Lessons Learned – The EV Project DC Fast Charge – Demand Charge Reduction, Part 2

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List of Acronyms

AC	Alternating Current
CHAdeMO	A Japanese fast charging standard for BEVs delivering up to 62.5 kW of high-voltage DC via a special electrical connector
ConEdison	Consolidated Edison
DC	Direct Current
DCFC	Direct Current Fast Charge EVSE
DOE	U.S. Department of Energy
DR	Demand Response - mechanisms for utilities, businesses and residential customers to cut energy use during times of peak demand or when power reliability is at risk
ESS	Energy Storage System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment - equipment that provides for the transfer of energy between electric utility power and an electric vehicle
GES	Ground Energy Storage
HECO	Hawaiian Electricity Company
ISO	Independent System Operator - creates energy and capacity markets and oversees electrical grid reliability
kW	Kilowatts - a measurement of electric power. Used to denote the power an electrical circuit can deliver to a battery
kWh	Kilowatt hours - a measurement of total electrical energy used over time. Used to denote the capacity of an EV battery
MGE	Madison Gas and Electric
PEV	Plug-in Electric Vehicle
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PSE	Puget Sound Energy
RTO	Regional Transmission Organization - coordinates, controls, and monitors an electricity transmission grid that is larger than a typical distribution grid; this organization moves electricity over large interstate areas
RTP	Real-Time Pricing - utility pricing is provided to assist a customer in selecting the lowest cost charge

SAE	Society of Automotive Engineers - standards development organization for the engineering of powered vehicles
SDG&E	San Diego Gas and Electric
SOC	State of Charge - the amount of energy left in an ESS as a percentage of the full amount
SRP	Salt River Project
TOU	Time-of-Use - an incentive-based electrical rate established by an electric utility, intended to balance the load by encourage energy use during non-peak times
V1G	Demand only control of Vehicle-to-grid – a concept that allows the charging demand (kW) of electric vehicles to be controlled to support the grid for various purposes. Unlike V2G however it does not include reverse power flow.
V2G	Vehicle-to-Grid - a concept that allows the energy storage in electric vehicles to be used to support the electrical grid for various purposes

1 Company Profile

ECOtality, Inc. (NASDAQ: ECTY), headquartered in San Francisco, California, is a leader in clean electric transportation and storage technologies. Its subsidiary, Electric Transportation Engineering Corporation (eTec) dba ECOtality North America (ECOtality), is the leading installer and provider of charging infrastructure for electric vehicles (EVs). ECOtality has been involved in every major EV or plug-in electric vehicle (PEV) initiative to date in North America and is currently working with major automotive manufacturers, utilities, the United States (U.S.) Department of Energy (DOE), state and municipal governments, and international research institutes to implement and expand the presence of this technology for a greener future.

ECOtality designed and currently manages the world's largest EV infrastructure demonstration - The EV Project. With a budget of over $230 million, The EV Project will deploy and study Level 2 Alternating Current (AC) Electric Vehicle Supply Equipment (EVSE) stations for residential use, Level 2 AC EVSE stations for commercial and Direct Current (DC) Fast Charge (DCFC) stations. This represents thousands of field assets, utilized in concert with the deployment of Nissan LEAF™ vehicles and Chevrolet Volt® vehicles.

The EV Project is a public and private partnership administered by the DOE through a federal stimulus grant, made possible by the American Recovery and Reinvestment Act (ARRA) and by the private investment of ECOtality and its partners.

The EV Project is an infrastructure study. The EV Project will deliver to ECOtality, the Government and the general public a wealth of directly-applicable technical and professional experience for jumpstarting regional EV adoption and replicating business models that lead to sustainable, market-based charge infrastructures.

One purpose of The EV Project is to identify potential barriers to the widespread adoption of PEVs and the deployment of EVSE units to support them. This process identifies topics of national interest in the early deployment of EV charging stations in order to facilitate discussion and resolution. This paper documents the issues associated with and The EV Project's proposed approach to the reduction of the demand charges.

2 Statement of Need

The first objective of The EV Project is to collect usage data from deployed EVSE to understand the charging behavior and habits of users. The second objective is to elucidate the motivations and hindrances to EVSE ownership. To achieve this second objective, it is important to consider the various factors that a prospective EVSE owner will weigh when deciding to purchase and install an EVSE unit.

One such factor that arises with EVSE ownership is the application of “demand charges”. These are charges levied by the utility, typically for commercial properties, for the peak power used during a billing cycle, regardless of the amount of energy drawn at this power rate. These demand charges can add significantly to the utility bill for an EVSE host, and can make EVSE hosting cost prohibitive. While demand charges are incurred for the AC Level 2 EVSE hosts, and the methods for demand charge reduction apply to both EVSE types, the DCFC hosts’ demand charge costs are likely to be more significant because of the much higher power draw by a DCFC. Thus, the methods for demand charge reduction are more likely to be applied in the DCFC case, and this white paper will focus on DCFCs.

This paper identifies issues associated with electric utility demand charges for power drawn by DCFC units and discusses opportunities for demand charge avoidance. These opportunities will become a part of the Micro-Climate™ process, the planning activity utilized by ECOtality North America to facilitate EVSE installation. The opportunities will be discussed with prospective EVSE hosts where appropriate, and steps will be taken to reduce or eliminate demand charges if necessary.

In 2012, ECOtality produced the white paper, - “Lessons Learned – The EV Project – DC Fast Charge – Demand Charge Reduction” ([6]) - which proposed six methods for demand charge reduction, three of which were discussed in detail and provided case studies of their usage. Following on from this work, this subsequent white paper discusses the remaining three demand charge reduction methods proposed but not discussed in the previous white paper. Subsequently, there is a section on a case study in which the methods are applied to a specific hypothetical EVSE installation. Finally, a concluding section is included to summarize the study findings.

3 Background

The demand charge incurred by a customer is related to the peak power used during a billing cycle. In contrast to the total energy usage that is the more familiar utility charge, a demand charge is incurred for a one-time occurrence of an elevated power level and is not a cumulative-type charge. Demand charge rates are specified in $/kW, and are usually incurred when the peak power used during a billing cycle rises above a specified threshold, but are sometimes incurred for any power level above zero. Certain utilities even levy a yearly peak power demand charge. Demand charges are the method by which utilities dis-incentivize power use during high demand periods and high peak demands.

For most U.S. utilities, the peak power for a given billing cycle is determined by calculating the average power in consecutive 15-minute intervals (from start to finish of the billing cycle) and extracting the highest average from the entire cycle of intervals. Some utilities will impose a demand charge for every kW of usage; others will impose no demand charge until a specified power threshold is surpassed. In some of the latter cases, the demand charge is calculated by subtracting the demand charge threshold power level from the highest average power from the set of intervals, and then multiplying the remainder by the demand charge rate. In other cases where a threshold exists, any incursion over the threshold will result in a demand charge for the entire average power level, not just the amount above the threshold. Since the power is averaged over the interval, it is possible for the power demand during an interval to exceed the threshold and still incur no demand charge, as long as the average power over the interval is below the threshold.

Demand charges can become quite significant, and can in fact dominate a utility bill in certain circumstances. A generic example of the effect of demand charges on a utility bill is shown below in Table 1, where the bills for a varying number of charged Plugin Electric Vehicles (PEVs) are shown, along with the cost per vehicle charged. In this example, the basic meter charge is $200 (regardless of the power and energy drawn by the EVSE); the demand charge is $10/kW, a typical commercial value; and the energy charge is $0.11/kWh, also a typical commercial value. Each PEV that is charged is assumed to use the full 60 kW available from the Blink DCFC for 20 minutes, for a total energy usage of 20 kWh per vehicle. A further assumption is that there is no other load on this particular meter. Implicit in this assumption is that this means that a new utility service is installed for the EVSE, and that the additional costs associated with a new service for the EVSE are ignored.

Table 1 - Demand charge scenarios

Scenario	Number of Vehicles Charged/ Month	Meter Charge	Demand Charge	Energy Charge	Monthly Total	Cost per Vehicle
1	0	$200	$0	$0	$200	N/A
2	1	$200	$600	$2.20	$802.20	$802.20
3	10	$200	$600	$22	$822	$82.20
4	100	$200	$600	$220	$1,020	$10.20
5	250	$200	$600	$550	$1,350	$5.40
6	500	$200	$600	$1,100	$1,900	$3.80

As shown in the table, the demand charge remains constant regardless of the number of vehicles charged, and that it becomes proportionally less of the bill as the number of vehicles charged increases. Furthermore, as the number of vehicles charged increases, the overall cost per vehicle falls dramatically. If a sufficiently large number of vehicles use the EVSE to charge, the demand charge becomes less of a concern. However, since the number of vehicle customers cannot be estimated with any precision and the site owners may be unwilling to incur large demand charges, strategies to reduce or eliminate these charges must be developed. The number of PEVs, and hence the number of EVSE users, will be low at first, but are expected to grow gradually. The demand charges incurred from hypothetical DCFC installations in EV Project areas can also be examined. The rates are taken from the schedules presented in Appendix A. For this analysis, a particular duty cycle will be assumed. The duty cycle involves three vehicles charging from 30-90% and seven vehicles charging from 30-60% per day, all at the maximum rate of 60 kW. The vehicles will all be assumed to be Nissan LEAFs, each with a useable energy storage system capacity of approximately 20 kWh. Thus, the three vehicles will each receive 12 kWh and the seven vehicles will receive 6 kWh for a total of 78 kWh per day. The DCFC will again be assumed to be the only load on the meter.

Some of The EV Project utility partners do not impose any demand charges for the power and energy demand of a DCFC installation:

1. Tucson Electric Power

2. Alameda Municipal Power

3. Silicon Valley Power

4. Pacific Gas and Electric

5. City of Palo Alto Utilities

The three utilities within The EV Project with the highest demand charge rates are all in California (these are given as the highest possible demand charge; demand charges may be lower at other times of the year and/or at other times of the day):

1. San Diego Gas and Electric: $16.85 per kW (for non-coincidental demand charge) plus $13.83/$5.05 per kW (Summer/Winter peak demand charge), for a total of up to $30.68/$21.90 per kW (Summer/Winter)

2. Southern California Edison: $17.05 per kW (summer demand charge) plus $12.18 per kW (Facilities charge), for a total of $29.20 per kW.
3. Burbank Water and Power: $10.03 per kW (Billing Demand Charge), $11.18 per kW (Special Demand Charge), for a total of $21.21 per kW.

Using the base and energy rates from Appendix A for the high demand charge utilities along with the demand charge rates, the monthly (30.4 days) bill for a DCFC installation with the assumed duty cycle could reach:

1. San Diego Gas and Electric: $58.22 (base) + $230.53 (energy) + $1840.80 (demand), for a total of $2149.55. The demand charge would be 86% of the total monthly bill.
2. Southern California Edison: $134.17 (base) + $211.13 (energy) + $1752 (demand), for a total of $2097.30. The demand charge would be 84% of the total monthly bill.
3. Burbank Water and Power: $16.27 (base) + $274.11 (energy) + $1272.6 (demand), for a total of $1562.98. The demand charge would be 81% of the total monthly bill.

It is clear from these examples that devising solutions to the demand charge problem associated with fast charging PEVs is imperative in order to prevent the hindrance to growth of this industry. The purpose of this white paper is to discuss the various options available for reducing or eliminating the demand charge for EVSE installations. It is unlikely that one method will be optimal for each specific location, and so all options should be considered on a case-by-case basis.

3.1 Previous ECOtality White Paper on Demand Charge Reduction for DCFC

In June 2012, a white paper was produced by ECOtality ([6]) which discussed the need to reduce demand charges attributed to EVSE units. Three methods to do so were explored, and a summary of the findings of this paper's analysis are as follows:

Option 1: Never allow the overall site power demand to exceed a specified value.

- The concept of this method is to ensure that the peak output of the EVSE never exceeds the value that is the difference between the demand charge tolerance and the expected peak demand of the site owner. The expected peak site demand can be obtained from historical usage data and so the peak power allowable for the EVSE to obtain a desired demand charge (i.e., below the demand charge tolerance) can be calculated and the DCFC can then be electrically limited at the time of installation.
- This method is very conservative, especially if the assumed peak demand is conservatively chosen with a margin of error. The maximum demand charge can be made to be very predictable. However, this conservativeness may force the user to accept a lower charge rate, and potentially result in dissatisfaction with the DCFC experience

Option 2: Attempt to ensure that the average power over the interval is less than or equal to a specified value.

- This concept is divided into two different methods (Method 2a and Method 2b) which involve allowing the sum of the peak site demand and EVSE power to exceed the value of the demand charge tolerance, but only for a short period of time.

a) Method 2a requires that the site peak power demand duration is well defined. Knowing the metering interval (usually 15 minutes, however, in some cases 30 minutes) with the highest peak and average site demand, the EVSE can be electrically limited at installation to ensure the average power over the 15 minute interval does not exceed the demand charge tolerance. Method 2a will allow for higher charge rates and increase user satisfaction then Method 1, but the host may incur larger demand charges as a result if the site power demand does not conform to the historical data.

b) Method 2b involves controlling the duration of the EVSE charge to allow full EVSE power, but only for a shortened duration such that the average power demand over the interval does not exceed the demand charge tolerance. Limiting the EVSE charge to a portion of the 15-minute interval may be a viable method until the number of vehicles increases to the point that demand charges are amortized over a large number of charges per month. This strategy may also be advantageous in that the user can be notified that the charge is done for the 15-minute interval and can perhaps be given the choice to disconnect. However, depending on the site data, Method 2b may result in the energy provided to the PEV being lower and the PEV having to wait for the next 15-minute cycle to commence, creating PEV owner dissatisfaction.

Option 3: Attempt to recoup the demand charge cost through structured pricing for EVSE charging.

- This method involves having the EVSE user being allowed to select different rates of charge (in units of kW) (e.g. “premium”, “regular”, and “economy”) with cost differences for each rate. The objective of this method is to compensate the host for demand charges, rather than attempting to reduce the incurrence of demand charges.
- The site demand data are largely irrelevant, but reliable data on user tier preferences and on user numbers are crucial to the pricing scheme settings in order to maintain the satisfaction of the EVSE host. The larger the number of users, the lower the price can be per charge for the customers. Furthermore, the more users that choose the higher-priced charge rate, the lower the price can be for all tiers.

4 Demand Charge Reduction Options

In order to determine the method for reducing the demand charge, the first step is to determine the following parameters for a given location:

a) What is the expected peak demand of the site owner in a billing period? Over how much of the 15-minute interval does the peak demand span?

b) What is the average site demand?

c) What is the utility rate structure? Is there a yearly maximum average power demand charge in addition to the billing cycle maximum average power demand charge?

d) What is the demand charge tolerance?

Once these parameters are specified, the next step is to choose from the possible methods for reducing the demand charge. As proposed in the previous ECOtality white paper, the following is a list of six methods for demand charge reduction:

1. Never allow the overall site power demand to exceed a specified value.
2. Attempt to ensure that the average power over the interval is less than or equal to a specified value.
3. Attempt to recoup the demand charge cost through structured pricing for EVSE charging.
4. Add a Ground Energy Storage (GES) system that buffers the EVSE unit from high power demands during charging.
5. Aggregate demand among multiple EVSE installations into one demand charge calculation, taking advantage of the diversity that may exist in individual unit usage.
6. Provide DR capability to the utility to either offset or circumvent demand charges.

As mentioned earlier, the first three options were investigated previously in detail in an ECOtality white paper ([6]) and as such, will not be further discussed here.

4.1 Demand Charge Reduction Method 4: GES Coupled with EVSE to Buffer High Power Demands

The fourth method of demand charge reduction (or elimination) is using a GES unit to assist an EVSE unit during a recharge, so as to buffer the high power demands. As shown in Figure 1, the arrangement allows for the GES unit to supply some or all of the power and energy needs of the EVSE during charging. The GES unit can then be recharged at or below the power demand threshold to minimize or eliminate power demand charges, and/or during off-peak time periods when energy prices are lower.

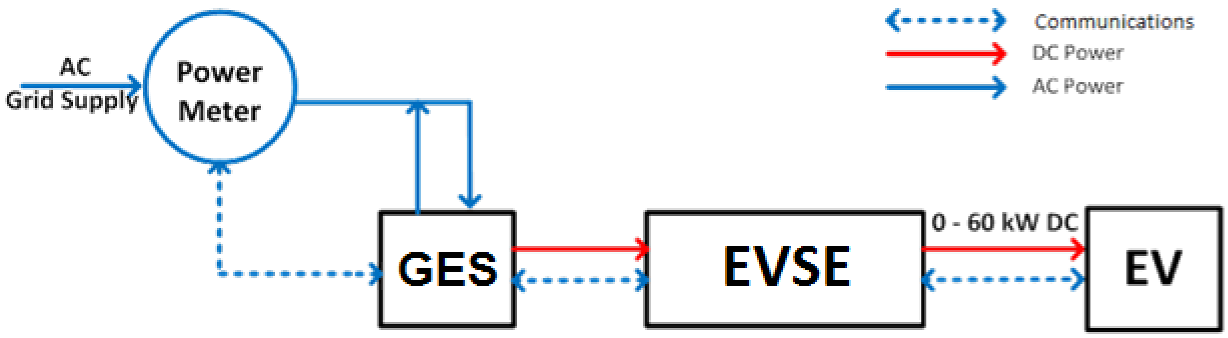

Figure 1 – GES-assisted recharging of an EVSE

The performance capability of the GES unit is dependent on the selected energy capacity (in units of kWh) and instantaneous power rating (in units of kW) of the EVSE unit. In addition to taking unit costs into consideration, the following points need to be determined in order to calculate the capacity and rating of the unit:

- **Discharge time and energy for one vehicle charge** - Determined by the size and charge logic of the PEV battery.
- **Number of back to back charges -** Determined by the customer use of the EVSE.
- **Time to recharge for one vehicle discharge -** Determined by the charging logic of the GES and the grid power supply.
- **Time to recharge from empty** - Determined by the charging logic and the size of the GES as well as the grid power supply.

It follows then that EVSE units with lower use and fewer back-to-back charges will also require a smaller-capacity GES unit, which subsequently will be cheaper. Figure 2 depicts an example of the demand curve of a DCFC over the course of 12 hours, and the subsequent capacity curve of the GES unit and demand curve seen by the AC grid as they combine to supply the EVSE. In this example, the GES unit has a usable capacity of 20 kWh and a discharge rate of 30 kW, in order to keep the instantaneous demand on the AC grid supply less than or equal to 20 kW.

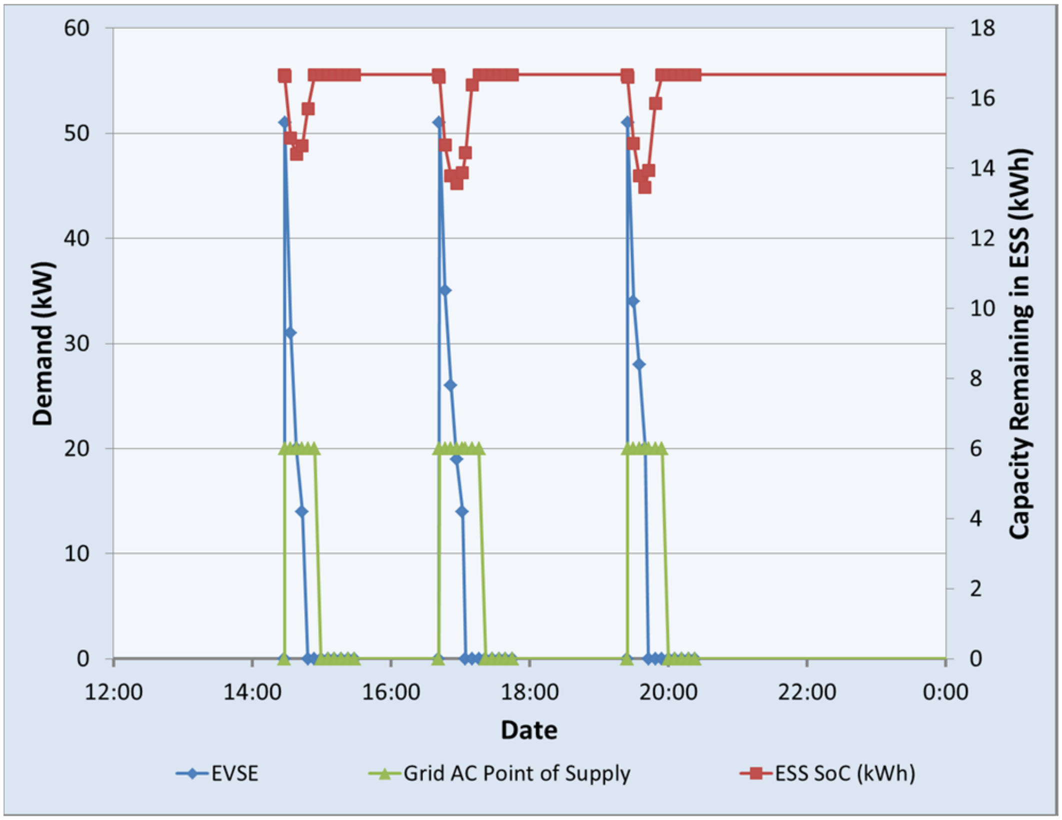

Figure 2 - Charging and discharging a GES to support DCFC demand over a 12-hour period

When determining the cost of a GES unit, there are two main modules – the power electronics and the battery – which dictate the price of the unit and are dependent on the kW and kWh requirements determined from the points mentioned before. The following are current approximate costs for each module, with a 100% markup likely for a complete GES purchased ready for installation.

- Inverter module and Power electronics – $300/kW
- Battery:
    - Lithium-ion (Li-ion) type - $1000/kWh
    - Lead type - $500/kWh

As an example, a GES unit that is required to deliver 40 kW of discharge, has a 20 kWh Li-Ion battery, and is ready for installation could cost $64,000 ($32,000 plus the 100% markup for overheads to bring the product to market). The ability to offset the cost of such a system would then be dependent on the annual savings in demand charges, and the required payback period. It could be anticipated that a Li-ion system would have an operational life expectancy of approximately seven to nine years, and a lead-based system would be approximately three to five years. Using the $64,000, 40 kW/20 kWh Li-ion system example described above, Table 2 compares the required annual savings in demand charges for a desired payback period to be achieved.

Table 2 - Example of a comparison of required annual savings in demand charges for desired payback period for a $64,000 GES

Desired Payback period (years)	Required Annual Savings in Demand Charges in order to achieve payback period
1	$64,000
2	$32,000
3	$21,333
4	$16,000
5	$12,800
6	$10,667
7	$9,143
8	$8,000
9	$7,111

When considering a GES unit for assisting a single DCFC unit, the 40 kW rate of discharge would be quite typical given that there are a large number of utilities in the U.S. which impose demand charges for 50-60 kW connections, but also have a rate available for connections ≤20 kW for which no demand charges would be imposed. Appendix B provides a comparison of what the potential annual savings in utility charges can be by installing a GES and reducing the peak demand from 50 kW to 20 kW for a DCFC that uses 7,016 kWh per year. From the analysis presented in Appendix B, it can be seen that while many utilities impose no or minimal demand charges for DCFC units, there are a number where the annual savings can be quite sizeable for a single DCFC unit supply. The analysis is summarized for several utilities in Table 3.

Table 3 - Example of annual potential savings on an electricity bill for changing from a 50 kW to a 20 kW services for a single DCFC unit consuming 7,016 kWh per annum

Utility	Annual Saving on Bill Switching from 50 kW to 20 kW Service[1]
SDG&E	$15,907
SCE	$11,469
MGE	$8,252
ConEdison	$7,020
HECO	$6,960
City of Tallahassee Utilities	$6,350
Pasadena Water and Power	$6,322

[1] Amounts calculated take into consideration the best rate available for a 50 kW service versus a 20 kW service. Further details and a break down into demand and energy costs can be found in Appendix B.

In the arrangement shown in Figure 1, there is a direct communications link between the EVSE and the GES units. This communication link is necessary so that when a charge event begins, the GES can determine whether there is sufficient stored energy to complete the charge.

- For CHAdeMO DCFC units, a change in maximum charging current cannot occur mid charge [3], so the DCFC will have to be limited to the maximum allowed AC grid instantaneous power from the beginning of the charge.
- For SAE J1772 DC Combo Connector EVSE units, a change in maximum charging current can occur mid charge [8]. The EVSE will therefore be supplied at the full 50 kW instantaneous power rating, until such time that the GES unit has been depleted. At this moment, the EVSE maximum charging power will then be reduced to the maximum allowed AC grid instantaneous power for the remainder of the charging event.

The communication link is highly desirable; however, if the GES unit was being installed to support an existing EVSE and a direct communication link could not be established, the GES unit would have to be appropriately sized so as to ensure that it would never be fully discharged. In the event that there were a sufficient number of back-to-back charge events to cause the GES unit to be fully discharged, the GES unit would not be able to change the charging current of the EVSE and the AC grid will be expected to supply the full, unconstrained demand of the EVSE. This subsequently negates the purpose of installing the GES unit, as demand charges will occur for the full EVSE instantaneous AC demand amount, as well as run the risk of overloading the AC fuse or circuit breaker if it was not rated for the corresponding level of demand.

4.2 Demand Charge Reduction Method 5: Aggregation of Multiple EVSE Installations into one Demand Charge to Benefit from Diversity

The fifth method for demand charge reduction is to aggregate multiple EVSE units into a single point of supply from the electric utility, so as to benefit from demand diversity. Assuming that there is always one or more EVSE units that is not in use at any time, the owner benefits from demand diversity and rather than have a demand charge that corresponds to the summed total of peak demand of each unit (which would be the case of individually supplying the units), the owner only pays a single demand charge for the aggregated peak (which would be expected to be less). An example of this arrangement is shown in Figure 3.

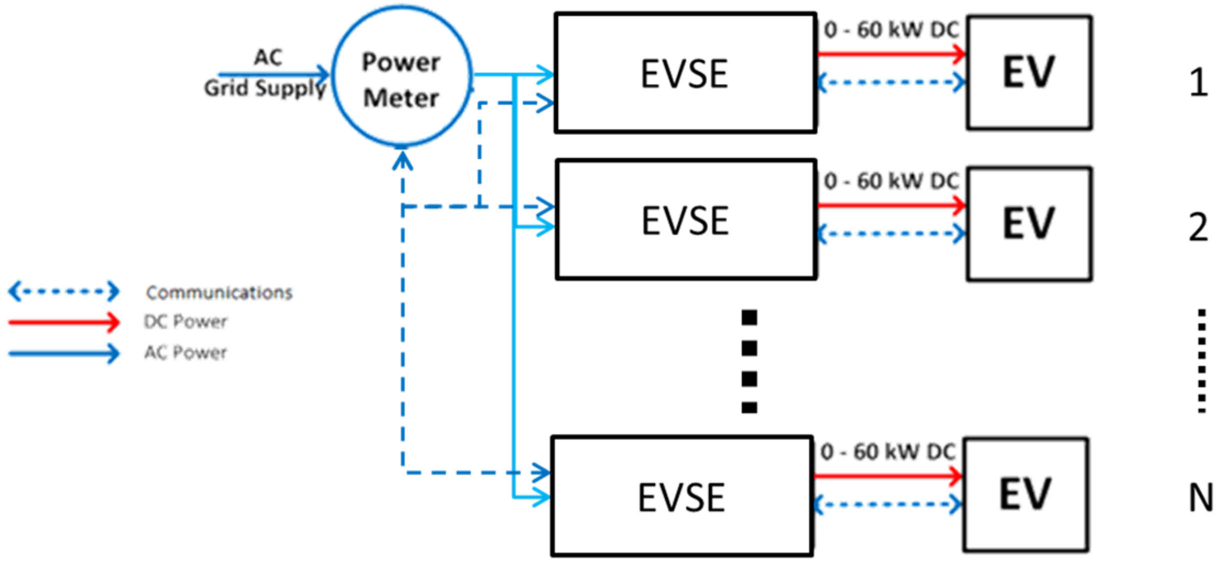

Figure 3 - Aggregation of multiple EVSE units supplied via a single grid connection

Given, for instance, that the retail cost of DCFC units is $30,000 to $85,000, it is unlikely that a business would purchase more than the number of DCFCs that are likely to be in use the majority of time (i.e., the owner expects a high utilization factor). It is therefore highly likely that in each billing period there will be a moment where each EVSE unit is in use at the same time. Subsequently, this will result in the peak demand for the billing period not being reduced through diversity. An example of this is shown in Figure 4, where the demand curves for the same week of two similar low-use DCFC unit installations have been aggregated. In the plot, it can be seen that for most of the week the two DCFCs are not in use at the same time; however, there are two occasions where the usage overlaps and a peak demand of 75 kW occurs in one instance.

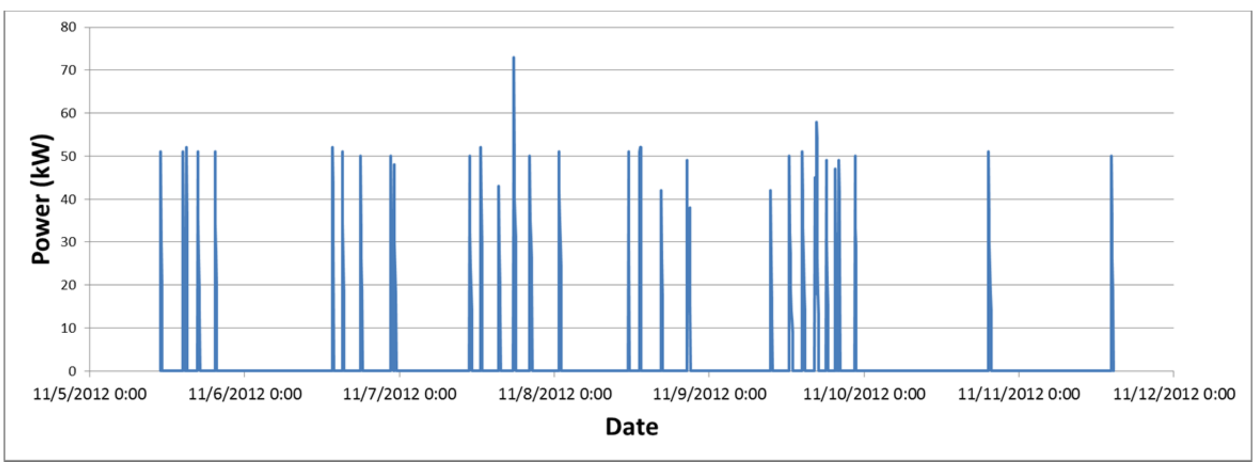

Figure 4 – Example of the aggregated demand curves for a typical week of two DCFC

One way to avoid this scenario would be to have an energy management system connected to each of the EVSE units that is capable of controlling the individual maximum demand of each unit. By doing so, the energy management system can be set to not allow the aggregated instantaneous peak demand to exceed a pre-determined amount. While this still allows the owner to benefit through demand diversity of the units, in the event of the aggregated demand approaching the pre-determined limit, units can either be delayed in starting, suspended, or have their maximum demand curtailed so as to ensure the limit is not breached. This method of managing the demand of EVSE units is a form of localized DR known as demand-only control.

4.3 Demand Charge Reduction Method 6: Provide DR Capability to the Utility

The sixth method of demand charge reduction (or offset) is the concept of providing DR to the electricity utility either directly or through a third-party aggregator, and in return avoiding some or all of the demand charges or having them offset by DR payments. DR programs are established to motivate changes in electricity use by customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized. As shown in Figure 5, there are several kinds of DR programs that can be implemented, with each type belonging to one of two groups: Price-Based DR (i.e., time-varying rates) or Incentive-Based DR (i.e., payments for reduction in demand or for provision of ancillary services); with the latter being the focus of this paper.

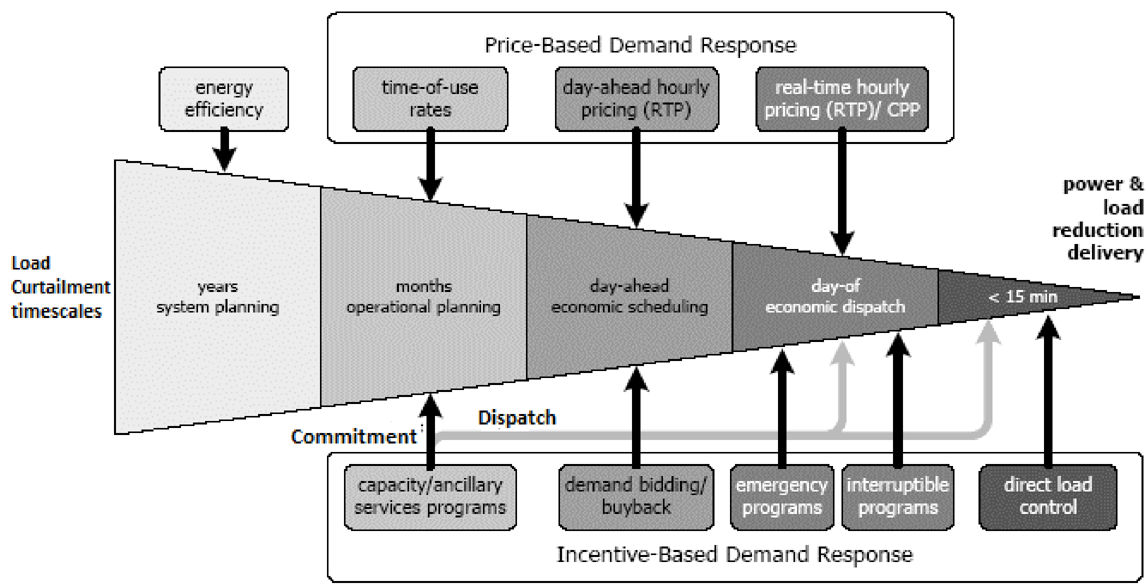

Figure 5 - Diagram of the different types of DR programs and their load curtailment timescales [1]

In the U.S., the opportunity to participate in DR programs and the corresponding rules for doing so are very much dependent on the location of the end user. Throughout much of the country, customers can participate in ISO/RTO-, utility-, or third-party aggregator-managed DR programs; however, in most instances, a single EVSE unit cannot participate directly, as a minimum aggregated demand of 100 kW is typically required. Generally, the only option is for end-users to go through a third-party aggregator who enlists multiple end-user sites and sells the combined load reduction to utilities and ISOs/RTOs. Typically, the aggregator will take a percentage of the DR incentive payments as compensation, and pass the remainder onto the end-user. Responding to a DR event can involve an end user either manually curtailing loads, or allowing for automated DR whereby the aggregator has the ability to curtail the load when a DR event occurs. As an example, Table 4 provides an overview of three third-party aggregator-managed DR programs, and three utility DR programs that are available for participation. In the case of the utility DR programs, in order for a single EVSE unit to participate, the EVSE would have to be enrolled via a third-party aggregator in order to meet the minimum demand size requirements; however, the utilities have a number of approved aggregators (often referred to as Curtailment Service Providers (CSPs)) available for end-users to use.

Table 4 - Example of three third-party aggregator-managed DR programs, and three utility DR programs

Program Rules	Third-Party Aggregator Managed DR Programs			Utility DR (Participation via an aggregator required for individual EVSE unit)		
	TVA-EnerNOC	SRP-EnerNOC	TEP-EnerNOC	Oncor Load Management	PG&E Capacity Bidding	SDG&E Capacity Bidding
Program Period	Year-round	Year-round	Year-round	Jun-Sep	May-Oct	May-Oct
Program Hours	Apr-Oct: 12 pm – 8 pm, M-F; Nov-Mar: 5 am – 1 pm, M-F	Jun–Sep: 12 pm – 8 pm, M-F; Oct–May: 5 am – 9 pm, M-F; Year-round: 7 am - 7 pm, Weekends	May–Oct: 11am – 6pm, M-F; Nov–Apr: 7 am – 7 pm, M-F;	Anytime at Oncor's discretion or local grid emergency	11 am - 7 pm, M-F	11 am – 7 pm, M-F
Dispatch Notification	30 min	10 min	30 min	60 min	Day-ahead: 3 pm day before; Day-Of: 2 hr 45min	2 h
Dispatch Duration	2-8 h	1-4 h	1-4 h	1-4 h	1-8 h	1-8 h
Dispatch Frequency	Max 40 h a year, 6 events per month or 2 consecutive days	Max 1 per day, 3 per week & 60 h per year	N/A	1-4 times per year plus 1 annual test	Max 1 event per day & Participants bid reduction amount either day-ahead or day-of	Max 1 event per day & Participants bid reduction amount either day-ahead or day-of
Incentive[2]	$22/kW per year	$20/kW per year	$22/kW per year	$40/kW per year	$0 to $21.57 / $24.81 (Day-Ahead / Day-of) per kW per month	$0 to $16.23 / $19.48 (Day-Ahead / Day-of) per kW per month
Minimum Demand	N/A	100kW	N/A	100kW	N/A	20kW reduction capability

[2] In each of these six DR programs, the incentives listed are paid regardless of whether a DR event occurs.

In order for an EVSE unit to provide DR, when instructed, the unit curtails its load by the amount and duration requested, and the EVSE host is paid either for each event the hosted EVSE unit responds to, or per month that the unit is available to participate. This method of controlling the demand of a PEV via an EVSE unit is commonly referred to as demand-only control, or V1G. This form of DR is well established and is already accepted as a reliable form of DR.

In addition to the V1G DR capabilities that can be provided by standard EVSE units, the GES-assisted recharging unit described in Section 4.1 is capable of providing bi-directional demand response (also known as vehicle-to-grid (V2G)). During a DR event, the GES unit can assist in providing DR in one of two ways:

- Demand-Only Control (V1G): the system can stop all demand from the grid but still continue to charge the PEV up to the maximum rated discharge rate of the GES and for the duration allowed by the energy capacity of the unit.
- Bi-directional Control (V2G): in addition to stopping all demand from the grid, the GES unit has the ability to export its stored energy to the grid whether or not a PEV is connected. If a PEV is connected, the charging of the PEV can be interrupted, and the GES can focus on exporting its energy purely to the grid.

While true V2G extends to the bi-directional control of energy flow from the PEV battery to the grid for the purpose of DR, this concept is still in its early stages and the standards and protocols associated with it are still in development [1]. Given that it is anticipated that actual commercialization is not likely in the near- to medium-term, the concept of using V2G from a PEV connected to an EVSE for DR has been omitted and deemed to be outside the scope of this white paper.

5 Case Studies

The following section discusses case studies for the demand charge reduction methods presented in Section 4 of this white paper. In the case studies, the DCFC unit is supplied by a dedicated utility service and is not part of a greater building service. The DCFC unit data are taken from an actual deployed unit located in the San Diego Gas & Electric (SDG&E) supply region that has been in-service since November 2012, with its usage typical of other DCFC installations. Based on the power and energy usage data captured from this unit from January 14th to February 12th 2013, Table 5 shows the corresponding attributes for this period.

Table 5 – Site Demand Data for Case Study (January 14th to February 12th 2013)

Statistic	Value
Peak Site Demand	Peak: 42.3 kW Non-Coincidental[3]: 42.3 kW
Monthly Energy Usage	On-Peak: 45 kWh Semi-Peak: 129 kWh Off-Peak: 225 kWh
Average Site Demand (Including time spent not-in-use)	0.1697 kW
Load Factor (Including time spent not-in-use)	0.4012%

A 50-60 kW DCFC unit falls into the SDG&E rate option – AL TOU Commercial – for connections >20 kW, which applies seasonal charges for energy and demand:

- Meter Charge: $58.22 per billing month
- Energy Charges[4]:
    - Summer (May to September):
        - On-Peak (11am-6pm M-F): $0.09722 per kWh
        - Semi-Peak (6am-11am & 6pm-11pm M-F): $0.07657 per kWh
        - Off-Peak (all other times): $0.05456 per kWh
    - Winter (October to April):
        - On-Peak (5pm-8pm M-F): $0.09643 per kWh

[3] Non-Coincidental is considered by SDG&E for the AL-TOU Commercial rate plan to be all time outside of the Peak time periods.

[4] The values stated for Energy Charges includes utility distribution charges and generation energy charges. This value fluctuates from month-to-month as the generation charges component is not a set value but rather is the average cost of generation for that month.

    - Semi-Peak (6am-5pm & 8pm-10pm M-F): $0.08562 per kWh
    - Off-Peak (all other times): $0.06556 per kWh
- Demand Charges[5] (applied from 0 kW):
  - Non-Coincidental: $16.85 per kW
  - On-Peak:
    - Summer: $13.83 per kW
    - Winter: $5.05 per kW

At a total of up to $30.68 per kW during summer billing months[6], of the 129 utilities reviewed in Appendix A, SDG&E has the highest monthly demand charge for 50 kW connections. In the case of the DCFC unit being studied, these charges result in an annual electricity bill of approximately $13,794, with demand charges accounting for 94% of the total (refer to Table 6). This therefore highlights the need in this case to find a cost-effective solution to reduce or offset the demand charges incurred in order to make the relative price per kWh for DCFC charging more reasonable and not prohibitive to the use of DCFCs for PEV charging.

Table 6 - Calculated and predicted winter, summer and annual electricity bills for DCFC case study

CALCULATED WINTER BILL (January 14 to February 12 2013)			
Meter Charge:			$58.22
kWh->	**Used (kWh):**	**Rates ($/kWh):**	**Total:**
On-Peak:	8	$0.0964	$0.77
Semi-Peak:	37	$0.0856	$3.17
Off-Peak:	94	$0.0656	$6.16
		kWh Total:	$10.10
kW->	**Amount (kW):**	**Rates ($/kW):**	**Total:**
Winter On-Peak:	42.3	$5.05	$213.62
Winter Non-Coincidental:	42.3	$16.85	$712.76
		kW Total:	$926.37
		Monthly TOTAL:	**$994.69**
		% of Bill is Demand Charges:	93.13%
PREDICTED EQUIVALENT SUMMER BILL			
Meter Charge:			$58.22

[5] Demand charges are calculated from the maximum average demand (in units of kW) in a 15-min interval in billing period

[6] This amount is the combination of the on-peak ($13.83/kW) and non-coincidental ($16.85/kW) demand charges

kWh->	Used (kWh):	Rates ($/kWh):	Total:
On-Peak:	15	$0.0972	$1.46
Semi-Peak:	30	$0.0856	$2.57
Off-Peak:	94	$0.0656	$6.16
		kWh Total:	$10.19
kW->	Amount (kW):	Rates ($/kW):	Total:
Summer On-Peak:	42.3	$13.83	$585.01
Summer Non-Coincidental:	42.3	$16.85	$712.76
		kW Total:	$1,297.76
		Monthly TOTAL:	$1,366.17
		% of Bill is Demand Charges:	94.99%

PREDICTED ANNUAL DEMAND			
Season:	Monthly Bill:	No. of Months:	Total:
Winter	$994.69	7	$6,962.84
Summer	$1,366.17	5	$6,830.87
			$13,793.71
		Predicted Annual Cost of Demand Charges	$12,973.39

5.1 Demand Charge Reduction Using Method 4

The fourth demand charge reduction method to be proposed involves using a GES unit to assist an EVSE during a charge event, as outlined in Section 4.1. In the case study presented, the single DCFC unit experiences a demand charge of $12,973 per annum on the SDG&E AL-TOU Commercial rate plan. As shown in the catalogue of available rate plans presented in Appendix A, SDG&E has a rate plan available to commercial connections ≤20 kW – General Service Schedule A – which has no demand charges. The following is a summary of the charges applicable to this rate plan:

- Meter Charge: $9.56 per billing month
- Energy Charges[7]:
  - Summer (May to September): $0.09511 per kWh
  - Winter (October to April): $0.08397 per kWh

[7] The values stated for Energy Charges includes utility distribution charges and generation energy charges. This value fluctuates from month-to-month as the generation charges component is not a set value but rather is the average cost of generation for that month.

Given that demand charges currently account for $12,973 or 94.5% of the annual bill, there is a significant opportunity for it to make financial sense to couple a GES unit to this DCFC to reduce the peak demand to 20 kW or less, and allow the change of rate plans.

Using the DCFC-GES calculator developed by ECOtality North America (the output screen is presented in Appendix C) and applying the monthly demand curve for the case study, it can be determined that the following GES attributes are required in order to keep the peak 15-minute average instantaneous demand below 20 kW:

- Instantaneous rate of discharge: 30 kW
- Battery energy capacity: 10 kWh usable (additional 20% required for oversizing, i.e., 12 kWh total)[8]

For a system with Li-Ion battery technology, the GES unit would be expected to cost $42,000[9] (including 100% markup for overheads to bring the product to market), in addition to the cost of the DCFC unit. Assuming that electricity prices remained unchanged, it would therefore take approximately 3.25 years to recoup the costs of the GES, and if the system had a lifespan of seven years, it would save the owner approximately an additional $48,500 over its remaining life. A simulated power flow plot for this example GES coupled DCFC system is shown in Figure 6, where the red line represents remaining capacity (kWh) of the GES, the blue line is the instantaneous demand (kW) of the DCFC, and the green line is the subsequent instantaneous demand on the grid AC point of supply. As can be seen in this plot, the GES is appropriately sized to supply the DCFC, without the need to forcibly curtail the rate-of-charge of the PEV, or increase the grid point of supply beyond 20 kW.

[8] During the month being examined, the DCFC experiences two back-to-back charges, with a third charge following shortly after. This would be considered a high usage event and given the 10 kWh system is able to effectively supply the demand during this event, it could be considered that this it is sufficiently sized for growth in usage over the life of the system.

[9] Total cost of GES = (30 kW*$300 + 10 kWh*$1.2_{(oversizing)}$*$1000)*$2_{(mark-up)}$ = $42,000

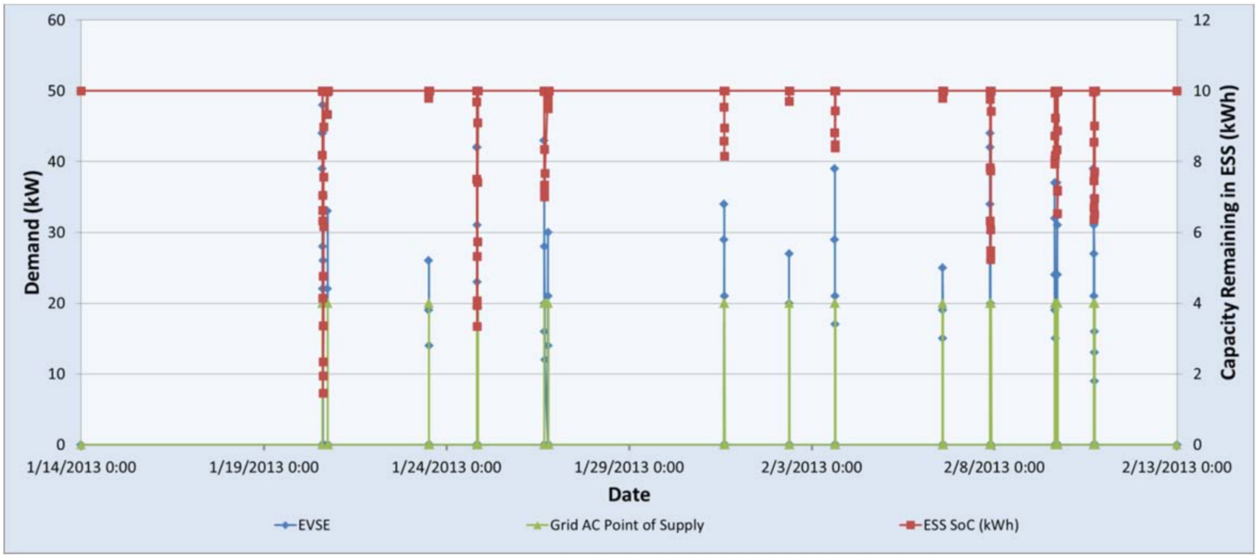

Figure 6 - Simulated power flow for GES-assisted recharging of SDG&E DCFC case study

5.2 Demand Charge Reduction Using Method 5

As discussed in Section 4.2, demand charge reduction Method 5 involves making use of demand diversity of multiple EVSE units supplied via a single metering point, so that the maximum site demand is equal to the highest demand of a single EVSE unit. For the case study described above, while there is only a single EVSE unit, the unit itself consists of two DCFC charging points and it employs the ‘delayed start’ demand diversity control strategy for maintaining an allowed maximum demand level (see Table 7 for a discussion of this strategy). By employing this strategy, the EVSE will never exceed the maximum demand of one vehicle of 50-60 kW as should there be a second PEV connected to the available DCFC port, the second charge will be delayed until the first charge is complete (a delay of up to 30 minutes maximum).

While more than a single DCFC unit per site is not a common practice at present due to insufficient demand for use, it is quite common for there to be multiple AC Level 2 EVSE units installed at the same site as a DCFC on the same dedicated service. Table 7 discusses each of the available demand diversity strategies that can be employed to ensure not to exceed the pre-determined maximum demand threshold. It is important to note that in order to implement these strategies, an EVSE management system of some sort will be required to communicate with, monitor, and control each EVSE unit.

Table 7 - Demand Diversity Strategies

Strategy	Description	Pros	Cons
Delayed Start	Once the maximum demand threshold is reached, each subsequent PEV connected to an EVSE is delayed until another PEV is finished charging and there is sufficient demand capacity available.	• Each EVSE user will know exactly when their vehicle will be charged as the delay can be calculated by the system at the time of plugging in. • Strategy favors PEVs in the order they plug-in.	• When paring DCFCs with AC Level 2 units, there is the potential for a DCFC to be delayed for a long period of time until an AC Level 2 is completed unless priority is given to DCFCs. • There is a risk of user-dissatisfaction from charges not starting immediately.
Demand Rationing	Once the maximum demand threshold is reached, any additional PEVs that are connected to an EVSE unit will result in the maximum total demand being rationed between all EVSE units.	• A multi-level rate scheme could be utilized whereby EVSE users pay for a 'priority' level which would give them a greater percentage of demand during rationing events. • All in-use EVSE units will be providing some charge to the PEVs, so the PEVs will receive some charge (unlike in delayed start where a significant period of time could pass before the charge commences).	• When rationing events occur, there is the potential to significantly affect the charging times of individual PEVs, which will cause uncertainty for users as to whether their vehicle will be sufficiently charged upon their return.
Complete-by	When a PEV is connected, the user can stipulate a delayed charged completion time. The system would then prioritize EVSE demand based on completion times in order to stay under the demand threshold. This strategy would also utilize either a 'delayed start' or a 'rationing' strategy for managing PEV charging to ensure completion by the desired time.	• EVSE users could receive a reduced billing rate for stipulating a longer charge time. Inversely, EVSE users who request the minimal time could be charged a higher rate. • Ability to prioritize DCFC units over AC Level AC units. • Could utilize a combination of the delayed start and demand rationing strategies to ensure PEVs are charged by the stipulated time.	• More complex system to implement and for users to understand. • Many users of commercial EVSE may not accept any delay to their charges since they do not expect to be using the EVSE unit for very long, making the Complete-by feature useless.

5.3 Demand Charge Reduction Using Method 6

The sixth method for reducing demand charges involves having the EVSE participate in DR programs and earning revenue for load reduction to offset demand charges. For the EVSE unit in this case study, as it is located in the SDG&E supply region, the only program available for it to participate in is “Capacity Bidding Program” (introduced in Table 4). According to the program rules ([2]), participants are required to be able to reduce their demand by at least 20 kW of their ‘baseline’ demand during DR events. The baseline is defined as the average consumption for the hours of 11 am to 7 pm for the ten weekdays immediately prior to the DR event.

Further to the program details provided in Table 4, the features of the SDG&E Capacity Bidding program include:

- **Program Requirement -** Commitment made prior to beginning of month.
- **Rewards -** Capacity payment for monthly pledge (see Table 8) and energy payment for actual hours of reduction.
- **Notification Lead Time** - Day–Ahead option: by 3 pm prior day; Day-Of option: minimum of 2 hours prior to event.
- **Participation -** Binding to the monthly pledged amount. Participants chose between Day-Of or Day-Ahead notification period, and between 4-, 6- or 8-hour participation duration (see Table 9 for per month participation requirements for each option). Participants also have the option of participating directly with SDG&E or through a third-party aggregator.
- **Risk -** Reduced incentives for lower reduction than pledged. Penalties apply for less than 50% reduction on pledged amount.

Table 8 - Load reduction incentive payments for SDG&E Capacity Bidding Program [9]

Product	May	June	July	August	September	October
Day-Ahead Program Option ($/kW-month):						
1 to 4 hours	5.37	7.35	13.54	15.11	9.77	4.71
2 to 6 hours	5.51	7.54	14.07	15.63	10.06	4.81
4 to 8 hours	5.65	7.76	14.71	16.23	10.49	4.94
Day-Of Program Option ($/kW-month):						
1 to 4 hours	6.44	8.82	16.25	18.13	11.72	5.65
2 to 6 hours	6.61	9.04	16.89	18.75	12.07	5.78
4 to 8 hours	6.79	9.31	17.66	19.48	12.59	5.93

Table 9 - Monthly participating requirements for SDG&E Capacity Bidding Program [9]

Day-Ahead/Of Products	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration Per Operational Month	Maximum Events Per Day
1 to 4 hours	1 hour	4 hours	24	1
2 to 6 hours	2 hours	6 hours	24	1
4 to 8 hours	4 hours	8 hours	24	1

Based on these requirements, while the single DCFC would be capable of reducing its demand by 20 kW when a PEV is connected and charging at full capacity, there are two significant risks that participants would face:

1. Since charge events presently are highly sporadic, there is a significant risk that when a DR event occurs that a PEV will not be connected and charging; therefore, the DCFC will be unable to respond and the participant will be subject to penalties.
2. The minimum participation duration available is 1-4 hours. Given the fast-charge nature of a DCFC and the fact a car is not typically connected for more than 15 minutes at a high demand capacity (>20 kW), it is almost impossible that a single DCFC unit will be capable of reducing its demand by 20 kW for 1 to 4 hours. This will make the participant also liable for penalties each time this occurs.

These points hence highlight the need for the DCFC to participate through a third-party aggregator which doesn't pass on any penalties or minimum response times, in order to avoid the risk of not meeting SDG&E's response requirements during a DR event. On SDG&E's website ([2]), a detailed list is provided of a number of third-party aggregators who are approved to provide access for individual loads into the Capacity Bidding Program. While any one of these third-party aggregators could be suitable, taking 'Energy Curtailment Specialists' (ECS) as an example[10], the DCFC unit would be able to participate through ECS without any risk of penalties for failure to respond. The DCFC unit owner would still have the option to choose between the day-ahead or day-of notification periods, with ECS estimating a 20 kW reduction yielding payments and savings of $640 to $900 in the first year. Considering that demand charges are expected to total almost $13,000 in one year, the potential offset available through DR program participation equates to about 7% at best in this case study. It would appear then that while participation in DR programs might provide sufficient offset in some utility supply regions with lower demand charges, they provide little financial relief for a DCFC unit in the SDG&E territory.

Beyond this case study, assuming this EVSE unit was part of a greater EVSE network, there is also the opportunity for the EVSE network operator to aggregate their EVSE units within the SDG&E supply territory and participate in the Capacity Bidding Program directly. This would allow the EVSE network operator the ability to hedge their risks of penalties by having a diversified EVSE demand portfolio, and maximize financial benefit by avoiding a percentage of

[10] ECS has been selected as an example because they have a great deal information available on their website ([7]) regarding participating in SDG&E Capacity Bidding Program.

DR payments being transferred to a third-party aggregator. However, this aggregated EVSE network approach raises the issue of having to ‘recruit’ each of the individual EVSE hosts into participating in the DR program. While some EVSE hosts will readily participate, if it means offsetting some of their demand charges, it is highly unlikely that all EVSE owners and users will readily participate due to the perceived inconvenience a DR event imposes on them, and so the EVSE network operator will have to determine a means of passing on sufficient incentives and compensation in order to make the aggregation work effectively.

6 Conclusion

As a follow up to a previous white paper produced as part of The EV Project ([6]), this white paper has discussed the concept of reducing demand charges imposed by electricity utilities on EVSE units, specifically DCFC units, by using three proposed methods. Based on the information and discussion around these methods which have been presented in this white paper, there are several conclusions that can be drawn.

Firstly, reiterating what was pointed out in the previous white paper, the need for accurate historical data is important when assessing each of the methods proposed. For instance, with Method 4, the GES unit needs to be appropriately sized such that it is capable of meeting the demand needs of the DCFC unit and become depleted of stored energy because the possibility of back-to-back charge events was not taken into consideration. In the case of Method 5, the historical data allow for the diversity in demand of the EVSE units to be compared and the threshold limit be investigated based on likely overlaps in demand. With Method 6, historical data are required in order to determine the baseline for a site in order to determine its suitability to participate in DR programs.

In order for each of the three methods presented to be successful, there needs to be in place an energy management system or remote EVSE monitoring and demand control capabilities in order to curtail or stop the power demand of an individual EVSE unit. This functionality is required in order to avoid exceeding the instantaneous demand threshold in the event of the GES becoming depleted of stored energy (Method 4), of a lack of demand diversity (Method 5), or a DR event occurring (Method 6). While ‘smart’ EVSE units generally have these capabilities as part of the EVSE network and back-office they are a part of (e.g., the Blink Network used by ECOtality EVSE units), there is also an increasing number of ‘dumb’ EVSE units, including DCFC units, becoming available for purchase which contain no remote communication or control capabilities. Obviously, in these cases, an energy management system would have to be retrofitted in order to ensure the units are able to be curtailed in real time as required.

Given Method 6 will require periods where the EVSE is either unable to provide a charge or at least a fast charge due to participating in a DR event, there is a serious risk of user dissatisfaction due to an inability to charge or resultant extended charge times. The acceptance of these inconveniences by the EVSE owner will be contingent upon sufficient compensation being provided, and at minimum, the users will need to be made aware that the EVSE unit will be providing DR services, so they do not just assume there is a fault or the units are unreliable. While a single EVSE unit will almost certainly have no choice but to go through a third-party aggregator in order to participate in a DR program, doing so provides protection against risk of penalties for under-performance. This can be considerably important given that there is the potential for frequent or ill-timed DR events to affect the unit’s ability to perform its core function of being a reliable PEV charging facility. However, there is also the opportunity for multiple EVSE units belonging to the same EVSE network operator to be aggregated to provide DR and benefit through the demand diversity of the units. Given the financial revenue potential per EVSE unit for participating in DR programs is not large, participation in DR programs should be viewed as a potentially complementing revenue stream and not as a sufficient means to avoid demand charges in the case of DCFC units.

Of the three methods discussed, Method 4 is probably technically the most promising; however, given the high up-front capital costs, it will only be suitable in a few cases where demand charges are very high. While in this white paper, the use of the GES unit has been focused on limiting demand to a pre-determined threshold, it can also be used for shifting energy demand to off-peak time period by sizing the battery appropriately. Obviously, this will increase the cost of the unit drastically, and as such would only be suitable where on-peak energy charges were high and accounted for a sufficient amount of the electricity bill. It is worth noting that ECOtality North America is presently conducting trials with several battery chemistries to assess the performance of a GES-assisted DCFC unit for the purpose of demand charge reduction/avoidance and energy demand shifting. It is also important to note that as second-use batteries become more available (due to more PEVs ageing), the cost of a GES could be reduced considerably, making this option much more attractive.

Finally, it is worth re-mentioning that the six methods discussed in detail in this white paper and the previous white paper produced as part of The EV Project are only some of the ways for reducing demand charges, and there are others that should be investigated and evaluated. Ultimately, the best solution for reducing or avoiding demand charges will be dependent on the location of the EVSE unit and the charges associated with the available utility rate structures. In many cases, it may be best to not make use of just one method, but rather a combination of two or more, so as to ensure that the EVSE unit offers reliable, low-cost charging capabilities.

7 References

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[3] "CHAdeMO", *CHAdeMO Association Website*, Accessed February 21 2013, http://www.chademo.com/

[4] "Commercial Demand Response - Capacity Bidding Program", *SDG&E*, San Diego California, 2010

[5] Macdonald, J., et al, "Demand Response Providing Ancillary Services: A Comparison of Opportunities and Challenges in the US Wholesale Markets", *Grid-Interop Forum 2012*, December 2012

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[7] "PowerPlay California", *Energy Curtailment Specialists*, Accessed on March 18 2013, http://www.ecsgrid.com/demand-response-programs/markets-a-programs-offered/demand-response-california

[8] "SAE J1772 – Electric Vehicle and Plug in Hybrid Electric Vehicle Conductive Charge Coupler", *SAE International*, October 2012.

[9] "Schedule CBP", *SDG&E*, San Diego California, 2010

Appendix A - Catalog of U.S. Electricity Utilities’ Rate Schedules

The following attached catalogue contains:

- EV-specific Residential Rates
- Commercial and Industrial rates for connections between 20 to 200kW

In total, there are 379 rates from 129 electric utilities from across 28 states in the United States of America.

(Note: These rates are correct as of December 2012)

Appendix A - Catalog
of US Electricity Utiliti

Appendix B - Electricity Charges for 20 kW vs. 50 kW Services in the U.S.

The following table provides a comparison of the Electricity charges for a 20 kW supply versus a 50 kW supply, where annual energy usage is 7,016 kWh (currently typical for installed DCFC unit). The purpose of the comparison is to show the available saving in reducing the peak demand when installing a 30 kW GES. These savings do not take into consideration the cost of the GES but are rather for analysis purposes.

The best available electricity rates per utility (as of December 2012) have been selected, and details of the corresponding rate can be found in Appendix A. Note that schedules that have been highlighted indicate that the maximum monthly peak demand is >20 kW but <50 kW, and as such an appropriately smaller sized GES unit could be installed, reducing the system cost.

State	Utility	20kW				50kW			SAVINGS			
		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge	Annual Demand Charge + Base Charges	Energy Charges		Total (no offsetting)
				No offsetting	Offsetting charging					No offsetting	Offsetting charging	
AL	Alabama Power	BEVT-EV ToU	1,680	636	500	BEVT-EV ToU	2,400	636	720	0	136	720
AL	Huntsville Utilities	Service 1	137	700	700	Service 1	137	700	0	0	0	0
AL	Muscle Shoals Electric Board	GSA-1	222	726	726	GSA-1	222	726	0	0	0	0
AZ	Arizona Public Service	E-32XS	245	888	888	E-32S	5,715	668	5,470	-220	-220	5,250
AZ	Salt River Project	E-36	910	744	744	E-36	2,109	744	1,199	0	0	1,199
AZ	Trico Electric Cooperative	GS2	357	968	968	GS2	492	968	135	0	0	135
AZ	Tucson Electric Power	GS-10	168	573	573	GS-10	168	573	0	0	0	0
CA	Burbank Water and Power	Schedule D	2,407	0	0	Schedule D	6,018	0	3,611	0	0	3,611
CA	Glendale Water and Power	LD-2A	4,490	0	0	LD-2A	6,241	0	1,751	0	0	1,751
CA	Los Angeles Department of Water and Power	Small General Service A1	1,278	0	0	Small General Service A1	3,078	0	1,800	0	0	1,800
CA	Southern California Edison	GS-1	317	1,089	1,089	GS-2	12,328	547	12,011	-542	-542	11,469
CA	Pacific Gas and Electric	A-1	240	1,222	1,154	A-1	240	1,222	0	0	68	0
CA	City of Palo Alto Utilities	E-2	0	921	921	E-2	0	921	0	0	0	0
CA	San Diego Gas and Electric	Schedule A	115	622	622	Schedule AL-TOU	16,034	610	15,919	-12	-12	15,907
CA	Silicon Valley Power	Schedule C1	89	1,060	1,060	Schedule C1	89	1,060	0	0	0	0
CA	Alameda Municipal Power	Schedule A-1	120	1,044	1,044	Schedule A-1	120	1,044	0	0	0	0

State	Utility	20kW				50kW			SAVINGS			
		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge	Annual Demand Charge + Base Charges	Energy Charges		Total (no offsetting)
				No offsetting	Offsetting charging					No offsetting	Offsetting charging	
CA	Hercules Municipal Utility	Schedule E-5	203	1,581	1,581	Schedule E-5	203	1,581	0	0	0	0
CA	Sacramento Municipal Utility District	GFN	144	878	878	GSS	4,344	796	4,200	-82	-82	4,118
CA	Pasadena Water and Power	S-1 Option A	206	712	712	M-1 Option A	6,765	475	6,559	-237	-237	6,322
CT	Connecticut Light and Power	Small General Service ToD	2,742	975	831	Small General Service ToD	6,162	975	3,420	0	144	3,420
DC	PEPCO	Schedule GS-ND	220	234	234	Schedule GS-LV	2,297	254	2,077	20	20	2,097
FL	Florida Power and Lighting	Schedule GS-1	83	634	634	Schedule GSD-1	6,636	354	6,553	-280	-280	6,273
FL	TECO Tampa Electric	GS	126	601	601	GS	126	601	0	0	0	0
FL	City of Tallahassee Utilities	Non-Demand	371	644	644	Demand	6,915	450	6,544	-194	-194	6,350
FL	Gainesville Regional Utilities	GS Non-Demand	312	561	561	GS Non-Demand	312	561	0	0	0	0
FL	JEA	GS Time of Day	252	850	850	GS Time of Day	252	850	0	0	0	0
FL	Progress Energy	GS-1	139	925	925	GS-1	139	925	0	0	0	0
GA	Georgia Power	GS-6	204	647	647	PLS-7	4,836	738	4,632	91	91	4,723
GA	Cobb EMC	CS-14	117	829	829	CS-14	117	829	0	0	0	0
GA	Flint Energies	FGS-20 Rate 2	1,660	504	504	FGS-20 Rate 2	3,899	504	2,239	0	0	2,239
HI	HECO	Schedule G	732	1,497	1,497	Schedule J	7,998	1,191	7,266	-306	-306	6,960
HI	HELCO	Schedule G	654	2,216	2,216	Schedule J	6,918	1,740	6,264	-476	-476	5,788
HI	MECO - Molokai	Schedule G	456	2,511	2,511	Schedule J	5,604	2,017	5,148	-494	-494	4,654
HI	MECO - Lanai	Schedule G	540	2,452	2,452	Schedule J	5,670	2,387	5,130	-65	-65	5,065
HI	MECO - Maui	Schedule G	480	1,869	1,869	Schedule J	5,850	1,608	5,370	-261	-261	5,109
IL	ComEd	Small Load Delivery	2,396	550	550	Small Load Delivery	5,544	550	3,148	0	0	3,148
IL	Ameren Illinois	DS-2 (Zone 1)	240	138	138	DS-2 (Zone 1)	240	138	0	0	0	0
IN	Northern Indiana Public Service Company (NIPSCO)	Rate 621	240	830	830	Rate 621	240	830	0	0	0	0
IN	Duke Energy Indiana	Rate CS	113	578	578	Rate CS	113	578	0	0	0	0
IN	Indianapolis Power and Lighting Company	Rate SS	137	518	518	Rate SS	137	518	0	0	0	0
IN	Indiana Michigan Power (AEP)	MGS-ToD	251	681	419	MGS-ToD	251	681	0	0	262	0

State	Utility	20kW				50kW			SAVINGS			
		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge	Annual Demand Charge + Base Charges	Energy Charges		Total (no offsetting)
				No offsetting	Offsetting charging					No offsetting	Offsetting charging	
KY	LG&E	GS	390	578	578	GS	390	578	0	0	0	0
KY	KU	GS	390	585	585	GS	390	585	0	0	0	0
KY	Kentucky Power (AEP)	MGS-ToD	172	1,038	699	MGS-ToD	172	1,038	0	0	339	0
KY	Warren RECC	GSA1	245	499	499	GSA1	245	499	0	0	0	0
KY	Pennyrile RECC	GSA1	209	778	778	GSA1	209	778	0	0	0	0
MA	National Grid	G-1	120	410	410	G-1	120	410	0	0	0	0
MA	NSTAR	T-2	3,616	615	615	G-2	9,828	797	6,212	182	182	6,394
MA	WMEC	G-0	3,907	194	194	G-0	9,228	194	5,321	0	0	5,321
MD	Baltimore Gas & Electric (BGE)	G - Type 1	138	764	764	G - Type 2	138	649	0	-115	-115	-115
MI	Consumers Energy	GS	240	842	842	GS	240	842	0	0	0	0
MI	Detroit Edison (DTE)	D3	105	782	782	D3	105	782	0	0	0	0
MI	Indiana and Michigan Power (AEP)	MGS-ToD	212	886	563	MGS-ToD	212	886	0	0	323	0
MI	City of Lansing	Rate 3	224	692	692	Rate 3	224	692	0	0	0	0
MN	Xcel Energy	Small General Service	103	693	693	Small General Service	103	693	0	0	0	0
MN	Alliant Energy	General Service Without Demand	256	505	505	General Service Without Demand	256	505	0	0	0	0
MN	Lake County Power	Basic Rate	504	474	474	Basic Rate	504	474	0	0	0	0
MN	Otter Tail Power Company	Small General Service	186	539	539	General Service	1,260	496	1,074	-43	-43	1,031
MN	East Central Energy	Small General Service	708	755	755	Small General Service	708	755	0	0	0	0
MN	Rochester Public Utilities	General Service	348	692	692	General Service	348	692	0	0	0	0
NJ	Atlantic City Electric	Monthly General Service	1,658	1,155	1,155	Monthly General Service	4,028	1,155	2,370	0	0	2,370
NJ	Jersey Central Power and Light	General Service Secondary	935	986	790	General Service Secondary	3,321	986	2,386	0	196	2,386
NJ	Orange & Rockland Pike County Light & Power Co. / Rockland Electric Company	General Service	1,034	334	334	General Service	2,765	334	1,731	0	0	1,731
NJ	PSE&G	GLP	1,703	58	58	GLP	4,182	58	2,479	0	0	2,479
NV	NV Energy - Northern	OGS-1-TOU	294	928	696	OGS-1-TOU	294	928	0	0	232	0
NV	NV Energy - Southern	OGS-1-TOU	292	614	474	OGS-1-TOU	292	614	0	0	140	0
NY	Central Hudson Gas & Electric	General Service - Demand Metered	2,952	415	415	General Service - Demand Metered	5,868	415	2,916	0	0	2,916

State	Utility	20kW Best Schedule	20kW Annual Demand Charge + Base Charges	20kW Annual Energy Charge: No offsetting	20kW Annual Energy Charge: Offsetting charging	50kW Best Schedule	50kW Annual Demand Charge + Base Charges	50kW Annual Energy Charge	SAVINGS Annual Demand Charge + Base Charges	SAVINGS Energy Charges: No offsetting	SAVINGS Energy Charges: Offsetting charging	SAVINGS Total (no offsetting)
NY	ConEdison	General Service Large Rate 1	4,855	167	167	General Service Large Rate 1	11,875	167	7,020	0	0	7,020
NY	National Grid	Small General Service - Non Demand	252	747	747	Large General Service - Secondary	3,598	323	3,346	-424	-424	2,922
NY	NYSEG	No.2	2,217	0	0	No.2	5,212	0	2,995	0	0	2,995
NY	RG&E	No.7	4,300	0	0	No.7	9,632	0	5,332	0	0	5,332
NY	LIPA	Rate 281	2,919	306	306	Rate 281	6,531	306	3,612	0	0	3,612
NC	Duke Energy Carolinas	SGS-NC	218	816	816	SGS-NC	1,130	816	912	0	0	912
NC	Progress Energy Carolinas	SGS-NC	252	761	761	MGS-NC	3,186	484	2,934	-277	-277	2,657
NC	Dominion NC Power	Schedule 5	858	0	0	Schedule 5	2,146	0	1,288	0	0	1,288
OH	AEP Ohio	GS-2	1,454	780	780	GS-2	2,769	780	1,315	0	0	1,315
OH	The Illuminating Company	GS	2,546	417	417	GS	7,471	417	4,925	0	0	4,925
OH	Ohio Edison	GS	1,080	0	0	GS	3,047	0	1,967	0	0	1,967
OR	Ashland Municipal Electric Utility	Commerci al Service	551	418	418	Commerci al Service	2,562	418	2,011	0	0	2,011
OR	Consumers Power, Inc.	Commerci al Service	948	435	435	Commerci al Service	2,640	435	1,692	0	0	1,692
OR	Emerald People's Public Utility	Schedule 25	144	580	580	Schedule 25	144	580	0	0	0	0
OR	Lane Electric Co-Op	GS-1C	360	424	424	GS-1C	360	424	0	0	0	0
OR	Springfield Utility Board	GS-1	360	359	359	GS-2	1,800	311	1,440	-48	-48	1,392
OR	Pacific Power	Schedule 23	673	192	192	Schedule 24	3,456	229	2,783	37	37	2,820
OR	Portland General Electric	Schedule 32	192	692	692	Schedule 38 - TOU	300	867	108	175	175	283
OR	Salem Electric	Schedule 3	157	548	548	Schedule 3	157	548	0	0	0	0
PA	PECO	GS	481	589	589	GS	481	589	0	0	0	0
PA	Pennsylvania Electric Company	GS-Small	179	0	0	GS-Small	179	0	0	0	0	0
PA	Met-Ed	GS-Small	258	0	0	GS-Small	258	0	0	0	0	0
PA	Pennsylvania Power & Light (PPL)	GS-2	1,442	651	651	GS-2	3,066	651	1,624	0	0	1,624
PA	West Penn Power	GS - 20	0	613	613	GS - 20	0	798	0	185	185	185
TN	Middle Tennessee Electric	GSA (<=50kW)	199	720	720	GSA (<=50kW)	199	720	0	0	0	0
TN	Duck River Electric Membership Corporation	GSA-1	240	739	739	GSA-1	240	739	0	0	0	0
TN	Harriman Utility Board	GSA (<=50kW)	336	800	800	GSA (<=50kW)	336	800	0	0	0	0

State	Utility	20kW				50kW			SAVINGS			
		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge	Annual Demand Charge + Base Charges	Energy Charges		Total (no offsetting)
				No offsetting	Offsetting charging					No offsetting	Offsetting charging	
TN	Athens Utilities Board	GSA (<=50kW)	383	510	510	GSA (<=50kW)	383	510	0	0	0	0
TN	Cookeville Electric Department	GSA (<=50kW)	240	730	730	GSA (<=50kW)	240	730	0	0	0	0
TN	Cleveland Utilities	GSA (<=50kW)	185	492	492	GSA (<=50kW)	185	492	0	0	0	0
TN	Nashville Electric Service	GSA (<=50kW)	305	766	766	GSA (<=50kW)	305	766	0	0	0	0
TN	EPB Chattanooga	GSA (<=50kW)	119	579	579	GSA (<=50kW)	119	579	0	0	0	0
TN	Lenoir City Utility Board	GSA (<=50kW)	183	725	725	GSA (<=50kW)	183	725	0	0	0	0
TN	Volunteer Electric Co-Op	GSA (<=50kW)	168	566	566	GSA (<=50kW)	168	566	0	0	0	0
TN	Murfreesboro Electric	GSA (<=50kW)	298	714	714	GSA (<=50kW)	298	714	0	0	0	0
TN	Sequatchee Valley Electric Cooperative	GSA (<=50kW)	247	756	756	GSA (<=50kW)	247	756	0	0	0	0
TN	Knoxville Utility Board	GSA (<=50kW)	204	750	750	GSA (<=50kW)	204	750	0	0	0	0
TN	Maryville	GSA (<=50kW)	193	692	692	GSA (<=50kW)	193	692	0	0	0	0
TN	Fort Loudoun Electric Cooperative	GSA (<=50kW)	333	684	684	GSA (<=50kW)	333	684	0	0	0	0
TN	Memphis Light, Gas and Water Division	GSA (<=50kW)	186	521	521	GSA (<=50kW)	186	521	0	0	0	0
TX	Oncor Electricity	Secondary Service	1,398	0	0	Secondary Service (LF=5%)	3,595	0	2,197	0	0	2,197
TX	Austin Energy	Secondary Service ToU	2,360	367	181	Secondary Service ToU	5,360	367	3,000	0	186	3,000
TX	AEP Texas - Central	Secondary Service	1,734	0	0	Secondary Service	3,572	0	1,838	0	0	1,838
TX	AEP Texas - North	Secondary Service	1,971	0	0	Secondary Service	3,830	0	1,859	0	0	1,859
TX	CPS Energy	PL	657	0	0	PL	1,773	0	1,116	0	0	1,116
TX	Entergy Texas, INC	Small General Service	98	396	396	General Service	3,030	138	2,932	-258	-258	2,674
TX	CenterPoint Energy Houston Electric,LLC	Secondary Service	2,818	0	0	Secondary Service	3,308	0	490	0	0	490
TX	Texas-New Mexico Power Company	Secondary Service	1,427	0	0	Secondary Service	3,328	0	1,901	0	0	1,901
VA	Dominion Virginia Power	Small General Service	186	429	429	Intermediate General Service Non-Demand	254	531	68	102	102	170
VA	Appalachian Power (AEP)	Small General Service	123	423	423	General Service ToD	174	714	51	291	291	342

State	Utility	20kW				50kW			SAVINGS			
		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge		Best Schedule	Annual Demand Charge + Base Charges	Annual Energy Charge	Annual Demand Charge + Base Charges	Energy Charges		Total (no offsetting)
				No offsetting	Offsetting charging					No offsetting	Offsetting charging	
VA	Rappahannock Coop	Small General Service	570	532	532	Small General Service	570	532	0	0	0	0
VA	NOVEC	Small Commercial Service	498	786	786	Large Power Service LP-1	4,200	690	3,702	-96	-96	3,606
WA	Clark Public Utilities	First Tier Schedule 34	300	540	540	Second Tier Schedule 134	4,758	323	4,458	-217	-217	4,241
WA	Seattle City Light	Small General Service	102	484	484	Small General Service	102	484	0	0	0	0
WA	Snohomish County Public Utility District	Small Load Schedule 20	117	543	543	Small Load Schedule 20	117	543	0	0	0	0
WA	Puget Sound Energy	General Service Schedule 24	295	525	525	General Service Schedule 24	295	525	0	0	0	0
WI	WE Energies	General Service Secondary	183	885	885	General Service Secondary	183	885	0	0	0	0
WI	Wisconsin Public Service	Small C&I GS - Urban	123	846	846	Small C&I GS - Urban	123	846	0	0	0	0
WI	Xcel Energy	Small General Service	120	747	747	General Service	360	396	240	-351	-351	-111
WI	Alliant Energy	General Service	187	804	804	General Service	187	804	0	0	0	0
WI	MGE	Small C&I L&P Service	104	982	982	C&I L&P Service - ToU	8,522	816	8,418	-166	-166	8,252
WV	Appalachian Power (AEP)	GS-ToD	252	864	864	GS-ToD	252	864	0	0	0	0
WV	MonPower - First Energy	General Service Schedule C	3,502	285	285	General Service Schedule C	8,034	285	4,532	0	0	4,532

Appendix C - GES and DCFC System Calculator

This simulator/calculator provides the user the ability to:

- Select/enter a DCFC demand profile
- Stipulate the attributes of the GES (capacity, charge and discharge rate, and efficiencies)
- Select an electricity demand charge schedule

From this information, the simulator will calculate:

- The time-based State of Charge (SOC) of the GES and the subsequent AC grid demand in relation to the DCFC demand profile.
- The peak AC Demand and lowest SOC of the GES (highlighted in results)
- The limiting factor of the GES (i.e. capacity or discharge rate)

From an easy observation of the results and the plot, the user can determine whether the GES is appropriately sized, what the demand effect on the AC grid is, and what savings are available compared to the cost of the GES.

Results:	Peak AC Demand (kW):	20
	Result Limiting Factor for Peak AC:	Size of GES is the Limiting Factor
	Lowest GES SOC (kWh):	1.45461263

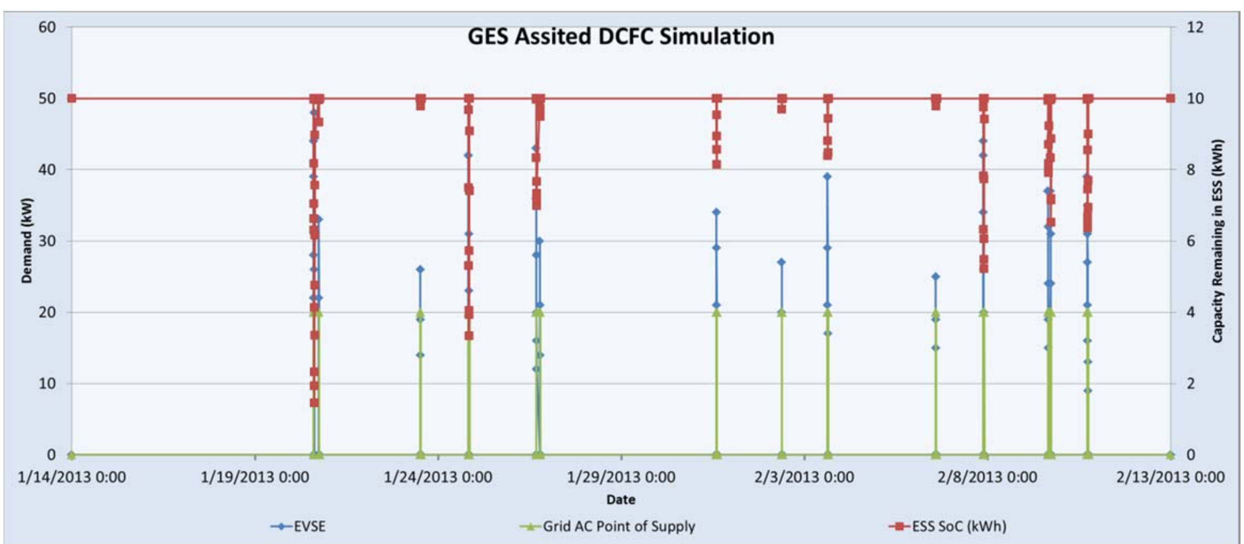

Figure 7 - Example of the outputs from the GES and DCFC simulator