Strategies for integrating high penetration renewables

A report in partial fulfillment of a California Solar Initiative (CSI) Grant requirement

July 25, 2011 (Version 1.0)

Energy+Environmental Economics

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Glossary

Ancillary services	set of services procured by the balancing entity for balancing and power quality maintenance purposes
DG	distributed generation
DER	distributed energy resources at a customer site (e.g., generation, efficiency, storage)
EE	energy efficiency
EMCS/ EMS	energy management control system/ energy management system
Fault (electrical)	short circuit that can occur anywhere in the grid
Load following	process of eliminating supply and demand deviations within the hour that occur on a ~ 5-20 minute timescale
Ramp	requirement to increase or decrease generation to meet sustained changes in demand; measured in MW / minute; early morning and late evening ramps are typical
RE	renewable energy
RPS	renewable portfolio standard (in California, 33% by 2020)
Regulation	ancillary service that is procured by the balancing authority to balance all deviations continuously; provide load following and frequency response

Setpoint	refers to a control system input or goal (e.g., temperature setpoint of an HVAC system)
Spinning reserves	on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 min of a dispatch instruction; needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings
Non-Spinning Reserve	off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions
TES	thermal energy storage
VAR	a measurement of reactive power

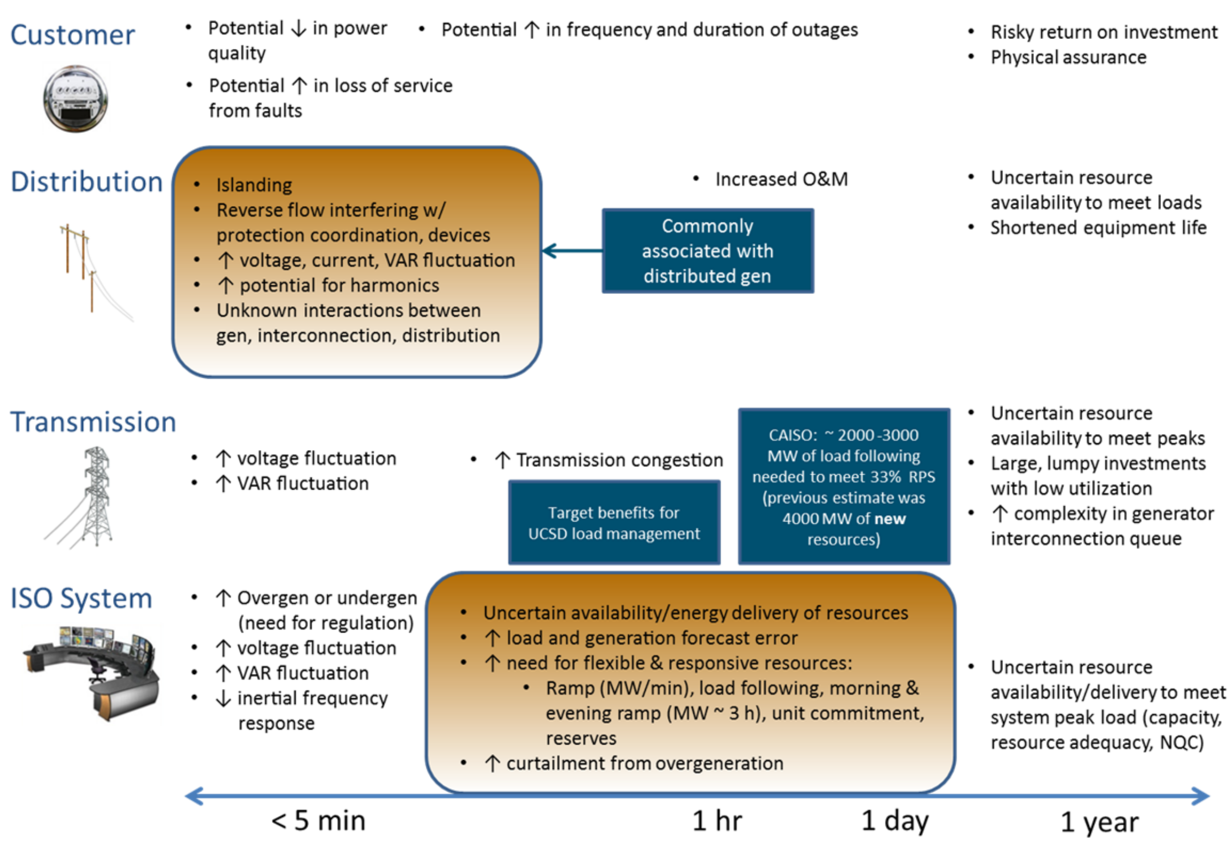
1 Challenges to integrating variable renewables

The development of large scale distributed and centralized renewables introduces new challenges to grid operators, utilities, and consumers. These problems are technical and regulatory in nature and exist across timescales that span operations to longterm planning. Challenges exist across end-use, distribution, transmission and the system (operator) level. These challenges exist because, unlike with conventional generation, renewables such as solar and wind are not dispatchable and we must cite them where the resource is available.

Renewable resources are often far from load centers, which means new transmission is needed; citing new transmission is a planning challenge. The issue of less control and flexibility in generation output affects the operation of the grid. Without variable renewables, grid operators manage generation to adjust to demand. With variable generation resources, the supply and demand matching effort becomes more complex. Finally, renewables may develop both in the form of large scale centralized generation, or as distributed generation. The distribution system is not designed and operated for large quantities of distributed generation. Large scale DG introduces power quality considerations at the distribution level.

Figure 1 lists these potential problems as they may occur at different timescales (from planning to operation) and at different locations on the grid. The list is not intended to be comprehensive but is intended to initiate useful discussion on the different types of problems renewables may introduce so we can later help frame the role that demand-side resources can play in helping to address them.

Figure 1: Potential grid problems from increased renewables



As shown in the figure, the problems can be roughly grouped into distribution level problems (mainly power quality) that are associated with distributed generation and balancing challenges at the balancing authority level that are associated with centralized RE. Recent modeling efforts by the CAISO suggest fewer regulation and load following needs may be needed to integrate 33% renewables, as compared to previous estimates (~ 4000 MW). These numbers will get continually refined; however, against this backdrop of uncertainty, developing multiple tools in the toolkit will only help alleviate potential future problems of renewables integration.

We describe each problem categorized by timescale.

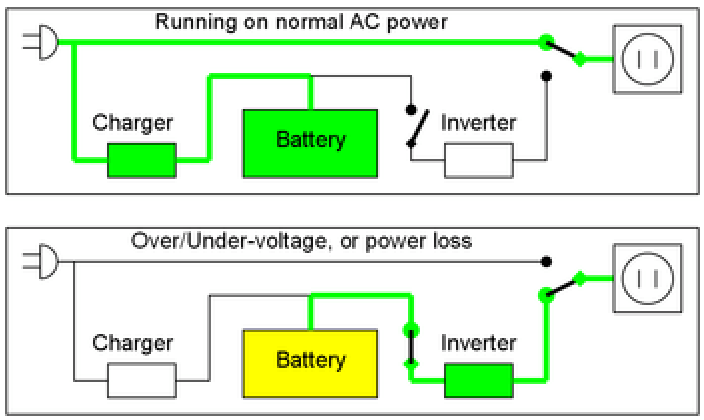
1.1 Real-time operations (less than 5 min)

1.1.1 CUSTOMER-LEVEL PROBLEMS

Broadly, customers may experience problems due to cascading effects of distribution and transmission level problems downstream. The primary concern to customers from increased renewables is reduction in power quality and increase in blackout events.

Potential decrease in power quality: Greater levels of renewable generation can potentially reduce power quality at the customer level. Customers at the end of distribution lines are vulnerable to voltage sags. With high penetration PV and DG, voltage spikes can occur at the point of injection in the feeder, making it more difficult to manage voltage quality on the feeder overall. Poor power quality may impact the performance and reduce the lifetime of electronic devices. Currently, mainly critical facilities (such as data centers) install uninterruptible power supply (UPS) systems.

Figure 2: Standby uninterruptible power supply system



Historically, installation of distributed generation at the customer site has not impacted power quality at the customer site for grid-connected systems because appropriate standards have been developed and adopted for DG interconnection.

Source: Department of Energy, 2010.

Potential increase in faults causing disconnection: If problems at the distribution level increase, such as transformer faults, resulting in an increased potential for outages, customers may be exposed to increasing frequency of service interruptions. Customers' risk to operational problems from increased RE will be depend on the risk of T&D level problems.

1.1.2 DISTRIBUTION-LEVEL PROBLEMS

Unintentional islanding: Islanding is a condition where a part of the electric utility's system is disconnected from the rest of the system and continues to operate. Unintended islanding is a specific case where one or more generating facilities operate a section of the utility's distribution system without utility oversight and control. (Utility operators may do this intentionally with their own generating equipment, for example, to keep one section of the system operating while another is being serviced.) Unintended islanding represents a potential safety hazard to utility personnel working on what they believe to be an isolated section of line. Steps must be taken to ensure the two systems are synchronized when reconnecting the island to the grid to prevent equipment damage and personal injury. Interconnection standards, IEEE standard 1547 and California's Rule 21, are designed, in part, to prevent unintentional islanding. If a behind-the-meter PV installation is not designed to participate in net energy metering (NEM) and export power to the grid, anti-islanding is not as great a safety hazard. In these cases, CPUC Rule 21 defines several methods to ensure a generating facility is non-exporting. These include functions that drop generation based on monitored power flows with the grid as well as certifications that the on-site generation never exceeds on-site load.

Rule 21 and IEEE 1547 specifies that a visible disconnect switch must be installed at every distributed generation facility. The manually-operated isolating switch (or a comparable device mutually agreed upon by the UDC and customer) near the point of interconnection must be capable of being reached quickly and conveniently 24 hours a day by the UDC. Rule 21 specifies that generating facilities with non-islanding inverters totaling one kVA or less are exempt from this requirement.

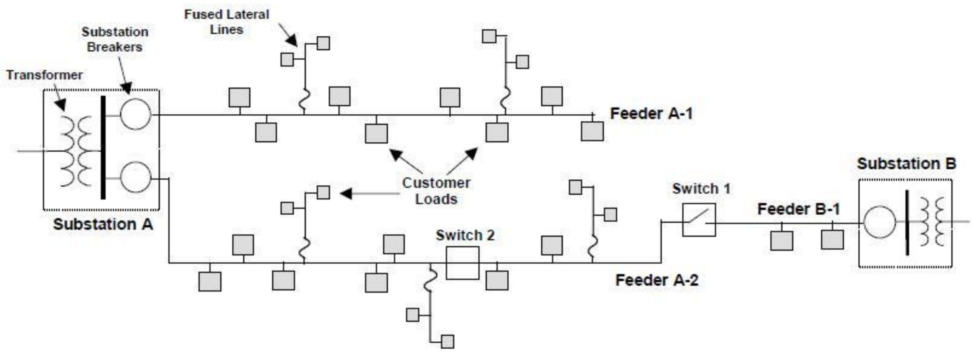
Source: California Energy Commission, 2003. , "California Interconnection Guidebook," 2003, **http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF**

Figure 3: Visible disconnect switch (source: Pasadena Water and Power <http://bit.ly/eskR0D>)

Interference with protection equipment from reverse power flow: Reverse power flow occurs when power generation exceeds power consumption in the distribution system, sending power in the reverse direction through the primary distribution feeders. Protection coordination systems are built into distribution systems to protect equipment and public in the event of electrical faults in a coordinated way that prevents loss of service. Because protection coordination systems were designed assuming one-way flow, distribution generation complicates the procedure.

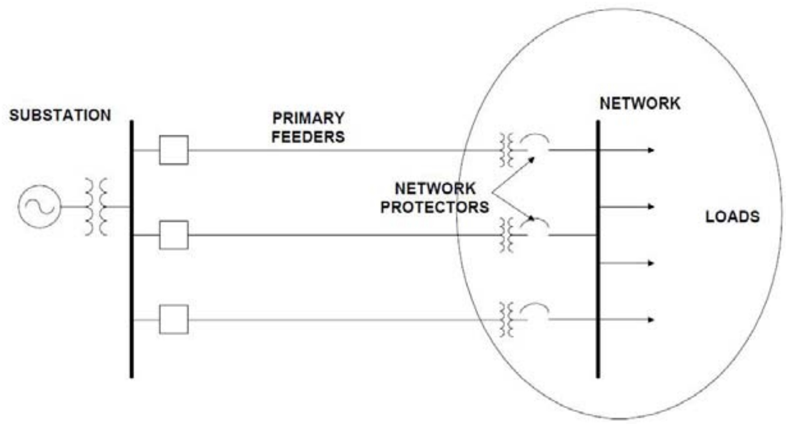
The two main types of distribution configurations in the U.S. are radial and networked configurations. In a radial system (Figure 4), loads are connected to one substation at a time and power flows from the substation to the load centers like spokes on a wheel. Radial systems are designed for one-way power flow.

Figure 4: Radial distribution system



In networked configurations (Figure 5), primary feeders are connected to a network of lower voltage lines (secondary feeders) that are connected to the loads. “Network protectors” are designed into networked distribution systems to prevent reverse power flow from the secondary lines to the primary feeders. These devices open and disconnect the circuit if reverse power flow is detected. If large enough, a distributed generator can have significant impacts on the proper operation of network protectors. For that reason, interconnection guidelines may differ substantially for network applications, and in some cases, distributed generators may be prohibited altogether.

Figure 5: Secondary network distribution system



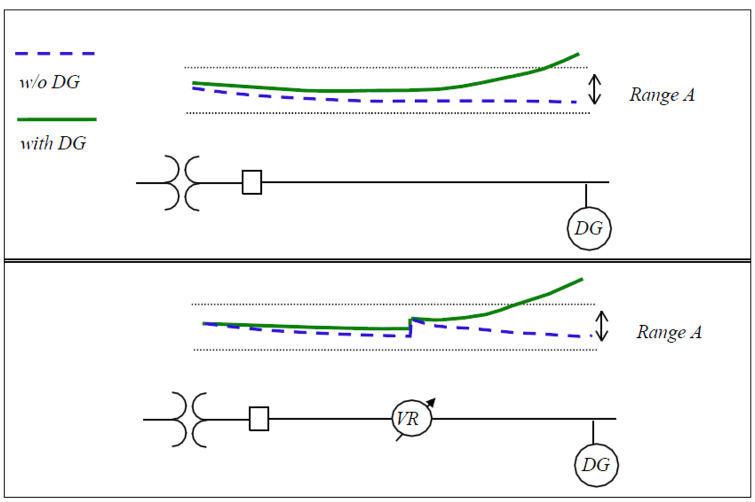
The benefits and problems from distributed generation will differ between network and radial systems. For example, a distributed generator sited within a network system may provide some measure of capacity benefit for the entire (localized) network, whereas the capacity benefits on a radial system is highly dependent on the precise location of the generator. A generator that improves voltage or losses on a radial system may have the opposite impact on a particular network system.

Sources: California Energy Commission and Energy and Environmental Economics, Inc., “Unbundling 2-2: Grid Benefits”; Von Meier, A., 2006 and 2010. “Smart grids and renewables integration: a story of coordination challenges”, 2010; Von Meier, A., “Electric power systems”, 2006.

Increased voltage, current, VAR fluctuation:

High penetrations of renewables at the distribution level — particularly solar PV — may lead to rapid voltage swings on distribution feeders due to rapid and unpredictable cloud events. A utility distribution company (UDC) defines criteria for maintaining voltage throughout the distribution system within prescribed tolerances, and will take measures to prevent very high or low voltages under normal or contingency conditions. Conventional measures used to provide voltage support include the installation of voltage regulators, capacitors, boosters, and in some cases upgraded line segments. Reactive power support has a powerful impact on supporting voltage, as there is a more direct relationship between voltage and reactive power flow than with real power flow. For that reason, capacitors are often preferred over regulators.

Figure 6: System impacts: voltage regulation (Source: Basso, 2009)



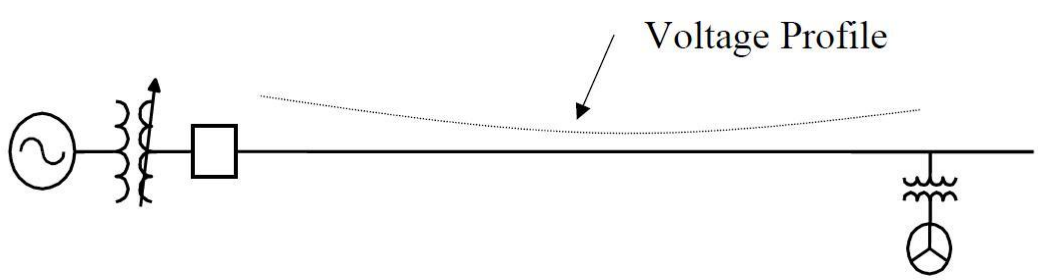
Voltage regulation refers to controlling periodic swings of the voltage on a particular part of the system caused by larger fluctuating loads. UDCs typically install voltage regulators with automatic tap changing mechanisms (these regulate voltage by altering the number of turns in the transformer).

In addition, operating voltage range of the distribution system affects the equipment requirements for DG producers. CPUC Rule 21 in California states that if the nameplate rating of the DG facility is 1 MW or greater, telemetering equipment at the point of interconnection may be required at the DG producer's expense. Rule 21 is applicable to all utilizes under jurisdiction of the CPUC. Several CA municipal utilities have adopted interconnection rules similar to Rule 21.

If the generating facility is interconnected to a portion of the UDC's distribution system operating at a voltage below 10 kV, then telemetering equipment may be required on generating facilities 250 kW or greater.

Distributed generation is often cited as having the potential to provide voltage and VAR regulation. Voltage support can be provided by injecting power into the system at the DG site, thereby reducing the current and corresponding voltage drop from the substation to the area (Figure 7). Solar PV output can provide voltage boosting during high load periods, when solar power is being generated. Solar PV coupled with storage may provide voltage regulation and VAR support benefits.

Figure 7: DG used to improve voltage conditions on a distribution feeder



Sources: California Energy Commission, "Unbundling 2-2: Grid benefits"; California Energy Commission, 2003, "California interconnection guidebook"; Basso, 2009.

Increased potential for harmonics: Harmonic distortion, or distortion of the power sine waves, is an indicator of power quality. Harmonic currents can cause overheating of transformers, which can cause failure of breakers and other devices. Inverters, which are co-located with distributed generation, produce harmonics of the power system frequency. If interconnection standards such as IEEE Standard 1547 (clause 4.3) are followed, then harmonics are not usually a problem. However, it's also possible that even if DG is compliant with IEEE 1547 (or Rule 21), interactions between these loads and the DG system can create harmonics. The potential for problems is case-dependent and is less likely with residential systems, than with commercial or industrial.

Source: Basso, 2009. "System impacts from interconnection of distributed resources: current status and identification of needs for further development". National Renewable Energy Laboratory Report TP-550-44727.

Unknown interactions among, interconnection and distribution equipment: The preceding individual potential problems from distributed generation have been discussed for decades, but what is not known is what the "system" level effects will be from massive penetrations of distributed generation, with these effects all co-mingling. As the number of DG units increase, the system complexity increases in a non-linear fashion in terms of the failure scenarios and hence, the mitigation. This is not a problem in the immediate future because DG is dominated by solar PV, which is not yet cost competitive with wind. However, as solar PV costs decrease, this scenario may change.

1.1.3 TRANSMISSION LEVEL PROBLEMS

Increased voltage and VAR fluctuation: Voltage or reactive power support is used to maintain voltage levels on the transmission system by providing or absorbing reactive power (kVAR). VAR support is currently supplied by generators, synchronous condensers, static VAR compensators, and inductor and capacitor banks. VAR support has been a benefit attributed to storage as well (Electric Power Research Institute, 2010). Increased wind penetration can increase voltage and VAR fluctuation through fluctuation in wind plant output. Depending on the generator type, wind plants can increase VAR support requirements. In California, reactive power is procured through contracts with generators. Simultaneously, as renewables displace conventional generation, the cost to provide VAR support may also increase.

Sources: Electric Power Research Institute, 2010, "Electricity Energy Storage Technology Options. A White Paper Primer on Applications, Costs and Benefits". Report 1020676.

1.1.4 ISO/ SYSTEM LEVEL PROBLEMS

Increased overgeneration or undergeneration: Demand and generation are constantly changing within the ISO's balancing area. Over-generation or under-generation may occur with increased renewables if the ISO is unable to modulate its generation resources rapidly enough to keep up with the fast fluctuations. Overgeneration and undergeneration will be reflected in a quantity called Area Control Error. Overgeneration can cause grid frequency to increase while undergeneration can lower frequency. The Area Control Error (ACE), measured in MW, is an instantaneous measure that reflects the mismatch in meeting a balancing authority's internal obligations of power requirements, along with a small obligation to maintain frequency. ISO performance is graded against NERC control performance standards (CPS and CPS 2). [1]

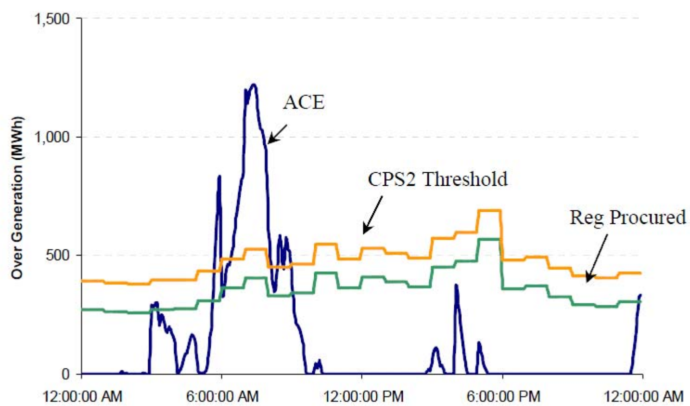
Uncertainty in wind and solar generation may lead to a shortage of regulation and load-following capability, which may result in over-generation or under-generation. Under

[1] Refer to NERC standards document.

extreme cases, the lack of regulation and load-following down capability might require curtailment of generation to resolve the problem as a solution to avoid over-generation or under-generation, which creates challenges for renewable energy producers.

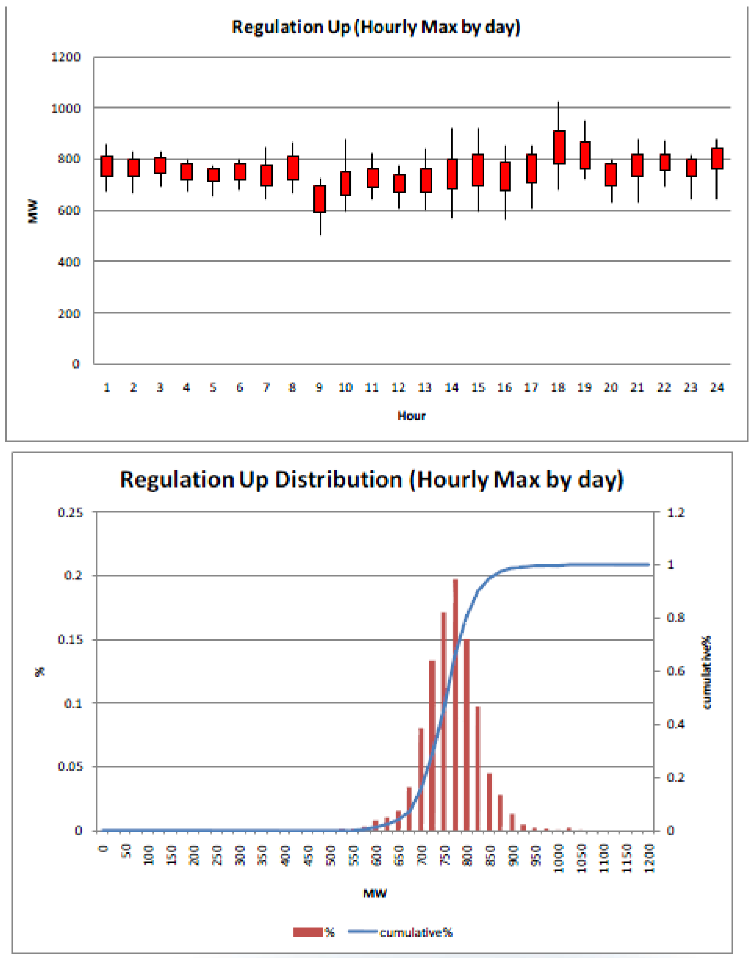
The CAISO 20% integration study simulates a condition, shown in Figure 8, for which thermal resources were fully dispatchable but all other resources followed fixed schedules. The load-following down capability is near zero in early morning hours, resulting in overgeneration and a CPS 2 violation.

Figure 8: Detailed overgeneration analysis of May 28, 2012 (Source: CAISO, 2010)



According to the recently released CAISO study of 33% renewables integration, roughly 600-900 MW of regulation up and down services will be needed in 2020 under a 33% RPS. The CAISO has not specified how much of this quantity is related to increased penetration of renewables; however, for context, today's regulation requirements are approximately 500 MW. The recent projections of regulation needs are less than previously projected in the 20% report (CAISO, 2020), which estimated roughly 1000-1300 MW of regulation needs in 2020.

Figure 9: Regulation needs for meeting California's 33% RPS (Source: CAISO, 2011)



Source: California Independent System Operator, 2010. "Integration of renewable resources. Operational requirements and generation fleet capability at 20% RPS"; California Independent System Operator, 2011. "Summary of preliminary results of 33% renewable integration study – 2010 CPUC LTPP Docket No. R.10-05-006.

Increased voltage fluctuation: As discussed in the previous section, increased wind can result in increased voltage fluctuations and increased reactive power (VAR) support requirements. This directly impacts CAISO procurement; currently CAISO procures VAR support through bilateral contracts.

Decreased inertial frequency response: Inertial frequency response is inherent in the system due to rotating characteristic of typical load (motor, pumps etc.) and conventional generation (synchronous generators). Inertial frequency response provides counter response within seconds to arrest the frequency deviation. System inertia can be defined as the total amount of kinetic energy stored in all spinning turbines and rotors in the system. Constant speed wind turbines contribute to system inertia but variable speed drive wind turbines control grid power independently and decouple generator torque from grid frequency (Abreu, 2006). Solar PV, does not provide system inertia, so increased solar PV will act, also, to decrease system inertia.

1.2 Hourly to daily considerations

1.2.1 CUSTOMER-LEVEL PROBLEMS

Potential increase in frequency/duration of loss of service: Customers may experience a greater number of loss of service events and of longer duration from problems occurring at the distribution or transmission level. Problems at the distribution level will be more localized, while transmission-level induced events will be spread over larger geographical distances.

Loss of service is the worst possible event from both the balancing authority and utility perspectives. Customers are more likely to see loads curtailed in effort to maintain stable conditions before experiencing accidental loss of service events.

1.2.2 DISTRIBUTION-LEVEL PROBLEMS

Increased operations and maintenance (~ 1 hr – 1 day): High penetration solar PV on the distribution system increases complexity in protection coordination systems, because these systems must be designed to accommodate two-way power flow. More complex protection coordination routines may require more maintenance and reliability testing, increasing O&M. Distribution –system smart grid applications, such as outage management systems and substation fault detection and diagnostic systems may help mitigate increasing O&M requirements.

1.2.3 TRANSMISSION LEVEL PROBLEMS

Increased transmission congestion (~ 20 min – 1 hr): Transmission congestion occurs when the physical capacity of the transmission infrastructure prevents electricity transactions from occurring. When transmission congestion occurs, locational marginal prices at the point of generation and point of delivery diverge. Adding new non-dispatchable generation upstream of a transmission constraint can be expected to increase congestion. Large scale renewables are frequently, though not always, located remotely from load in transmission-constrained areas.

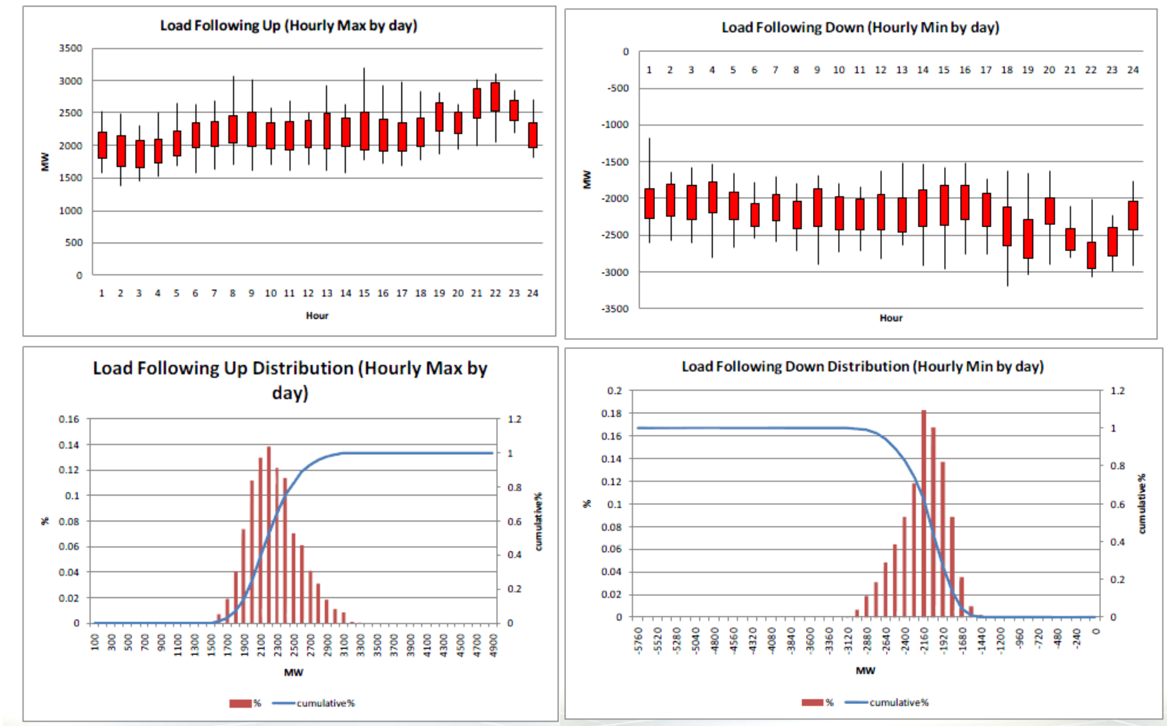
1.2.4 ISO/ SYSTEM LEVEL PROBLEMS

Uncertain availability/ energy delivery of resources: This is a commonly cited problem associated with non-dispatchable renewable energy. There is a less than 100% likelihood of knowing the output availability from renewable resources (true for conventional generators as well, but to a much lesser extent). The lack of a scheduling requirement of renewables complicates operations and increases reserve requirements.

Increased load and generation forecast error: Both increased wind and solar generation increase the load/generation forecast error. Error is greater for more advanced forecasts (e.g., 1 day error is greater than 5-min error). The CAISO (2010) report simulates effects of forecast error in detail. Both variability in wind/solar production and error in forecast increase both load following and regulation requirements substantially, which we discuss elsewhere.

Increased need for flexible and responsive resources: More renewables will almost certainly increase the need for flexible and responsive resources to provide ramp (MW/min over ~2/3 hours), load following (balancing within the hour), contingency reserves and regulation. Per CAISO (2010), variability in wind and solar generation impacts the regulation and load-following *requirements*, while uncertainty in output (due to forecast error) impacts the regulation and load-following *capability*. Uncertainty in generation may result in inadequate regulation and load-following capability committed to daily operations. The CAISO estimates roughly 2000-3000 MW of load following capability will be required to meet the 33% RPS (Figure 10) (CAISO, 2011), which includes roughly 1000 MW of new capacity. This is a reduction in the total load following capability reported in the 20% integration report (CAISO, 2010), which estimates ~ 4000-5200 MW load following needs in 2020. More load following can result in more fossil units (e.g., combustion turbines) operating at less efficient heat rates (increasing pollution).

Figure 10: Load following needs for meeting 33% RPS (Source: CAISO, 2011)



Source: California Independent System Operator, 2011. "Summary of preliminary results of 33% renewable integration study – 2010 CPUC LTPP Docket No. R.10-05-006.

Increased curtailment from overgeneration: In California, the wind tends to blow at night when demand is lowest. In order to balance supply and demand, the output from dispatchable generators must be reduced. Some generators, such as nuclear and coal do not lend themselves to output reductions. If not enough flexible generation is available to reduce its output, wind energy may have to be curtailed. This can have adverse consequences for both renewable energy producers, which may lose revenue due to reduced sales, and utilities, which may not be able to comply with RPS requirements.

1.3 Daily to long-term planning considerations

1.3.1 CUSTOMER-LEVEL PROBLEMS

Risky return on investment: Customers who invest in renewable energy may face uncertain returns due to uncertainty in incentives, and/or uncertainty in technology performance. This problem exists, also, for developers of renewable energy where research has shown decreased investment due to uncertainty of tax credits.

Physical assurance: Distributed PV is currently limited in the capacity benefit that it can provide to utilities. In 2003, CPUC Decision 03-02-068 set criteria that distributed generation must meet to allow a utility to defer capacity additions and avoid future costs from DG. DG facilities must meet these criteria to qualify for capacity payments.

- Distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth
- The unit must be installed and operational in time for the utility to avoid or delay expansion or modification
- DG must provide appropriate “physical assurance” to ensure a real load reduction on the facilities where expansion is deferred

Decision 03-02-068 further defined “physical assurance” as *“the application of devices and equipment that interrupts a distributed generation customer's normal load when distributed generation does not perform as contracted. An equal amount of customer load to the distributed generation capacity would be interrupted to prevent adverse consequences to the distribution system and to other customers.”*

The physical assurance provision means that in order to get capacity value for a DG facility, the DG facility must be able to drop load equivalent to the capacity of the generator. DG owners must therefore also be able to provide demand response to receive capacity payments.

Source: California Public Utility Commission, Decision 03-02-068, 2003

1.3.2 DISTRIBUTION-LEVEL PROBLEMS

Shortened equipment life: The distribution level real-time operational problems may result in increased wear and tear of components, accelerating replacement schedules of regulators, tap changes, and protective devices, as well as requiring new capacity of distribution lines and/or components.

Conversely, one of the cited benefits of DERs is reduced need for voltage and VAR regulators. So, if DERs (storage, inverters) are used to provide greater voltage/VAR control, it's possible that the costs for distribution components could decrease.

Uncertain resource availability/delivery to meet feeder/substation peak loads: In theory, greater DG may reduce the capacity requirements of distribution feeders and substation components, especially for solar PV, as solar generation roughly occurs over peak load conditions (with some lead). It is possible that a distribution system could be undersized for real conditions if peak load is higher than expected, and solar PV output is lower than expected. This scenario is less likely because of physical assurance rules and loads correlate well with solar output (high load when there is high solar incidence). Also, distribution planning tends to conservatively size systems.

1.3.3 TRANSMISSION LEVEL PROBLEMS

Increasing renewables can result in the following Transmission planning scale challenges.

- Uncertain availability/energy delivery & resource availability/ delivery to meet coincident peak load. Uncertainty in renewables generation increases the uncertainty of available resources for meeting peak demand. This is mitigated, somewhat, by ensuring there are dedicated resources that can meet the reserve margin requirements.
- Large & lumpy investments with low (initial) utilization. This makes cost allocation/cost recovery for large investments more risky. Risk of low utilization lines is greater with renewables being located in remote areas and if they are not collated with generation that can utilize the lines at other times.
- Increased complexity in generator interconnection queue. Planning becomes harder as it is not clear exactly when these resources will come online.

1.3.4 ISO/ SYSTEM LEVEL PROBLEMS

Uncertain resource availability/delivery to meet system peak demand: With more renewables in operation, the uncertainty of having adequate resources for meeting peak demand increases. This is mitigated through both unit commitment (need to start up fossil units to remain prepared to meet loads if renewables generation suddenly drops) and through net qualifying capacity (NQC), a measure of how much system capacity renewable generation can be counted on to provide during peak hours versus how much must be procured from other dispatchable resources.

2 Market-supported technical solutions

2.1 Existing solutions

This project will explore how load participation in the wholesale markets can help integrate large amounts of renewables into the grid. We describe the services that load can provide to help integrate RE and the existing markets that value that service.

There will be a significant increase in the requirement for flexible and responsive resources, in particular for the CAISO to provide ramp and intra-hourly load balancing. The CAISO has estimated ~ 2000-3000 MW of load following resources will be needed to support the integration of renewables. We focus much of these solutions around the 5 min – 20 min timescale.

Broadly speaking, distributed resources can provide the following services.

- Demand response (e.g., control of building systems, HVAC, lighting, processes)
- Permanent load shifting (e.g., thermal storage, batteries, process shifting)
- Responsive load / load following (not typically provided by DERs, though it is technically feasible)
- Distribution level volt/VAR control (e.g., storage, advanced inverters)

2.1.1 DEMAND RESPONSE

Loads can provide peak load management through demand response. DR can be provided by reducing (or increasing) end-use consumption and adjusting onsite generation. UCSD is equipped with many distributed resources to provide DR.

2.1.1.1 CAISO proxy demand response

Customers can participate in the CAISO Proxy Demand Resource (PDR) program. In the PDR program, end-use customers can participate in the CAISO markets (day-ahead market, real-time market, residual unit commitment market, or non-spinning reserve markets) through an aggregator A DR event is triggered by CAISO dispatch. Loads must be able to measure and verify their demand reductions.

The CPUC has limited participation to IOU's for now. Each IOU has 1 DR program bidding into CAISO PDR in 2011.

2.1.1.2 Resource adequacy and CAISO reliability demand response program

Currently, DR resources cannot receive resource adequacy payments directly through participation in the CAISO markets. The CAISO is currently developing the rules for demand response to qualify for resource adequacy payments.

2.1.1.3 CAISO reliability demand response program

The reliability demand response program will be developed in 2011 and implemented in 2012 and is aimed to integrate existing retail *emergency-triggered demand response programs* into the CAISO markets and to receive resource adequacy payment. RDRP development is an outgrowth of a settlement agreement before the CPUC to reach agreement on future megawatt quantity limitations of emergency-triggered demand response programs that count as resource adequacy capacity. The RDRP will enable large commercial and industrial customer interruptible load programs, small commercial and residential customer air-conditioning cycling programs, and agricultural pumping load curtailments.

2.1.1.4 Utility programs

There are many demand response programs offered by the utilities that fall under time-varying rates or interruptible programs (e.g., PG&E's Base Interruptible Program). Time-varying rates include time-of-use (TOU), critical peak pricing (CPP) and real-time pricing and incent customers to move loads to off-peak conditions through a price signal. Interruptible programs provide a regular monthly capacity payment ($/kW) and an energy payment ($/kWh) when an event is called. Interruptible programs are typically for large direct access or bundled customers with high loads.

2.1.1.5 CAISO participating load pilot program

The participating load pilot program curtails demand from participants based on direction from the CAISO in real-time dispatch. Currently, this program is used mainly to reduce load from pumps managed by the California Department of Water Resources (~3000 MW). This program may be expanded to consider additional participation.

2.1.1.6 Open automated demand response

Open automate demand response (Open ADR) is a communications protocol that facilitates the automation of the event signal and response at the end-use. The purpose of Open ADR is to provide a pathway to facilitate DR automation that is not restricted by propriety communications protocols and hardware. Currently, Lawrence Berkeley National Laboratory (LBNL) is managing the Open ADR pilots, which are focused on event based DR. Open ADR has been adopted by the California IOUs. Past implementations have focused on commercial buildings (e.g., IKEA).

LBNL with PG&E is currently pursuing an Open ADR pilot to explore the use of Open ADR to integrate renewables through direct participation in the CAISO markets.

2.1.2 RESPONSIVE LOAD (LOAD FOLLOWING)

2.1.2.1 CAISO Proxy demand response

The CAISO proxy demand response allows customer end use loads, through an aggregator or Demand Response Provider, to participate in the CAISO markets by bidding their demand responsive loads into the day-ahead market, residual unit commitment (RUC), real-time energy, and non-spinning reserves ancillary services market. PDR is the main pathway to provide load following services.

2.1.2.2 Open ADR

LBNL with PG&E is currently testing the ability of Open ADR to provide load following and regulation benefits through a series of demonstration projects through 2011. As of April 2011, the buildings have been selected and will give up control at night for a short duration.

2.1.3 FAST RESPONSE (REGULATION AND VOLT/VAR CONTROL)

Regulation: There are many distributed technologies that can respond on a less than 5 minute time scale to reduce or increase loads and are technically capable of providing regulation services. Building HVAC systems, lighting, computer facilities, batteries, with the right set of equipment level controls, could all be programmed to respond on a fast response basis to provide regulation.

Currently, there is no market for load-based regulation. The CAISO stakeholder process for Regulation Energy Management is currently active and slated for introduction in September 2011.

Volt/VAR control: There will be a need for increased volt/VAR control with increased renewables. Currently, there is no wholesale market for VAR support at the CAISO. Rather, VAR support for the transmission system is procured through bilateral contracts with generators.

2.1.4 PERMANENT LOAD SHIFTING

The utilities have engaged in pilot studies of permanent load shifting (PLS) and recently submitted proposals of PLS program expansion to the CPUC. Unlike DR, PLS shifts load from peak to off-peak on a regular basis. The consumer incentive has typically been a combination of capital cost incentives, performance incentives, and rates.

PLS technologies span three broad categories: thermal storage, electrical storage/ mechanical storage and process shifting. Among these systems, chilled water and ice systems represent majority of existing installations, while batteries and some forms of process shifting are newer. Process shifting technologies are probably the least explored, such as shifting pumping energy, charging pallet jack lifts at night, and shifting computing load (via cloud computing or other means).

PLS systems can be used to provide both capacity benefits and responsive load services, much like systems that can provide DR. A key technical difference between PLS systems and traditional DR resources is that PLS systems physically have more storage capacity, whether it is in terms of thermal storage capacity or electricity storage capacity. It is technically feasible to vary the rates at which these systems can be discharged and charged, thus providing responsive load. As a result, these systems have flexibility— in theory — to provide services without altering the level of service.

2.2 Potential solutions

2.2.1 DEMAND RESPONSE

2.2.1.1 Reducing distribution feeder peak load

Distributed energy resources (DER) can help maximize generation and minimize peak loads through the feeder (via DG, storage, inverters). These resources can be managed to maximize generation and minimize loads during local substation/feeder peak events.

Distribution peak load reductions could be measured at the distribution level (e.g., substation) to prove aggregative load reductions and verification of end-use demand response. This provides redundancy to the consumer-level measurements and greater visibility of load reductions to the utility.

There is a high level of interest among utilities and active ARRA pilots.

2.2.1.2 Enhanced utility DR programs

Current utility DR programs include interruptible rates that include air conditioning control and cycling programs. These programs could be enhanced. As the smart grid advances and electronic equipment become equipped with interoperable and communicating controls, these devices could be controlled in real-time – for example by a 3rd-party entity or utility – to provide both capacity and load following benefits. The GridWise pilot program in the Pacific northwest went beyond air conditioner cycling and control and tested control of other home appliances.

Information and behavior based energy efficiency and demand response may offer new technology pathways for enhanced utility programs. OPOWER, Google's PowerMeter and ENERGY STAR'S Portfolio Manager promote energy savings by benchmarking consumers' energy consumption and displaying this result in compelling ways. It is conceivable that these types of information programs could be coupled with smart meters to facilitate DR events based on real-time conditions. An example message may be, "If your dorm reduces its load by 20% now for 1 hour, then you will help California to meet its 33% RPS goal without adding 0.05 tons of CO2 into the air."

2.2.1.3 Direct capacity payment

Currently, participating loads do not receive a direct capacity payment. In other jurisdictions, such as PJM, energy efficiency and demand response can bid into the forward capacity market. If California implements a forward capacity market, participating loads could directly receive capacity payments.

2.2.1.4 Voltage support for addressing sag & conservation voltage reduction

Voltage sag is of greatest concern during peak load hours and hot afternoons. DERs, such as batteries, DG, can provide voltage support during these times.

Conservation voltage reduction (CVR) /optimized voltage control is a process in which the voltage in the distribution system is reduced in a way that does not compromise voltage supply to the last customer. Metering at the end-use can facilitate real-time optimized CVR. This technique will serve to reduce overall stress to the distribution system and can also reduce real power consumption at the end use.

2.2.2 RESPONSIVE LOAD

2.2.2.1 Open ADR

The PG&E's "Participating Load Pilot" program, collaboration with LBNL and PG&E, showed that commercial and industrial DR resources could bid into the CAISO day-ahead market for non-spinning reserves. The PLP model submits a price sensitive demand curve in the day-ahead market and a pseudo-generator supply curve representing the DR resource's real-time dispatch capability (Kiliccote, 2010).

LBNL and PG&E are further exploring the use of Open ADR to enable load participation in the markets for integrating renewables. They will be testing routines in buildings that could potentially provide both regulation and non-spinning reserves (Kiliccote, 2010).

2.2.2.2 Load following and ramp

The same resources that provide DR and PLS could be used, in theory, to provide load following and ramp. These resources include building level HVAC systems, lighting, distributed generation, battery storage (including electric vehicles), thermal storage, and process shifting. The types of control adjustment can vary from a start/stop to increase/ decrease in service, with the response time ranging from instantaneous to 5-20 minute timescale.

As an example, the charge duration and rate of batteries and thermal storage systems could be adjusted to fulfill increased morning ramp requirements in the future. A challenge to implementing variable charging/ discharging is that this is counter to standard operational practice. For example, thermal storage systems are currently charged at night well before the building "wakes" up and in regular, repeatable patterns. For loads to provide load following and ramp capabilities, building-level practices need to be flexible.

2.2.3 FAST RESPONSE

2.2.3.1 CAISO regulation energy management

The CAISO stakeholder process for Regulation Energy Management is currently active. Load participation in the markets is currently limited to PDR. This product is slated for introduction in September 2011.

A strategy could be to participate in a pilot of the CAISO regulation energy management or in response to a simulated signal.

2.2.3.2 DG distribution system protection and support, Volt/VAR support

Volt/VAR support could be provided to local distribution systems on an automated basis or through utility control. In the automated scenario, fast response DERs automatically respond to system frequency and voltage. In the utility controlled scenario, the utility would send a control signal to the DERs. The equipment that could provide volt/VAR support includes storage, smart inverters and distributed generation.

2.2.3.3 Concentrated DG distribution system protection & support

Fast response advanced inverters could be used to provide local distribution system support tailored to integrating high penetration of distributed generation (and EV charging). Distribution equipment could be protected from reverse flow, over/under voltage etc. There is a high level of interest among utilities and there are active ARRA pilots looking into this issue.

2.2.4 COMMUNITY BASED DISTRIBUTED ENERGY RESOURCES

Community distributed energy resources could be used to demonstrate potential for community based storage, distributed generation and EV charging in residential and commercial setting. The resources could be community located rather than behind-the-meter. Such a program could be managed by utility or third-party.

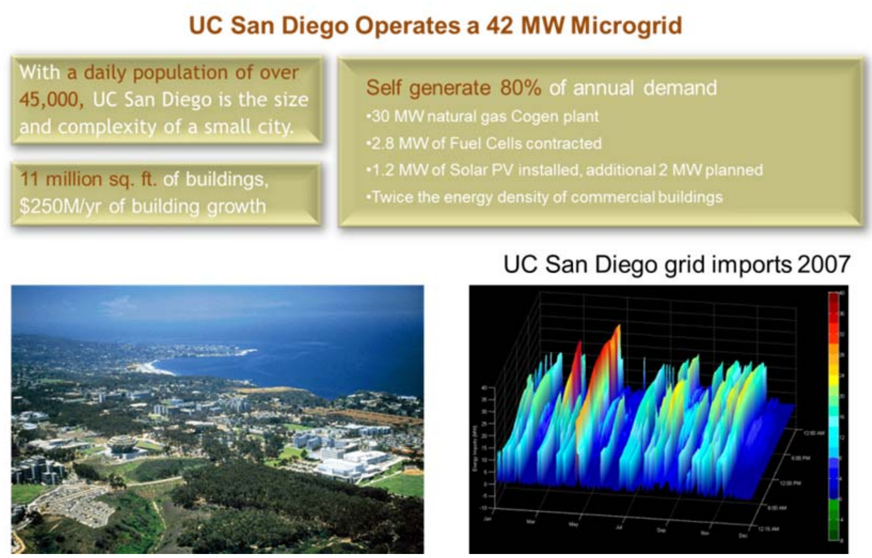
There is some utility interest for this concept and it is being discussed among utility and policy circles, but communication, ownership and payment structures must be further developed.

3 UCSD Viridity project

3.1 Description of UCSD system

UCSD operates a 42 MW microgrid that provides 80% of its annual demand. It is a direct access customer with a daily population of ~ 45,000.

Figure 11: Description of UC San Diego microgrid



The UCSD microgrid includes the following resources:

- 30 MW from two natural gas turbines (3rd being considered)

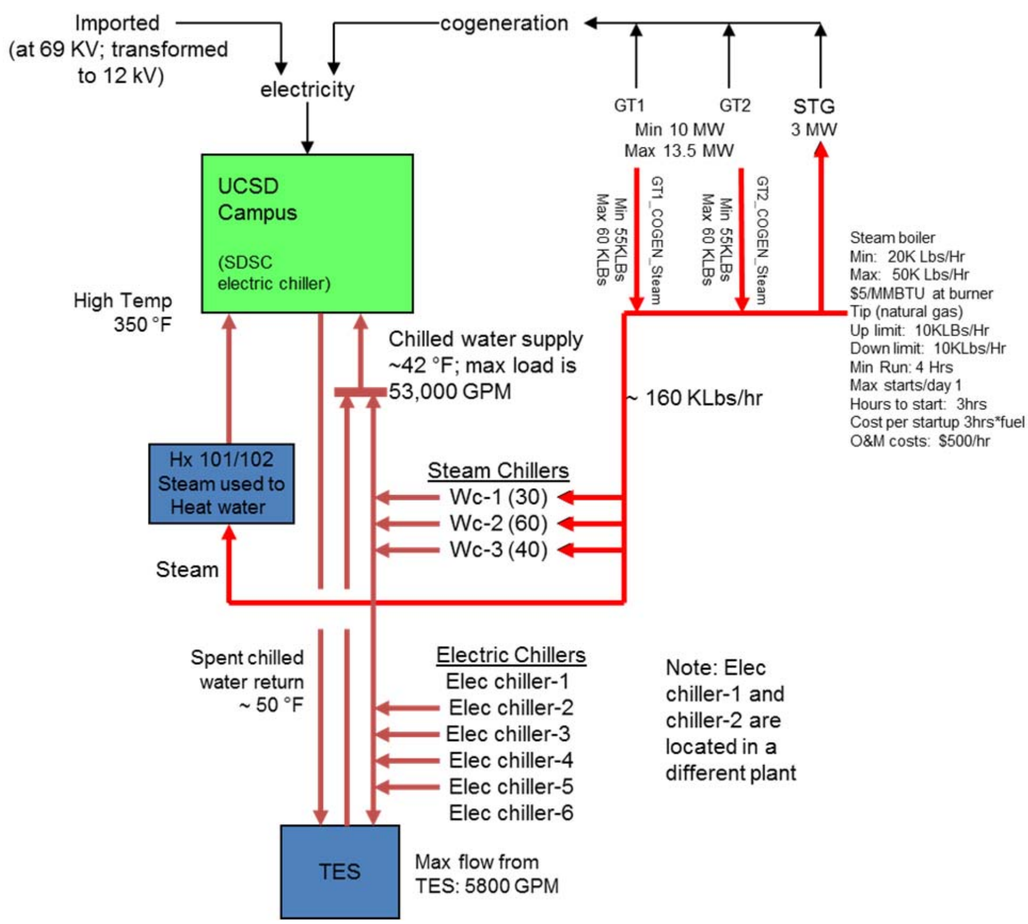
+ 32 MW total of diesel generators (backup); operating limit of 1.5 hours/month
+ 2.8 MW of fuel cells
+ 3.9 million gallon chilled water tank
+ 6 4500 ton electric chillers
+ 3 2400 ton steam chillers
+ Heat exchanger for converting waste steam into hot water
+ Auxiliary boilers (for meeting additional heating needs)
+ 900 kW of PV off-campus on net-meter basis
+ 8 MW of storage (potentially)
+ Electric vehicles and charging stations (future)
+ 11 million sq ft of buildings (growing yearly)
+ Power Analytics controller, Paladin
+ OSI monitoring system (PI software; in development)
+ 60,000 monitored power measurements through the ION system
+ Building and central plant level controls systems

The central plant is operated 24x7 year round. The natural gas generators are at the core of the microgrid operations. UCSD operates the generators to follow load, rather than to export power. The generators are not turned off unless negative electricity prices are observed. The waste steam from the generators is used to meet the campus' heating needs and part of the campus's cooling load by fueling steam chillers. Auxiliary boilers and electric chillers in combination with a thermal storage tank (TES) are used to meet the remaining heating and cooling needs, respectively. The steam chillers are operated as "baseload" units with the electric chillers and TES tank providing for the remaining campus cooling load.

The TES has the capacity to provide for a fraction (roughly 10-20%) of the campus' cooling needs and is operated between the peak period of 11am to 6pm. The thermal storage tank is charged from midnight to 6 am, on a daily basis, using the electric chillers if the nighttime campus cooling needs are met by the steam chillers. The TES charge timing is determined manually.

Figure 12 describes the central plant steam and electricity configuration.

Figure 12: UCSD central plant steam and electricity configuration



The campus participates in the SDG&E Capacity Bidding Demand Response Program. During an event, the campus control systems are used to move the zones into unoccupied status, which raises the temperature setpoints from 72 °F to 76 °F. Notices are also sent campus wide to encourage efficiency and conservation. UCSD can achieve a ~ 10 MW drop in load through demand response actions.

3.2 VPower summer 2011 demonstration

With this project, Viridity's VPower system will be integrated into the UCSD's microgrid control system. VPower will receive information from the existing UCSD monitoring and control systems (namely the Power Analytics Paladin system) and compute optimal schedules for the monitored resources, which will include a mix of resource types across the campus. The summer of 2011 will be the first joint implementation of VPower and Paladin on the UCSD campus. In this early implementation and testing phase, VPower will not itself implement the dispatch recommended by the optimization engine. The recommended dispatch will be presented to the system operators for implementation at their discretion. This is done to allow UCSD operators to test and become familiar with the new systems before allowing automated control. Strategies implemented in the summer of 2011 will therefore focus on those with a 5-30 min response timeframe.

In the summer of 2011, testing will be performed primarily, if not entirely, in the Paladin simulation environment. The Paladin master controller uses a detailed model of the UCSD campus microgrid, which is continuously validated with the extensive network of installed meters and sensors. That model is made available in a simulation environment, where the dispatch strategies developed with VPower can be tested. This provides an accurate, flexible and safe environment for testing dispatch strategies prior to physical implementation. The most promising strategies tested in simulation mode in the summer of 2011 will be refined and developed for actual implementation in subsequent months as operators gain comfort and familiarity with the VPower and Paladin systems.

The strategies selected for evaluation will be implemented in three steps. First, the project team will identify the specific campus resources that can be dispatched with each strategy. The design operating parameters for each strategy will input into VPower. Second, VPower will develop an optimal dispatch strategy and iterate the dispatch with Paladin until a feasible dispatch is identified. Finally, the cost and impacts of the strategy will be quantified and measured against a baseline scenario without the strategy.

To date, the following resources have been modeled in VPower:

- Gas turbines and diesel generators
- Electric and steam chillers
- EV charging stations
- Fuel cells
- Thermal storage tank
- Solar PV and batteries integrated with solar PV
- Buildings modeled as interruptible load

The summer implementation goals will focus on the resource connection and modeling in VPower, developing baseline information for these systems, and simulating the effect of control changes using the “simulation” mode of VPower. This module will allow the team to evaluate the hypothetical benefits from a variety of changes to how the resources are managed.

The project will target many of the existing solution and possible solution categories and identify the value proposition of these broad load response strategies:

- Demand response
- Permanent load shifting
- Enhanced demand response triggered by local (feeder) conditions, rather than system conditions
- Load following, morning and evening ramp
- Local distribution system protection and support

We will evaluate a range of technical strategies that could provide load balancing and demand response services. These strategies may include:

- Variations in charging and discharging rates and schedules of storage (EVs, thermal)
- Schedule changes in generator and fuel cell operation
- Demand response of buildings and temperature reset strategies for chillers

For each resource that is modeled in VPower, the availability of that resource, ramp rates and other key operational parameters and constraints are defined. The figure below is a screen shot from VPower where the availability of a generator — in this case a natural gas turbine — is defined.

Figure 13: VPower generator resource availability definition


http://viridity.ucsd.edu/vpower/resource/logical-fueled-generator/forecast-list?resourceId=27

Optimization Inputs - Logical Fueled Generator

Select Logical Fueled Generator: GT1_COGEN_Electric

07-15-2011

Period Ending	Fixed Mode	Fixed Generation MW	Min Generation Capacity	Max Generation Capacity	Availability
01:00	0	0.00	0.00	13.50	1.0
02:00	0	0.00	0.00	13.50	1.0
03:00	0	0.00	0.00	13.50	1.0
04:00	0	0.00	0.00	13.50	1.0
05:00	0	0.00	0.00	13.50	1.0
06:00	0	0.00	0.00	13.50	1.0
07:00	0	0.00	0.00	13.50	1.0
08:00	0	0.00	0.00	13.50	1.0
09:00	0	0.00	0.00	13.50	1.0
10:00	0	0.00	0.00	13.50	1.0
11:00	0	0.00	0.00	13.50	1.0
12:00	0	0.00	0.00	13.50	1.0
13:00	0	0.00	0.00	13.50	1.0
14:00	0	0.00	0.00	13.50	1.0
15:00	0	0.00	0.00	13.50	1.0
16:00	0	0.00	0.00	13.50	1.0
17:00	0	0.00	0.00	13.50	1.0
18:00	0	0.00	0.00	13.50	1.0
19:00	0	0.00	0.00	13.50	1.0
20:00	0	0.00	0.00	13.50	1.0
21:00	0	0.00	0.00	13.50	1.0
22:00	0	0.00	0.00	13.50	1.0
23:00	0	0.00	0.00	13.50	1.0
00:00	0	0.00	0.00	13.50	1.0

Besides identifying benefits from controlling *existing* resources, we will also identify the value proposition that may be available from larger magnitude load responses that may be physically possible through additional *new DERs.* That is, the analysis will determine the *value* of various load response profiles, setting the cost-effective ceiling for additional technology investment.

3.3 Cost-effectiveness Analysis

We will evaluate the value proposition to UCSD of implementing identified strategies, using existing incentive and rate structures, as well as hypothetical rate and incentive structures that may be supported in the future. (See the companion paper that discusses rates and tariffs for more details.) The cost-effectiveness approach, which evaluates the net benefits, will be the anchor tenant analysis of the value proposition.

These strategies will also be evaluated for their potential benefits at the utility and societal level using a cost-effectiveness approach. UCSD is a direct access customer receiving transmission level service from SDG&E. However, to make the study more broadly relevant, we will also model UCSD energy costs based both utility retail rates and wholesale energy prices. Under each scenario, the benefits to society (Total Resource Cost - TRC), the utility (Utility Cost Test/Program Administrator Cost Test - PAC), the customer (Participant Cost Test - PCT) and non-participating ratepayers (Ratepayer Impact Measure - RIM) will be calculated.

Figure 14: Cost-effectiveness Evaluation

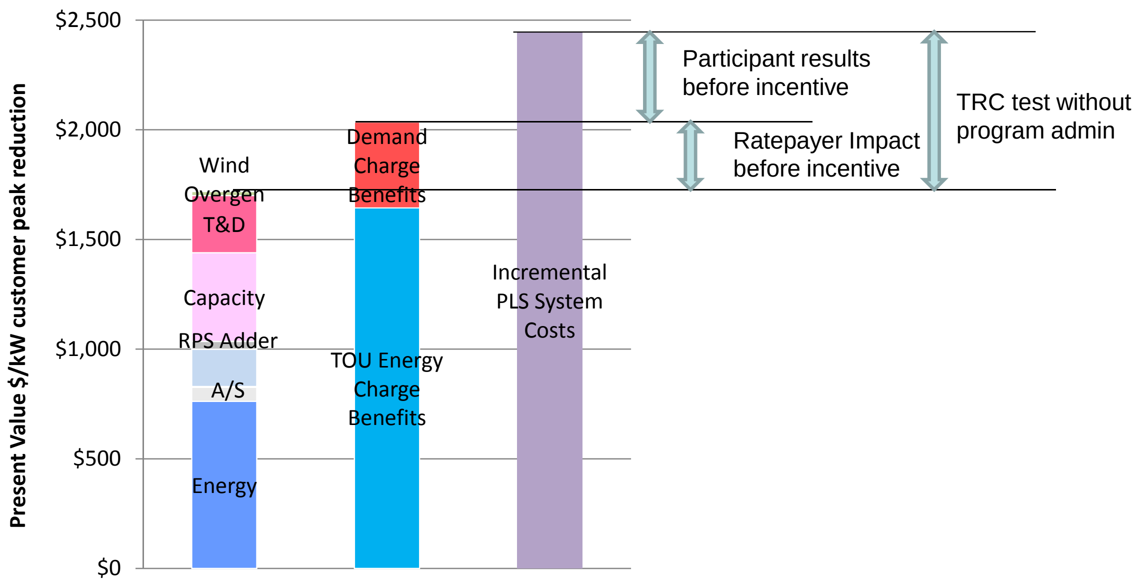


Figure 14 illustrates an example result of the cost-effectiveness tests. In this example, the participant requires a ~ $500/kW incentive to break even on permanent load shifting (PLS) strategy, on a lifecycle basis. The ratepayer impact test shows that non-participant rate-payers will transfer ~ $250/kW to participants without an incentive or ~ $750/kW with an incentive that meets the participant "break-even" criteria. The TRC is negative by ~ $750/kW (excluding program administration).

3.3.1 STRATEGIES

Three example strategies that illustrate the testing planned for summer 2011 are presented here.

3.3.1.1 Demand Response Program

UCSD enrolls in a Capacity Bidding Demand Response Program. UCSD receives a payment per month to commit to 500 kW of demand reduction when called during the 6 summer months (Figure 15). UCSD will receive notice by 9 am the day of the event. Event may last from 2-6 hours. Calls are limited to 24 hours in one month and 1 event per day. Event calls will be simulated in VPower, allowing the optimization to re-dispatch selected resources to provide the targeted load reduction. The cost of providing the load reduction will be compared against a baseline scenario. The cost to UCSD will include both the actual costs for re-dispatching campus resources, and imputed costs for departments and personnel that must modify behavior.

The Capacity Bidding Demand Response Program includes a baseline methodology, based on the highest 3 of the last 10 days. However this methodology is not adequate to estimate the baseline load for the diverse set of resources and loads on the UCSD campus. We will therefore develop alternative baseline methodologies and compare those against the method in the tariff.

Figure 15: SDG&E Capacity Bidding Program Payment Options

Load Reduction Incentive Payment, Day-Ahead Program Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
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

Load Reduction Incentive Payment, Day-Of Program Option ($/kW-month):

Product	May	Jun	Jul	Aug	Sep	Oct
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

3.3.1.2 Morning and Evening 3-hour Ramp

Morning and Evening Ramp: VPower smoothes the 3 hour morning and evening ramp for campus load. In the morning, VPower begins ramping up campus load 2 hours earlier than normal, reducing the MW/Hour ramp rate up for the campus. In the evening, VPower begins the ramp 1 hour earlier, and ends it 1 hour later, reducing the MW/hour ramp rate down. Target may be set in VPower as a desired or maximum MW/hour ramp rate for campus load. The cost to UCSD of modifying their normal operations will be calculated and compared against a baseline scenario.

3.3.1.3 Economic Demand Response/Energy Exports

UCSD's current operation of its microgrid is highly determined by the relatively inexpensive cost of natural gas and relatively expensive cost of electricity. The natural gas resources are operated to the maximum extent that the waste heat can be productively used. However, UCSD does have physical capacity to import electricity to meet its entire electrical needs and operate boilers and electric chillers to meet cooling and heating needs. This strategy will explore how current market conditions may or may not favor this operational scenario. Additional analysis will be conducted to determine what the price points are for such an operational scenario to become economically viable. Various external factors, such as increasing cost of natural gas, or shift away from natural gas to biogas (such as to meet University of California carbon neutrality conditions) could influence future operation of the microgrid in significant ways.

3.4 Future VPower capabilities in automated response

The 2011 implementation of VPower will utilize the simulation software module of VPower. Future operation of VPower will include implementing automated dispatch within the VPower-Paladin systems to optimize control of UCSD's DERs on an automated basis. With the experience gained in the summer of 2011 and planned automation of VPower optimal dispatch recommendations, new renewable integration strategies will be developed for testing in subsequent months. We anticipate that these strategies will incorporate faster response times which will be particularly useful for local distribution support and integration of high penetration PV.

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