Statewide Joint IOU Study of Permanent Load Shifting

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Glossary

CE	Cost effectiveness
CEC	California Energy Commission
CPUC	California Public Utility Commission
DR	Demand Response
DSIRE	Database of State Incentives for Renewable Energy
EM&V	Evaluation, Measurement and Verification
IMIOC	Internal melt ice on coil
ISAC	Ice storage air conditioning
PAC	Program Administrator Cost Test
PG&E	Pacific Gas and Electric Company
PLS	Permanent load shifting
RIM	Ratepayer impact measure test
SCE	Southern California Edison
SCHW	Stratified chilled water
SDG&E	San Diego Gas and Electric
TES	Thermal energy storage
Ton-hour	Unit of cooling energy (equivalent to 12,000 BTUs)
TOU	Time of use
TRC	Total resource cost test

1. Executive Summary

The purpose of this study is to investigate cost-effectiveness and program design to expand the use of permanent load shifting (PLS) within the SCE, PG&E, and SDG&E service territories ("Joint Utilities"). PLS refers to a broad set of technologies that shift electricity use from peak to off-peak periods. This report is an outcome of the California Public Utility Commission (CPUC) Order D.09-08-027 "Decision adoption demand response activities and budgets for 2009 through 2011" and will provide more information to the Joint Utilities on PLS for use in preparing proposed Demand Response programs, including PLS, to the CPUC.

Energy and Environmental Economics, Inc. (E3) and StrateGen Consulting were selected by the Joint Utilities and the CPUC to conduct this study. E3 and StrateGen Consulting (the "project team") used a collaborative stakeholder process with two workshops, numerous stakeholder interviews and meetings, and the release of a publicly available cost-effectiveness tool to develop the study results. The project team also gathered and used data from each of the utility PLS Pilot Programs, and technology vendor data in the public domain and under Non-Disclosure Agreements (NDAs).

As described in this report, the study addresses the following areas:

- Definition of Permanent Load Shifting
- Cost-effectiveness of PLS
- PLS Program 'Best Practices" and Stakeholder Input
- Proposed PLS Program Design Elements, including Standard Offer

1.1. Definition of PLS

For the purposes of this study, the project team proposed and uses a broad definition of PLS. With support of the stakeholder group, a 'technology neutral' definition was proposed based on the impact of the electricity usage profile, rather than the technology used to create the impact. Additional guiding principles include business/ownership neutrality, and the measurable shift at program level for EM&V. PLS is defined with the overarching goal of "routine shifting from one time period to another during the course of a day to help meet peak loads during periods when energy use is typically high and improve grid operations in doing so (economics, efficiency, and/or reliability)."

The type of load shape impact that meets the PLS definition can be delivered by technologies in three broad categories; electrical energy storage, thermal energy storage, and process shifting (see Table 1). Each technology category and individual technologies within each class have their own unique costs, benefits, strengths and limitations. For example, some of the technologies are mature and in wide use, such as thermal storage systems for building cooling systems, and some are still emerging such as electric battery storage; some provide a 'static' set shift in load pattern, while others can provide a 'dynamic' response based on electric system conditions. There are also process shifting efforts that involve rescheduling the use of electricity. For all of these categories, it will be extremely challenging to create a single, simple, technology neutral PLS program design that appropriately addresses the differences in the costs and benefits of the technologies to establish a common design framework.

Table 1: PLS technology applications, categories and examples

Application	Category	Primary characteristics/ examples
Stationary	Thermal storage	Generate ice or chilled water at night, then use this stored ice or chilled water to provide cooling during the day.
Stationary	Non-thermal storage	Chemical batteries, mechanical storage – e.g., fly wheels, modular compressed air (CAES)
Stationary	Facility process shifting	Processes conducted within a facility that are shifted from one time period of the day to another
Mobile	Plug-in electric vehicles	Not in scope (Because mobile storage has a concurrent proceeding at the CPUC)

While the PLS definition is broad, there are many elements that this report has found to be outside the scope of PLS. First, PLS is not solely event-based demand response. Second, PLS is not behavior-based energy efficiency. PLS is provided and quantified by discrete equipment or controls, not solely by general customer behavior modification, and it does not reduce the level of customer service. Third, the load reduction and shifting that can be achieved by best practices commissioning, retro-commissioning or adjustment of controls is not considered PLS, unless such practices are being applied directly to existing legacy PLS technologies (such as unused thermal storage tanks) and are not currently being implemented through energy efficiency programs. We also exclude, by stakeholder consensus, the inclusion of electric vehicles in PLS. Finally, PLS is not achieved through fuel switching.

1.2. PLS Cost-Effectiveness

The project team emphasized the importance of cost-effectiveness of PLS throughout the development of the study. E3 focused on the overall societal and ratepayer cost-effectiveness of PLS, given current California electricity market conditions. StrateGen Consulting focused on the value proposition to the end-user and whether a given PLS program design was likely to result in significant adoptions. This approach was designed to provide more information to the Joint Utilities as they decide the scope and scale of their proposed PLS programs and to provide more information for establishing incentive levels that balance the costs to ratepayers and expected program adoption rates.

To value the benefits of PLS to ratepayers, and to California as a whole, E3 developed a PLS cost-effectiveness framework that is similar to the framework used to evaluate the benefits of utility distributed generation programs such as the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP) [Decision 09-08-026, August 20, 2009][1]. A similar framework is also currently being considered for use in evaluating the cost-effectiveness of demand

[1] http://docs.cpuc.ca.gov/published/FINAL_DECISION/105926.htm

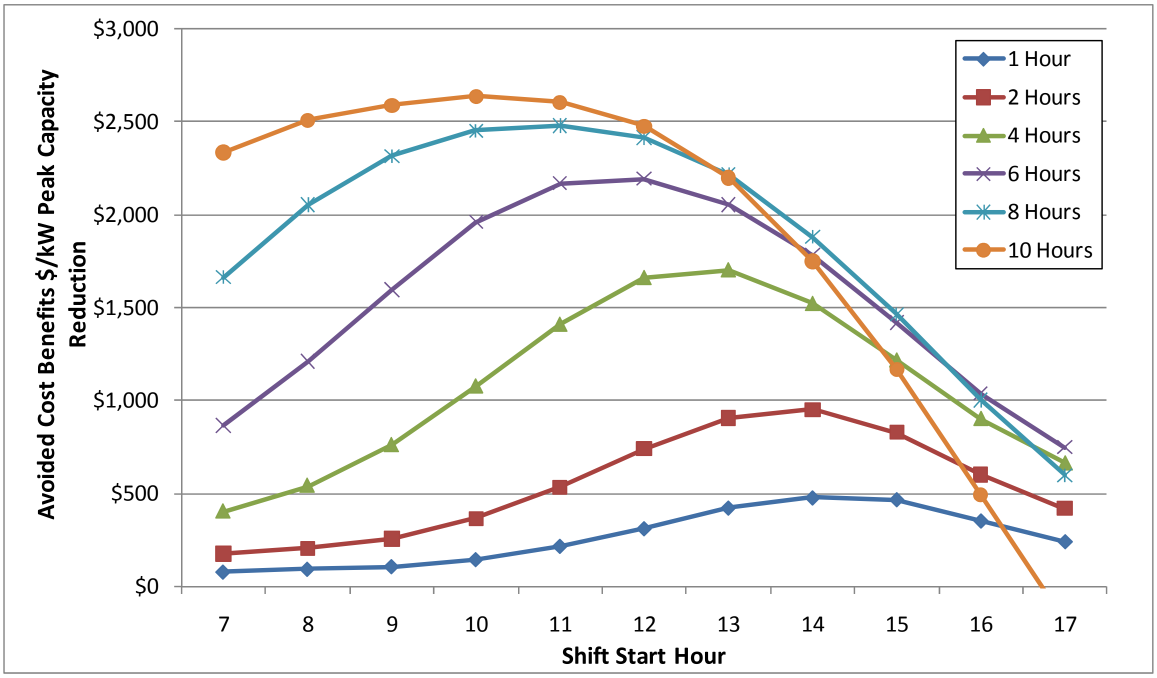
response [R. 07-01-014]. The precursor to each of these was the development of avoided costs for energy efficiency adopted by the CPUC in 2004 and 2005 [R.04-04-025][2].

The avoided cost benefits provided by PLS include electrical energy, losses, ancillary services, system (generation) capacity, transmission and distribution capacity, environmental costs, and avoided renewable energy purchases. We also investigated the renewable integration benefits of load following and over-generation that could be provided by PLS.

As shown in Figure 1, using this new PLS cost-effectiveness framework, the lifecycle value of the avoided cost benefits of PLS technologies (assuming 15 year project life estimates) is in the range of $500/peak kW to $2500/peak kW, depending on the number of hours the PLS system can shift load, and what hour the load shifting starts. These figures are calculated based on the kW value of the load shift and are 'technology neutral', and do not include benefits from other value streams. They assume the 'best case' operational profile in that they assume the maximum load shift every day of the year, and off-peak usage at the least cost period during the night. For example, a 6-hour load reduction beginning at 12pm over an assumed 15-year life is valued at ~ $2200/kW (or $365/kWh stored capacity).

[2] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/36203.pdf

Figure 1: Broad Scenario Analysis – Avoided Costs



While the project team believes these figures are appropriate for currently available PLS technologies, we note that the benefits in Figure 1 do not include the provision of ancillary services such as regulation that some PLS technologies plan to provide[3]. In addition, some stakeholders have suggested that a 15-year life is too short and longer lived installations will have greater lifecycle value.

To address these issues, the report presents these sensitivities and many others. For example, an assumed 30-year project life cycle is estimated to increase lifecycle avoided cost benefits by approximately 30%. The main results are also shown in terms of lifecycle $/kWh-stored, which is a common capacity metric for batteries. The "in-situ" cost-effectiveness of both simulated and real installations (such as from the utility PLS pilots) are also provided.

Using the California Standard Practice Manual (SPM) framework for evaluating the cost effectiveness of ratepayer funded programs that the CPUC relies on for

[3] A number of battery technologies providers have indicated their ability and interest to provide ancillary services as well as load shifting.

other distributed resources, the installed PLS system costs must be less than the lifecycle benefits in order to pass the Total Resource Cost (TRC) test. While the installed system costs specific to PLS are often difficult to ascertain (for example, due to customer confidentiality), or the costs were obtained under a nondisclosure agreement (NDA) and cannot be shared in this report, certain classes of thermal storage are likely to pass the TRC (e.g., warehouse precooling achieved by controls modifications, improvement of existing thermal storage systems, medium-sized ice-based storage, chilled water for new construction and expansion applications); these technologies are more mature and their lifecycle values tend to be within the range of the avoided cost benefits. Emerging grid connected battery technologies and smaller scale[4] thermal storage systems with higher costs are less likely to pass the TRC cost-effectiveness test at their current system costs.

One of the objectives of this study was to determine what level of incentive payment would be appropriate. From a ratepayer perspective, an incentive can be provided to reduce the incremental costs of PLS systems over standard non-PLS technology without any ‘cross-subsidy’ at a level equal to the lifecycle benefits presented in Figure 1 ***less*** the bill savings the end-user receives by operating the PLS system. One can think of the bill savings as ‘paying’ the end-user for the societal benefits they provide with their PLS system. This study finds that even when the PLS operations are designed to maximize bill savings, there are some situations when an incentive payment can be provided without any cross-subsidy. The actual value of this ‘ratepayer neutral’ incentive level depends on the PLS system operation and the specific retail tariff.

Using a ‘generic’ rate that is representative of medium and large commercial customers’ rate structures, we find an incentive payment of ~ $100/peak kW to $800/peak kW for PLS is possible without any cross-subsidy. When modeling specific IOU rates, the rate payer neutral incentive levels range from roughly

[4] Smaller scale thermal storage is defined as units < 10kW, such as those installed on small commercial buildings that do not have central cooling plants.

-$800/peak kW to $1600/peak kW. Ratepayer neutral incentive levels for specific installations are also provided in the main body of the report.

1.3. Value Proposition to End-User

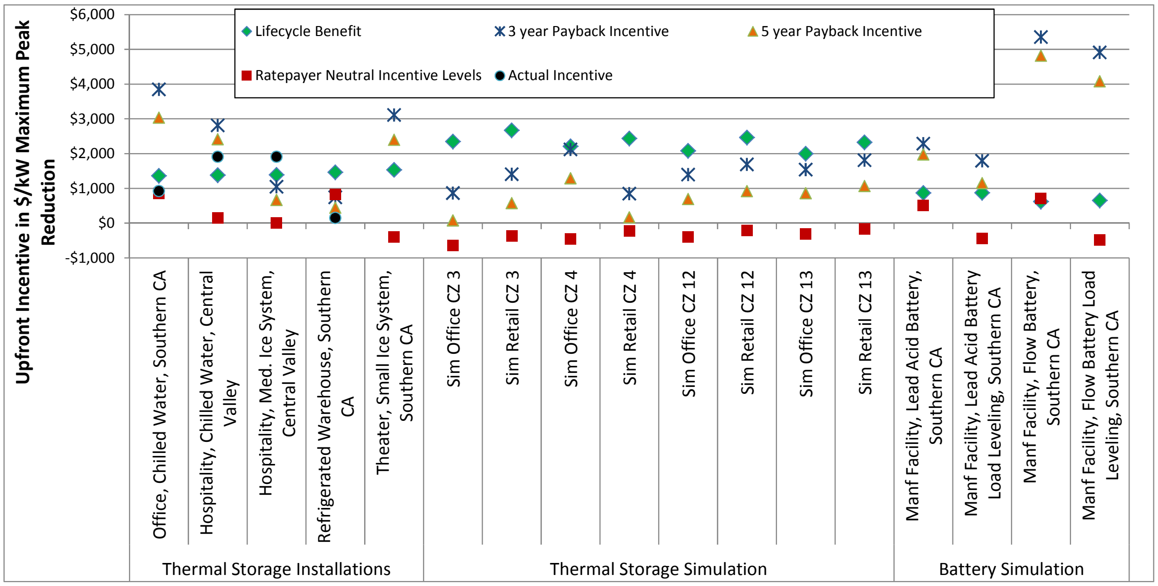
While the economic analysis of demand side programs focuses on the costs and benefits to society and the funding levels needed to develop cost effective programs, customers will ultimately need to see the direct benefits of PLS technology adoption to their core business to justify their investment of capital and time, and their assumption of various project risks. The StrateGen Consulting team evaluated the end-user value proposition to determine incentive levels that would be needed to promote the likely adoption of specific PLS technologies, based on stakeholder feedback on customer-specific required payback periods. The analysis also provides insights into other elements of the program design that are important to encourage PLS technology adoption, such as the investment business model, financeability, and mitigation of tariff risk related to changes in bill savings over time.

Numerous stakeholders provided consistent input that the end-user's financial hurdle for adoption is a minimum 3 to 5 year payback. This is a significant financial hurdle that typically requires greater than 15% internal rates of return. Stakeholders also uniformly expressed concern on how tariff structure changes can undermine the economic return of PLS projects, and that to date, such 'tariff' risk' has been largely uncontrollable. StrateGen tested these required payback hurdles by conducting a project-specific value proposition analysis of simulated PLS systems and IOU pilot project data.

For simplicity, a $/max kW incentive level for shifted off peak load was calculated to achieve three and five year paybacks. However, it is important to note that such incentives can be structured in a variety of ways, which is further described in the program recommendations section.

The following graph overlays several simulated PLS system payback scenarios for various building types in different California climate zones for thermal storage, along with simulations for battery storage simulations for manufacturing building load profiles. The simulations compare the amount of the required incentive levels ($/kW) for encouraging PLS customer adoption for 3 and 5 year paybacks. Also included are two of the SPM cost effectiveness evaluation tests[5] for comparison:

Figure 2: Required Incentives. Lifecycle Benefit & Ratepayer Neutral Incentive Levels



The chart above indicates that the required incentive levels for the thermal storage simulations range from about $100 to $1,000/kW to achieve a 5 year payback for the end user and approximately $860 to $1,800/kW to achieve a 3 year payback. The battery simulations' required incentive levels range from $1,100 (5 year payback) to over $5,000 (3 year payback) to achieve required customer investment payback levels. It is important to note that the battery simulations were performed for only two different battery technologies among a wide range of possible battery technologies. The results will vary tremendously depending on the specific type of battery technology used. For many simulated examples, the 3 and 5 year payback incentive levels are less than the total lifecycle benefits, but are still greater than the ratepayer neutral incentive levels.

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5 The Program Administrator Cost (PAC) and Ratepayer Impact Measure (RIM) tests

1.4. PLS Market Assessment

The assessment of the PLS market opportunity is based on an overview of PLS incentive programs in the U.S. and stakeholder feedback gathered from California IOU program personnel, third party vendors, engineers, PLS technology suppliers, and other individuals and companies[6].

The majority of the programs around the country are utility-sponsored thermal energy storage standard offers. Other program types include special TOU rate structures or technology-neutral load shifting programs. The following conclusions are based on a review of fifteen utility programs in the U.S.:

- Funding feasibility studies improves outcomes and customer commitment, and is a core part of many programs' incentive structure.
- A number of programs offer special TES/PLS rates that accompany incentives, which not only reduce tariff risk and provide greater certainty for economic return, but also improve payback and encourage efficient system operation.
- Programs that do not provide an adequate up front incentive will struggle to attract customers, particularly in today's challenging economic climate.
- Utility-ownership reduces costs through increased purchase volume and more efficient customer targeting, but this model may not be of interest to many utilities due to the complexity of utility ownership for behind-the-meter, customer sited assets (particularly very small PLS systems).

While this study is exploring a variety of PLS technologies, due to PLS program eligibility requirements, it is important to note that most of the program design feedback reflects experience with thermal energy storage systems from the PLS pilots. Table 2 summarizes the stakeholder feedback into consensus feedback, or feedback that was expressed and agreed upon by most stakeholders, and non-

[6] Over 30 stakeholder interviews were conducted

consensus feedback, representing areas of disagreement regarding the ideal approach to encouraging PLS.

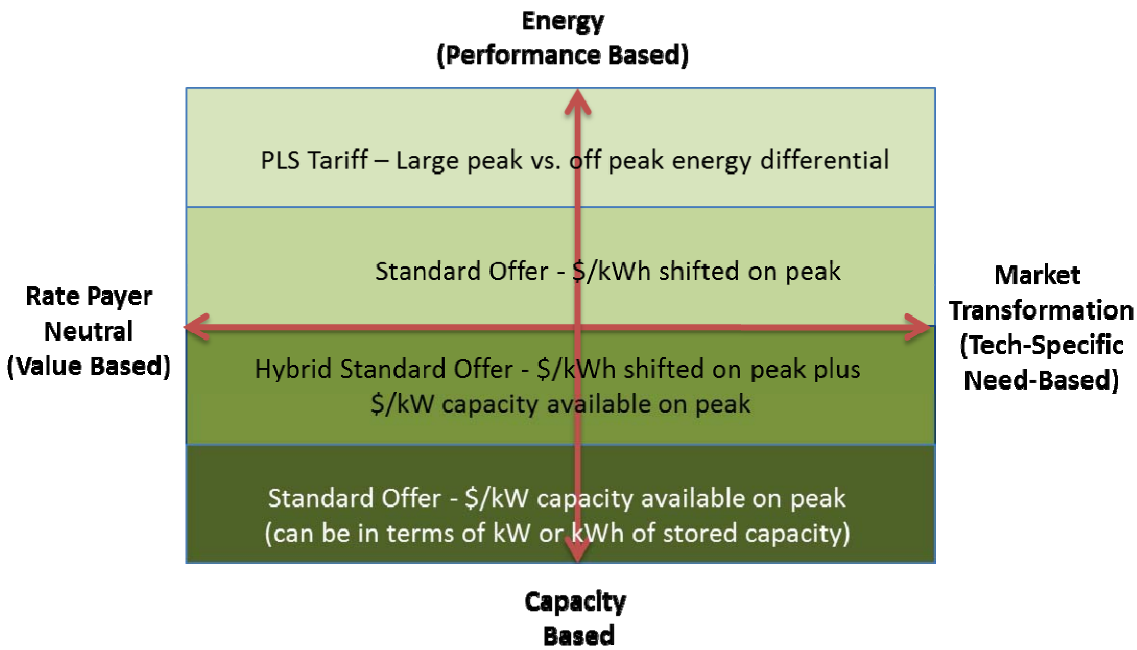
Table 2: Consensus and non-consensus feedback

Consensus	Non-Consensus
Lack of consistent and transparent rate structures that promote PLS are an impediment	Desired incentive levels and structure of incentive (e.g., Tariff based only or tied to capacity/ hours shifted)
A standard offer is preferable to an RFP, as it more easily encourages technology neutrality, and participation by smaller stakeholders	Tailoring of incentives to technology class and size.
Incentive levels need to take into account all project and market entry costs, deliver 3-5 year payback, and not exclude any technologies from participation	Required metering/monitoring, specifics as to what needs to be monitored and at what level of detail
Consistency in programs across IOU service territories is important	Allocation of PLS budget (e.g. marketing vs. implementation funding)
Program complexity adds costs and discourages market participation	Potential for market expansion
Lack of education/training about PLS technologies — their design, implementation and operation — is a severe challenge	

1.5. PLS Program Recommendations

There are a number of dimensions by which the CPUC can consider standard offers for PLS program design. The most fundamental dimensions are the program structure and the monetary value of the incentive itself. The following chart illustrates these dimensions, each with its own respective continuum. Shown left to right, a PLS program at one end of the spectrum can have no impact to ratepayers. In this case, the incentive would be ‘ratepayer neutral’. This level of incentive could have a lenient program limit since there is no ‘cross-subsidy’ for ratepayers, nor an explicit goal of encouraging large amounts of well-operated PLS systems in the field. At the other end of the spectrum would be incentives whose levels are set based on the technology cost to encourage more ‘robust’ commercial adoption at the technology specific level, perhaps based on achieving certain payback or internal rate of return requirements by targeted end-users. This level of incentive would be useful to encourage ‘market transformation' of the PLS technology, would have tighter program caps to protect ratepayers, and a goal to reduce costs (and incentives) over time. From top to bottom, the program can be geared toward incentivizing energy shifting on peak over time, or, at the other end of the spectrum, be more focused on pure capacity.

Figure 3: Standard Offer Program Design Framework



Given the currently higher costs of grid connected battery applications and smaller scale thermal systems, the Joint Utilities and the CPUC may consider developing programs to encourage these technologies for market transformation reasons, as they can play a role in providing a high value use of 'super off-peak' renewable energy generation ("over-generation") in the future.

As described in the program design findings, should the Joint Utilities and CPUC seek to develop an incentive program for PLS, we recommend segmenting the PLS program offering into at least two general technology categories; a 'mature' PLS technology category that is available to any PLS technology with nearly 'ratepayer neutral' incentive levels; and an 'emerging' PLS technology category that provides higher incentive payments (though limited in quantity) to specific PLS technologies such as small' thermal storage and electrical battery storage that have the potential to provide more 'dynamic' system response in the future suitable to support renewable integration. We recommend that process shifting be further evaluated to determine appropriate industries and loads to target for program development.[7]

In addition, a number of best practices were observed from the pilots and other PLS programs nationwide that are worth considering for California. The following summary of the PLS program design recommendations should be considered:

- Divide PLS Program into at least two categories based on technology; one for mature large scale PLS, and one for emerging PLS technologies, with different program designs and goals.
    - Mature: Large scale PLS deployment that minimizes ratepayer incentives and provides thermal-based solutions
    - Emerging: Market transformation for storage with focus on integration with renewable resources and energy efficiency
- Program design should address each of the three stages of the PLS system deployment through incentives, reports, or EM&V, to increase the quality of the deployed PLS systems. These include;
    - (1) feasibility and design of PLS systems,
    - (2) quality control of construction and post-construction functional performance testing, and
    - (3) persistence of PLS operations.
- Provide consistent and predictable bill savings to encourage long term customer investment in PLS technology, that

[7] These program recommendations are based on our survey of best practices, utility pilot data analysis, stakeholder interviews, cost-effectiveness results, and workshop discussion.

- Provides a financeable level of long term rate stability to encourage the initial capital outlay in a PLS system. This can be done with a separate PLS rate, or by a 'guarantee' of minimum on- to off-peak rate differentials or 'grandfathering' existing TOU rates
- Offers a 'super' off-peak rate to encourage charging after midnight or 2am when the overgeneration problem is expected to be the worst and energy has the lowest cost, and

- Encourage sustained PLS performance using performance-based incentives and regular EM&V;
    - Performance-based incentives could be achieved through one of two approaches depending on technologies;
        - A 'PLS' tariff with TOU rate differentials provides some incentive to operate the PLS system well, and does not require a specific baseline development. This approach is more suitable for thermal storage.
        - A standard offer model based on an energy payment ($/kWh shifted) provides a direct performance-based incentive, but would require strict guidelines for calculating baselines for thermal or process shifting PLS technologies. Therefore, this approach is easier to provide to electrical battery systems. This approach also reduces potential for "gaming" with battery systems (where batteries are used for non-PLS purposes such as for providing uninterruptible power supply).
    - Both incentive approaches should be coupled with an EM&V requirement to provide an 'operations report' and operational data of the system and the whole customer load.

- Incentives and incentive structure directly influence PLS design and operations, so it is important to provide incentives consistent with program goals
- Simplicity and transparency of the performance metrics are critical to minimizing program cost and encouraging customer adoption

As per the CPUC order that initiated this report, the Project Team has included a detailed discussion of a PLS standard offer proposal that could apply generally to any permanent load shifting technologies including, but not limited to, thermal energy storage. The specifics of the Standard Offer are covered in detail in Section 6 of this report.

2. Introduction and Purpose of Study

2.1. Policy Background

2.1.1. CPUC Regulatory Background[8]

PLS has existed for many years as an electric customer demand side technology that enables customers to reduce their energy bills by shifting loads from peak periods, when rates are higher, to off-peak periods when rates are lower. However, PLS has most recently been addressed in state regulatory policy through the IOUs' existing demand response programs.

In 2006, California experienced a severe heat storm that prompted the CPUC to issue an Assigned Commissioner Ruling to augment the IOU's recently approved DR programs for 2007 and 2008, and to improve program performance with the adoption of new programs and technologies. Workshops and discussions were held on the performance of existing DR programs, and the recommendations to improve and augment these programs were filed. Based on the recommendations, the CPUC's decision D.06-11-049 was issued in 2006 ("Order Adopting Changes to 2007 Utility Demand Response Programs") that advised the IOUs on DR program improvements, as part of a broader effort to assure system reliability and affordability.

Included in D.06-11-049 were a number of DR program modifications and approval for new program designs for 2007 and beyond. While not specifically considering PLS as energy efficiency or demand response, the CPUC determined that load shifting from PLS may reduce the need for capacity investments, reduce the likelihood of shortages during peak periods and lower system costs overall by reducing the need for peaking units.

[8] Information on the regulatory background were obtained through CPUC documents and discussion with the CPUC and IOU working group involved with this study.

Numerous parties, including Ice Energy, consumer advocacy groups, and the IOUs expressed their support for PLS programs using incentive funds from the IOU's DR programs. As a result, the CPUC ordered the IOUs to pursue RFPs and bilateral arrangements for five year PLS projects from third parties that could be implemented by the summer of 2007. The decision also allowed the IOUs to allocate portions of their existing demand response budgets to offset the initial installation costs of PLS technologies.[9] In total, the decision allowed $24 million of demand response budget to be shifted to PLS pilot projects ($10 million for PG&E, $10 million for SCE and $4 million for SDG&E). The decision did not specify a preference for any particular technology, but directed the utilities to consider cost-effectiveness and other factors, such as ease of implementation. The decision also specified that each utility was to file an advice letter with the CPUC by February 28, 2007 that described the proposals chosen.

Subject to D. 06-11-049, each IOU issued an RFP for PLS pilot projects. After proposals were solicited, each IOU evaluated their proposals using their own criteria. Key evaluation criteria in PG&E's RFP process included a benefit-cost ratio, bidder's track record and performance in load shifting programs, and the methodology used to produce demand and energy savings. Key evaluation criteria in SCE's RFP process included cost, ease of implementation, the amount of load shifting to be obtained by summer of 2008, potential for growth and expansion, and reliability. Key evaluation criteria in SDG&E's RFP process included cost effectiveness, load growth potential, reliability, marketability, and program's ability to deliver energy savings with peak load shifting.

In accordance with D. 06-11-049, SCE and SDG&E filed advice letters with the CPUC on February 28, 2007 that described the selected PLS proposals. PG&E filed an advice letter on February 28, 2007 but were still in negotiations with PLS vendors. On March 29, 2007 PG&E filed a supplemental advice letter that described the selected PLS proposals. During this time, SCE filed an advice letter recommending a non-thermal based PLS pilot program, which was rejected by

[9] The CPUC's D.06-11-049 can be found here: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/62281.pdf .

the CPUC. A subsequent update of the advice letter incorporating three different thermal based PLS technologies was later approved. Further details on the PLS pilot are in Section 2.2.

During 2008, the IOUs filed applications for IOU specific DR program and budget applications for approval of 2009-2011 DR programs. During the regulatory process in which parties provide comments on the applications and during evidentiary hearings, Transphase requested the CPUC to expand the existing PLS program and to require utilities to create a PLS standard offer program that could provide rebates up to $1,400 per installed kW of PLS over the 2009-2011 period. Ice Energy also encouraged the expansion of the PLS program within IOUs demand response program applications. The IOUs proposed to continue the existing pilot programs, as initially ordered through 2011, and not expand these pilots beyond their authorized scopes.

CPUC responded in D.09-08-027, "Decision Adopting Demand Response Activities and Budgets for 2009 through 2011".[10] The decision mandated the IOUs to conduct a study (this study) to examine ways of expanding PLS; explore a standard offer for PLS, including, but not limited to thermal energy storage; consider ways to encourage PLS, such as through TOU rates or another RFP process; summarize PLS offerings in the US; and evaluate an appropriate incentive payment for a future standard offer. The findings of this report will inform proposals to expand PLS in the IOU's 2012-2014 demand response applications, which are due by January 30, 2011.

The CPUC provided additional guidance in the "Administrative Law Judge's Ruling Providing Guidance for the 2012-2014 Demand Response Applications".[11] The guidance includes clarification on the definition of PLS. The ruling states that PLS involves shifting energy use from one time period to another on a recurring basis and often involves storing electricity produced during off-peak hours to use to support load during peak periods. Examples of PLS include battery storage,

[10] The CPUC decision D.09-08-027 can be found here: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/106008.pdf.
[11] See http://docs.cpuc.ca.gov/efile/RULINGS/122575.pdf

thermal energy storage, and altering processes to shift the time of use or order of production activities.

PLS as a demand side customer measure continues to be currently managed and evaluated through the IOU's demand response regulatory proceedings. In October 2010 the CPUC stated in the proposed cost-effectiveness protocols for demand response, "Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities", that it expected the demand response cost-effectiveness protocols to apply to PLS projects, although the CPUC may approve specific protocols for PLS in the future.[12]

2.1.2. Other Policy Background

There have been additional policy initiatives by the CEC and CPUC to study energy storage and enhancements to demand response that involve PLS. The CEC's "Energy Storage and Automated Demand Response Technologies to Support Renewable Energy Integration" initiative aims to establish a technology baseline for its 2011 Integrated Energy Policy Report (2011 IEPR) and develop policies to accelerate the deployment of energy storage and automated demand response technologies. The CEC is also leading the development of a 2020 Energy Storage Strategic Vision that will feed into the 2011 IEPR. The CPUC is required to initiate a storage focused rulemaking pursuant to AB2514. That proceeding will, by 2013, determine whether cost-effective and technologically feasible energy storage procurement targets should be established for 2015 and 2020. PLS technologies are covered under both the CEC and CPUC initiatives.

2.2. PLS Pilots

2.2.1. SCE

Three PLS proposals were developed by the IOUs and approved by the CPUC in SCE's RFP process. They included Honeywell Utility Solutions administering an Ice Energy (packaged ice storage) program, ROI-CAC administering a chilled

[12] The CPUC proposed decision can be found at: http://docs.cpuc.ca.gov/efile/PD/125044.pdf

water program, and Cypress Limited administering a CALMAC (packaged ice bank) program. These three proposals provided marketing, installation, commissioning, and evaluation and measurement.

ROI-CAC enrolled four TES chilled water project customers at the beginning of the program. These included three legacy thermal storage systems were retrofitted and one new TES central plant was constructed. In each of the retrofitted cases, the TES tanks were either partially used or undersized. The modifications included chiller repiping, replacement, improved cooling towers, controls and pumping.

The Honeywell program marketed Ice Energy's Ice Bear technology which required Honeywell to work with contractors, developers and city agencies. The target customer size was 200-500 kW with a goal of subscribing 2,500 kW shifted in total. To date, 2,205 kW have been reserved in applications to the program with 142 kW in actual projects (21 Ice Bears). An incentive level of $1,100/kW is being used and projects are now in measurement and verification mode to demonstrate seasonal operations and shifting.

For the Cypress PLS program, a 5,000 kW program target was set with a $250/kW customer incentive; 3,710 kW has been reserved to date with 2,449 kW completed. These projects tend to be larger community colleges.

2.2.2. PG&E

PG&E's PLS program, "Shift & Save", aims to promote TES. The program is implemented by Cypress and Trane U.S. Inc. Both vendors have full responsibility for the program and delivering the actual load shift results. The total program shift goal is 7,950 kW and eligible customers are bundled service commercial, industrial, agricultural, or large residential customers. Cypress currently has a program goal of 6,750 kW subscribed under four customers with ~ 125 kW installed to date.[13] Among these, one is new, three are retrofit and all

[13] Note, Cypress's original goal was 2,700 kW from ice storage air conditioning but was recently increased to 6,750 kW, and expanded to include other technologies.

use ice storage air conditioning. Trane U.S. Inc. has 1,200 kW subscribed with three customers. Two of the installations are new and one is a retrofit. The technologies include stratified chilled water and internal-melt-ice-on coil.

PG&E reviews the PLS program in three parts: (1) the project is evaluated for participation, (2) the project is evaluated for an installation incentive and (3) following the submission of EM&V reports at the end of the summer, the project is evaluated for persistence payments.

2.2.3. SDG&E

SDG&E has two PLS programs: EPS' refrigeration zone control module that precools freezers, allowing them to operate without mechanical cooling during peak periods and Cypress' gas absorption and gas engine driven air conditioning systems. The total program goal was 3,200 kW and to date, 2,900 kW has been subscribed. The incentive levels for EPS are $150/kW. The incentives for Cypress are $500/kW for systems greater than 100 tons and $700/kW for smaller systems. These levels were based on bidders' proposals.

2.3. Definition of PLS

The CPUC has defined PLS through regulatory orders and filings. In D.06-11-049 PLS is defined as "when a customer moves energy usage from one time period to another on an ongoing basis." The CPUC does not consider PLS to be an energy efficiency program because PLS does not always reduce energy consumption; the CPUC does not consider PLS to be a demand response program if it is not dispatchable or price responsive on a day-ahead or day-of basis.

For the purposes of this study, PLS is defined with the overarching goal of "routine shifting from one time period to another during the course of a day to help meet peak loads during periods when energy use is typically high and improve grid operations in doing so (economics, efficiency, and/or reliability)." This definition is guided by the principles of technology neutrality, business/ownership neutrality, and the measurable shift at program level for evaluation, measurement and verification.

The proposed definition is based on several elements: 1) permanent; 2) load shifting; 3) location; and 4) additional value streams. By permanence, PLS must provide a sustained capacity of load shifting in normal operation a large number of days per year for many years. Through load shifting, PLS decreases usage during peak hours and shifts loads to other hours to provide operational and resource planning benefits for the utility or ISO systems (such as increasing load to reduce ramp requirements). The location element requires the PLS technology to be located behind an electricity customer's meter, making all customer classes eligible to participate. Finally, while PLS services are essential, additional value streams should be provided if the PLS technology has the capability.

Table 3 shows the different applications and technology categories and provides examples of each.

Table 3: PLS technology applications, categories and examples

Application	Category	Primary characteristics/ examples
Stationary	Thermal storage	Generate ice or chilled water at night, then use this stored ice or chilled water to provide cooling during the day.
Stationary	Non-thermal storage	Chemical batteries, mechanical storage – e.g., fly wheels, modular compressed air (CAES)
Stationary	Facility process shifting	Processes conducted within a facility that are shifted from one time period of the day to another
Mobile	Plug-in electric vehicles	Not in scope (Because mobile storage has a concurrent proceeding at the CPUC)

The following elements are outside the scope of PLS. First, PLS is not solely event-based demand response. While PLS does provide for shifting in normal operations, it does not provide shifting in response to electrical grid emergencies or constraints as event based demand response does. Second, PLS is not behavior-based energy efficiency. PLS is provided and quantified by discrete equipment or controls, not solely by general customer behavior modification, and it does not reduce the level of customer service. Third, the load reduction and shifting that can be achieved by best practices commissioning, retro or recommissioning, or adjustment of controls is not considered PLS, unless such practices are being applied directly to existing legacy PLS technologies (such as unused thermal storage tanks) and are not currently being implemented through energy efficiency programs. Finally, fuel switching is not PLS.

3. Study Methodology

The PLS cost-effectiveness evaluation is performed using two models. The first model, the PLS Cost-effectiveness Tool (PLS CE Tool), is designed to assess a wide variety of technologies and scenarios, and overall PLS program cost-effectiveness. It uses publicly available and stakeholder provided data in a transparent model to calculate the cost-effectiveness of a PLS technology or program. The PLS CE Tool is implemented in Analytica and can be downloaded and run using the free Analytica Player, and modified using the Analytica platform.[14] With the tool, the balance between customer incentives and the impact on non-participating ratepayers is evaluated. Using 8,760 hourly PLS system impacts, customer loads, retail rates and avoided costs, the tool calculates the net present value of the costs and benefits over the life of PLS technology. With the Analytica Free Player, stakeholders can view and audit the calculations, as well as see how the cost-effectiveness results would change for the 15 California IOU tariffs modeled.

A more detailed financial pro-forma model, developed by StrateGen, provides a more in-depth analysis of cost-effectiveness from the participating customer perspective. This model analyzes specific customer scenarios with customer specific financial information. Much of the data required for an analysis of this depth is held as proprietary for the customer or technology provider and this model is not available for public review.

[14] Available for download from Lumina Decision Systems, Inc. at http://www.lumina.com/ana/player.htm

Ratepayer Perspective

E3 PLS Cost-effectiveness Tool

- Public and transparent
- Avoided cost calculations using public data
- Public cost estimates and those provided through public stakeholder process
- Cost test results at program level
- Evaluate trade-offs between customer, utility and non-participating ratepayer costs and benefits

Industry Perspective

StrateGen Proforma

- Proprietary tool (inputs & outputs provided publicly)
- Financial Proforma with cash flow
- Participant perspective
- Supports evaluation of incentives and rate design to encourage adoption

Figure 4: Summary of the E3 PLS Cost-effectiveness Tool and the StrateGen Proforma model.

3.1. Cost effectiveness

3.1.1. PLS Modeling Inputs

Four broad input categories are required for PLS cost-effectiveness evaluation: PLS system costs, PLS system performance and load impacts, retail customer rates, and avoided costs. These are described below.

3.1.1.1. PLS System Costs

PLS system costs were gathered from utility program managers and from technology vendors. The PLS CE Tool uses representative estimates of system costs for the range of available technologies, and program level costs where available. Where necessary, we worked with customers and technology vendors to produce more detailed cost estimates.

3.1.1.2. PLS System Performance

The utilities and technology community provided the project team with data on system performance. The data provided varied substantially in terms of temporal duration, interval, and baseline information. The project team worked closely with the utilities and vendors to construct 8,760 hourly profiles of PLS kW impacts. These impacts were used to estimate the customer bill savings and the avoided cost benefits over the life of the PLS technology. Where available, the customer's end-use load profile was used in combination with the PLS system impacts to calculate a before and after load shape. In other cases, end-use load data was not available and the PLS impact alone was used. End-use load data is most important for evaluating demand charge bill savings, but not necessary for evaluating bill savings from energy charges and avoided cost benefits. As several stakeholders have noted, it is important that the hourly input data (load impacts and avoided costs) be in alignment to provide meaningful results.

3.1.1.3. Retail Tariffs

Recent tariffs were gathered from the IOU websites for the residential, commercial and industrial classes. A full range of demand charges, TOU rate differentials and dynamic rates were included for all three utilities. The rates are entered into both models, each of which calculates the rate applicable for each hour in each month based on the tariff rules. With this disaggregated rate data, the models calculate the change in the customer bills realized with PLS.

3.1.1.4. Avoided Costs

Avoided cost benefits provided by PLS and other Distributed Energy Resources (DER) include seven categories: generation energy, losses, ancillary services, system (generation) capacity, T&D capacity, environmental costs, and avoided renewable purchases. In addition to these benefit categories, we also investigated the renewable integration benefits of load following and overgeneration that could be provided by PLS.

The avoided costs used for this analysis are derived from the Distributed Generation (DG) Cost-Effectiveness framework adopted by the CPUC in D. 09-08-026, which specifies the use of a marginal avoided cost-based approach to distributed resource valuation. The avoided costs are calculated using the Avoided Cost Calculator with some modifications. The Avoided Cost

Calculator draws heavily on the methods established by other CPUC cost-effectiveness assessments for distributed resources including distributed generation (DG), demand response (DR), and energy efficiency (EE). Additional information on the calculation of avoided costs is in Appendix A.

3.1.1.5. Modeling Approach

Both the PLS CE Tool and the StrateGen Proforma model compare the cost of installing and operating the PLS system with the benefits generated over the life of the system. The PLS CE Tool uses system costs expressed in $/kW installed and annual O&M costs expressed in $/kW-Yr. For the StrateGen Proforma Model more detailed customer specific cost and financing inputs are used.

The PLS system impacts are estimated on an 8,760 hourly basis and the avoided cost components are also calculated on an 8,760 basis. In the case of generation and T&D capacity, the benefit values (in $/kW-Yr.) allocated to specific hours (in $/MWh) are based on system load and temperature data, respectively. Retail rate impacts are also calculated on an hourly basis for energy charges and a monthly basis for demand charges.

The models compute the present value of the system installation and operating cost and compare those against the present value of the applicable benefits for each cost-effectiveness test.

3.1.2. Cost-effectiveness Tests

The cost-effectiveness of individual technologies and overall utility PLS program offerings are evaluated. These tests are described in the *California Standard Practice Manual for the Economic Analysis of Demand-Side Programs and Projects*, commonly referred to as the *Standard Practice Manual* (SPM), issued by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) in 2001. The four cost-effectiveness tests performed for this analysis are summarized in Table 4 and described below.

Table 4. Cost effectiveness tests applied in scenario analysis tool

Cost Test	Acronym	Purpose
Total Resource Cost Test	TRC	Financial impact from a societal level is used to determine whether the program should be offered. Incentive levels do not change the TRC result.
Ratepayer Impact Measure	RIM	Impact on non-participating ratepayers is used to balance the incentives so that other ratepayers are not disproportionately impacted by the program
Program Administer Cost	PAC	Input on ratepayers overall is used to estimate the total costs of the program net of system benefits
Participant Cost Test	PCT	Financial proposition to the customer is used to define incentive and shows relative attractiveness of the program and estimating participation

3.1.2.1. Total Resource Cost-effectiveness Test (TRC)

The TRC is the primary test used to evaluate the overall cost-effectiveness of DERs in California and many other jurisdictions. It measures the net benefits to the region as a whole, irrespective of who bears the costs and receives the benefits. Unlike the other cost tests, the TRC does not take the view of any particular stakeholder. The incremental costs of purchasing and installing the PLS system above the cost of standard equipment that would otherwise be installed, and the overhead costs of running the PLS program are considered. The avoided costs are the benefits. Bill savings and incentive payments are not included, as they yield an intra-regional transfer of zero ('benefits' to customers and 'costs' to the utility that cancel each other on a regional level).

The TRC does not evaluate distributional impacts among stakeholders. The other three tests are distributional tests that evaluate the net benefits to different stakeholders. These include non-participating ratepayers (RIM), the utility or program administrator (PAC) and the participant (PCT).

3.1.2.2. Ratepayer Impact Measure

The Ratepayer Impact Measure (RIM) examines the impact of the program on non-participating customers through changes in utility rates. The RIM test is used to define the 'ratepayer neutral' incentive level. Most DERs that provide energy efficiency put upward pressure on retail rates as the remaining fixed costs are spread over fewer kWh and do not ‘pass’ the RIM test. In the case of PLS, energy sales are shifted from higher cost on-peak periods to lower cost off-peak periods. This can reduce utility revenues and put upward pressure on utility rates if the total bill savings is less than the savings in utility avoided cost. The costs included in the RIM test are program overhead and incentive payments and the cost of lost revenues due to reduced sales. The benefits included in the RIM test are the avoided costs of energy saved or shifted (same as the TRC).

3.1.2.3. Program Administrator Cost-effectiveness Test

The Utility/Program Administrator Cost Test (PAC) examines the costs and benefits of the program from the perspective of the entity implementing the program (utility, government agency, non-profit, or other third-party).[15] The costs included in the PAC are overhead and incentive costs. Incentive costs are payments made to the customers to offset purchase or installations costs. The PAC does not include bill reductions. The benefits are the lifecycle avoided costs.

3.1.2.4. Participant Cost-effectiveness Test

The Participant Cost Test (PCT) examines the costs and benefits from the perspective of the customer installing the PLS system. Costs include the incremental costs of purchasing and installing the PLS system above the cost of standard equipment that would otherwise be purchased by the customer. The benefits include customer bill savings, incentives and any applicable government tax credits or incentives.

[15] The UCT/PAC was originally named the Utility Cost Test. As programs management has expanded to government agencies, not-for-profit groups and other parties, the term “Program Administrator Cost Test” has come into use, however the computations are the same. This document refers to the UCT/PAC as PAC for simplicity.

3.1.2.5. Cost-effectiveness Test Summary

The primary cost and benefit categories for each test are shown in Table 5. The TRC, RIM and PAC all include the same avoided costs as benefits to the region (in the case of the TRC) and to the utility (in the case of the RIM and PAC). Expressing the regional perspective, the TRC does not include incentive payments or bill savings, which are intra-regional transfers.

The RIM includes all costs that must be borne by non-participating ratepayers, including program overhead and incentives, which are additional expenditures incurred by the utility that increase the total revenue that the utility must collect. The RIM includes bill reductions as revenue losses, which increases the amount of revenue that must be collected from other customers, putting upward pressure on rates. The PAC looks at the utility revenue requirement only, including program overhead and incentive payments as costs. Note that the system cost is not included.

Finally, the PCT looks at the customer perspective. The benefits to the customer are the bill savings and incentives. These benefits are weighed against the cost to the customer of installing and operating the PLS system.

Table 5: Costs and Benefits Included in Each Cost-effectiveness Test

Component	TRC	RIM	PAC	PCT
Avoided Cost Benefits	Benefit	Benefit	Benefit	-
Equipment and install costs	Cost	-	-	Cost
Program overhead costs	Cost	Cost	Cost	-
Incentive payments	-	Cost	Cost	Benefit
Bill Savings	-	Cost	-	Benefit

3.1.3. PLS Avoided Cost Benefits

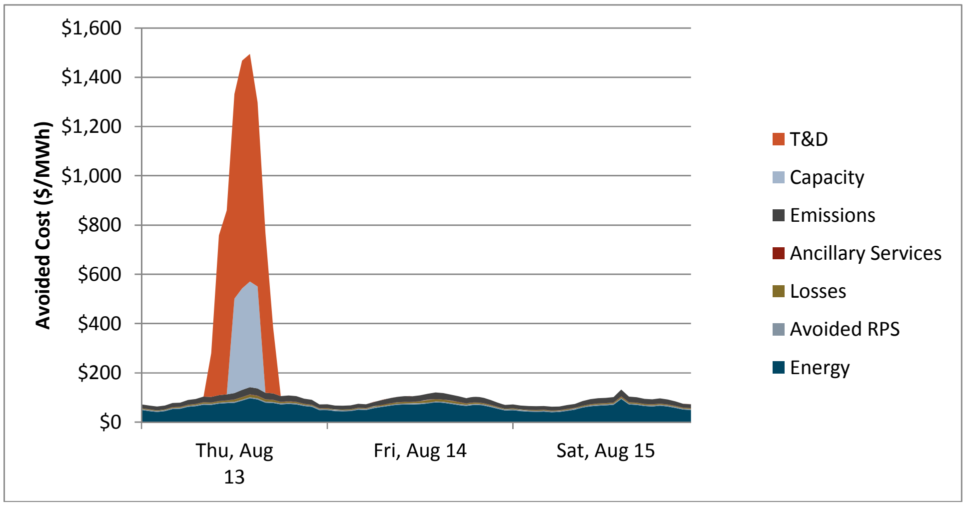
Avoided cost benefits provided by PLS (and DERs in general) include seven categories: Generation Energy, Losses, Ancillary Services, System (Generation) Capacity, T&D Capacity, Environmental costs, and Avoided Renewable Purchases. The value is calculated as the sum in each hour of the seven individual components. A more detailed description of each of the components is provided in Table 6.

Table 6: Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource
Avoided RPS	The avoided net cost of procuring renewable resources to meet an RPS Portfolio due to a reduction in retail loads

Figure 5 shows a three-day snapshot of the avoided costs, broken out by component, for Climate Zone 13. As shown, the cost of providing an additional unit of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 5 of almost $1,000/MWh in a few hours are driven primarily by the allocation of generation and T&D capacity to the highest load hours, but also by higher wholesale energy prices during the middle of the day.

Figure 5: Three-day snapshot of energy values in CZ2



3.1.3.1. Generation Energy

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. In the near term (2010-2014), the value of energy is based on forwards for NP15 and SP15. In the long run, the avoided cost of energy is calculated based on an MPR-style gas price forecast and an assumption that market heat rates will remain flat beyond 2014. The hourly shape of the value of energy is based on historical day-ahead LMPs at the PG&E and SCE load aggregation points—these historical data sets are used to adjust the annual averages to obtain an hourly shape in each year. The hourly shaped values of energy are further adjusted by losses factors that capture the lost energy between the point of wholesale transaction and the point of delivery. These factors vary by time-of-use period and are specific to each utility.

3.1.3.2. Generation Capacity

The generation capacity value captures the reliability-related cost of maintaining a generator fleet with enough nameplate capacity to meet each year's peak loads. With the current surplus of capacity on the CAISO system—expected reserve margins for the summer of 2010 are in the range of 30-40%—the current value of capacity is low. The avoided cost of capacity transitions to a long-run value based on the cost of new entry for a new combustion turbine in

2015 and is calculated for each year thereafter. As with energy, the value of capacity is adjusted upwards for peak period losses on the wholesale system. The value of capacity is further scaled up by 15% to capture the value associated with a permanent load shift off peak. As with demand-side resources, PLS resources reduce peak loads and planning reserves requirements such that the shift of 1 kW to an off peak period results in a reduction in net supply requirements of 1.15 kW.

The residual capacity value in each year is allocated to the top 250 CAISO system load hours. The top 250 hours are selected based on the system loads over the four years from 2006 to 2009 and are used to generate monthly allocation of the 250 hours. The approach of averaging four years of historical data captures the potential diversity of peak loads across different years. (This method was adopted in response to comments regarding the DR Cost-effectiveness Protocols.) The allocation of the hours *within* a month are based on the CAISO system loads from July 2009 to June 2010.

3.1.3.3. Ancillary Services (A/S)

The reduction in the procurement of spinning and non-spinning reserves is included as a benefit stream in the avoided costs. The Avoided Cost Calculator assumes that the value of spinning reserves in each hour is equal to 1.0% of the value of energy in that hour.

3.1.3.4. T&D Capacity

The avoided costs include the value of the potential deferral of transmission and distribution network upgrades that could result from reductions in local peak loads. Through an analysis of general rate cases, E3 has gathered utility-specific data on the value of transmission and distribution system deferrals on growth-related infrastructure. The network constraints of a distribution system must be satisfactory to accommodate the area’s local peaks; accordingly, the DG Cost-effectiveness Framework allocates the deferral value in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. Because local loads were not readily available for this analysis, hourly temperatures were used as a proxy to develop allocation factors for T&D value.

3.1.3.5. Environment

Reductions in load also reduce emissions of greenhouse gases. While the future of carbon pricing is uncertain, E3 has included it as a benefit, using the Synapse Mid-Level forecast of carbon prices specifically designed for integrated resource planning in the electricity sector. Hourly emissions rates are calculated based on the hourly market prices, from which the implied heat rate of the marginal generator is calculated.

3.1.3.6. Avoided Renewable Purchases

Because of California's commitment to reach an RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will result in an additional benefit by reducing the required procurement of renewable energy to achieve RPS compliance. This benefit is captured in the avoided costs through the RPS Adder. The RPS adder is calculated by subtracting the expected energy, capacity, and emissions values from the levelized busbar cost of a marginal potential wind farm in California. Because this adder is flat in all hours, it has a relatively minimal effect on the valuation of most PLS systems, which do not result in substantial net reductions in retail sales.

3.1.3.7. 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. Load following is one of two additional avoided cost benefits considered specifically for PLS. 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, 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, however, shows that the primary driver of load following requirements is not forecasted load, but instead load and intermittent generation forecast error. Technologies that are dispatchable with notification times of 20 minutes or less could potentially provide load following services in the future. PLS technologies and operations that are not dispatchable within 20 minutes or less may not reduce load following requirements.

3.1.3.8. 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. The PLS CE Tool includes the expected hours in which overgeneration is most likely to occur in each year based on the expected level of wind penetration.

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.

3.1.4. Key Sensitivities

There are two aspects of the PLS modeling that may significantly impact the cost-effectiveness results: the use of short-run vs. long-run generation capacity value, and aligning PLS system impacts with the allocation of generation capacity and T&D capacity value to individual hours. The general scenario modeling results (Section 4.1.3) explore sensitivity to the short-run vs. long-run generation capacity. The sensitivity to capacity value is explored with the case studies (Sections 4.1.4 and 4.1.5).

3.1.4.1. Short vs. Long-run Capacity Value

The forecast of generation capacity value includes both a short-run and a long-run component; the transition point between the two occurs in the resource balance year. The short-run value of capacity is based on the 2008 resource adequacy value of $28/kW-Yr. The relatively low value reflects the large surplus of capacity currently available on the CAISO system. Capacity value in the years between 2008 and resource balance is calculated by linear interpolation. Beginning in the resource balance year, the value of capacity is calculated based on the cost of a simple-cycle combustion turbine (CT), as that is the first year in which new capacity resources may be needed to meet the growth of peak loads and reliability requirements. The long-run capacity value is equal to the CT's annualized fixed cost, less the net revenues it would earn through participation in the real-time energy and ancillary services markets—this figure is the "capacity residual." This long-term capacity value is ~ $100/kW-Yr or more in most studies of residual capacity value or Cost of New Entry (CONE).

The use of short- vs. long-run values for generation capacity has a substantial impact on the cost-effectiveness of DR and PLS. There are two schools of thought regarding whether the short- or long-run generation capacity value is the most appropriate for valuing DERs. Ratepayer advocates argue that 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 and the region as a whole. Others argue that relying on short-run values does not appropriately reflect the position of energy efficiency and demand response at the top of the loading order. In addition, parties argue that with a planning reserve margin the condition of sufficient or excess capacity will persist indefinitely, preventing EE or DR from ever receiving the higher, long-term capacity value that is typically used when evaluating investments in traditional generation capacity. The use of a long-term capacity value throughout the period of analysis is done in the sensitivity analysis.

3.1.4.2. Aligning PLS Impacts with Load, Weather and Prices

PLS impacts were gathered from case studies that sometimes spanned different time periods. The generation and T&D capacity values are, on the other hand, allocated to individual hours based on system load and temperature from July 2009 to June 2010. For some case studies, the impacts may not line up with the 2009-2010 period. Such discrepancies may affect estimates of demand charge reductions and avoided costs, which are based on the coincidence of the system impacts with customer load, and may also be weather dependent.

Sensitivities are performed (Sections 4.1.4 and 4.1.5) to account for the possibility that the cost-effectiveness modeling does not fully capture the generation capacity value of some PLS systems, due to misalignment with PLS data. No sensitivities on the T&D capacity value are included since the inclusion of T&D capacity value as an avoided cost benefit from PLS or DR is controversial.

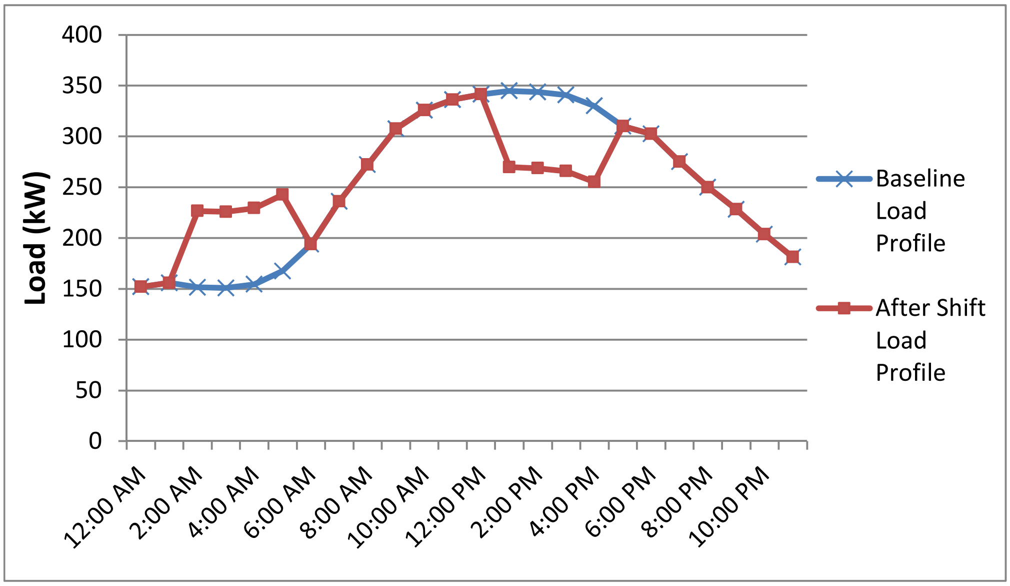
3.1.5. Broad Scenario Analysis ("Matrix")

A broad scenario analysis was conducted to evaluate the avoided costs and bill savings of PLS over a range of hypothetical conditions. The broad scenario analysis is based on generic, idealized, shift profiles without specific technology performance data. This approach allows for exploring the idealized value of load shifting, independent of any specific PLS technology performance or environmental factors.

The assumed shift is constant, occurs every day of the year, and is flat over the duration of the discharge. For each sensitivity in the broad scenario analysis (e.g., for a specified climate zone and round-trip efficiency), there are 66 shift profiles. Each of the 66 profiles is defined by the shift start hour (each hour between 7 am and 5 pm) and the shift duration (1, 2, 4, 6, 8 and 10 hours). For each profile, the shift occurs every day of the year. There are a total of 66 combinations of shift profiles based on a shift start hour ranging from 8 am to 6 pm and discharge duration of 1, 2, 4, 6, 8 and 10 hours.

Figure 6 illustrates the before and after load profiles for one day of the shift profile with a shift start hour of 13 and a duration of 4 hours. This shift has a constant discharge output from 1 PM until 5 PM every day of the year.

Figure 6: One Day of a Shift Profile with 4 Hour Duration and Shift Start at 1 PM



3.1.5.1. Generic Benefit Matrix Assumptions

Round-trip efficiency: Round-trip efficiency is defined as the fraction of energy discharged, relative to the energy required for charging. If the PLS device is assumed to have 100% round-trip efficiency, the shifted profile will consume the same amount of energy relative to the baseline profile. Some PLS devices, such as batteries, will have a round-trip efficiency of less than 100%. Other PLS devices, such as well-designed thermal storage systems, may show an energy efficiency improvement relative to the baseline cooling unit and show a “round-trip” efficiency greater than 100%.

In developing the Matrix avoided costs, the hypothetical PLS device is initially assumed to have 100% round-trip efficiency. Sensitivities were separately conducted for 80% and 120% round-trip efficiencies.

Baseline profile: The baseline profile for all the broad scenario analysis examples is the California Commercial End-Use Survey (CEUS) “All Commercial” load profile, normalized to a peak load of 500 kW. The baseline profile does not impact the avoided cost calculations in any way, since the avoided costs are dependent only on the difference between the baseline and shifted profile. The baseline profile does, however, impact bill savings.

Charging sequence: For the broad scenario analysis, we assume the PLS device is not able to charge faster than it can discharge, so charge kW is set equal to the peak capacity reduction. For a 100% efficient PLS device the number of charging hours will equal the number of discharging hours. An inefficient device will have more charge hours than discharge hours.

Each of the 66 shifts is assigned a least cost charge start hour that minimizes the avoided cost penalties from charging. For example, for the 4 hour discharge in Figure 6, the charge start and duration are 1 AM and 4 hours, respectively. We determine least cost charge start hour for each of the 66 shift profiles based on the average avoided costs from all climate zones. For each shift profile, the discharge hours are considered unavailable for charging, and then the minimum charge period of the required duration is selected.

Bill Impacts: Hypothetical bill impacts were estimated to conduct a RIM test for the broad scenario analysis. A generic rate with both TOU energy charges and an on-peak demand charge was defined. The generic rate is roughly an "average" of all the IOUs general service tariffs and does not represent a specific rate. In summer, the on-peak energy charge is $0.20/kWh and the off-peak charge is $0.10/kWh. In winter, the on-peak energy charge is $0.12/kWh and the off-peak energy charge is $0.09/kWh. The peak period throughout the year is Monday-Friday, 12-6 PM, excluding holidays. The on-peak demand charge is $10/kW year round.

3.1.6. Cost effectiveness of individual cases

The cost-effectiveness of specific PLS cases were estimated to benchmark against the results of the broad scenario analysis. The cost-effectiveness tests applied are the TRC, participant, and ratepayer impact (RIM) tests. To review, the TRC test evaluates the cost-effectiveness of the example installation to society as a whole. The participant cost test evaluates the cost-effectiveness of the PLS installation from the perspective of the technology owner. The RIM test evaluates the cost-effectiveness of the PLS installation from the perspective of a non-participant ratepayer.

Figure 7: Cost-effectiveness Evaluation

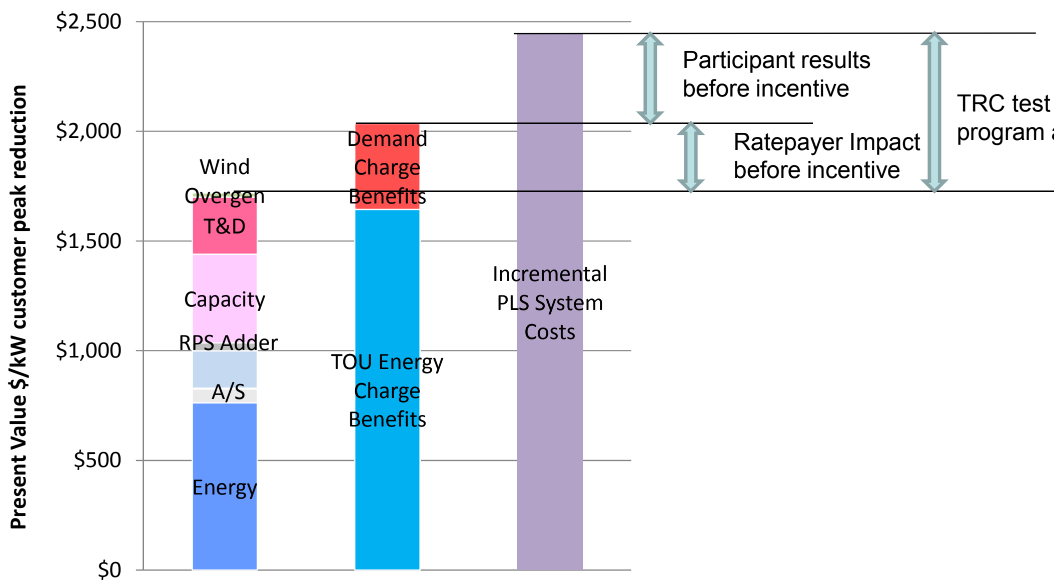


Figure 7 illustrates an example result of the cost-effectiveness tests. In this example, the participant requires a ~ $400/kW incentive to break even on the PLS technology cost, on a lifecycle basis. The ratepayer impact test shows that non-participant rate-payers will transfer ~ $300/kW to PLS participants without an incentive or ~ $700/kW with an incentive. The TRC is negative by ~ $800/kW (excluding program administration).

3.1.7. Specific Case Studies: Simulated Installations

The broad scenario modeling estimates the "idealized" value of shifting (an upper bound) for a range of hypothetical shift scenarios, independent of the PLS technology employed. To explore the value of more realistic PLS scenarios, simulated scenarios of chilled water and battery technologies were evaluated.

Simulated Stratified Chilled Water Scenarios: A set of eight partial-shift (50%) chilled water scenarios, generated by the EnergyPro building energy simulation software, were evaluated. The modeled outputs were provided by

PG&E and were developed for PG&E by Green Building Studio to inform PG&E's evaluation of their Permanent Load Shift program[16]. Two different building types (office and retail) in four different climate zones (3, 4, 12 and 13) were evaluated. For each of the eight combinations, a baseline and TES scenario were generated. The baseline system has an HVAC system and building design that meets Title 24 energy code requirements. The TES scenario incorporates a chilled water tank that is designed to offset 50% of the peak load.

The TES tank size for the different scenarios ranges from ~ 350 to 700 ton-hours. The TES is used as the primary cooling source from 12-6pm, provides supplemental cooling from 8am-12 pm, with remaining capacity discharged from 6 pm – 10 pm. The TES is recharged from 10 pm – 6 am. The chillers and TES are unused on holidays and weekends.

Rough estimates of the TES system costs were estimated using the TES capacity (in ton-hours) and applying a range of $150/ton-hr - $400/ton-hr. These values were selected based on information provided by stakeholders, where the range is due to differences in level of engineering, material of the tank, and whether the tank is below or above ground. Smaller chilled water systems tend to be more expensive, on a unit basis, compared to larger systems.[17]

It is worth noting that an ice storage system may be more typically applied over chilled water for a system this size. However, the cost of such a system is expected to be within the range selected here (The profiles for ice storage, however, will be different from the chilled water profiles).

Simulated Battery Scenarios: Two battery technologies were also simulated for the analysis. The first battery technology is a bipolar lead-acid battery with performance and cost data supplied by the manufacturer, AIC/East Penn. The second battery technology is a vanadium redux flow battery with performance

[16] Cristofani, M., Debacker, S. B., Welland, J., Pacific Gas and Electric, Evaluation of Load Impacts of the Pacific Gas and Electric Company Permanent Load Shift Program. April 2010.
[17] The modeling assumed nominal additional chiller capacity for the TES system, such that the TES had a dedicated chiller; we did not attach additional incremental cost for the TES case.

and cost data supplied by the manufacturer, Prudent. While several other battery technologies do exist and are commercially available, these two technologies were the only battery specifications supplied by stakeholders with enough data to support the required analysis.

The battery sizes were selected based on the case study loads available and the availability of battery size data from the manufacturer to optimize the kW capacity and kWh duration. Load data from two different manufacturing facilities in Southern California were used to generate before and after profiles. The bipolar lead-acid battery is priced the same on a kWh capacity rating for 100kW sizes or greater (i.e. a 100kW, 200kWh system would be priced the same on a $/kWh basis as a 100kW, 800kWh system). The vanadium redux flow battery data only allowed for one size system to be selected to optimize for the case study load profiles—a 200kW, 800kWh system size. The primary reason for the differences between these battery costing metrics was the lack of detailed data for multiple vanadium redux flow battery kWh duration and kW capacity specifications.

Given the relative flexibility in operational dispatch of battery energy storage, including the two battery technologies modeled in this study, several sensitivities were conducted around these batteries and include the following:

- Simple daily permanent load shifting every weekday of the year
- Dynamic dispatchable load leveling every weekday of the year

3.1.8. Specific Case Studies: IOU PLS Pilots and Recent Installations

Information was collected from the IOU PLS pilots and other recent installations, including program and equipment costs, performance data and/or trend data, EM&V reports & load data. Ideally, baseline and PLS system 8760 hourly profiles of energy and maximum hourly kW (at the building level), and representative cost data would be available. Such information is not easily available, however. Some PLS systems have not been operating very long, nor have they been monitored regularly. Not all systems have available baseline information (which would require some level of monitoring before the PLS system is installed, or post-installation monitoring in which the PLS system is not operating). Lastly, even in situations for which such data are available, it is not clear whether the performance of the PLS system for that particular period is representative, complicating the insights that can be drawn from the data. Despite these challenges, exploring the PLS pilots can be useful, not for determining the value of a program, but for providing insights into how a future program could be improved based on real performance.

In some cases, it was possible to generate 8760 hourly profiles of baseline and PLS systems. Four PLS pilots all using different types of PLS technologies were evaluated (Table 7).

Table 7: Specific case studies from IOU PLS Pilots

Case	PLS Technology	Data Sources	Baseline Development
Southern California office building	Stratified chilled water (tune-up of existing TES, though existing TES was not used for PLS)	Year round 15-min load data & central plant efficiency levels, provided by engineer	Central plant efficiencies were used to develop cooling loads, which were combined with representative shapes to generate baseline profiles
Refrigerated warehouse	Precooling (termed "refrigerator flywheeling") facilitated by the installation of controls	Year round 15-min load data, EM&V reports, 1-min trend data for 1 month	Round-trip efficiency based on the baseline and PLS measurements documented in EM&V report were applied to actual load data
Hospitality central valley, chilled water	Stratified chilled water	EMCS Trend data for summer period, EM&V reports, 15 min load data	Baseline model used in EM&V was applied to trend data to generate a baseline profile. 15 min load data were used to generate building level profiles.
Hospitality central valley, ice	Internal melt ice on coil system	EMCS Trend data for summer period, EM&V reports, 15 min load data	Baseline model used in EM&V was applied to trend data to generate a baseline profile. 15 min load data were used to generate building level profiles.
Theater	Small ice storage air conditioning	Ice Energy	Provided by Ice Energy

The methodology and data for generating 8760 profiles were case specific. In some cases, the data revealed some periods where the PLS system was not operating. For such periods, the baseline and PLS profiles were identical. In other case, the data were dropped or were missing. In such cases, linear interpolation and EM&V reports were used to fill the gaps. Information for the off season was not always available. In these cases, extrapolation to the shoulder months was conducted based on examining the building level load data (to determine if the PLS system was operating), and applying representative factors to these months (for example, by applying CEUS load profile information).

3.2. End-User Value Proposition

StrateGen completed more detailed financial analysis of the case studies using their in-house analysis tools to model the value proposition of PLS systems from the end-use customer perspective. Because of the detailed project-specific inputs required to produce meaningful results in StrateGen's financial model, only the case study examples were analyzed.

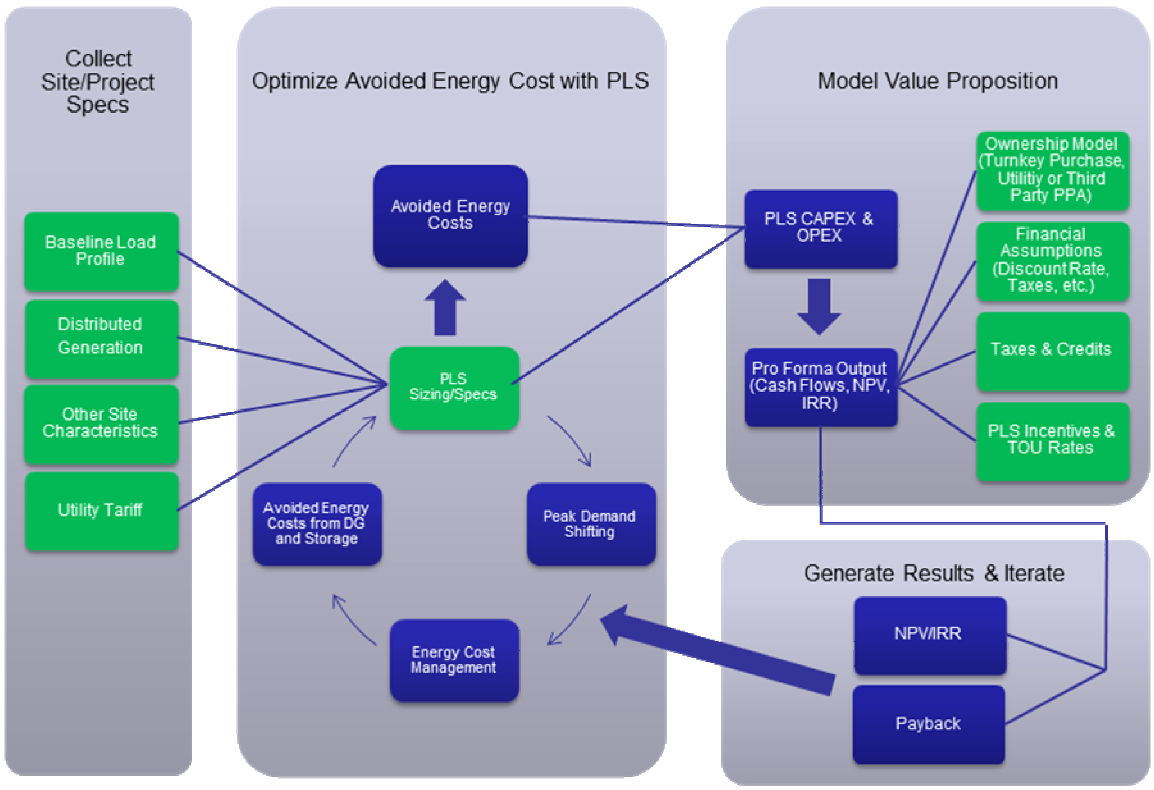
Every effort was made to ensure that the same assumptions used in the cost effective analysis — project costs, 8760 hourly load profiles, and tariff structures — were used in the value proposition analysis.

The existing tools that StrateGen has developed focus only on the customer perspective, but at a level of detail sufficient to evaluate specific project economics. Therefore, the modeling that StrateGen completed provides more detail and adds perspective to the analysis presented to interested parties at the end-user level. Project specific details include the PLS equipment's CAPEX, OPEX, performance specifications, 8760 hourly electric bill savings, incentive levels, tax effects, and other financial considerations for the entire lifecycle of the project.

StrateGen's analysis tools can also generate optimal sizing and dispatch of certain categories of PLS technologies, such as batteries. Optimal dispatch includes load leveling to maximize end-customer bill savings. The optimization model uses historical 8760 hourly load data to calculate the optimal set points for the charge and discharge of a battery system every day. The two battery technology case examples were utilized to demonstrate what load leveling dispatchability implies for the end user value proposition.

A detailed flow chart of StrateGen's modeling approach is shown below:

Figure 8: Flow Chart of StrateGen's Value Proposition Analysis



Once each case example was loaded into the model, StrateGen then solved for the incentive levels that stakeholders indicated would be required to drive customer adoption. For this study financial hurdles of three and five year simple paybacks were utilized based on stakeholder feedback during the course of the study. In addition to the simple payback hurdles, StrateGen solved for the required incentive levels to achieve a 15% internal rate of return.

The incentive structures modeled to achieve these financial hurdles include $/kW peak capacity shifted upfront incentives and TOU rate differential requirements.

3.3. Market Assessment

The Project Team assumed that market size is not the primary limiting factor in the development of a viable California PLS market. Economic constraints, such as current system costs and ratepayer neutral incentive levels, will limit market growth. Therefore, the analysis focuses on evaluating these constraints, gathering feedback from industry stakeholders on drivers and barriers to adoption, and assessing trends in existing PLS programs across the U.S.

The U.S. market overview was compiled through utility program websites, the Database of State Incentives for Renewable Energy (DSIRE), and interviews with utility program managers. Stakeholder feedback was gathered during interviews with California IOU program personnel, third party vendors, engineers, PLS technology suppliers, and others relevant to PLS (Table 8).

Table 8: Stakeholder interviews

Utilities	Program Managers
SCE	Cypress Ltd.
SDG&E	EPS
PG&E	Honeywell Utility Solutions
Florida Power & Light	Trane
Glendale Water & Power	
Southern California Public Power Authority (SCPPA)	
Engineers	**OEMs**
ASW Engineering	AIC/East Penn
Cogent Energy	Cristopia Ice Balls
Davis Energy Group	CALMAC
Enovity	Ice Energy
Invensys Group	International Battery
KS Engineers	Prudent Power
LBNL	PVT Solar
Moudood Aslam	Transphase Company
Retrofit Originality Inc.	Xtreme Power
Schneider Electric	
UC Davis Energy & Supply Chain Management	

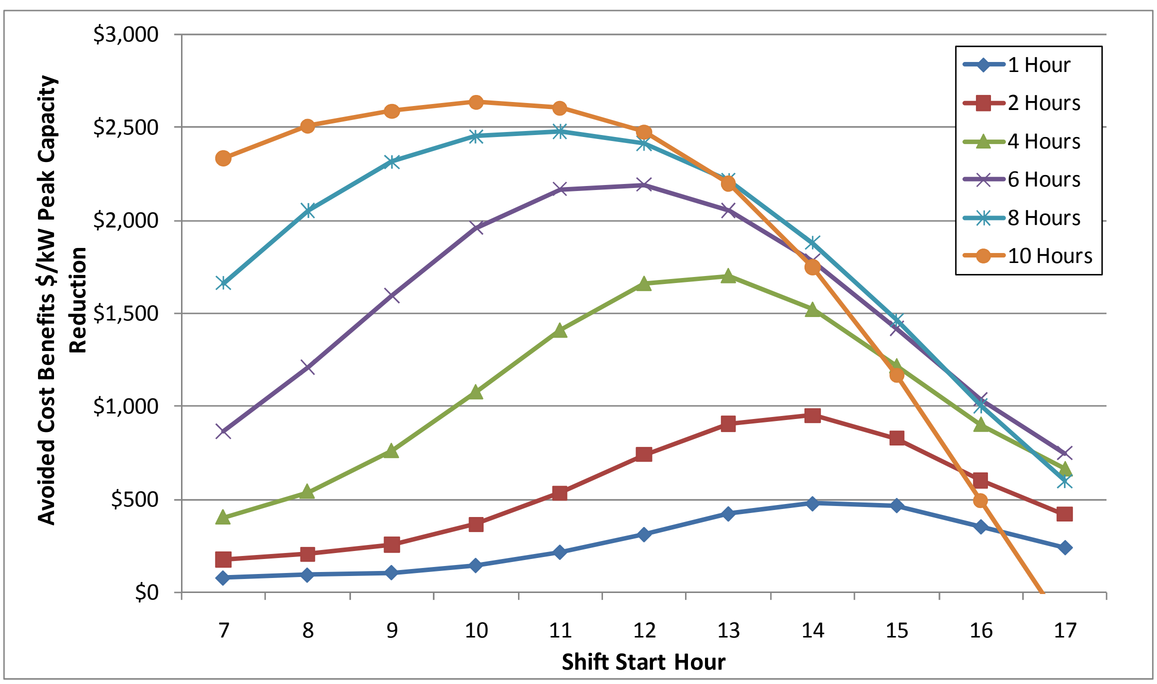
4. Modeling Results

4.1. Cost-effectiveness

4.1.1. Avoided Cost Benefit Matrix

Figure 9 presents the broad scenario avoided cost results in graphical form for the 66 idealized shift scenarios in climate zone 12. The avoided costs are in present value benefits for the lifetime of the system, which is assumed to be 15 years unless stated otherwise (a sensitivity for 30 years was also performed), and are normalized to peak kW capacity reduction. The kW peak capacity reduction is defined as the maximum hourly change in energy reduction relative to the profile baseline. We examined other normalization factors such as average on peak period demand reduction or total kWh shifted per day, but kW peak capacity reduction is used as the default metric because of its broad applicability across various shift profiles and also its usefulness for comparison to other capacity resources such as a combustion turbine.

Figure 9: Broad Scenario Analysis – Avoided Cost Benefits



The present value of avoided cost benefits represent the total benefits to the region as a whole (TRC), the utility (PAC) and ratepayers (RIM). The range of avoided costs is wide and peaks at ~ $2,600/kW (representative of a daily 10 hour discharge from 10 AM to 8 PM). Shifts of 6 hours or more can achieve avoided cost benefits above $2,000/kW shifted for many scenarios.

From a TRC and PAC perspective, a PLS system that has a total cost less than the avoided costs will still provide net benefits. In the RIM test, the bill impacts of participants are compared to the avoided costs.

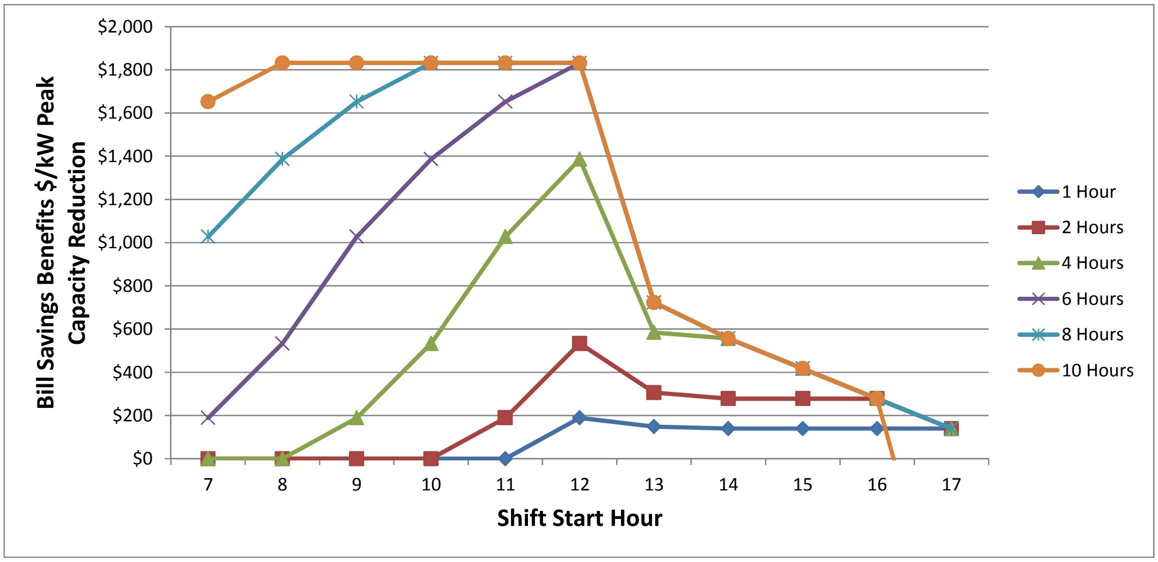
The matrix shows the value for a system that provides an identical absolute shift each day of the year. It represents an ***upper bound*** of avoided cost benefits that is unlikely to be achieved in practice. Because all values are in terms of kW peak capacity reduction, *a* constant discharge across hours and days of the year will show the maximum possible value for a given summer peak shift. Any reduction of shift below the maximum discharge in certain hours, days or months would simply lead to lower shift benefit values without changing the normalization factor (peak capacity reduction). Consider two identical PLS devices but where one operates year round and the other operates only in the summer. Both could have the same peak capacity reduction based on an hour occurring in the summer. Both would therefore be normalized using the same factor. However, the device running year round would have some additional benefits derived from the shift benefits occurring in winter.

4.1.2. Bill Savings and Rate Payer Neutral Incentive

Figure 10 shows the bill savings for the 66 shift profiles under the generic rate.[18] One important factor in the bill savings is that the baseline profile (the CEUS generic commercial shape) peaks at ~ 12 pm. Therefore, shifts that occur after 12 pm do not accrue benefits for demand charge reductions and have lower total bill savings.

[18] Generic rate characteristics: Summer on peak energy charge $0.20/kWh, off peak charge $0.10/kWh; winter on peak charge is $0.12/kWh, off peak charge is $0.10/kWh; peak period all year is 12-6 pm Mon-Fri, excluding holidays. On peak demand charge is $10/kW all year round.

Figure 10: Broad Scenario Analysis – Bill Savings Benefits – Generic Rate



The rate payer neutral incentive is defined to be the maximum incentive such that the RIM test ratio is set to 1. For each profile in the analysis, the maximum incentive is equal to the avoided cost benefits (Figure 9) minus the bill savings benefits (Figure 10).

Figure 11: Broad Scenario Analysis – Rate Payer Neutral Incentive

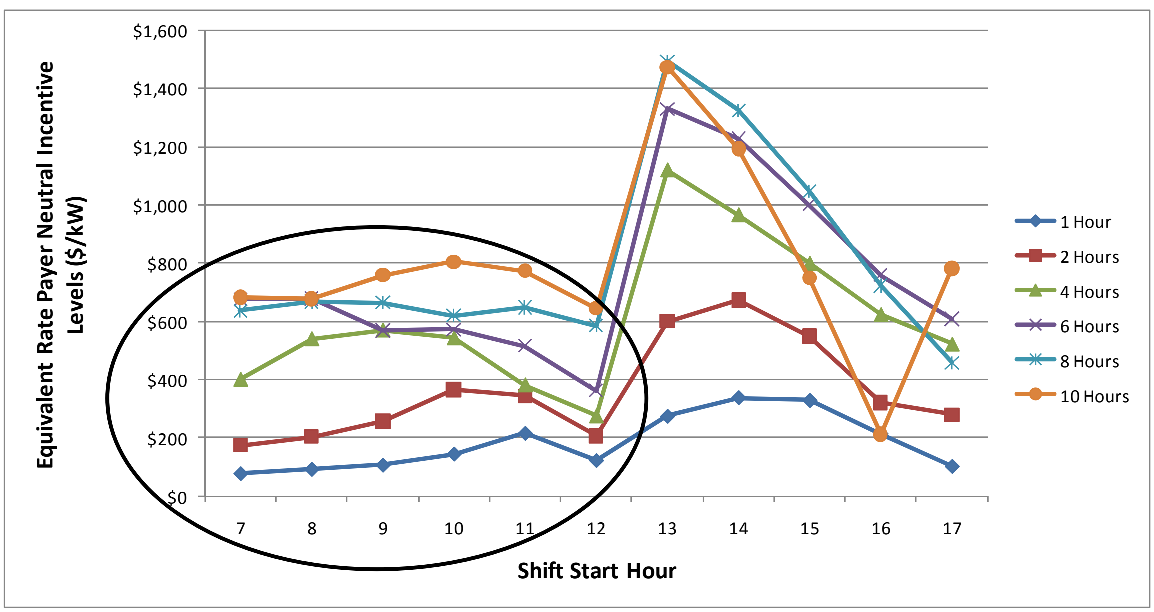


Figure 11 shows that for shifts that begin at 12 pm or earlier, incentives average ~ $450/kW and range from $75 - $800/kW. The higher incentives shown for systems that begin after 12 pm are irrelevant as they would represent incenting a PLS owner with additional money to run the PLS system less effectively.

As shown in Figure 11, under the broad scenario analysis, some incentive levels are possible to keep non-participating ratepayers unaffected. However, incentive levels are generally lower than the incentives currently offered in pilots and those cited by stakeholders as necessary incentive levels for spurring investment. That said, specific rate structures and various rate options for potential PLS customer can lead to widely differing results.

4.1.3. Sensitivity Analyses

4.1.3.1. Sensitivity to Bill Savings and Rate Payer Neutral Incentive

This section explores the sensitivity of rate payer neutral incentive levels to retail rates. We repeated the previous broad scenario analysis with five California IOU rates that span customer class and rate type (i.e., TOU with and without demand charge, non-coincident and peak-time only demand charges). The customer is assumed to be on the respective rate before installing the PLS system. Table 9 lists the rate payer neutral incentives.

Table 9: Ratepayer Neutral Incentive Levels for Broad Scenario Analysis*

	Minimum, Median and Maximum of Incentive ($/Peak kW reduction) +				
	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours
Generic Rate	$210	$280	$360	$590	$645
	$300	$460	$540	$630	$766
	$370	$570	$570	$660	$805
PG&E A6	($80)	($190)	($680)	($730)	($830)
	($20)	($60)	($250)	($680)	($810)
	$90	($20)	($150)	($460)	($790)
PG&E A10 TOU S	$200	$560	$780	$1,020	$1,550
	$350	$810	$1,220	$1,380	$1,600
	$580	$1,160	$1,390	$1,560	$1,610
PG&E E20 P	$190	$260	$100	$140	$500
	$270	$370	$370	$430	$630
	$310	$400	$490	$620	$660
SDG&E	$200	$450	$250	$390	$840

	Minimum, Median and Maximum of Incentive ($/Peak kW reduction) +				
	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours
ALTOU	$350	$520	$700	$760	$960
	$580	$1,220	$1,400	$1,400	$1,450
SCE TOU-8B	$350	$660	$840	$1,080	$1,920
	$410	$860	$1,340	$1,650	$1,980
	$590	$1,290	$1,710	$1,980	$2,010

* Assumes maximum shift on a daily basis, minimum cost period charging, and best discharge period. Does not include potential value in regulation or other ancillary services. For the PG&E tariffs, avoided costs were taken from climate zone 12; for the SDG&E tariff, avoided costs were taken from climate zone 10; and for the SCE tariff, avoided costs were taken from climate zone 14. Customer is assumed to be on the respective rate before implementing PLS.
+ Baseline profile is a general all commercial CEUS.

4.1.3.2. Seasonal Sensitivity

The subsequent figures explore the sensitivity of the avoided costs to the summer (May to October) and winter (November to April) seasons.

Figure 12: Broad Scenario Analysis – Avoided Costs Seasonal Sensitivity – May to October

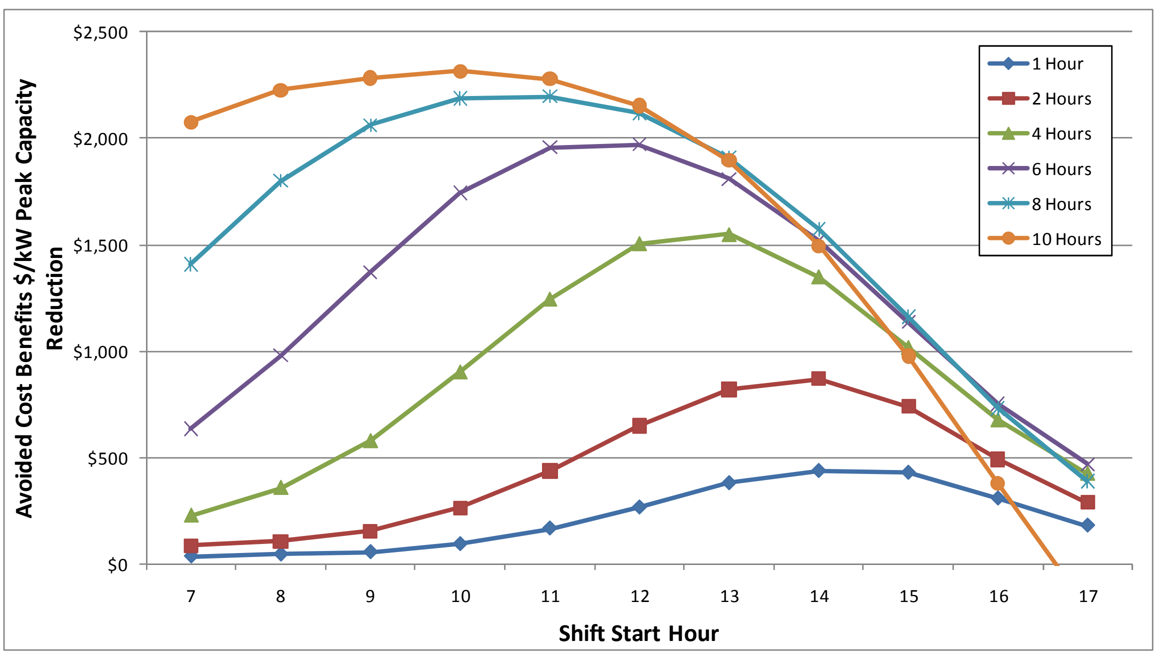
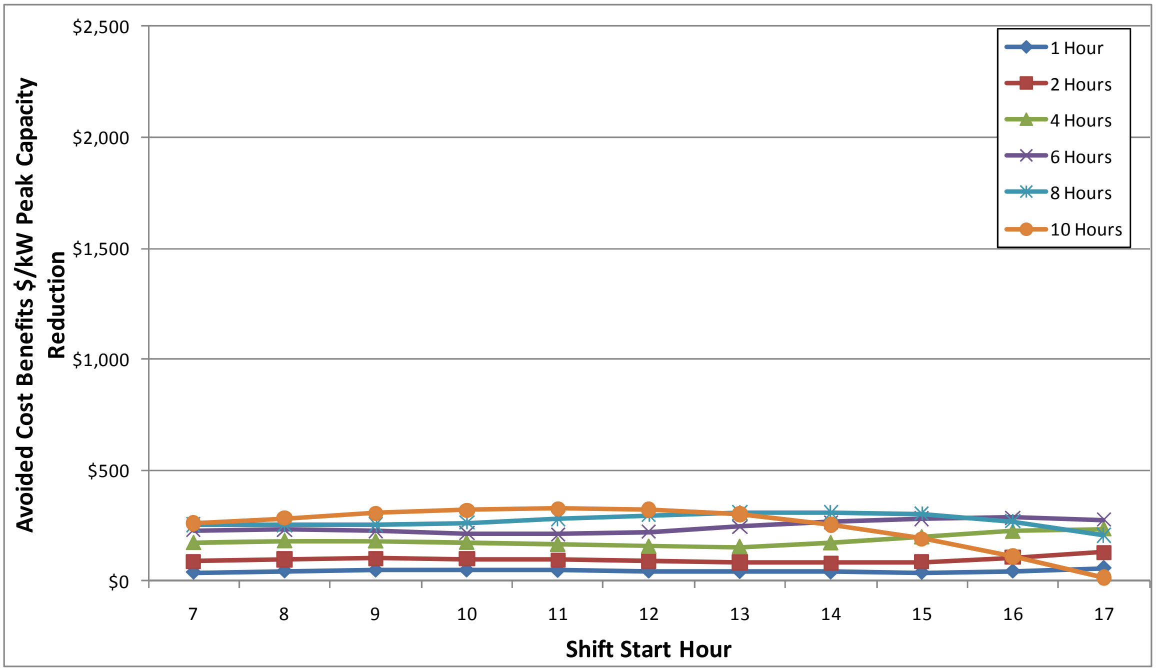


Figure 13: Broad Scenario Analysis – Avoided Costs Seasonal Sensitivity – November to April



The subsequent figures explore the sensitivity of the avoided costs to the summer (May to October) and winter (November to April) seasons.

Figure 12 and Figure 13 illustrate that the avoided costs, for the broad scenario analysis, are accrued predominately during the summer. Avoided costs in the winter are approximately 80% less than those in the summer. Winter avoided costs are also less sensitive to the discharge time.

Figure 14: Broad Scenario Analysis – Bill Savings Seasonal Sensitivity – May to October

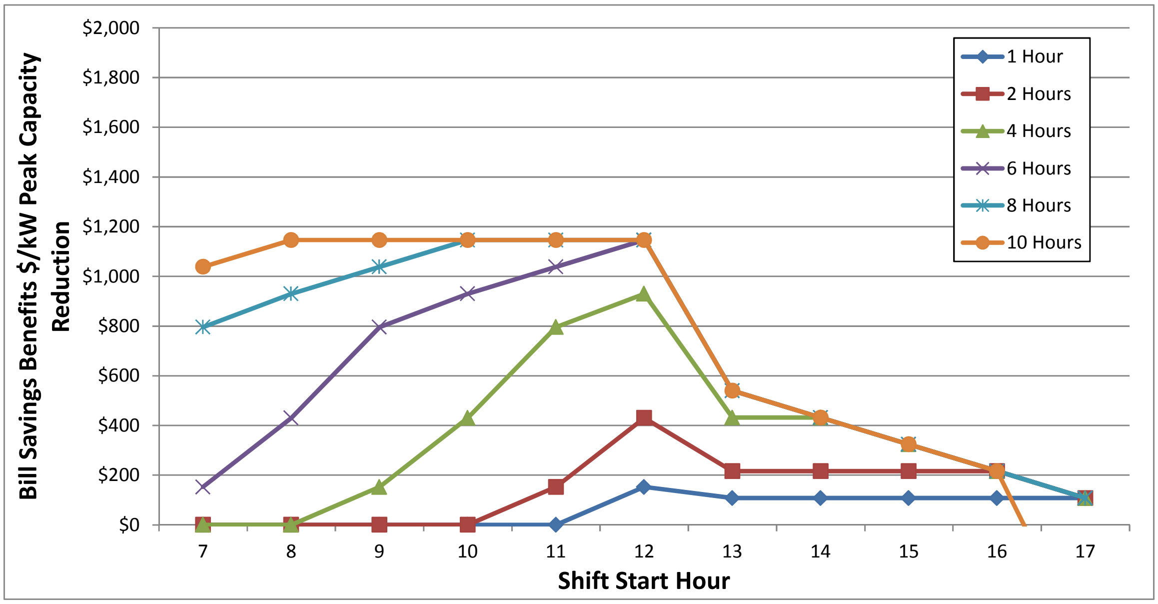


Figure 15: Broad Scenario Analysis – Avoided Costs Seasonal Sensitivity – November to April

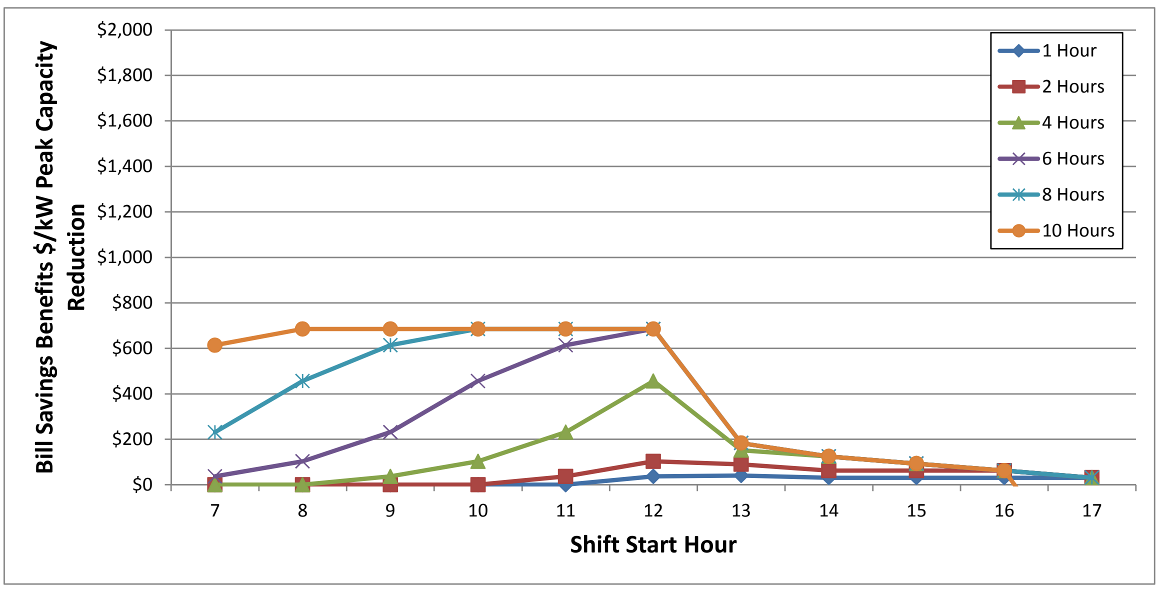


Figure 14 and Figure 15 show that the difference in summer and winter bill savings is not as great as the seasonal difference in avoided costs savings. Bill savings are roughly 60% less in winter than in summer but are still significant. These broad scenario comparisons are made based on the generic rate. The comparisons suggest that winter PLS operation is likely to impact bill savings more than avoided costs.

4.1.3.3. Sensitivity to Energy Efficiency

All previously shown results are based on a round-trip efficiency of 100%. The next set of sensitivities varies the assumptions of energy efficiency.

Figure 16: Broad Scenario Analysis – Avoided Costs Sensitivity to Energy Efficiency – 80% Roundtrip Efficiency

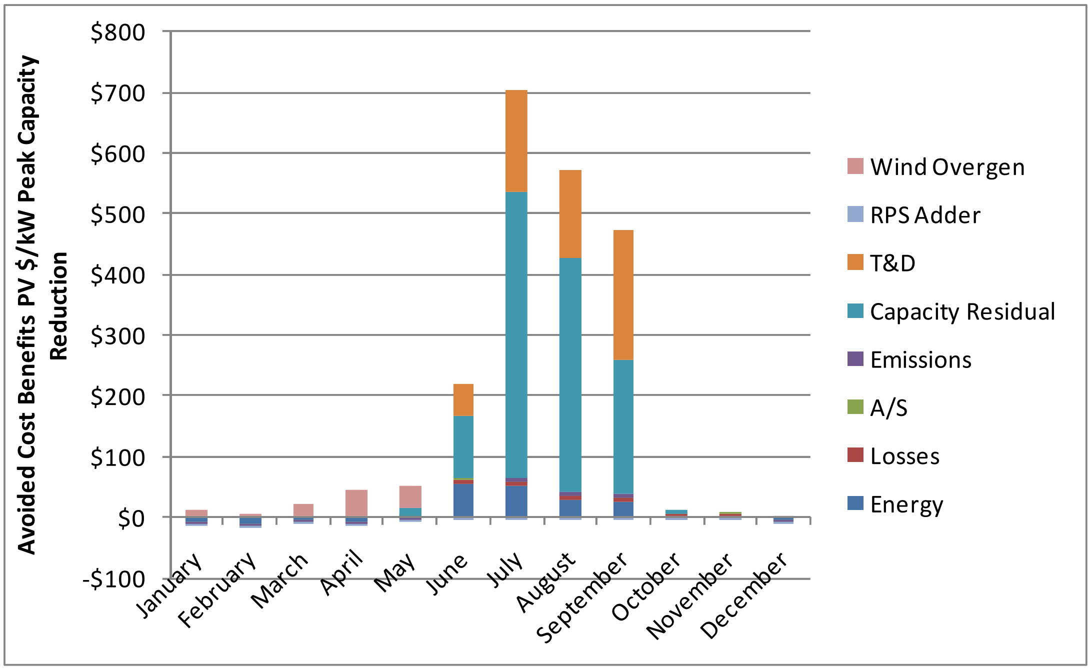


Figure 17: Broad Scenario Analysis – Avoided Costs Sensitivity to Energy Efficiency – 100% Roundtrip Efficiency

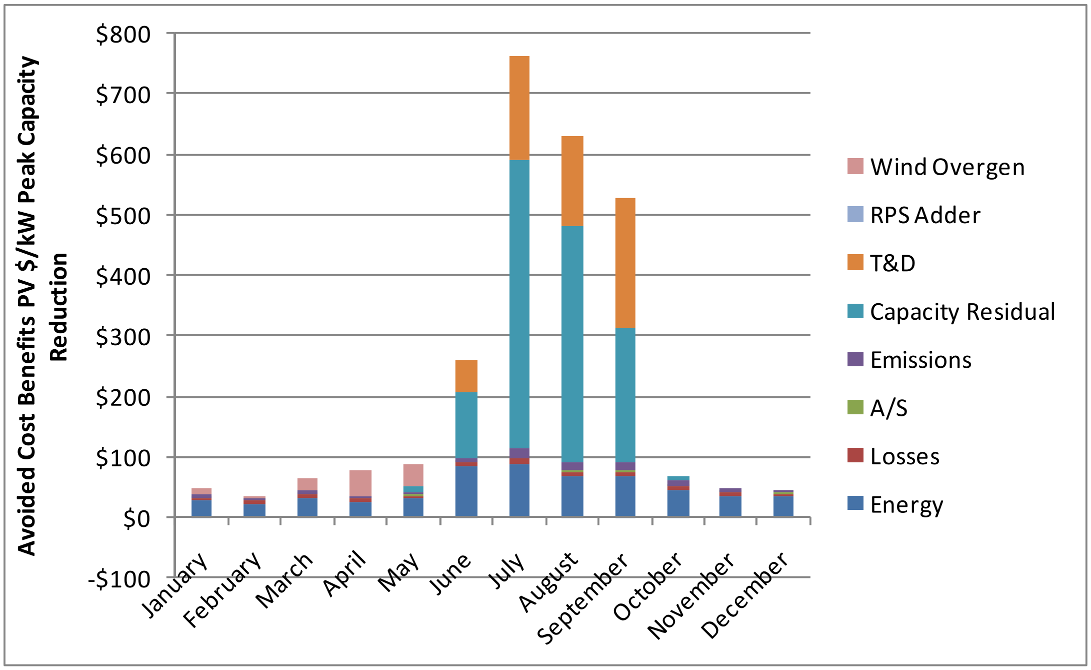


Figure 18: Broad Scenario Analysis – Avoided Costs Sensitivity to Energy Efficiency – 120% Roundtrip Efficiency

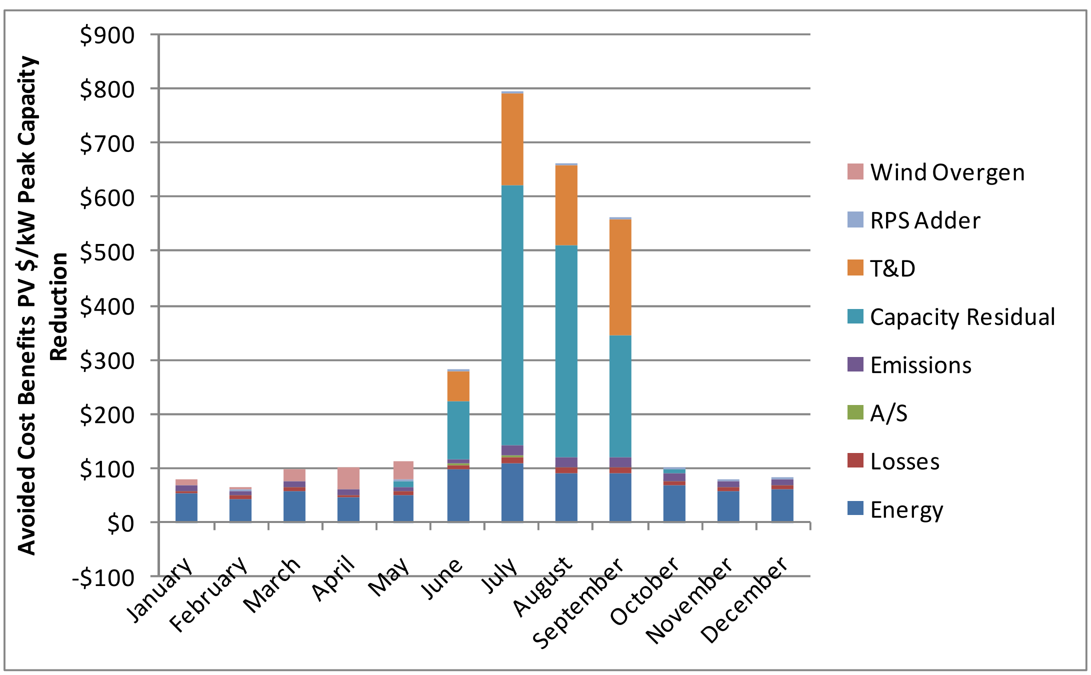


Figure 16, Figure 17, and Figure 18 show the monthly avoided cost benefits broken out by avoided cost components for a single shift profile among the 66 included in the broad scenario analysis. The shift profile examined here is a 10 hour daily discharge that occurs from 10 AM to 8 PM. The 120% efficient system most closely represents a thermal energy storage unit that demonstrates a 23% efficiency gain over the baseline cooling unit. The 120% efficient system shows an increase in avoided cost benefits of 13%, relative to the 100% efficient system. The energy efficiency impact is most clearly seen in the energy component of the avoided costs; the T&D and Capacity benefits are unaffected. In fact, as the system loses efficiency, the avoided cost benefits in the shoulder and winter months decrease significantly, and can even become negative as seen with the 80% roundtrip efficiency example.

Figure 19: Broad Scenario Analysis – Bill Savings Sensitivity to Energy Efficiency – 80%

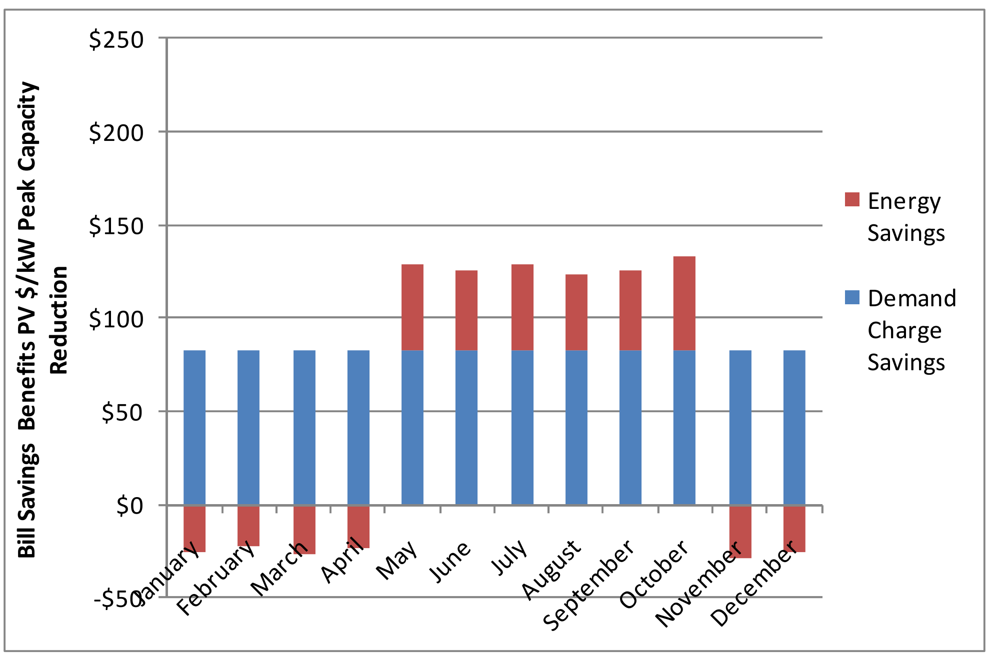


Figure 20: Broad Scenario Analysis – Bill Savings Sensitivity to Energy Efficiency – 100%

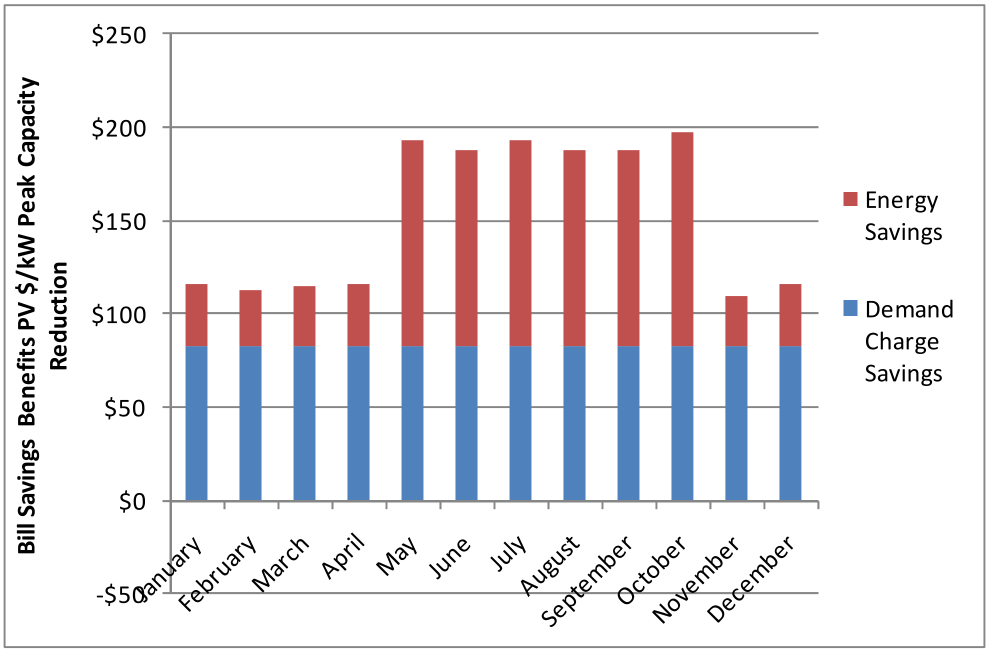


Figure 21: Broad Scenario Analysis – Bill Savings Sensitivity to Energy Efficiency – 120%

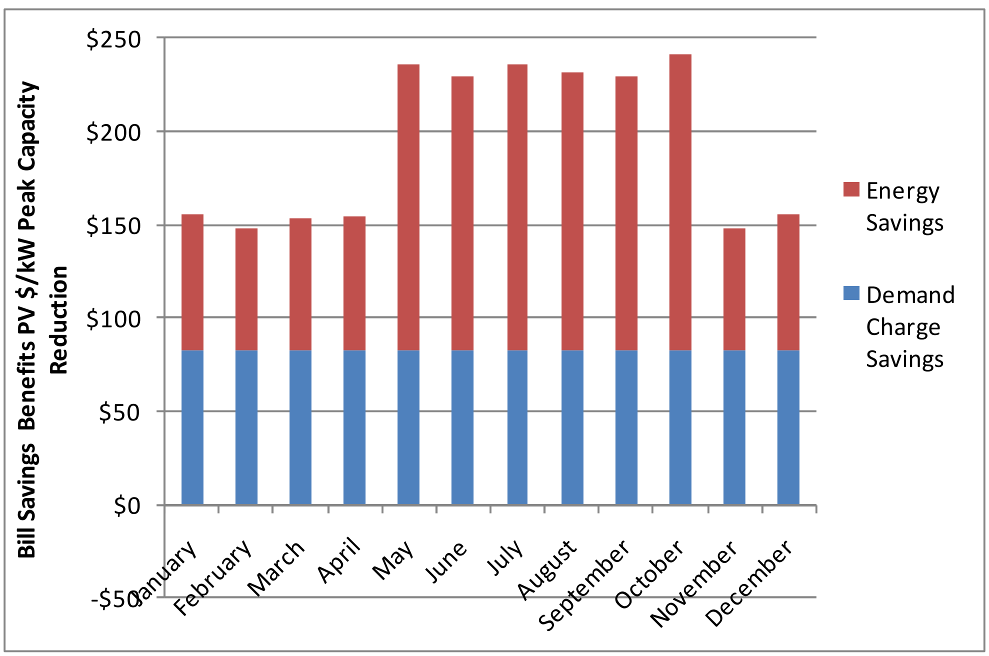
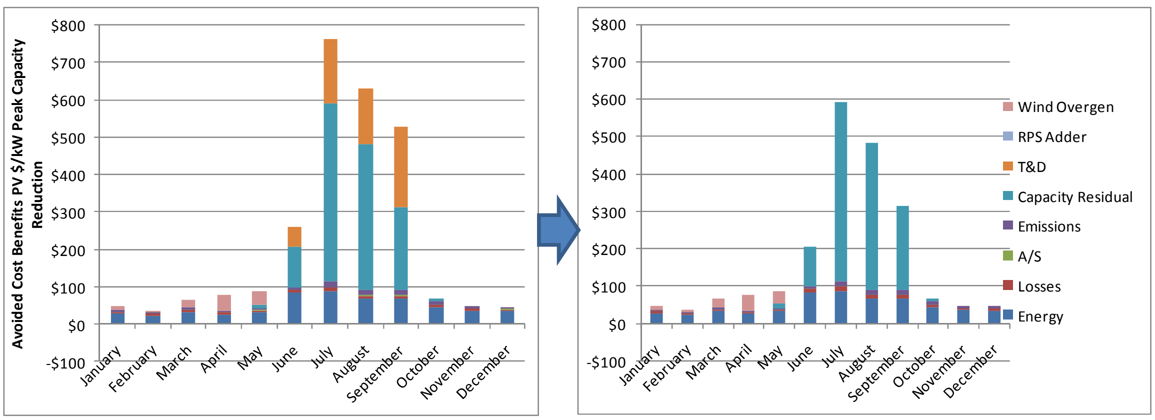


Figure 19, Figure 20, and Figure 21 show the monthly bill savings benefits broken out by bill savings components for the three energy efficiency scenarios, using the generic tariff. Energy efficiency has more impact on bills than on avoided cost benefits. The 120% efficient system increases bill savings benefits by ~30%, compared to ~15% for avoided costs. The 80% efficient system reduces bill savings by ~40%, compared to a ~30% reduction in avoided costs.

4.1.3.1. Sensitivity to T&D Avoided Costs

Some stakeholders have suggested that PLS systems should not accrue avoided cost benefits for deferring T&D investments. Figure 22 shows a 10 hour idealized shift with and without T&D avoided costs. The total lifecycle avoided costs are 22% lower without T&D avoided costs.

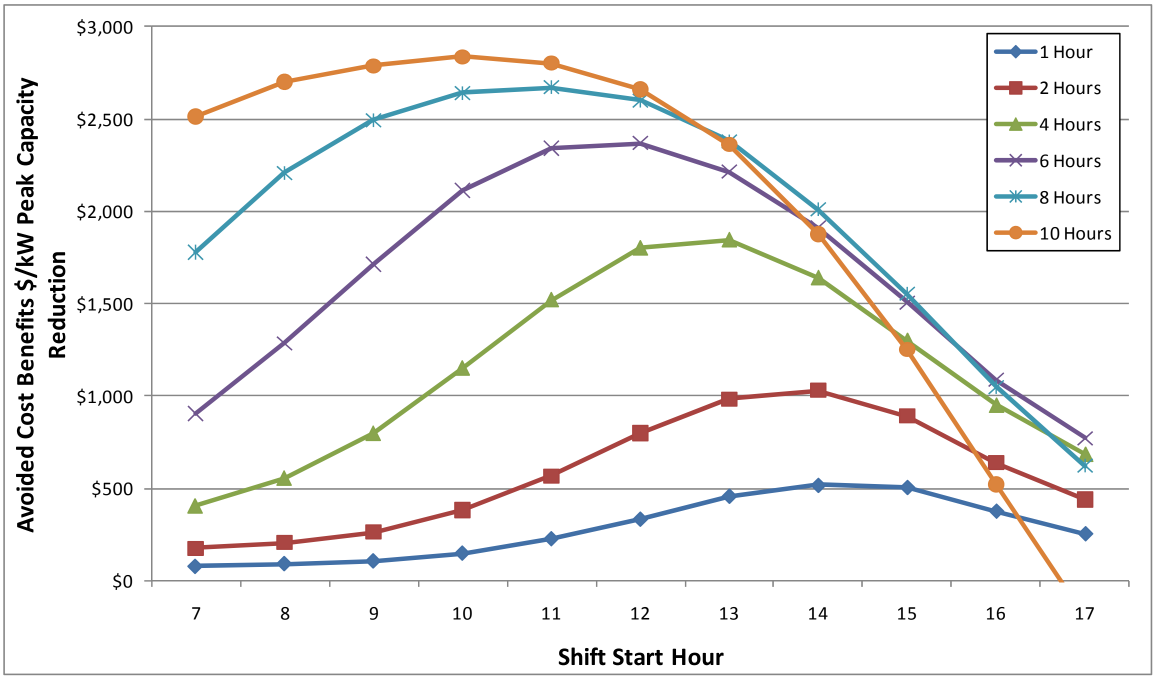
Figure 22: Broad Scenario Analysis – Sensitivity to T&D Avoided Costs – 2010



4.1.3.2. Sensitivity to Resource Balance Year

A sensitivity to resource balance year was explored. Currently there is sufficient energy capacity to meet demand in California. The resource balance year is the year in which energy demand is projected to increase such that new capacity additions will be required. These additions are most likely to come in the form of a combustion turbine. However, as detailed in Appendix A, the resource balance year affects the value of capacity provided by a PLS system. The default resource balance year in the current avoided costs is 2015. Figure 23 shows that if the resource balance year is set to 2010, meaning a new CT is required for capacity today, there is a ~ 7% increase in the total present value of avoided cost benefits.

Figure 23: Broad Scenario Analysis – Sensitivity to Resource Balance Year – 2010



4.1.3.3. Sensitivity to Technology Lifetime

Some PLS technologies can last longer than 15 years. Figure 24 shows that if the technology lifetime is set at 30 years, rather than 15 years, the lifecycle avoided costs increase by ~ 35% relative to the base case in Figure 9. Assuming the same generic rate, the bill savings increase by ~ 30% relative to the base case (Figure 25). For shifts that begin at 12 pm or earlier, incentives average at $640/kW and range from ~ $100 - $1150/kW (Figure 26).

While some PLS systems (or components of PLS systems) such as chilled water tanks may last longer than 15 years, recall they cannot deliver the idealized avoided costs represented in the figures below.

Figure 24: Broad Scenario Analysis – Avoided Cost Sensitivity to Tech. Lifetime – 30 Year Lifetime

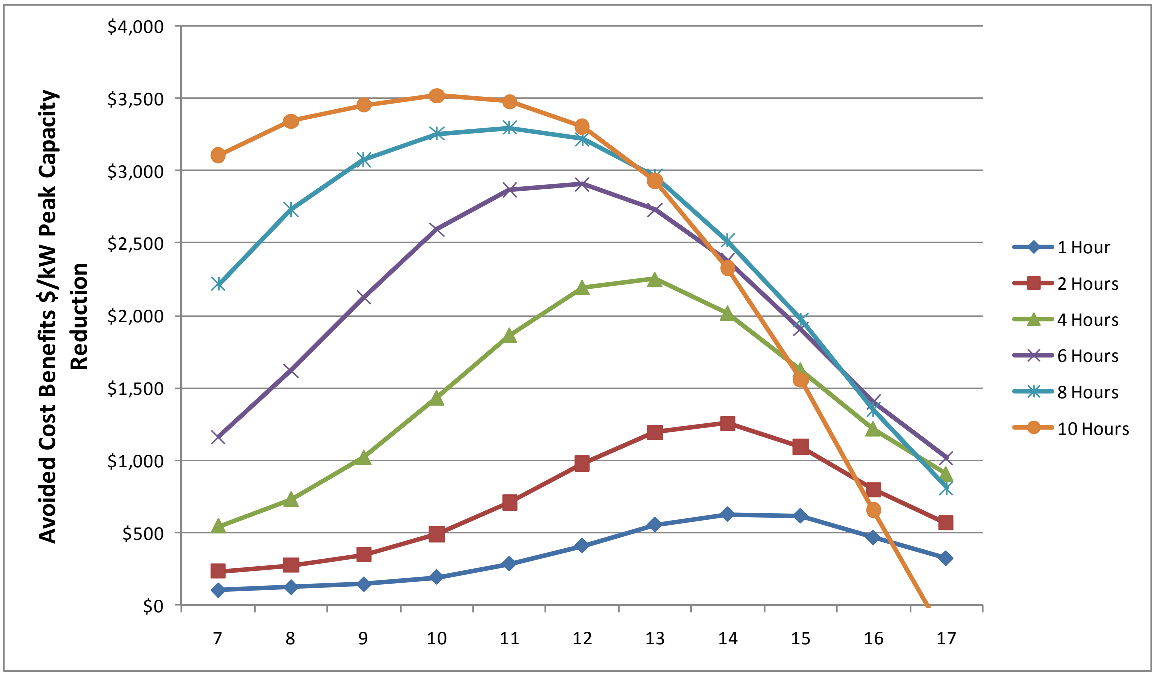


Figure 25: Broad Scenario Analysis – Bill Savings Sensitivity to Tech. Lifetime – 30 Year Lifetime

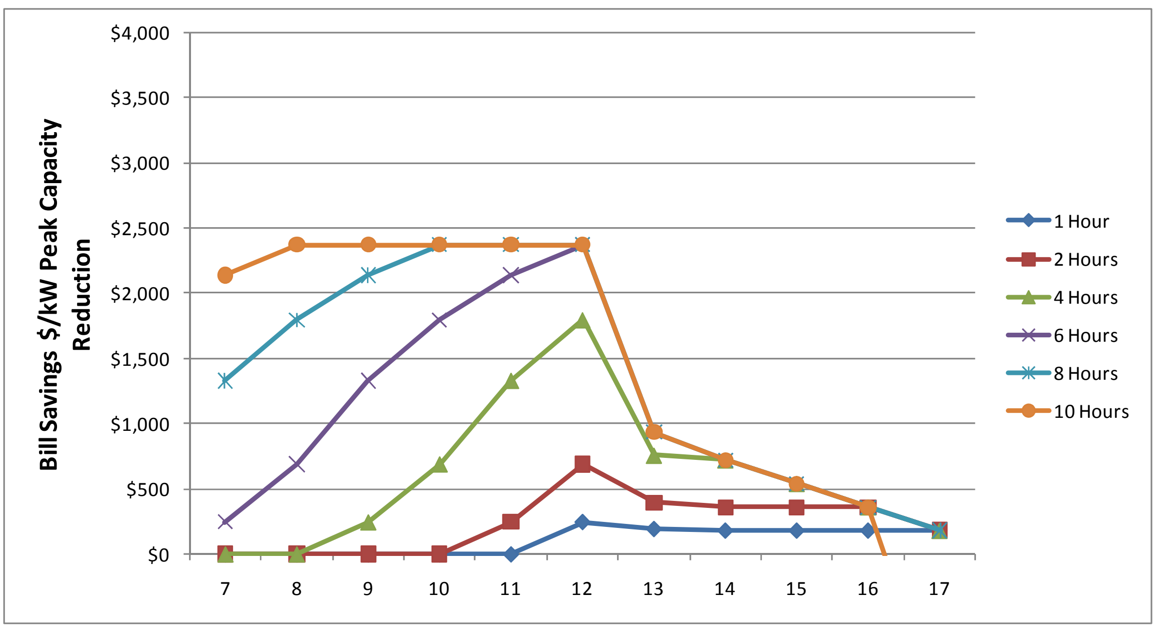
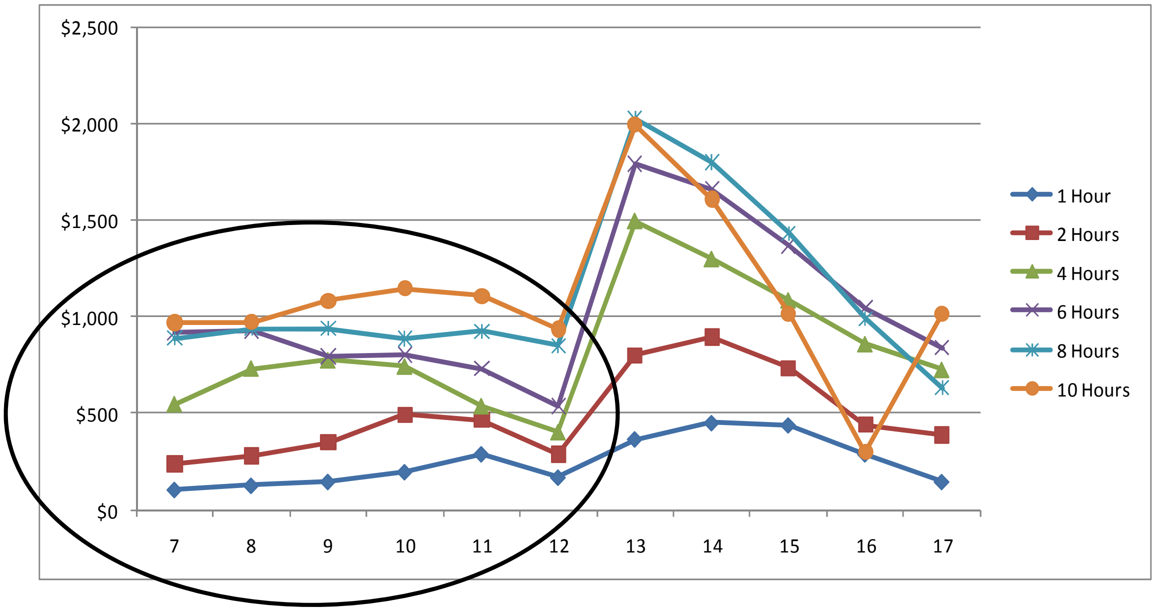


Figure 26: Broad Scenario Analysis – Rate Payer Neutral Incentive Sensitivity for Assumed Technology Lifetime of 30 Years

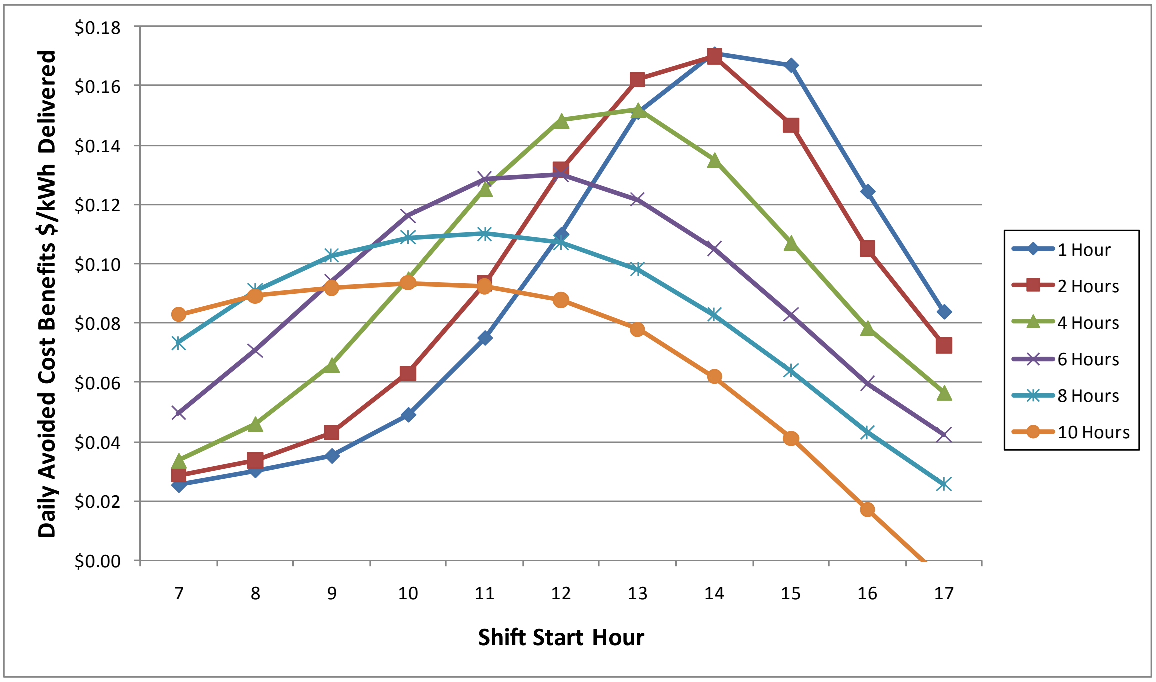


4.1.3.4. Energy Basis Sensitivity

The results shown, thus so far, have been in units of $/kW Peak Capacity Reduction. The value, on an energy basis, offers some insight. For example, when using $/kW as a metric, the 10 hour duration batteries typically result in a higher value because they shift more total energy throughout the day. For some technologies, however, the cost of installed energy is a constraint. Therefore, it is useful to know when it is most valuable to discharge on an energy basis.

Figure 27 represents the same set of scenarios as presented in Figure 9 but with the avoided costs normalized to the average daily kWh shifted. By using this metric, the highest value duration and start hour profiles are not the 10 hour durations, but rather the 1 and 2 hour durations. A 1- or 2-hour duration starting at 2 pm provides the highest avoided cost benefit on an equivalent energy basis. For battery technologies with limited installed energy and customizable discharge power, a short duration output in the afternoon provides the most grid value.

Figure 27: Broad Scenario Analysis – Avoided Cost on an Energy Basis



4.1.3.5. Sensitivity to Additional Ancillary Services Revenues

Some PLS technologies may be able to provide ancillary services, although this capability has yet to be demonstrated. We estimate the value of providing regulation and spinning reserve. As theoretical values we chose to model these values as an upper bound for what a PLS technology might accrue in the ancillary services markets. For our modeling of regulation, the PLS technology bids into the regulation up market whenever it is charging or full and bids into the regulation down market whenever it is discharging or empty. For spinning reserve, the technology bids into the spinning reserve market whenever it is fully charged. In practice, there are factors such as an energy-biased regulation signal and imperfect foresight that would reduce the value of the ancillary services benefits shown in Figure 28 and Figure 29.

The ancillary service benefits used are 15 year projections of ancillary services values which have the same hourly shape as the 2009-2010 CAISO historical values corresponding to our avoided cost energy price period. These historical values were escalated into the future at the same rate as our projected escalation of energy prices in the avoided cost model.

Figure 28: Broad Scenario Analysis – Sensitivity to Ancillary Services – 6 Hour Duration

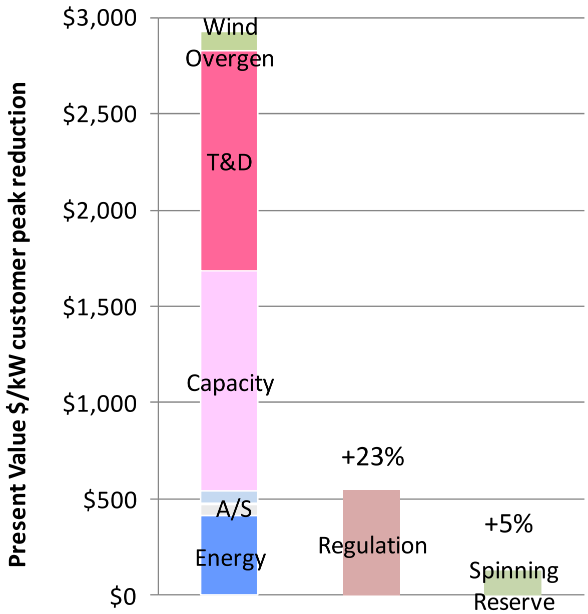


Figure 29: Broad Scenario Analysis – Sensitivity to Ancillary Services – 1 Hour Duration

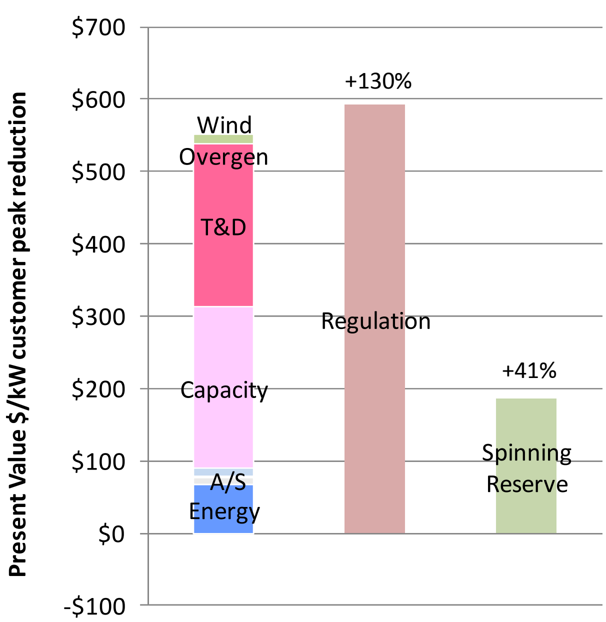


Figure 28 shows the additional value that regulation or spinning reserve could provide to a PLS system that is able to participate in those markets. Figure 28 represents a 6 hour shift every day starting at 12 PM. Figure 29 represents a 1 hour shift everyday starting at 2 PM. Regulation and spinning reserve represent greater incremental values to the avoided costs of the permanent load shift product for the shorter duration discharge.

4.1.3.6. Summary of Avoided Cost Sensitivities

Table 10 shows the sensitivities we ran to look at the avoided cost values. All the sensitivities shown were carried out on idealized shift profiles. Table 10 lists the directional impact and relative impact, for each sensitivity, on avoided costs.

Table 10: Summary of Avoided Cost Sensitivities

Avoided Cost Sensitivities	Directional Impact	Relative Magnitude in Terms of Lifecycle Avoided Costs
T&D	The elimination of T&D avoided costs **reduces** total avoided costs.	For a 10 hour idealized shift, removing T&D avoided costs reduces total avoided cost benefits by **~20%.**
Seasonal Shift	A shift for only part of the year **reduces** avoided costs	Compared to a year-round shift, a shift from May to October reduces the broad scenario analysis avoided costs on average ~ **15%.**
Energy Efficiency	A decrease in roundtrip efficiency **reduces** avoided costs	Compared to a 100% round-trip efficient system, an 80% round-trip efficient system reduces avoided costs by ~ **15%** for a 10 hour idealized shift.
Technology Lifetime	A longer technology lifetime **increases** avoided costs**.**	A technology lifetime of 30 years increases the avoided costs by ~ **35%.**compared to a 15 year lifetime.
Ancillary Services	Additional ancillary services capabilities **increases** avoided costs.	For a 6 hour idealized system, regulation benefits could supplement the avoided costs by **~25%** and spinning reserve could increase value by **~5%.**
Resource Balance Year	An earlier resource balance year **increases** avoided costs	A resource balance year of 2010 relative to the baseline resource balance year of 2015 increased avoided costs benefits by **7%.**

4.1.4. Specific Case Results: Simulated Scenarios

The cost effectiveness results for the simulated case studies are summarized in Figure 30. The simulated thermal storage examples generally pass the TRC test, while the simulated battery scenarios do not. The thermal storage examples marginally fail the RIM test under the specific tariff (PG&E A10 TOU[19]), while some battery examples pass the RIM test, depending on the load profile. The battery examples were modeled using a TOU rate that included summer and winter demand charges, as well as a noncoincident demand charge[20].

Figure 31 summarizes the incentive levels for these same case studies based on the RIM and PAC tests. Since the thermal storage examples do not pass the RIM test, a *negative* rate payer neutral incentive level is estimated. This result implies that the rate itself provides an incentive to the participant that is in excess of the value of the PLS system. The PAC test incentive is roughly $2000/kW (the avoided cost benefits) for these examples. The RIM test results are mixed for the battery profiles. In some cases, the rate provides the incentive — specifically for the load leveling examples. This result is not surprising, since the battery operation was optimized for bill savings. The battery incentive, based on the PAC test, is roughly $500-700/kW.

[19] The PG&E A-10 TOU, as of November, 2010: on-peak to off-peak TOU energy differential of $.03/kWh in the summer and $.01/kWh in the winter. It also has peak day pricing rate of $.90/kWh which was modeled as being called on 15 days (the maximum allowable). In addition, there is an all-hours demand charge of $10.88/kW in summer and $6.53/kW in winter.

[20] Characteristics of rate used to model battery scenarios: summer on peak energy charge of $0.11/kWh, off peak $0.07/kWh; winter on peak energy charge of $011/kWh, off peak $0.08/kWh; summer demand charge of $13/kW, winter demand charge of $5/kW; noncoincident demand charge of $13/kW.

Figure 30: Summary of Simulated Example Cost Effectiveness

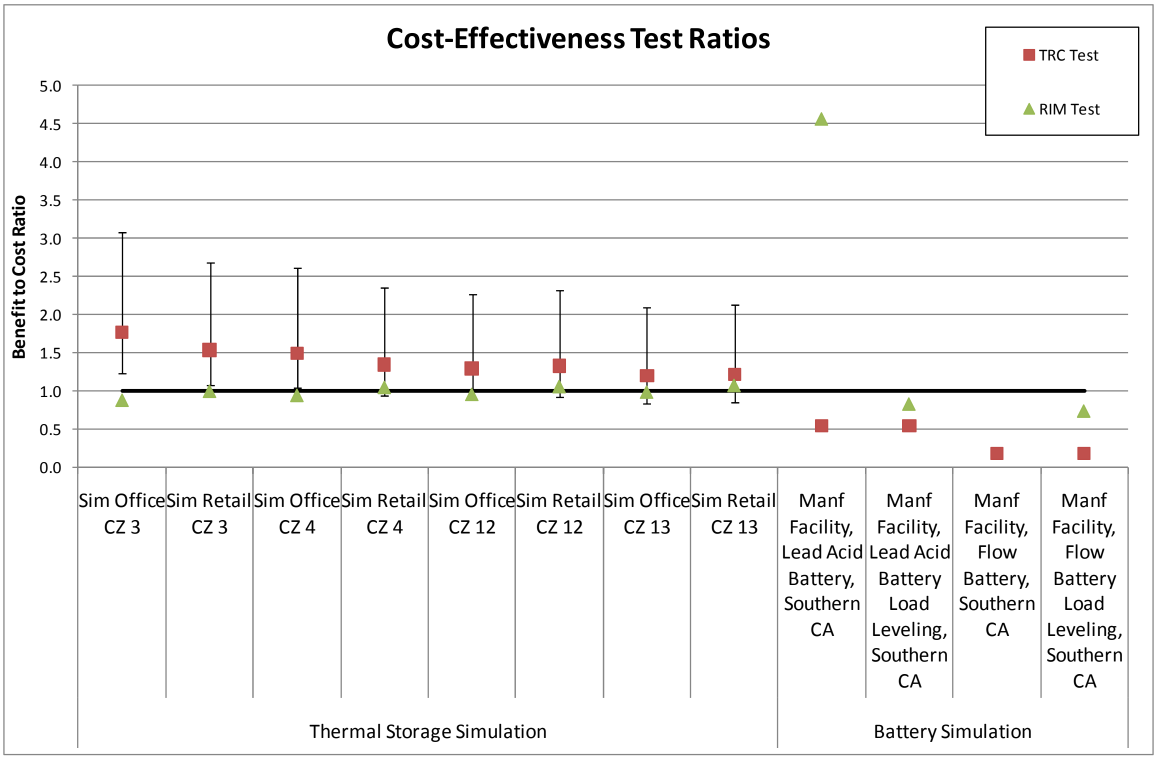
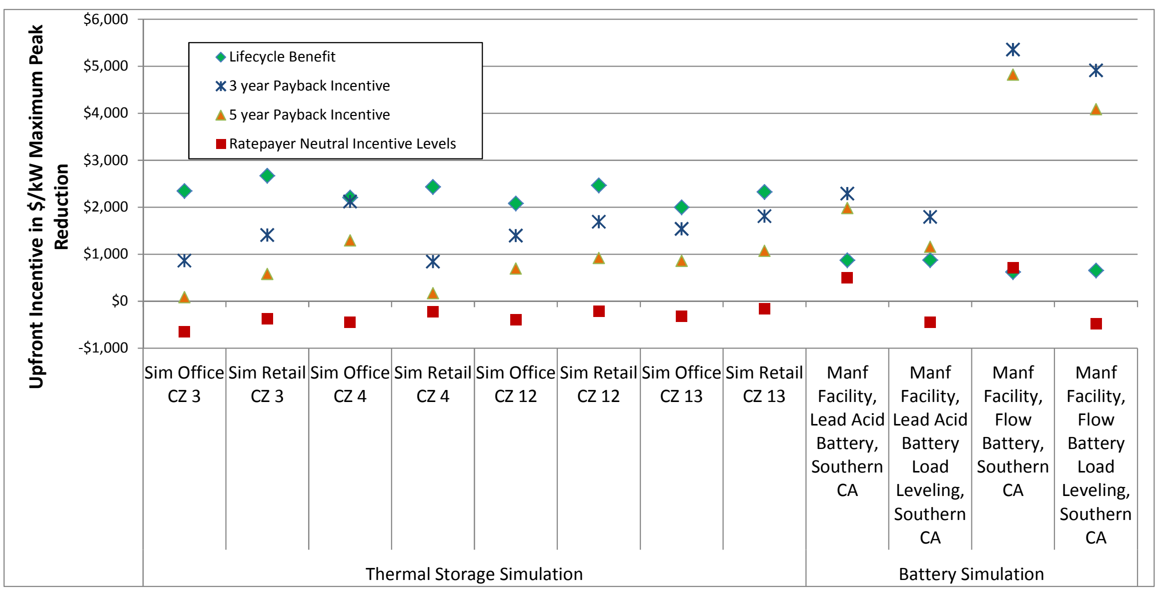
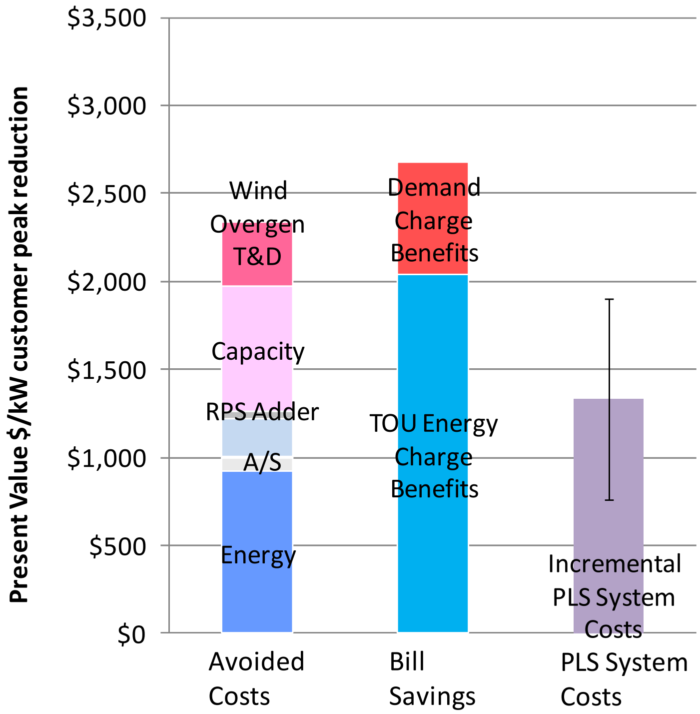


Figure 31: Summary of Simulated Examples Incentive Levels



Recall that eight partial shift chilled water scenarios were evaluated for two building types (office & retail) in four climate zones (3, 4, 12, and 13). The office simulation in climate zone 3 is shown in Figure 32.

Figure 32: Specific Case Results – Simulation Office CZ 3



In this example, the PLS installation passes the TRC test, but fails the RIM test. Based on a ratepayer neutral incentive cap, the system does not merit an incentive. The RIM test result, however, is specific to the underlying tariff and holds true only so long as the utility tariff stays consistent. The PLS system costs are generally less than the bill savings, indicating a positive participant cost test for the range of costs assumed[21]. For this example, over the lifetime of the project, the bill savings offset the cost of the PLS system.

The thermal storage examples are based on hourly outputs from an energy simulation program. Because the eight sets of load shapes exhibited similar cost-effectiveness results, individual figures for all cases are not shown.

[21] As noted in Chapter 3, the system costs are estimated assuming $150-$400/ton-hr unit costs.

4.1.5. Specific Case Results: PLS Pilots and Recent Installations

The Project Team performed a “retrospective” cost-effectiveness analysis of recent installations. While it is not appropriate to make a policy decision on the value of a program using cost-effectiveness results of individual installations, real data can provide some insight into how programs may be improved.

There are a number of caveats to interpreting the results:

- The results are based on historical performance, not “ideal” or optimized operation of the PLS system.
- In some cases, PLS systems are designed with a certain load in mind. For a variety of reasons, the historical data may not reflect that intended load (such as due to weather, changes in operating conditions or occupancy)
- All costs and benefits are normalized to the observed maximum peak reduction, which may less than or greater than the design peak reduction, a common metric used by manufacturers.

Figure 33 summarizes the cost-effectiveness test results from recent installations. Most of the installations pass the RIM Test, which implies that the current rate does not provide benefits to the participant at the rate at which the PLS system provides grid benefits. Some systems pass the TRC test.

The refrigerated warehouse shows the highest TRC test and highest RIM test. This system, based on the monitored period of operation, provides greater societal level benefits than the cost of the system, and at no cost to non-participating ratepayers. The relative low TRC test for some of the other thermal systems does not mean that these systems cannot provide benefits comparable to the cost of the system, but rather, they did not over the monitored period.

Figure 33: Summary of Case Results Cost Effectiveness

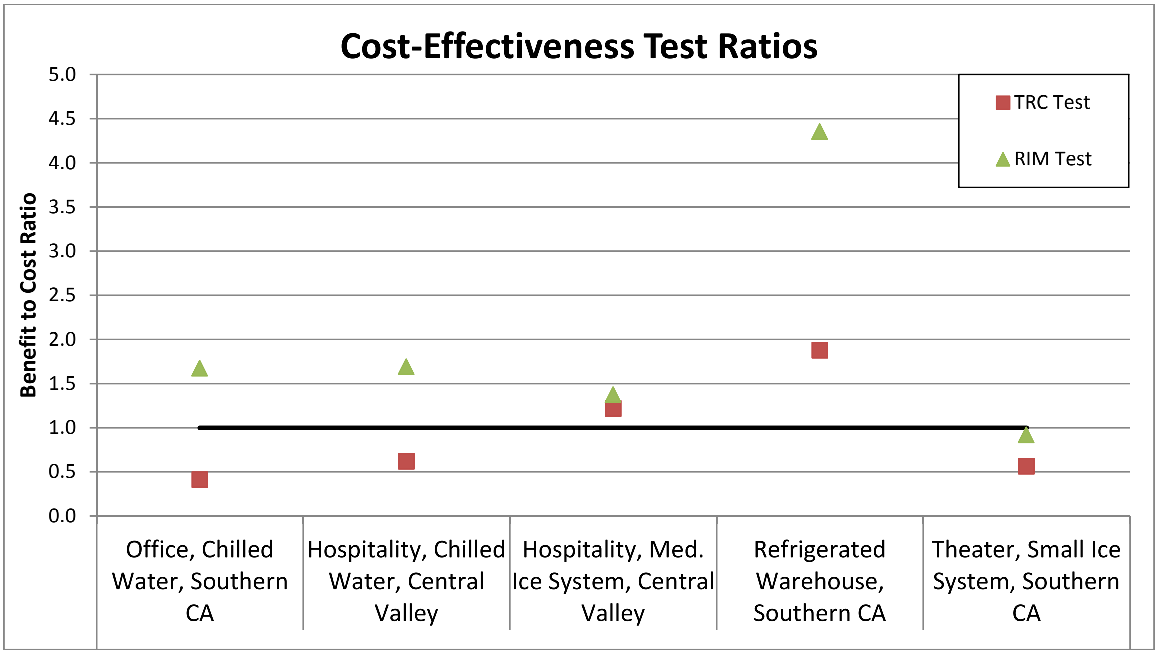


Figure 34: Summary of Case Studies Incentive Levels

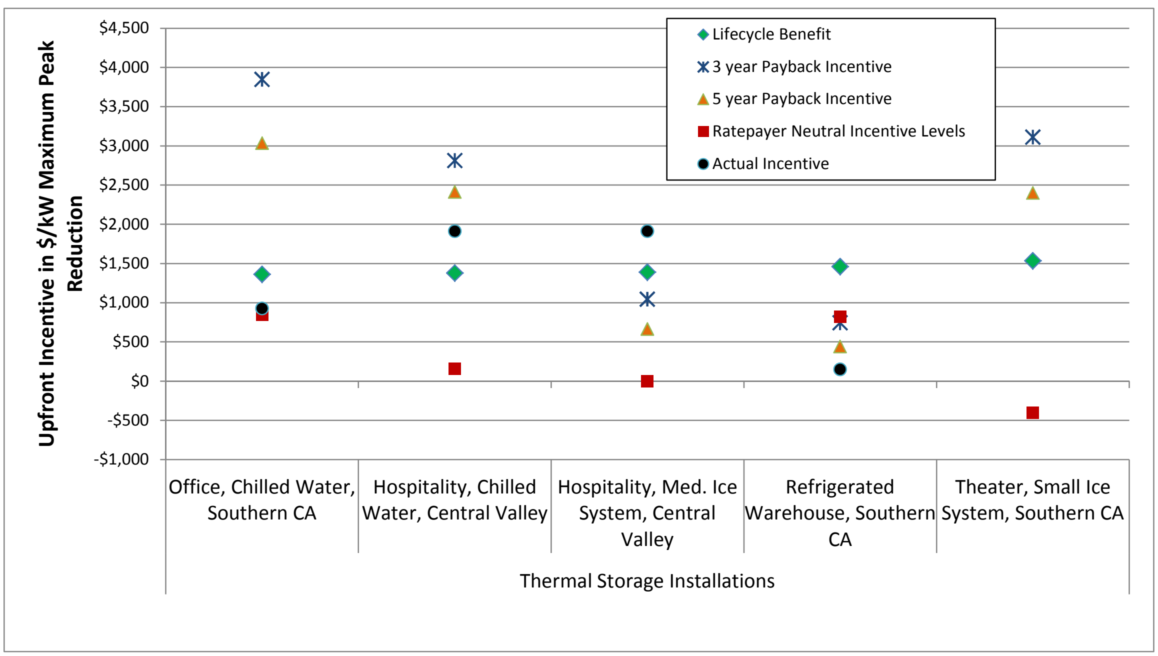


Figure 34 provides estimates of the upfront incentive level that could be justified based on the monitored data, using the PAC and the RIM tests. The actual incentives provided by the IOUs, on a $/kW basis, are also shown.

For three of the scenarios (office, southern CA, refrigerated warehouse, hospitality-chilled water), the equivalent ratepayer neutral incentive is positive, with a maximum level of ~$1200/kW (the office building with chilled water). The refrigerated warehouse example results in a ratepayer neutral incentive of ~ $800/kW. For both these examples, the actual incentive is less than the RIM and PAC based incentives.

Both hospitality examples show PAC based incentives of ~ $1000/kW and small ratepayer neutral incentives. In these cases, the actual incentive is roughly double the PAC incentive, although the incentive is applied to a contracted kW reduction, not the “observed” peak reduction that is the normalizing factor for the PAC and RIM test incentives.

The remainder of this section describes additional features of the examples.

Figure 35: Specific Case Results – Refrigerated Warehouse

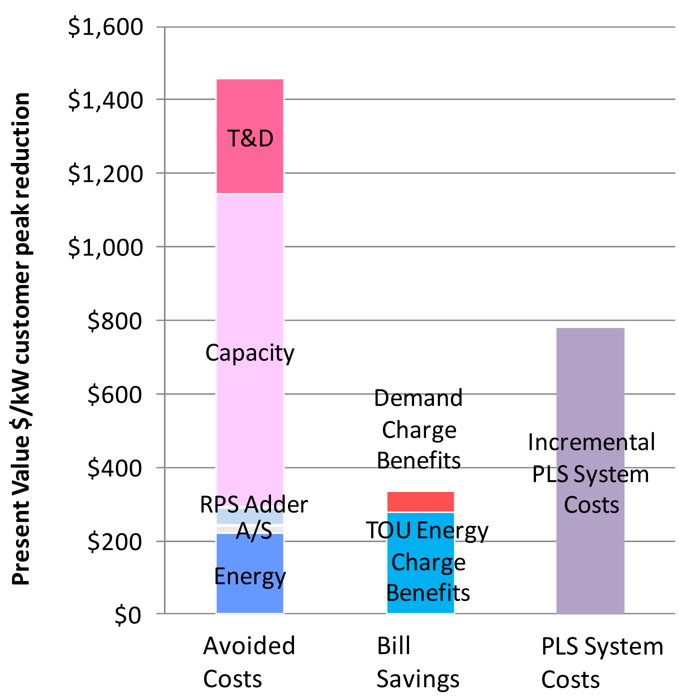


Figure 35 shows the cost effectiveness results of a refrigerated warehouse. The tariff of the warehouse customer has a small ($0.03-$0.04/kWh) on-peak to off-peak TOU energy differential. In addition, there are additive demand charges for all-hours demand and on-peak demand. The demand charge for this example is based on 15 minute data. This system passes the TRC and RIM tests but does not pass the participant test. The ratepayer neutral incentive for this system would be ~$1130/kW.

This system is a hybrid thermal – process shifting PLS technology. The warehouse is precooled where the product within the warehouse serves as the thermal storage entity. This PLS technology is infrastructure "light" in that the load shifting was enabled through the installation of controls. Three key features rendered this example to be an appropriate candidate for this technology.

- The unloading schedule of the warehouse was modified to facilitate maintaining product temperature requirements during the peak period. This process-shifting element was a key enabler and without it, the warehouse would have been unable to load shift.
- The products in this warehouse are not under FDA regulations or other food regulations that may otherwise prevent the use of this technology.
- The climate is favorable to warehouse precooling.

This example was one of the most cost effective among the case studies; however, this example has unique attributes and it's not clear how many more such opportunities exist.

Figure 36: Specific Case Results – Office Chilled Water System – Historical Operation

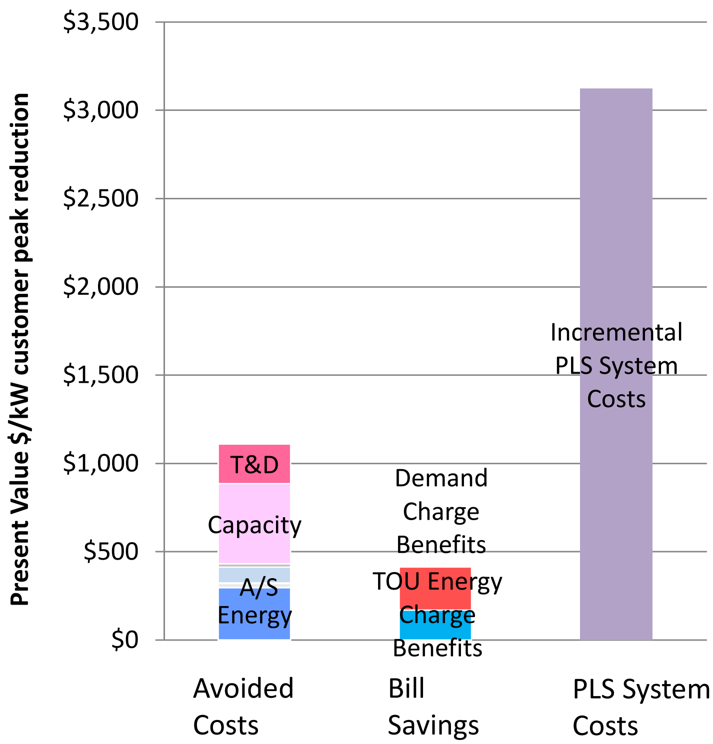


Figure 36 shows historic data for an office chilled water system in Southern California. This customer's rate includes a TOU energy charge differential of $0.07/kWh and $0.02/kWh in the summer and winter, respectively. The demand charge is based on all hours demand. The office chilled water system does not pass the TRC or participant tests but passes the RIM test. The maximum ratepayer neutral incentive is estimated at ~ $690/kW.

Figure 37: Specific Case Results – Office Chilled Water System –Improved Operation

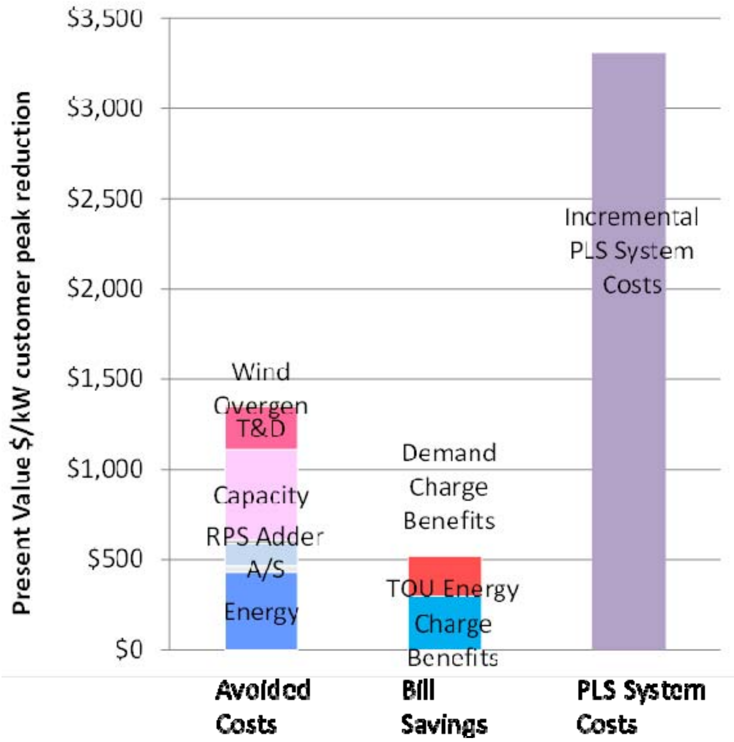


Figure 37 shows an improved scenario for the same example. This scenario deviates from the historical operation in three distinct ways: the energy efficiency upgrades that were in process during the monitored period are assumed to be complete; the charging of the TES is assumed to begin at 11 pm rather than 6 pm; and the TES operates all year round (the actual data showed large periods where the TES did not operate). The lifecycle avoided costs are ~15% higher, relative to the historic profile (on an absolute basis) and bill savings are nominally higher. The system passes the RIM test, with an estimated maximum ratepayer neutral incentive of $840/kW. The example does not pass the TRC or participant tests.

The office building example has some unique characteristics. While the facility had a TES tank in place, it was not used for shifting, but as an additional chiller when the existing chiller capacity could not maintain load; however, due to poor engineering, the TES was not effective as a “third” chiller. The incremental PLS system cost includes the engineering and controls improvements which provided energy efficiency improvements (~ 40%) and the cost to engineer and install a TES tank of comparable size. The actual cost of this system (less the tank cost) is less than the incremental cost shown above, but this comparison is not appropriate for comparing with the estimated avoided costs. An additional distinction is that the TES achieves a 30 °F temperature differential ("Delta T") rather than a typical 15 °F, which serves to reduce the all-in estimated cost.[22]

The modeled baseline reflects a conventional plant that met the full load with an energy performance equivalent to the preretrofit cooling plant performance.

Figure 38: Specific Case Results – Hospitality, Chilled Water System, Central Valley

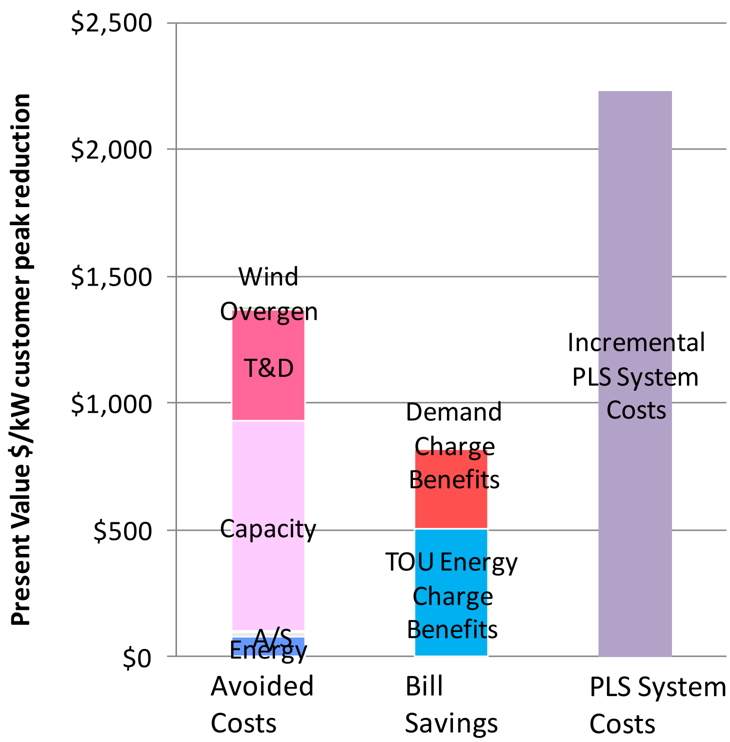


Figure 38 shows data for a hospitality facility chilled water system in the Central Valley. The tariff of this customer has an all-hours demand charge and a summer on-peak demand charge, and a $0.06/kWh TOU energy charge differential in summer and a $0.01/kWh TOU energy charge differential in winter.

[22] The estimated cost is ~$2,700/kW for a 30 °F "Delta T" system (on a design-peak-reduction basis), but would have been ~$4000/kW for an equivalent 15 °F Delta T system.

The demand charges are calculated using 15 minute data. The chilled water system does not pass the TRC or participant test but passes the RIM test. The maximum ratepayer neutral incentive is $560/kW.

Figure 39: Specific Case Results – Hospitality, Medium Ice System, Central Valley

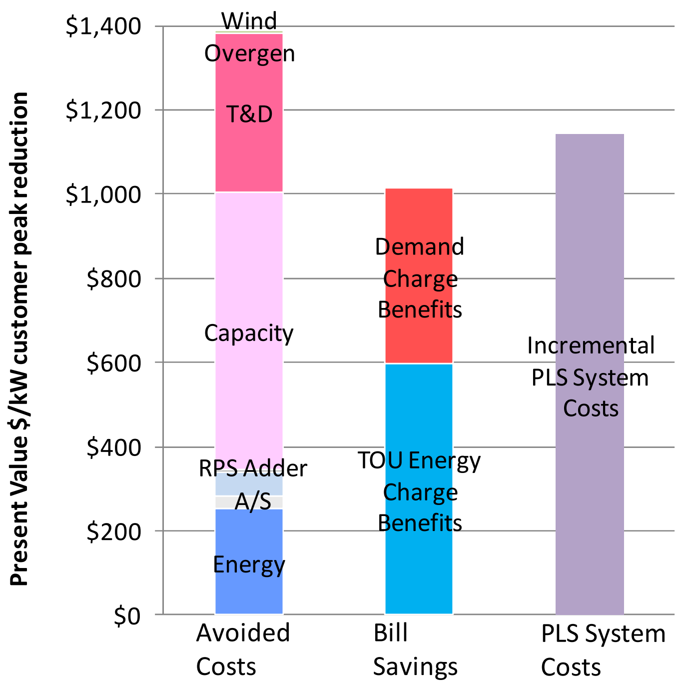


Figure 39 shows data for a hospitality facility medium ice system in the Central Valley. The tariff of this customer has an all-hours demand charge and a summer on-peak demand charge, a $0.06/kWh TOU energy charge differential in summer and a $0.01/kWh TOU energy charge differential in winter. The demand charges for this example are calculated using 15 minute data. The chilled water system does not pass the TRC or participant test but passes the RIM test. The rate payer neutral incentive would be $380/kW.

In general, the thermal storage systems did not provide avoided cost benefits that matched either the broad scenario modeling results or the simulated chilled water examples. Sub-optimal charging, round-trip efficiencies (inefficiencies), and variable shifts throughout the year act to reduce the avoided costs.

Figure 40: Specific Case Results – Theater, Small Ice System, Southern California

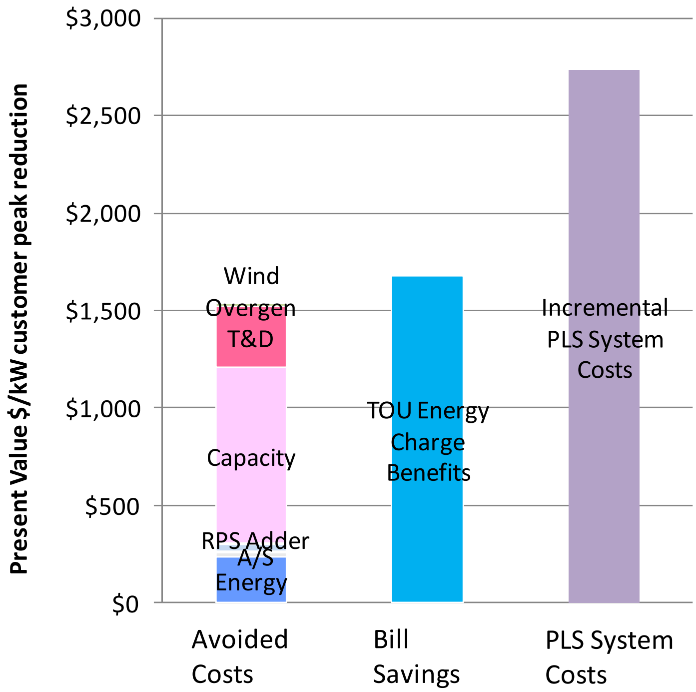


Figure 40 shows data for a theater facility small ice storage air conditioning system in Southern California. The tariff has $0.33/kWh and $0.04/kWh TOU energy charge differentials in summer and winter, respectively. This tariff has no demand charge. The small ice system does not pass any of the CE tests.

Two caveats are important to viewing these results. First, the rate that was applied is not reflective of the actual rate, but was selected because it represents a TOU rate without demand charge, and can thus be applied to evaluate savings where building level load data are not available. The actual savings to the customer may be greater or lower, depending on the real rate. Second, Ice Energy's current business model is utility ownership[23]. Because the participant does not pay for the installation, viewing the results from the participant cost

[23] Per communication with Ice Energy, Ice Energy's business model has changed significantly since the start of the PLS pilot program. Today, Ice Energy provides specific offset capacity (MWs) and offset energy (MWHs) under contract to a utility expressed as a $/kW offset, for a contract term typically 20 to 25 years. Ice Bear energy storage units are installed at no cost to customers, and these assets are aggregated and managed via a real-time control network in accordance with the utility's business objectives.

test under the new business model may not be significant because it will always be positive (assuming positive bill savings).

Figure 41: Specific Case Results – Batteries

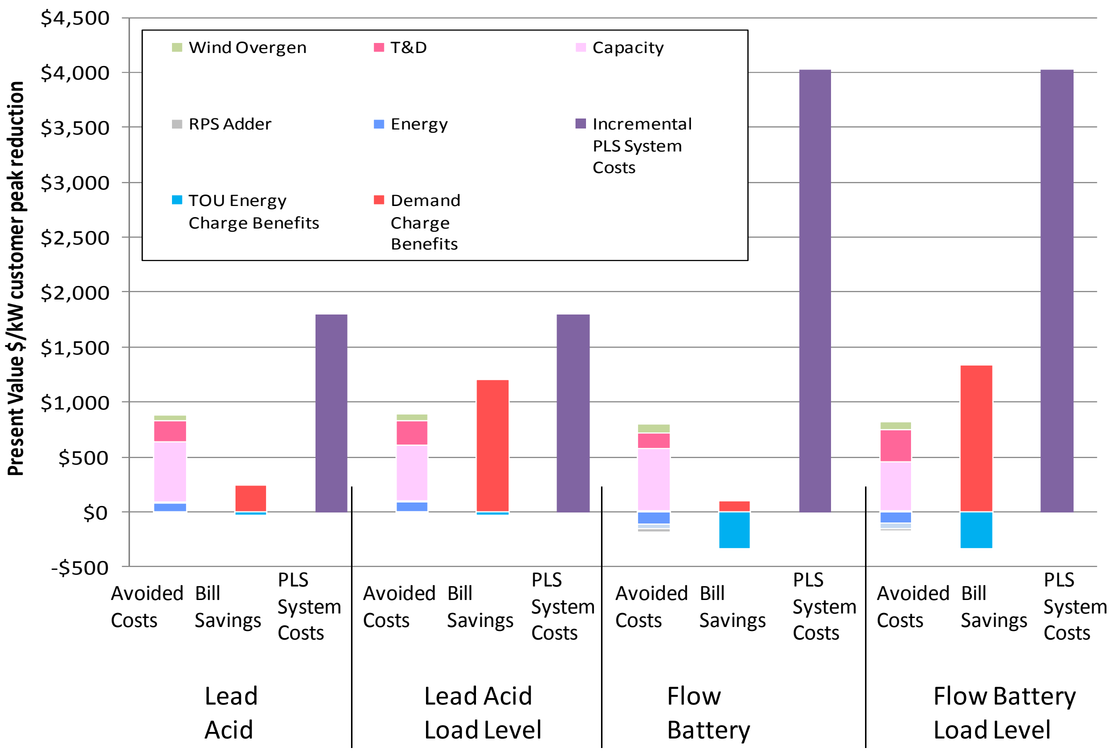


Figure 41 shows the cost-effectiveness test for four battery examples. None of the battery systems pass the TRC or the participant cost test, although the non-load level scenarios for both batteries pass the RIM test because the demand charge savings are lower. For non-load leveling outputs, the ratepayer neutral incentive is $660/kW for the lead acid battery and $850/kW for the flow battery. The tariff of the customer for all the batteries is the same. The tariff has an all-hours demand charge and an on-peak demand charge year-round. The tariff also has a $0.04/kWh TOU energy charge differential in summer and a $0.03/kWh TOU energy charge differential in winter. The demand charge for this example is calculated using hourly kWh data.

4.1.6. Case Studies: Generation Capacity Value Sensitivities

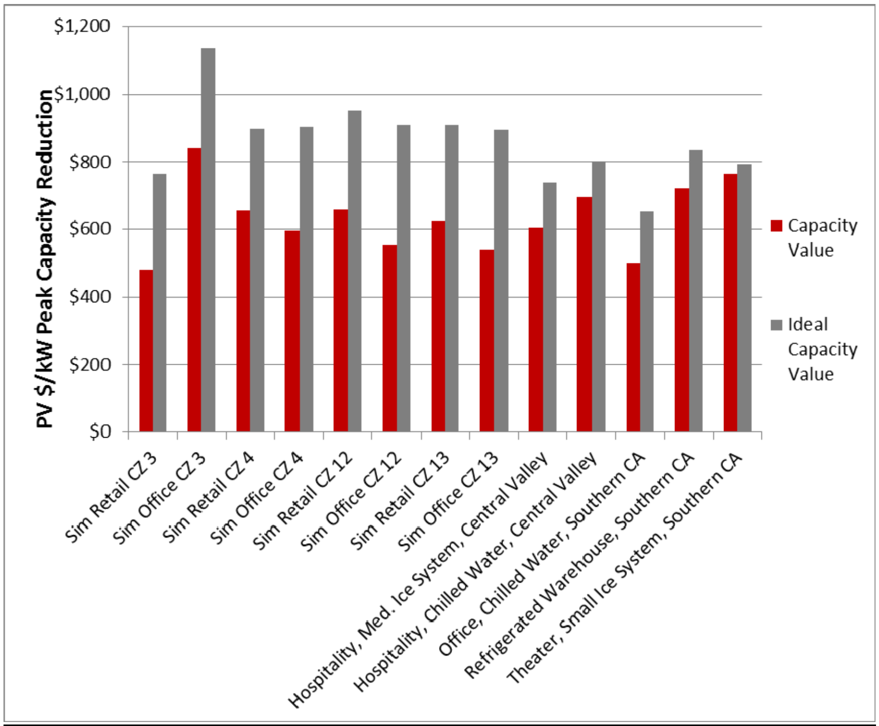
The Project Team performed sensitivity analysis to the generation capacity value to explore the effect of misalignment between the hourly load data and avoided costs. For each simulated and real example, the idealized generation capacity value was estimated. The idealized value is based on aligning the maximum daily reductions with the capacity avoided costs in a way that maximizes their value. Table 11 shows the relative increase in capacity value that result from assuming idealized alignment between the avoided costs and load data. Figure 42 shows the idealized capacity value alongside the estimated capacity value.

Table 11: Capacity value sensitivity

Example	Idealized Value Increase over Base Capacity Value (%)
Sim Retail CZ 3	60%
Sim Office CZ 3	35%
Sim Retail CZ 4	35%
Sim Office CZ 4	50%
Sim Retail CZ 12	45%
Sim Office CZ 12	65%
Sim Retail CZ 13	45%
Sim Office CZ 13	65%
Hospitality, Med. Ice System, Central Valley	25%
Hospitality, Chilled Water, Central Valley	15%
Office, Chilled Water, Southern CA	30%
Refrigerated Warehouse, Southern CA	15%
Theater, Small Ice System, Southern CA	5%

The simulated chilled water scenarios show the greatest sensitivity to realigning the data. The real installations would see at most a 30% increase in generation capacity value, with some examples showing good alignment (e.g., theater small ice system). These margins do not alter the main observations from the analysis.

Figure 42: Case study analysis of ideal capacity value



4.2. End User Impacts

The purpose of the end user analysis is to estimate incentive levels that will drive customer adoption of PLS technologies. This analysis looks exclusively at the simulated and example case studies because project-specific details are required to produce meaningful project-level value proposition results.

For each of the simulations and examples in the end user analysis, the same load data, tariff structure, and system specification and costs were utilized as in the cost effectiveness analysis section described in the previous sections.

4.2.1. Project Paybacks before Incentives

Nearly all of the simulations and real installations resulted in payback periods greater than 5 years (stakeholder feedback indicated that 5 year payback periods are the current hurdle to drive commercial customer adoption of PLS equipment). In fact, only the "low cost" simulated stratified chilled water scenarios demonstrated paybacks of less than 5 years without incentives. The following chart lists the specific payback periods before the introduction of incentives:

Table 12: Simulation and Example Payback Periods Before Incentives

	Simple Payback Period (Years)		
Simulation/Example	**High Cost**	**Average Cost**[24]	**Low Cost**
Sim Office CZ 3	6.8	5.2	3.3
Sim Retail CZ 3	8.6	6.4	4.2
Sim Office CZ 4	12.2	8.7	5.6
Sim Retail CZ 4	7.2	5.5	3.5
Sim Office CZ 12	9.7	7.1	4.6
Sim Retail CZ 12	10.6	7.6	4.9
Sim Office CZ 13	10.9	7.8	5.0
Sim Retail CZ 13	11.7	8.3	5.4
Sim PLS 4h PLS Mfg Flow Batt		N/A[25]	
Sim PLS 4h Mfg Lead Acid Batt		N/A	
Sim Load Leveling 4h Mfg Flow Batt		N/A	
Sim Load Leveling 4h Mfg Lead Acid Batt		9.5	
Ex Office Building, Chilled Water, Southern California		N/A	
Ex Hospitality, Chilled Water System, Central Valley		N/A	
Ex Hospitality, Medium Ice System, Central Valley		9.5	
Ex Refrigerated Warehouse, Southern California		8.5	

[24] Average cost data available for all examples, but only chilled water simulations include high and low cost estimates

[25] N/A indicates that the project did not have a year in which cumulative cash flows become positive without incentives

4.2.2. Incentive Level Requirements

The modeled payback periods for the case studies (not including incentives) suggest some level of incentives are required to drive customer adoption. Based on stakeholder feedback, payback periods of three to five years are needed to drive customer adoption. To calculate the necessary incentive levels, StrateGen began the analysis with a simple up front incentive payment in units of $/max kW shifted to off-peak. Then the end user value proposition model solved for the $/max kW shifted incentive levels required to achieve simple payback periods of three and five years. Figure 43 overlays the simulations results of the required incentive levels with the PAC and RIM Test rate-payer neutral incentive levels:

Figure 43: Required Incentive Levels vs. PAC & RIM Tests for Simulated Case Studies

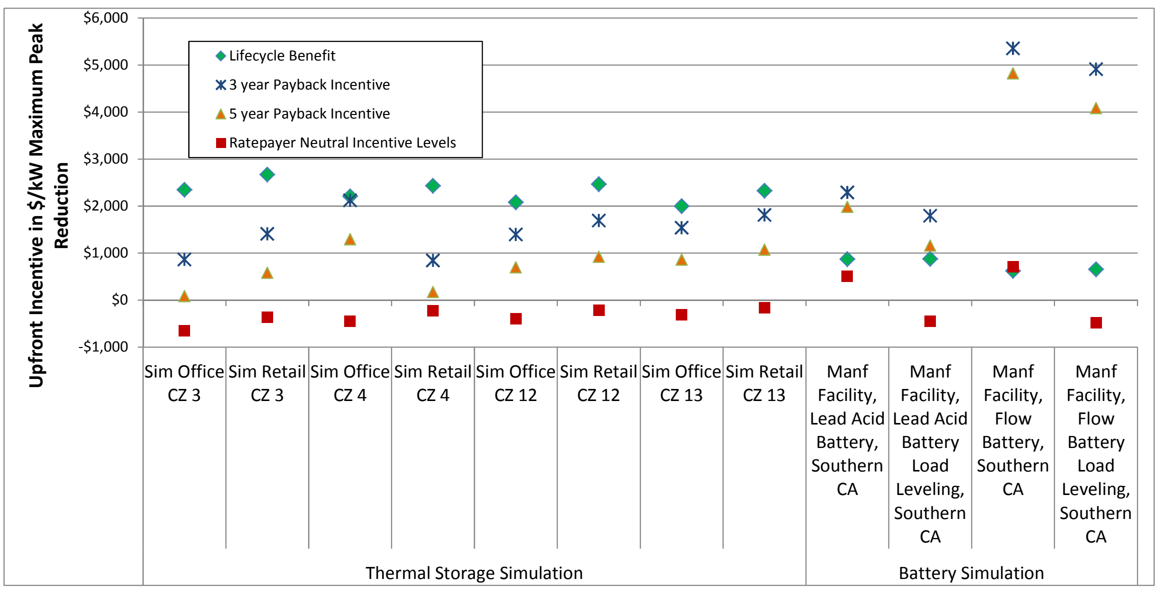
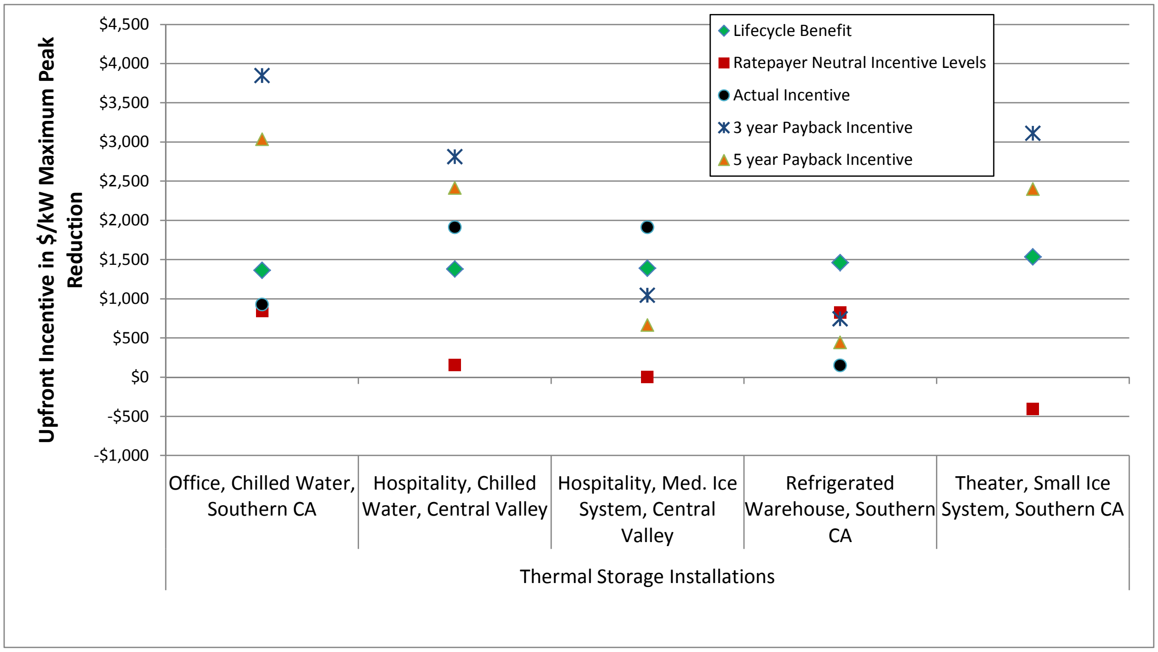


Figure 43 indicates that required incentive levels for the thermal storage simulations range from about $100 to 1,000/kW to achieve a 5 year payback for the end user and approximately $860 to $1,800/kW to achieve a 3 year payback. The battery simulations' required incentive levels range from $1,100 to over $5,000 to achieve required payback levels. Several of the 3 and 5 year payback incentive levels for the simulated examples are less than the PAC based incentives but greater than the RIM based incentive levels.

Figure 44 overlays the required incentive levels for the PLS Pilots and recent installations with the PAC and RIM Test rate-payer neutral incentive levels:

Figure 44: IOU Pilot Project Required Incentive Levels vs. PAC & RIM Tests for PLS Pilots and Recent Installations



As shown on Figure 44, the required incentive levels for the thermal storage projects range from ~ $400 to 3,560/kW for a 5 year payback and ~ $700 to $1,800/kW for a 3 year payback to the end user. With the exception of the Refrigerated Warehouse example, nearly all of the required incentive levels are greater than the RIM and PAC test levels. Also, as indicated by the black dot data points, the office building and chilled water example actual pilot incentive levels were less than the required incentive levels to achieve three or five year paybacks. The actual pilot incentive levels for the medium ice and refrigerated warehouse were much closer to the estimated three and five year payback incentive levels.

4.2.3. Sensitivities to Incentive Level Requirements

In addition to estimating three and five year payback $/kW incentive levels, StrateGen conducted the following sensitivities:

- Required $/kW upfront incentive to achieve a 15% internal rate of return (IRR)

- On to off peak-peak TOU rate differential required to achieve a five year payback

Table 13 compares the required incentive levels to achieve a 15% IRR versus a three and five year payback period:

Table 13: Comparison of incentive levels for three and five year paybacks

	Required Upfront Incentive Level ($/kW)		
Simulation/Example	**15% IRR Hurdle**	**5yr Payback Hurdle**	**3yr Payback Hurdle**
Office, Chilled Water, Southern CA	3680	3030	3850
Hospitality, Chilled Water, Central Valley	2980	2410	2810
Hospitality, Med. Ice System, Central Valley	760	660	1040
Refrigerated Warehouse, Southern CA	500	440	740
Theater, Small Ice System, Southern CA	2900	2400	3110
Sim Office CZ 3	-50	80	860
Sim Retail CZ 3	560	570	1410
Sim Office CZ 4	1470	1290	2120
Sim Retail CZ 4	80	160	840
Sim Office CZ 12	730	690	1400
Sim Retail CZ 12	1010	920	1690
Sim Office CZ 13	950	850	1540
Sim Retail CZ 13	1200	1070	1810
Manf Facility, Lead Acid Battery, Southern CA	2440	1980	2290
Manf Facility, Lead Acid Battery Load Leveling, Southern CA	1330	1150	1790
Manf Facility, Flow Battery, Southern CA	6000	4820	5350

For most of the simulations and example cases, the 15% IRR hurdle equates to required incentive levels between the three to five year payback hurdles. The time value of money, operating expenses, and tax effects make direct comparison of IRR and simple payback difficult.

In the following sensitivity, a TOU tariff modeled after a simplified PG&E A6 tariff is utilized. This modified A6 rate has TOU time periods similar to A6 with the exception of eliminating the mid-peak time period in the summer to simplify the definition of the required TOU differential between peak and off peak. The following table defines the TOU rates and time periods modeled:

Table 14: Modified PG&E A6 Tariff

Simplified A6 Tariff Definitions	Summer	Winter
Peak Time Period	12PM-6PM	8AM-10PM
Off-Peak Time Period	6PM-12PM	10PM-8AM
Peak Period Energy Rate ($/kWh)	$0.45331	$0.16567
Off-Peak Period Energy Rate ($/kWh)	$0.11691	$0.11691
Demand Charges ($/kW)	N/A	N/A

Using this modified A6 tariff, StrateGen modeled the required on to off-peak rate differential to achieve a five year simple payback. The results of this analysis are presented in the following table:

Table 15: Required TOU Rate Differential to Achieve 5yr Payback

	Required TOU On to Off-Peak Differential	
Simulation/Example	**Summer**	**Winter**
Office, Chilled Water, Southern CA	$0.25	$0.02
Hospitality, Chilled Water, Central Valley	$0.33	$0.05
Hospitality, Med. Ice System, Central Valley	$0.36	$0.06
Refrigerated Warehouse, Southern CA	$0.41	$0.08
Theater, Small Ice System, Southern CA	$0.45	$0.09
Sim Office CZ 3	$0.43	$0.08
Sim Retail CZ 3	$0.51	$0.11
Sim Office CZ 4	$0.49	$0.10
Sim Retail CZ 4	$0.73	$0.19
Sim Office CZ 12	$0.87	$0.24
Sim Retail CZ 12	$2.05	$0.68
Sim Office CZ 13	$1.55	$0.49
Sim Retail CZ 13	$1.80	$0.58
Manf Facility, Lead Acid Battery, Southern CA	$1.97	$0.64
Manf Facility, Lead Acid Battery Load Leveling, Southern CA	$0.63	$0.16
Manf Facility, Flow Battery, Southern CA	$0.33	$0.05

The required TOU differentials to achieve a five year payback vary significantly across the case studies and range from $0.25/kWh to over $2.00/kWh in the summer months and from $0.02/kWh to $0.67/kWh in the winter months. This is primarily due to PLS system efficiency and total project cost.

5. Market Issues and Stakeholder Feedback

5.1. State of the Industry

This section first provides an overview of other programs around the country, highlighting different program types, incentive levels and key takeaways. A summary of stakeholder input gathered during interviews or feedback submitted after workshop sessions follows.

5.1.1. Permanent Load Shifting Programs

The following list represents an overview of load shifting programs around the country, followed by a discussion of takeaways. The majority of the programs presented here are utility-sponsored thermal energy storage incentive programs. Other program types include special TOU rate structures or technology-neutral load shifting programs. This information was compiled through utility program websites, the DSIRE website, and interviews with utility program managers and other industry stakeholders.

5.1.1.1. Program Overview

Anaheim Public Utilities (California)[26]

Program: TES and TOU

Anaheim Public Utilities offers business and industrial customers a thermal energy storage incentive of up to $21,000. The program objectives emphasize financial savings, peak energy shifting, and energy savings. Eligible systems include refrigerant-based thermal energy storage air conditioning systems and ice storage units approved under Title 24; central plant, chilled water circulation cooling systems are not eligible. Participating customers may also qualify for a new time-of-use thermal energy storage rate. Eligible customers include those

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[26] Anaheim Public Utilities program details can be found here: http://www.anaheim.net/article.asp?id=4132

shifting a minimum of 20% of the monthly maximum on-peak demand to off-peak as a result of thermal energy storage installations. If the customer fails to shift 20% of demand, or exceeds 500 kW for a given meter for any 3 months over a 12 month period, they are deemed ineligible for this special developmental rate.

This program is currently fully subscribed and will not accept new applications for funding until July 1, 2011.

Austin Energy (Texas)[27]

Program: TES, TOU, and Feasibility Incentive

Austin Energy's Power Saver™ program offers incentives for thermal energy storage projects. In order to make smaller installations more attractive, rebates are tiered based on system size: $300/kW for 0-100 kW shift; $150/kW for 100-500 kW shift; $50/kW for >500 kW shift or higher. Participating customers are required to shift between 20% and 50% of on-peak summer demand or 2,500 kW (whichever is less). Austin Energy requires a feasibility study for projects with anticipated demand shift of 100kW or greater, and offers a 50% feasibility study incentive, up to $7000. Participants must be billed for electricity on any demand rate and use the TES TOU rider.

According to a Summit Blue report commissioned by SCE, "since incentives are very low, interest in this product is minimal."[28]

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[27] Austin Energy program details can be found here: http://www.austinenergy.com/Energy%20Efficiency/Programs/Rebates/Commercial/Commercial%20Energy/thermalEnergyStorage.htm

[28] Summit Blue, 2009, pg. 24

Burbank Water and Power (BWP) (California)[29]

Program: TES

BWP's *Energy Solutions* program provides businesses with thermal energy storage rebates of $800/kW of peak demand saved. Incentives are capped at 25% of the installed cost of the measure, and range from $4728 to $8544, depending on the size and age of the unit installed. Additionally, the annual customer rebate total may not exceed $100,000.

Connecticut Light and Power (CL&P)[30]

Program: Peak Demand Reduction

CL&P's *Demand Reduction* program offers commercial and industrial customers guidance regarding customer electricity usage, including strategies to reschedule usage to off-peak. In the first stage, a CL&P representative will analyze the facility's electricity usage patterns and develop a proposal for installing or implementing measures based on these findings. Incentives are available to offset the cost of recommended upgrades. Eligible projects include reset temperature controls, lighting controls, water cooler controls, vending machine controls, water heater controls, process controls, HVAC controls, and miscellaneous load controls. However, all projects are approved on a case-by-case basis, so additional measures that perform load rescheduling or curtailment may be eligible for incentives. After the measures are completed and the demand reduction and energy savings have been verified, the customer receives the incentive payment.

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[29] BWP program details can be found here: http://www.burbankwaterandpower.com/index.php/incentives-for-businesses/energy-solutions-business-rebate-programs

[30] CL&P program details can be found here: http://www.cl-p.com/Business/SaveEnergy/LoadManagement/DemandReduction.aspx

Duke Energy (Ohio[31], North Carolina[32], South Carolina[33])

Program: TES

Duke Energy's Smart $aver® Incentive Program offers thermal energy storage incentives in Ohio, North Carolina, and South Carolina. Businesses can receive $190/kW shifted for thermal energy storage systems with less than a MW shift. For larger systems, businesses can apply for custom incentives. Used equipment and equipment already receiving incentives from a different Duke Energy program are not eligible for the incentives.

Florida Power and Light (FPL)[34]

Program: TES, TOU and Feasibility Incentive

FPL provides incentives for businesses, schools and colleges to install thermal energy storage systems. Participating customers receive $2500 toward a pre-approved feasibility study conducted by a professional engineer, as well as $464-$580 per ton of cooling load removed from the summer on peak period. The actual incentive level depends on the equipment installed. FPL provides an additional $16 to $20 per ton for initial commissioning. A TOU rate is available to all Florida IOUs, which improves system payback. FPL has incorporated a seasonal demand rate which significantly shortens the peak period window (from 9 to 3 hours). This has allowed customers to design systems for a much smaller window, and thus reduce costs.

The program is technology neutral, but technologies typically installed include static ice and chilled water systems. Marketing for the program involves a two-fold approach: a direct sales model targeting large customers, and an indirect

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[31] Duke Energy Ohio program details can be found here: http://www.duke-energy.com/ohio-large-business/energy-efficiency/chillers-thermal-storage.asp

[32] Duke Energy North Carolina program details can be found here: http://www.duke-energy.com/north-carolina-large-business/energy-efficiency/nclb-smart-saver-incentives.asp

[33] Duke Energy South Carolina program details can be found here: http://www.duke-energy.com/south-carolina-large-business/energy-efficiency/sclb-smart-saver-incentives.asp

[34] FPL program details were gathered during an interview with FPL and from here: http://www.fpl.com/business/energy_saving/programs/interior/thermal.shtml

sales model targeting the design (architectural and engineering) community. According to FPL, working with the design community has been a very effective approach, as it allows them to indirectly market to a number of customers through a single design firm. FPL also offers workshops and seminars throughout the state to outline program incentives and guidelines.

Gulf Power (Florida)[35]

Program: Residential TOU

Gulf Energy's *Energy Select* program offers residential customers a special "Residential Service Variable Pricing" (RSVP) rate. The RSVP rate features four different prices based on time of day, day of week, and season. Customers who opt in are required to purchase an Energy Select thermostat in order to reschedule central heating and cooling, electric water heating, and pool heating to run more in the lower price periods and less in peak periods. The program also includes opportunities to participate in demand response events via remote communication with the Energy Select thermostat.

Longmont Power and Communications (LPC) (Colorado)[36]

Program: TES

As a part of Longmont's *Commercial Energy Efficiency Program*, businesses can receive up to $500/kW for thermal energy storage systems (as well as a number of other technologies that perform energy efficiency measures such as lighting, heating, and controls). Only commercial rate customers by LPC and Platte River Power Authority are eligible.

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35 Gulf Power program details can be found here: http://www.gulfpower.com/energyselect/the_rate.asp

36 LPC program details can be found here: http://www.ci.longmont.co.us/lpc/bus/eep_homepage.htm

MidAmerican Energy (Iowa[37], Illinois[38], South Dakota[39])

Program: TES

As a part of MidAmerican's *Energy Advantage* program, non-residential customers can receive incentives to purchase and install high-efficiency building systems equipment. The program focuses primarily on space heating and cooling systems, and provides incentives for eligible thermal energy storage systems. The specific rebate level is customized based on incremental cost, peak demand reduction, annual energy use reduction and annual energy cost savings. Other equipment types that qualify include (but are not limited to) boilers over 2.5 million Btu input capacity; ground-source heat pump systems 135 million Btu/hr or greater; premium-efficiency motors over 200 HP; process boiler, chiller and refrigeration improvements; energy management systems; direct-fired heating systems; thermal energy storage; variable air volume conversions; waste-recovery systems; process and heat-recovery heat pumps; new and replacement window systems; and insulation upgrade projects.

As of March 2009, there were only two customers participating in the program.[40]

Minnesota Power[41]

Program: TOU

Minnesota Power offers a Controlled Access/Storage Heating rate for residential and commercial space heating and water heating in off-peak periods. Eligible storage includes storage room units, a central storage furnace, a central hot water system, or slab heat. Off-peak is defined as 11pm to 7am. Residential off-

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37 MidAmerican Energy Iowa program details can be found here: http://www.midamericanenergy.com/ee/ia_bus_custom_systems.aspx

38 MidAmerican Energy Illinois program details can be found here: http://www.midamericanenergy.com/ee/il_bus_custom_systems.aspx

39 MidAmerican Energy South Dakota program details can be found here: http://www.midamericanenergy.com/ee/sd_bus_custom_systems.aspx

40 Summit Blue, 2009, pg. 22.

41 Minnesota Power program details can be found here: http://www.mnpower.com/customer_service/cost_savings/commercial_storage_offpeak_heating.htm

peak rates are 3.943 cents per kWh, and require an $8 monthly service charge. Commercial rates are divided into two rates: primary service is 3.643 cents per kWh with a $10.50 monthly service charge; secondary service is 3.943 cents per kWh and a $10.50 monthly service charge.

Minnesota Power also has a residential and commercial "Dual Fuel" program, which incentivizes buildings with a non-electric back-up heating system to switch away from electric heat during periods of high demand. However, this is an event-based program, not a scheduled shift.

NYSERDA (New York)[42]

Program: TES

NYSERDA's *Existing Facilities* program provides performance-based incentives for energy efficiency and peak demand reductions, including energy or thermal storage systems. Eligible energy storage projects can receive rebates based on geographic location: the "Upstate" rebate is $300/kW and the "Downstate" rebate is $600/kW. The total incentive amount cannot exceed the lesser of $2,000,000 or 50% of the project cost. In addition, performance-based projects must qualify for an incentive of at least $10,000.

Otter Tail Power (Minnesota, North Dakota, South Dakota)[43]

Program: TES

Otter Tail Power provides rebates of $10 to $60 per kW for new thermal storage systems. The incentive level varies based on the rate on which the system is installed, and requires a minimum installation of 9 kW. The RDC rate provides $20/kW and applies to systems up to 100 kW. The Deferred-load rate offers $30/kW up to 200 kW, then $10/kW up to 1,000 additional kW. The Fixed-time-

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[42] NYSERDA program details can be found here: http://www.nyserda.org/programs/Existing_facilities/default.html

[43] Otter Tail Power program details can be found here: http://www.otpco.com/SaveEnergyMoney/Rebates.asp

of-delivery rate provides rebates of $60/kW up to 200 kW, then $20/kW for up to 1,000 additional kW. Qualified systems include thermal storage central furnaces, room units, underfloor cable or panel systems, or electric boilers installed to serve underfloor systems.

Progress Energy Florida (PEF)[44]

Program: TES

PEF provides business customers incentives for installing thermal energy storage systems. Eligible customers can receive up to $300/kW of reduced cooling load during peak hours and can also opt in to a time-of-use rate. PEF provides a free "business energy check" as an initial step, which will determine eligibility and provide guidance. Only new equipment are eligible and customers must perform a preliminary feasibility study to receive any incentives.

Southern California Public Power Authority (SCPPA)[45]

Program: Utility-Owned TES

In January 2010, SCPPA announced a 53 MW distributed energy storage program with a goal of "reducing exposure to costly peak power and improving the reliability of the electrical grid."[46] SCPPA has partnered with Ice Energy to offer a utility-owned, cafeteria-style program to member utilities. In terms of compensation, SCPPA has contracted to pay Ice Energy a set per-project payment, and has budgeted for an annual "health check" and minor maintenance. The program has currently subscribed 8 MW, with Glendale Water and Power as the first utility to get approved and move forward. Glendale is currently installing approximately ten Ice Energy units a week, and anticipates

[44] PEF's program details can be found here: http://www.progress-energy.com/custservice/flacig/efficiency/index.asp

[45] SCPPA program details were gathered during an interview with SCPPA and from here: http://www.scppa.org/pages/misc/press.html

[46] SCPPA Press Release: http://www.scppa.org/pages/misc/press.html

installing over 250 units by the end of this year. Utilities can hire local contractors or work with Ice Energy installers.

According to SCPPA, a utility-owned business model is advantageous due to the aggregate cost savings achieved through mass installations. To manage the challenge of customer O&M issues, SCPPA has contracted with Ice Energy to provide a 24 hour call center to handle initial calls from customers experiencing problems.

Tennessee Valley Authority (TVA)[47]

Program Type: TOU

Effective April 2011, TVA will implement new wholesale rates that will more accurately reflect the cost of power based on time of use. The stated objectives of the change are "to reduce peak power demand and find alternatives to building more expensive power plants."[48] Distributors within TVA territory currently define rates based on general TVA guidelines, but retain the authority to determine individual rate structures based on customer needs. Under the new system, distributors will have the choice of two options: the "Seasonal Demand or Energy Rate" or the "Time-of-Use Rate." The Seasonal Demand and Energy rate structure applies seasonal demand charges, with the highest demand charges in summer. The Time-of-Use rate structure varies pricing based on the season and time of day, with the highest rates in summer afternoons.

TVA has offered TOU pricing to some large commercial and industrial customers for several years, and reports significant benefits. Peak demand has been reduced by several hundred MWs, and some participants have enjoyed up to 30% reductions on their bill. Starting in the fall, distributors will be allowed to offer new TOU rates to commercial and industrial customers with over a MW of demand. Customers with demand of over 5 MW will have the option of the

[47] TVA rate details can be found here: www.tva.gov/news/releases/julsep10/Rate_Change.pdf
[48] www.tva.gov/news/releases/julsep10/Rate_Change.pdf

existing firm rate, the new Time-of-Use rate, or a new Seasonal Demand and Energy rate. These rate changes are designed to be revenue neutral for TVA.

5.1.1.2. Program Takeaways

Feasibility Studies

Funding feasibility studies improves outcomes and customer commitment, and is a core part of many programs' incentive structure. FPL, which provides up to $2500 for a pre-approved study conducted by a professional engineer, considers the feasibility study requirement a key piece in program success. Austin Energy also requires a feasibility study for projects with anticipated demand shift of greater than 100 kW, and will fund up to 50% of the cost up to $7000. Progress Energy also requires a feasibility study.

A feasibility study could potentially provide additional value by incorporating ongoing monitoring. One suggestion by an industry stakeholder is to integrate monitoring into the feasibility study. For example, the program could require engineers to commit to a specific level of monitoring as a part of the feasibility study, which can help improve the quality of the TES design.

Special Rates

A number of programs offer special TES/PLS rates that accompany incentives, which not only improve payback but encourage efficient system operation. For example, Anaheim Public Utilities recently instituted a new “developmental” TOU TES rate. Customers who fail to shift a minimum percentage of peak demand or kW (whichever is less), are ineligible for the special rate. The program is currently subscribed. FPL created a special seasonal demand rate, which shrinks the peak period window from nine to three hours. A shorter peak period window has allowed customers to design less costly systems, increasing the attractiveness of the program. Other programs with special rates include Gulf Power, Minnesota Power, and TVA.

Adequate Incentives

Programs that do not provide an adequate up front incentive will struggle to attract customers. Incentive levels vary widely, from $10/kW to $800/kW, with a number of additional incentives, such as commissioning incentives or free training programs, adding to the overall value. Some programs have struggled to fully subscribe due to low incentives, such as Austin Energy, which offers tiered rebates from $50-$300/kW based on program size.[49] The available rates also impact the success of an incentive. For example, interest in MidAmerican Energy's program is limited due to relatively low on-peak rates.[50] One option for improving overall program success is to offer a variety of incentives that address different barriers. For example, FPL provides an incentive of $464-$580 per ton for the equipment, with an additional $16-$20 per ton for initial commissioning (performance testing), and $2500 to fund a feasibility study.

Ownership Models

Utility-ownership reduces costs through increased purchase volume. Focused customer targeting, marketing, and capture can be more efficient and cost effective given a utility’s knowledge base of its own customers. Utility-ownership also eliminates the capital investment hurdle and TOU rate change risks compared with customer-owned business models. However, utility ownership can increase administrative costs and impose burdens on the utility. To avoid issues with ongoing operations and maintenance, SCPPA contracted with Ice Energy to provide a 24 hour call center to manage initial customer calls.

5.1.2. Stakeholder Feedback

While the following categories are not comprehensive, they represent highlights from the most commonly expressed perspectives and observations throughout the interview process. Feedback related to specific technologies has been taken into account, but may not be explicitly stated in the summary feedback below.

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[49] Summit Blue, 2009, pg 24
[50] Summit Blue, 2009, pg 22

Individual summaries of stakeholder feedback are included in Appendix B. Please note that while this study is exploring a variety of PLS technologies, due to PLS program eligibility requirements, much of the program design feedback reflects experience with thermal energy storage systems.

5.1.2.1. Overall Program Design

Table 16 groups the stakeholder feedback into consensus feedback, or feedback that was expressed and agreed upon by most stakeholders, and non-consensus feedback, representing areas of disagreement regarding the ideal approach.

Table 16: Consensus and non-consensus feedback

Consensus	Non-Consensus
Lack of consistent and transparent rate structures that promote PLS are an impediment	Desired incentive levels and structure of incentive (e.g., Tariff based only or tied to capacity/ hours shifted)
A standard offer is preferable to an RFP, as it more easily encourages technology neutrality, and participation by smaller stakeholders	Tailoring of incentives to technology class and size.
Incentive levels need to take into account all project and market entry costs, deliver 3-5 year payback, and not exclude any technologies from participation	Required metering/monitoring, specifics as to what needs to be monitored and at what level of detail
Consistency in programs across IOU service territories is important	Allocation of PLS budget (e.g. marketing vs. implementation funding)
Program complexity adds costs and discourages market participation	Potential for market expansion
Lack of education/training about PLS technologies — their design, implementation and operation — is a severe challenge	

Program Type: Most stakeholders indicated a preference for a standard offer over an RFP process. Few companies are prepared to bid into a traditional utility program and a standard offer also supports a technology-neutral approach.

Eligibility: Many stakeholders expressed concern that participating technologies demonstrate commercial viability. Suggested criteria include passing the TRC test, providing evidence of commercial success, or requiring a performance guarantee. In terms of customer eligibility, new construction, retrofit capacity expansions and system fine-tuning are more cost effective and may not require incentives, or may require lower incentives, in comparison to a full retrofit. For example, incorporating TES into new construction allows downsizing of many other system elements, which can reduce costs. By looking at the incremental cost difference, the payback may be two to three years.

In terms of customer class, many respondents did not indicate a preference based on a specific customer type (for example, commercial versus residential), but instead, based on cost and size. Larger systems are often more cost effective than smaller systems. However, this observation led to differing conclusions, with many stakeholders preferring a least-cost approach, which may favor large commercial or industrial systems; others indicated support for residential systems because they are typically more expensive and in need of incentives.

Program Structure: Program structure preferences, such as the incentive level or payment system, differed. One suggested option involved a single standard offer paid directly to the end-customer (versus third party vendors). However, technologies target different customer classes; a tiered standard offer may offer more opportunities for additional technologies and customers to participate.

Program Consistency: Maintaining consistency in program requirements gives rise to a number of benefits. For example, consistent, straightforward EM&V requirements for each IOU could streamline the process, making participation more attractive, increasing transparency, and potentially lowering costs. Additionally, a consistent statewide standard offer would encourage commercial customers, who may control multiple facilities, to participate throughout California.

Program Complexity: While many requirements exist to ensure outcomes, overly complex or burdensome requirements add to costs and discourage participation. For example, rebate structures with complex persistence payments can deter customers and increase the cost of program administration.

Marketing: Challenges sourcing customers varied widely based on technology and customer class. Demonstrating an attractive payback was the strongest indicator of success, although some customers respond to “green” marketing and will opt in based on environmental attributes of a system. In addition, targeting customers in the ideal rate class is challenging. Marketing would be much more efficient if IOUS and third party vendors worked together to source customers: IOUs have access to confidential customer information, including rate classes, and could initially screen and contact eligible customers. Stakeholders also indicated that placing limitations on the type of customer that can participate introduces significant barriers to program subscription. Beyond utility-vendor collaboration, one option for improving marketing efficiency is to work with the design community. Instead of targeting individual customers, designers are often aware of multiple eligible projects, which reduces marketing costs and also increases buy-in.

Training and Education: Lack of education and training among architects, engineers, contractors, operators and program managers on thermal energy storage is a significant barrier, and needs to be taken into account when estimating costs and should be integrated into program design. Program duration can limit training opportunities; more established PLS programs indicate a multiple year "learning curve" to reach efficiency and lower costs in the long term.

5.1.2.2. Incentives and Costs

Payback: Incentives need to align with acceptable payback periods for each sector to drive demand. For the commercial sector, a two to three year payback is generally necessary, although the economic downtown has placed downward pressure on required payback periods. The public sector, along with institutions such as college campuses, will accept longer payback periods of five to seven years or more.

Comprehensive Approach: All market entry costs need to be taken into account when determining incentive levels and cost effectiveness. Unexpected costs, such as unanticipated structural engineering issues, architectural requirements, or a limited number of contractors trained to do install, can all add to overall program costs. In addition, each technology may require a different skill set for installation, which should be considered in program design.

However, while private operating cost savings may not offset the cost of implementing TES to the end-user, social benefits often do. In addition, building power plants is extremely difficult and expensive, and may be subject to additional regulations in the future which increase costs. Coal plant retirement will also place additional pressure on the system, and anticipating these needs may be beneficial.

Rate Structure: The majority of respondents expressed interest in a more favorable rate structure. Suggestions include creating a special PLS-specific tariff, which could eliminate the need for any additional incentives in the form of rebates or a standard offer. Eliminating off-peak demand charges will encourage PLS, and on-peak demand charges could be increased to meet revenue neutrality requirements.

“Tariff risk” is a significant concern, and many customers are unwilling to install systems due to fear that the rate structure will change. Moreover, systems are subject to the classic split incentive issue: the building engineer does not pay the utility bills and thus is not motivated to reduce costs. Beyond guaranteeing more favorable rates, allowing a shorter PLS peak period is another option for lowering initial costs. In Florida Power and Light's TES program, customers requested a shorter window for shifting, and were able to decrease system size and thus overall cost. In addition, current rate schedules are too complicated, creating additional challenges to optimizing system operation (such as through control sequences). However, the tariff structure may need to be utility-specific.

Feasibility Studies: Many PLS programs provide funding for an initial feasibility study, which can improve outcomes and customer commitment. See Program Takeaways (Section 5.1.1.2) for additional background on the role of feasibility studies in PLS programs.

Utility Financial Incentives: Utilities have a fiduciary responsibility to their shareholders to provide a return on their investment, and installing PLS technologies can be counter to this responsibility. If the utilities were able to include properly designed and deployed PLS systems in their asset base, there would be a large demand by utilities to deploy these technologies.

5.1.2.3. Performance

Baseline Data: For TES systems, it can be challenging to acquire baseline data because the practice of monitoring, even of existing EMCS systems, is not typical practice. The expense of monitoring (if no instrumentation exists) can be a challenge. This makes it difficult to measure the relative performance of PLS systems. Establishing baseline for some processes – such as batch industrial processes – will be more challenging for industrial facilities than in buildings. For other PLS technologies, such as batteries, monitoring is less challenging.

Additional Value Streams: Most PLS systems are not taking advantage of additional value streams such as energy efficiency or demand response. However, combining PLS and energy efficiency may lead to better overall system design. For example, TES systems can range from energy neutral at the site to site energy efficiency improvements over 45%. At the same time, round-trip energy neutrality requirements may lead to additional complexity and costs.

Operations and Maintenance: For the most part, ongoing operation and maintenance costs were not a concern to respondents, although requirements vary depending on customer class. For example, a residential or small commercial system needs to be designed to limit ongoing maintenance.

Ongoing Performance and Monitoring: Energy efficiency and performance monitoring is very important for existing facilities when upgrading an existing TES or upgrading a non-TES to a TES system. Without monitoring, it is impossible to identify poor operating strategies, and substantial energy waste occurs. Specific measurement and verification requirements will differ based on technology, such as installing chilled water flow and temperature sensors on TES systems. A monitoring requirement could be a part of the feasibility study. For example, the program could require engineers to commit to a specific level of monitoring as a part of the feasibility study. Alternatively, additional incentives could be provided for monitoring, similar to FPL's current program, or incentives could be paid only after a customer has demonstrated shift through system metering.

Existing Systems: A number of PLS systems were installed during previous programs, or outside of any incentive structure. Many of these existing systems are not run optimally, and there may be potential to “fine-tune” for less money than a full retrofit or a new install. For example, improving the temperature differential for chilled water is essential for optimal operations, but many of these systems are running at a very low differential.

6. Program Design Recommendations

6.1. Overall Cost-effectiveness of PLS

6.1.1. Total Resource Cost Test

The Total Resource Cost test (Section 3.1.2.1) is typically used to evaluate if the CPUC should pursue a particular program. The test is used in the evaluation of energy efficiency, distributed generation, and demand response programs. We use the same approach to evaluate PLS. The TRC compares the avoided cost benefits to the region with the incremental[51] cost of installing and operating the PLS system, and the PLS program marketing and overhead costs.

TRC = Avoided Cost Benefits –(Incremental PLS System Cost + PLS Program Admin Costs)

TRC perspective shows that the installed incremental cost of PLS technologies must be in the range of $950/kW, $2,190/kW, and $2,640/kW to be cost-effective for 2-hour, 6-hour, and 10-hour systems respectively ($475/kWh, $365/kWh, $264/kWh), indicated by Table 17.

Table 17: Upper Bound on Avoided Cost Benefits by Dispatch Type *

Shift Duration	Maximum Lifecycle Avoided Costs ($/peak kW reduction)	Maximum Average Daily Avoided Costs ($/kWh delivered/ day)
2 Hours	$950	$0.17
4 Hours	$1,700	$0.15
6 Hours	$2,190	$0.13
8 Hours	$2,480	$0.11
10 Hours	$2,640	$0.09

* Assumes load reduction occurs during the highest value hours, charging during the lowest cost hours (mainly 2am to 5am), and maximum shift on all days of the year.

The results from the simulated and actual utility pilot data show lifecycle benefits somewhat less than the best case shown in the table above. This is due to less

[51] The term "incremental" refers to the "additional" cost of the PLS system. For example, in new construction, the PLS system may add some cost but achieve some cost savings in other places. The incremental cost incorporates the cost of the PLS system, minus the cost savings achieved elsewhere. For a retrofit application, the incremental cost is typically the entire cost of the PLS system.

than ideal shifts on some days. However, the data from the actual systems we evaluated is not a good predictor of maximum possible value since the systems were operating to optimize local utility retail rates and not maximizing total avoided costs. For example, a system might charge beginning at 8pm based on the utility tariff, but this would be a higher cost time from an avoided cost perspective than charging beginning at midnight or 2am.

Table 18: Range of TRC Costs and Benefits by Technology Type Based on Case Studies

Technology Type	Lifecycle TRC Benefit ($/kW)	Lifecycle TRC Cost* ($/kW)	Net Lifecycle TRC Benefits ($/kW)
'Medium' to 'large' thermal storage	$1,360-$2,670	$1,140-$3,310	($1,950)- $1,020
Process shifting applications: Based on refrigerated warehouse	$1,315-$1,610	$750-$915	$570-$695
'Small' thermal storage systems: Based on Ice Energy Example	$1,380-$1,685	$2,460-$3,000	($1,320)-($1,080)
Battery storage systems	$620-$880	$1,800-$4,030	($3,400)-($924)

* Lifecycle cost does not include admin or other program costs; Costs for the examples are based on the capital costs normalized to the observed peak reduction, rather than a design peak reduction.
+ These categories included one example each; the range shown is based on assuming an uncertainty of ± 10% around the point estimate.

Incremental system costs vary widely across different PLS technologies. Thermal systems in the utility pilot programs are in the range ~ $1,000/kW to $3,300/kW (normalized to the peak "observed" reduction, not design peak reduction). Industry provided cost estimates that range from below $500/kW to as high as $4,000/kW (where the costs are normalized to design peak reduction). The wide range is due to differences between the costs for new construction or expansion applications vs. retrofit applications, above ground vs. below ground installations, and size of the application. For example, large chilled water installations (such as those greater than 50,000 ton-hours) for new construction and expansion applications that are above ground were cited to be significantly less expensive than chilled water retrofit applications with the tanks installed underground. Total installed battery storage costs are estimated to be in the range of $1,800/kW to $4,030/kW for a discharge duration of 4-6 hours ($300-$1,010/kWh installed). Process shifting costs are expected to be broad, ranging from very low to high.

Comparison of the lifecycle benefits and the lifecycle costs indicates that well-designed ‘medium’ and ‘large’ thermal systems pass the TRC test given current costs and performance. While the range of costs for process shifting is large, there are undoubtedly applications that pass the TRC. Potential process shifting applications include timing the charging of electric batteries in pallet jacks and forklifts, or shifting usage on electrical end uses such as operation of pool pumps, or pumping load, or also specific industry processes that can be designed to operate off-peak. Some applications such as pre-cooling in refrigerated warehouses also pass the TRC test.

However, a number of emerging PLS technologies do not pass the TRC cost test at their current costs. The Joint utilities and CPUC will need to decide whether to encourage these technology types. These include most, if not all of the technologies in the battery storage space providing PLS, as well as ‘small’ thermal storage systems, even assuming an idealized operating profile.

Given this difference, it makes sense to divide the PLS market into mature and emerging categories and have different program designs that are appropriate for each.

6.1.2. Considerations for a Market Transforming PLS Program

The decision to encourage the technologies that do not pass the TRC test today should be based on a number of factors. In particular, three key considerations of whether PLS is a useful element in managing loads in the future should be considered in rough order of importance.

Renewable Integration. PLS provides a high value use of electricity in low load periods, reducing expected ‘overgeneration’ at night, particularly in Southern California as the state adds wind resources to meet the 33% RES standard. Reducing overgeneration adds ~ 5% to the total value of PLS in the modeling. Some PLS technologies also provide a ‘dynamic’ response that may be able to provide regulations services or other system integration benefits. Renewable integration will become an increasing concern as California adds significant intermittent renewable generation capacity to meet the 33% RES.

Energy Efficiency. Some PLS designs have the potential to save not just cost, but energy, overall, at the system level. Reducing energy use in California will remain a priority in the long term. From this perspective, energy efficiency should be considered from a 'system' perspective including reduction of higher on-peak losses and generally worse efficiency of gas fired generation on peak.

Capacity Needs. PLS provides capacity by shifting loads from the peak to off-peak period, thereby avoiding the need to build new generation capacity. However, current reserve margins in California are extremely high (>30%) and are forecasted to be above the planning reserve margin (PRM) beyond 2020. There may be local capacity constraints, particularly if once-through-cooling generation is retired, but capacity should not be a driving need for investing in new technology development. As described in Section 3.1.4.1, however, some parties argue that capacity incentives to demand-side resources should not necessarily be limited to the short-run generation capacity value. They argue that the priority placed on EE and DR in the loading order, and the need for consistency in program offerings to attract and retain customers should support higher incentives even in times of excess capacity.

Given this outlook, the technologies that provide opportunity for renewable integration, particularly dispatchable technologies, and overall system energy efficiency seem particularly attractive technologies for California to encourage. Technologies in this category include most electric storage (battery) technologies as well as 'small' thermal storage systems.

To encourage these technologies, a 'market transformation' program could be developed, geared toward creating manufacturing scale in the industry, as well as local capability for PLS implementation; this includes design, construction, and maintenance, which will lead to lower costs and higher performance over time. Today, California currently has a number of programs with market transformation goals for other technologies, including the California Solar Initiative (CSI), and the Self-generation Incentive Program (SGIP).

6.1.3. Conclusions Based on the TRC Test

Create a 'mature' PLS program with the goal of maximizing the adopted MW of cost-effective PLS technologies. The program should be available for all PLS ('technology neutral') but will most likely encourage 'medium' and 'large' thermal shifting technology (particularly for expansion and new construction applications), as well as low-cost process shifting and precooling. The emphasis of the 'mature' PLS program category would be on achieving a high penetration of economical, high performance systems.

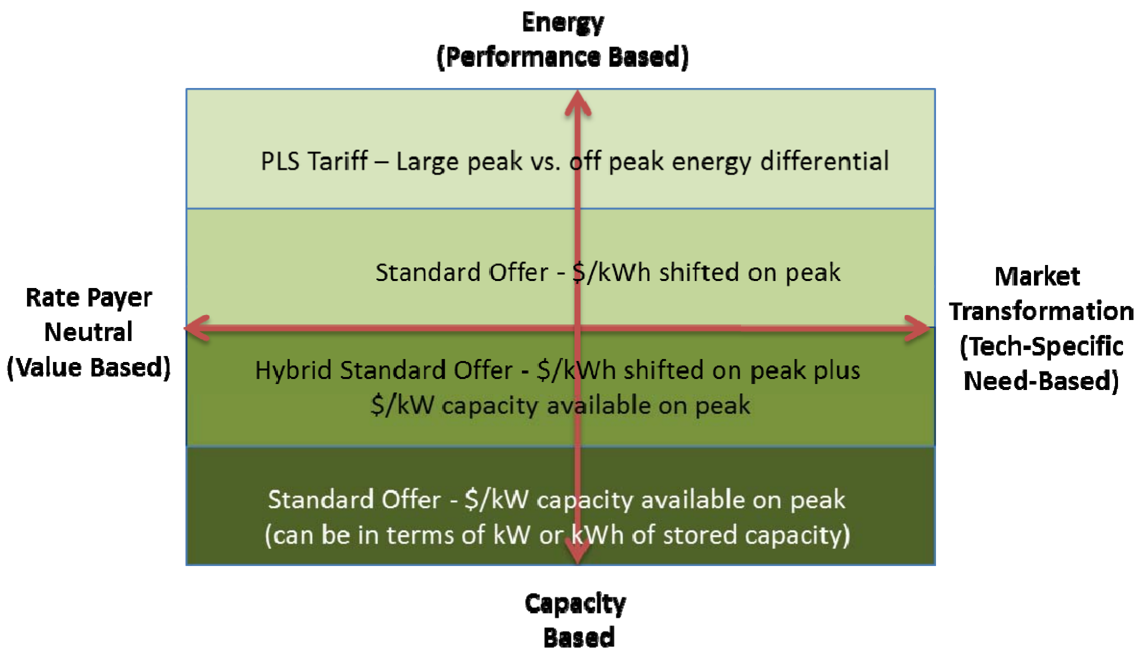
Create a separate track for 'emerging' PLS technologies that provide renewable integration and/or energy efficiency benefits with promise of long term cost reductions with an emphasis on market transformation. Only select technologies would be eligible for the higher 'emerging' PLS category including 'small' thermal shifting devices (<10kW peak load shift) with dispatchable capability, and electrical battery storage. The emphasis of the 'emerging' PLS program category would be to develop a greater number of 'load responsive' technologies.

6.2. PLS Program Design Framework – Standard Offer

There are a number of dimensions by which the CPUC can consider standard offers for PLS program design. Perhaps the most fundamental dimensions have to do with the basics of program structure and $ value of the incentive itself. Figure 45 illustrates these dimensions, each with its own respective continuum. For example, a PLS program at one end of the spectrum can have no impact to ratepayers. In this case, the incentive would be essentially 'ratepayer neutral'. At the other end of the spectrum would be incentives whose levels are set to ensure commercial adoption at the technology specific level, perhaps based on achieving certain payback or internal rate of return requirements by targeted end users. In this case, the incentive would be focused on 'market transformation' similar to the California Solar Initiative (CSI) or the California Self Generation Incentive Program (SGIP).

The vertical axis represents the PLS program structure; it can be geared toward incentivizing energy shifting on peak, or, at the other end of the spectrum, be more focused on pure capacity. The former, if paid on a "$/kWh of actual energy shifted on-peak" would be purely performance based. The latter, if paid on a $/kW capacity basis would require additional minimum requirements for duration. The capacity-based incentive, for example, could be translated into a $/kWh shifting capacity. Additional monitoring/verification would likely be necessary with capacity based incentives to ensure performance compliance.

Figure 45: Standard Offer Program Design Framework



The CPUC's goals with respect to PLS and any potential program will influence where the program falls on these continuums, as well as the form of the incentive itself. The chart below includes several examples of different incentives that could be created – they are presented along the continuum of energy/performance based vs. capacity based only, as the overall $ value of the incentive can vary tremendously depending on the CPUC's priorities with respect to market transformation. We describe each incentive type further.

PLS Tariff. A PLS tariff could establish a fixed differential between peak and off peak on an energy or $/kWh shifted basis. Similarly, a PLS tariff that shifts more cost from energy to on peak demand charges would provide a financial incentive to shift demand from peak to off peak. A number of stakeholders voiced strong support for establishing simple transparent tariffs that maintain on and off-peak differentials over many years; this would be very effective in stimulating development of PLS. A ‘PLS’ tariff with TOU rate differentials provides some price incentive to operate the PLS system well, and does not require a specific baseline development. This approach is more suitable for thermal storage. Specific PLS tariffs were also noted as a key success criteria in many of the programs researched out of state, provided the tariff was persistent for a number of years to help ensure project economic viability.

Standard Offer. An alternative to creating a PLS specific tariff is to pay for kWh shifted on peak. A standard offer model based on an energy payment ($/kWh shifted) provides a direct performance-based incentive. This approach is easier to provide to electrical battery systems. As stated earlier, measuring the kWh shift for thermal systems and process shifting is more challenging than for battery systems, given their baseline measurement requirements. Shifted kWh could be metered/measured on site, and remotely tracked. It would be critical that such payments would be of sufficient duration to provide economic certainty for any PLS project. A comparable example to this form of incentive would be the current California Solar Initiative, which pays an incentive pre-kWh generated.

Hybrid Standard offer. A combination of $/kWh shifted on peak and $/kW capacity based incentive could be used. PLS has value for energy and capacity — creating a hybrid incentive program could incentivize and reward both.

Capacity Based Standard offer. This type of program could provide incentives based on capacity shifted from on peak to off peak. If a pure capacity incentive were used, clarification would need to be provided on the duration of the capacity shifting that is eligible. As mentioned above, capacity can be stated both in terms of kW and well as kWh. The kWh method would automatically factor in the duration of shifting capability of the specific technology. For capacity based standard offers, the performance that would need to be verified would be the system's 'availability'. Because the incentive is paid up front and not directly tied to performance (e.g., Actual kWh shifted on peak), additional methods of ensuring accountability and performance would need to be developed. The PG&E pilot, for example, requires detailed reporting of energy shift and savings through its EM&V requirements.

One key advantage of standard offer program options is that they encourage technology development and innovation, provided they are technology neutral. Further, a transparent standard offer would also enable a diverse group of stakeholders to participate. An RFP approach, in contrast, would likely need to specify the technology solution in advance, and qualified bidders would be limited primarily to large firms capable of managing utility-scale programs.

Regardless of the form of the standard offer, simplicity, accountability and persistence are key elements. Simplicity means that the program should be easily communicated, implemented and monitored. Accountability means that the incentives provided should be as closely tied to actual value delivered as possible. Persistence means that the fundamental drivers of project economics need to be in place for many years – sufficient for participants to realize economic return from their investment.

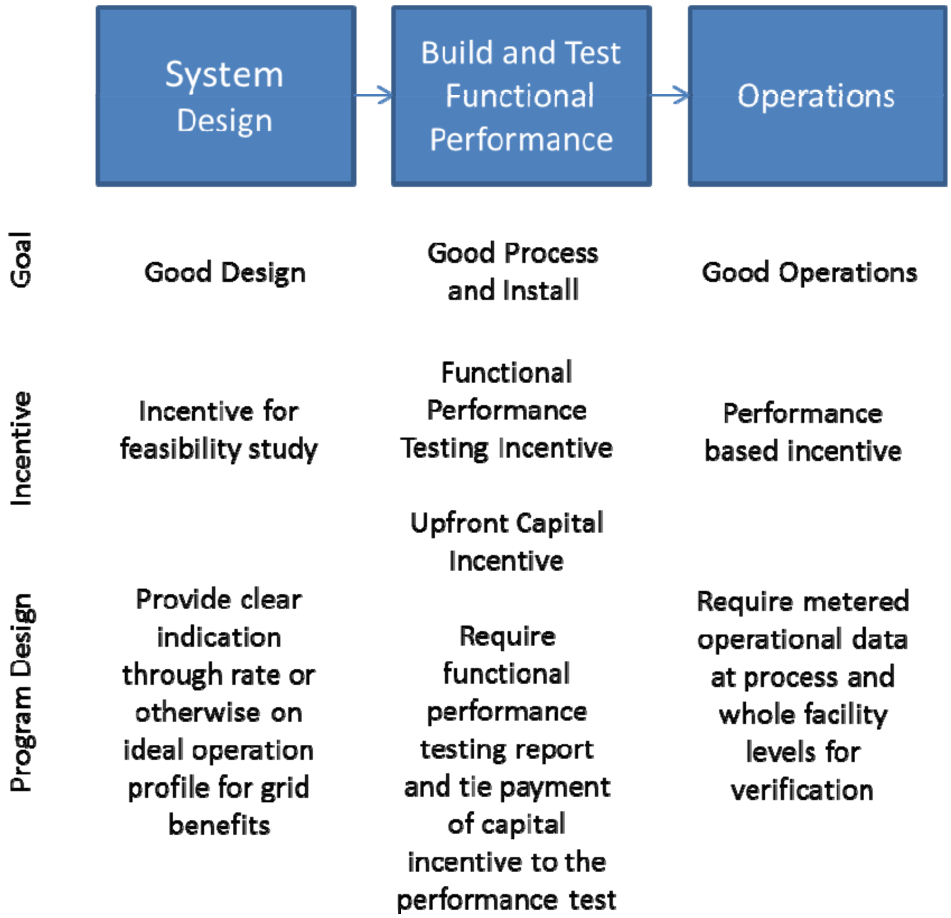
The market transformation goals of the PLS program would similarly benefit from adhering to these three core tenets. Simplicity, accountability and persistence will facilitate the entry of new investors and other financial stakeholders, and thus fuel the evolution of alternative ownership models to PLS deployment, namely, third party owned systems and the availability of third party debt financing for PLS projects. The availability of capital, both equity and debt are critical to expanded implementation of PLS.

6.3. PLS Program Design Characteristics

Whether mature or emerging technology, the review of best practices nationwide, and other data collected from technology providers leads to some common recommendations for PLS program design, regardless of the PLS technology or the ultimate incentive structure chosen.

Three stages of project execution are important to overall PLS success, including system design, build and functional testing, and operations. Poor execution at any stage can result in less than ideal benefits. The following diagram provides a template program design that focuses on each stage.

Figure 46: Recommended Characteristics of a PLS Program



While the details of design, functional performance testing, and operations will be specific to the type of technology and technology class, and more detailed for thermal storage systems for example, all elements are applicable — and important — for any type of PLS technology. The main objective is to ensure the PLS system integrates properly into the overall building with positive results.

6.3.1. System Design

Provide Clear Incentive / Rate Signal for System Design

One of the key lessons learned from reviewing the PLS Pilot data and conversing with stakeholders is that the PLS control algorithms are established to maximize bill savings. Therefore, the PLS rate designs and / or other incentives associated with performance must be clearly articulated and available during the system design phase. There may be limited flexibility for some PLS technologies to adjust the operations schedule significantly after the system is designed (such as for process shifting and thermal systems). As discussed under incentives, there are several choices to indicate preferred periods of performance including the time schedule for time-of-use energy charges, time schedule for demand charges, or a performance payment based on time of day.

The Joint Utilities should also consider defining 'super off-peak' periods to indicate the relative value of charging during the middle of the night, rather than at the beginning of the off-peak period. For example, in one real-world example, charging began at 8pm, which was the start of the off-peak period, although a lower cost societal PLS system would begin charging at midnight or 2am.

Require Technical and Economic Feasibility Study

Another 'best practices' lesson based on interviews around the country is that it is important to require a technical feasibility study to ensure that the application is engineered appropriately, and also establish a baseline against which to measure performance during initial commissioning and ongoing operations. The requirements of a technical feasibility study could vary by technology. The process shifting and thermal storage PLS applications, by their nature, are integrated into the overall operations of the host site and therefore warrant more extensive technical feasibility approaches than electrical battery storage. Smaller, 'standard package' systems might also have different technical feasibility requirements. The requirements of the technical feasibility study that should be considered include:

- System design and specifications

- Forecasted baseline and modified cooling / process load shape as well as expected whole building baseline and modified consumption profiles.
    - Characterization of expected load modification: peak kW reduction, expected shifted energy, system efficiency
    - Minimum expected performance for use in EM&V studies (% shifted, # days shifted, minimum efficiency)
- Financial/economic feasibility based on anticipated application, pre and post load shape and applicable tariff
- Functional performance testing plan to follow project construction
- Monitoring plan for routine operations

6.3.2. Build and Test Functional Performance

Require functional performance testing of the installation to verify that the PLS system provides the load reduction identified in the technical feasibility study. [52]

Good construction / installation and functional performance testing of the PLS systems is important to ensure the PLS system is working as intended. Therefore, the PLS technologies should conduct post-construction functional performance testing and document the results in a required report. Requirements of the report may include:

- Verification that the system is installed and operating correctly and as planned in the feasibility study and engineering drawings
- Verification that expected operation profile can be achieved

[52] Functional performance testing is an important component of what is known as the commissioning process in HVAC. Commissioning is an overall process that ensures the building performs as per the owner's intent. The functional performance testing component of commissioning is sometimes referred to simply as commissioning or "initial commissioning", such as in the Chapter 5 review of PLS markets where commissioning incentives are included. See California Commissioning Collaborative, "California Commissioning Guide: New Buildings", for more information on commissioning and functional testing.

- Verification that the load modification metrics can be achieved
- Verification that the anticipated economic returns can be achieved

6.3.3. Operations

Require regular reporting of operational data to verify persistence of good performance.

A well designed system, if not operated well, will not provide anticipated system benefits. Some of the PLS Pilot projects did not perform well in the field. The need for an incentive to maintain excellent operations over time is the primary driver behind the overall recommendation to provide, to the extent possible, a performance based incentive based on kWh of energy actually shifted on peak.

Operational reports should be required to see if the PLS systems are performing well, as expected in the project viability and commissioning studies, and are still in service. Particularly with very flexible technologies such as electrical battery storage, there may be significant opportunities to collect a PLS incentive and operate in an alternative mode (such as an Uninterruptable Power Supply - UPS)

Along with the operational report, there should be some approach developed for removing a customer from the PLS program when the facility is abandoned, is not meeting performance levels or is no longer operational.

6.4. Establishing Incentive Levels for Standard Offer

To illustrate the range of possibilities with respect to the $ value of any incentive (x axis in Figure 45), our study used two approaches. The first approach calculates the ‘ratepayer neutral’ incentive level that could be provided without a cross-subsidy from non-participating ratepayers. The second approach calculates the incentive level required to attract reasonable participation in the program. The balance of these two factors — ratepayer subsidy and participation — will be an important part of overall program design, and highly dependent on CPUC goals/objectives for PLS.

6.4.1. Ratepayer Neutral Incentive Levels

The ratepayer neutral incentive level is predominantly driven by an expectation of avoided cost benefits on the one hand, and the portion of those benefits that are provided to the customer through the retail rate design on the other. If the retail rate does not pass on all of the system benefits to the PLS customer, an additional incentive can be provided without a subsidy. The range of incentive level depends on the amount of shift and timing. Table 19 shows the range of ratepayer neutral incentive levels.

Table 19: Upper Bound on Ratepayer Neutral Incentive Level Using Broad Scenario Analysis*

	Minimum Median and Maximum of Incentive ($/Peak kW reduction) +				
	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours
Generic Rate	$210	$280	$360	$590	$645
	$300	$460	$540	$630	$766
	$370	$570	$570	$660	$805
PG&E A6	($80)	($190)	($680)	($730)	($830)
	($20)	($60)	($250)	($680)	($810)
	$90	($20)	($150)	($460)	($790)
PG&E A10 TOU S	$200	$560	$780	$1,020	$1,550
	$350	$810	$1,220	$1,380	$1,600
	$580	$1,160	$1,390	$1,560	$1,610
PG&E E20 P	$190	$260	$100	$140	$500
	$270	$370	$370	$430	$630
	$310	$400	$490	$620	$660
SDG&E ALTOU	$200	$450	$250	$390	$840
	$350	$520	$700	$760	$960
	$580	$1,220	$1,400	$1,400	$1,450
SCE TOU-8B	$350	$660	$840	$1,080	$1,920
	$410	$860	$1,340	$1,650	$1,980
	$590	$1,290	$1,710	$1,980	$2,010

* Assumes maximum shift on a daily basis, minimum cost period charging, and best discharge period. Does not include potential value in regulation or other ancillary services. For the PG&E tariffs, avoided costs were taken from climate zone 12; for the SDG&E tariff, avoided costs were taken from climate zone 10; and for the SCE tariff, avoided costs were taken from climate zone 14. Customer is assumed to be on the respective rate before implementing PLS.
+ Baseline profile is a general all commercial CEUS.

The tables below convert the **median ratepayer neutral incentives** from Table 19 into equivalent energy ($/kWh) and TOU differential (additional $/kWh) metrics. The stored energy metric, in $/kWh of installed storage capacity, is a particularly useful capacity metric for batteries as the capacity duration across battery technologies can vary tremendously.

To estimate the additional TOU differential, we assume that the PLS technology is running with a full shift on 60% of the days, and calculate the TOU rate differential, in addition to the reference rate, that is equivalent to the rate payer neutral incentive on a lifecycle basis. For example, the generic rate used in the broad scenario analysis has a TOU differential of $0.10/kWh in the summer and $0.03/kWh in the winter. An increase of the TOU differential by $0.04/kWh is equivalent to an upfront incentive of $766/kW for a 10 hour idealized system.

Table 20: Equivalent Incentive - Generic Rate - Climate Zone 12

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$300	$460	$540	$630	$766
$/kWh storage	$150	$115	$90	$79	$77
Additional TOU Δ $/kWh	$0.08	$0.06	$0.05	$0.04	$0.04

Table 21: Equivalent Incentive - PG&E A6 - Climate Zone 12

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	($20)	($60)	($250)	($680)	($810)
$/kWh storage	($10)	($15)	($42)	($85)	($81)
Additional TOU Δ $/kWh	($0.01)	($0.01)	($0.02)	($0.05)	($0.04)

Table 22: Equivalent Incentive - PG&E A10TOU - Climate Zone 12

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$350	$810	$1,220	$1,380	$1,600
$/kWh storage	$175	$203	$203	$173	$160
Additional TOU Δ $/kWh	$0.09	$0.11	$0.11	$0.09	$0.09

Table 23: Equivalent Incentive - PG&E E20P - Climate Zone 12

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$270	$370	$370	$430	$630
$/kWh storage	$135	$93	$62	$54	$63
Additional TOU ∆ $/kWh	$0.07	$0.05	$0.03	$0.03	$0.03

Table 24: Equivalent Incentive - SDG&E ALTOU - Climate Zone 10

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$350	$520	$700	$760	$960
$/kWh storage	$175	$130	$117	$95	$96
Additional TOU ∆ $/kWh	$0.09	$0.07	$0.06	$0.05	$0.05

Table 25: Equivalent Incentive - SCE TOU8B - Climate Zone 14

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$410	$860	$1,340	$1,650	$1,980
$/kWh storage	$205	$215	$223	$206	$198
Additional TOU ∆ $/kWh	$0.11	$0.11	$0.12	$0.11	$0.11

Assuming good system design, successful construction and operation, incentives in this range can be provided to any PLS system without a cross-subsidy. Since there is no subsidy, program caps and limits can be eliminated or established loosely to encourage a broader market. Using the same economic framework on the broad scenario analysis, these incentive levels can be customized based on the specific utility tariff, or for a specific PLS tariff if designed.

The table above provides the total incentive levels. These incentives can be paid in installments across the project development and operational phases, entirely as upfront capital payments, or entirely as performance based incentives (per kWh actually shifted on peak). If the incentive is entirely performance based or paid out over time it is critical that the time value of money be taken into consideration in program design.

These incentives can be calculated for a specific PLS rate and then combined together. Alternatively, these incentive levels can be combined with 'grand-fathered' rates, if offered.

6.4.2. Incentive Levels based on Expected Payback

Given the installation costs of different technologies, we do not expect that a ratepayer-neutral incentive level will be sufficient to encourage all of the PLS technologies that IOUs and CPUC may wish to promote. The project team evaluated a range of technologies and then identified the incentive levels necessary to achieve three and five year payback levels for the installations. These three and five year hurdles are based on stakeholder feedback that PLS projects require to drive customer adoption.

The following table is based on the limited number of project data points that the study team was able to collect through the stakeholder process. Therefore, these estimates of required incentive levels to meet end customer payback periods are limited in terms of technology performance and cost data, customer load profiles, and tariff options. More sample data would likely produce a broader range of end customer required incentive levels.

Table 26: Range of Required Incentive Levels by Technology Type for Case Studies

Technology Type	5-Year Payback ($/kW)	3-Year Payback ($/kW)	Stakeholder Suggested Incentives ($/kW)
'Medium' to 'large' thermal storage	$660 to $3,030	$1,000 to $3,800	$500 to $1,500
Process shifting based on refrigerated warehouse precooling *	$360 to $440	$680 to $830	N/A
'Small' thermal storage systems *	$2,160 to $2,640	$2,800 to $3,420	> $2,000

Technology Type	5-Year Payback ($/kW)	3-Year Payback ($/kW)	Stakeholder Suggested Incentives ($/kW)
Battery storage systems	$1,150 to $4,820 ($330 to 1,100/kWh[53])	$1,790 to $5,350 ($560 to 1,340/kWh)	N/A[54]

* These categories included one example each; the range shown is based on assuming an uncertainty of ± 10% around the point estimate.

Technology specific incentive levels based on expected payback may have a number of limitations, including:

- Difficulty establishing a true cost of installation across a diverse range of technologies, specific use-cases, variations in engineering & design approaches and quality, varying cost of materials, labor and other factors. This becomes a bigger challenge when "systems" design and integration is necessary (rather than working with discrete widgets that integrate in a "plug and play" fashion).
- Updating required incentive levels over time, potentially leading to 'boom' and 'bust' cycles if the incentive is set either too high or too low

By providing technology specific incentives, the principle of technology neutrality is not maintained. This is an ideological decision that must be made by the CPUC. There is no single incentive that will provide the "perfect" incentive level for all technology classes, or even types of technologies with a class. A single incentive would likely result in two scenarios: (1) the incentive is so low that very few installations are deployed and (2) the incentive is too high, such that many installations occur where some technologies are incented beyond the level that otherwise would have been sufficient to make the installation happen. Even with technology-class or technology specific incentives, it will be difficult to avoid the above scenarios altogether.

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[53] Assumes four hour duration battery

[54] No existing PLS battery storage installations were included in stakeholder feedback, but current SGIP incentive levels for battery storage systems are $2,000/kW

6.4.3. Considerations for RFP- based Program Designs

The RFP approach used by the IOUs during the pilots had many merits. However, using the same approach for future program design has some limitations. RFP processes can exclude many players in the market, such as small technology and engineering firms, from participating. RFPs do bring some economies of scale to program administration; however, those efficiencies are entirely dependent on the details of the program. Further, a number of stakeholders cited the limitation that RFPs often pre-specify eligible technologies, thus further limiting participation.

6.4.4. Considerations on Retail Rate Design

Review of the existing system data from utility pilots and technology vendors indicates that the PLS charge and discharge periods are set to maximize bill savings based on the retail rates. Therefore, the default signal on when to charge or discharge is provided by the retail rate. In addition, stakeholders overwhelmingly supported the concept of a mechanism to reduce or eliminate risk of tariff modifications that reduce the savings from PLS such as narrowing the time-of-use price differentials or extending the customer demand charge to off-peak periods after the capital investment is made. Therefore, retail rate design is very important for PLS and capturing the most grid benefits.

In particular, existing rate structures do not have a 'super off-peak' rate that would provide lower energy costs for increased energy usage in the middle of the night. The broad scenario analysis benefits are in part driven by the low energy cost and overgeneration benefits of overnight charging. The charging period matters for cost-effectiveness at a system level.

Certainty of the rate design can be accomplished in at least two ways;

PLS Rate. Provide a voluntary PLS rate for qualifying projects that meet set performance standards. Update the PLS rate in a way that preserves the TOU differentials and demand charge periods but allows for the same overall fluctuation as the otherwise applicable tariff schedule. The PLS rate also provides the opportunity to provide a ‘super off-peak’ rate to encourage charging at very low cost periods.

Grand-fathering. Allow ‘grand-fathering’ existing customer TOU rates when specific conditions occur that jeopardize the economics of the PLS system. Stakeholders expressed support for this approach through comments at and following the workshop, and through interviews.

While grand-fathering rates is attractive from a conceptual standpoint, it is likely to be more difficult to implement than providing a separate PLS tariff because rates will need to update over time as to their overall level and it will be difficult to define what changes are allowable and which are not in a ‘grand-fathering’ application.

6.4.5. Performance Based Incentives

Performance based incentives by definition, are only paid when the load shifting actually occurs and in the quantity they occurred. This incentive structure can be accomplished in a ways.

The first is to use the retail rate itself as the ‘performance based incentive’. The better the PLS system performs, the lower the bill will become. This includes both overall energy efficiency (because using less energy will reduce bills), as well as shifting and timing of energy consumption given the time-of-use rate structure. This form of incentive would encourage PLS, as mentioned above, if greater certainty in future tariff rate changes was established.

Another approach to performance based incentives would be to pay an incentive per kWh shifted on peak. By directly monitoring and metering and paying for the actual energy shifted on peak, the incentive would be directly tied to performance. Measuring the actual kWh shift for thermal systems and process shifting is more challenging than for battery systems, given their baseline measurement requirements. However, there is less opportunity for “gaming” with thermal systems than with battery systems, which have many other non-PLS uses (such as for providing uninterruptible power supply), so it may be more important to implement a performance based kWh incentive for battery systems than others.

Capacity based PLS incentives could potentially also be performance based (i.e., to measure availability), but the performance might be more difficult to measure/monitor, especially if the goal is to shift demand from on peak to off peak periods.

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APPENDIX A:

AVOIDED COSTS

Appendix A: Methodology for Determining Utility Avoided Cost

Overview

This appendix describes the avoided cost methodology developed pursuant to the Distributed Generation (DG) Cost-effectiveness Framework adopted by the Commission in D. 09-08-026. The avoided cost methodology described herein below provides a transparent method to value net energy production from distributed generation using a time-differentiated cost-basis. This appendix provides the background and methodology used to evaluate the benefits of distributed generation technologies. The utility avoided costs represent one of the primary the societal benefit streams for distributed energy resources (DER) such as energy efficiency, demand response and distributed generation. This appendix describes the general avoided cost methodology develop pursuant to the DG Cost-effectiveness Framework.

The electricity produced by distributed generation has significantly different avoided cost value depending on the time (and location) of delivery to the grid. The value of electricity production varies considerably between day and night and across seasons. Furthermore, because of the regional climate differences and overall energy usage patterns, the relative value of producing energy at different times varies for different regions of the California. The time- and location-based avoided cost methodology reflects this complexity.

By using a cost-based approach, valuation of net energy production will reflect the underlying marginal utility costs. The avoided costs evaluate the total hourly marginal cost of delivering electricity to the grid by adding together the individual components that contribute to cost. The cost components include Generation Energy, Losses, Ancillary Services, System (Generation) Capacity, T&D Capacity, Environmental costs, and Avoided

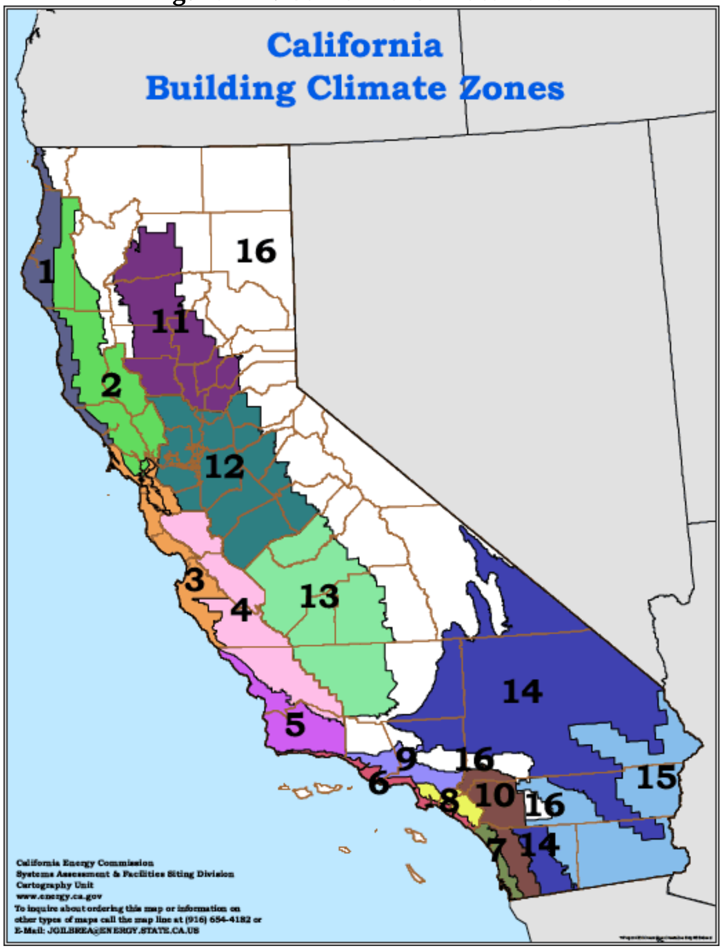
Renewable Purchases. The utility avoided cost value is calculated as the sum in each hour of the six individual components.

Methodology

Climate Zones

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The DG Cost-effectiveness Framework adopts the sixteen California climate zones defined by the Title 24 building standards in order to differentiate between the value of electricity in different regions in the California. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure A-1 is a map of the climate zones in California.

Figure A-1. California Climate Zones



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in Table A-1. Hourly avoided costs are calculated for each climate zone.

Table A-1. Representative cities and utilities for the California climate zones.

Climate Zone	Utility Territory	Representative City
CEC Zone 1	PG&E	Arcata
CEC Zone 2	PG&E	Santa Rosa
CEC Zone 3	PG&E	Oakland
CEC Zone 4	PG&E	Sunnyvale
CEC Zone 5	PG&E/SCE	Santa Maria
CEC Zone 6	SCE	Los Angeles
CEC Zone 7	SDG&E	San Diego
CEC Zone 8	SCE	El Toro
CEC Zone 9	SCE	Pasadena
CEC Zone 10	SCE/SDG&E	Riverside
CEC Zone 11	PG&E	Red Bluff
CEC Zone 12	PG&E	Sacramento
CEC Zone 13	PG&E	Fresno
CEC Zone 14	SCE/SDG&E	China Lake
CEC Zone 15	SCE/SDG&E	El Centro
CEC Zone 16	PG&E/SCE	Mount Shasta

Overview of Avoided Cost Components

For each climate zone, the avoided cost is calculated as the sum of six components, each of which is summarized in the table below.

Table A-2. Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissionsCO2 associated with the marginal generating resource
Avoided RPS	The avoided net cost of purchasing procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail salesdue to a reduction in retail loads

In the value calculation, each of these components is estimated for each hour in a typical year and forecasted into the future for 30 years. The hourly granularity of the avoided costs is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads reported by CAISO's MRTU system between July 2009 and June 2010; Table A-3 summarizes the methodology applied to each component to develop this level of granularity.

Table A-3. Summary of methodology for avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Combination of market forwards through 2014 and a long-run forecast of California gas prices through 2040	Historical hourly day-ahead market price shapes from MRTU OASIS
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from energy and AS markets	Hourly allocation factors calculated as a proxy for rLOLP based on CAISO hourly system loads
Ancillary Services	Scales with the value of energy	Directly linked with energy shape
T&D Capacity	Survey of utility transmission and distribution deferral values from general rate cases	Hourly allocation factors calculated using hourly temperature data as a proxy for local area load
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy and capacity value associated with that resource	Flat across all hours

The hourly time scale used in this approach is an important feature of the avoided costs used in the DG Cost-effectiveness framework for two reasons:

1. Hourly costs capture the extremely high marginal value of electricity during the top several hundred load hours of the year; and

2. Hourly costs can be matched against historical hourly generation data, allowing for a robust analysis of the value of different distributed generation technologies.

Figure 2 shows a three-day snapshot of the avoided costs, broken out by component, in Climate Zone 2. As shown, the cost of providing an additional unit of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost (over $1,000/MWh) are driven primarily by the allocation of generation and T&D capacity to the highest load hours, but also by higher wholesale energy prices during the middle of the day.

Figure A-2. Three-day snapshot of energy values in CZ2

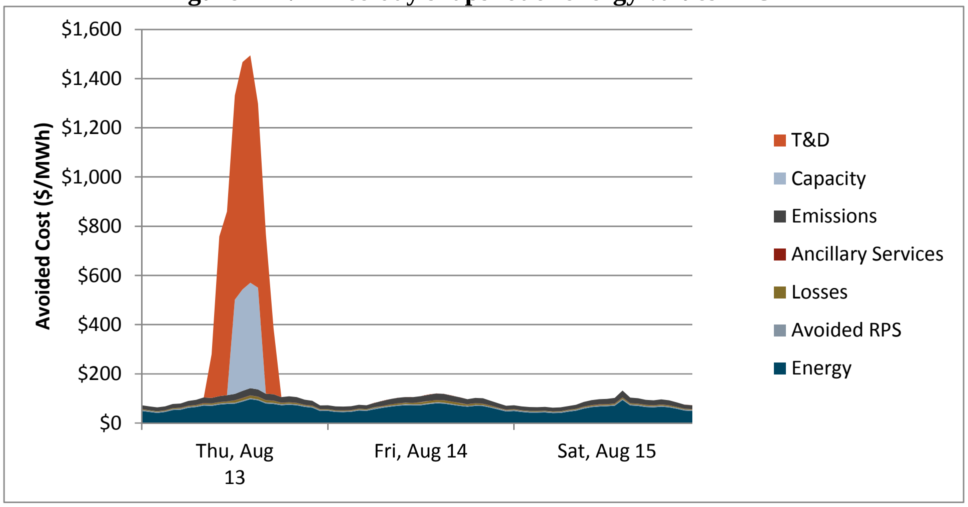


Figure 3 shows average monthly value of load reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting increased hydro supplies and imports from the Northwest; and peaks in the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average in these months.

Figure A-3. Average monthly avoided cost (levelized value over 30-yr horizon)

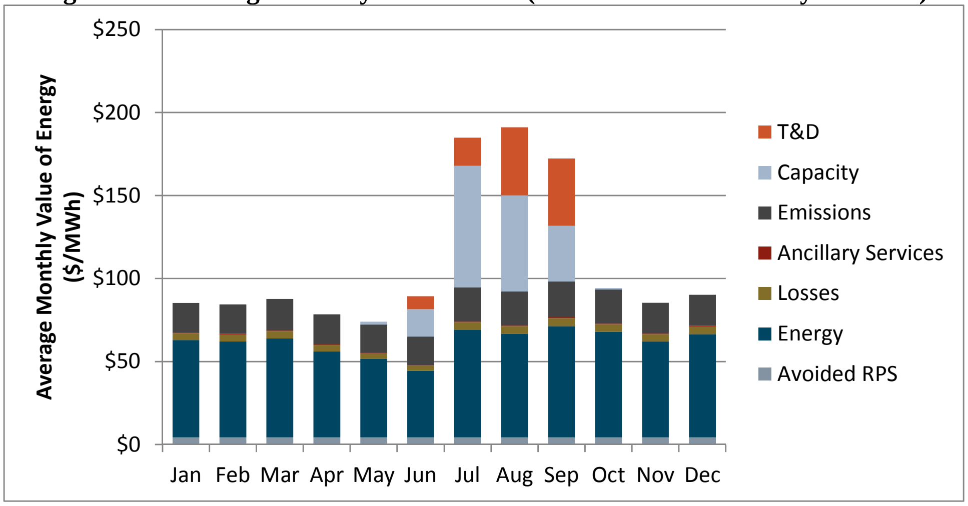
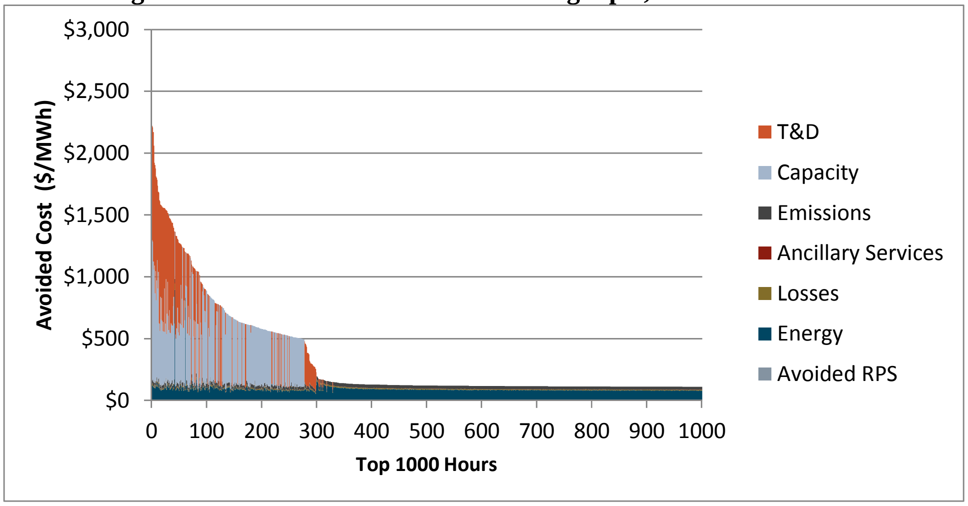


Figure 4 shows the components of value for the highest value hours in sorted order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours—this is because most of the value associated with capacity is concentrated in a limited number of hours. While the timing and magnitude of these high costs differ by climate zone, the concentration of value in the high load hours is a characteristic of the avoided costs in all of California.

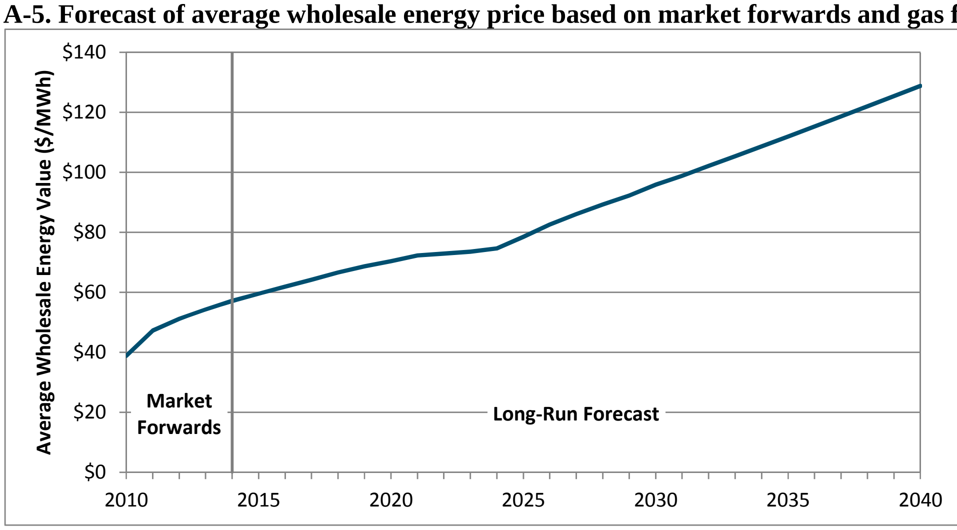
Figure A-4. Price duration curve showing top 1,000 hours for CZ2



Generation Energy

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. The forecast values of energy include short and long-run components. The wholesale value of energy through 2014 is based on market forwards for NP15 and SP15. The long-run value of energy is calculated based on the assumption that the average market heat rate will remain stable; the implied market heat rate based on 2014 forwards is extended through 2040. The long-run value of energy is calculated by multiplying the monthly forecast of gas prices in California by this market heat rate. The combined forecast is shown in Figure A-5.

Figure A-5. Forecast of average wholesale energy price based on market forwards and gas forecast.



An hourly shape that mimics movements of the day-ahead market for wholesale energy yields differential hourly energy values. Because the hourly avoided costs are being matched against loads and distributed generation, all of which are highly weather-correlated, the hourly price shape maintains the daily and hourly variability of actual historical wholesale markets. The hourly shape is derived from day-ahead LMPs at load-aggregation points in northern and southern California obtained from the California ISO's MRTU OASIS. In order to account for the effects of historical volatility in the spot market for natural gas, the hourly market prices are adjusted by the average daily gas price in California. The resulting hourly market heat rate curve is integrated into the avoided cost calculator, where, in combination with a monthly natural gas price forecast, it yields an hourly shape for wholesale market energy prices in California.

The hourly values of energy are adjusted by losses factors to account for losses between the points of wholesale transaction and retail delivery. The losses factors used in the avoided cost calculation vary by utility, season, and TOU period; and are summarized in Table A-4.

Table A-4. Marginal energy loss factors by time-of-use period and utility.

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Generation Capacity

The generation capacity value captures the reliability-related cost of maintaining a generator fleet with enough capacity to meet each year's peak loads and the planning reserve margin. The long-run basis for the value of capacity is the capacity residual of a new combustion turbine: the unit's annualized fixed cost less its net margin earned during operations in CAISO's energy and ancillary services markets. This framework for capacity valuation assumes that CAISO has reached resource balance: the net available supply is just enough to meet expected peak demands plus the planning reserve margin. Under such circumstances, a CT would receive the full capacity residual as a capacity payment, earning just enough revenue to cover its fixed costs (there would be neither an incentive to enter the market nor an incentive to exit).

Resource Balance Year and Near-Term Capacity Valuation

Currently, the CAISO has a tremendous excess of capacity: based on the CEC's *Summer 2010 Electricity and Supply and Demand Outlook*, under normal conditions, the minimum reserve margin in 2010 will be 29%—well above the required planning reserve margin of 15% (see Table A-5). Even in extreme weather conditions that would cause unusually high demand, the minimum reserve margin would be 17%. Due to the excess capacity available on the CAISO system, the proxy market value of capacity is substantially diminished in the near term.

Table A-5. Expected reserve margins for the summer of 2010.[1]

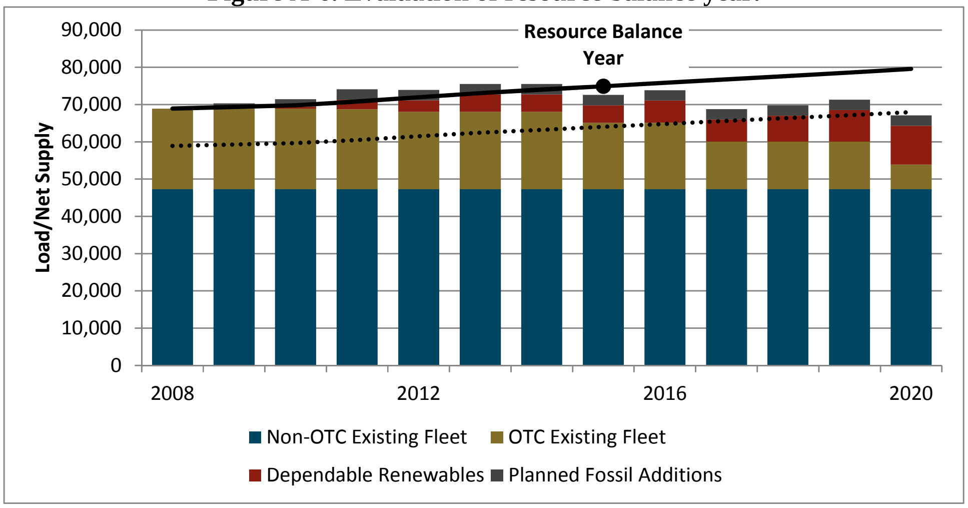
	June	July	August	September
Total Net Supply (MW)	62,078	62,334	62,328	62,462
1-in-2 Peak Demand (MW)	43,271	46,646	48,497	44,124
1-in-10 Peak Demand (MW)	46,952	50,620	52,601	47,908
Reserve Margin (1-in-2 Demand)	43%	34%	29%	42%
Reserve Margin (1-in-10 Demand)	32%	23%	18%	30%

Because of the excess system capacity, the Avoided Cost Calculator assumes that the value of capacity in the near term is less than the full capacity residual. E3 assumes that the value of capacity in 2008 was equal to $28/kW-yr—cited in CAISO testimony as a reasonable proxy for resource adequacy value. This value should increase annually as the reserve margin decreases with peak load growth until the year in which supply is equal to peak demand plus the planning reserve

[1] Table reproduced from the CEC's *Summer 2010 Electricity Supply and Demand Outlook*

margin—this is known as the resource balance year and is calculated to be 2015 (see Figure A-6).[2]

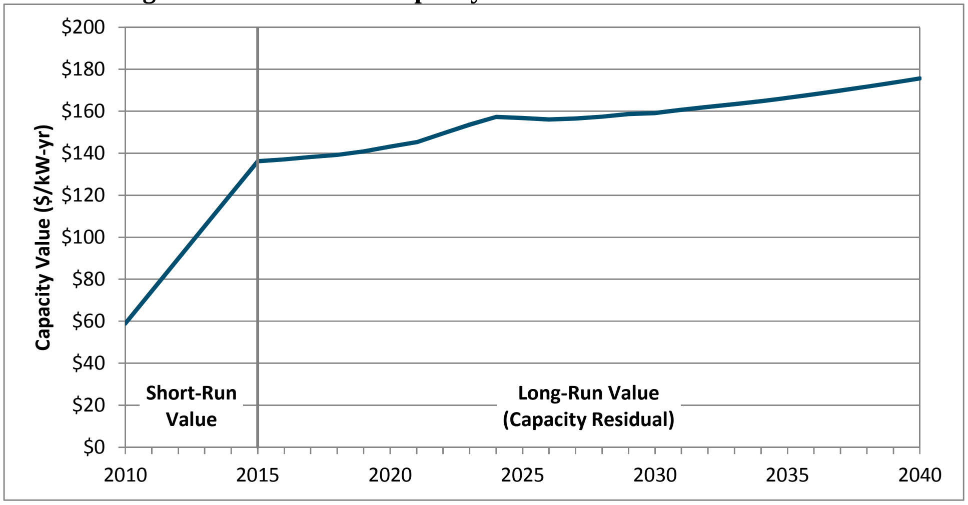
Figure A-6. Evaluation of resource balance year.



In the resource balance year and each year thereafter, the value of capacity is equal to the full capacity residual. Between 2008 and the resource balance year, E3 uses a linear interpolation to calculate the annual increases in capacity value. The final forecast of capacity value is shown in Figure A-7.

[2] The resource balance year is evaluated by comparing the CEC's forecast of peak loads in California with California's expected committed capacity resources. The forecast for expected capacity includes several components: 1) existing system capacity as of 2008, net of expected plant retirements; 2) fossil plants included in the CEC's list of planned projects with statuses of "Operational," "Partially Operational," or " Under Construction"; and 3) a forecast of renewable capacity additions to the system that would be necessary to achieve California's 33% Renewable Portfolio Standard by 2020 based on E3's 33% Model.

Figure A-7. Forecast of capacity value included in avoided costs.



Calculation of the Capacity Residual

The DG Cost-Effectiveness Framework calculates the capacity residual of the CT for each year of the avoided cost series by dispatching a representative unit against an hourly real-time market price curve and subtracting the net margin from the unit's annualized fixed costs. The hourly shape of the real-time market is based on historical real-time data gathered from CAISO's MRTU system; in each year, the level of the real-time market price curve is adjusted to match the average wholesale market price for that year. The CT's net margin is calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the sum of fuel costs and variable O&M) plus a bid adder of 10%; in each hour that it operates, the unit earns the difference between the market price and its operating costs. In each hour where the market prices are below the operating cost, the unit is assumed to shut down. The revenues earned through this economic dispatch are grossed up by 11% to account for profits earned through participation in CAISO's ancillary services markets.[3] The final figure is subtracted from the CT's annualized fixed cost—calculated using a pro-forma tool to amortize capital and fixed operations and maintenance costs—to determine the CT residual in that year.

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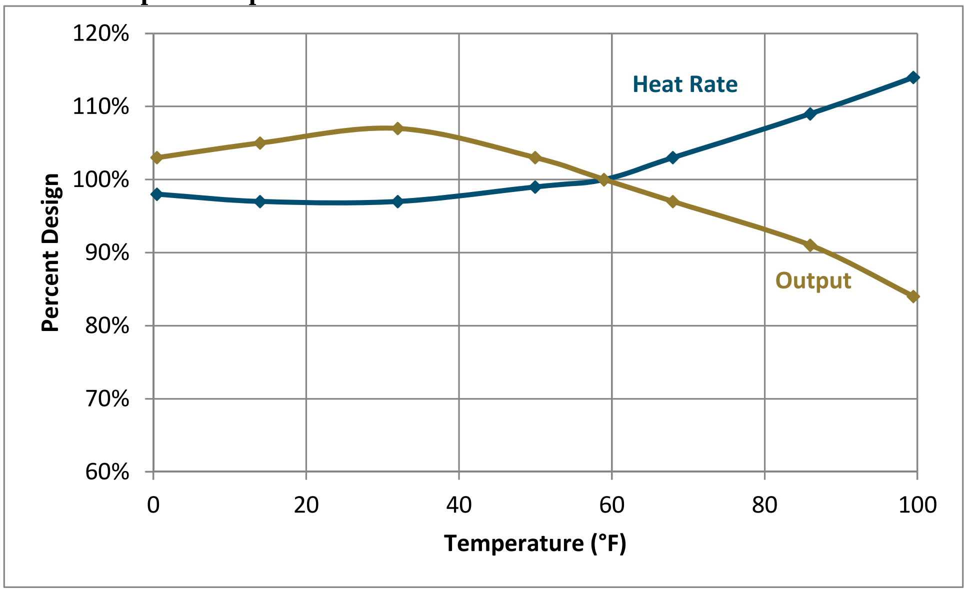
[3] This figure is based on an analysis of new combustion turbine operations presented in the CAISO's *2009 Market Report on Market Issues and Performance.*

CT Performance Adjustments

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions,[4] but the unit's actual performance deviates substantially from these ratings throughout the year. In California, deviations from rated performance are due primarily to hourly variations in temperature. Figure A-8 shows the relationship between temperature and performance for a GE LM6000 SPRINT gas turbine, a reasonable proxy for current CT technology.

Figure A-8. Temperature-performance curve for a GE LM6000 SPRINT combustion turbine.



The effect of temperature on performance is incorporated into the calculation of the CT residual; several performance corrections are considered:

- In the calculation of the CT's dispatch, the heat rate is assumed to vary on a monthly basis. In each month, E3 calculates an average day-time temperature based on hourly temperature data throughout the state and uses this value to adjust the heat rate—and thereby the operating cost—within that month.

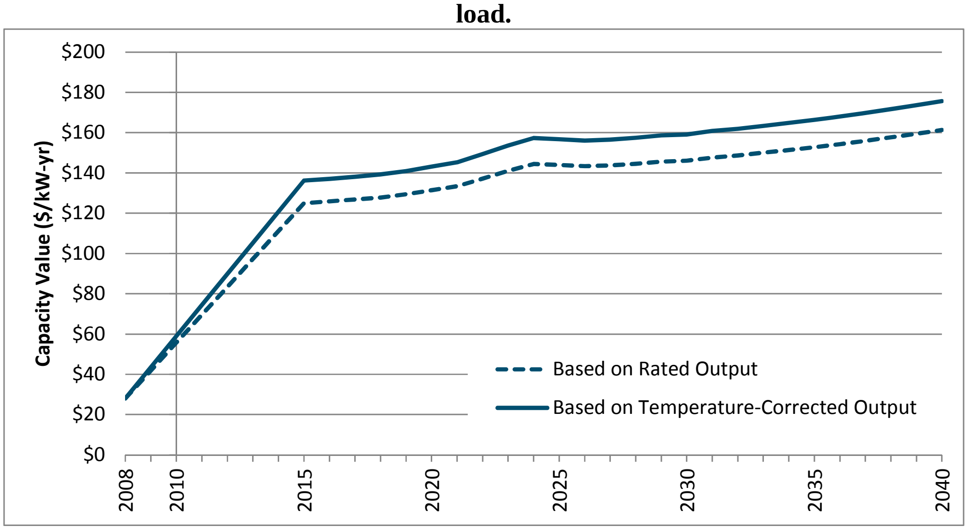
- Plant output is also assumed to vary on a monthly basis; the same average day-time temperature is used to determine the correct

[4] ISO conditions assume 59ºF, 60% relative humidity, and elevation at sea level.

adjustment. This adjustment affects the revenue collected by the plant in the real-time market. For instance, if the plant's output is 90% of nameplate capacity in a given month, its net revenues will equal 90% of what it would have received had it been able to operate at nameplate capacity.

- The resulting capacity residual is originally calculated as the value per nameplate kilowatt—however, during the peak periods during which a CT is necessary for resource adequacy, high temperatures will result in a significant capacity derate. Consequently, the value of capacity is increased by approximately 9% to reflect the plant's reduced output during the top 250 load hours of the year as shown in Figure A-9.

Figure A-9. Adjustment of capacity value to account for temperature derating during periods of peak load.



Other Adjustments to the Capacity Residual

The valuation of capacity includes an adjustment for losses between point of generation and delivery similar to energy. In order to account for losses, the annual capacity value is multiplied by the utility-specific losses factor applicable to the summer peak period, as this is the period during which system capacity is likely to be constrained.

Additionally, the Avoided Cost Calculator includes a discretionary adjustment for reductions in the planning reserve margin. Resources that are used to meet the planning reserve margin receive 100% of the value of capacity; resources that reduce the forecast of peak load and the planning reserve margin receive 115% of the value of capacity. Whether this adjustment should be included varies on a resource-by-resource basis and should be carefully considered.

Hourly Allocation of Capacity Value

The Avoided Cost Calculator bases its allocation of capacity value to a subset of hours upon hourly system load data collected from January 2006 through June 2010. In each full calendar year, hourly allocators are calculated for that year's top 250 load hours; the allocators, which sum to 100% within each year, are inversely proportional to the difference between the annual peak plus operating reserves and the loads in each hour. This allocation methodology, which serves as a simplified and transparent proxy for models of relative loss-of-load probability (rLOLP), results in allocators that increase with the load level.

The annual series of allocators for each of the full calendar years are used to develop reasonable estimates of the relative fraction of capacity value that is captured within each month as shown in Figure A-10. By considering loads within the four-year period from 2006-2009, the Avoided Cost Calculator captures the potential diversity of peak loads across different years.

Figure A-10. Calculation of monthly capacity allocation based on historical data from 2006-2009.

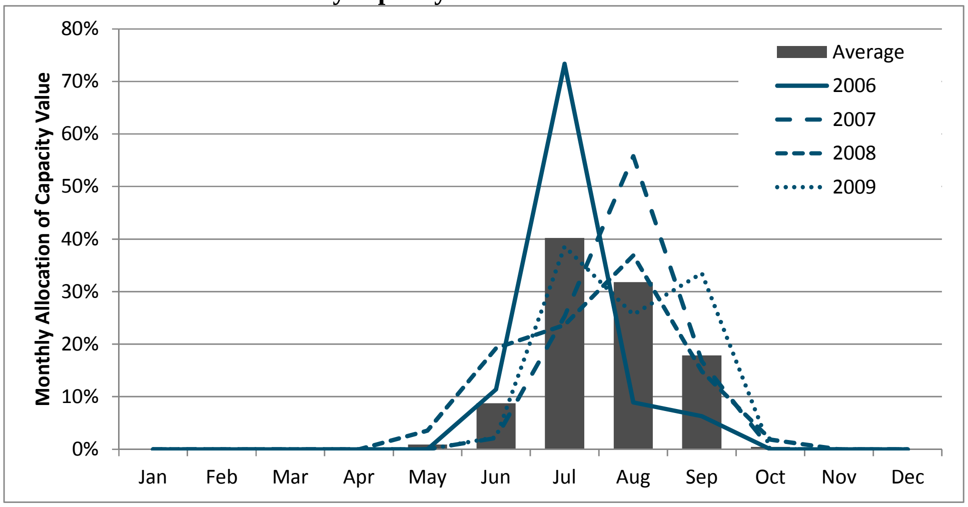
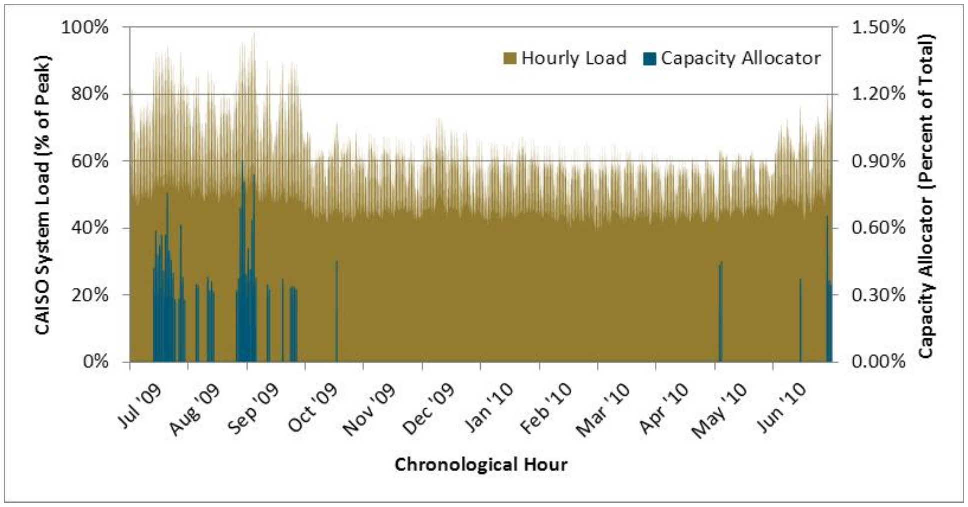


Table A-6. Summary of monthly capacity allocation based on historical load data from 2006-2009.

Month	Capacity Allocation (%)	Number of Constrained Hours
January	0.0%	0
February	0.0%	0
March	0.0%	0
April	0.0%	0
May	0.9%	2
June	8.8%	22
July	40.2%	100
August	31.8%	80
September	17.8%	45
October	0.5%	1
November	0.0%	0
December	0.0%	0
Total	**100.0%**	**250**

Hourly allocators based on CAISO system loads from July 2009 through June 2010 are calculated using the historical monthly allocation of capacity. The algorithm used to allocate the value of capacity to hours within this calendar year parallels the process used for the historical analysis but shifts the time scale from allocation across an entire year to allocation within single months. Thus, for each month between July 2009 and June 2010, the value of capacity is allocated to the number of constrained hours in that month so that the allocators sum to the total monthly allocation shown in Table A-6. As with the historical analysis, the allocators are inversely proportional to the difference between the month's peak load plus operating reserves and the load in the relevant hour.

Figure A-11. Hourly allocation of generation capacity based on loads from July 2009 through June 2010.



Ancillary Services (A/S)

Besides reducing the cost of wholesale purchases, reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services. The CAISO MRTU markets include four types of ancillary services: regulation up and down, spinning reserves, and non-spinning reserves. The procurement of regulation services is generally independent of load; consequently, behind-the-meter load reductions and distributed generation exports will not affect their procurement. However, both spinning and non-spinning reserves are directly linked to load—in accordance with WECC reliability standards, the California ISO must maintain an operating reserve equal to 5% of load served by hydro generators and 7% of load served by thermal generators.

As a result, load reductions do result in a reduction in the procurement of reserves; the value of this reduced procurement is included as a value stream in the Avoided Cost Calculator. It is assumed that the value of avoided reserves procurement scales with the value of energy in each hour throughout the year. According to the CAISO's *2009 Annual Report on Market Issues and Performance*, total spending on reserves in 2009 amounted to 1.0% of the value of total wholesale purchases. E3 uses this figure to assess the value of avoided reserves procurement in each hour.

T&D Capacity

The avoided costs include the value of the potential deferral of transmission and distribution network upgrades that could result from reductions in local peak loads. The marginal value of T&D deferral is highly location-specific; E3 has gathered utility data on utility T&D investment plans and computed the cost of planned T&D investments on a $/kW-yr basis. Synthesizing data gathered from general rate cases of the three major IOUs, E3 has calculated statewide average deferral values for both transmission and distribution infrastructure. As with generation energy and capacity, the value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table A-7. These factors are lower than the energy and capacity adjustments because they represent losses from transmission and distribution voltage levels to the retail delivery point.

Table A-7. Losses factors for transmission and distribution capacity.

	PG&E	SCE	SDG&E
Distribution	1.048	1.022	1.043
Transmission	1.083	1.054	1.071

The network constraints of a distribution system must be satisfactory to accommodate the area's local peaks; accordingly, the Avoided Cost Calculator allocates the deferral value in each zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. Because local loads were not readily available for this analysis, hourly temperatures were used as a proxy to develop allocation factors for T&D value, a methodology that has been benchmarked against actual local load data and was originally developed for the E3 Calculator used to evaluate the benefits of utility energy efficiency programs. This approach results in an allocation of T&D value to several hundred of the hottest — and likely highest local load — hours of the year (Figure 12). Figure A-13 shows the total allocation of T&D within each month for each of the climate zones. Different weather patterns throughout the state result in unique allocators for T&D capacity.

Figure A-12. Development of T&D allocators for CZ2

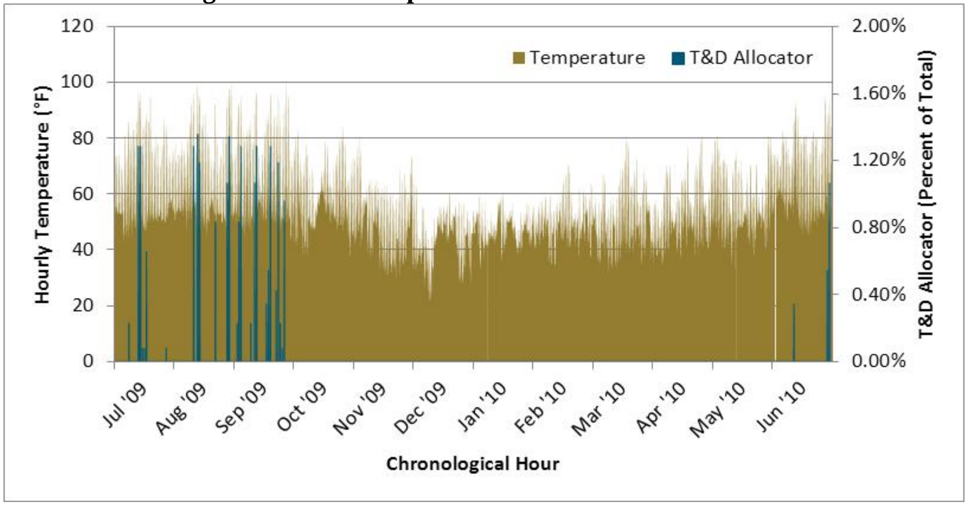
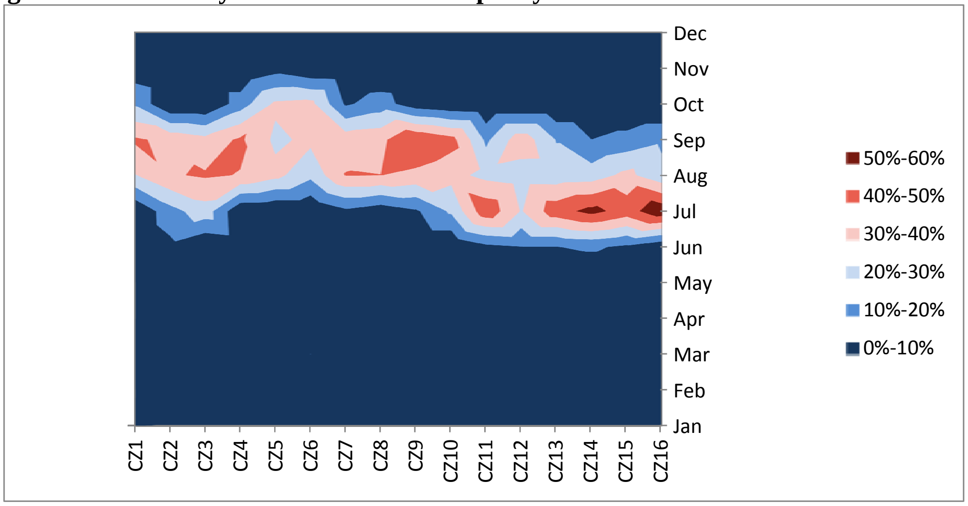


Figure A-13. Monthly allocation of T&D capacity value across the sixteen climate zones.



Environment

The environmental component is an estimate of the value of the avoided CO2 emissions. While there is not yet a CO2 market established in the US, it is included in the forecast of the future. While there is some probability that there will not be any cost of CO2, that the likelihood of federal legislation establishing a cost of CO2 is high Since a forecast should be based on expected value, the avoided costs forecast includes the value of CO2.

More challenging for CO2 is estimating what the market price is likely to be, given a market for CO2 allowances is established. The price of CO2 will be affected by many factors including market rules, the stringency of the cap set on

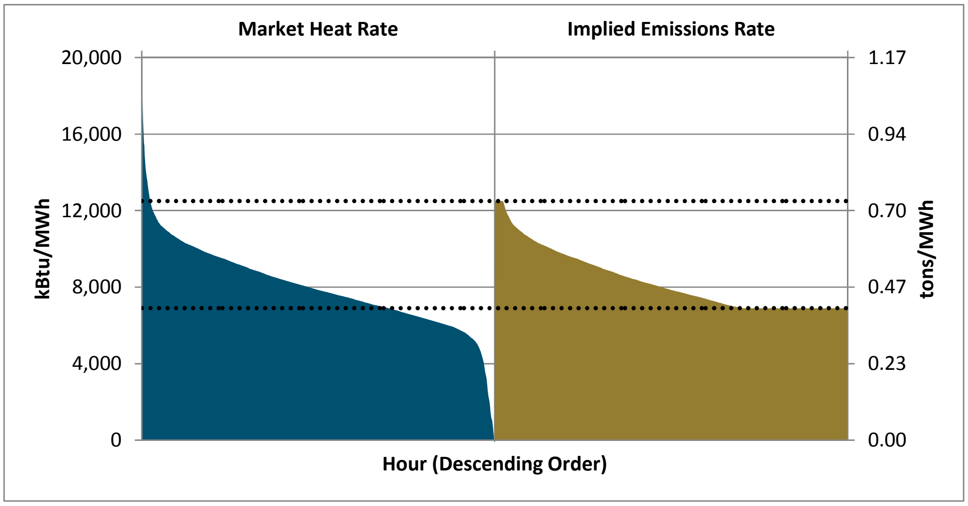
CO_2 allowances, and other elements. The DG Cost-effectiveness Framework uses a forecast developed by Synapse Consulting through a meta-analysis of various studies of proposed climate legislation. The mid-level forecast included in this report was developed explicitly for use in electricity sector integrated resource planning and so serves as an appropriate applied value for the cost of carbon dioxide emissions in the future.

Assuming that natural gas is the marginal fuel in all hours, the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by a range of heat rates for proxy natural gas plants shown in Table A-8; the hourly emissions rates derived from this process are shown in Figure A-14.

Table A-8. Bounds on electric sector carbon emissions.

	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	6,900
Emissions Rate (tons/MWh)	0.731	0.404

Figure A-14. Hourly emissions rates derived from market prices (hourly values shown in descending order).



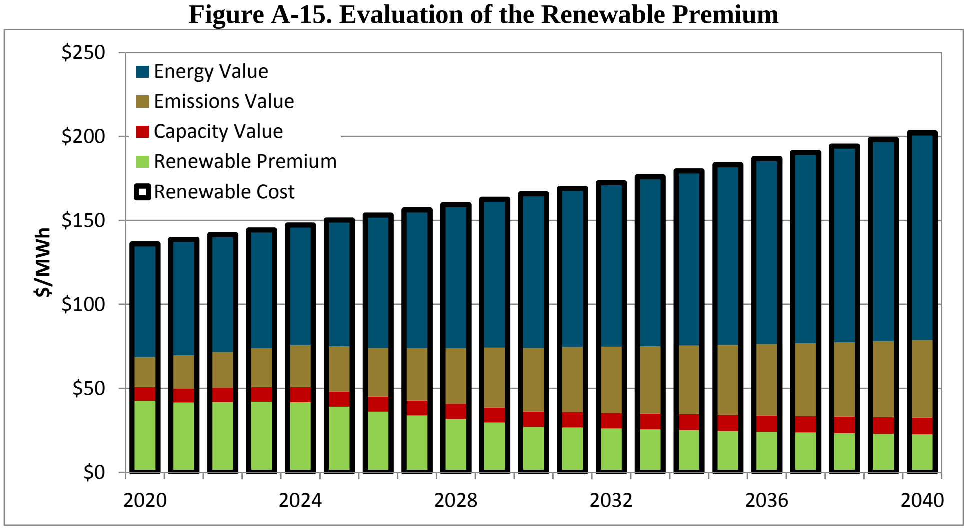
Avoided Renewable Purchases

The DG Cost-effectiveness Framework also includes the value of avoided renewable purchases. Because of California's commitment to reach a RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will result in an additional benefit by reducing the required procurement of renewable energy to achieve RPS compliance. This benefit is captured in the avoided costs through the RPS Adder.

The calculation of benefits resulting from avoided purchases of renewables begins in 2020. Because of the large gap between existing renewable resources and the 33% target in 2020, the rate of renewable procurement up until this year is unlikely to change with small reductions to the total retail load. However, after 2020, any reduction to retail sales will reduce requirements to obtain additional resources to continue compliance with the 33% case. As a result, the value of avoided renewable purchases is considered a benefit associated with load reductions beyond 2020.

The RPS Adder is a function of the Renewable Premium, the incremental cost of the marginal renewable resource above the cost of conventional generation. The marginal renewable resource is based upon the Fairmont CREZ, the most expensive resource bundle that is included in the renewable portfolio in E3's 33% Model 33% Reference Case. The Renewable Premium is calculated by subtracting the market energy and capacity value associated with this bundle, as well as the average CO2 emissions from a CCGT, from its levelized cost of energy as shown below. The RPS Adder is calculated directly from the Renewable Premium by multiplying by 33%, as, for each 1 kWh of avoided retail sales, 0.33 kWh of renewable purchases are avoided.

Figure A-15. Evaluation of the Renewable Premium



Key Data Sources and Specific Methodology

This section provides further discussion of data sources and methods used in the calculation of the hourly avoided costs.

Natural gas forecast

The natural gas price forecast, which is the basis for the calculation of the CCGT all-in cost, is based upon from the CPUC MPR 2009 Update. This forecast is based upon NYMEX Henry Hub futures, average basis differentials, and delivery charges to utilities. The forecast is shown in Figure 16. The MPR's forecast methodology has been expanded to incorporate expected monthly trends in gas prices—commodity prices tend to rise in the winter when demand for gas as a heating fuel increases. Figure A-17 shows three snapshots of the monthly shape of the natural gas price forecast.

Figure A-16. Natural gas price forecast used in calculation of electricity value (mean, maximum, and minimum shown for each year)

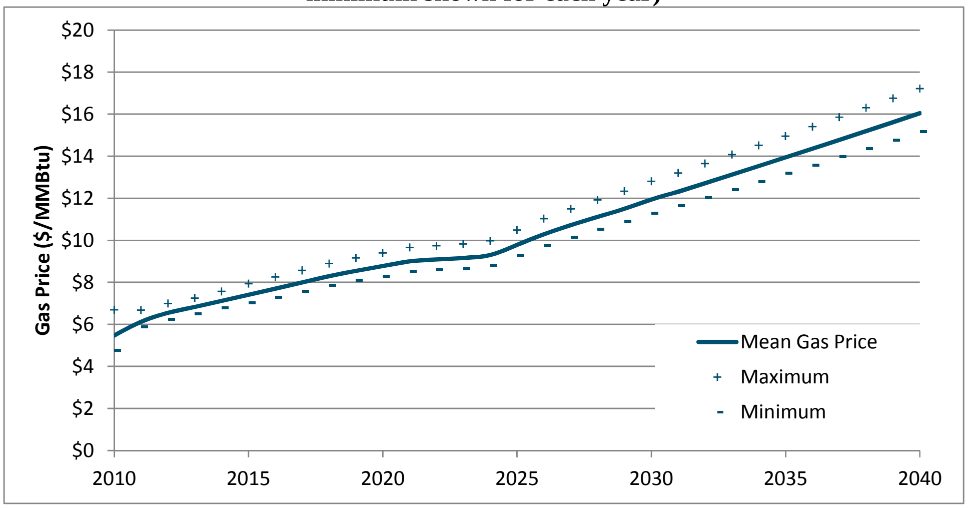
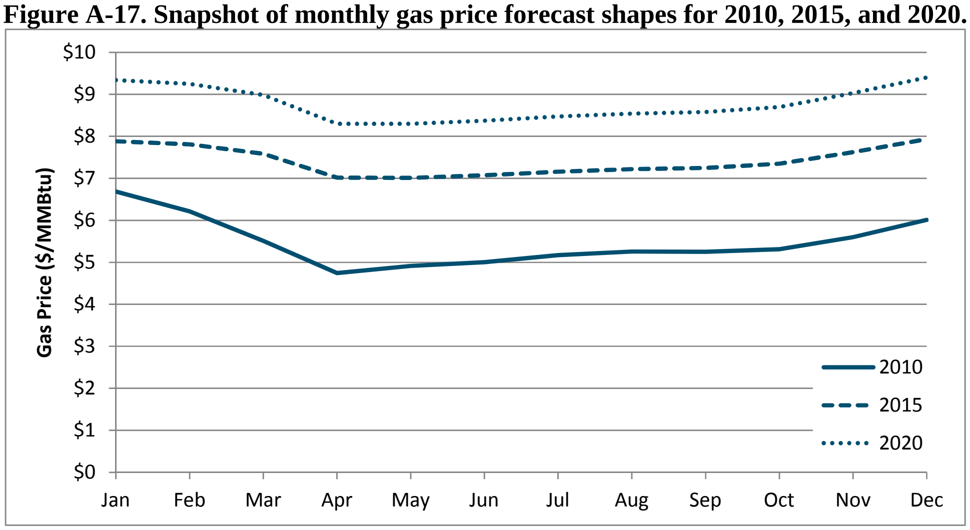


Figure A-17. Snapshot of monthly gas price forecast shapes for 2010, 2015, and 2020.



Power plant cost assumptions

The cost and performance assumptions for the new simple cycle plants are based on the 100 MW simple cycle turbine included in the California Energy Commission's Cost of Generation report.

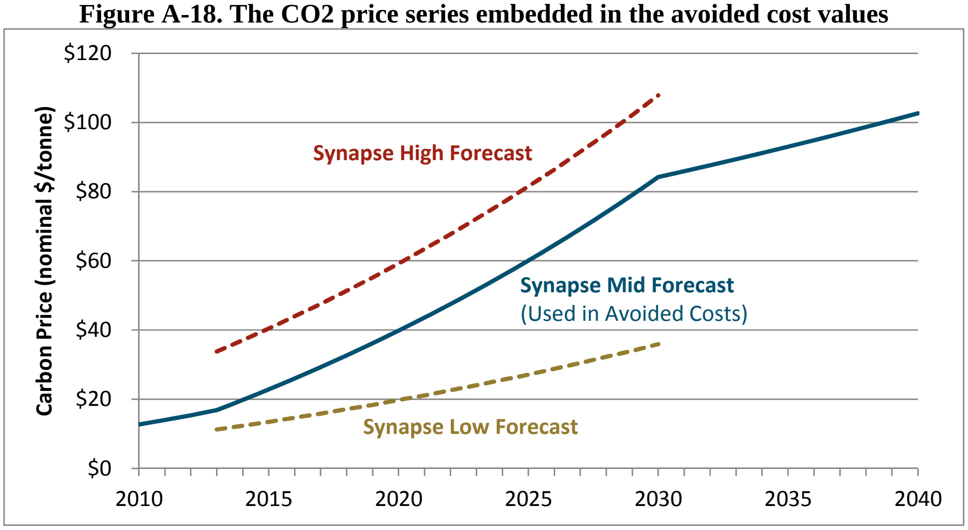
Table A-9. Power plant cost and performance assumptions (all costs in 2009 $)

	Simple Cycle Gas Turbine
Heat Rate (Btu/kWh)	9,300
Plant Lifetime (yrs)	20
Instant Cost ($/kW)	$1,230
Fixed O&M ($/kW-yr)	$17.40
Variable O&M ($/kW-yr)	$4.17
Debt-Equity Ratio	60%
Debt Cost	7.70%
Equity Cost	11.96%

Cost of CO2 Emissions

The CO2 cost projection is taken from a meta-analysis of CO2 price forecasts. Figure A-18 summarizes the Synapse price forecasts; the mid-level forecast is used in the calculation of avoided costs.

Figure A-18. The CO2 price series embedded in the avoided cost values



The marginal rate of carbon emissions is interpolated from the hourly value of energy assuming that the marginal generator burns natural gas in all hours.

Calculation of the System Capacity Allocators

The following calculation sequence is used to compute a capacity cost allocation factor in each of the top 250 system load hours. This methodology is applied in the calculation of the hourly avoided cost of electricity:

1. Compute the system capacity that provides 7% operating reserves = peak load * 1.07

2. Compute a relative weight in each hour as the reciprocal of the difference between the load in each of the top 250 hours and the planned system capacity

3. Normalize the weights in each hour to sum to 100%

Calculation of the T&D Capacity Allocators

The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on Sundays and holidays) and order them in descending order

2. Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by 2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step

3. Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight

APPENDIX B:

STAKEHOLDER FEEDBACK

Appendix B: Stakeholder Feedback

Please note that the following views are those of the interviewees or industry stakeholders who submitted feedback, and not necessarily views of E3 or StrateGen. In addition, they are summaries, and are not an exhaustive list of all feedback provided.

Interview Summary Notes

IOUs

SDG&E

- Would have liked less money for marketing and more for implementation
- Like the idea of payment milestones, but they need to be simple to reduce administrative costs
- Refrigeration is tricky: some customers had to change their business model because of the economy (i.e., what they store), at which point PLS is no longer a viable option
- Currently a large part of the program is fuel switching, which may not be an option in the current definition

SCE

- Need a rate that provides a sustainable payback, and a guarantee that the rate structure will stay in place. One option might include a 10 year PLS tariff, or a guarantee for as long as the standard offer is available.
- However, a rate is not enough – only a handful of engineers understand the market, which is a big issue
- A lot of challenges with Honeywell because of technology expense and engineering challenges

PG&E

- Smaller systems seemed more difficult to sell, even with higher incentives. As a result, Cypress has experienced challenges selling the smaller capacity systems it was limited to in its original contract, which is why the Cypress contract was recently expanded to include additional technologies.
- It has been an onerous process for both sides to track performance for incentive payments.

Pilot Vendors:

Honeywell

- Significant implementation challenges: weight of unit led to structural engineering costs, which were not covered in the incentives; schools had DSA requirements; limited # of contractors to do install
- Existing customers seem very satisfied with unit, and actual is close to estimated shift, and no maintenance issues
- Targeting customers was a big issue: would be helpful to work with SCE to target customers with the correct rate structure
- Tried to run education/training for contractors, but payback wasn't good enough and most lost interest
- Either need a very high incentive (the current incentive is just not good enough), or a lower incentive and new rate

Cypress

- PG&E direct access requirement was very challenging; would want all customers allowed to participate
- Significant implementation issues: weight/structural engineering, DSA requirements, expense

- PG&E monitoring requirements were very complex and added to cost; energy neutrality requirements made the program even more complex, and seems out of scope of PLS

- PG&E rebate structure with persistence payments made it too complex and a deterrent to customers – need to focus more on customer education

- With SCE, no problem getting fully subscribed, but had to bundle because of low rebate – need a higher rebate to truly drive demand

- Refurbishment of TES units is cost effective, potential for a lot of projects

- TES and gas cooling is too complex for a standard offer

- For incentives, $500/kW is bottom limit, $750 is “sweet spot.” Also, need certainty in rates. Would recommend a traditional utility program, then when market grows go to standard offer + TOU.

- Lack of education/training in design community is a huge issue.

Trane

- Implementation challenges: weight, DSA, expensive (even at $2000/kW, 15 year payback)

- Generally targeted old units that needed replacement and new construction, to get around above issues

- Could probably get by with a $1000-$1200/kW incentive without energy neutrality (~$200 more with energy neutrality)

- RFP process seemed to work well. A standard offer would be challenging because of the range in technologies. Rate needs more certainty.

- interested in a voluntary special tariff for PLS customers

- Challenges getting baseline data

Retrofit Originality Inc.

- Should focus on PLS and EE; otherwise allows for poor design. With CAC, very successful in doing EE and PLS.
- A lot of units that aren't running optimally. Would be cost effective to go and fine tune these systems.
- Would recommend combination of utility rates, tax incentives, and rebates, because a program needs some owner incentive
- Needs to be a 3 year payback for commercial ($1300/kW won't get you far because its a 10 year payback)
- Likes idea of a graduated incentive that incorporates EE
- Training is a huge deal...need more training, performance-based commissioning.

EPS

- Joint vendor-IOU effort in targeting customers would be much more effective
- Many more potential customers than served in the program – potential for expansion
- Some challenges in customer scheduling or customer equipment issues (not related to EPS technology)
- In a future program, would need additional funds for marketing
- Challenges because of economy: baseline dropped (so didn't get projected demand savings) and some installations were no longer able to load shift due to changing product profile
- Additional flexibility in terms of shifting window would lead to additional benefits

- Facility related off-peak demand charge could be a big deterrent.
- Ice manufacturing is an ideal candidate for EPS technology: a perfect fit in terms of climate, product type, ability to process shift unloading of product

Other:

Klaus Schiess (KS Engineering)

- A guaranteed rate is essential...need better rate structure to incent, at which point there is no need for a rebate.
- Training and educational tools are also essential
- A lot of existing systems could be fine tuned
- Need more quality control in feasibility studies
- Wants to expand COOLAID

Cogent

- Minimum threshold for incentive level: 5-7 year for public, 2-3 private
- For incentive, 50% at application and 50% at the completion would be ideal. Combined TOU differential and demand charge would also be good.
- For technologies, ice is "more forgiving" but investment is not as good. Chilled water is challenging because of operating differential

ASW

- Very challenging to get baseline data in order to measure performance
- No one will buy unless it's less than a 5 year payback, so batteries are very challenging (have found 20+ year payback)
- Ice storage seems to require more knowledge than the typical operator has. Also, smaller ice systems seem very challenging and too expensive.

- Have to have certainty in rates, and incentive should be paid out over 5 years and based on performance
- Majority of systems not working at full capacity – a lot of potential to fix systems

Ken Gillespie (PG&E)

- Key benefit is reducing ampacity at the meter
- Improving delta T for chilled water is essential
- Smaller ice systems can be challenging due to maintenance issues. Fr example, the facility owner might not understand how to maintain glycol levels.
- Lack of training/education is a huge issue

Transphase

- Technology neutral is a good thing
- EM&V was overly complex...added a lot of additional costs/effort ($40-50k)
- Any program should be heavily performance-based
- With a more favorable rate schedule, a standard offer might be unnecessary
- Prefers market value oriented approach, where the value of shifting a kW should be the same and thus receive the same incentive
- There would be challenges in a residential market – no economies of scale, and the education aspect would be a huge burden
- Maintenance costs were negligible – found customers using systems after 20 years w/ few problems

- For energy efficiency, should look at site vs. source energy, including heat rates of the power plants. In theory, avoided costs should reflect heat rates and cost of production, rates should reflect avoided costs.

Schneider Electric

- Generally a 2 year payback is necessary. Some industries, such as pharmaceuticals, might tolerate longer paybacks like 7 years. At 10+ years, this is definitely too much risk.
- Waste water treatment plants may be a good target
- Has encountered a lot of rate change fear
- Equipment: most facilities will not want to purchase bigger equipment that would allow them to shut off during the day and turn on at night

Cristopia

- Feasibility studies were not done well, due to engineer lack of tracking
- Challenge in marketing – building owners don't care about load shift because the savings are passed on. Better in buildings where owner is tied to costs.
- Need a sustainable business model, which means changing rate structure
- There are opportunities to process shift across the system, but no one would bother because of rate structure

SCPPA

- Customers are unwilling to make investment because of TOU risk
- Huge cost advantages to doing high volume – primary incentive for utility-owned model, but also good for society
- Equipment maintenance responsibilities vary widely, so can be complex

- Utility doesn't want to deal with O&M call, so set up a call center
- Pre and post-installation analysis is very challenging

Invensys

- Establishing baseline for some processes – such as batch processes – will be more challenging for industrial facilities than in buildings
- Liquid processes (water utilities, etc.) may be good candidates for process shifting, as well as paper mills
- 2-3 year payback (1 in the recession) necessary, although “green” focus can shift this somewhat

Enovity

- Need customized sequences to get value, which should be done building by building
- At low loads, it is better to run the tank because the chiller does not run very efficiently at low load and one can also avoid start and stop problems from an under-loaded chiller.
- Big issue – some customers opt out of energy purchasing, with a fixed $/kWh rate 24/7 from provider. With the inefficiencies of running a TES system (compared to chilled water plant), this becomes more expensive, and the customer would save money by not using the system

Davis Energy Group

- Precooling – need an efficient envelope in order to store cooling
- If a building can tolerate 8-10 degree float, can do a lot with precooling (but many people are unwilling to tolerate any change in service)

- Much easier to work with new construction, as you can plan for space and existing construction tends to be poor
- Rate structures don't reflect the peak load problems
- “Green” marketing might be effective
- Good to see how people are going to interact with the system before going in

Glendale

- Targeting government buildings
- People tend to assume that the PLS technology is to blame when something goes wrong, but typically it has been an issue with some other equipment
- Biggest challenge has been dealing with building owners. Need to sit down and educate them, which can be time consuming but effective
- Utility-ownership seems to be working very well

FPL

- Very cost effective to work with the design community...then you don't need to target specific projects, as they will often know of a number of eligible projects. Cuts down on marketing costs.
- Their program targets a 4-6 year payback, which is not enough for many customers, who want a 2-3 year payback
- A lot of efficiencies in dealing with government/schools. For example, there may be a number of buildings that can all be done at once.
- Had some customers who wanted to participate for environmental reasons, but most are interested in saving money

- TES has worked really well under current rate design (summer window: 12pm-9pm), but many customers have requested to shorten that window, so created seasonal demand rate from 3-6. Now can design smaller systems to shift for 3 hours – much more economical.
- Very important to shorten this window, and to create a rate just for TES.
- Need bill analysis, engineer sign off...feasibility study is very important
- 5 year learning curve (but may be quicker with technology today) – just need to stick with it in terms of training
- Recommend: want to deal with customers that have qualified technician – not just a lightbulb changer. Also – need to reach out to the customers who are cutting edge. Though it is proven technology, it is a new application for them.

Ice Energy

- Rate structure is a huge issue
- Limited to direct access customers – very challenging to subscribe program
- Utility ownership models work well
- Standardization/consistency is extremely valuable in any program structure

Workshop Feedback Summary Notes

Complete versions of feedback received are available at this link: http://www.ethree.com/public_projects/sce1.html. Please note the feedback has been edited to remove confidential information or specific company names where necessary.

Klaus Schiess, KSEngineers

- The report would benefit from a deadline extension and an additional workshop
- The only way to achieve PLS goals is a rate that reflects real time pricing or a TOU rate. If the rates alone do not achieve these goals, then other incentives have to be offered.
- The analysis uses examples from the pilot projects, but these projects do not represent the experience of TES as a whole
- TRC evaluation should not have any influence on the decision to have a PLS program or not
- The concept that California has sufficient capacity until 2015 should not have any influence on the decision making process

Paul Valenta/Mark MacCracken/Terry Andrews, Calmac

- Properly designed partial storage systems (vs. full storage) using ice operate more efficiently, require less space, require fewer incremental costs, while having better life cycle values, a lower connected load and requiring less ratepayer funding.
- More information is necessary on how projects were selected for the analysis
- Incremental costs in the report may not be accurate, and a 15 year life-cycle is not accurate for a Calmac system
- Other PLS programs should be studied to determine specifically why they do or do not work

C. Clark, BG&E

- BG&E, along with several TES equipment manufacturers, presented several educational seminars with large customers and consulting engineers. Results were positive.

- If projects are designed to take advantage of all the tools that ice offers, the initial system cost is often less than a conventional system of the same capacity, and can result in a two to three year payback.

- Designs that take a conventional chiller system and add ice storage can result in a six to eight year payback.

- When ice storage systems are compared to conventional systems, generally only the cost of the ice and chiller are compared to the chiller cost of a conventional system, which does not include other relevant cost savings such as overall downsizing.

Scot Duncan, Retrofit Originality Inc.

- Utilities have a fiduciary responsibility to their shareholders to provide a return on their investment, and installing PLS technologies can be counter to this responsibility. If the utilities were able to include properly designed and deployed PLS systems in their asset base, there would be a large demand by utilities to deploy these technologies.

- Energy efficiency and performance monitoring are very important when upgrading an existing TES or upgrading a non-TES to a TES system. Otherwise poor operating strategies go unknown, and substantial energy waste occurs.

- The monitoring requirement could be a part of the feasibility study.

- Adequate rate structures are needed not only to get TES in place but to maintain optimal operation.

- TES tanks in a chilled water storage application last far longer than 15 years

- Building power plants is extremely difficult and expensive, due to regulations. It is unrealistic to estimate the actual cost of building something that may not be able to get permitted or built in the actual quantities that will need to get built for future growth and replacement of existing capacity that may get retired.

- TES systems can range from energy neutral at the site to site energy efficiency improvements of over 45%

John Andrepont, The Cool Solutions Company

- The analysis should be employing lower installed capital costs for medium to large-scale TES installations

- New construction or retrofit capacity expansions can often be economically justified without utility cash incentives.

- To capture a larger market penetration by TES, utility incentives would play a major role in providing the necessary economic incentive to the owners.

Stephen Clarke, AIC and East Penn Manufacturing

- TES is over represented in the analysis, which may bias program design. Immediate availability of cost effective battery based systems appears to be poorly understood by those involved in the generation, distribution and regulation of electricity.

- The biggest barriers are 1) the lack of TOU pricing at the customer side of the meter and 2) certainty that PLS system deployment will not be hindered directly or indirectly by service providers.

- Incentives other than meaningful TOU price signals are not required and should be a low priority.

- Any PLS program must be technology-neutral
- Process Shifting requires nothing other than TOU pricing differentials
- If anything, residential customer based storage should be prioritized since a) the other classes represent systems of a scale that could be provided under other programs and initiatives, and b) domestic scale storage, if implemented cost effectively, would potentially have the largest beneficial impact.
- A standard offer matched with TOU pricing based incentives will drive broad adoption of standardized packaged systems, maximizing cost, reliability and service utility
- RFP based systems tend to become dominated by players with existing RFP departments, and are typically not those organizations who exist to develop viable PLS systems and technologies.
- We should be looking to incentivize standardized and packaged systems, which do not require a feasibility study.

Doug Ames, Transphase

- Total capital cost from the utilities' pilots were exaggerated compared to normal installation costs
- Each installation should include a feasibility study, as well as pass a TRC test
- A cost-based approach conflicts with a technology-neutral approach, and provides impetus for manufacturers' costs to remain high. It also may be unconstitutional.

SDG&E

- TES and non-TES categories should not be split any further without compelling reason

- Process shifting should be included in a standard offer or RFP
- Commercial, industrial, and public sector should be prioritized over residential customer classes for now
- A standard offer is preferred, perhaps with 3-5 year contracts
- TOU energy benefits are modest and therefore persistence may be an issue
- Operational savings are somewhat customer specific based on their load profile. The ability to mitigate customer inconvenience will be what drives adoption, with greater inconvenience requiring greater incentives.
- TOU operational savings combined with a one-time (or short term) incentive to cover technology upgrades should be sufficient.
- The tariff structure should be utility specific
- A feasibility study seems reasonable, and could be included in a Technology Audit (TA).

AES

- PLS provides social and private benefits, yet often private operating cost savings do not offset the cost of implementing TES to the end-user.
- Social benefits often offset the implementation costs, especially for larger projects. Thus, incentives are necessary and desirable to promote TES.
- AES supports a program that seeks to exploit the less costly projects first and consider the usefulness and effectiveness of smaller projects thereafter, which will naturally occur if incentive levels are equal.
- Standard offer is superior to RFP. The combination of higher transaction costs for an RFP process and the timing mismatch with building owners would result in higher costs for projects that are implemented.

- An RFP is limiting: a host of other technologies, vendors, and opportunities are eliminated from the field for the duration of the RFP.
- End-users focus on three issues: economic viability, managing uncertainty, and ongoing involvement through monitoring and verification. The cost/benefit equation must overcome the sum of these factors.
- In order to simplify an incentive program, shift calculations could be based on efficiencies according to existing chiller age, in three categories: older than 20 years, 11 to 20 years, and younger than 11 years.
- AES would support incentive levels between $1500 and $2000/kW given current tariff structures
- It may be appropriate to eliminate off-peak demand charges for all customers, rather than single out TES. On-peak demand charges could be increased to meet revenue neutrality requirements.
- Rate certainty is important (perhaps 5 years for private sector and 10 years for public sector)
- A feasibility study would be a low-cost, effective tool for a PLS program
- The RIM test needs to be either modified or de-emphasized.
- Even if California has excess capacity through 2015, this should not stall program implementation
- If separate financing were available for TES projects, they would not need to compete with other projects for limited capital. Attempts to use utility rate base financing would probably entail complications that would make it unappealing.

Feedback on Costs Following Workshop

Three stakeholders provided formal feedback on costs of thermal systems, following the workshop: Doug Ames (Transphase), Cool Solutions and CB&I.

Due to the length of the Transphase response, we refer the reader to the full document on the website, which is named "Install Costs Per kW Transphase-SCE PSA.pdf". (see this link: http://www.ethree.com/public_projects/sce1.html)

The Cool Solutions and CB&I feedback is provided below.

TES Project Data and Capital Cos J.S. Andrepont - The Cool Solutions Company 15- Nov - 10

TES Initial Operation (year)	Application Type	State	TES Type	TES Load Shift Amount (% of peak)	TES Capacity (ton-hrs)	Peak Cooling Load Shift (tons)	Peak Electric Load Shift (kW)	TES Tank Installed Cost ($ x 10^6)	Approx. TES Project Installed Total Cost ($ x 10^6)
2003	District Cooling	FL	chilled water	near 100%	160,000	20,000	15,000	2.782	8.0
1990	Corporate R&D	MI	chilled water	38%	68,000	7,000	5,250	2.566	5.2
2011	University Campus	IL	chilled water	29%	50,000	9,750	7,508	3.767	5.6
1993	University Campus	WA	chilled water	partial	17,750	2,536	2,092	1.200	2.5
2002	Airport	TX	LoTempFluid	near 100%	90,000	30,000	21,000	2.800	10.0
2004-2007	University Campus	AZ	Ice	partial	24,000	3,000	2,250	n.a.	4.2

TES Initial Operation (year)	Application Type	State	Total cost per ton-hr $/ton-hr	Total TES Project Unit Cost ($/kW)	Utility DSM Incentive ($/kW)	Net Capital Savings after Credit for Smaller Chiller Plt ($ x 10^6)
2003	District Cooling	FL	50.0	533	none	over 5.0
1990	Corporate R&D	MI	76.8	994	none	3.6
2011	University Campus	IL	111.8	745	none	2.4
1993	University Campus	WA	140.8	1,195	none	1.5
2002	Airport	TX	111.1	476	none	6.0
2004-2007	University Campus	AZ	176.0	1,878	n.a.	n.a.

Additional Notes on Costs, per correspondence with Cool Solutions Co.:
- Above are for above grade tanks. The "TES Tank Installated cost" would be roughly double for an undeground tank.
  (Based on this assumption, the $/ton-hour costs range from ~ $70/Ton-hr to $200/Ton-hr and ~ $600/kW to $1500/kW)
- As projects get bigger, economies of scale result. Smaller systems tend (such as for a 1,000 ton-hr application) are more typically ice.
- Chilled water systems especially get economies of scale because there are a number of fixed costs, independent of size.
- Costs vary greatly due to a number of factors, such as union/non-union, above/below ground .
- Ice systems tend to be more modular, so the $/ton-hr do not vary as much

Additional feedback on costs and program design:
New construction/ expansion vs. pure retrofit:
- New construction and expansions do not often need rebates. With expansions, existing chiller capacity can be used for the expansion (instead of installing new chillers)
- It is hard to tap into pure retrofit market without DSM incentives

On operational challenges:
- With larger systems, they have not encountered problems with engineering and operational support. District cooling systems, especially, have good dedicated staff.

23-Nov-10

CB&I Historical Data for Above Ground, Welded Steel, Chilled Water Thermal Energy Storage Tanks in California

Initial Operation Date	Owner Type	Region	State	TES Capacity (ton-hrs)	Peak Discharge (tons)	Sales Value	$ / ton-hr (see footnote for $/kW)
2001	Private Owner	Southern	CA	16,100	2,670	$585,646	$36.38
2001	University/College	Northern	CA	40,000	8,170	$1,815,300	$45.38
2002	Private Owner	Southern	CA	6,000	2,580	$413,500	$68.92
2002	University/College	Northern	CA	20,500	5,000	$1,173,938	$57.27
2002	Hospital	Southern	CA	10,700	1,200	$721,400	$67.42
2003	Hospital	Southern	CA	8,235	1,080	$667,928	$81.11
2003	Government	Central	CA	3,000	400	$325,030	$108.34
2003	Government	Central	CA	4,000	500	$433,370	$108.34
2003	Government	Central	CA	3,500	500	$379,200	$108.34
2006	University/College	Central	CA	30,000	3,000	$1,312,100	$43.74
2007	University/College	Southern	CA	7,200	1,570	$780,000	$108.33
2007	University/College	Southern	CA	15,000	3,910	$1,150,750	$76.72
2008	University/College	Southern	CA	40,000	5,000	$4,200,000	$105.00
2009	Government	Northern	CA	52,000	11,680	$4,117,965	$79.19
2009	School	Southern	CA	7,700	1,100	$924,000	$120.00
2009	University/College	Northern	CA	2,650	440	$523,360	$197.49
2009	Private Owner	Southern	CA	8,500	1,180	$854,630	$100.54
2009	Hospital	Northern	CA	3,880	2,700	$791,600	$204.02
2010	School	Southern	CA	1,000	250	$377,900	$377.90
2010	Private Owner	Southern	CA	12,000	3,030	$1,879,736	$156.64

$/kW Cost Estimate:

- Information on the efficiencies of the central plant for each example are not known. Assuming a 1 kW/ton efficiency, the Total Sales Value in $/kW is ~ $160/kW to ~ $1500/kW with a median of $610/kW.

Additional notes based on correspondence with Brian Clark, CBI:

1. The projects are a mix of expansions and new construction. Costs are variable, so projects should be looked at individually.
2. The retrofits are a tough sell because the system already has what is needed to meet capacity and it is difficult to justify costs to add to that system.
3. "Total Sales": These are all-in quoted cost that includes engineering, materials, construction and are only for the tank portion.
4. The scope(s) among projects may differ slightly. The total sales numbers make a good reference for a budget estimate. It would be in the interest of a prospective tank owner to come to CBI with a request for a budget estimate. With a few pieces of information, CBI can give better budget estimates.
5. These tanks are not considered a commodity and cannot be corralled into distinct price brackets based on size alone, although, as can be seen from the table, you tend to get more for your dollar with a larger tank.

APPENDIX C:

ERRATA, MARCH 2011

In chronological order

Figure 2: Required Incentives. Lifecycle Benefit & Ratepayer Neutral Incentive Levels

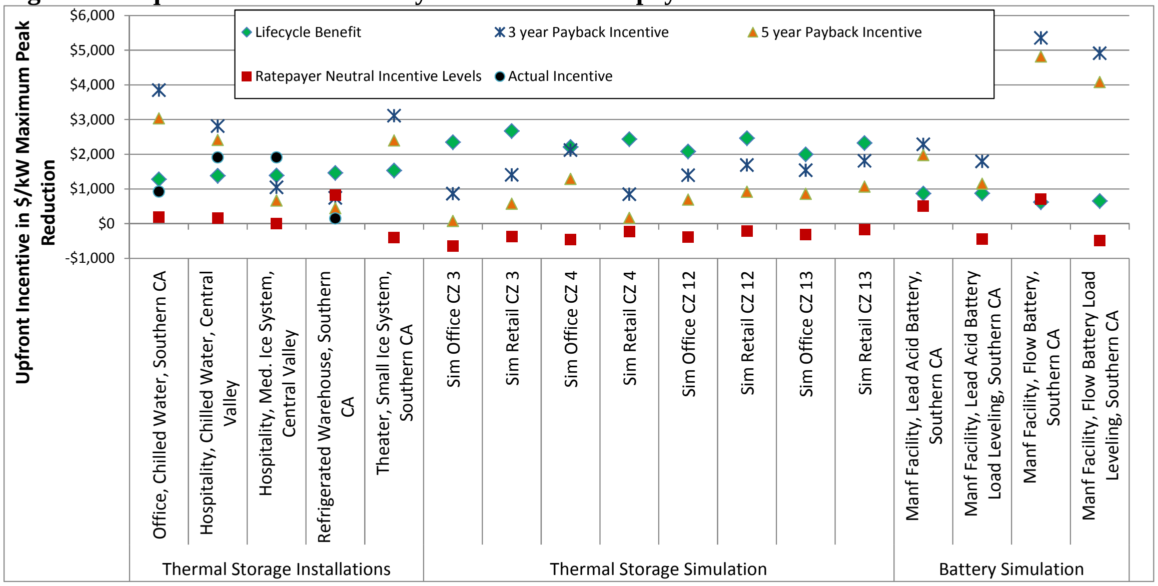


Table 9: Ratepayer Neutral Incentive Levels for Broad Scenario Analysis*

	Minimum, Median and Maximum of Incentive ($/Peak kW reduction) +				
	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours
Generic Rate	$210	$280	$360	$590	$645
	$300	$460	$540	$630	$766
	$370	$570	$570	$660	$805
PG&E A6	($80)	($190)	($680)	($730)	($830)
	($20)	($60)	($250)	($680)	($810)
	$90	($20)	($150)	($460)	($790)
PG&E A10 TOU S	$200	$560	$780	$1,020	$1,550
	$350	$810	$1,220	$1,380	$1,600
	$580	$1,160	$1,390	$1,560	$1,610
PG&E E20 P	$190	$260	$100	$140	$500
	$270	$370	$370	$430	$630
	$310	$400	$490	$620	$660
SDG&E ALTOU	$200	$370	$140	$220	$740
	$330	$450	$540	$570	$770
	$520	$1,080	$1,230	$1,220	$1,270
SCE TOU-8B	$190	$200	($110)	($30)	$730
	$230	$280	$370	$580	$870
	$270	$430	$760	$900	$950

Figure 33: Summary of Case Results Cost Effectiveness

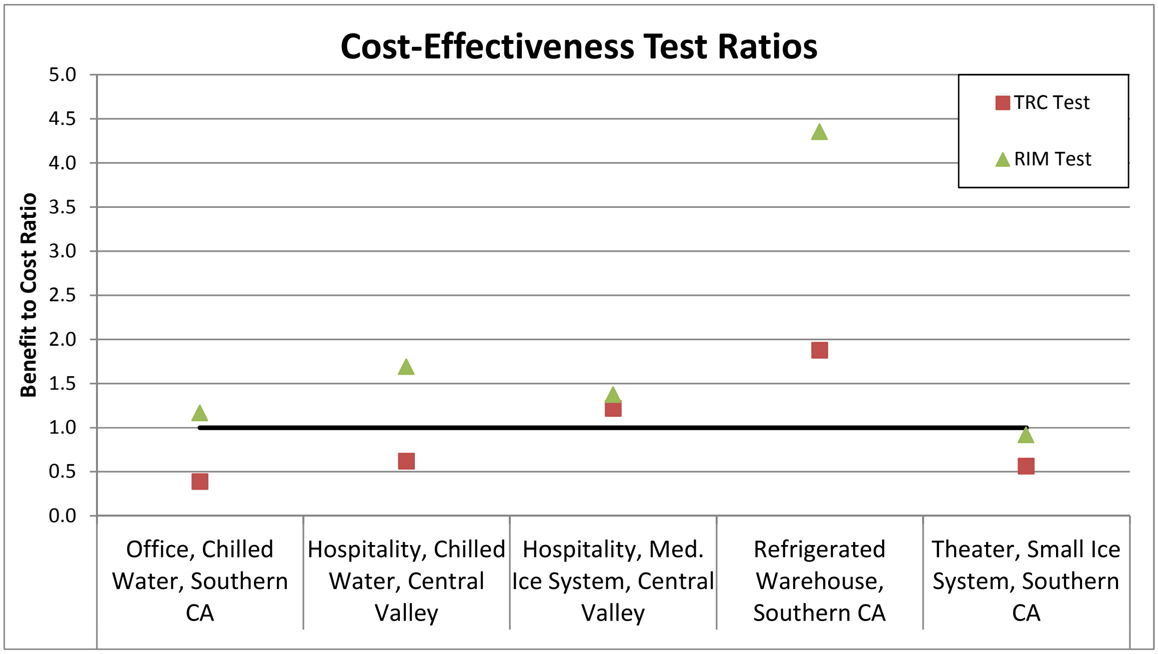
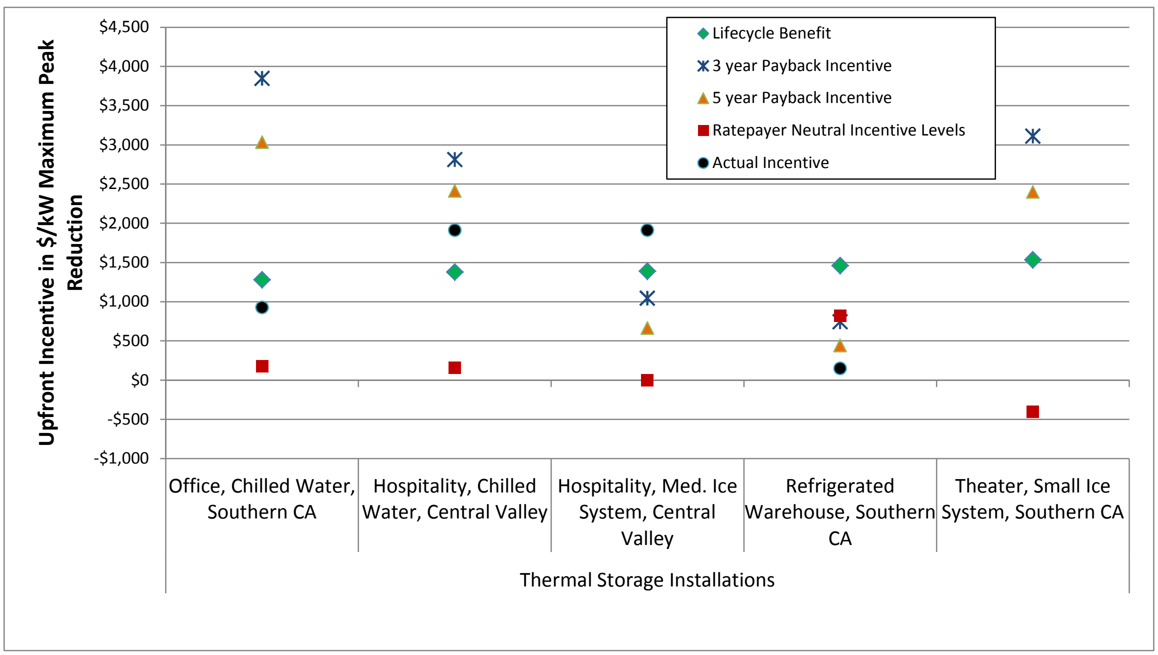


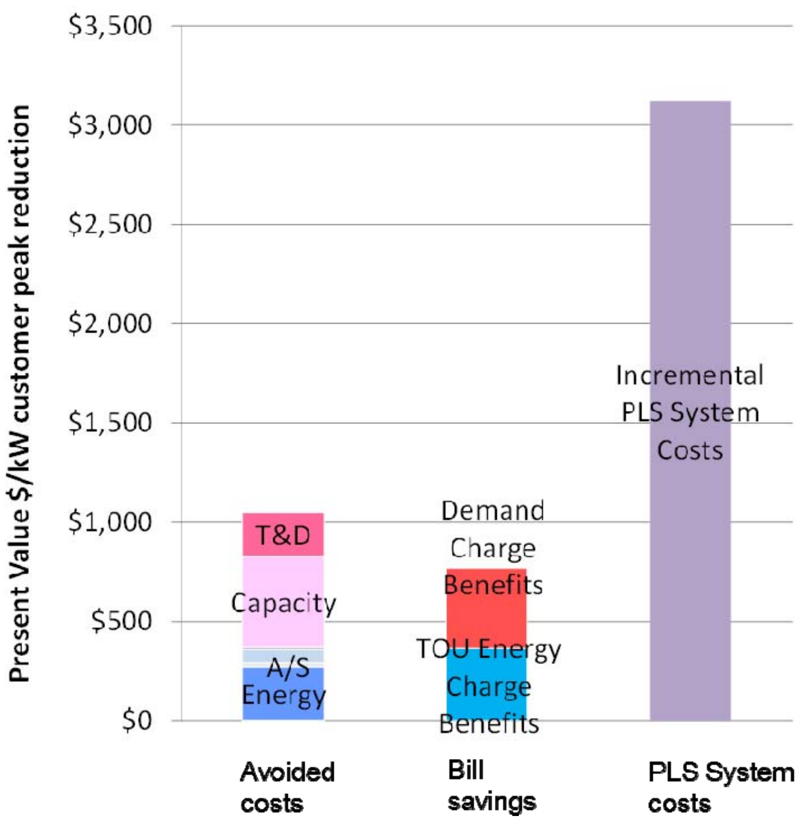
Figure 34: Summary of Case Studies Incentive Levels



Page 73 paragraph 1:

For three of the scenarios (office, southern CA, refrigerated warehouse, hospitality-chilled water), the equivalent ratepayer neutral incentive is positive, with a maximum level of ~$800/kW (the refrigerated warehouse example). For the refrigerated warehouse example, the actual incentive is less than the RIM and PAC based incentives.

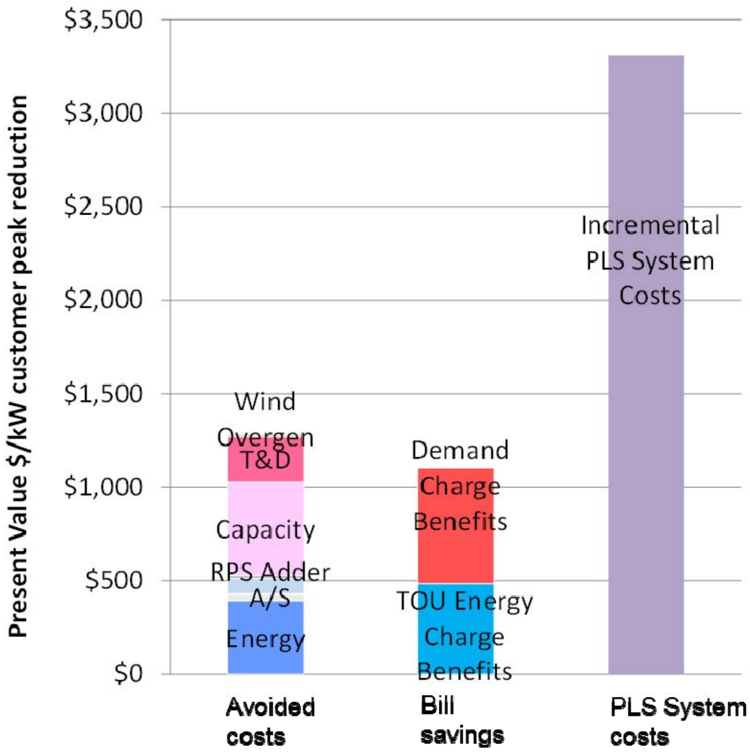
Figure 36: Specific Case Results – Office Chilled Water System – Historical Operation



Page 75, paragraph below figure 36, last sentence:

The maximum ratepayer neutral incentive is estimated at ~ $280/kW.

Figure 37: Specific Case Results – Office Chilled Water System –Improved Operation



Page 76, paragraph below figure 37, sentence 4:

The system passes the RIM test, with an estimated maximum ratepayer neutral incentive of $180/kW.

Page 78, paragraph below figure 39, sentence 4:

The ice system passes the TRC and RIM tests but not the participant test.

Figure 44: IOU Pilot Project Required Incentive Levels vs. PAC & RIM Tests for PLS Pilots and Recent Installations

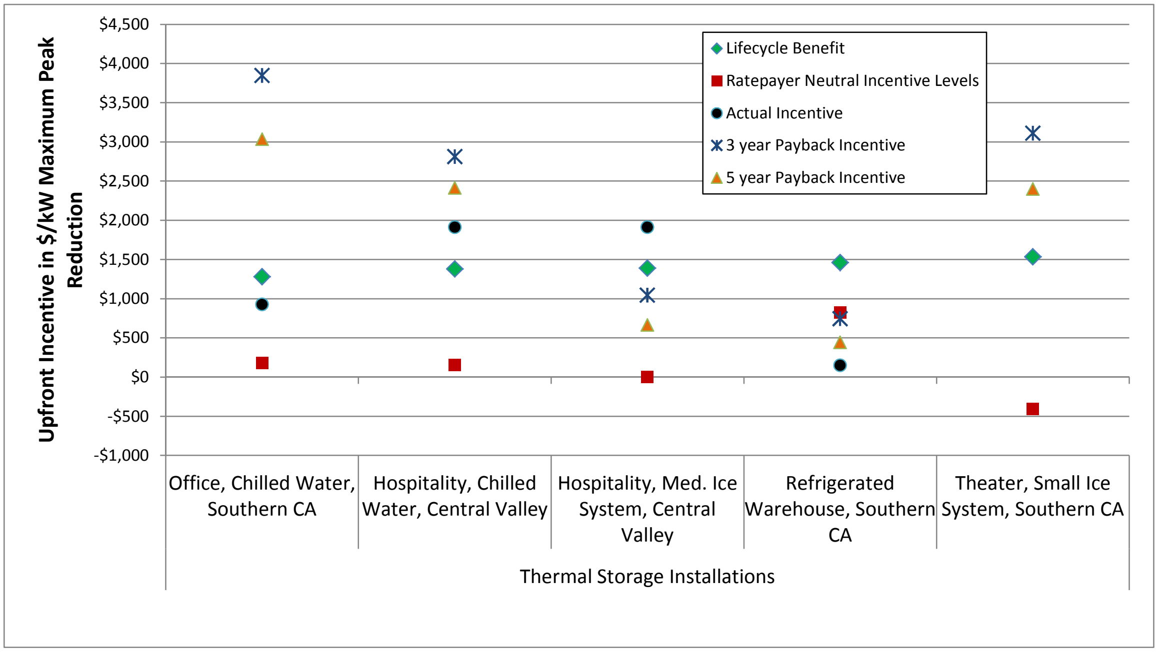


Table 18: Range of TRC Costs and Benefits by Technology Type Based on Case Studies

Technology Type	Lifecycle TRC Benefit ($/kW)	Lifecycle TRC Cost* ($/kW)	Net Lifecycle TRC Benefits ($/kW)
'Medium' to 'large' thermal storage	$1,280-$2,670	$1,140-$3,310	($2,030)- $1,020
Process shifting applications: Based on refrigerated warehouse	$1,315-$1,610	$750-$915	$570-$695
'Small' thermal storage systems: Based on Ice Energy Example	$1,380-$1,685	$2,460-$3,000	($1,320)-($1,080)
Battery storage systems	$620-$880	$1,800-$4,030	($3,400)-($924)

Table 19: Upper Bound on Ratepayer Neutral Incentive Level Using Broad Scenario Analysis*

	Minimum Median and Maximum of Incentive ($/Peak kW reduction) +				
	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours
Generic Rate	$210	$280	$360	$590	$645
	$300	$460	$540	$630	$766
	$370	$570	$570	$660	$805
PG&E A6	($80)	($190)	($680)	($730)	($830)
	($20)	($60)	($250)	($680)	($810)
	$90	($20)	($150)	($460)	($790)
PG&E A10 TOU S	$200	$560	$780	$1,020	$1,550
	$350	$810	$1,220	$1,380	$1,600
	$580	$1,160	$1,390	$1,560	$1,610
PG&E E20 P	$190	$260	$100	$140	$500
	$270	$370	$370	$430	$630
	$310	$400	$490	$620	$660
SDG&E ALTOU	$200	$370	$140	$220	$740
	$330	$450	$540	$570	$770
	$520	$1,080	$1,230	$1,220	$1,270
SCE TOU-8B	$190	$200	($110)	($30)	$730
	$230	$280	$370	$580	$870
	$270	$430	$760	$900	$950

Table 24: Equivalent Incentive - SDG&E ALTOU - Climate Zone 10

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$330	$450	$540	$570	$770
$/kWh storage	$165	$113	$90	$71	$77
Additional TOU Δ $/kWh	$0.09	$0.06	$0.05	$0.04	$0.04

Table 25: Equivalent Incentive - SCE TOU8B - Climate Zone 14

	2 Hour	4 Hour	6 Hour	8 Hour	10 Hour
$/kW upfront	$230	$280	$370	$580	$870
$/kWh storage	$115	$70	$62	$73	$87
Additional TOU Δ $/kWh	$0.06	$0.04	$0.03	$0.04	$0.05