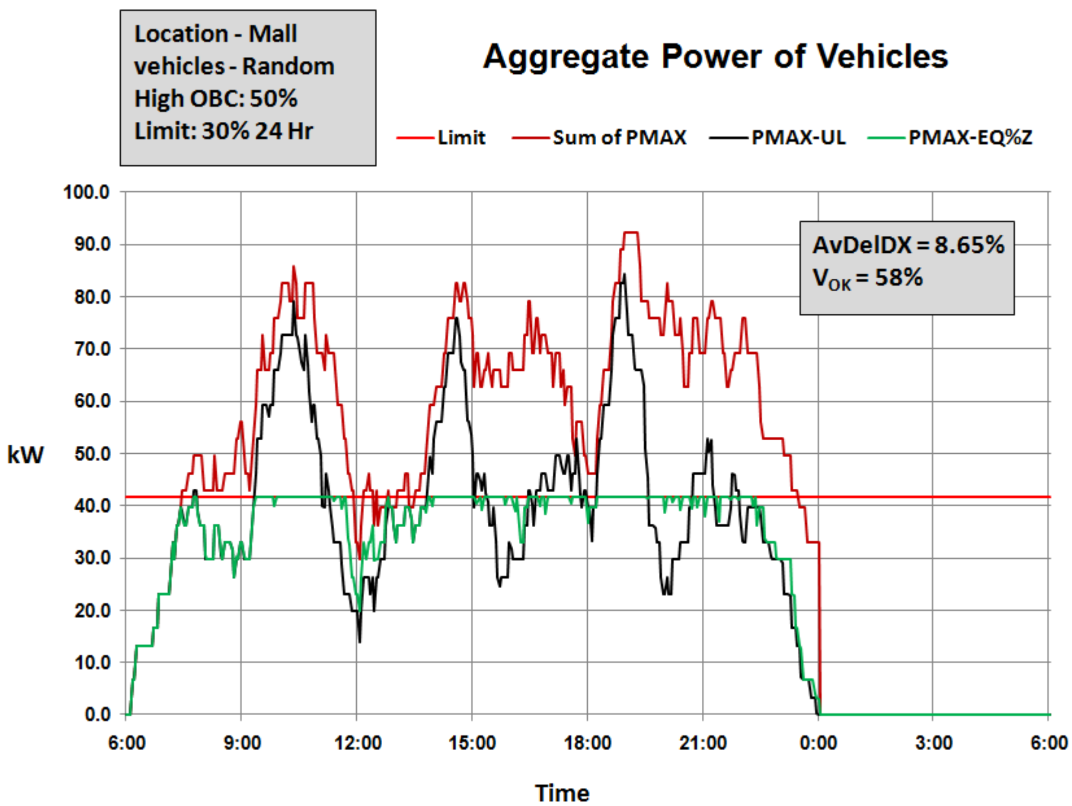


Figure 87 is a timeline for limited and unlimited charging.

sum of PMAX curve and follows the rise very closely, but drops off much quicker. This behavior would be expected because the required energy transfer is much less than the total energy available and vehicles will finish early. The green line shows what happens when power limiting is applied. Everything above the limit is clipped and power is applied in regions where the unlimited PMAX line fell below the grid limit. The limiting strategy resulted in an AvDelEX of 8.65% and only 58% of the vehicles completed successfully. This is what unlimited and limited charging looks like. In less demanding scenarios with higher grid power levels, the limiting strategy will not cause disappointment and it will still clip the peaks.

The simulation allows a flat power limit to be established for the full 24 hour day at 20%, 30%, 40%, 50%, 60%, or 100% of the maximum facility power level. The maximum facility power level is the product of the number of charge stations selected and the charge station power level of 7.7 kW. A charging site with 18 charge stations was used for all of the examples in this section – a power level of 139 kW. A limit of 30% corresponds to 41.6 kW – this is only 2.3 kW per vehicle if all 18 charge stations were occupied. The simulation also allows for a demand response notch of either two, four, or eight hours (centered at 4:00 p.m.) with levels of 20%, 30%, or 40%. This is used in association with an overall flat limit of 50%, 60%, or 100% of capacity.

The effect on vehicle metrics is shown in Figure 88 for a 30% demand response window on an overall 40% flat limit. **All simulations in this section are Monte Carlo runs of 2000 passes.** Data is provided for windows of two, four, and eight hour windows and the baseline 30% flat level for 24 hours. As expected the impact of limiting gets worse as the length of time at the 30% level increases. AvDX is always greater than VvDX, which is always greater than the pure miss (AvDelEX). The ratios for required (RefEX) to available (AvailEX) energy and available to maximum energy and the vehicles OK metric are shown by lines and read on the axis on the right side of the chart.

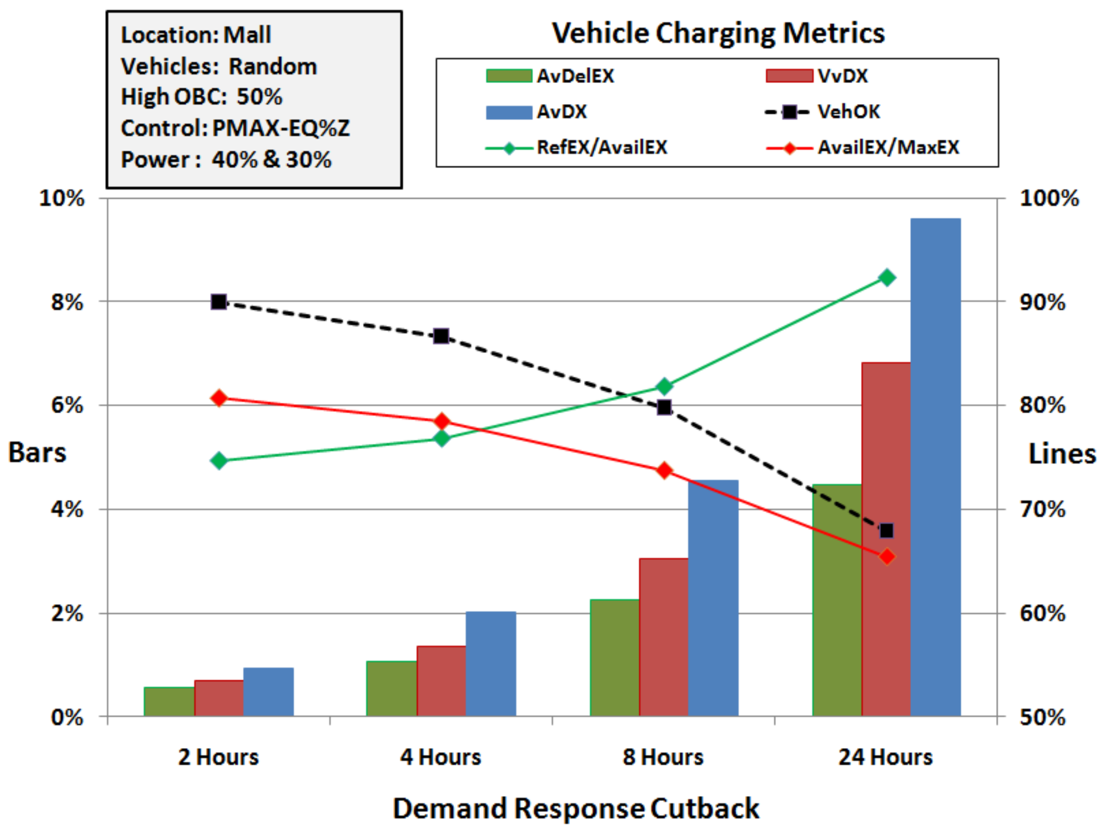


Figure 88 shows the effect of a demand response window on vehicle metrics.

Figure 89 shows the variation of metrics for five different locations. Because of the long stays the Work location has significant slack and it has zero disappointment at 30% power. The High Stress is the most difficult scenario and it shows in the metrics. Mall and City24 are almost equal in all measures except VvDX. The virtual vehicle is impacted by the extra six hours of nighttime occupancy at low power levels. The relationship of AvDX to AvDelEX is more consistent across the locations.

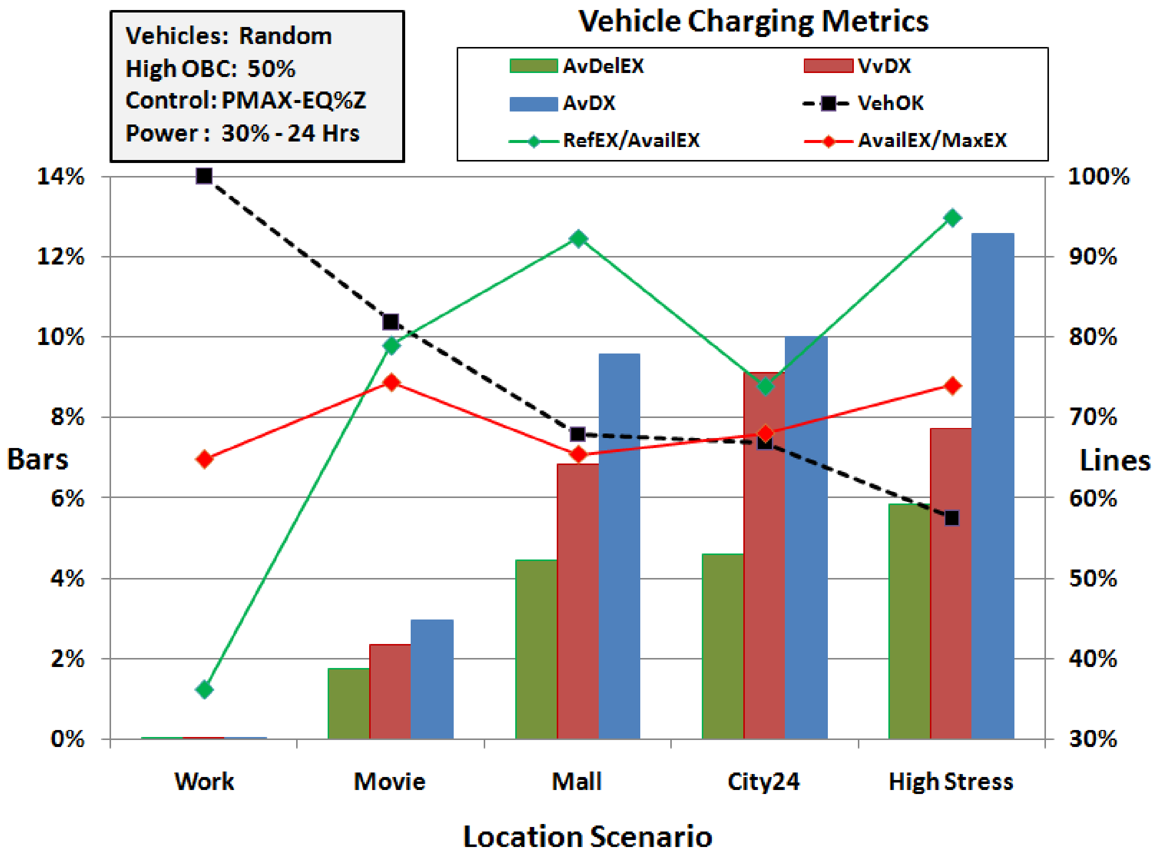


Figure 89 shows the effect of locations of vehicle metrics.

The effect of on board charger power selection is shown in Figure 90 and the effect of vehicle mix is shown in Figure 91. As the percent of high power chargers increase for the same location scenario, the level of AvDelEX increases almost linearly. The expected value of the battery capacity increases as the vehicle mix changes from a pure PHEV Mix to a pure BEV Mix. This increases the required energy transfer for each vehicle and the energy miss (AvDelEX) increase almost linearly. AvDX shows some variation with the square of AvDelDX and therefore AvDX has a more geometric growth rate. The percent of vehicles successfully completing charging also tracks the vehicle mix battery capacity very well. This is expected because as the amount of energy transfer is increased for the same charger power and duration of stay, the potential for missing transfer is increased. The vehicle successful completion rate is almost flat at 70% as charger power increases. In this case the required energy and duration are not changing – only the charger power. The percent of power cutback will be greater for higher power charger mixes but the amount of time to charge is shorter for the vehicles when power is available. Vehicles with low UF can easily complete, but vehicles with high UF at connection will have a higher DX.

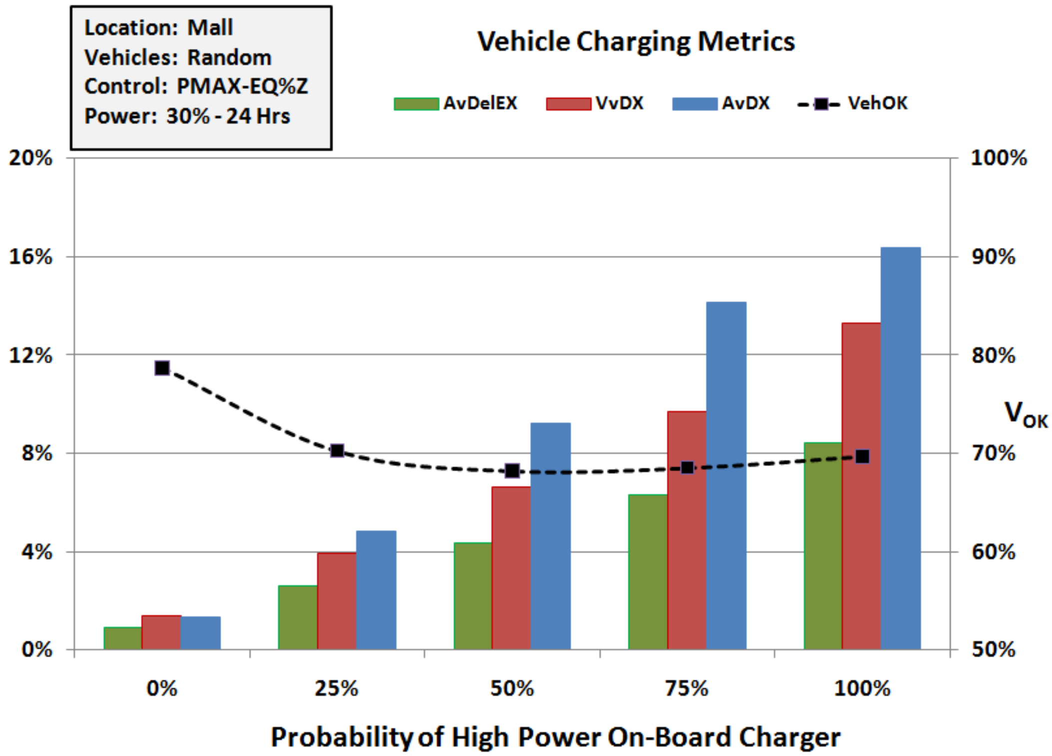


Figure 90 shows the effect of onboard charger selection on vehicle metrics.

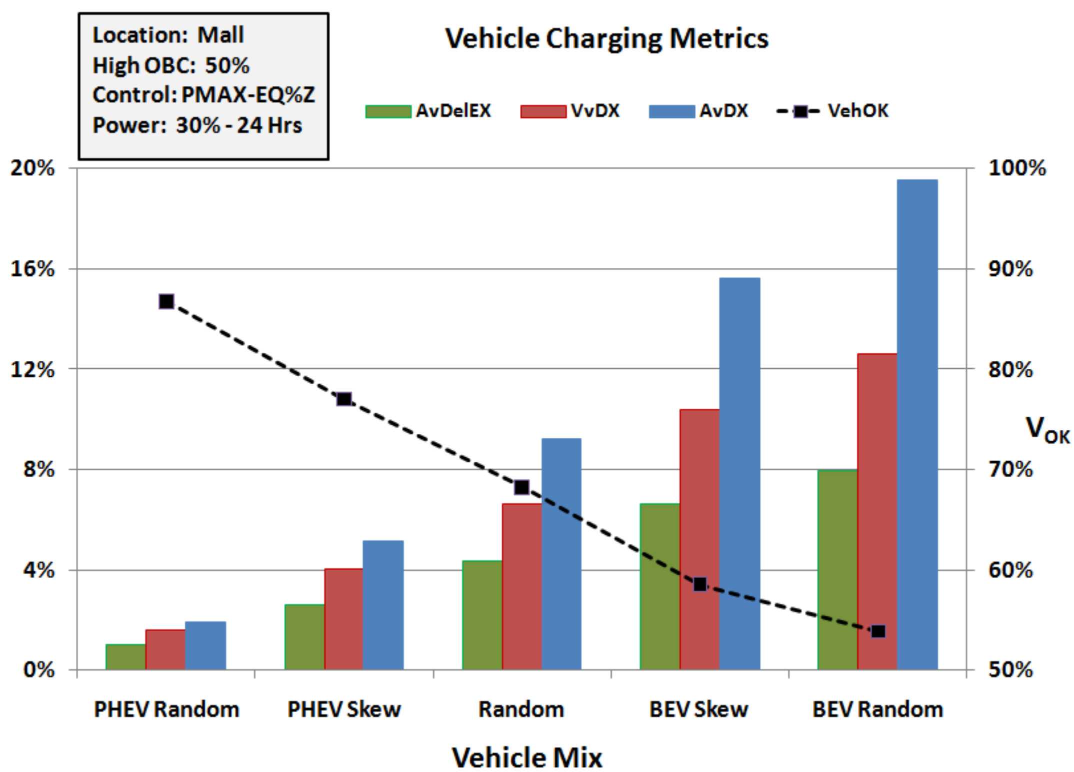


Figure 91 shows the effect of vehicle mix on vehicle metrics.

As discussed earlier, if an ETESS unit is available it can be called on to provide power and energy to offset some or all of the impact of the grid power limit. **Even with a severe limit to only 30% of the facility capacity for 24 hours, a 25 kW ETESS with three hours of storage almost eliminates all disappointment.** This is a Monte Carlo average and individual passes will show higher levels of disappointment, others will have none. The benefit of a 25 kW unit with only one hour of storage also shows dramatic improvement over the operation without an ETESS unit.

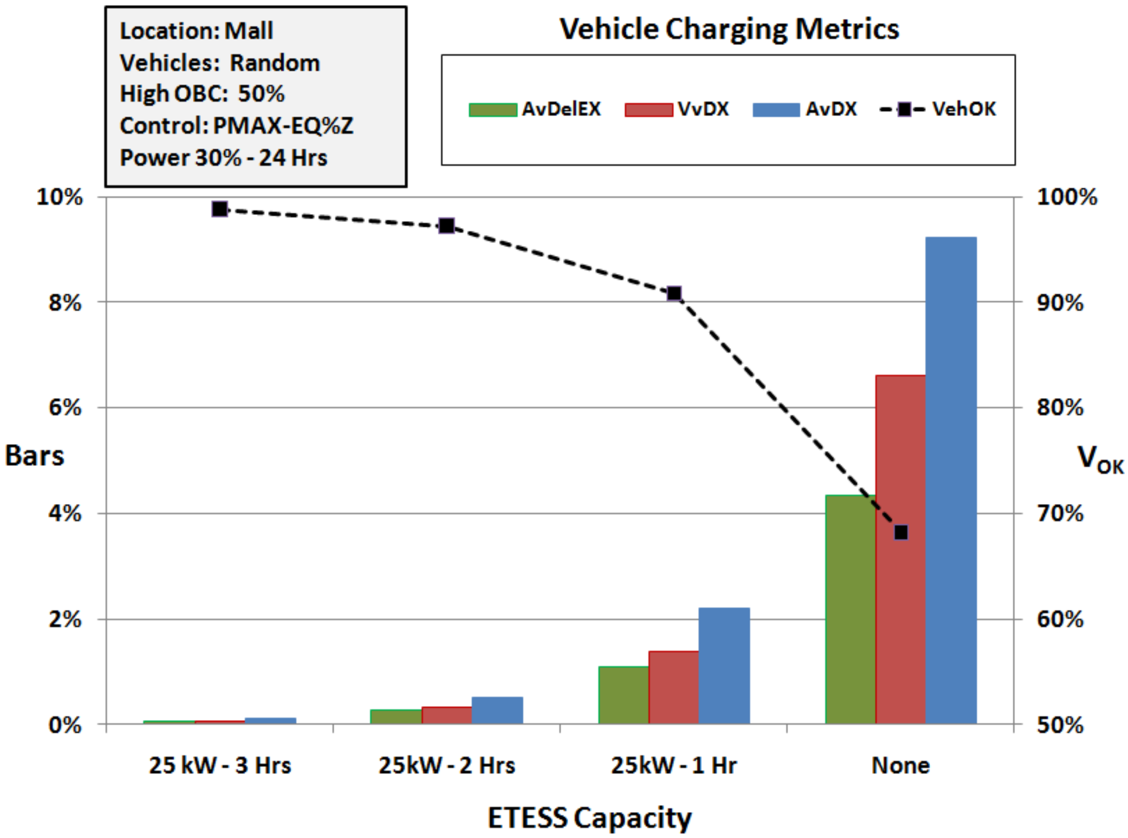


Figure 92 shows the effect of ETESS on vehicle metrics.

All of the simulations so far have been built on the PMAX strategy for initial power allocation and the equal percent rollback without folding back power clipped by dropping below PMIN – the "EqPctZero" limiting strategy selection. Now we will look at the relative performance of different choices of strategy. First we will look at how three allocation strategies (PMAX, 1.1*PAV, and MIX) work with four limiting strategies (EqPctZero, EqPctFold, WtdPAF, and SeqPAF). The impact of these strategy selections on the AvDX metric will be compared. This is shown in Figure 93. The AvDX value is indicated by a vertical bar. The bar colors designate the initial charging strategy. They are grouped in sets by the four limiting strategy. The best overall is to use the MIX strategy for initial application and an equal percent reduction with fold back for limiting. The MIX strategy is also the best strategy to use with any of the limiting strategies. The PMAX strategy is the poorest overall with any limiting strategy. It is the overall worst when combined with the sequential power allocation factor. The 110% of PAV strategy was significantly off from the MIX strategy and close to PMAX for both of the equal percent reduction modes. The more exotic PAF modes performed reasonably well with the MIX strategy, but not as well as the less complex folded equal percent algorithm. Five of these twelve strategies have been expanded in Figure 94 to show all of the metrics.

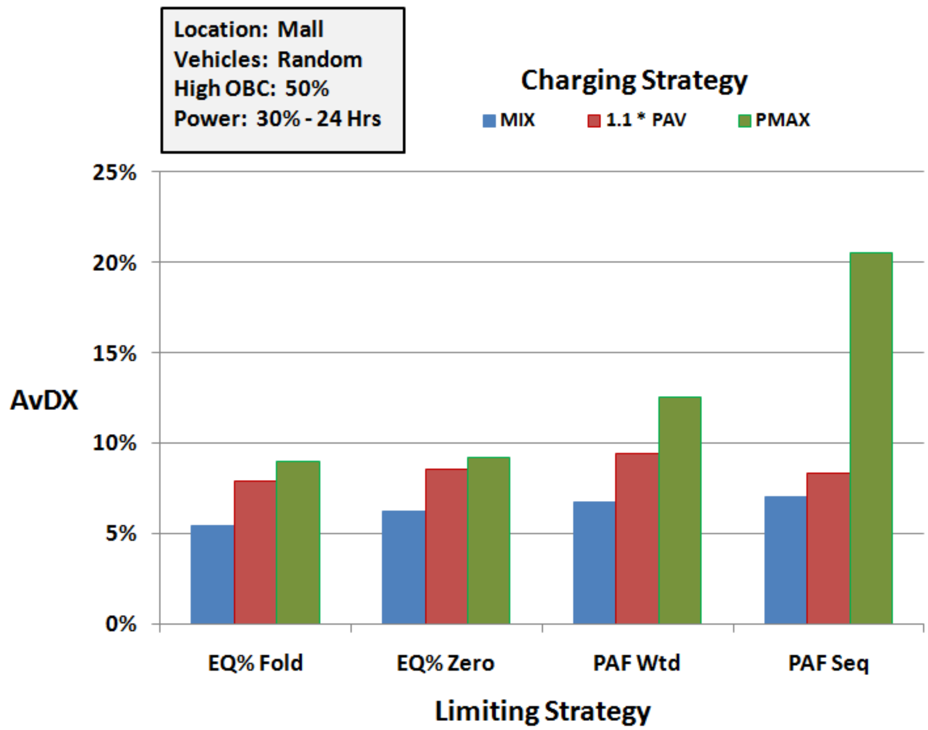


Figure 93 compares combinations of three initial allocation and four limiting strategies.

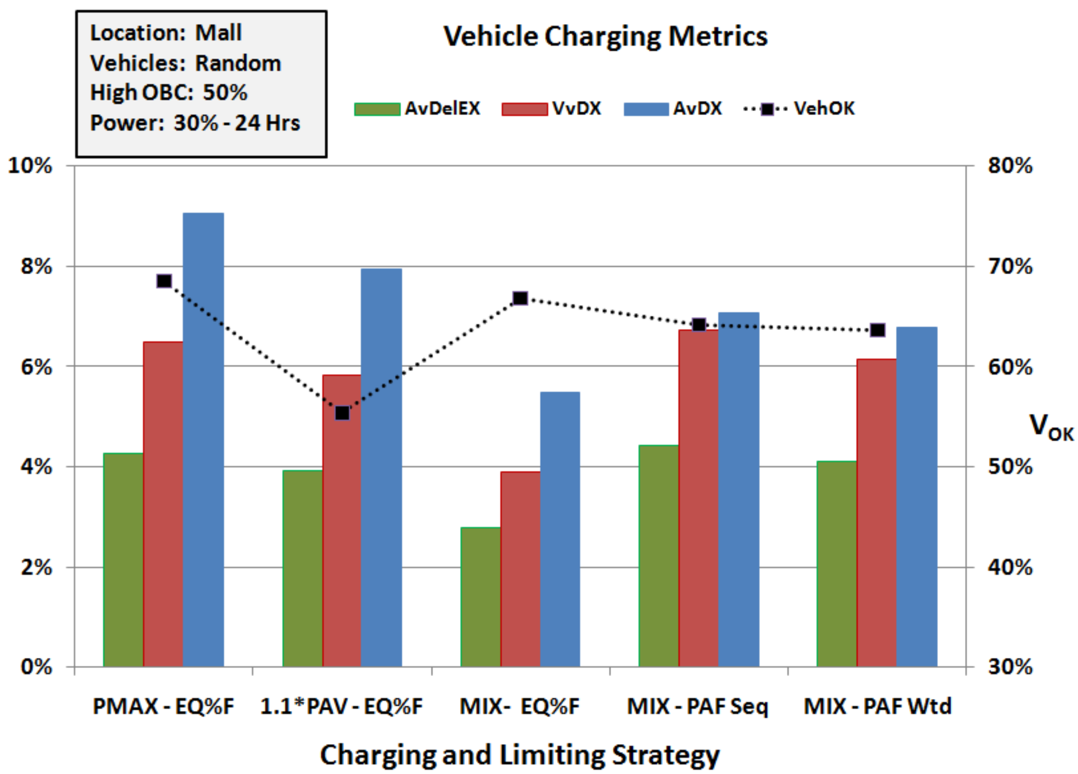


Figure 94 compares five strategies for power allocation and limiting.

The equal percent with fold back limiting strategy was the most favorable for each of the three initial allocation strategies, so these are all shown. The two PAF limiting strategies were also selected for the MIX strategy. The MIX with simple scaled limiting is the best in all measures except for the percent of vehicles that complete satisfactorily. For this metric the PMAX strategy is slightly better. The MIX PAF strategies did not beat the MIX with simple percent reduction for any measure, although the AvDX performance for the PAF strategies was better than that of either PMAX or PAV. This is a very extreme reduction in facility power and the disappointment metric are high. It was selected to differentiate the metrics.

More Vehicle State Variables

Several new state variables for the vehicles were introduced in this chapter. They are listed in Table 9. These supplement those defined in Table 6 in Chapter 8. These are measures of energy transfer and metrics for customer disappointment.

Table 9 defines additional vehicle state variables.

Other State Variables		
Power Allocation and Use		
	PCMD	Power Commanded by ETESS
	PDEL	Power Used by Vehicle
Energy Transfer Measures		
	EGAP	Energy Gap in Battery
	EXACT	Actual Energy Transfer
	EXGAP	Energy Transfer Gap to EXRQD
Reference Values and Metrics		
	EXMAX	Maximum Possible Energy Transfer
	EXREF	Reference Energy Transfer Request
	UFREF	Reference UF
	DF	Disappointment Factor
	DX	Disappointment Index
	PAF	Power Allocation Factor

Chapter Summary

New concepts of Disappointment Factor and Disappointment Index were created as a way of characterizing individual PEV customer disappointment beyond the basic measures, such as the yes-no of a charging session being successfully completed or the percent gap in requested energy transfer. Metrics for assessing the aggregate disappointment for all of the vehicles that charge during a day at a charging facility were also developed. Alternative concepts for allocating available power among all of the connected vehicles to stay within grid power limits and minimize customer disappointment were also explored using these metrics.

11 *System Performance Metrics*

The primary purpose of a PEV charging facility is to charge vehicles - a PEV does not park at a charging facility to not be charged. The primary objective must always be to complete the requested energy transfer for every PEV before its estimated time of departure. This objective may sometimes conflict with constraints on the availability of power from the grid. The ETESS system must balance the prime objective with considerations for facility power management. Metrics for assessing disappointment of PEV customers for incomplete charging were discussed in the last chapter. In this chapter metrics for exceeding grid power constraints will be developed and used to assess performance of ETESS and iPEM logic.

Grid Power Metrics

The charging facility will draw whatever power it needs from the grid unless it is disconnected or the electric power grid cannot sustain the overall system loads. Power just flows to the loads and the only way to reduce the power flow is to reduce the loads. This is what the iPEM software does by setting the maximum power level for each connected vehicle. An ETESS unit can discharge energy into the facility and reduce the external demand for power or charge its own battery and increase the load on the grid. The chart in Figure 95 shows the power flowing into a charging facility from the grid during one day. In this case the facility has a 24 hour limit at 50% of its maximum charge station capacity (69 kW) and there is a

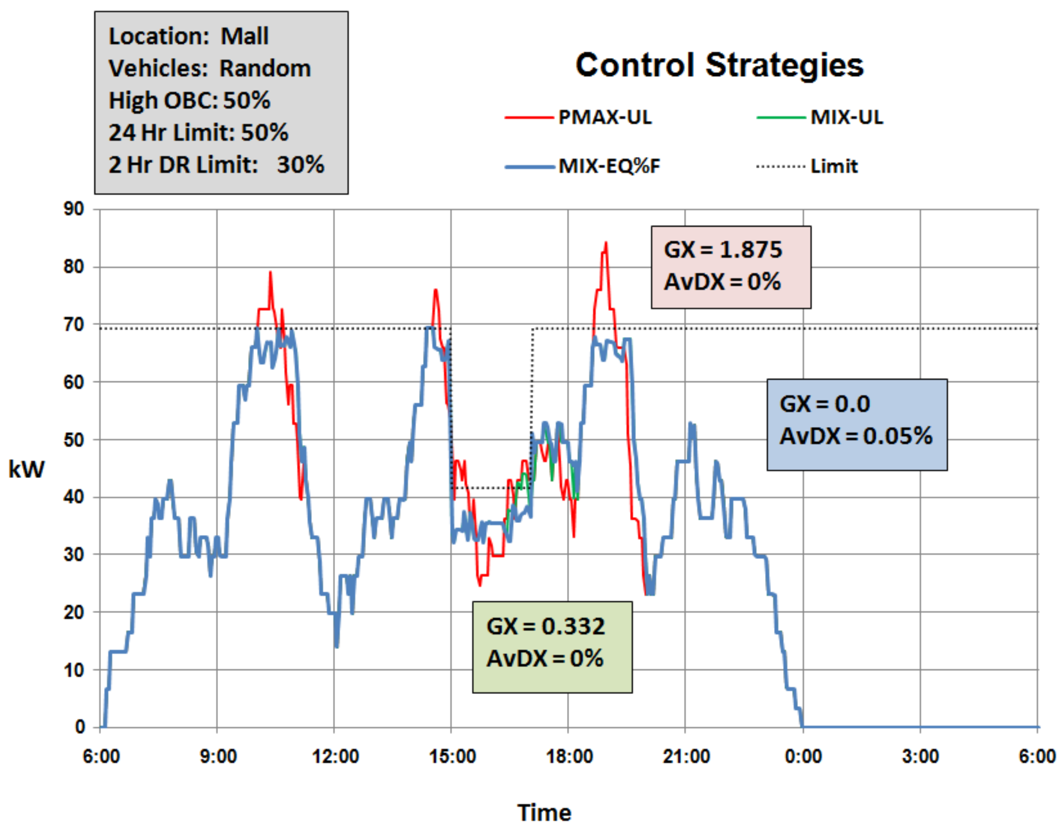


Figure 95 shows power flows for a charging facility for a typical day.

two hour demand response cutback to 30% from 3:00 to 5:00 p.m. If the vehicles are not controlled or they are all authorized to charge using an unlimited PMAX strategy, the power pokes through the limit (the PMAX UL red line). Fortunately in this exact run of the simulation the peak power demand has dropped right during the demand response window.

A MIX strategy for initial power allocation followed by hard limiting using equal percent with fold back does much better than the pure PMAX approach (as shown by the blue line). This logic clipped the peaks and stayed under the demand response cutback. There was only a slight disappointment for PEV customers with an AvDX of only 0.05%. The MIX strategy without the hard limit does reasonable well. This is shown by the green line. Power just nibbles up into the end of the demand response window and this has no vehicle disappointment. The blue line (Limited Mix) overlays the other strategies when they are at the same power level – this shows that for most of the time all three strategies allow vehicles to charge at their rated power.

The chart shows a color coded box for each strategy that shows the AvDX and a metric called GX. This is the Grid Limit Exceeded metric. GX is zero using MIX with full limiting, 0.332 with MIX without limiting, and 1.875 with unlimited PMAX. This metric will be discussed in the next section.

Grid Power Limit Exceeded Metric (GX)

In Figure 96 the horizontal line is a grid power limit (P_{GL}) and grid power (P) has exceeded the limit at certain points. The excess power (ΔP) is the difference between grid power (P) and the limit (P_{GL}), but only when it is positive (exceeding the limit): A Grid Power Limit Exceeded Metric (GX) is defined as:

$$GX = 3.16\sqrt{\sum_{i=1}^{480}\left(\frac{\Delta P_i}{P_{GL}}\right)^2} \qquad \{\boldsymbol{Limit}\ \Delta\boldsymbol{P} > 0\}$$

The constant of 3.16 was selected to make GX equal to 1.0 for a $\Delta P/P_{GL}$ of 0.1 for a 30 minute period in the ETESS simulation (which uses three minutes per interval). A value of 0.1 for $\Delta P/P_{GL}$ for 60 minutes (20 intervals) yields a GX of 1.4 and a GX of 2.0 is produced for a 0.2 value of $\Delta P/P_{GL}$ for 30 minutes - these two cases have the same energy value (area under the curve). GX is proportional to the RMS power of ΔP. For the same RMS power, the effect is greater if the limit is lower.

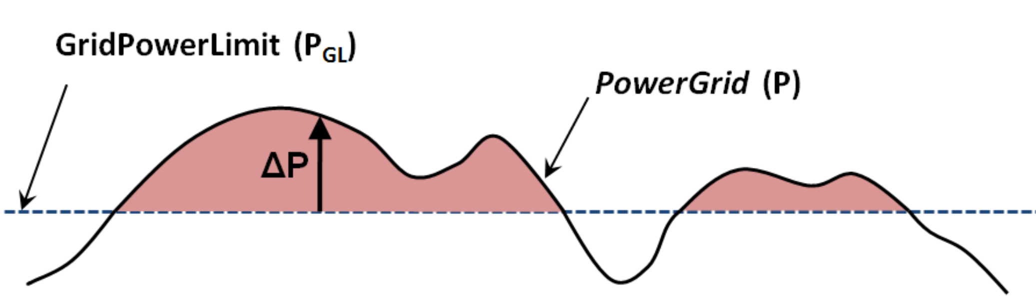


Figure 96 shows grid power exceeding a grid power limit.

Monthly Peak Demand

A commercial customer of a utility normally pays both a monthly demand charge and an energy charge. The demand charge is based on the highest power used at any time during the month. This is based on an average power over either a 15 minute or 30 minute interval, depending on the utility. The ETESS simulation uses a 30 minute average. If the demand meter peaked at 60 kW at 2:00 p.m. on the third Wednesday of the month and the demand charge was $15.00 per kW, the monthly demand charge would be $900. This can be a significant part of the monthly power bill for a commercial customer.

During each pass of the simulation, the average peak power is measured. These daily peaks can be collected for a Monte Carlo simulation and the mean and standard deviation of the average peaks calculated. Figure 97 shows the effect of smoothing when using grid power averaged over 30 minutes. In a demand meter the average power will lag the actual power by 30 minutes – however, in the simulation the average has been shifted back by 15 minutes to align with the actual power.

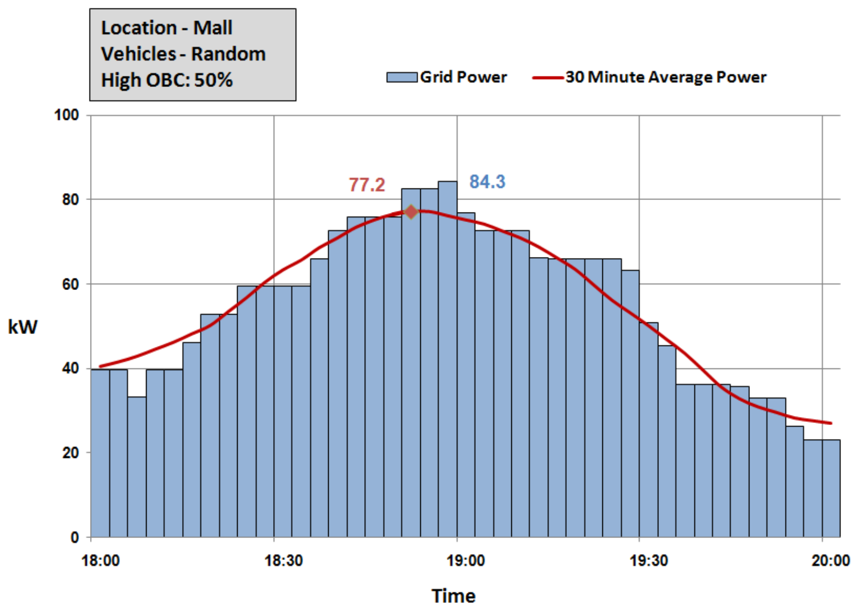


Figure 97 shows actual and average grid power.

You cannot use the mean value of peak demand from the Monte Carlo simulation to determine the likely demand charge. You must not exceed a target limit for 30 days. You need to find the value of average peak power that will yield a probability of not exceeding the limit over 30 days. In the equation below "***p***" is the probability of not exceeding a target value of peak power on any single day:

$$\boldsymbol{p^{30} = 0.95}$$

For a 95% confidence of not exceeding the target for 30 days, the probability of not exceeding it on any single day is 0.9983 – this corresponds to a one sided sigma value of 2.93 based on a cumulative normal distribution. The 30 day average peak can be defined by

$$\boldsymbol{Monthly\ Peak\ Value = (Mean\ of\ Peaks) + 2.9275 * (Standard\ Deviation\ of\ Peaks)}$$

The monthly peak value can be reduced by reducing the mean value and also by reducing the variation. A system that manages to a limit will do both.

Examples of Grid Power Metrics

Figure 98 shows grid metrics for GX, the average daily peak, and the 30 day peak for two initial power allocation control strategies (PMAX and MIX) – the unlimited strategy is selected for power limiting. The values of the metrics are shown for grid power limits from 20% to 60% of capacity. These examples are all based on 18 charge stations with a 100% capacity of 138.6 kW – a 40% limit is 55.4 kW.

GX is significantly impacted by the grid limit. Because there is no active limiting, the magnitude and duration of power exceeding the limit increases significantly as the limit becomes lower. The MIX strategy does slightly better because it does some smoothing of the peaks.

The peaks and 30 day peaks are not impacted at all using the PMAX strategy – the values are constant. The grid limits are used for allocation in the MIX strategy, so there is some improvement as the limit tightens and power is shifted. This works well if there is reasonable margin but as the limit gets lower the logic will call for higher power levels later to compensate for earlier reductions and delays. The 30 day peak for MIX is optimum at 40% in this example.

The vehicle disappointment metrics, such as AvDX, will be zero as long as power limiting is not used, and when a power limiting strategy is used, GX will be zero. A comparison will be shown later in this section, but the examples that follow will not force a hard limit for power.

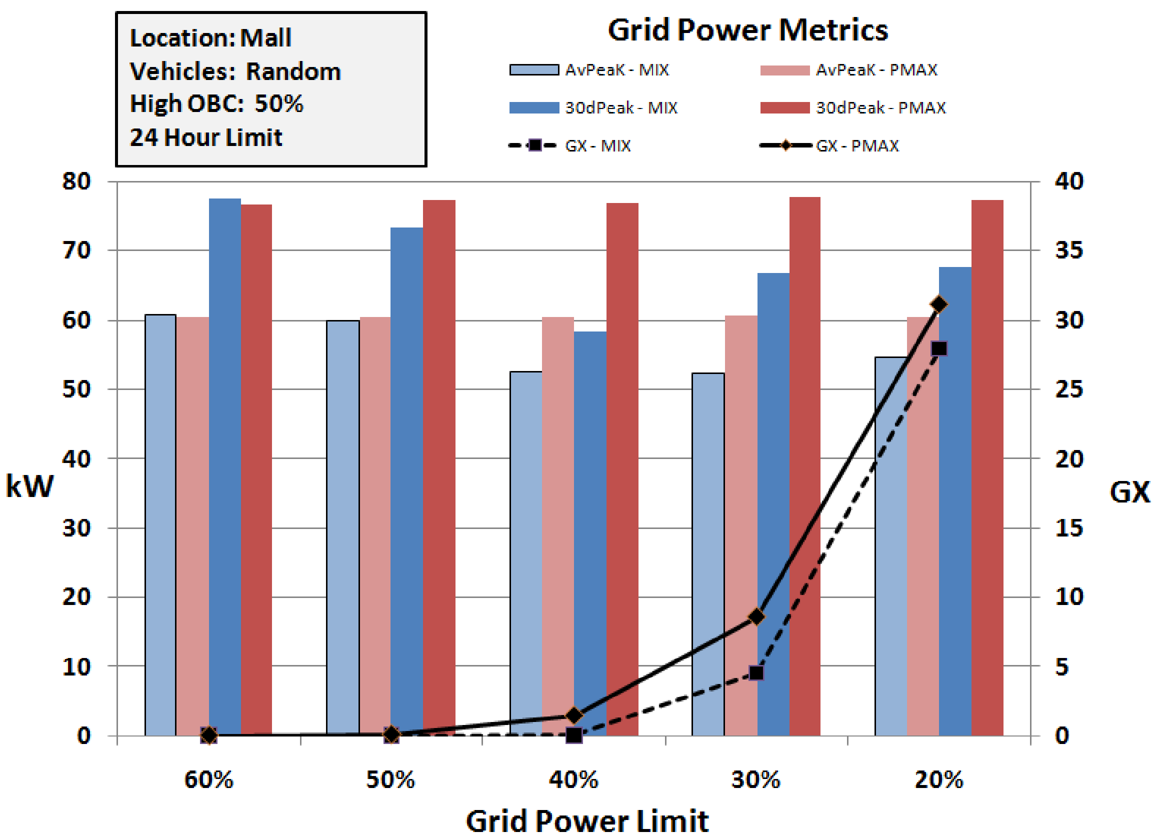


Figure 98 shows Grid Metrics versus Grid Power Limit for two control strategies.

Figure 99 shows the impact of a demand response reduction of 30% for two, four, eight, and 24 hours. The nominal limit is set to 40%. The metrics are shown for both the PMAX and MIX control strategies. GX rises as expected as the length of the reduction in limit from 40% to 30% increases. The 40% limit is 55.4 kW and the 30% limit is 41.6 kW. Even without hard limiting, the MIX strategy holds the average peak below the 55.4 kW limit. It is managing the three minute control intervals, which helps keep the 30 minute averages below the three minute peaks. The peaks do not vary with the PMAX strategy, as expected. GX is always worse with PMAX than with MIX.

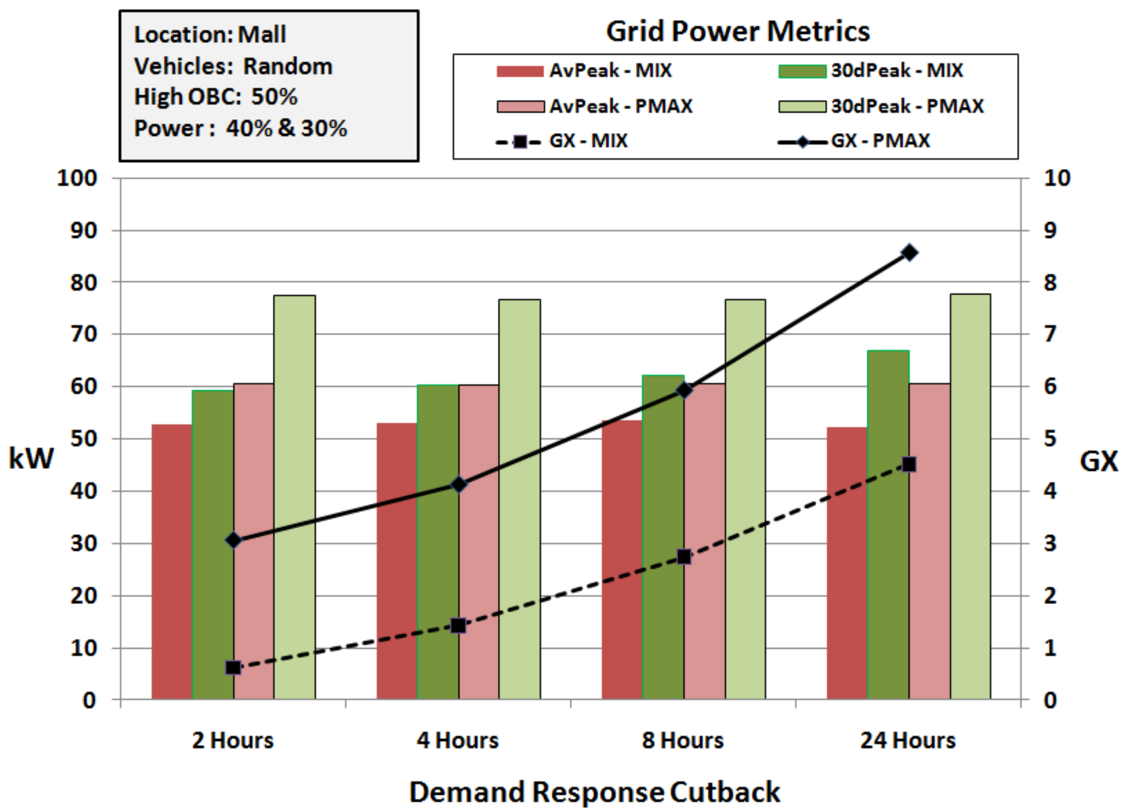


Figure 99 shows the Grid Metrics for a Demand Response Cutback.

The next series of charts show the impact of the on board charger power, the vehicle mix, and the location scenario on the grid power metrics. These all use the MIX strategy without limiting and a flat grid power limit at 30%. These are very similar to the charts shown in Chapter 10 where a limiting strategy was used (GX = 0) and vehicle disappointment measures were charted. Figure 100 shows the effect of on board charger power level, Figure 101 shows the effect of vehicle mix, and Figure 102 shows the effect of location.

The trends for vehicle disappointment in Chapter 10 and grid metrics in this chapter are similar. In Chapter 10 a grid GX of zero is traded against increasing vehicle disappointment and in this chapter a vehicle AvDX of zero is traded versus an increasing GX - grid versus vehicle. Someone is disappointed. You either exceed the grid power limit or disappoint the vehicles – after some initial power allocation. This tradeoff is illustrated in Figure 103.

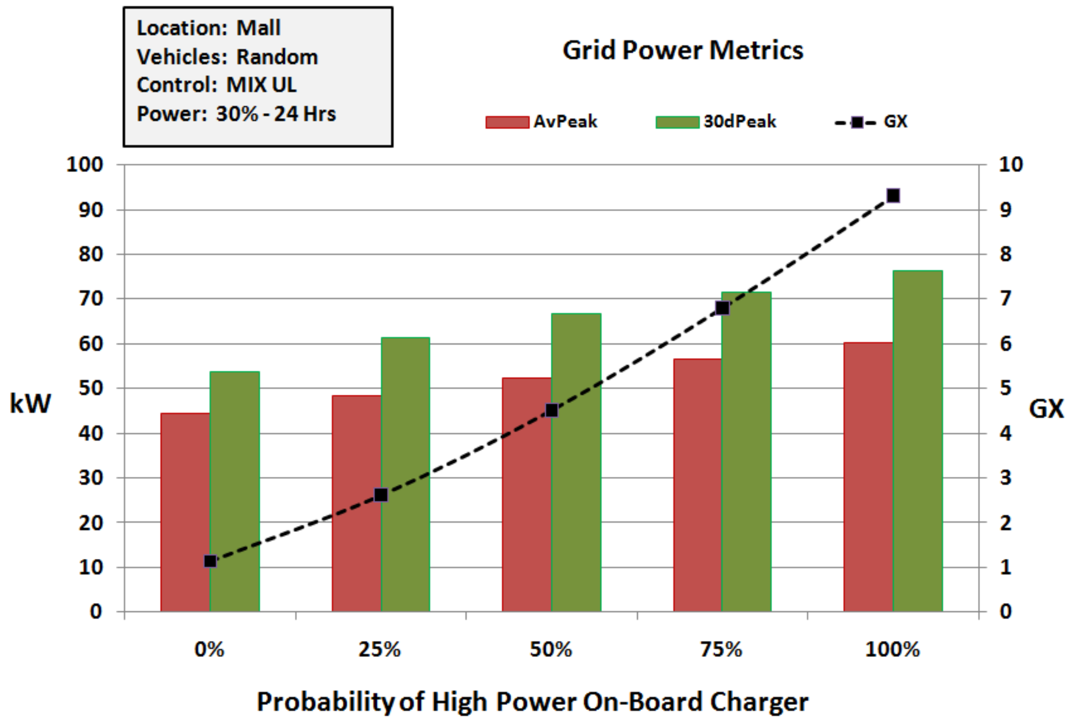


Figure 100 shows the effect of on-board charger rating on grid power metrics.

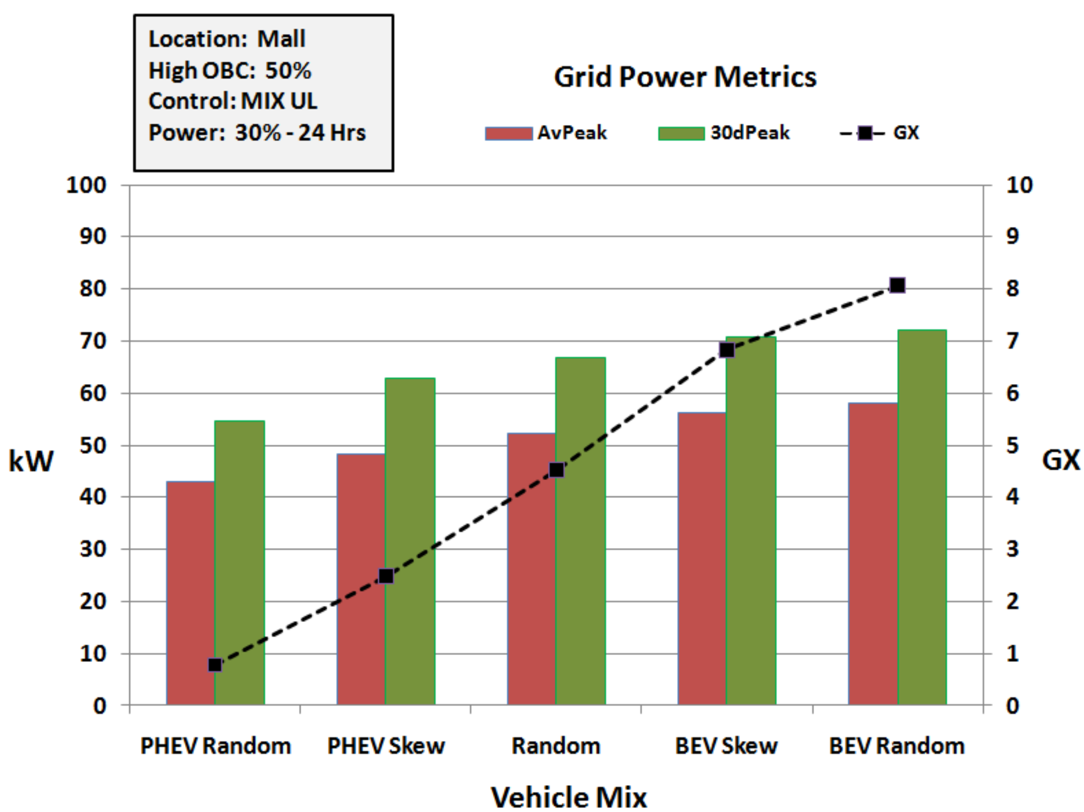


Figure 101 shows the effect of vehicle mix on grid power metrics.

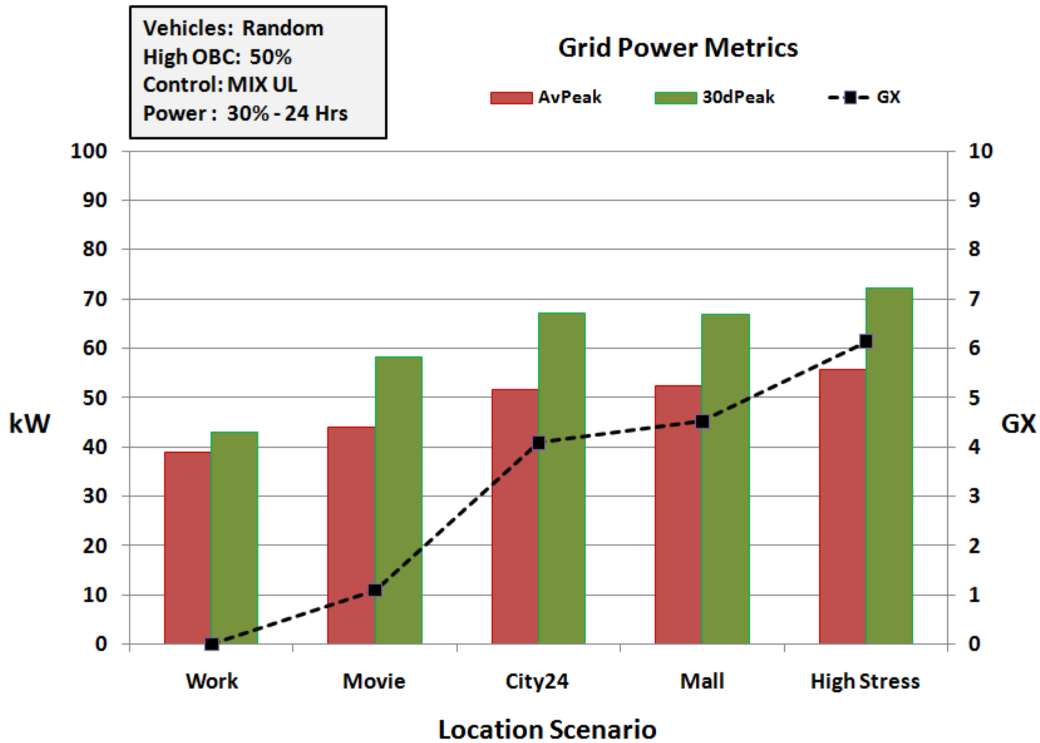


Figure 102 shows the effect of location scenario on grid metrics.

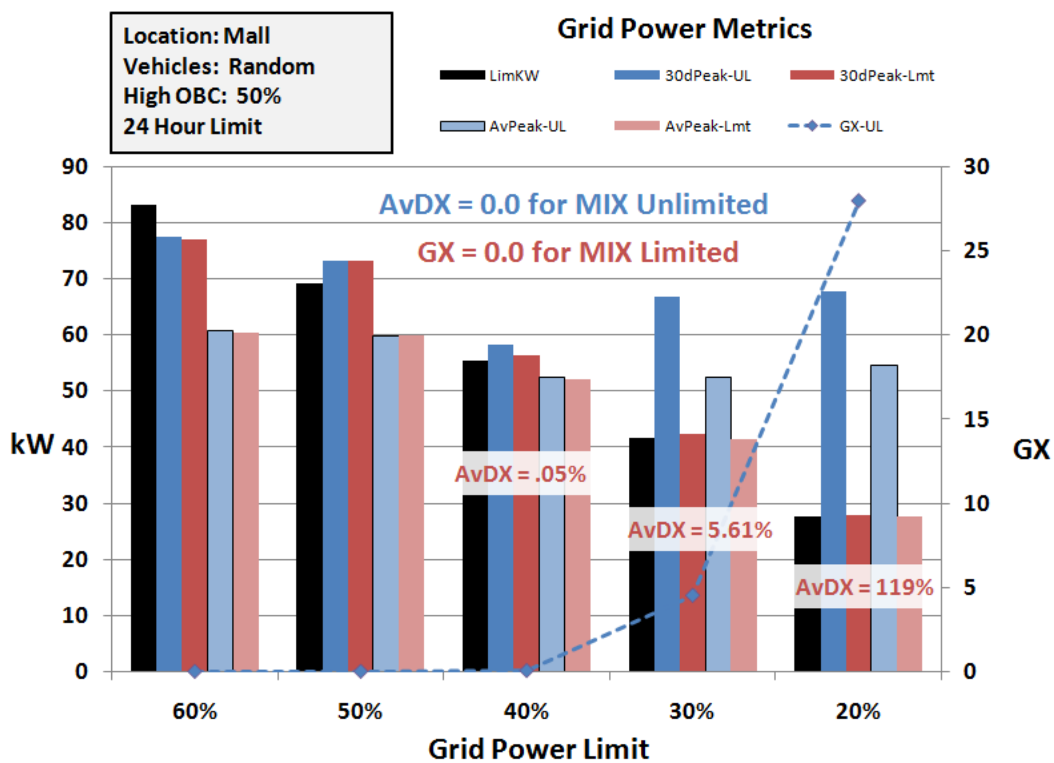


Figure 103 shows the effect of limiting on grid power metrics.

One way to not disappoint vehicle customers and also stay within grid limits is to deploy an ETESS unit. This is shown in Figure 104. Three ETESS configurations are evaluated against a grid power limit of 30% - 41.6 KW. This is a demanding limit and a 25 kW ETESS with three hours of storage is able to hold the limit. GX starts to climb as the energy storage is reduced. Figure 92 in Chapter 10 showed that ETESS was very effective at holding AvDX low (with GX = 0) using the MIX strategy with limiting. With the MIX strategy without limiting, AvDX is zero and GX rises when ETESS does not have sufficient energy.

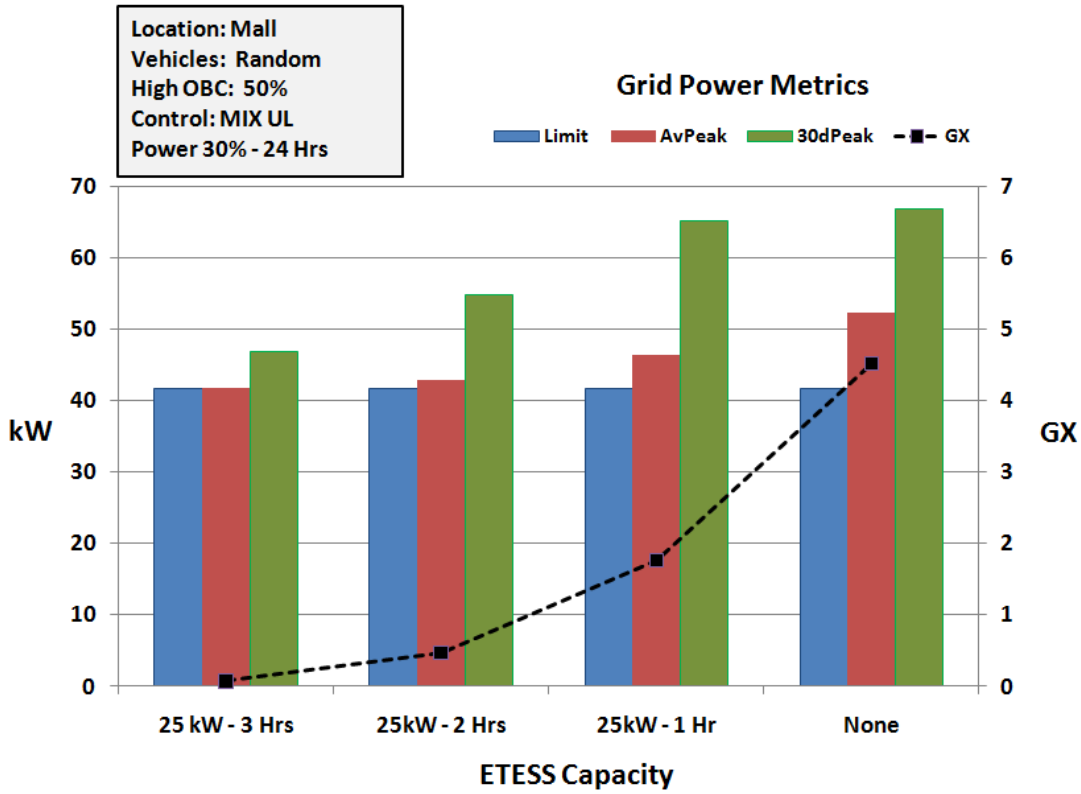


Figure 104 shows how ETESS can help manage grid power.

ETESS Operation

During the earlier discussion of charge station utilization in Chapter 9, timelines and probability distributions were shown for charge station occupancy and charge station use. The simulation also produces this same type of information for PEV power, grid power, ETESS power, and ETESS SOC. While the single pass and Monte Carlo timelines, probability distributions, and summary metrics are useful for understanding the dynamics of the simulation, they are not as useful for determining whether the system is meeting its objectives. The composite metrics, such as AvDX, GX, and others, are more useful for this purpose. Composite metrics for ETESS performance will be introduced in the next section.

Figure 105 shows facility power flows for a mall location scenario, random vehicle mix, 50% high power chargers, and a 25 kW ETESS unit with three hours of energy storage. The unlimited MIX control strategy is used. The 24 hour Grid Power Limit is 50% with a demand response cut back to 30% for four hours. Power is measured on the left axis and ETESS SOC on the right axis. The chart shows PEV power, grid power, and ETESS power. When ETESS power goes negative it is providing power to compensate for PEVs demanding more than the grid power limit. For this pass ETESS is needed to hold grid power below the limit. The PEV power can be seen spiking above the grid limit primarily during the demand response cutback, and it is being compensated by ETESS power. SOC declines steadily during the cutback window. After the demand response limit ends, ETESS recharges and the SOC climbs.

The Grid30 line is a 30 minute average power. The ETESS unit is managing to the basic three minute interval that is used for the simulation and not the average interval. The average is a lagging indicator and not useful for control purposes. In these simulation plots the 30 minute average has been centered at 15 minutes delay to better align it with the underlying grid power plot.

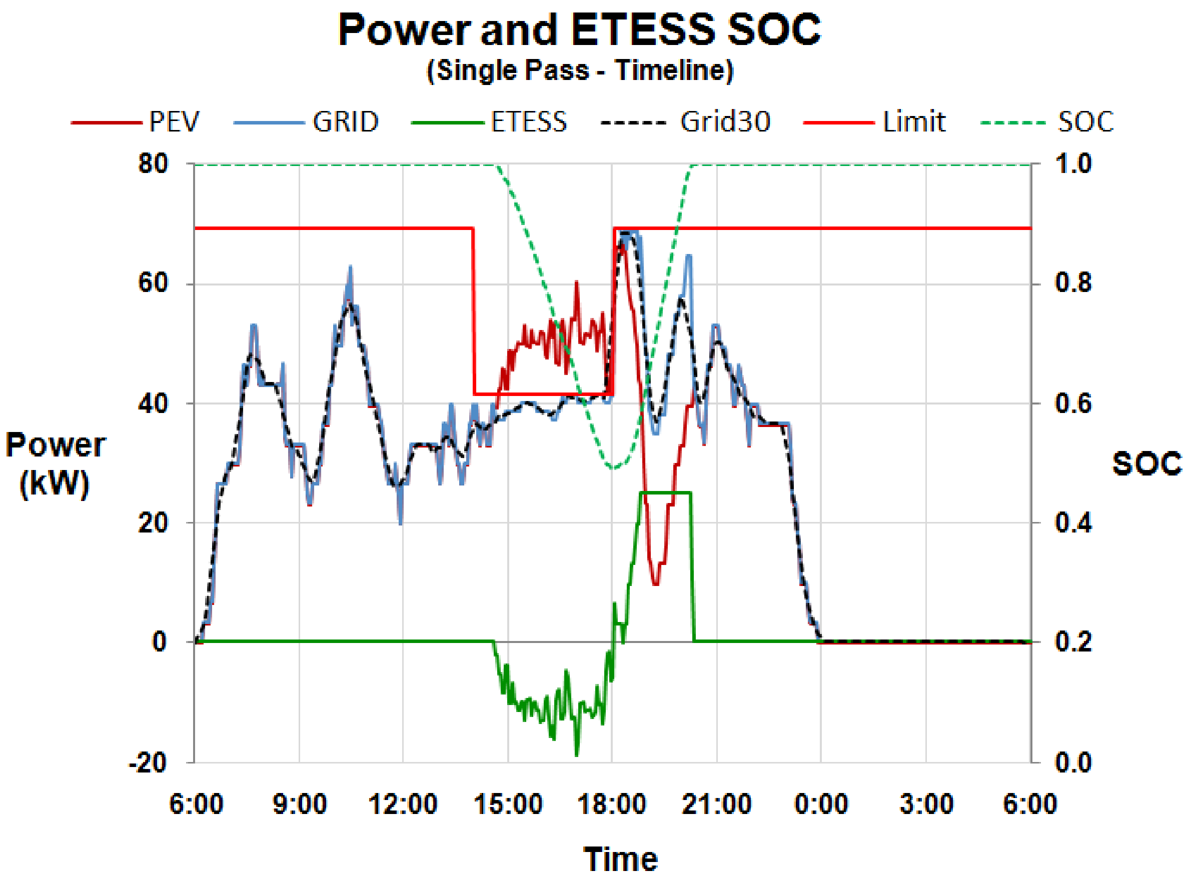


Figure 105 shows power flows and ETESS SOC for a single pass.

Figure 106 is from a Monte Carlo simulation of 2000 passes for the same scenario. The previous chart came from one of the 2000 passes. This Monte Carlo chart only shows the mean value at any specific time interval across all of the 2000 passes – an ensemble average. This smoothes much of the variation of the single pass. In this scenario the average PEV power during the demand response notch is always less than the grid limit. Still, individual passes will have variations above the mean value and ETESS will engage to hold grid power below the limit – the average PEV power is greater than the average grid power and ETESS power is negative. ETESS SOC drops during the notch. When the demand response cutback ends, ETESS recharges. The average grid power is higher than the PEV power after the window.

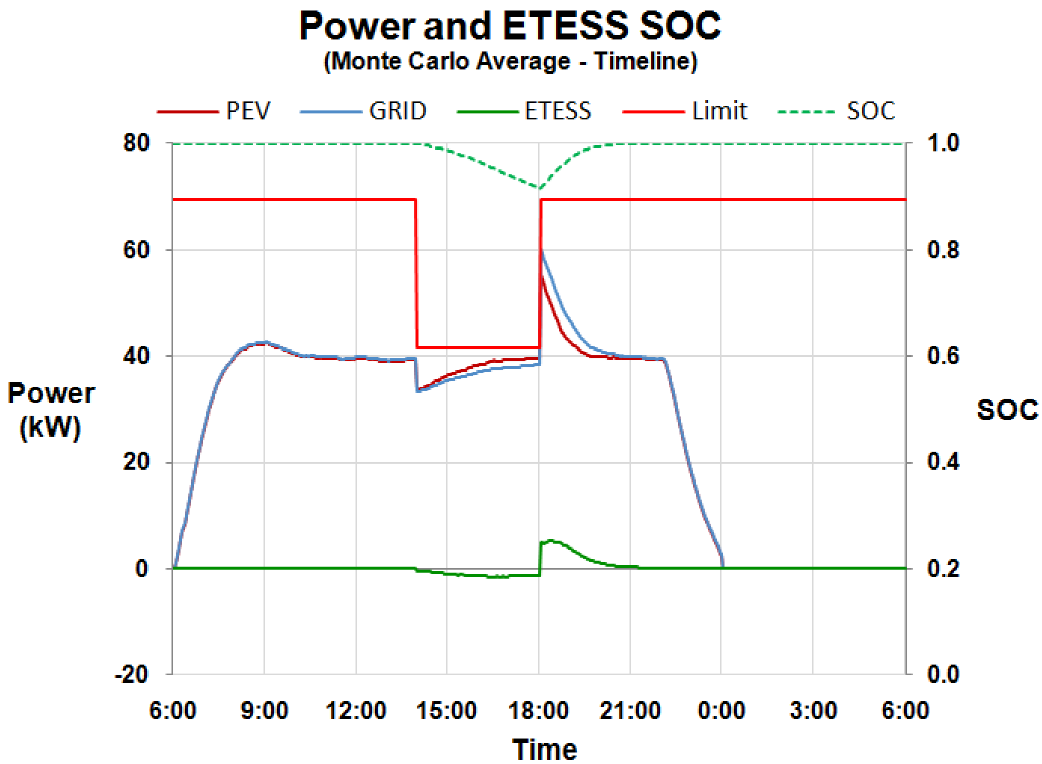


Figure 106 shows parameters from a Monte Carlo simulation.

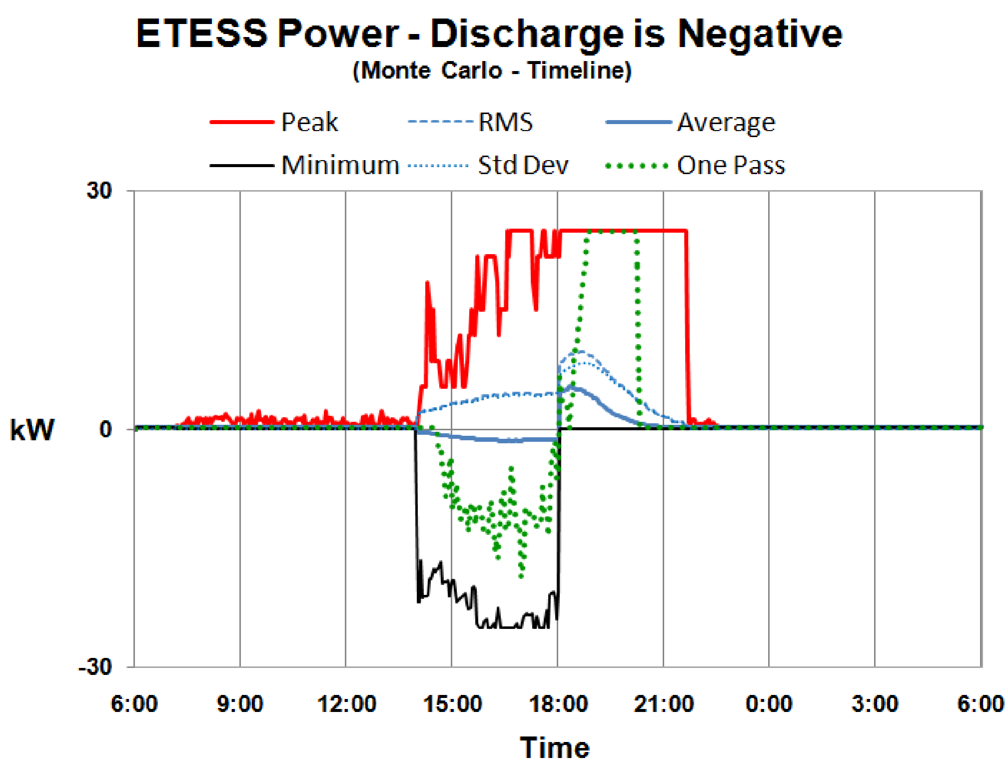


Figure 107 shows ETESS power parameters from a Monte Carlo simulation.

Figure 107 shows the peak value, RMS, average, and minimum value for ETESS power for each time interval across all passes. It also shows a single pass and the standard deviation. The single pass is included to give some perspective on the underlying frequency content in each of the 2000 passes that have been averaged. The average ETESS power is identical to that in Figure 106 for ETESS power and shows a discharge during the demand response window and charging after the window. The RMS value is always positive, as expected. The peak discharges (minimum values) occur during the demand response window. The peak charging at 25 kW occurs immediately after the window. There are some charging peaks during the window because over 2000 passes some will have periods where PEV charging drops below the demand response limit and maybe significantly below.

Figure 108 a histogram for the ETESS power distribution for the Monte Carlo simulation. As expected the peak is at zero power because the system is idle for most of the 24 hours - it is actually at 200 Watts to reflect a steady hotel load for the system. The histogram spreads from -25 kW to 25 kW which is the capacity of the ETESS unit in this scenario. The cumulative distribution shows the same jump from charging to discharging. The single pass is one of the more extreme cases.

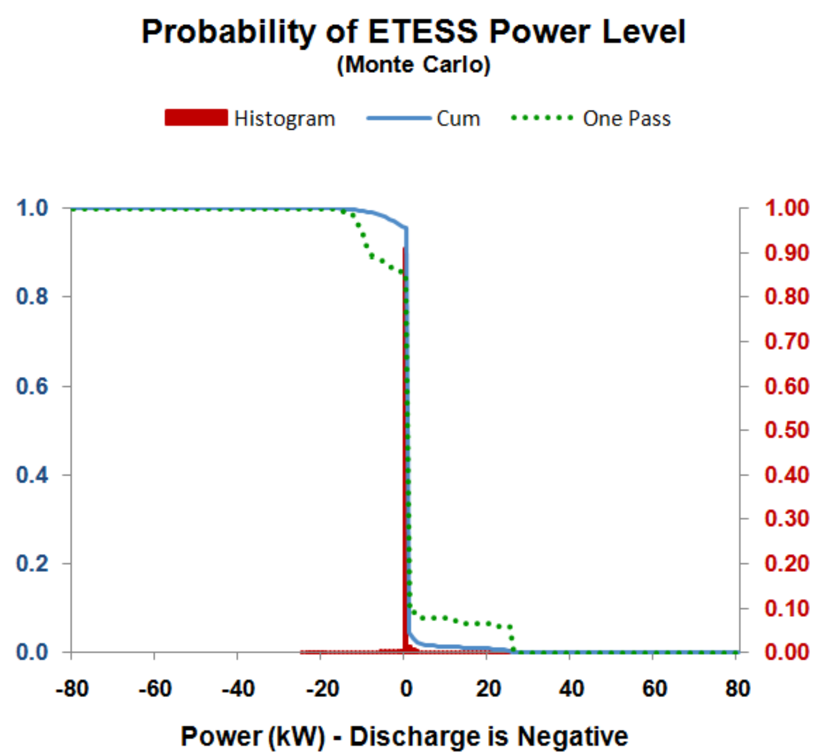


Figure 108 shows a histogram and cumulative distribution for ETESS power.

Timelines from the Monte Carlo simulation for ETESS state of charge (SOC) are shown in Figure 109. The peak value for SOC is 1.0 across all 24 hours – this reflects specific intervals in some of the passes where ETESS is not needed. The lowest value for all 2000 passes is approximately 0.2 at the end of the demand response window at 6:00 p.m. The mean value also reaches a minimum at 6:00 p.m. The standard deviation for SOC is greatest at the end of the window. The SOC timeline for a single pass is also shown and is the same as in Figure 105. Figure 110 shows several passes from the simulation along with the average grid power, average ETESS SOC, and grid power limit. There is significant pass to pass variation.

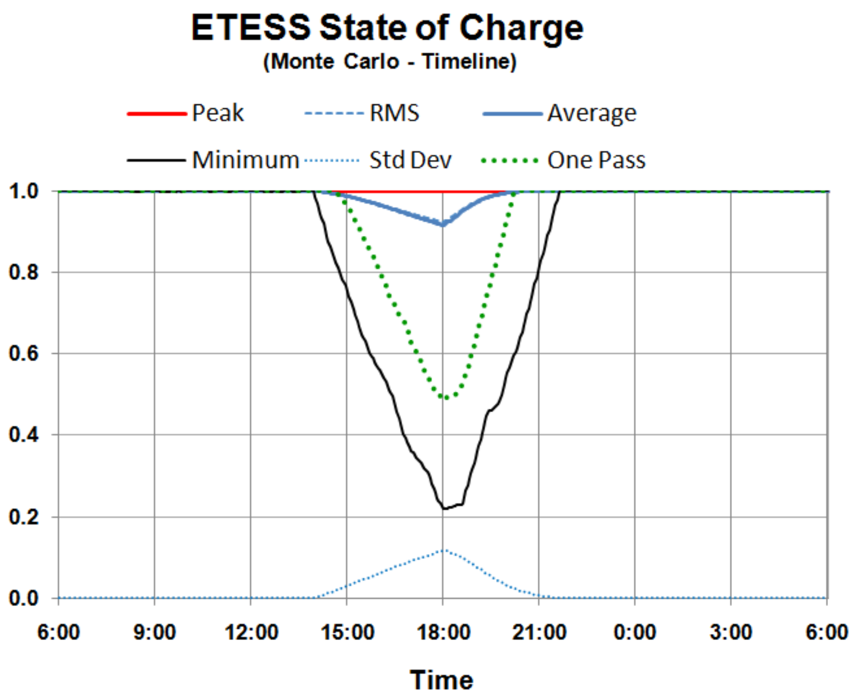


Figure 109 shows a timeline for ETESS SOC from a Monte Carlo simulation.

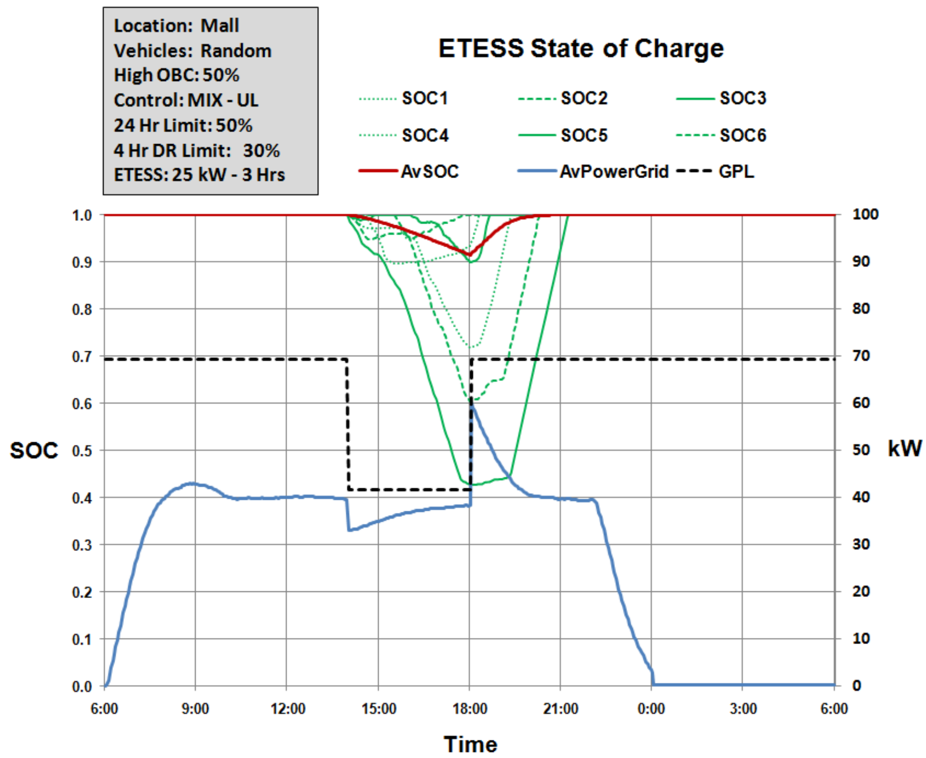


Figure 110 shows ETESS SOC for several simulation passes.

Figure 111 shows Monte Carlo timelines plot for grid power. The chart shows the peak power, RMS power, average power, and minimum power for each time interval across all passes. It also shows a single pass and the standard deviation. While the ETESS system was able to keep the average below the demand response notch, some of the peaks have exceeded the limit. The standard deviation is reduced during the window because ETESS is clipping most of the peaks and rises slightly after the window because of the ETESS recharging.

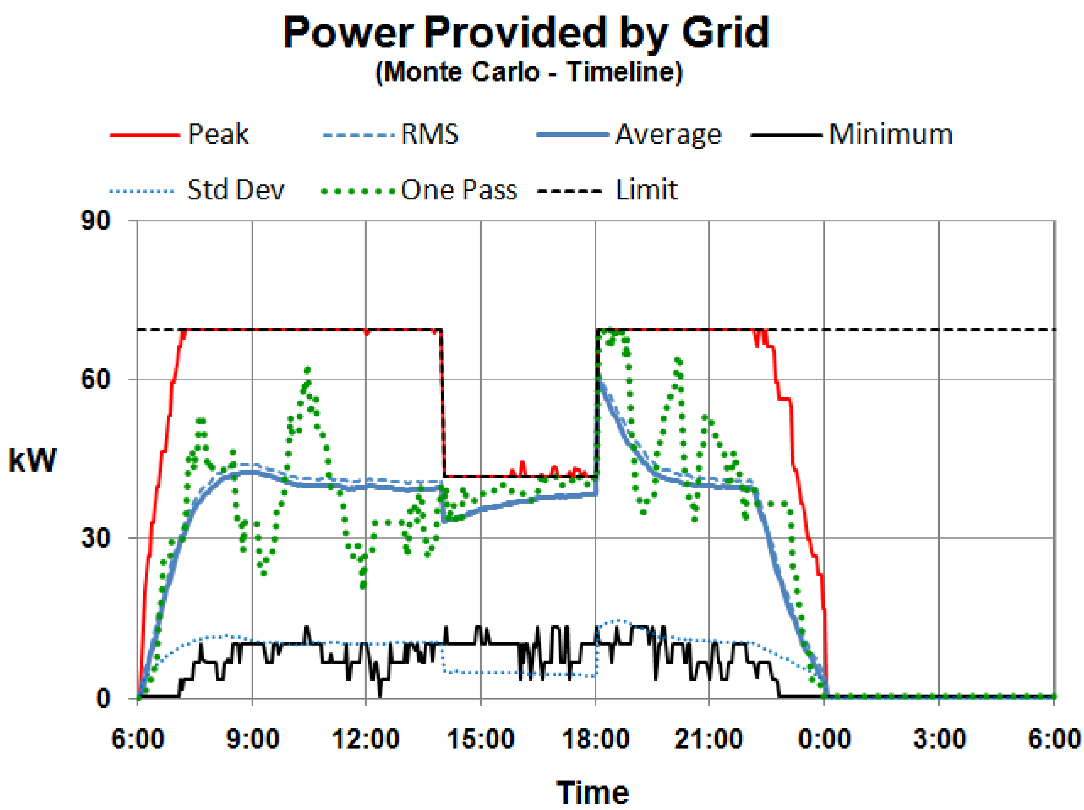


Figure 111 shows grid power parameters from a Monte Carlo simulation.

Figure 112 shows a histogram for grid power from the Monte Carlo simulation. The vehicle chargers are either 3.3 kW or 6.6 kW and the histogram shows peaks at multiples of 3.3 kW. It is not exclusively at these values because a MIX strategy is being used. A cumulative distribution for grid power is also shown. For comparison a cumulative distribution of grid power is included from a single run along with the Monte Carlo cumulative distribution for PEV power. This chart shows that grid power exceeds 35 kW for 50% of the time and 25% of the time the grid power is above 40 kW.

The timelines, histograms, and cumulative distributions are useful for developing an understanding of the dynamics of the system. Still, the summary metrics such as AvDX and GX are more useful for comparing scenarios and control concepts. Figure 113 shows a summary results worksheet from this Monte Carlo simulation. The 25 kW ETESS with three hours of storage has kept AvDX and GX at zero for this scenario. The worksheet also shows several ETESS metrics that will be explained in the next section.

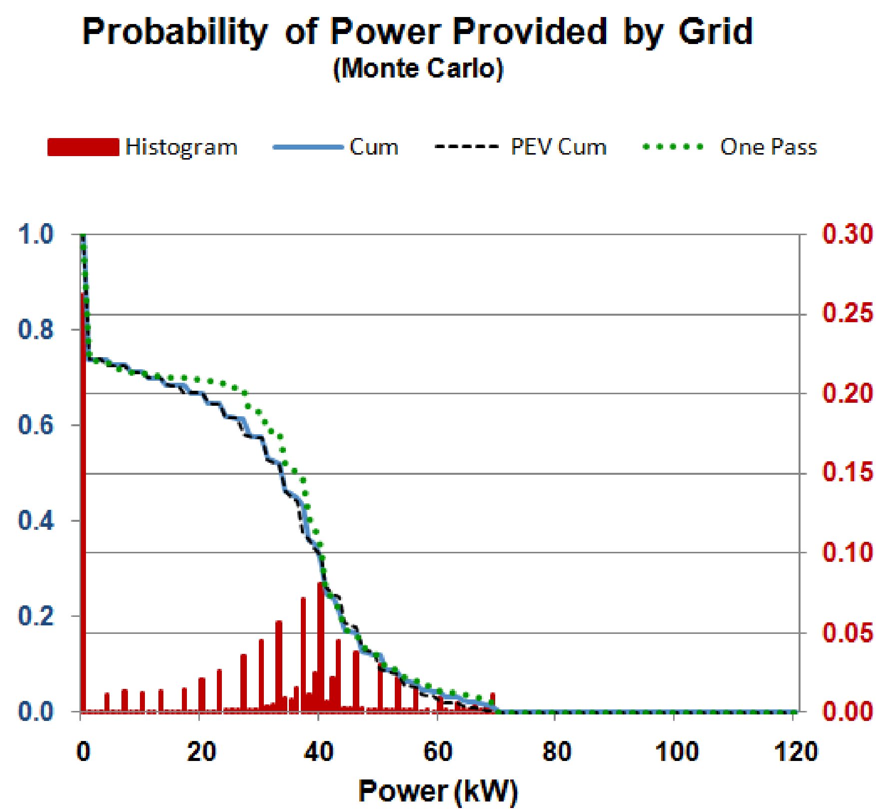


Figure 112 shows a histogram and cumulative distribution for grid power.

Simulation Identification	8946603
Locations	
Charge Station Quantity	18
Location Scenario	Mall
Arrival Rate Multiplier	1.00
Vehicles	
Vehicle Mix Scenario	Random
High Power Charger Probability	50%
Control	
Vehicle Charging Strategy	MIX
Vehicle Limiting Strategy	UnLimited
ETESS Charging Strategy	RC 25kW
Power Limits	
Grid Power Limit - Facility	50%
Demand Response Limit	30%
Demand Reponse Hours	4
ETESS	
ETESS Available	ON
ETESS Power	25
ETESS Hours of Storage	3
ETESS Initial State of Charge	1.00
Mode	
Monte Carlo Simulation	Yes
Repeat Pass	No

Metric	One Pass	Monte Carlo
CS Occupied	48.8%	50.0%
CS Use/Occupied	75.1%	71.1%
Vehicles Not OK	0.00%	0.00%
Vehicles OK	100.00%	100.00%
AvDX	0.00%	0.00%
VvDX	0.00%	0.00%
AvDelEX	0.00%	0.00%
Avail/Max	87.71%	86.92%
Ref/Avail	73.87%	69.54%
GX	0.000	0.000
Peak	68.4	63.4
30DayPeak95%	-	79.4
EX	0.202	0.021
MaxDropSOC	0.513	0.093
CumDropSOC	0.513	0.097
PctPwrOut	39.4%	21.7%

Figure 113 shows a summary results worksheet from the simulation.

ETESS Metrics

The vehicle metrics and grid power metrics are externally focused. They relate to assessing disappointment for PEV customers or to economic consequences of exceeding grid limits or monthly demand charge targets. The ETESS metric are primarily focused at assessing the stress on the unit. These measures will help with defining the power and energy capacity of the ETESS unit. They also can serve as a proxy for maintenance and life expectancy of the unit. Only a few of the metrics generated for ETESS by the simulation will be discussed here – only those that will be used in this chapter.

Average Power during Discharge

ETESS moves power in two directions. It can provide power to the PEVs and reduce the demand on the grid. It can also recharge and consume power from the grid. If the ETESS unit were 100% efficient the average power over the day would be zero if the unit started and ended with a full battery, but the unit is not 100% efficient at either charging or discharging and there are steady "hotel" loads while it is operating during the day. This will result in a new positive (charging) average power over the day. The RMS power is a more useful measure of the total demand on the unit.

Because the one key purpose of the unit is to provide power and energy to the vehicles when there are grid power limits in effect, it is useful to look at the performance during discharge. Discharge is driven by external events, such as the PEVs and grid limits, whereas the ETESS unit has more control over when and how it charges. A useful metric for each pass is the average power over the time that the unit is actually providing power. This can be normalized to the rated power of the unit (**PctEtessPwrOut)**.

Range of Decrease in ETESS State of Charge

Another measure of stress is how deep the unit discharges during the day. Two measures are used for this purpose. One approach is to record the lowest value of SOC reached during any pass of the simulation (**MinEtessSOC**). This is subtracted from 1.0 to get the maximum drop in SOC (**MaxDropSOC)**. This metric does not recognize that the unit may cycle several times during the day. Another metric can be generated by adding all of the decreases in SOC that happen during the day (**CumDropSOC**). These two measures will be the same if there is a single smooth dip in SOC across the day. If there is significant cycling the cumulative drop will be larger than the single maximum, which is included in calculation of the cumulative drop.

Composite ETESS Index (EX)

A single metric for ETESS (EX) was created that combines the discharge power and the cumulative drop in SOC. This is defined as:

$$\boldsymbol{EX = CumDropSOC * PctEtessPwrOut}$$

The product was used rather than a weighted sum. If the ETESS unit discharges at its rated power and drops to an SOC of zero and then recharges, this would yield an EX of 1.0 – it could exceed this value if the cumulative drop exceeded 1.0, but it is not likely that the ETESS power would average out at the rated value. EX can never be less than zero.

ETESS Performance

The performance of ETESS is best measured by how AvDX is reduced when the grid power is actively limited (GX = 0) or how GX is reduced when PEV power is not limited (AvDX = 0). The ETESS metrics are a measure of stress on the ETESS unit and provides some measure of proper sizing of the unit. Figure 114 shows both ETESS metrics and GX for all of the ETESS configurations in the simulation. The sequence is based on the order of energy storage (kWh) with the lower power units placed first for configurations with the same energy capacity. In the simulation, unlimited power is set to 150 kW and unlimited energy is set to 24 hours – a value is needed and these values exceed the capacity of 18 charge stations. Therefore UL-1H is 150 kWh and 25-UL is 600 kWh.

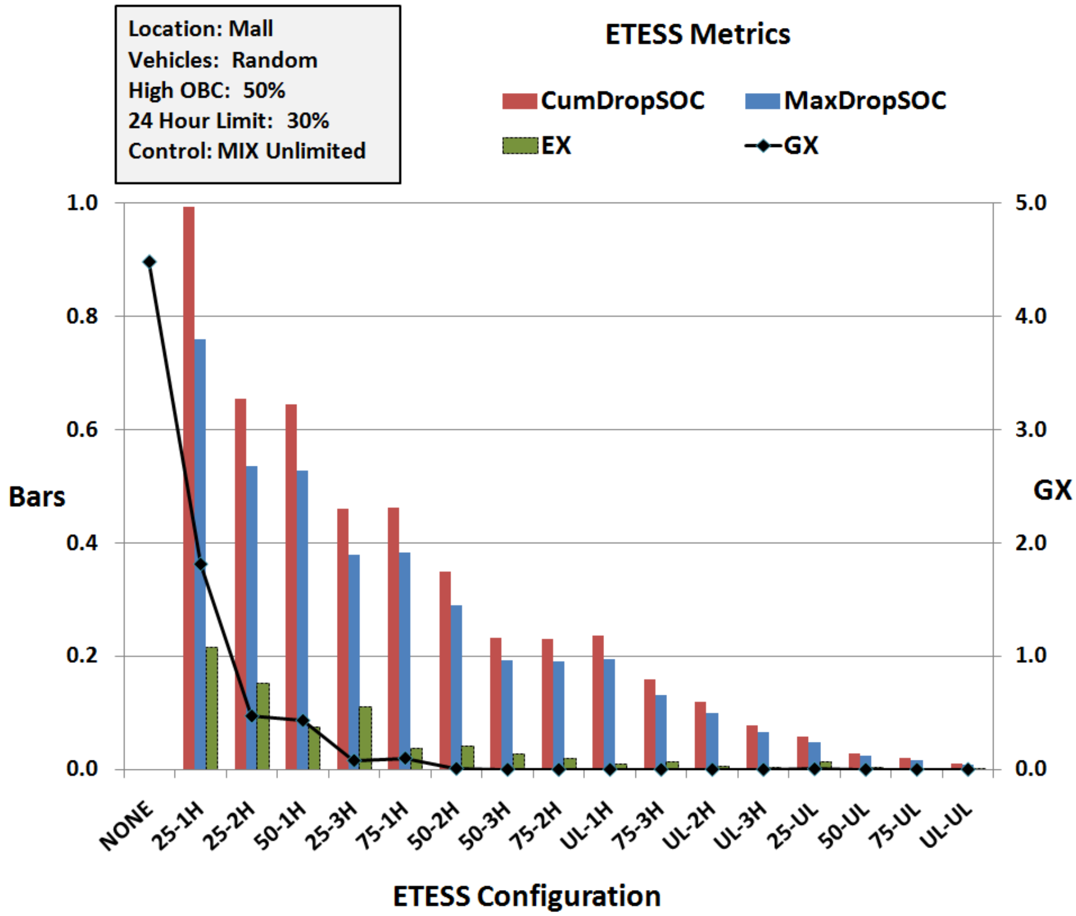


Figure 114 compares SOC, GX, and EX metrics for ETESS configurations.

As discussed earlier the Cumulative drop in SOC (CumDropSOC) will always be larger than the maximum drop in SOC (MaxDropSOC). EX will always be less CumDropSOC because it is the product of CumDropSOC with the ratio of the average discharge power and rated power (PctEtessPwrOut). GX drops rapidly as energy storage is added to the system for this scenario and almost reaches zero at 75 kWh of energy storage. As the storage capacity increases the CumDropSOC decreases – it goes from approximately 0.45 for a 25-3H ETESS unit to 0.15 for a 75-3H ETESS unit. For this scenario the 25-3H ETESS unit performs fine for managing facility loads and the 75-3H unit allows 50kW and 150 kWh of reserve capacity for use in providing ancillary services to the grid.

Figure 115 shows the percent of rated power used during discharge of the ETESS unit (PctEtessPwrOut) for different ETESS configurations. GX is also shown. The configurations are organized in the sequence of increasing power and then by storage capacity within each power class. The need for power is established by the PEVs and the scenario and is not dependent on the ETESS power and energy capacity. If 25 kW of power is adequate, the higher power capacity is not needed and the ratio of average discharge power to rated capacity will drop as capacity is increased. This is clearly shown in the chart. The 25 kW units are energy limited for lower energy capacity units and this reduces the average power. That is why the power ratio increases as battery capacity is increased. For those units with over 75 kWh of storage the power ratio remains flat as storage capacity increases. At least 75 kWh of energy is needed for this scenario to take GX close to zero. The GX for the 50-1H unit is worse than the 25-3H unit because the scenario requires the extra energy and not the extra power. The Mall location, Random vehicle mix, 50% high power charger, and 24 hour 30% grid limit is demanding and the 25-3H ETESS unit performs well.

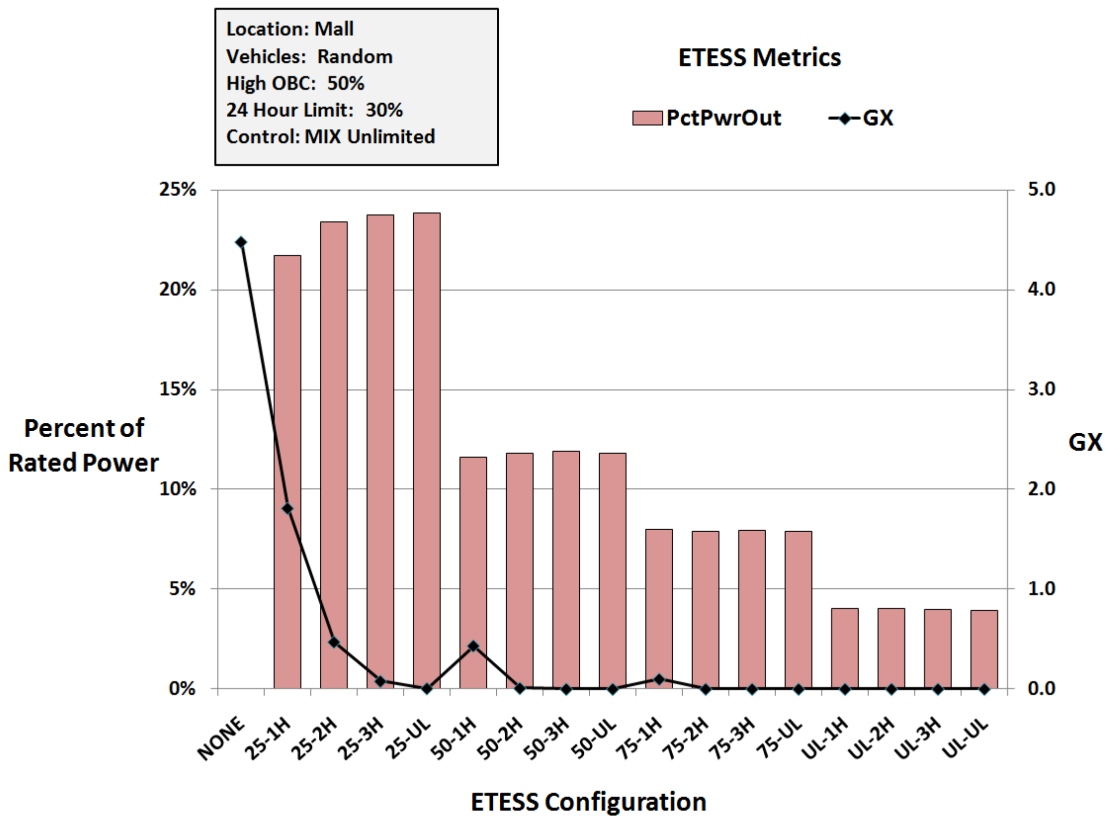


Figure 115 shows the effect of ETESS configuration on the ETESS power rating.

Figure 116 shows two other scenarios that are more demanding. One is the Mall but with 100% high power chargers and a BEV only random mix. The other is the High Stress scenario with 100% high power chargers (6.6 kW) and only 100 mile range BEVs. CumDropSOC and EX are shown as bars and measured on the left axis, and GX is shown by a line and measured on the right axis. The 25-3H ETESS can hold grid power below limits on these higher stress scenarios – CumDropSOC is greater than one on both and GX is high and only slightly improved over no ETESS unit. The 75-3H unit brings GX to zero for the Mall-BEV scenario but still cannot hold the High Stress scenario – the battery is depleted. This High Stress scenario is extremely demanding and not very realistic but does show the ETESS metrics. Figure 117 shows the same High Stress scenario but with the 30% limit only during a two hour demand response window. In this case even the 25-3H ETESS holds GX to 1.0 and the 75-3H ETESS drives GX to zero.

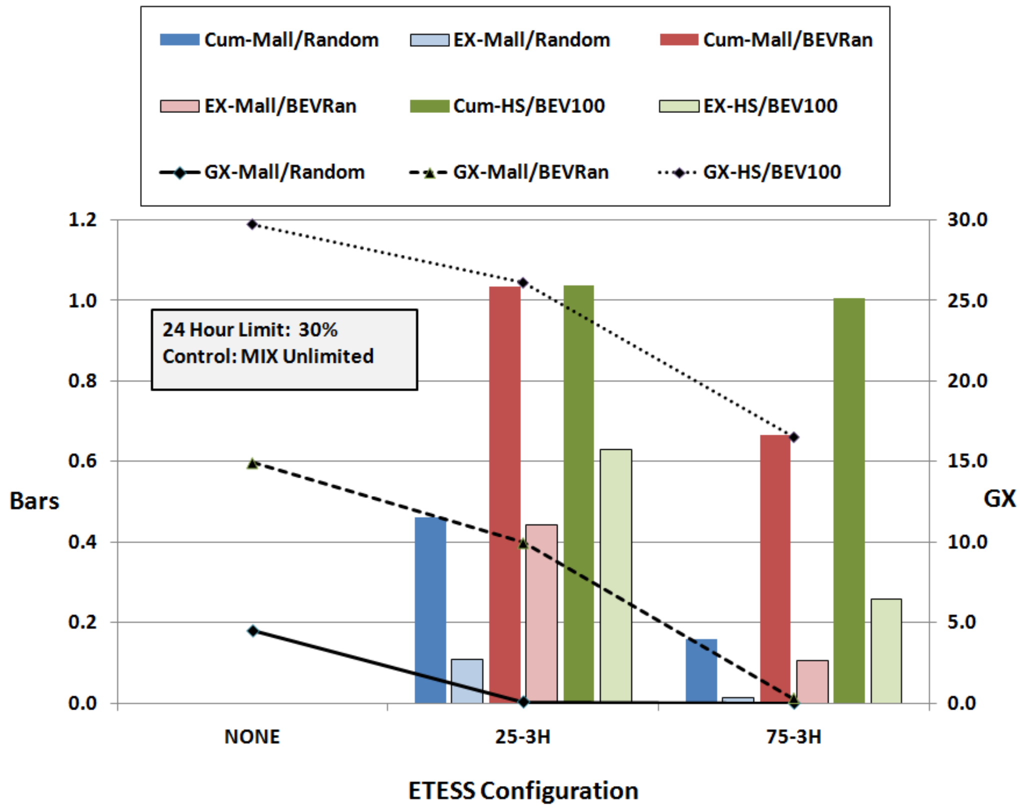


Figure 116 compares scenarios for two ETESS configurations.

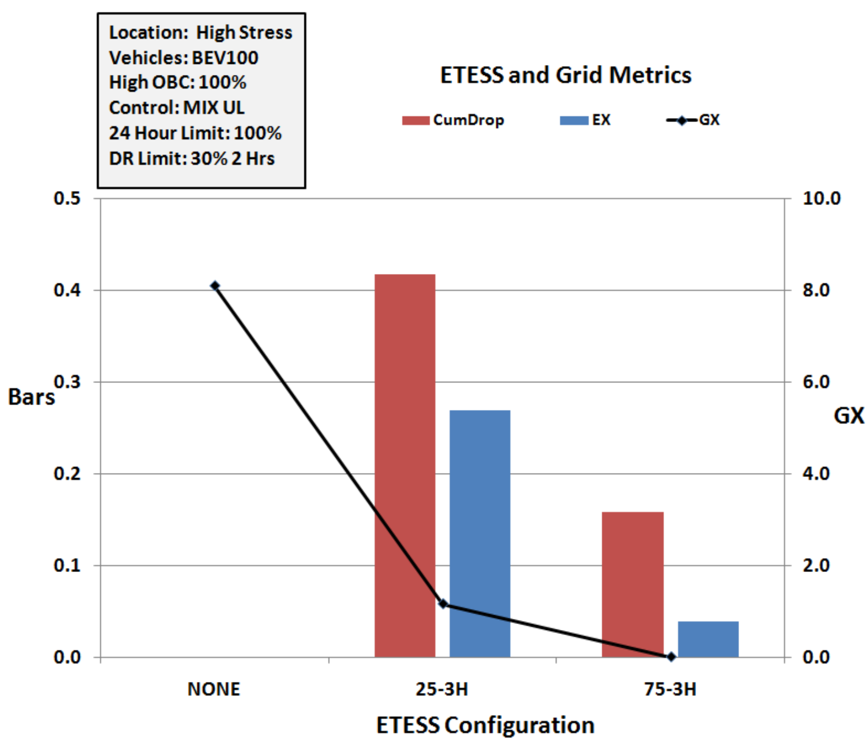


Figure 117 shows the High Stress scenario with a two hours demand response window.

Blended Limiting Strategy

In Chapter 10 several iPEM approaches were evaluated. There is an initial power application, followed by the commitment of ETESS power and energy (if available), and then a cutback on power authorization to the vehicles to stay within limits. This always kept the facility within limits (a GX = 0) but resulted in some disappointment of PEV customers. The purpose of the chapter was to explore ways to measure PEV customer disappointment. One of the key measures was AvDX. The approach in this chapter was to use the MIX strategy for initial power allocation to the PEVs, apply ETESS, and then take no further action (the Unlimited Strategy). This will always satisfy PEV requirements (AvDX = 0), but the grid limit can be missed (GX > 0).

These limiting strategies do not have to be mutually exclusive. It is possible to create a blended limiting strategy by using the actual limit for the initial allocation and then using a slightly higher limit for the post ETESS hard limiting. This allows some softness in the limiting and allows a tradeoff between AvDX and GX. This is shown in Figure 118 by a plot of AvDX versus GX. Two curves are shown: one without an ETESS and one with a 25-3H ETESS. The 25-3H plot is easy to miss because it is the small red line at the lower left corner of the chart.

This corner is expanded in Figure 119 where the 75-3H ETESS is also shown. For the ETESS plots the blended strategies are not shown and the actual curves may be bowed similar to the no ETESS curve and not straight lines.

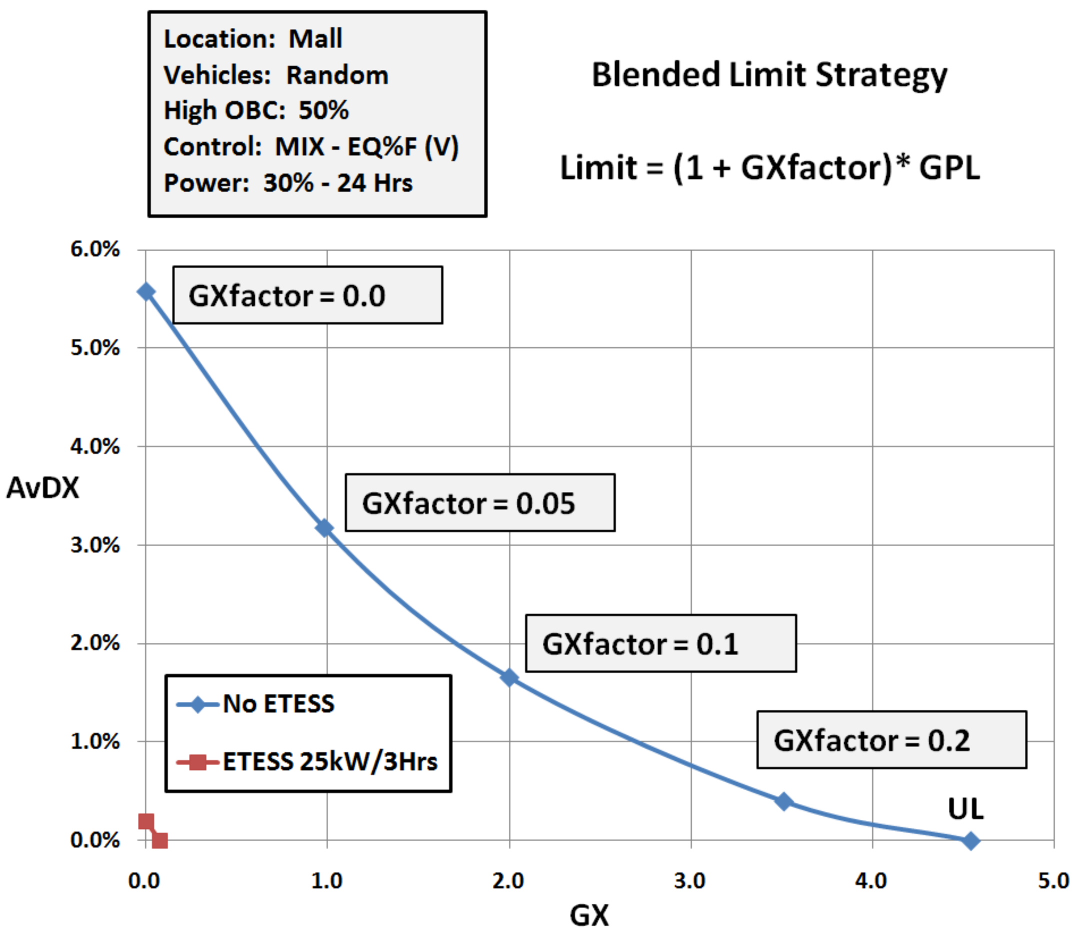


Figure 118 shows the effect of blended limiting on AvDX and GX.

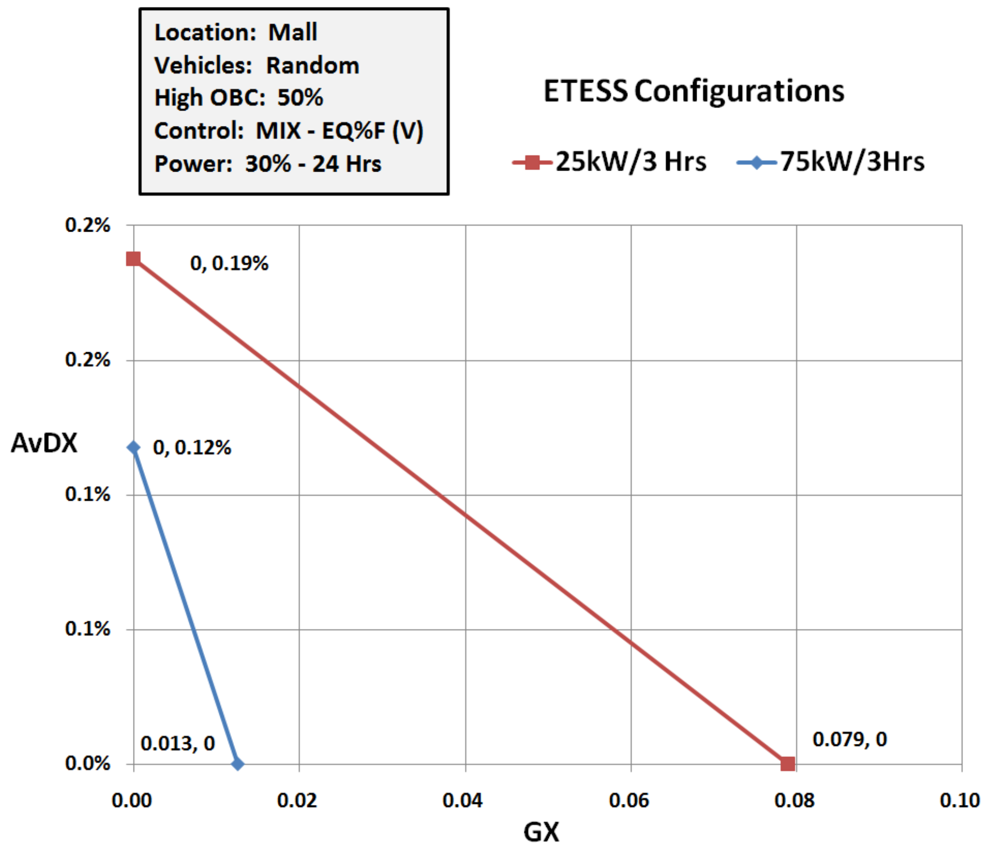


Figure 119 shows the effect of blended limiting with ETESS.

Chapter Summary

Metrics for evaluating the performance of iPEM logic and ETESS units for managing grid power were developed. These include a Grid Power Exceeded Metric (GX) and a Monthly Peak Demand value. These were compared for several scenarios. Metrics were also developed to assess the stress on the ETESS unit during operations. These include the maximum drop in SOC of the unit, the sum of all decreases in SOC over the 24 hours (cumulative drop in SOC), the ratio of the average power used during discharges and the rated ETESS power, and a composite ETESS index (EX). ETESS configurations were compared using the ETESS metrics and GX for several scenarios.

The ETESS unit works. It improves on iPEM logic in controlling both AvDX and GX. A 25 kW unit with three hours of storage can support 18 charge stations for many scenarios. This may be adequate for use only within a facility. The 75 kW ETESS unit with three hours of storage provides additional margin for facility internal use and will allow the unit to provide ancillary services.

12 *Simulation Summary*

One of the key accomplishments during this project was the creation of a multivehicle charging simulation. The primary purpose of the simulation was to understand the interaction between groups of vehicles, the ETESS unit, and the grid.

The simulation was designed to allow the evaluation of iPEM algorithms and ETESS energy storage to manage the aggregate power demand of the facility and minimize disappointment of the PEV customers. The use of ETESS for providing ancillary services to the grid was not part of this simulation. A portion of the total ETESS power and energy capacity will be allocated for each use – external grid services and internal facility power management. The simulation only deals with the ETESS capacity reserved for internal use with the vehicles.

ETESS Capacity and Charge Station Quantity

The ETESS simulation was designed to support a maximum of 18 charge stations. This was based on the screen display size, but it is a reasonable upper limit. The simulation allows sites to be configured with 6-to-18 charge stations. The iPEM logic needs enough charge stations in use to be able to effectively allocate power, but if the number of charge stations gets too large the ETESS capacity becomes limiting. For a large facility, several ETESS units should be used and higher tiers of logic should be used to allocate power limits to each of the ETESS units at the facility.

The simulation allowed the evaluation of ETESS units with 25, 50, or 75 kW of power and from one to three hours of usable storage capacity. Simulations of ETESS show that a 25 kW unit with three hours of usable storage could adequately support up to 18 AC Level 2 charge stations for many charging location scenarios and mixes of vehicle types. A 75 kW ETESS unit with three hours of storage was effective for almost all scenarios - although this can consume the entire capacity of the 75 kW ETESS unit and leave nothing for ancillary services.

Performance Metrics

The primary purpose of a PEV charging facility is to charge vehicles - a PEV does not park at a charging facility to not be charged. The primary objective must always be to complete the requested energy transfer for every PEV before its estimated time of departure. This objective may sometimes conflict with constraints on the availability of power from the grid. The ETESS system must balance the prime objective with considerations for facility power management.

You cannot control or minimize what you do not measure. New concepts of **Disappointment Factor (DF)** and **Disappointment Index (DX)** were created as a way of characterizing individual PEV customer disappointment beyond the basic measures, such as the yes-no of a charging session being successfully completed or the percent gap in requested energy transfer. **Average Disappointment Index (AvDX)** was created as a metric for assessing the aggregate disappointment for all of the vehicles that charged during a day at a charging facility.

Metrics for evaluating the performance of iPEM logic and ETESS units for managing grid power were also developed. These include a **Grid Power Exceeded Metric (GX)** and a Monthly Peak Demand value.

Metrics were developed to assess the stress on the ETESS unit during operations. These include the maximum drop in SOC of the unit, the cumulative drop in SOC over 24 hours, the ratio of the average power used during discharges and the rated ETESS power, and a composite ETESS index (EX).

PEV Power Authorization

The logic for authorizing a charging power level for each connected PEVs is done in three steps during each three minute control interval of the simulation. The first step is to define an initial power allocation for each connected PEV based on a selected PEV Power Allocation Strategy. Next, the aggregate power demand of all of the connected PEVs is tested against a grid power limit and if the total required power is less than the limit, the PEV power allocation is made. If it is greater than the limit, ETESS power is allocated if an ETESS unit is available and it has not been depleted. If ETESS can fully compensate for the excess of the PEV power over the grid limit, the PEV power allocation and ETESS power allocation is made. The third step executes a selected PEV Power Limiting Strategy if the net power of the PEVs and ETESS still exceeds the grid limit. The allocation of power to each PEV may then be reduced from the initial allocation to keep the net power within limits.

Three PEV Power Allocation Strategies were designed and tested. One strategy is to authorize each PEV to start immediately at the rated power of its on board charger (**PMAX Strategy**). Another allocation strategy used 110% of the average power required to complete the energy transfer during the estimated duration of the charging session (**1.1*PAV Strategy**). The last was slightly more complex and used a concept called **Utilization Factor (UF)** to perform the initial power allocation (**MIX Strategy**). The MIX Strategy starts all vehicles at PMAX if it can stay within the grid limit, but if it cannot, it shifts some PEVs to a delayed start and shifts other PEVs to an average power. The MIX strategy was the most effective, both with and without ETESS, and with any of the limiting strategies.

Five PEV Power Limiting Strategies were designed and tested. One limiting strategy is to not enforce any limit (Unlimited Strategy). Two limiting strategies roll back the PEV power proportional to the PEV share of the total power, but never lets any PEV draw less than 1.4 kW – these PEVs are turned off. One of these strategies folds back this clipped power to other vehicles (**EQ%F Strategy**). A concept called the **Power Allocation Factor (PAF)** based on the Disappointment Index (DX) of each PEV was also tested. Two methods for limiting were constructed using PAF, one called Sequential PAF and the other called Weighted PAF. All of the post ETESS algorithms used some intelligence and improved performance, and the simplest equal percent rollback approach was most effective. The EQ%F Strategy was superior to the others with any of the allocation strategies.

System Performance

It was demonstrated by simulation that, even when each PEV is allowed to immediately start charging at the rated power of its on board charger (**PMAX Strategy**), ETESS can help reduce the impact on the grid. Nevertheless, even without an ETESS, it is possible to optimize the power allocation to reduce peaks. This is the concept that we called **intelligent Power and Energy Management (iPEM)**.

It was beyond the scope of this project to design and demonstrate “final” iPEM algorithms, but a few simple approaches were evaluated. The simple MIX allocation strategy with the Equal Percent limiting strategy showed the potential value of iPEM, even without an ETESS. This may result in some PEV customer disappointment (AvDX > 0) for certain scenarios, but the grid limit is held (GX = 0). The MIX strategy without limiting improves on unconstrained charging (PMAX and Unlimited strategies) in all scenarios. Still, the grid limit may still be exceeded (GX > 0), although AvDX is always zero when hard limiting by software is not enforced.

The application of ETESS power always improves on iPEM logic in controlling both AvDX and GX. An allocation of 25 kW and 75 kWh of ETESS capacity for facility use will support 18 charge stations for many scenarios. This may be adequate for use only within a facility. The full 75 kW ETESS unit with three hours of storage provides additional margin for facility internal use and will allow the unit to provide ancillary services.

Conclusions

ETESS is technically feasible. Much work needs to be done to create "final" iPEM algorithms and validate metrics to be used for optimization, but it is all technically feasible. Future PEVs will provide the communication capability and control modes that will allow iPEM logic to coordinate the charging session and limit PEV power consumption. The ETESS unit is just a variant of the DESS unit and several projects are underway to design and demonstrate DESS units over the next few years. There will certainly be many technical issues to overcome in the detailed design, implementation, testing of a DESS. This is true of any new product development project, but it can and will be done.

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New York State Energy Research and Development Authority

17 Columbia Circle
Albany, New York 12203-6399

toll free: 1 (866) NYSERDA
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fax: (518) 862-1091

info@nyserda.org
www.nyserda.org

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