Tariffs and incentives for integrating high penetration renewables

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

July 26, 2011 (Version 1.0)

Energy+Environmental Economics

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Table of Contents

1 Introduction 10

2 Tariff Barriers 12

2.1 Low Resolution Metering and Billing Determinants 12

2.2 Rate Complexity and Uncertainty 13

2.3 Demand and Stand-by Charges 13

2.4 Baseline Calculation 14

2.5 Dual Participation 14

2.6 Limited Incentives of Dynamic Pricing 15

3 Market Participation Barriers 17

3.1 Limited Access to Wholesale Markets 17

3.2 Complexity of Scheduling and Settlement 18

3.3 Infrastructure 20

4 Regulatory Barriers 21

4.1 Limited Capacity Payment Options 21

4.2 Physical Assurance 21

4.3 Interconnection Process for DG 22

4.4 Net-Energy Metering Limitations 23

5 Rate and Tariff Strategies 24

5.1 Existing Options 24

5.1.1 TOU and Demand Charges 24

5.1.2 DR Incentives Payments 24
5.1.3 Critical Peak Pricing (CPP) and Peak Time Rebate (PTR) 25
5.2 Utility Focused Options 26
5.2.1 Two-Part Rates 26
5.2.2 Capacity and Performance Based Incentives for Local Distribution Support 26
5.3 CAISO Focused Options 27
5.3.1 Real-Time Pricing 27
5.3.2 Regulation Energy Management 27
5.3.3 Spinning and Non-Spinning Reserve 28
5.3.4 Load Following 28
5.3.5 3 Hour Ramp 29
5.3.6 Overgeneration 29
6 Selected for Evaluation 30
6.1 TOU and Demand Charges 30
6.2 Critical Peak Pricing and Peak Time Rebate 30
6.3 Two-Part Rates 31
6.4 Capacity and Performance Based Incentives for Local Distribution Support 31
6.5 Spinning Reserve 31
6.6 Load Following 31
6.7 Ramp 32

Glossary

AMI	Advanced metering infrastructure
Ancillary services	set of services procured by the balancing entity for balancing and power quality maintenance purposes
CSP	curtailment service provider
CLAP	custom load aggregation point
DA	direct access
DG	distributed generation
DER	distributed energy resources at a customer site (e.g., generation, efficiency, storage)
DLAP	default load aggregation point
EE	energy efficiency
ESP	energy service provider
LSE	Load serving entity
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

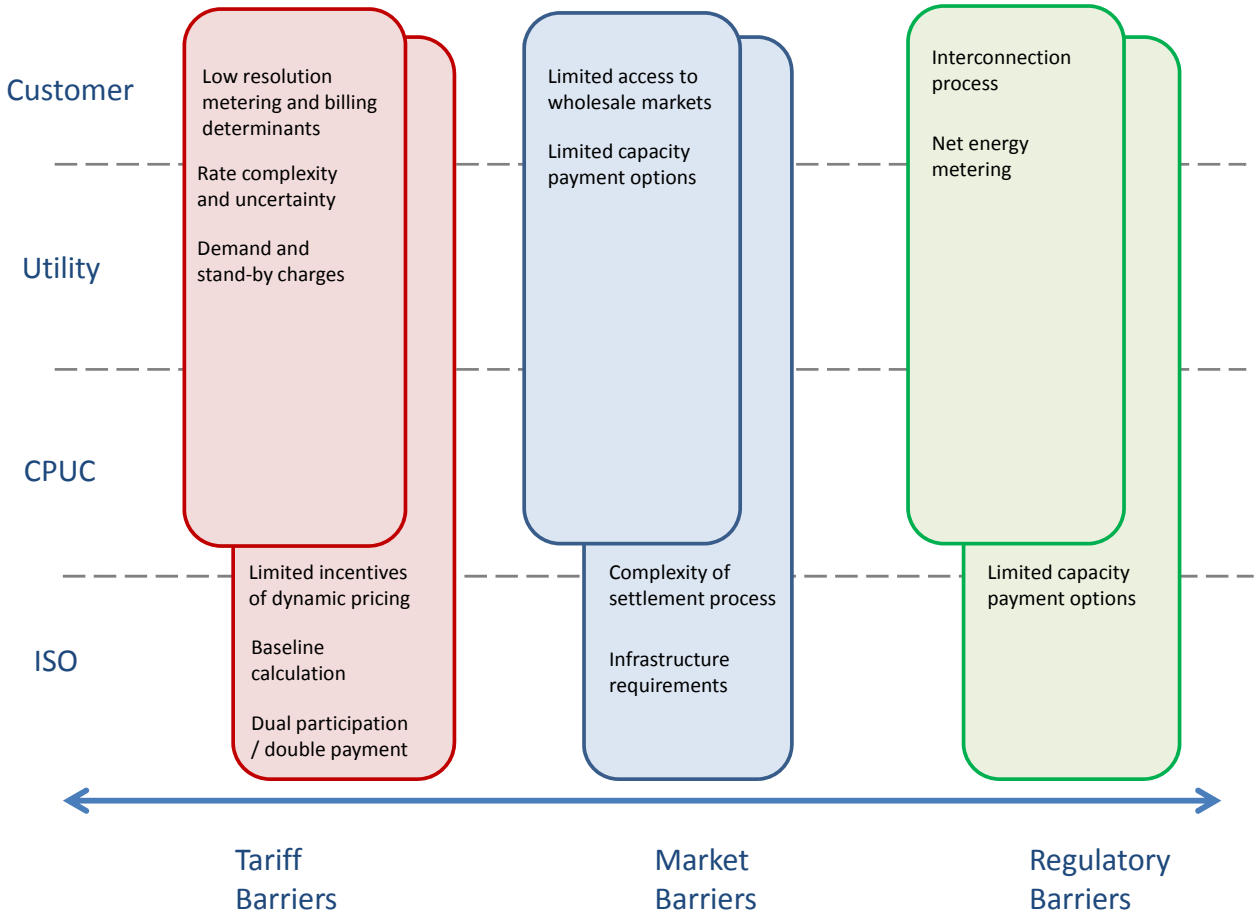
RE	renewable energy
RPS	renewable portfolio standard (in California, 33% by 2020)
Regulation	ancillary service that is procured by the balancing authority to balance all deviations continuously; provide load following and frequency response
SC	scheduling coordinator
Spinning reserves	on-line reserve 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
TOU	time of use rate
VAR	a measurement of reactive power

1 Introduction

This report describes the rate designs and incentives to motivate responsive customer load management that will be evaluated in the UCSD-Viridity implementation of VPower under the CSI RD&D grant proposal. We focus on rates and incentives that we can rigorously analyze with the resources and VPower implementation planned for the summer of 2011. Mirroring the strategies described in the PV Integration report, the rates and incentives will focus on encouraging customer response in the 5-30 minute time frame. This time frame aligns with the need identified by numerous reports for flexible generation resources to integrate increasing penetrations of intermittent renewable energy resources. We first describe challenges utilities face in encouraging real-time customer load management with Distributed Energy Resources (DERs). We describe how current utility rates and incentives both do and do not address these challenges. We then describe several alternatives that potentially provide increased incentives to customers without burdening ratepayers. Finally, we propose several tariff structures and business models for testing with VPower on the UCSD campus.

Figure 1 summarizes the market, tariff and regulatory barriers that impede customer load management through distributed energy resources.

Figure 1: Barriers to Customer Load Management with Distributed Energy Resources



2 Tariff Barriers

Utilities and regulators manage multiple conflicting objectives in designing rates, only one of which is providing efficient pricing signals to customers. Indeed it is inherently difficult to design rates that collect the average embedded cost for the existing utility system while also providing pricing signals based on marginal costs for an additional unit of consumption (or conservation). As a result, the rates commonly used in California and throughout the US present some barriers to the adoption of real-time load management strategies.

2.1 Low Resolution Metering and Billing Determinants

Even with the implementation of AMI for all customers, current metering and billing does not measure or charge for the services that promote active real-time load management. AMI meters record loads on 15 minute intervals. This provides much more granular information than previously available for most customers. Still, many of the anticipated impacts of renewable generation and high PV penetration occur over even shorter time frames. The CAISO has identified load following, which responds to follow changes in load over a 5-20 minute time frame, as a key need for renewables integration. Dynamic pricing on 15 minute intervals may be capable of providing some incentives for load following. However, even the most refined retail rates taking full advantage of price signals and AMI will be limited in their ability to address needs that occur over shorter time frames such as voltage support, frequency regulation and backflow protection. Utilities will also be limited in their ability to charge customers for burdens they impose on the utility system over short time frames.

Limited billing resolution presents a challenge for utilities and regulators; they do not want to charge ratepayers twice for the same service. Customers may impose service requirements, but not pay for the costs of relying on the utility for grid services such as voltage and VAR support and load following during some hours. Those same customers participating in new programs designed to promote PV integration

could potentially earn additional payments from the utility for providing those same services during other hours.

2.2 Rate Complexity and Uncertainty

"Tariff risk" is a significant concern for many customers. They are unwilling to install capital intensive systems based on the payback under current rate structures for fear that rates will change. Moreover, such investments are subject to the classic split incentive issue: the facility owner does not pay the utility bills and thus is not motivated to reduce costs. In addition, with variable customer load profiles energy bills under rate schedules with ratcheting demand charges, tiers and TOU rates are difficult to predict. All of these factors lead to a sub-optimal level of capital investment in DER's relative to the benefits they can provide.

2.3 Demand and Stand-by Charges

Customer options for using non-utility generation have increased over the years to include distributed generation, demand response, direct access and community choice aggregation. In response utilities have sought to collect a greater portion of their fixed costs for serving a customer's peak load through demand and stand-by charges. In PG&E's most recent general rate case, the utility is seeking to move a substantial portion of the time differentiation in rates from the generation to the transmission and distribution component. Ratcheting demand charges that change based on the customers coincident and/or non-coincident peak 15 minute load interval pose a significant and unpredictable risk to customers. One brief period of cloud cover, malfunction or high load can significantly reduce anticipated savings from PV or load management systems. As a result, customers often ignore or heavily discount anticipated bill reductions associated with demand savings (Wiser et al. 2007).

2.4 Baseline Calculation

For load based resources, a calculation of the customer's baseline load that would have occurred under normal operations is often used to determine the level of performance and therefore compensation for a service such as demand response. Baseline calculations must balance multiple objectives and are inherently challenging. Some stakeholders argue that customer acceptance is of paramount concern. They see a need for a single, uniform and transparent methodology that can be easily understood by customers. Others argue that accuracy is essential; otherwise load based resources will never be viewed as reliable or comparable to generation by system operators. In addition they argue that only relatively accurate (and presumably more complex) methods will minimize opportunities for gaming. Still others see the need to rely on baseline calculations in and of itself as a fundamental flaw of demand response and other load based resources. They believe baseline calculations will inevitably be inaccurate, potentially confusing and complex and provide gaming opportunities that cannot be effectively mitigated. They argue it makes more sense to charge customers for what they use, rather than to try to pay them for what they do not.

There are at least three different applications for baseline calculations, each of which might require a potentially unique methodology. Those applications are 1) impact estimates for forecasting and scheduling, 2) impact estimates for determining cost-effectiveness, and 3) baseline calculations for payment and settlement. It might be, for example, that the methodology for forecasting might err on the side of being more complex, accurate and conservative, whereas the methodology for payment is more transparent and simple, so as to facilitate customer participation.

The conflicting goals of simplicity and accuracy present potentially significant challenges to developing consensus around and implementing rates and incentive structures that promote responsive load.

2.5 Dual Participation

There is a proliferation of rates, incentive programs and competitive wholesale markets accessible to end-use customers. There is a concern on the part of regulators and ratepayer advocates that the potential for

dual participation be effectively managed. With programs managed by separate entities and utility departments it is easy to imagine a customer being able select a retail rate, enroll in a demand response program and participate in a CAISO real-time energy or ancillary services market, earning bill reductions and multiple payments for the same load reduction. On the other hand, there are many legitimate reasons for a customer or aggregator to participate in multiple programs with different objectives and target loads. CPUC rules on dual participation, described in D. 09-08-027 and D. 10-06-002, generally err on the side of being more restrictive until further experience is gained and the issues can be given full consideration.

A related complication is that of a potential double payment for retail load participating in wholesale energy and ancillary service markets. FERC recently ruled that retail loads participating in ISO markets must be paid the same market price that is paid for generation (Docket No. RM10-17-000; Order No. 745, issued March 15, 2011). This position treats loads just like a generator and minimizing billing and settlement complexity for the ISOs. However it also results in a potential for double payment to the retail customer. The customer is paid by the ISO for reducing load and is also paid by the utility for the same load reduction in the form of reduced energy charges. This leads to a risk of overpayment from non-participating ratepayers for the load reduction realized.

2.6 Limited Incentives of Dynamic Pricing

Some argue that real-time or dynamic pricing for energy and utility services is the most economically efficient method for encouraging customers to manage their load to minimize costs. One limitation of this approach is described above; the 15 minute interval data is not sufficient to provide compensation for shorter duration responses that will be needed for PV integration. Another challenge is that market prices are simply not sufficiently dynamic. Resource adequacy markets require Load Serving Entities (LSEs) to procure most of their anticipated generation capacity requirements in advance. With sufficient capacity procured in advance, day-ahead and real-time energy prices are less volatile. The recent economic slowdown has also led to a reduction and reserve margins in excess of 30%. In addition, the CAISO reports that more than 75% of its load is self-scheduled outside the wholesale energy markets. Excess capacity and

lower natural gas prices have significantly reduced on- to off-peak price differentials. This, combined with relatively inelastic customer demand for energy limits the effectiveness of dynamic pricing alone to motivate customer energy management.

3 Market Participation Barriers

3.1 Limited Access to Wholesale Markets

CAISO markets offer the potential for payments for more flexible resources that can meet the requirement of participating in energy and AS markets as compared to retail DR programs. The CAISO (and the CPUC) has espoused a vision of greater reliance on economic triggers for DR programs that operate year round with more frequent calls. The CAISO has implemented the Proxy Demand Resource (PDR) product for DR programs to participate directly in energy and spinning reserve markets, and is currently implementing the Regulation Energy Management (REM) for load to provide regulation in AS markets. The CPUC has limited participation in PDR to IOU sponsored programs for the first year until more experience is gained.

Parties have argued for some time that telemetry requirements designed for generation need to be modified to allow economic aggregation of load resources. Still, clear regulations regarding aggregation have not been developed by the CAISO and continue to be approved on a case by case basis. CAISO requires all participants to be, or be represented by, a certified Scheduling Coordinator (SC). The significant investment in time, resources, and costs associated with taking on the role of a CAISO-certified scheduling coordinator will keep almost all customers who participate in PDR doing so through their LSE or a Curtailment Service Provider (CSP).

Even so, some stakeholders are concerned that the metering and communications infrastructure will prove too costly for CSPs wishing to engage in direct participation with their DR customers. Some fear that the expected cost of telemetry needed to provide 4-second telemetry data will be exorbitant for all but the largest firms and thereby eliminate participation in ancillary services markets. Others question whether such requirements, designed for transmission level customers, are realistic or appropriate for DR programs that aggregate the loads of distribution level residential and commercial customers. Generators expect to pay for telemetry as a cost of doing business; for demand, telemetry is an added expense that is unrelated

to their core business. Less onerous and costly metering and telemetry requirements will need to be developed for aggregated DR programs for smaller customers, perhaps using sampling techniques.

3.2 Complexity of Scheduling and Settlement

It is difficult to clearly delineate the boundaries between parties scheduling the load and load reductions of DR customers. This is particularly problematic with direct access; utility or CSP customer portfolios may include both bundled and direct access customers whose load is embedded in the schedule submitted by the utility on the one hand and the Energy Service Provider (ESP) on the other. To facilitate participation and avoid discrimination, DA customers are permitted to enroll in DR programs marketed by the IOUs and CSPs, and CSPs are permitted to enroll customers from multiple LSEs. The IOUs, however, may not act as a SC for the DA customers. In many cases the CSP is not an SC, so the CSP or customer must hire a third party to schedule for them. In the exchange of schedules and information between all the parties, it will be difficult to determine which enrolled DR MWs are or are not already included in the respective schedules submitted by utilities, CSPs and ESPs. In such cases, the party responsible at each step of the scheduling and settlement process is not at all clear.

The complexity in scheduling and settlement is closely related to the technology and infrastructure barriers described below. The potential for things to fall between the cracks can pose risks significant enough to inhibit participation, or at least increase transaction costs. For example it is not always clear either within the utility or CAISO or between the different entities, what their different roles, responsibilities or capabilities are at different stages of the process. Different entities or departments often interpret a rule or tariff in dissimilar ways. These problems have been addressed to some extent in other ISO markets as they have worked to integrate load-based or limited energy resources.

One aspect of the current PDR proposal is also a potential barrier. DR bids in both the Day-Ahead and Real-time markets will be reflected in the LSEs day-ahead schedule. The load reductions realized due to DR bid in by a CSP will result in a cost savings to the LSE but no corresponding payment from the LSE to the CAISO

or the CSP. Under the current proposal, there will be a need for payments from the LSE to the CSP to settle outside of the CAISO process. This will require individual bilateral negotiations between each CSP and LSE. The risk and transaction costs associated with such settlements occurring outside the markets add to the burden of customers participating directly in wholesale markets.

An additional issue is that customers pay one price for load and another price for load reduction bid into the CAISO markets. LSE's buy energy from the CAISO at a Default Load Aggregation Point or Default LAP, which is a weighted average of the individual nodes in their service territory. The largest customers may choose to enroll in the CAISO Participating Load product and pay a nodal price as opposed to the Default LAP price for their load. They are also paid the nodal price by the CAISO for load reductions. Because participation is voluntary, many argue that only those customers at low cost nodes consistently below the Default LAP would choose to participate in the Participating Load program. The customer would realize savings by paying a nodal price for load that is below the Default LAP most of the year. Others claim that this will not be a problem as only the LSE's would see the nodal vs. LAP prices for load and that the customer would continue to pay retail rates and therefore would not perceive a cost savings for load.

The PDR product is designed for CSPs and aggregated portfolios of DR customers. Unlike Participating Load, it does not change the price charged for load. However, PDR does pay for DR at a Custom LAP that reflects the nodes at which customers in the DR portfolio are located. The load, however, continues to be priced at the Default LAP for the LSE. This again creates gaming opportunities. With capacity payments offered for DR, customers may be encouraged to enroll premises at low cost nodes that are less likely to be actually dispatched by the CAISO for DR. At the same time customers in a high cost CLAP have an incentive to over schedule load and offer DR, receiving payments for phantom load when dispatched for DR by the CAISO.

3.3 Infrastructure

The infrastructure costs associated with the CAISO market design and mapping millions of customers to thousands of nodes are not to be underestimated. Some are worried that the systems and processes necessary to map retail customers to nodes for purposes of participating in DR will prove costly. While the CAISO envisions that nodes will remain relatively stable, the utility distribution circuits that connect to those nodes are reconfigured and expanded over time. When dealing with millions of retail customers, it is not unreasonable to expect that changes in the linkage between customers and nodes might occur frequently. The costs to implement the communication of scheduled loads and bills between the CAISO, utilities, CSPs, ESPs and retail customers may also be significant. Utility software systems used in generation, distribution and retail business units often have difficulty communicating data within the company, much less to external parties. Unlike generation, load participation requires a high level of coordination and communication with functional areas such as customer services and retail billing that have not historically required a great deal of interaction with wholesale procurement.

The CPUC has directed the IOU's to pursue alignment of DR resources with MRTU and CAISO markets. The utilities have raised some potential cost issues in addition to telemetry. Forecasting participating load will require modifying existing software, and DR programs are not integrated with the wholesale side of the utilities. The CPUC will continue to review the costs associated with integrating utility DR programs into CAISO markets and enabling direct participation to determine if the benefit to ratepayers warrants the investment.

4 Regulatory Barriers

4.1 Limited Capacity Payment Options

The CPUC has implemented Resource Adequacy (RA) requirements to ensure the procurement of sufficient capacity resources by LSEs under its jurisdiction. The CPUC has also ruled that dispatchable DR programs should count towards meeting RA requirements. DR resources therefore have a value to the LSE to the extent they reduce the amount of capacity the LSE must purchase to meet RA requirements. At this time, however, there is no mechanism or market that provides capacity revenues directly to the DR customer or Curtailment Service Provider. The only capacity payments for DR resources currently available in California are those provided by the regulatory driven programs managed by the IOUs.

On the one hand, many IOU DR programs offer incentives higher than the capacity prices currently available in bilateral RA markets in a period of excess capacity. On the other hand DR programs are focused predominately on a model of a limited number of calls for load reductions. Though utilities are moving more towards a 365 days a year operation for some programs, the number of options remain limited. Furthermore, programs are approved on a three year cycle.

This severely limits the flexibility of DR programs alone to provide incentives that reflect the value of continuously available and dispatchable distributed energy resources. Moreover, demand resources can be brought to market far quicker than new generation can be built. Program design should take advantage of this characteristic of demand resources.

4.2 Physical Assurance

Distributed PV is currently limited in the capacity benefit that it can provide to utilities. In 2003, CPUC Decision 03-02-068 laid out the criteria distributed generation must meet to allow a utility to defer

capacity additions and avoid future costs. DG facilities must meet these criteria in order to qualify for capacity payments.

- The 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. The physical assurance provision thus requires DG owners to also be able to provide demand response in order to receive capacity payments.

4.3 Interconnection Process for DG

Customers and DG vendors have long argued that the process of interconnecting a project with the utility is too long, burdensome and costly. It is not uncommon for interconnection studies to take several months and, in some cases, more than a year. With higher PV penetration, utilities face an increasing volume of interconnection requests, which will only add to the potential for delays. Interconnection requirement and system upgrades that utilities view as essential for system reliability and protection are seen as unnecessarily conservative and onerous by DG providers. The studies

alone can require significant upfront investment by the customer, with no assurance that their project can ultimately be connected cost-effectively.

4.4 Net-Energy Metering Limitations

Net-energy metering (NEM) allows a customer with behind-the-meter distributed generation to spin their meter backward and sell electricity to the grid. California's net-energy metering (NEM) law, which took effect in 1996, requires the state's investor-owned utilities – PG&E, SCE, and SDG&E – to offer NEM tariffs to customers with wind, solar, biogas, or fuel cell generation up to 1 MW in size. Under California's statute, utilities must make NEM available to customers until the total NEM rated generating capacity exceeds 2.5 percent of the utility's aggregate customer peak demand. PG&E voluntarily extended the cap to 3.5 percent in 2009.

Under NEM, customers receive bill credits for excess generation (generation exceeding electric load) that is exported to the grid. Any excess bill credits at the end of a billing month may be applied against the following month's bill. Under the original law, any net-excess generation remaining at the end of each 12-month period was granted to the utility with no compensation to the customer. In 2009, AB 920 amended the law to allow PV customers, beginning in January 2011, to either roll-over the credit indefinitely or receive compensation for the net excess generation at a to-be determined valuation. The various options for appropriately determining the value of net excess generation that is carried over are somewhat complex and difficult to implement. Furthermore, the retail rate is not an accurate indicator of the marginal avoided generation cost of the utility. This leads to an inherent tension between the utilities, which want to limit enrollment and DG proponents that want to encourage adoption.

5 Rate and Tariff Strategies

5.1 Existing Options

5.1.1 TOU AND DEMAND CHARGES

Time-of-Use (TOU) rates provide a price incentive for customers to reduce or shift load from the peak load periods that impose the highest cost on the utility. TOU rates are predominately voluntary or Opt-in. The CPUC is encouraging, and in some cases requiring, utilities to transition towards default or Opt-Out time varying rates, including TOU and Critical Peak Pricing (CPP, see below) elements.

Demand charges that are assessed on the customers non-coincident(coincident) peak load also provide an incentive to reduce loads during the customer(utility) peak load hours.

Electricity demands by customer class are price-responsive, with a conservative price elasticity estimate of around -0.1.[1] Thus, a suitably designed tariff enabled by AMI can cost-effectively encourage customer conservation and load shifting. However, as described above, the revenue collection constraint implies that time-varying rates for the high-cost (low-cost) hours are necessarily set below (above) the marginal cost.

5.1.2 DR INCENTIVES PAYMENTS

The IOU's each offer several DR program options for retail customers, with a variety of incentive structures. The utilities submitted applications to the CPUC for their proposed 2012-14 DR programs on March 1, 2011. Some provide a capacity payment in $/kW-month for a fixed amount of demand reduction to which a customer commits in advance. Other programs are on a pay for performance basis, and pay for the kW or kWh actually reduced. Incentive payments for event based load reduction or load shifting are well established and accepted by customers, utilities and regulators. A similar model could well be designed for more flexible and continuous load response.

[1] R. Orans, C. K. Woo, B. Horii, M. Chait, and A. DeBenedictis, "Electricity Pricing for Conservation and Load Shifting," *The Electricity Journal*, vol. 23, no. 3, pp. 7-14, Apr. 2010.

Existing DR programs pay incentives that generally exceed the current RA capacity value and therefore exceed the cost-effective level using an avoided cost framework[2]. The use of short- vs. long-run values for generation capacity has a substantial impact on the cost-effectiveness of DR. In a market with excess capacity, the lower, short-run value best expresses the actual capacity costs avoided and therefore the economic benefits realized by utility ratepayers from load reductions. On the other hand, California has placed energy efficiency and demand response at the top of the Energy Action Plan loading order. Some argue that such programs should not be penalized because a surplus of fossil generation exists and that some consistency in DR incentives is necessary to attract and retain DR participants.

5.1.3 CRITICAL PEAK PRICING (CPP) AND PEAK TIME REBATE (PTR)

In February 2010, the CPUC adopted dynamic rate structures for PG&E's commercial, industrial, and agricultural customers. This was the first step of larger effort to implement dynamic electricity prices for all California consumers. These rates are designed to reflect the cost of electricity production during periods of high demand. First, large commercial and industrial customers and then medium and small commercial customers were placed on Peak Day Pricing tariffs. The Peak Day Pricing Tariff has a TOU rate structure and on the few hottest days of the year, include additional price for energy consumed between 2 p.m. and 6 p.m.. This was the first time in California that customers were enrolled in dynamic rates by default, with the option to Opt-out. Additional TOU and dynamic rate options are offered to residential and small commercial customers on a voluntary, Opt-in basis.

SCE's large commercial and industrial customers are also defaulted to CPP rates. SCE currently plans to begin moving all nonresidential customers to mandatory TOU rates in January 2012. Small and medium business customers and large agricultural and pumping customers will be moved to Critical Peak Pricing (CPP) rates in conjunction with TOU, with the option to opt-out. SDG&E implemented CPP for large and medium size commercial and industrial customers in 2008. SDG&E will offer a Peak Time Rebate program in 2011 for residential customers with smart-meters.

[2] The CPUC 2010 Resource Adequacy Report shows RA prices on the order of $25/kW-Yr.

CPP and Peak Time Rebates (PTR) provide an economic incentive for load reductions without requiring a specific level of performance. For customers with a high degree of sophistication and flexibility, more complex and nuanced peak-time pricing signals would be possible.

5.2 Utility Focused Options

5.2.1 TWO-PART RATES

Two part rates offer an alternative incentive payment for conservation and load shifting. The first part is the bill for the customer's established consumption pattern under the existing tariff design. A second rate is layered on the existing rate to provide a larger incentive for customers to reduce or shift load. The customer does not see a bill change if it maintains its consumption pattern. When the consumer reduces consumption as compared to its baseline, it receives bill credits. Similarly, when the customer exceeds its established consumption pattern during peak periods, additional charges are applied. The bill credits and charges are based on a utility's long-term avoided costs rather than embedded average costs and provide a stronger incentive to reduce or shift load. Two-part rates overcome one disadvantage of TOU tariffs, which typically have rates below the utility's on-peak marginal cost. If a utility's cost of generation is increasing over time, marginal-cost-based rates would over-collect the utility's revenue requirement. Two part rates, on the other hand, can increase the price signal for cost-effective conservation and load shifting without such overcollections.

While an inverted block tariff with time-varying rates may be seen as an obvious alternative, it is seldom adopted for non-residential customers because of its severe bill impacts attributable to customer diversity in size and TOU consumption pattern. A voluntary or opt-in rate for more sophisticated customers with detailed historical load data is a potentially viable alternative for large commercial and industrial customers with load management capabilities.

5.2.2 CAPACITY AND PERFORMANCE BASED INCENTIVES FOR LOCAL DISTRIBUTION SUPPORT

Capacity based incentives for local distribution support would parallel the capacity payments for existing DR programs. Rather than focusing on system generation capacity, capacity payments would be based on benefits provided to the local distribution system. Like other capacity based products or services, the

participant would receive a $/kW-month payment for being available to be dispatched by the utility if needed, whether or not they are actually used. Capacity payments would be based on the value of the services that support the local distribution system, such as voltage support, VAR support and deferred capital investment described in this and numerous other reports.

5.3 CAISO Focused Options

5.3.1 REAL-TIME PRICING

Real-time pricing has long been advocated by economists. With implementation of CAISO MRTU and AMI, real-time pricing appeared closer to reality for a period of time. California's experience with the energy crisis of 2001 has left legislators wary of subjecting unsuspecting customers to potentially large rate shocks, even if only for a few hours a year. Nevertheless, sophisticated customers could enroll in real-time pricing on a voluntary basis and potentially take advantage of price differentials.

Exposure to real-time prices is currently limited to customers participating in utility sponsored programs participating enrolled in the CAISO Proxy Demand Resource product. PDR, however, is built on a demand response model to be called only during periods of need or emergency.

Simply switching from a utility's energy rates to a real-time rate based on CAISO prices is not feasible, as utility rates are not based on real-time energy costs. The two options are constructing a utility tariff with real-time energy rates that, combined with other customer or delivery charges, recovers the appropriate revenue requirement for the utility. An alternative is to layer a real-time based incentive for deviations from a baseline as described in the two-part rate description above.

5.3.2 REGULATION ENERGY MANAGEMENT

Regulation energy management will allow limited energy resources, including loads to bid into the ISO's regulation markets. Under the proposal, the ISO will manage the resources' state of charge. The ISO will discharge the resource for regulation energy associated with regulation up and will charge the resource for regulation energy associated with regulation down. The ISO will use offsetting dispatches of energy from the real-time energy market, if necessary, so that the resource can satisfy its regulation capacity award

over an entire hour. The ISO has completed a stakeholder process to finalize the design of its regulation energy management proposal and is commencing efforts to file any necessary tariff revisions for implementation in 2012.

5.3.3 SPINNING AND NON-SPINNING RESERVE

Spinning and Non-Spinning Reserve are used by the CAISO to maintain system frequency stability during emergency operating conditions or contingencies. Spinning reserve is online and synchronized to the grid with the capacity to increase generation within 10 minutes. Non-spinning reserve is off-line, but can be started and ramped up to capacity within 10 minutes.[3] Load is inherently synchronized with the grid and is now permitted to provide both spinning and non-spinning reserves in CAISO AS markets. In 2010, CAISO spinning reserve prices averaged $5.11/MWh, only slightly less than the average regulation up price of $6.83. Non-spinning reserves prices were much lower, averaging $0.66/MWh

5.3.4 LOAD FOLLOWING

Load following refers to the capability to manage the difference between 20 minute ramps and 5 minute energy schedules set by the CAISO. While not a discrete service or market product currently, load following has been identified as a key requirement for integrating increasing penetration of intermittent renewable resources. By increasing off-peak load and reducing on-peak load, permanent load shifting (PLS) would appear to have the potential to reduce load following requirements, particularly in the morning and evening ramp periods. The CAISO 20% RPS Study finds that the primary driver of load following requirements is not forecasted load, but instead load and intermittent generation forecast error. Shifting load on a fixed schedule (as in PLS), therefore does not appreciably reduce load following requirements. However, technologies that are dispatchable with notification times of 20 minutes or less could potentially provide load following services.

[3] Each ISO has slightly different market definitions and operational requirements for their reserve markets.

5.3.5 3 HOUR RAMP

Meeting the morning and evening ramp will also become an increasing challenge for CAISO with increasing renewables penetration. As loads increase in the morning and decrease in the evening, the CAISO must have enough flexible generation to follow the upward or downward ramp over 3 hours or more. The CAISO expects the challenge of meeting morning and evening ramp to increase significantly with increased wind and solar generation. Wind generation will fall off in the morning just as load begins to increase. Then as solar starts to produce energy in the late morning, fossil units will have to be ramped back down. Discretionary loads (such as vehicle charging) and energy storage have the potential to provide both ramp up and ramp down over several hours.

5.3.6 OVERGENERATION

Overgeneration is excess generation that must be curtailed or spilled when load is below minimum generation from base load, hydro and must take resources. As increasing penetration of wind and solar resources are added to the grid, the number of hours during which generation exceeds net loads will increase. Overgeneration is driven primarily by intermittent wind, which has higher generation during off-peak hours when loads are the lowest. With anticipated wind generation of ~2,500 MW in 2010, overgeneration does not appear to be an issue. However, by 2020, installed wind capacity may reach ~9,000 MW. Modeling performed by E3 suggests this would lead to ~1,700 hours of overgeneration, predominately in spring, when hydro generation is high and loads are moderate.

Curtailing wind generation would impose a cost on the utility in terms of lost RPS qualifying generation. For each MW of wind curtailed, an additional MW of RPS qualifying generation must be purchased. The estimated cost of marginal renewable generation each year is included as an avoided cost benefit, starting about ~$90/MWh in 2008.

6 Selected for Evaluation

The following incentives and business models selected for evaluation are described below. The analysis will proceed in four phases. First, rates and incentive levels for each strategy will be developed. Rates may be drawn from existing or proposed tariffs filed by the IOUs. Alternatively representative examples will be developed if no relevant tariff exists. Program incentive levels will similarly be drawn from existing examples or developed internally. Second, specific resources and dispatch strategies will be developed to test and evaluate the rates and incentives developed. Third, the rate and incentives for each approach will be fed to VPower as price signals. VPower and Power Analytics will jointly determine the optimal dispatch schedule both with and without the selected rate/incentive program. Finally the impacts and costs of the resulting optimized dispatch calculated by VPower will be evaluated. The economic evaluation will take place first in simulation and then, to the extent practical with UCSD Campus operating constraints, on the microgrid itself.

6.1 TOU and Demand Charges

E3 will evaluate existing rates from each IOU for commercial and industrial customers. The Analytica model that will be used to perform the economic evaluation contains a wide range of rates from the three IOU's and selected municipal utilities. Rates will a range of demand charges and TOU price differentials will be evaluated. These will include, but not be limited to A-6, A-10 TOU and E-20P for PG&E, TOU-8B for SCE and AL-TOU for SDG&E.

6.2 Critical Peak Pricing and Peak Time Rebate

E3 plans to draw from existing or proposed CPP and PTR rates for testing with the VPower system. Based on our experience with existing CPP and PTR rates, we plan on modifying and enhancing those rates to take advantage of the flexibility and capability of the VPower system. One criticism of CPP rates is that they are not cost based; in order to drive response from relatively inelastic demand, prices CPP rates must be several times higher than the actual cost of delivering on-peak energy.

6.3 Two-Part Rates

E3 proposes to develop two part rates that could feasibly be implemented by utilities in California. The base rate for a baseline load profile will be designed to recover the necessary revenue requirement. Higher rates for deviations from the baseline will provide a stronger incentive to reduce or shift the customer's net load. The rates will be designed to not over or under collect the utility's revenue requirement and also reflect Long-run Marginal Costs.

6.4 Capacity and Performance Based Incentives for Local Distribution Support

E3 will develop avoided cost based capacity and performance based incentives for managing net load to support the local distribution system. Avoided costs for transmission and distribution capacity, losses, frequency, voltage and VAR support, as well as other benefits, will be calculated. The most recent General Rate Case filings and T&D investment plans from each IOU provide some detail on the value of deferring investments in T&D capacity.

6.5 Spinning Reserve

We plan on obtaining real-time pricing signals from the CAISO. The process for feeding CAISO prices to VPower is still being evaluated and developed. However, we will evaluate strategies for standing ready to provide several MWs of spinning reserve to be called by the CAISO with a 10 minute notice. A key research question is what strategies can be motivated by the relatively low spinning reserve prices in most ISOs.

6.6 Load Following

Real-time or historical spinning reserve prices can also provide a lower bound indication of the value of load following. Spinning reserve prices will be used to provide economic incentives for continuously

following load in both the up and down directions. We will also provide alternative estimates of load-following value or prices. Production simulation modeling being undertaken for the CPUC LTPP and CAISO Transmission Planning process will quantify the quantity of load following needed under alternative future scenarios.

6.7 Ramp

If practical, we will also estimate the value of a 3-hour ramp product for the CAISO. Unit commitment and ramp needs are determined by production simulation runs. Absent a market, the cost or value of 3-hour ramp may be difficult to determine. However, if the multiple production simulation runs from the LTPP and Transmission Planning process can be effectively used, they may provide some insight into the requirement for and value of 3-hour ramp. These values would then be provided to VPower as an input.