ATTACHMENT 1

Self Generation Incentive Program (SGIP) Staff Proposal
September 2010

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Excel worksheets supporting Appendix A and B are available on the CPUC's Energy Division/SGIP Web site: www.cpuc.ca.gov/PUC/Energy/DistGen/SGIP.

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1. Executive Summary

The purpose of this Energy Division Staff Proposal is to recommend modifications to the Self Generation Incentive Program (SGIP). This process was initiated in response to Senate Bill (SB) 412 (Stats. 2009, ch. 182), which authorizes the Commission to determine what technologies should be eligible for SGIP based on greenhouse gas (GHG) emissions reductions. Staff used the opportunity provided by SB 412 to take a broader look at SGIP and to consider a full range of program modifications intended to improve program outcomes.

This Staff Proposal presents a wide range of recommendations based on analysis of historical SGIP data, SGIP measurement and evaluation studies, party comments in this proceeding, and publicly available information on distributed generation technologies. In addition, staff hosted a workshop on January 7, 2010 to take ideas from parties on how to modify the SGIP program in response to SB 412.

All staff recommendations are intended to support the Commission's decision making process. These recommendations do not represent the final decision of the Commission. Please see the accompanying ruling in Rulemaking (R.) 10-05-004 for information about how and when to respond to this Staff Proposal with public comment. Staff anticipates and welcomes productive feedback and input from parties on the recommendations contained in this document. Staff has made every effort to explain the reasoning and analysis that led to the specific recommendations in the proposal in order to facilitate effective public input.

Several recommendations herein are preliminary. Staff intends to update certain identified portions of this proposal in response to information expected in the future. The staff proposal sections expected to be updated are noted as such. Regardless of whether a specific recommendation is noted as preliminary, future information obtained through the public input process may modify this staff proposal and, or any decision of the Commission related to the SGIP.

1.1 Technology Eligibility

Staff proposes three primary guiding principles as criteria for determining eligibility of proposed technologies in SGIP.

Cost-Effectiveness - SGIP should support distributed energy resource (DER) technologies that are cost-effective, or represent the potential to be cost-effective in the near future.

- A cost-effectiveness evaluation of SGIP is currently being conducted by Itron, Inc. Results of that evaluation should be available in the fall of 2010. Staff did not replicate that analysis herein. Instead, staff developed a framework for program modifications independent of the cost-effectiveness evaluation results.

- Itron's analysis will review program cost-effectiveness retrospectively and prospectively, and the analysis will include a variety of cost-benefit tests, as per the cost-benefit methodology adopted for distributed generation in Decision (D.) 09-08-026.
- Staff recommends that the Commission consider whether a technology has the potential to meet the Total Resource Cost (TRC) cost-effectiveness test, on a prospective basis, before making its final Decision on incorporating that technology into the SGIP. Staff recommends the Commission exclude from the program any technologies that do not demonstrate the potential for cost-effectiveness in the near future.
- The staff proposal will need to be updated with the cost-effectiveness information once it becomes available.

Greenhouse Gas Emissions Reductions – The SGIP should support technologies that are expected to produce fewer GHG emissions than they avoid from the grid.

- This GHG emissions reduction principle is consistent with SB 412 which requires that technologies funded under the program "will achieve reductions of greenhouse gas emissions"
- "Technology" refers to a certain class of generators (e.g. microturbines) while "product" refers to a specific item within that class (e.g. Capstone C200)
- Staff recommends applying this requirement at the technology level for as many technologies as possible, such that certain technologies would be Commission-approved for funding because they were certain to reduce greenhouse gas emissions. However, certain technologies vary substantially in terms of their production characteristics, and staff recommends those technologies would be approved for SGIP funding at the product level. Manufacturers of technologies which are not automatically pre-qualified can submit verified documentation showing the efficiency and performance of their specific product to the Program Administrators, who will be responsible for maintaining SGIP technology and product eligibility lists.
- Staff does not recommend applying the requirement for GHG emissions reductions at the individual project level. "Project" refers to a product operating at a specific location under the host site's demand parameters.
- The staff proposal relies on various input assumptions with respect to technology operational characteristics. The GHG emission reductions analysis is based on input assumptions received from stakeholders.

Need for Financial Incentives - SGIP incentives should not be provided to technologies that do not need them to achieve deployment. SGIP incentives should provide sufficient payment to stimulate DER technology deployment, but only after consideration of whether the technology has a need for financial incentives. The actual incentive level should consider the need for financial incentives such that the incentive encourages deployment but does not overpay.

- For technologies that can provide a reasonable rate of return for customers, defined as a 15% internal rate of return, without incentives, staff recommends that no incentives be provided. Staff chose this rate of return because the majority of SGIP participants are commercial customers, and these customers typically require a payback between 6-8 years, which corresponds to an IRR range of approximately 8-14%. Staff intentionally chose the least conservative end of the IRR spectrum, a 15% IRR cut off to account for the fact that DG technologies have other non-financial barriers. In addition, staff recognized that the Commission had previously used similar IRR ranges in adopting the initial incentive levels under the California Solar Initiative (CSI) program in 2006.[1]
- In determining the need for financial incentives, staff also considered whether other ratepayer-funded incentive programs exist for specific technologies. The SGIP should not duplicate efforts of other programs.
- The staff proposal relies on technology cost information from (a) the SGIP project database (for capital costs) and (b) estimates of ongoing operational and maintenance (O&M) costs from the preliminary work of the cost-effectiveness contractor. In addition, the cost-effectiveness contractor is undertaking a broader review of publicly available information about technology capital costs, and once finalized, the Staff Proposal will be updated with any new information about technology capital and/or O&M costs.

Staff applied the above criteria to current, past and proposed technologies. The results of staff's analysis are summarized in Table 1 below, but the results and input assumptions are explained in more detail in Section 4. As noted above, recommendations may change once the updated cost-effectiveness and technology cost information is received from Itron. This information may necessitate modifying the need for financial incentives, as well as contribute to the recommendation of actual incentive levels.

[1] CPUC Decision 06-08-028 establishing the California Solar Initiative, pg 18. Available online at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/59186.htm

Table 1. SGIP Technology Eligibility Preliminary Results

Technology	Fuel/ Application	SGIP Eligibility Status	Preliminary Recommendation
Wind Turbines	Wind	Currently Eligible	Include as Pre-approved
Fuel Cells	Non-Renewable, Electric only	Currently Eligible	No – Except potentially on a per product basis
	Non-Renewable, CHP	Currently Eligible	Include as Pre-approved
	Renewable, Electric only or CHP	Currently Eligible	Include as Pre-approved
Gas Turbines	Non-Renewable, CHP	Previously Eligible (thru '08)	Include as Pre-approved
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	Include as Pre-approved
Microturbines	Non-Renewable, CHP	Previously Eligible (thru '08)	No – Except potentially on a per product basis
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	Include as Pre-approved
Internal Combustion Engines	Non-Renewable, CHP	Previously Eligible (thru '08)	No
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	Include as Pre-approved
Organic Rankine Cycle Engines	Waste Heat, Bottoming Cycle CHP	Proposed	No
Energy Storage	Stand-alone	Proposed	Not at this time
	DG-integrated	Currently Eligible*	Include as Pre-approved
Pressure-reduction Turbines	In-conduit hydroelectric	Proposed	No

* Energy storage only currently eligible when coupled with wind or fuel cells.

1.2 *Incentive Mechanism*

Staff recommends that SGIP incentives continue to be technology-specific and based on technology cost. Technology-specific incentives should be based on the amount of incentive necessary to achieve a reasonable return on investment for a customer.

Staff recommends replacing the current up-front, capacity-based incentive with a hybrid performance based-incentive (hybrid-PBI). The proposed hybrid-PBI would be structured as follows:

- Initial Payment - 25% of the base incentive at project commissioning based on system capacity.
- Annual Payments – approximately 15% of the base incentive at the end of each year, for five years, based on actual measured performance.

The hybrid-PBI is intended to provide "sticker shock" relief for DER projects with high capital costs, while ensuring that projects are designed and maintained to maximize performance over the project life. Projects which exceed expected performance would be paid accordingly, with a maximum payment of 5% over expected performance. The purpose of the cap would be to ensure that budget planning could occur since a per-project contingency will need to be accounted for in the overall program budget. Ensuring the performance of SGIP systems is an important point and is necessary for achieving the environmental and grid support goals of SGIP, as well as protecting ratepayer investment in these technologies.

While parties have argued that past performance is not a good indicator of the future, it would be unsound to ignore the wealth of performance data generated by nearly a decade of SGIP program evaluations.[2] This data shows that CHP systems installed under SGIP have performed much worse than what was expected (and incentivized). Some CHP systems installed under SGIP have not remained in operation at all, and those in operation have performed at lower than expected levels of efficiency. Findings of systems funded by SGIP include:[3]

- Many CHP systems funded under the SGIP have ceased operating altogether; including 26 percent of those sampled in the April 2010 CHP Performance Investigation.
- CHP system capacity factors have declined by an average of 5.9 percent per year.
- CHP systems' hours of operation declined by an average of 8.2 percent per year.

1.3 Incentive Decline

In addition to the hybrid-PBI incentive mechanism, staff recommends that SGIP adopt a modest incentive decline, to facilitate self-sufficiency and cost reductions in the market for SGIP technologies. Staff recommends a 10 percent decline in incentives every two years. The first incentive decline shall occur on January 1, 2012.

1.4 Additional Program Modification Recommendations

Staff also recommends several additional modifications to SGIP design and program administration.

- Measurement & Evaluation (M&E) – M&E activities should be based on evaluating program impacts against Commission articulated program purpose and objectives. Staff recommended program purpose and objectives for SGIP are described in more detail in Section 4.1.

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[2] SGIP Program Evaluations can be found at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

[3] Self Generation Incentive Program, Combined Heat and Power Performance Investigation, Prepared by Summit Blue Consulting, April 2010. Available online at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

- Metering Requirements – As a condition of incentives, all SGIP projects should be required to install their own metering and provide metered performance data to program administrators on a quarterly basis. Previously, the SGIP M&E budget has funded metering at significant expense.
- Marketing and Outreach (M&O) – Program Administrators should improve marketing and outreach efforts to enhance program effectiveness. M&O activities should focus particular attention on identifying and addressing non-cost barriers to DER deployments in California.
- Export of Electricity to the Grid – Limited export of electricity from SGIP facilities may be allowable in certain circumstances to facilitate optimal and efficient sizing of DER. The requirement that projects be sized only to serve onsite load should be reconsidered in those situations where a tariff exists to compensate a system owner for excess generation, e.g. the CHP feed-in tariffs.
- Energy Efficiency Requirements – SGIP projects should be required to comply with energy efficiency audit requirements similar to California Solar Initiative (CSI) energy efficiency requirements in order to receive incentives. Before installing DER, SGIP customers should consider a range of energy efficiency opportunities in order to ensure their DER is sized appropriately for their site.
- Maximum Reservation Hold Time – Program Administrators should be required to report on a quarterly basis on all projects that have exceeded the 18-month timeline and the reason for any extensions to reservations in order to ensure unviable projects are not blocking the project reservation queue.

2. Background

On October 11, 2009, the Governor signed Senate Bill (SB) 412 (Stats. 2009, ch. 182) into law. Importantly, SB 412 authorizes the Commission, in consultation with the California Air Resources Board (ARB), to determine eligible technologies for the Self Generation Incentive Program (SGIP) based on the requirement that they "achieve reductions of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006." SB 412 also imposes several other changes on SGIP.

On November 13, 2009, ALJ Dorothy Duda issued a Ruling[4] in the Commission's distributed generation (DG) rulemaking (R.) 08-03-008, soliciting comments from parties on implementing the provisions of SB 412 and noticing a public workshop. The Ruling asked parties to consider several questions related to SB 412 implementation. Specifically, the Ruling asked for proposals of specific technologies that should be included in SGIP. Party comments and proposals were filed on December 15, 2009.

On January 7, 2010, the Energy Division held a public workshop to consider the questions posed in the Ruling and to discuss proposals put forth by parties. The agenda and all documents presented at the workshop are available from the CPUC's website, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/workshops.htm. Reply comments to the Ruling were filed after the workshop on January 19, 2010.

In the November 13, 2009 Ruling, ALJ Duda ordered the Energy Division to issue a report based on the workshop and party comments, including Energy Division recommendations on implementing SB 412. This Staff Proposal fulfills that obligation.

In May 2010, the Commission closed R.08-03-008 and opened a new rulemaking, R.10-05-004 to continue to handle matters related to the SGIP and CSI programs.

2.1 SGIP Overview

Commission Decision (D.) 01-03-073 launched SGIP in 2001 in response to Assembly Bill (AB) 970 (Ducheny, 2000), which required the Commission to initiate load control and distributed generation activities in response to the California energy crisis. The SGIP has become one of the largest distributed energy resources (DER) incentive programs in United States. At the end of 2009, SGIP included over 1,280 DER systems, representing over 340 MW of installed capacity.[5]

Historically, SGIP has provided capacity-based incentives for clean DER designed and installed to offset a customer's onsite electricity demand. Electricity and gas customers of Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Sou thern

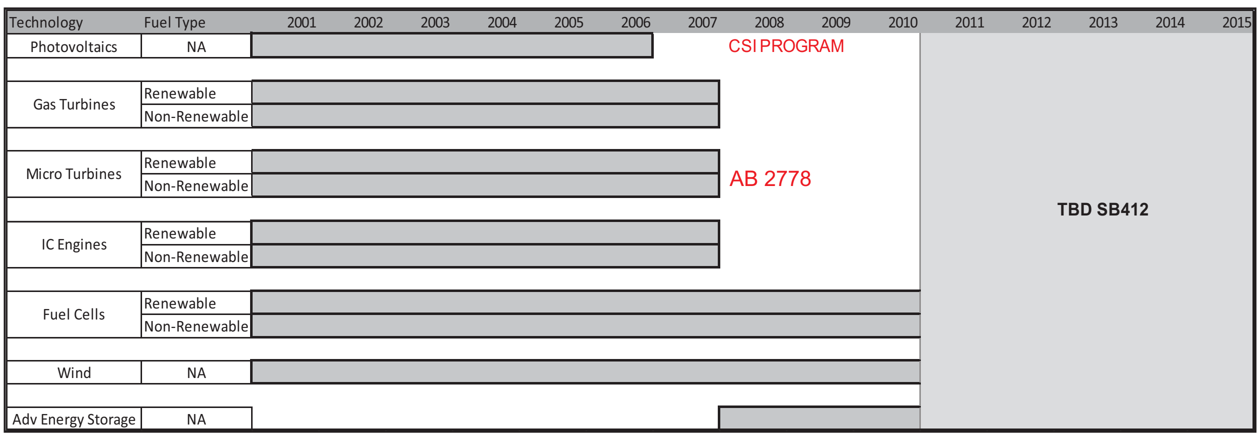
[4] The November 13, 2009 ALJ Ruling is available from the CPUC's website at, http://docs.cpuc.ca.gov/efile/RULINGS/109738.pdf

[5] More information on SGIP impacts can be found in the CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation, http://www.cpuc.ca.gov/NR/rdonlyres/11A75E09-31F8-4184-B3A4-2DCCB5FB0D2D/0/SGIP_Impact_Report_2008_Revised.pdf

California Gas Company (SCG), and San Diego Gas & Electric (SDG&E) are eligible. The SGIP is administered by PG&E, SCE, SCG, and California Center for Sustainable Energy in SDG&E's territory. The four Program Administrators (PAs) manage the day to day operations of the program in their respective territories, and the PAs administer the program in accordance with the SGIP Program Handbook.[6]

Eligible SGIP technologies have included both renewable and fossil fuel[7] powered systems. D. 01-03-073 originally established incentives for solar photovoltaics (PV), wind turbines, fuel cells, microturbines, internal combustion (IC) engines and gas turbines. Solar PV technologies were removed from SGIP beginning January 1, 2007 when the California Solar Initiative was created. Gas turbines, microturbines and IC engines were removed from the program beginning January 1, 2008, by AB 2778 (Stats. 2006, ch. 617), which limited SGIP to wind and fuel cell generating technologies only. In D. 08-11-044, the Commission included advanced energy storage (AES) technologies in SGIP, if the AES is coupled with a wind or fuel cell generating technology. Table 2 below shows all current and past SGIP technologies and their eligibility status by year.

Table 2. SGIP Technologies by year (shaded indicates eligible), 2001-present



SB 412 amended the statute relating to SGIP and removed the restriction that SGIP only provide incentives to wind and fuel cell generating technologies. In addition, SB 412 imposed several other changes to the program. Specifically, SB 412 did the following:

- Enables the CPUC to expand eligible technologies
  - The CPUC and ARB shall determine eligible technologies that will achieve reductions of greenhouse gas emissions.
  - The CPUC may consider other public policy interests, including, but not limited to, ratepayers, and energy efficiency, peak load reduction, load management, and environmental interests.

[6] More background information on SGIP, including legislative and regulatory history appears in the introduction of the SGIP Handbook, http://www.cpuc.ca.gov/NR/rdonlyres/F47DC448-2AEB-473F-98D8-CC0CC463194D/0/2010_SGIP_Handbookr4100506.pdf
[7] Fossil fueled systems were required to utilize waste heat through cogeneration, if combustion operated, or meet an electrical efficiency standard for fuel cells.

- Extends SGIP through 2015, and imposes limits on budget collections in future years.

- Requires fossil fueled combustion technologies to be adequately maintained so that during operation, they continue to meet or exceed the established efficiency and emissions standards.

- Requires the Commission to ensure that distributed generation resources are made available in the program for all ratepayers.[8]

2.2 SGIP Legal and Regulatory History

The CPUC's SGIP Website has archived links to numerous state laws and CPUC decisions and rulings.[9]

AB 970 (Ducheny, 2000)
Required the CPUC to initiate load control and distributed generation activities.

D. 01-03-073
- Established the Self Generation Incentive Program.
- Established incentives for solar photovoltaic technologies, wind turbines, fuel cells, microturbines, internal combustion engines and small gas turbines. All technologies using natural gas as a fuel source were required to meet waste heat recovery standards.

AB 1685 (Leno, 2003)
- Extended the SGIP through 2007.
- Established NO_x emissions standards for SGIP projects.

AB 1684 (Leno, 2004)
- Exempted projects that meet waste gas fuel and permitting requirements from NO_x emissions standards set forth in AB 1685.

D. 04-12-045
- Modified SGIP to incorporate provisions of AB 1685.
- Reduced incentive payments for most SGIP technologies.

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[8] Energy Division staff interprets this requirement to mean that all customer classes that contribute to SGIP through rates, including residential, commercial and industrial customer classes, shall be eligible for incentives. Historically SGIP had a minimum system size requirement of 30 kW, the result of which was that SGIP consisted primarily of commercial and industrial customers. Energy Division staff recommends only maintaining the 30 kW minimum size requirement for wind and renewable fuel cells, since the CEC's Emerging Renewables Program offers incentives to those same two technologies if they are less than 30 kW. For all other technologies, staff recommends no minimum size requirement and believes that this will ensure that incentives are available to residential customers as well as commercial and industrial customers.

[9] See CPUC Website: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/pucregprocess.htm

D. 06-01-024 (later modified by D.06-08-028 and D.06-12-033)

- Established the California Solar Initiative (CSI) and ordered changes to SGIP in 2006 in order to accommodate the transition of solar program elements from SGIP to CSI beginning January 1, 2007.

AB 2778 (Lieber, 2006)

- Extended SGIP until January 1, 2012.
- Limited eligible technologies beginning January 1, 2008 to fuel cells and wind systems that meet emissions standards required under the distributed generation certification program adopted by the State Air Resources Board.
- Requires that eligibility of non-renewable fuel cell projects be determined either by calculating electrical and process heat efficiency according to PU Code 216.6 or by calculating overall electrical efficiency.

D. 08-04-049

- Removed the 1 MW cap on incentives for 2008 and 2009 allowing projects to receive lower incentives on a tiered structure for the portion of a system over 1 MW.

AB 2267 (Fuentes, 2008)

- Established an incentive increase of 20% for SGIP projects from a California supplier, referred to as the "California Adder". This incentive increase applies only to the technology portion of the incentive; the incentive increase is not applied to any additional incentive provided to technologies using renewable fuel.

D. 08-11-044

- Determined that Advanced Energy Storage systems coupled with eligible SGIP technologies are eligible to receive an incentive of $2/watt.
- Revised the process for the review of SGIP program modification requests.

D. 09-09-048

- Granted a petition to modify SGIP, expanding eligibility for "renewable fuel" incentives to "directed biogas." Directed biogas includes renewable fuel that is injected into a natural gas pipeline and nominated for use at a SGIP facility via contract.

D. 09-12-047

- Ordered the SGIP Program Administrators (PAs) to hire an independent entity to conduct an SGIP audit. The purpose of this audit is to review accounting data, ratepayer collections and expenditures, confirmed reservations and dropouts, interest earned, and reasons for project extensions. The audit will also include recommendations on how SGIP PAs can be consistent and improve in areas of budget reporting and program oversight.

D. 10-02-017

- Revised D. 08-11-044 so that Advanced Energy Storage systems coupled with fuel cells must meet site specific requirements for on-site peak demand reduction and be capable of discharging fully at least once per day in order to be eligible for the $2/watt incentive.

- Determined that Advanced Energy Storage systems coupled with eligible technologies under the SGIP must install metering equipment capable of measuring and recording interval data on generation output and advanced energy storage charging and discharging.

3. SGIP Workshop Report

On January 7, 2010, the Energy Division held a public workshop to consider program changes to SGIP in light of SB 412. The workshop specifically considered the questions raised by ALJ Duda in the November 13, 2009 Ruling, and party comments filed in response to that Ruling.[10]

3.1 Questions from November 13, 2009 ALJ Ruling

The Ruling asked parties to respond to the following questions:

1. How do the new program requirements in SB 412 impact the existing SGIP? Should SGIP continue to offer technology differentiated incentives, or should the program consider a single incentive structure based on reductions in greenhouse gas emissions? What process should the Commission and ARB use to determine whether technologies meet the greenhouse gas emissions reduction requirement in SB 412?

2. Given SB 412, what new technologies should be considered for SGIP eligibility? (Parties interested in proposing specific technologies for consideration were asked to submit detailed proposals, paying particular attention to how the technology meets the greenhouse gas emissions reductions requirement in SB 412.)

3. What additional program modifications, if any, should be made to the SGIP in light of SB 412? Specifically, how should the Commission consider other public policy interests besides greenhouse gas emissions reductions in implementing SGIP? (Public Utilities Code Section 379.6 (e) authorizes the Commission, in administering SGIP, to "evaluate other public policy interests, including, but not limited to, ratepayers, and energy efficiency, peak load reduction, load management, and environmental interests.") In an effort to align the incentives with these policy objectives, should the SGIP consider performance based incentives, where projects are paid incentives based on actual production as opposed to an up-front, capacity-based incentive?

4. In light of the January 2016 sunset date for SGIP in SB 412, how should SGIP prepare to wind down? Should SGIP consider implementing a declining incentive structure to facilitate the transformation of DG markets so that DG technologies do not continue to rely on incentives beyond 2016? How might this declining incentive structure be designed?

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[10] An archived audio cast of the workshop is available online, http://www.californiaadmin.com/cgi-bin/cpuc.cgi

3.2 Workshop Overview

The workshop on January 7, 2010 considered the above questions and party responses to these questions filed by December 15, 2009 to the R. 08-03-008 docket. Party responses are available from the docket card for this proceeding, http://docs.cpuc.ca.gov/published/proceedings/R0803008.htm.

The workshop was divided into three main parts:[11]

- An overview of SGIP impacts from the program's inception to the present;
- A discussion of the questions raised in the ALJ Ruling; and
- Presentations of proposed technologies.

3.2.1 SGIP Overview

Energy Division staff opened the workshop with a high level overview of the program, followed by presentations from Itron and Summit Blue of ongoing measurement and evaluation (M&E) studies.[12] Itron and Summit Blue are consultants contracted by the SGIP Working Group to conduct M&E of the program.

Itron presented results from its most recent SGIP Impacts Evaluation, which was first released in June 2009 and reflected program impacts through 2008. The presentation highlighted energy and peak demand impacts as well as GHG emissions impacts of SGIP projects installed since the program's inception. The workshop presentation and the complete evaluation report are available online:

- SB 412 workshop presentation on SGIP Impacts (January 7, 2010), http://www.cpuc.ca.gov/NR/rdonlyres/0DF241E8-EE28-4754-8348-2CB76D0333A5/0/Presentation2SGIPImpacts.pdf
- "CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation" (July 2009), http://www.cpuc.ca.gov/NR/rdonlyres/11A75E09-31F8-4184-B3A4-2DCCB5FB0D2D/0/SGIP_Impact_Report_2008_Revised.pdf

Next, Summit Blue presented preliminary findings from two forthcoming measurement and evaluation reports. Summit Blue's presentation focused primarily on research undertaken as part of its Market Characterization Report, which included a review of clean distributed generation technologies that might be considered for eligibility under SGIP.[13] Summit Blue then discussed preliminary results of participant and industry interviews conducted for its forthcoming Market-Focused Process Evaluation related to performance based incentives. The Market-Focused Process Evaluation was released in

[11] The workshop agenda is available from the CPUC's website at, http://www.cpuc.ca.gov/NR/rdonlyres/C0CDEB0A-58E0-4F14-B7CA-D197A17C001B/0/WorkshopAgendaFINALSB412.pdf

[12] All workshop presentations are available from the CPUC's website, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/workshops.htm

[13] Market Characterization Report is available here: http://www.cpuc.ca.gov/NR/rdonlyres/EAEF4051-300A-4915-948F-FAD8E706F8AB/0/SGIP_market_characterization_report.pdf

May 2010. This report, and all other SGIP reports, can be accessed online at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/

3.2.2 Discussion

Following the presentations from the M&E consultants, Energy Division staff led a discussion to solicit feedback from parties on potential program modifications to the SGIP. Staff pointed out that the questions posed in the ALJ Ruling and in the workshop did not imply that the CPUC would necessarily make any major changes to the program. SB 412 required the CPUC to determine that SGIP technologies reduce GHG but did not impose any greater requirement for program modifications.

However, staff felt that SB 412 provided an opportunity to take a closer look at the program and the market for DER and consider whether program changes may be appropriate. Staff clarified that the intent of the workshop was to generate discussion to inform staff's recommendations.

Energy Division staff divided the discussion into four parts, based on four sets of questions:

1. What should be the objectives and goals of SGIP?
2. What should be the basis for determining incentives?
3. How should SGIP ensure performance?
4. Additional Considerations
    a. Generation for export: Should DER that export power for sale be eligible for SGIP?
    b. Locational preference: Should SGIP target DER located in high-value areas? How should those high-value areas be defined? How should SGIP incentives be designed to encourage locating DER in those areas?
    c. Declining Incentives: Should SGIP consider implementing a declining incentive structure? How might this declining incentive structure be designed?
    d. Energy Efficiency: How should SGIP support complementary demand side management at host sites such as energy efficiency?
    e. Allocation: How should budget be allocated across various technology groups?

Energy Division staff facilitated the discussion, which provided an opportunity for workshop participants to provide direct input to staff. The recommendations below reflect this input, as well as formal comments and informal conversations with parties and experts.

3.2.3 Technology Presentations

In comments filed on December 15, 2009, several parties submitted proposals for inclusion of new technologies pursuant to question #2 of the Ruling. Those parties included:

- California Energy Storage Alliance (CESA) – energy storage
- California Clean Distributed Generation Coalition (CCDC) – combustion-based combined heat and power (CHP) technologies including gas turbines, reciprocating engines, microturbines, micro engines, and steam turbines
- TAS and Waste Heat Solutions – waste heat organic Rankine cycle (ORC) engines
- Guardian Industries – waste heat organic Rankine cycle (ORC) engines
- Capstone Turbines – microturbines
- Zeropex AS – pressure reduction turbines
- PVT Solar, Inc. – solar combined heat and power (CHP)

After reviewing the proposals, Energy Division staff spoke with each individual party. With the exception of PVT Solar, each party made a presentation of its proposal at the workshop.[14] Parties that proposed the same or similar technologies presented jointly. Presentations for new technologies took place in the afternoon session of the workshop in the following order:[15]

1. California Clean DG Coalition (CCDC) and Capstone Turbines:
    - Combined Heat and Power (CHP)

2. California Energy Storage Alliance (CESA):
    - Energy Storage

3. TAS, Waste Heat Solutions and Guardian Industries:
    - Waste Heat Organic Rankine Cycle (ORC) engines

4. Zeropex:
    - Pressure Reduction Turbines

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[14] After several meetings between PVT Solar and Energy Division staff the two parties determined that PVT's technology more appropriately belongs in the California Solar Initiative (CSI) and CSI-Thermal programs.

[15] All of the technology proposal presentations are available from the CPUC's website, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/workshops.htm

4. Staff Proposal

Staff recommends that the Commission consider modifications described herein to the SGIP, including clarification of program purpose and objectives, changes to the incentive structure, and changes to SGIP eligibility requirements. These recommendations are intended to improve program implementation and ensure that ratepayers receive the greatest benefit from their investment in the SGIP.

4.1 Program Principles

Staff recommends that the Commission articulate a clear purpose for the SGIP, which is essential for a successful program. Clear articulation of this purpose will guide Energy Division staff and program administrators through the program implementation.

4.1.1 Program Purpose

In D. 01-03-073, the Commission stated the rationale of establishing SGIP as follows,

> "In AB 970, the California legislature demonstrated that renewable technologies and self-generation are a policy priority. Self-generation and the use of renewables can provide significant benefits to Californians by improving the quality and reliability of the state's electricity distribution network, which is critical to the state's economic vitality, while protecting the environment and developing "green" technologies. The statute directs the Commission to adopt incentives for distributed generation to be paid for enhancing reliability, and differential incentives for 'renewable or super-clean distributed generation resources.'
>
> The self-generation incentives provided through this program are intended to:
>
> - Encourage the deployment of distributed generation in California to reduce the peak electric demand;[16]
> - Give preference to new renewable energy capacity; and
> - Ensure deployment of clean self-generation technologies having low and zero operational emissions."[17]

While the SGIP has always had a focus on low or zero emissions technologies, GHG emissions in particular were not identified as a criterion for eligibility until now. SB 412

[16] For this reason, self-generators installed primarily as backup or emergency power are not eligible for the program.

[17] D. 01-03-073, "Attachment 1: Adopted Programs to Fulfill AB970 Load Control and Distributed Generation Requirements," pp. 22-23.

clarifies that eligibility for incentives shall be based on GHG emissions reductions, but also recognizes that "other public policy interests" may be considered in developing the program.

Based on SB 412, Energy Division staff recommends that the Commission revisit the purpose of the SGIP, and clearly articulate the policy objectives going forward in order to guide program implementation. Many of the principles that guided the development of the SGIP, such as peak demand reduction, and development of clean self generation technologies, remain important.

Staff recommends the Commission adopt the following statement of purpose.

Proposed SGIP Statement of Purpose:

Through the provision of incentives to clean DER technologies, SGIP should contribute meaningfully to:

- Reduced customer electricity purchases and demand reduction;
- Electric system reliability through improved transmission and distribution system utilization;
- GHG emissions reductions in the electricity sector; and
- Market transformation for clean DER technologies.

4.1.2 Guiding Principles

In addition to the above statement of purpose, staff recommends that the Commission adopt the following set of guiding principles for evaluating new technologies and informing program design modifications. Staff recommends that the first three guiding principles should be the primary criteria used to evaluate technologies for SGIP eligibility. These three guiding principles are discussed throughout this document as the three "screens" for assessing technology eligibility. Staff recommends that the other guiding principles be considered in evaluating technologies for eligibility, and or in designing details of the SGIP. All of the proposed guiding principles were considered by staff in developing the recommendations in this proposal.

Proposed SGIP Guiding Principles:

1. SGIP should only support DER technologies that are cost-effective, or represent the potential to achieve cost-effectiveness in the near future.
2. SGIP should only support technologies that produce fewer GHG emissions than they avoid from the grid.
3. SGIP incentives should provide sufficient payment to stimulate DER technology deployment without overpaying. SGIP incentives should not be provided to technologies that do not need them to earn a reasonable return on investment.

4. SGIP should support behind the meter "self-generation" DER technologies, which serve the primary purpose of offsetting some or all of a host-customer's on-site demand.
5. SGIP should only support commercially available technologies.
6. SGIP should target best of class DER by paying for performance.
7. SGIP incentives should focus on projects that efficiently utilize the existing transmission and distribution system.
8. SGIP should complement the structure of and be coordinated with existing ratepayer supported programs, especially the California Solar Initiative, which is aimed at transforming the market for renewable distributed generation by driving down prices and increasing performance of DER.

4.2 Technologies Considered for Potential SGIP Eligibility

In its analysis of potential technologies for inclusion in SGIP, staff considered eight technologies operating in a variety of applications with both renewable and non-renewable fuel sources, including previously eligible SGIP technologies[18] and several additional technologies that were proposed for inclusion in the program by parties. The technologies and fuel/applications considered are shown in Table 3. Staff notes that the forthcoming SGIP cost-effectiveness evaluation will consider SGIP technologies under three different fueling scenarios: renewable fuel, non-renewable fuel, and directed biogas. This staff proposal, when framed in early 2010, did not incorporate directed biogas as a specific technology application. Depending on the outcome of the cost-effectiveness evaluation, it may be necessary to modify this staff proposal to consider directed biogas on a per technology basis.

Since its inception, the SGIP has provided incentives only to technologies that are commercially available, and staff recommends in guiding Principle #4 that the SGIP maintain this criterion. The list of technologies, which represents technologies explicitly proposed for inclusion in the SGIP, while not inclusive of all DER technologies, does represent those DER technologies that staff believes are commercially available today. As new DER technologies emerge from research and development toward commercial availability, the same process for evaluating technologies described in this proposal may be applied.

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[18] Solar PV and other solar-based technologies were not considered, since these technologies are eligible for incentives through the California Solar Initiative (CSI) and CSI Thermal programs.

Table 3. SGIP Technologies Considered for Eligibility

Technology	Fuel/Application	Current SGIP Status
Wind Turbines	Wind	Currently Eligible
Fuel Cells	Non-Renewable, Electric only	Currently Eligible
	Non-Renewable, CHP	Currently Eligible
	Renewable, Electric only or CHP	Currently Eligible
Gas Turbines	Non-Renewable, CHP	Previously Eligible
	Renewable, Electric only or CHP	Previously Eligible
Microturbines	Non-Renewable, CHP	Previously Eligible
	Renewable, Electric only or CHP	Previously Eligible
Internal Combustion Engines	Non-Renewable, CHP	Previously Eligible
	Renewable, Electric only or CHP	Previously Eligible
Organic Rankine Cycle Engines	Waste Heat, Bottoming Cycle CHP	Proposed
Pressure-reduction Turbines	In-conduit hydroelectric	Proposed
Advanced Energy Storage	Stand-alone	Proposed
	DG-integrated	Currently Eligible*

*Currently limited to applications where AES is coupled with wind and/or fuel cells only.

4.2.1 Cost-Effectiveness

The first guiding principle recommended above is that SGIP should only support DER technologies that are cost-effective or represent the potential to be cost-effective in the near future. Cost-effectiveness is an important measure that this Commission uses in determining how to allocate limited ratepayer funds. The SGIP program evaluator will use the years 2015 and 2020 in examining the cost-effectiveness of various technologies on a prospective basis. Staff does not make a firm recommendation of whether to use the 2015 or 2020 date as a deadline for the cost-effectiveness screen.

In D. 09-08-026, the Commission adopted a methodology for evaluating the cost-effectiveness of distributed generation (DG). In that Decision, the Commission stated that, "The primary purpose of this inquiry into cost-benefit methodologies is to assure that the state's support for DG projects, such as those funded through the Commission's Self-Generation Incentive Program (SGIP)[19] and the California Solar Initiative (CSI), is

[19] Effective January 1, 2008, Pub. Util. Code § 379.6 limits SGIP eligibility to wind and fuel cell technologies. The cost-benefit methodology adopted in this order will apply to all technologies that may have received incentives under SGIP prior to 2008, such as solar photovoltaics, microturbines, internal combustion engines, and combined heat and power plants.

evaluated in an economically sound manner." That Decision approved three cost-effectiveness tests for evaluating distributed generation, the Participant Test, the Total Resource Cost (TRC) Test, and the Program Administrator Cost Test.

Staff recommends that the TRC, which is the most comprehensive of the cost-effectiveness tests, should be the basis of determining eligibility for future SGIP projects. Technologies must achieve - or have the potential to achieve - a TRC benefit-cost ratio of greater than 1 in the near future.

This policy objective that SGIP fund technologies that have a potential to be cost-effective in the near or medium term is not a current requirement for SGIP eligibility. However, it is consistent with many of the other demand side management programs the Commission oversees, including the IOU's energy efficiency programs. Staff recommends that investment of ratepayer funds in the amount that has been authorized for SGIP should be made to technologies that are cost-effective or represent the potential to become cost-effective in the near future.

A cost-effectiveness analysis of SGIP based on the methodology approved in D. 09-08-026 is currently being conducted by a consultant and is expected to be finalized in the fall of 2010. Staff recommends that the results of this analysis be considered by the Commission in determining which technologies should be eligible for incentives under the SGIP.

In the analysis presented below, staff did not attempt to replicate the cost-effectiveness evaluation currently being conducted under contract, nor does staff intend to prejudge that evaluation. Staff intends to update the Staff Proposal recommendations with respect to cost-effectiveness once the results of the consultant study are available, and therefore the results of the cost-effectiveness screen are reported as "to be determined" (TBD) in Table 6 on page 29.

4.2.2 GHG Reductions Requirement

Public Utilities (PU) Code Section 379.6 (a) (2) states that, "Eligibility for incentives under the [SGIP] program shall be limited to distributed energy resources that the commission, in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code)." SB 412 also states that the CPUC may consider other public policy interests in determining program eligibility. Energy Division staff consulted with ARB staff in the GHG emissions analysis described in this section.

Staff's second guiding principle states that the SGIP should only support technologies and/or specific products that produce fewer GHG emissions than they avoid from the grid. Thus staff recommends that GHG emissions reductions be one criterion of three primary criteria used to determine eligibility in the SGIP.

Staff proposes a GHG emissions-screening test for proposed technologies. Technologies that pass this screen may be eligible for the SGIP. Whether a technology is ultimately included in the program, and the amount of any incentive will be determined only after the cost-effectiveness screen, the GHG screen, and the need for financial incentives screen. Passing the GHG emissions screen does not by itself indicate that a technology will be eligible for incentives. However, technologies that do not pass the screen shall not be considered, since this would violate PU Code Section 379.6 (a) (2). Ideally the GHG screen is applied on a technology-wide basis, and in most cases, that is what staff recommends. In the case of electric only fuel cells and natural gas powered microturbines, the proposed technologies show a wide range of product dependent configurations – and those technologies will need to be evaluated on a per product basis.

The GHG emissions screening methodology developed by staff looked at each technology using reasonable assumptions about expected performance of the technology and the GHG emissions from the grid that would be avoided. Assumptions about expected performance are explained in greater detail in Appendix A, which discusses the GHG emissions screen methodology. The GHG emission screen methodology is applied to each technology configuration in an Excel worksheet, available on the Energy Division's SGIP Web site: www.cpuc.ca.gov/PUC/Energy/DistGen/SGIP

To provide flexibility for technologies that are not approved on an upfront technology basis, staff recommends a per-product GHG reductions verification option. Under this option, a manufacturer would have to submit their specific product specifications for PA verification of stated performance. The PAs would pre-establish a methodology for determining GHG reductions, the same or similar to that used on a technology wide basis herein, and determine whether a particular product could be placed on an eligibility list.

Renewable technologies were deemed de facto eligible, as they were assumed to produce zero emissions from generation. In the case of directed biogas, this de facto assumption becomes more complex as the molecules being used are actually natural gas, and because different baselines (i.e. flaring vs. venting) greatly alter the GHG reduction benefits. Therefore, staff's analysis focused on natural gas-fueled technologies and energy storage. Results of this analysis appear in Table 4 below.[20]

[20] Staff's proposed methodology is explained in Appendix A.

Table 4. GHG Emissions Reduction Screening Results

Technology	Fuel/Application	GHG Reducing
Wind Turbines	Wind	Yes – Renewable
Fuel Cells	Non-Renewable/Electric only	No – Except potentially on a per product basis
	Non-Renewable/CHP	Yes
	Renewable/Electric only or CHP	Yes – Renewable
Gas Turbines	Non-Renewable/CHP	Yes
	Renewable/Electric only or CHP	Yes – Renewable
Microturbines	Non-Renewable/CHP	No[21]– Except potentially on a per product basis
	Renewable/Electric only or CHP	Yes – Renewable
Internal Combustion Engines	Non-Renewable/CHP – lean burn Non-Renewable/CHP – rich burn	Yes – lean burn No – rich burn
	Renewable/Electric only or CHP	Yes – Renewable
Organic Rankine Cycle Engines	Waste Heat/Bottoming Cycle CHP	Yes
Pressure-reduction Turbines	Hydro/In-conduit	Yes – Renewable
Advanced Energy Storage	Stand-alone	No
	DG-integrated	Yes

4.2.3 Need for Financial Incentives

The third guiding principle states that, "SGIP incentives should provide sufficient payment to stimulate DER technology deployment without overpaying. SGIP incentives should not be provided to technologies that do not need them."

Above, staff recommends that only those technologies, which are cost effective or represent the potential to become cost effective in the near future using the TRC test, should be considered for eligibility. While it may seem intuitive that if a technology is cost-effective then it shouldn't need an incentive from SGIP, this is not necessarily the case. For several reasons, technologies that meet the TRC cost effectiveness test may

[21] Discussed in more detail in Section 4.6.3.

require additional support in order to achieve broad customer adoption. Those reasons include:

- Positive Externalities – DER technologies may provide benefits to the grid, which do not provide direct financial benefit to the end-use customer. These benefits may include GHG emissions reductions, grid reliability, and transmission and distribution infrastructure investment deferral.
- Market Transformation Objectives – Technologies that may not be cost-effective today, but have the potential to be cost-effective in the near future, can be supported along the path toward cost-effectiveness through incentives. By facilitating greater deployment of these technologies, SGIP may help these technologies achieve economies-of-scale, which can drive down costs. However, SGIP is likely to only be a small part of the global market for these technologies, and staff does not expect that the California market can play a significant (or measurable) role in market transformation.
- Overcoming Investment Risk – Technologies that may be marginally cost-effective for end-use customers may not experience widespread adoption because of perceived investment risk. By increasing the potential rate of return for customers, incentives can encourage greater adoption of newer technologies.

Staff's review of DER technology costs, sought to answer two questions:

1. Do the proposed technologies require an incentive to achieve a reasonable return on investment for the customer?
2. What is the impact of SGIP incentives on customer return on investment?

Based on the answer to these two questions, staff makes a recommendation about whether the technology needs financial incentives.

In order to complete this analysis, staff relied on available SGIP programmatic project cost data as well as data obtained through conversations with technology manufacturers and DER project developers. Staff relied on these resources to develop assumptions about technology capital costs, operations and maintenance (O&M) costs, fuel costs, electricity costs, expected operational life, and expected performance of each technology. A complete description of the inputs and assumptions used to complete this analysis for all electricity generating technologies appears in Appendix B. An Excel workbook demonstrating the application of this methodology is available from the Energy Division's website at: www.cpuc.ca.gov/PUC/Energy/DistGen/SGIP
Parties may use this appendix to inform their comments.
For energy storage, because the operational characteristics of these technologies are more dependent on the specific energy storage technology and application, staff relied on analysis conducted for an Energy Division staff white paper in 2009. The white paper appears in Appendix C. The white paper explicitly considers customer investment in energy storage as a stand-alone resource and in applications where it is coupled with distributed solar PV.

Table 5 shows the staff calculated internal rate of return (IRR) and simple payback for each technology considered with and without SGIP incentives. Based on these results, it appears that some of the technologies considered do not require incentives to achieve a reasonable return on investment for the customer. Staff considered a 15% IRR (without incentives) reasonable for the purposes of this analysis. This figure represents the mid-range of observed rates of return in capital equipment purchases and is in line with the cutoff for IRRs used by the Commission in 2006 when considering the initial California Solar Initiative rebate level for commercial solar PV installations.

Staff acknowledges that its analysis is simplified and does not take into account all of the costs and benefits associated with each technology. Furthermore, the analysis relied on a number of assumptions, and therefore actual individual project economics may differ from what is shown here. However, the analysis is meant to be an approximation, and the assumptions used are generally conservative and therefore tend to favor a conclusion of financial incentive need for the various technologies considered.

Table 5. IRR for Technologies with and without SGIP incentives

		No Incentives		Current or Previous Incentive Levels			Need for Financial Incentives
Technology Type	Sample System Size (kW)	IRR	Simple Payback (Years)	Current/ Previous Incentive ($/Watt)	IRR	Simple Payback (Years)	
Wind	387	17%	6.6	$ 1.50	26%	4.4	Incon-clusive
Fuel Cell – Electric Only/NG	100	-14%	NA	$ 2.50	-4%	NA	Yes
Fuel Cell – CHP/NG	400	-9%	NA	$ 2.50	1%	9.4	Yes
Fuel Cell – Biogas	400	-6%	NA	$ 4.50	6%	6.6	Yes
Gas Turbine – CHP/NG	1000	13%	6	$ 0.60	21%	4.6	Yes
Gas Turbine – Biogas	1000	3%	8.9	$1.00	8%	6.9	Yes
Microturbine – CHP/NG	165	-2%	NA	$ 0.80	5%	7.6	Yes
Microturbine – Biogas	165	-12%	NA	$ 1.30	-6%	NA	Yes
IC Engine – CHP/NG	800	16%	5.6	$ 0.60	24%	4.4	No
IC Engine – Biogas	800	3%	8.9	$ 1.00	8%	7.0	Yes
Organic Rankine Cycle	100	33%	3.8	NA	NA	NA	No
Advanced Energy Storage, stand-alone[22]	n/a	0-6%	12-22	$ 2.00	0-17%	5-17	Yes
Advanced Energy Storage, DG-integrated (Solar PV)[23]	n/a	1.9-5.8%	13-22	$ 2.00	3-7.6%	10-20	Yes
Pressure Reduction	100	50%	3.0	NA	NA	NA	No

[22] The analysis in Appendix C assumes slightly different characteristics for energy storage systems than the GHG emissions analysis in Appendix A. Namely, Appendix C considers energy storage systems with 6 hours of discharge capability at rated capacity.

[23] The analysis in Appendix C considered the IRR and payback of the combined energy storage and solar PV system, assuming a CSI PBI incentive of $0.15/kWh over five years for the solar.

Most technologies listed show a low rate of return – demonstrating that there is a need for financial incentives. Some exceptions and special cases are noted below.

- Waste Heat ORC engines and Pressure Reduction Turbines show the highest rates of return, 33% and 50% respectively. These extremely high rates of return demonstrate these technologies do not need financial incentives.
- In addition, CHP gas turbines and IC Engines using natural gas can achieve rates of return of 13% and 16% respectively. The CHP gas turbine and IC engine results are considered borderline since there are so many assumptions built into the model.
- Fuel cells show a negative rate of return. Fuel cells are currently participating in SGIP, with directed biogas projects being by far the most common. The recent proliferation of fuel cells in the program is likely due to project-specific characteristics, the California adder of 20% for products manufactured in California, and/or the tiered incentives for projects over 1 MW.
- The cost data staff used to analyze wind project financial need is extremely limited due to the fact that only 2 wind projects have successfully been installed through SGIP. In the proposal below, staff notes several additional challenges to wind development, which impact project specific costs, such as project siting and permitting challenges. Therefore, staff recommends that incentives for wind continue to be offered at the same levels as currently offered until more data is available on SGIP wind project costs.
- Although the stand-alone storage analysis demonstrates that there may be some need for financial support for that technology, staff recommends that the Commission wait until the utilities have completed the cost-effectiveness evaluation of their permanent load shifting (PLS) pilot programs, undertaken in their Demand Response portfolios, before determining whether to include stand-alone storage in SGIP.

4.3 Technology Recommendations

Staff recommends that only those technologies that meet the first guiding principle of cost-effectiveness, the second guiding principle of GHG reducing, and the third guiding principle of financial need, be eligible for SGIP. Table 6 summarizes the results of staff's analysis. Because the results of the SGIP cost-effectiveness evaluation results are not yet available, this criterion will not be applied at this time.

All of the technologies in Table 6 below are discussed in greater detail below. For technologies that are recommended for inclusion in SGIP, staff recommends the Commission adopt technology-specific minimum operating requirements to ensure that technologies perform as expected.

Table 6. SGIP Technology Eligibility Analysis Preliminary Results

Technology	Fuel/ Application	Current SGIP Eligibility Status	Cost-Effectiveness	GHG Reductions	Need for Financial Incentives	Preliminary Recommendation[24]
Wind Turbines	Wind	Currently Eligible	*TBD*	*Yes*	*Inconclusive*	Include as Pre-approved
Fuel Cells	Non-Renewable, Electric only	Currently Eligible	*TBD*	*No***	*Yes*	No, Except Potentially on a Per-Product Basis
	Non-Renewable, CHP	Currently Eligible	*TBD*	*Yes*	*Yes*	Include as Pre-approved
	Renewable, Electric only or CHP	Currently Eligible	*TBD*	*Yes*	*Yes*	Include as Pre-approved
Gas Turbines	Non-Renewable, CHP	Previously Eligible (thru '08)	*TBD*	*Yes*	*Yes*	Include as Pre-approved
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	*TBD*	*Yes*	*Yes*	Include as Pre-approved
Micro-turbines	Non-Renewable, CHP	Previously Eligible (thru '08)	*TBD*	*No****	*Yes*	No, Except Potentially on a Per-Product Basis
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	*TBD*	*Yes*	*Yes*	Include as Pre-approved
Internal Combustion Engines	Non-Renewable, CHP	Previously Eligible (thru '08)	*TBD*	*Lean burn - Yes Rich burn - No*	*No*	No
	Renewable, Electric only or CHP	Previously Eligible (thru '08)	*TBD*	*Yes*	*Yes*	Include as Pre-approved
Organic Rankine Cycle	Waste Heat, Bottoming Cycle CHP	Proposed	*TBD*	*Yes*	*No*	No
Energy Storage	Stand-alone	Proposed	*TBD*	*Yes*	*Yes*	Not at this time
	DG-integrated	Currently Eligible*	*TBD*	*Yes*	*Yes*	Include as Pre-approved
Pressure-reduction Turbines	In-conduit hydroelectric	Proposed	*TBD*	*Yes*	*No*	No

[24] Requires Cost-Effectiveness Results Prior to Final Recommendation.

Notes:
*Currently limited to applications where Energy Storage is coupled with wind and/or fuel cells. Staff recommends that Energy Storage be included as eligible if coupled with any renewable DG technology, including solar PV. Staff recommends that the Commission wait until the utilities have completed the cost-effectiveness evaluation of their permanent load shifting (PLS) pilot programs, undertaken in their Demand Response portfolios, before determining whether to include stand-alone storage in SGIP.
** These technologies are not GHG reducing using minimum efficiency standards as required by statute. To achieve GHG reductions, these technologies would have to perform on a per product basis at a higher level.

4.3.1 Wind

There has been very little participation from wind turbines in SGIP. The reasons for this level of participation have been studied in SGIP market characterization reports.[25] The issues cited in the reports include the difficulties associated with siting, building and installing wind turbines for self-generation in the size range eligible for the SGIP. Cost has not been identified as a primary challenge. There also may be challenges associated with the fact that wind projects are only eligible for full retail NEM up to the first 50 kW of generation, as opposed to solar where full retail NEM is available up to 1 MW of generation. The Emerging Renewables Program, overseen by the California Energy Commission, offers rebates for wind projects under 30 kW. Over 100 wind projects have been developed through the ERP program. A California Energy Commission study in July 2009 examined the wind marketplace and the need for incentives for wind.[26]

Staff's analysis of SGIP wind project costs indicates that wind turbines may not require incentives to achieve a reasonable customer payback. Without incentives, staff's analysis indicates that an IRR of 15% is possible for wind turbine systems. We note that the data used to calculate this relies on a very limited dataset of the SGIP project database and several important assumptions. The cost information was based on two wind projects that have successfully completed projects through the SGIP. The permitting and siting challenges associated with wind development likely result in vastly different project development costs from one project to another. The projects that have been successfully developed through the SGIP may have had few challenges compared to the wind projects that have not been developed. Therefore, it is unclear whether the costs of developing and permitting a new distributed wind project are accurately reflected in this limited data.

The other important assumption used in this analysis is the capacity factor assumed for these wind projects. Staff assumed a capacity factor of 30%, which may be high for a distributed wind project in a less than ideal wind zone. By decreasing the capacity factor to 22%, the IRR of a wind turbine without any incentive drops to less than 11%. It may

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[25] The most recent Market Characterization Report conducted for SGIP was completed in February 2010 and is available on the CPUC website, http://www.cpuc.ca.gov/NR/rdonlyres/EAEF4051-300A-4915-948F-FAD8E706F8AB/0/SGIP_market_characterization_report.pdf.
[26] California Energy Commission, Emerging Renewables Program, Small Wind Incentive Study, July 2009, Prepared by Kema. Available here: http://www.energy.ca.gov/2009publications/CEC-300-2009-003/CEC-300-2009-003.PDF.

be appropriate to lower the expected capacity factor given that distributed wind projects need to be developed where there is customer interest and corresponding load, not just where there is an idealized wind speed. It is difficult to determine what realistic capacity factors would be for wind in the size ranges eligible for the SGIP and meeting all of the other program eligibility requirements. Staff encourages specific information from parties that can help improve its analysis and help inform the Commission's decision-making.

As a result of these tremendous uncertainties, staff is cautious about any recommendation that would exclude wind from the SGIP. Since wind generation represents potential for significant GHG emissions reductions, and since wind technology, though proven at larger scales, has not seen much penetration in the SGIP, staff recommends retaining wind in the program. Furthermore, staff recommends that the SGIP marketing and outreach (M&O) efforts focus increased attention on addressing the other market barriers that have prevented greater adoption of wind.

4.3.2 Fuel Cells

Currently, SGIP provides two different incentive levels for fuel cells operating in four different configurations. Eligibility requirements for fuel cells differ whether they are operating as CHP or electric only, and also depending on the type of fuel they use. These are described in the table below.

Table 7. Current SGIP eligibility status for fuel cells

System Configuration		Electric Only	CHP
Fuel Type / Incentive Level	Non-renewable	\$2.50/W incentive; 40% electrical efficiency requirement	\$2.50/W incentive; PU Code Section 216.6 efficiency requirement[27]
	Renewable	\$4.50/W incentive; No minimum efficiency required	\$4.50/W incentive; PU Code Section 216.6 efficiency requirement

As staff's analysis indicates, fuel cells operating in each of these configurations can have significantly different impacts. In particular, electric-only fuel cells fueled with non-renewable natural gas do not result in GHG emissions reductions relative to the grid. Therefore, staff recommends that only the following types of fuel cells with the following performance requirements should be eligible for SGIP incentives.

CHP Fuel Cells / Non-renewable - Currently, fuel cells using a non-renewable fuel may either meet a 40% electrical efficiency or a CHP efficiency of 42.5% based on PU Code

[27] PU Code Section 216.6 requires that "cogeneration" systems use at least 5% of their energy output as useful thermal energy. It also requires that cogeneration systems achieve 42.5% efficiency calculated as annual electrical energy output plus one-half of the annual thermal energy output divided by the annual fuel energy input.

Section 216.6 in order to qualify for SGIP incentives. Staff's analysis suggests that both of these standards are too low to ensure that fuel cells will reduce GHG emissions pursuant to SB 412. Therefore, staff recommends that the SGIP adopt the 62% total system efficiency standard adopted by the CEC pursuant to PUC Section 2843.[28] This standard was set forth in the Waste Heat and Carbon Emissions Reduction Act, which has objectives similar to the SGIP, including GHG emission reductions from distributed CHP generation. Staff feels that this efficiency standard represents an appropriate standard for small CHP technologies, and will ensure that CHP fuel cells reduce GHG emissions. Furthermore, staff recommends that if these guidelines are updated by the CEC at any time, the updated guidelines should apply to SGIP projects on a going forward basis.

Fuel Cells / Renewable / CHP and Electric-only – Staff's analysis of renewable fuel projects considered biogas applications where biomass is converted to biogas through anaerobic digestion and combusted in a generator located on the same site. The availability of useful thermal applications located on the same site as a renewable fuel source can be a limiting factor for CHP using renewable fuel. However, since renewable fuel generation technologies do not produce any GHG emissions from generation, there is no need to require minimum CHP efficiency standards in order to ensure GHG emissions reductions. GHG emissions reductions will be achieved simply through the generation of electricity using a renewable fuel.

Therefore, staff recommends that fuel cells using renewable fuel not be required to operate as CHP, and not be required to meet a minimum efficiency standard. Staff notes that the additional savings from operating as CHP and the performance based incentive, shall motivate renewable fuel cell customers to operate their systems as efficiently as possible. This scenario is demonstrated by SGIP Program Evaluation reports, which show that the majority of renewable CHP customers are utilizing waste heat even though they are not explicitly required to do so. However, the evaluation reports and this analysis only apply to onsite biogas.

In the very different case of directed biogas projects – which do not require additional capital equipment but may have higher fuel costs – staff notes that minimum efficiency standards may or may not support the goals of the SGIP. Instead, the more relevant question is whether there is a financial need for an incentive. Comments on minimum efficiency requirements for directed biogas contracts are welcomed.

[28] California Energy Commission, Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act, Public Utilities Code, Section 2840 Et Seq. January 2010. Available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-016/CEC-200-2009-016-CTF.PDF

Table 8: Recommended SGIP eligibility status for fuel cells

System Configuration		Electric Only	CHP
Fuel Type / Incentive Level	Non-renewable	Not eligible except on a per product basis dependent on GHG results	CEC guidelines for CHP pursuant to PU Code Section 2843
	Renewable	No minimum efficiency	No minimum efficiency

4.3.3 Combustion Technologies

Combustion technologies, including Gas Turbines, IC Engines, and Microturbines are not currently eligible for SGIP incentives. Previously these technologies were eligible for incentives if they operated as CHP at certain minimum efficiency levels or if they operated using a renewable fuel. Each of these cases is addressed below.

Combustion, CHP/Natural Gas - Staff analysis indicates that there is only one CHP combustion technology using natural gas that can achieve reliable GHG emissions reductions and demonstrate a financial need: the gas turbine. Therefore, staff recommends that the gas turbine technology be pre-approved for inclusion in the SGIP, when using natural gas. As noted in section 4.2.2, manufacturers of microturbine natural gas CHP systems may opt to have their product tested. If performance meets required standards for GHG reductions, this product would be recommended as eligible for SGIP incentives. Staff does not recommend providing incentives for natural gas powered IC Engines.

Staff's analysis suggests that some combustion technologies using natural gas and operating as CHP can provide GHG emissions reductions. However, whether a technology reduces GHG emissions depends both on the electrical efficiency of the technology and the overall CHP efficiency of the technology. Technologies with very low electrical conversion efficiencies, must achieve much higher overall CHP efficiencies in order reduce GHG emissions.

Staff's analysis also indicates that one CHP combustion technology (IC engines), when operating at high enough efficiency levels to produce GHG emissions reductions, can achieve greater than 15% IRR on investment without subsidies.

- Gas turbines - Gas turbines have the potential to provide GHG emissions reductions at expected performance levels. They also appear to provide an IRR just under the target return of 15%. Therefore, staff recommends gas turbines for inclusion in the SGIP.

- Microturbines - Microturbines may have advantages over other combustion technologies in terms of producing fewer emissions of NO_x and other criteria pollutants. However, SB 412 requires the Commission to ensure that SGIP technologies will reduce GHG emissions.

Staff's analysis indicates that microturbines would produce more GHG emissions than they would avoid at the proposed minimum efficiency standards. According to comments filed by CCDC, microturbines have an electrical conversion efficiency of 25.2%. At this electrical conversion efficiency, microturbines would need to achieve a total CHP efficiency of 63.9% to break even from a GHG emissions standpoint. At a total CHP efficiency of 62%, which staff recommends as the minimum standard for SGIP, microturbines would have to have an electrical conversion efficiency of 28.2% to break even from a GHG emissions standpoint. In order to ensure that microturbines reduce GHG emissions, specific performance standards for microturbines would have to be established in excess of the standard proposed by staff.

CCDC[29] suggests that microturbines are capable of achieving total CHP efficiencies in excess of 70%; however, it is uncertain if microturbines can achieve these efficiencies in all practical applications. Furthermore, determining what an appropriate minimum efficiency limit should be proves challenging. A standard that merely achieves GHG emissions neutrality is not sufficient. The emissions factor of the grid is projected to get even lower over time as the result of a variety of GHG-reducing initiatives including the Renewable Portfolio Standard and Integrated Demand Side Management programs. New, more efficient fossil fuel resources and higher penetrations of zero emissions renewables will replace older, less efficient fossil fuel resources. A minimum threshold that achieves neutrality today likely will result in net GHG emissions produced in the future. Thus, any technology which does not unequivocally reduce GHG emissions today is not recommended to be included in the SGIP on a pre-approved basis. Manufacturers could apply to have a technology approved on a per product basis, but staff notes that microturbines have a marginal GHG reduction potential.

- IC Engines - According to comments filed by CCDC, rich burn engines have an electrical conversion efficiency of 27.1%. At this electrical conversion efficiency, engines would need to achieve a total CHP efficiency of 62.7% to break even from a GHG emissions standpoint. At a total CHP efficiency of 62%, rich burn engines would have to have an electrical conversion efficiency of 28.2% in order to break even from a GHG emissions standpoint.
  Lean burn engines, which have a higher electrical conversion efficiency than rich burn engines, can achieve GHG emissions reductions with a total CHP efficiency of 62%. Therefore, staff used lean burn engines in its cost analysis. However, lean burn engines are able to achieve IRR in excess of 15% without incentives.

- Staff is not currently able to determine how realistic and or enforceable a different treatment of rich and lean burn engines would be. Staff welcomes comments on this issue, but recognizes that it might be a moot point if IC engines do not pass the "need for financial incentives" screen. The combination of questionable GHG emissions benefits for some IC engines, and financial returns in excess of 15%

[29] http://docs.cpuc.ca.gov/efile/CM/111520.pdf

> without incentives for engines that do reduce GHG emissions, lead as to recommend not including IC engines in the SGIP.

Staff acknowledges that CHP technologies can contribute to GHG emissions reductions, and may provide additional grid benefits, such as local capacity and reliability in constrained areas of the grid. Staff also recognizes that there may be some market barriers to greater deployment of CHP in California, beyond cost. Although staff does not recommend incentives for some of these technologies, staff does encourage the Commission to consider providing non-incentive support for highly-efficient, small CHP. In section 4.5.3., staff recommends using SGIP marketing and outreach (M&O) funds to support greater customer education about DER technologies, including CHP. Staff also recommends that M&O resources might be deployed to further analyze and develop recommendations for addressing non-cost market barriers to CHP.

Combustion, Renewable - Staff's analysis suggests that combustion technologies operating onsite renewable biogas cannot necessarily provide reasonable customer return on investment without subsidies. Furthermore, renewable biogas, which produces zero or negative[30] net emissions from generation, represents the potential for significant GHG emissions reductions. Therefore, staff recommends that combustion technologies using biogas be included in SGIP.

In its analysis, staff considered biogas applications where biomass is converted to biogas through anaerobic digestion and combusted in a generator located on the same site.[31] In addition to biogas from anaerobic digestion, there may be additional sources of renewable fuel, such as through gasification or direct combustion of solid waste material, which may be appropriate for consideration in the SGIP. There was not sufficient data available for staff to analyze the costs associated with other biofuel applications. However, staff recommends that any RPS-eligible renewable fuel that can be used in a gas turbine, IC engine or microturbine should be eligible for SGIP incentives.

Directed biogas applications do not require any additional fuel cleanup equipment or other modifications as their prime movers use natural gas. The only effect on financial return is the higher incentive level received for projects that show a contract for purchase of biogas somewhere within, or interconnected to the WECC. Generally, these contracts appear to cost more per MMbtu than typical natural gas contracts. Due to the limited information available on biogas contracts, though, this issue remains unclear. Staff welcomes comment on the cost and viability of directed biogas contracts. Furthermore, staff expects the cost-effectiveness report to include a breakdown of information for each technology in the directed biogas context, and this information may lead to staff modifying recommendations about directed biogas.

[30] If renewable biomass feedstock would otherwise be vented to the atmosphere as methane, then capturing and combusting this methane avoids considerable emissions.

[31] Staff also considered directed biogas in its analysis. However, due to the limited number of directed biogas projects in California there was limited data for this analysis. Preliminary analysis of directed biogas projects indicates that these projects may be more expensive than onsite biogas due to the costs associated with infrastructure to inject the gas into a pipeline and transport it to an end-use customer.

Since renewable fuel generation technologies do not produce any GHG emissions from generation, there is no need to require minimum CHP efficiency standards in order to ensure GHG emissions reductions, so long as the technology is using onsite renewable fuel. GHG emissions reductions will be achieved simply through the generation of electricity using a renewable fuel. Therefore, staff recommends that combustion technologies using onsite renewable fuel not be required to operate as CHP, and not be required to meet a minimum efficiency standard. Staff notes that the additional savings from operating as CHP, as well as the reward of a performance based incentive, should motivate renewable CHP customers to operate their systems as efficiently as possible.

4.3.4 Waste Heat Organic Rankine Cycle Engines

Bottoming cycle CHP, or distributed generation fueled by waste heat from an existing industrial or commercial process, offers the potential for additional electricity generation with minimal to zero additional fuel input. There are several technologies capable of doing this, but few with very extensive track records in the marketplace. In this proceeding, the Commission received a proposal to include Organic Rankine Cycle Engines, operating on waste heat as an eligible SGIP technology. Staff's analysis indicates that Waste Heat ORC engines can currently provide a reasonable customer return on investment without subsidies. Staff recognizes the GHG emissions reduction potential of these technologies, but cannot justify paying an incentive to a technology that can achieve a 30% IRR in the absence of incentives.

4.3.5 Pressure Reduction Turbines – in-conduit hydro

In comments to the ALJ Ruling on November 13, 2009, Zeropex proposed that pressure reduction turbines be eligible for SGIP incentives. While this technology is compelling and appears to have potential applications in California, our analysis of cost indicates that these technologies can achieve very high return on investment for customers, in excess of 40%, and very short payback without any incentives. Staff notes that there may be regulatory or other barriers that are preventing more widespread adoption of this technology. However, additional incentives through the SGIP would not appear to address those barriers, and would not be a prudent use of ratepayer funds.

4.3.6 Energy Storage

In comments to the ALJ Ruling on November 13, 2009, the California Energy Storage Alliance (CESA) suggested an expansion of energy storage eligibility in SGIP in two ways. Currently the SGIP provides incentives to energy storage technologies that are coupled with on-site wind or fuel cell generating technologies. CESA recommends that storage should be eligible for incentives if it is coupled with other renewable distributed generation technologies, such as solar PV, and also that storage as a stand-alone DER technology should be eligible for incentives. A thorough discussion of energy storage appears in Appendix C. Recommendations are summarized here.

Energy Storage integrated with Renewable DG – As the Commission already determined in D. 08-11-044, energy storage coupled with a DG resource can support the SGIP objective of peak demand reduction. Now that the Legislature has removed the restriction that SGIP can only support wind and fuel cell generating technologies, staff recommends expanding the opportunities for energy storage coupled with DG. Specifically, staff recommends that energy storage should be eligible for incentives if it is coupled with any other renewable DG technology, including solar PV and onsite renewable biogas CHP. Energy storage coupled with DG can provide multiple benefits to customers and the grid. According to staff's analysis, energy storage can also provide GHG emissions reductions depending on the "round trip efficiency" of the particular technology. Round trip efficiency and other performance requirements recommended for energy storage are discussed further below.

Stand-alone Energy Storage – Staff notes that many of the same benefits provided by energy storage coupled with renewable DG can be provided by stand-alone energy storage. However, staff notes that that through the Commission's Demand Response programs, each of the three large IOUs currently has a pilot program for permanent load shifting (PLS) resources. These pilot programs provide incentives for resources that permanently shift load from on-peak to off-peak times, including energy storage resources. The Commission has ordered the IOUs to conduct a cost-effectiveness evaluation of the PLS pilot programs, which is expected in November 2010. Staff recommends that since the PLS pilot programs and stand-alone energy storage incentives through the SGIP might serve similar purposes, the Commission should be cautious about duplicating efforts.

Staff recommends that the Commission consider the results of the PLS cost-effectiveness evaluation, before deciding how to proceed with incentives for stand-alone energy storage in the SGIP. There may be distinct types of technologies that could be supported through SGIP incentives that are not fully valued in the PLS context. Likewise, the Commission may decide that PLS does not belong in the Demand Response programs.

Minimum Efficiency

Staff recommends that the performance and operating requirements for energy storage in D. 08-11-044 and modified in D. 10-02-017, be maintained. In addition, staff recommends that energy storage technologies be required to meet a minimum "round trip efficiency" requirement in order to ensure that they achieve GHG emissions reductions through charging and discharging.

Staff's analysis of the GHG emissions impacts of energy storage, described in Appendix A, indicates that a minimum round trip efficiency of approximately 67.9% is necessary in order to ensure that energy storage technologies reduce GHG emissions. However, staff notes in the description of that analysis that many of the assumptions used are speculative and that in order to determine the precise emissions impact of an energy storage technology, granular data on the charging and discharging times of an energy storage device, as well as granular data on the marginal generating unit on the grid in each of those time periods, would be necessary. To be conservative, staff recommends that the Commission adopt a round trip efficiency requirement of 70% for energy storage technologies applying for SGIP incentives. This requirement should ensure that energy storage technologies meet the SB 412 requirement of GHG emissions reductions.

Staff welcomes comments from parties on this round trip efficiency requirement and in particular requests input from parties on which energy storage technologies would be able to achieve this 70% round trip efficiency requirement.

4.4 SGIP Incentive Design Issues

4.4.1 Eligible system size

The SGIP currently has a minimum size requirement for wind turbines and renewable fuel cells of 30kW. This minimum size requirement is intended to ensure that there is minimal overlap with the California Energy Commission's Emerging Renewables Program (ERP), which offers incentives for projects using the same technologies less than 30kW. There is no minimum size for non-renewable fuel cells. All projects are capped at a maximum size of 5MW.

Staff recommends that the Commission consider streamlining the offer of incentives to technologies that overlap with the ERP program.

Minimum size –

Staff recommends that the minimum size requirement for wind and renewable fuel cells remain in place only as long as the ERP continues to provide incentives for these technologies. If the ERP program is discontinued or interrupted at any time, the SGIP should automatically be able to offer incentives for wind and renewable fuel cell technologies under 30 kW without additional Commission action. For all other technologies, staff recommends that there be no minimum size requirement. Consistent with SB 412, which requires the Commission to ensure that incentives under this program are available to all customers, removing the minimum size requirement for other technologies should ensure that residential and small commercial customers have access to incentives.

Maximum size –

Staff recommends that the Commission eliminate the maximum size restriction of 5MW for all technologies participating in SGIP. The tiered incentive structure (see Section 4.4.4), which only provides incentives for the first 3 MW of a project's capacity, and the requirement that projects be sized to meet a customer's onsite-load, should provide sufficient limitations on the maximum size and cost of any single project. Staff recommends retaining the program requirement that projects be sized to meet onsite load. Removing the maximum size cap, however, enables systems greater than 5MW, which may not be financially viable without incentives for the first 3 MW, to become eligible. Larger project sizes may allow certain technologies to achieve wider adoption without costing the program any additional funding.

4.4.2 Technology Differentiated Incentives

Parties proposed, and staff considered establishing, a single incentive structure for all SGIP technologies based on the value of the benefits to the grid (i.e. positive externalities) provided. However, staff is concerned that developing such an incentive structure may be too complex and vary too much from project to project based on a variety of project specific characteristics. Furthermore, it may be difficult to incorporate market transformation effects into a single, value-based incentive structure.

Therefore, staff recommends that SGIP continue, as it has in the past, to provide technology-differentiated incentives, based on technology economics. As a starting point, staff looked at historical SGIP incentive levels. All of the technologies recommended for inclusion in the program, except energy storage,[32] have successfully installed projects with SGIP incentives. Development of some technologies has progressed more slowly than others, but all technologies have demonstrated that they can be successfully developed at these incentive levels.

Staff recommends relying on the cost information in the forthcoming SGIP cost effectiveness evaluation to inform specific incentive levels. The goal of these incentives should be to stimulate installations of clean DG technologies which pass the three screens highlighted in this proposal. This staff proposal will be updated at a future date with recommendations for actual incentive levels.

In advance of making a specific proposal on incentive levels, staff would like to acknowledge several issues related to the SGIP incentive levels that stakeholders and the Commission might consider before the Commission makes a final decision on program modifications:

Biogas Incentives - Incentives for biogas fuel cells are $2/Watt higher than natural gas fuel cells ($4.50/Watt vs. $2.50/Watt) even though staff's cost analysis suggests that biogas fuel cells have higher returns than natural gas fuel cells. The reason for this is that although biogas systems require higher capital investment in fuel clean-up equipment, they have much lower operating costs as they typically do not have to purchase fuel during the life of the project (in the case on on-site biogas). Staff supports a higher incentive for biogas fuel cells now since they provide much greater benefit in terms of GHG emissions reductions and still have very low market penetration. However, staff recommends that the Commission consider reducing this incentive in the future to a level that more closely tracks the natural gas incentive amount. Through the end of 2009, there were only 7 biogas fuel cell projects completed in SGIP. Since then, there has been a much greater level of fuel cell participation in SGIP, with the vast majority of these projects using directed biogas. This could indicate that on-site biogas fuel cell project development is complex and time intensive, perhaps requiring a higher incentive for those projects utilizing on-site biogas. Alternatively, there could be non-economic aspects to the low market uptake, where some kind of "market barrier" removal (e.g. case

[32] Energy storage was only included in SGIP in late 2008, and even then it was limited to applications where storage was coupled with wind or fuel cells. Staff attributes the lack of completed energy storage projects to these limitations, and therefore does not recommend modifications to the incentive level for energy storage at this time.

studies, promotion, performance guarantees, local permit assistance, or other market facilitation activities) may be more useful than direct incentives in building market uptake. See further discussion of Marketing and Outreach in Section 4.5.3 below. Staff recommends the Commission monitor this technology and market, and consider reducing the incentive for biogas fuel cells at a later date if project activity and economics indicate that the incentive is too high. Staff welcomes comment on this issue.

Solar Incentives Comparison - Incentives for most of the technologies recommended above exceed the incentive levels currently offered for solar in the CSI.[33] However, with the exception of wind, all the SGIP technologies have additional fuel costs that factor into self-generation project economics, unlike solar PV. In addition, many SGIP technologies produce more energy on a per watt basis than solar. For example, fuel cells produce 2 to 3 times more energy on an installed watt basis than solar PV since fuel cells regularly have a capacity factor over 60% and PV has a capacity factor of about 20%. The higher incentives for fuel cells, combined with the higher energy production value for fuel cells, indicates that the State is currently providing a significantly larger capital incentive per watt to SGIP technologies than solar technologies. In making any cost comparisons between SGIP and CSI, it is important to note these differences in capacity factors and operating costs.

4.4.3 Hybrid Performance Based Incentive (PBI)

One of the challenges that prior measurement and evaluations (M&E) studies of the SGIP have revealed is that many of the projects that have received incentives have not performed as expected. In many cases, projects have not been able to maintain performance at the minimum efficiency requirements of the program during their project life. These challenges were discussed by Itron in its presentation of SGIP Impacts at the January 7, 2010 workshop.[34]

Many parties suggested that staff should not consider past performance as an indicator of future performance. While staff agrees that past performance may not necessarily be the best indicator of future performance, we nevertheless recommend that SGIP adopt more stringent performance assurance requirements. This would serve to avoid historical problems with low actual capacity factors of projects that received their incentives upfront. Staff's analysis of GHG emissions and technology cost relies on technologies performing at expected levels of production and over expected lifetimes. Therefore, staff recommends several program modifications intended to ensure that these expected levels of performance are met or exceeded.

Some parties have suggested, and staff agrees, that the Commission should adopt a performance-based incentive (PBI) mechanism for the SGIP. A PBI has been very successful in the California Solar Initiative in motivating well-designed, high performing solar systems. However, parties have pointed out several difficulties in adopting a PBI for SGIP.

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[33] In PG&E and SDG&E territories, CSI incentives for residential solar are currently at $0.65/Watt. Incentives for solar have declined to these levels from $2.50/Watt since the beginning of 2007 through a targeted program focusing primarily on a single technology.

[34] http://www.cpuc.ca.gov/NR/rdonlyres/0DF241E8-EE28-4754-8348-2CB76D0333A5/0/Presentation2SGIPImpacts.pdf

Parties have argued that SGIP technologies require an upfront incentive, since the barrier to deploying their technologies has to do primarily with first-cost. It is unclear why this challenge should be any greater for SGIP technologies than solar PV, which has a much higher first cost per kW than most SGIP technologies. (See Appendix B, Table B1 for SGIP technologies' installed costs/kW, ranging mostly between $2,300 - $7,300 per kW, with several fuel cell outliers in the $9-12,000 range.) Solar PV, by comparison may cost $7,500 – $9,000 per CEC-AC kW depending upon system size. Parties also point out that the PBI mechanism, which pays customers monthly for five years, based on the measured output of their systems, is overly complicated. They argue that creating a PBI for SGIP, which includes multiple different technologies, would be even more complicated.

Staff appreciates many of these concerns, but continues to believe that a performance based incentive mechanism is the best way to guarantee project performance. Due to the very dramatic decrease in observed capacity factor in SGIP projects (5.9%/year),[35] staff feels a method for rewarding performance will help SGIP achieve its goals. Staff also believes that a performance based incentive mechanism can be designed and implemented easily and still achieve this objective.

To address some of the market stakeholder concerns, staff recommends a hybrid performance-based incentive that consists of an upfront, capacity-based payment, and multiple annual performance payments based on actual energy deliveries. The starting point for calculating payments is the incentive amount that staff's analysis indicates is necessary to enable a customer to achieve a reasonable return on investment. Payments would be structured as follows:

- *Upfront Capacity-based Payment* = 25% of incentive.
  - This payment would be made when a project is commissioned, consistent with the existing rules of the SGIP program.
- *Annual Performance Payments* = approximately 15% of incentive, paid each year for five years.
  - *Payment Schedule*: Annual performance payments will be paid at the end of each year, for five years. Payments shall be based on actual measured performance of a SGIP system during the previous 12 month period. Payments shall be made within one month of transfer of metered data from the customer to the program administrator for the relevant 12 month period.
  - *Payment Conditions*: Annual performance payments will be made only to projects that meet and maintain the technology-specific minimum operating performance requirements during the year for which the payment is due. All projects will be required to monitor and report actual "round trip efficiency" on a quarterly basis to the program administrator. At the end of each year, based on actual reported data, the program administrator will determine whether a project qualifies for the annual

[35] Self Generation Incentive Program, Combined Heat and Power Performance Investigation, Prepared by Summit Blue Consulting, April 2010. Available online at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

payment. To qualify for payment, a project must perform within 2 percentage points of the predicted "round trip efficiency" over the year. Predicted efficiency will be established on an upfront basis at the time a project is approved for its first upfront capacity-based payment.

- *Performance-Based Incentive Payment Calculation*
  - *Generating Technologies*: Annual performance payments are designed to be approximately 15% of the incentive per year. However, actual payments will be based on measured energy deliveries and will vary depending on actual system output during the year. The capacity-based payment amount (15% of incentive), will be converted into an energy payment amount ($/kWh) using reasonable assumptions about capacity factor for each technology. Parties are welcome to comment on what the source for the assumed capacity factor for each technology should be. This energy payment amount will be multiplied by the number of kWh delivered during the year to calculate the payments. Energy payment amounts ($/kWh) will vary between technologies based on the base incentive amount and the capacity factor for each technology.
  - *Energy Storage Technologies:* Payment based on total energy deliveries may not be appropriate for energy storage technologies, which may provide the greatest benefit by discharging in limited quantities to smooth DG output and/or customer load. Payment based on energy deliveries may create an incentive for energy storage technologies to discharge more than is necessary or beneficial. Therefore, staff recommends that energy storage technologies receive annual payments based on availability during peak hours. Energy storage technologies must meet all operational requirements discussed above and must be available during peak weekday hours (or semi-peak hours during winter months), at least 80% of the time during the year and 90% of the time during the summer peak period. Availability shall be defined as days in which the energy storage device discharged at least partially during peak hours. Comments especially are invited on the definitions of peak times and appropriate percentages of availability, as well as on a methodology for calculating availability (i.e. # of peak days in a year * # days discharged, etc).

4.4.4 Tiered Incentive Rates

Staff recommends that the Commission maintain the current tiered incentive structure adopted in D. 08-04-049. Though changes in incentive tiers have been proposed, staff does not have enough information on installed projects to determine whether economies of scale for larger systems merit lowering their incentive rate. This tiered incentive structure offers a declining incentive for projects greater than 1 MW and up to 3 MW, as shown in Table below.

Table 9. Tiered Incentive Rates

Capacity	Incentive Rate
0-1 MW	100%
1 MW – 2 MW	50%
2 MW – 3 MW	25%

Staff believes that this tiered incentive structure is compatible with the hybrid performance based incentive structure proposed in Section 4.4.3. For example, incentive payments for a 2.5 MW Wind turbine using current SGIP incentive amounts would be calculated as follows:

- *Incentive*:
    - 1st tier = 1MW * $1.50/Watt = $1,500,000
    - 2nd tier = 1MW * $0.75/Watt = $750,000
    - 3rd tier = 500 kW * $0.375/Watt = $187,500
    - Total incentive = $2,437,500
- *Upfront capacity based payment ($) =*
    - $2,437,500 * 25% = $609,375
- *Annual performance payments ($/kwh) =*
    - $2,437,500 * 15% = $365,625
    - $365,625 / (8760 hours/year * .30 capacity factor * 2,500 kW) = $0.056/kWh

4.4.5 Additional Performance Assurance - Warranty

In addition to a performance based incentive program, staff recommends that all SGIP projects be required to have a full warranty for parts and service for a reasonable expected useful project life.

Currently SGIP only requires projects have a five-year warranty on parts, but staff believes requiring a service warranty for DER projects is important. Many potential customers do not have experience or personnel to operate and maintain a DER resource. Past M&E studies of SGIP have noted a lack of proper maintenance as one reason for poor project performance. Therefore, staff feels that to protect the ratepayer's investment in DER incentives, the program should ensure these systems are properly maintained by requiring a full warranty on parts and service as a condition of receiving an incentive.

Staff also believes that a five-year warranty on an asset that is expected to last 10 or 20 years is insufficient. Instead, staff recommends the following warranty periods for SGIP technologies:

- 10 years - all technologies except wind turbines
    - 10 years is conservative given input received by staff that many of these technologies can last well beyond that length of time. However, 10 years is consistent with the expected project life used in staff's analysis of costs.

- 20 years – wind turbines
  - Wind turbines are a relatively mature technology and a 20 year warranty is consistent with the projected effective lifespan.

Staff recommends that proof of warranty be submitted during the application process. Several parties have raised concerns about service warranty standards, and what types of warranties should be acceptable for purposes of SGIP. Staff recommends that following adoption of a final decision, the program administrators should hold a workshop with equipment manufacturers, project developers and DER customers to determine appropriate warranty standards consistent with the direction of the Commission.

4.4.6 Declining incentives based on market penetration volumes

An important aspect of the incentive design raised by ALJ Duda in the November 13, 2009 Ruling, is whether the SGIP should adopt a declining incentive structure based on market penetration volumes, similar to that used in the CSI incentive design. Declining incentive structures can be used to facilitate market transformation by providing smaller subsidies over time. Declining incentives are intended to coincide with the decline in DER technology costs as the technologies increase scale.

The California Solar Initiative has very successfully implemented a declining incentive structure that is based on decreasing the incentive as more solar is developed. The declining steps are "triggered" as targets of capacity (in MW) of solar in the program are reached. In 2007, when that program began, incentives for solar PV were as high as \$2.50/Watt. Incentives in the California Solar Initiative now – three years later – are as low as \$0.35/watt[36] in some service territories, and the CSI continues to receive record numbers of applications each month.

Several parties have noted that applying a declining incentive structure, like the one developed for CSI, to the SGIP would be unworkable. The number of different technologies and the relatively small number of projects of each technology that can be funded through the SGIP makes it difficult to establish MW triggers for declining incentives.

While staff agrees that a declining incentive structure like the one designed for CSI would be difficult to implement with highly granular "steps" for the range of SGIP technologies, staff nevertheless believes that declining incentives are critical to implementing a successful program attempting to transform the market for DER technologies. In order for these technologies to be able to exist without subsidies, SGIP incentives must provide a pathway toward self-sufficiency. Toward this end, staff recommends a fairly modest decline in incentives triggered at the end of each year.

Starting on January 1, 2012, staff recommends that the incentives for SGIP technologies decline by 10% annually. The incentives recommended here should remain in place

[36] PG&E Non-Residential CSI projects are in Step 8, as of September 28, 2010, http://csi-trigger.com/

through the end of 2011, and starting in 2012, all incentive amounts should decline by 10%. And each year after that until the end of the program, the incentives should decline by an additional 10%.

4.4.7 SGIP Budget Allocation amongst Technologies

The SGIP budget is currently allocated equally between renewable and non-renewable technology categories.[37] The Commission has authorized the program administrators to freely move funds from the non-renewable category to the renewable category as needed. In order to move funds from the renewable category to the non-renewable category, program administrators must file an Advice Letter seeking authorization from the Commission. Staff sees no reason why the basic premise for this allocation of the budget should change in light of recommended program modifications.

However, staff does recommend the following clarifications:

- Energy storage:
  - Energy storage coupled with a renewable DG technology on-site, such as solar, wind or biogas, shall be funded out of the *renewable* budget allocation.
  - All other energy storage technologies shall be funded out of the *non-renewable* budget allocation.
- The designations "Level 2" and "Level 3" should be eliminated. Implemented when the program had three separate budgets, these designations are out of date and confusing for customers. Instead, the budget should be divided between "renewable" and "non-renewable" categories. Staff welcomes comment on whether the "renewable" category should be further designated between generation technologies which cause emissions "at the source" and those which do not (i.e. renewable fuel cells vs. wind turbines).

4.4.8 Status of SGIP Budget Availability

This entire SGIP staff proposal relies on the simple premise that there are funds available for future SGIP projects. In D.09-12-047, it became clear that an exact accounting of SGIP funds available was not available. D. 09-12-047, Ordering Paragraph 3 requires that the SGIP PAs conduct an audit of SGIP expenditures and ratepayer collections to ensure expenditures do not exceed authorized budgets. It is also expected that this audit will determine, definitively, the amount of available funds per program administrator.

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[37] D. 01-03-073 originally established three technology categories (Level 1, Level 2, and Level 3) and rules for transferring funds between categories. As the list of eligible technologies has changed over time, so have the technology categories. In particular, Level 1 technologies were removed from the program when PV was moved to the CSI program in 2007. Currently the program is divided into two categories, Level 2 and Level 3, as set forth in the SGIP Program Handbook. Level 2 includes renewable technologies (wind, and fuel cells using renewable fuel) and non-renewable technologies (fuel cells using natural gas). Staff recommends abolishing the Level 2 and Level 3 category labels in favor of more simplified and clear "renewable" and "non-renewable" categories.

In accordance with the decision, the SGIP is currently being audited by a third party CPA firm with work expected to be completed by January 10, 2011.[38] The goal of this audit is two-fold: to ensure the accuracy and uniformity of project information being recorded by the program administrators, and to evaluate the SGIP process and provide recommendations to enhance the efficiency and accuracy going forward. Completion of this audit will not affect the budget allocation per se, but will verify funds remaining and clarify outstanding issues with varied accounting practices in PA territories.

The Commission may need to modify some of this staff proposal in light of information that may be obtained in the future about the status of SGIP budget availability.

4.5 Additional SGIP Program Modifications

In addition to the technology and incentive modifications recommended above, staff would like to address several additional program design and administration issues. Several of these issues were raised by parties in comments. Other issues staff has identified based on observations and experience in implementing the SGIP.

4.5.1 Measurement & Evaluation

Since its inception, SGIP has undertaken an extensive measurement and evalution (M&E) process. A full list of SGIP M&E reports can be accessed from the CPUC's website.[39] These reports, which include annual Impacts Evaluations, Process Evaluations, Market Characterization Reports, Renewable Fuel Use Reports, and Cost-Effectiveness Evaluations[40] have all contributed to staff's analysis and recommendations in this proposal.

Following the implementation of program changes pursuant to SB 412, staff recommends that the Commission provide clear guidance for future SGIP M&E work:

- Articulate a clear program purpose and objectives, consistent with staff recommendations in section 4.1, along with expenditure targets to guide M&E activities.
- Specify a preference whether M&E activities will continue to be carried out by consultants under contract to the Program Administrators, or if the Energy Division staff will oversee this process directly (as it currently does for CSI).
- Affirm that all ongoing M&E studies of solar technologies (including solar projects originally funded through the SGIP) should be handled through the CSI M&E process. This will streamline solar M&E and reduce duplication that currently occurs since some solar projects are considered in SGIP analyses and others in CSI analyses.
- Specify a specific M&E budget for the SGIP program.

[38] On September 22, 2010, ALJ Duda issued an email to the service list extending the audit due date from October 1, 2010 to January 10, 2011.
[39] http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm
[40] An updated Cost-Effectiveness Evaluation of SGIP is expected to be released in late summer 2010.

4.5.2 Metering requirements

Staff recommends that all SGIP facilities be required to install metering and monitoring equipment as a condition of receiving incentives, and that this data be provided to program administrators, the Energy Division or their designated consultants in a consistent format on a quarterly basis. Accurate metering and monitoring data will be necessary to calculate and verify performance for the purposes of PBI payments. This data will also improve M&E studies of the program as a whole, providing better feedback on program successes and failures, and informing current and future policy development. Currently metering and monitoring equipment for M&E purposes is installed and monitored on only a sample of systems. This monitoring is done by an M&E consultant and paid for out of the administration budgets of the SGIP program administrators.

Staff recommends that the Commission expand the metering and reporting requirements recently adopted for advanced energy storage systems in D. 10-02-017 to all SGIP technologies. The responsibility for metering and monitoring shall belong to the SGIP customer. All SGIP projects must:

- Install metering equipment capable of measuring and recording 15-minute interval data on generation output, and (where applicable), fuel input, heat output (for CHP) and storage system charging and discharging.
- Provide data by the system owner or its designee to the Program Administrator, directly to Energy Division staff and/or to relevant M&E contractors on a quarterly basis for the first five years of operation.

Additionally,

- The program administrators along with Energy Division Staff shall hold a public workshop to establish specific protocols to govern the metering and data reporting requirements for SGIP systems. The program administrators shall submit metering and monitoring protocols through a Tier 2 AL that modifies the SGIP Program Handbook within 60 days of the adoption of a final Decision.
- For M&E purposes, the investor-owned utilities shall be required to provide interval data on total energy consumption for project sites (which is different than the system production data described above that must be provided by the system owner) to the Program Administrators, Energy Division staff and relevant M&E contractors. This should be done for a period of five years.

4.5.3 Marketing and Outreach

Historically, there has been very little money spent on marketing and outreach (M&O) by the SGIP PAs, despite the fact that there has been money incorporated into the administration budgets of each of the program administrators for this purpose. The Commission has never set aside a specific amount of M&O funding, and therefore any spending on M&O was effectively a reduction in the amount of funds available for administration and M&E.

In order for the SGIP to effectively stimulate the markets for clean DER technologies, staff recommends a more active and coordinated approach to M&O.

- M&O Activities - Staff recommends that M&O activities should focus on two areas: informing and educating customers about DER opportunities, and addressing market barriers to DER adoption.
    - *Education and Outreach* – Education and outreach activities should focus generally on DER and not merely on promoting SGIP. This is a significant departure from past M&O activities, which have focused almost exclusively on promoting SGIP.
        - Outreach efforts should seek to inform customers about the full range of DER (except solar, which is addressed by CSI M&O activities), including technologies that are no longer eligible for SGIP, such as some CHP technologies. These efforts should be coordinated with other utility demand side management programs, including CSI, energy efficiency, and demand response.
        - Highlighting Past Successes – SGIP has collected extensive data on installed projects. Using this data, education and outreach efforts should highlight successful projects representing past and present SGIP technologies.
    - *Addressing Market Barriers* – There are a number of challenges associated with the development of DER that are not related directly to cost and cannot be addressed purely with incentives. These challenges include interconnection, permitting, and site feasibility assessment. Many of these challenges were identified in the SGIP Market Characterization Report released earlier this year.[41] Using M&O funds, program administrators should develop tools to assist potential DER customers in overcoming these market barriers. These activities should be coordinated with other state agencies and stakeholders, as discussed further below.
- Budget Allocation - There should be a specific budget allocation for M&O activities, and program administrators should be required to spend these funds on approved M&O activities. Currently, 10% of the SGIP budget of each program administrator is set aside for "administration", which includes general administration, M&E and M&O.[42] A specific budget allocation for M&O should encourage program administrators to spend money on this important area of program administration. Staff recommends that 3% of the budget be allocated for this purpose. This allocation should come out of the 10% already allotted for program administration activities.
- M&O Committee - The SGIP working group should create a committee dedicated to M&O. This committee should coordinate efforts across program administrators and include representation from other DER stakeholders to leverage collaboration and enhance more uniform statewide outreach efforts.

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[41] SGIP Market Characterization Report, 2010 http://www.cpuc.ca.gov/NR/rdonlyres/EAEF4051-300A-4915-948F-FAD8E706F8AB/0/SGIP_market_characterization_report.pdf

[42] This was originally established in D.04-12-045, and reaffirmed in subsequent CPUC Decisions on the SGIP budget.

- Interagency Cooperation - Staff recommends that the SGIP working group coordinate marketing and outreach efforts with the CEC's Emerging Renewable Program to improve communication and outreach around small wind and renewable fuel cell DER, which are eligible under both programs.
- Stakeholder Cooperation – Staff recommends that the SGIP working group enhance coordination efforts with industry groups and other organizations that seek to promote DER technologies, such as the California Stationary Fuel Cell Collaborative (CaSFCC), the California Energy Storage Alliance (CESA), and others.
- M&O Plans - Staff recommends that the SGIP program administrators be required to submit a M&O plan via a Tier 2 Advice Letter, on an annual basis detailing their expected activities and expenditures on SGIP M&O.

4.5.4 Export of electricity to the grid

Several parties have proposed that SGIP technologies be able to export electricity and also receive SGIP incentives. CHP parties claim that they can optimally size their system if they have flexibility to export some power to the grid. Storage parties claim that additional benefits can be derived if storage systems can participate in ancillary services markets.

At this time, staff does not recommend providing incentives to SGIP facilities that export electricity for sale on a net basis.[43] The intent of the SGIP, as the name suggests, has been to facilitate self-generation intended to offset customer load. However, staff acknowledges that some limited export from SGIP facilities may be consistent with this intent. Staff offers the following ideas for consideration:

- Limited Export – the SGIP might consider allowing projects to export a small percentage of their output to the grid in order to optimize system sizing. For CHP systems, for example, optimal system efficiency may be achieved by sizing a system to the thermal needs of a host customer site. Consequently, the electricity production of the CHP system may exceed the host customer's electricity demand. The AB 1613 program, adopted by this Commission in D. 09-12-042, addressed the tariff issues associated with exporting that power. However, it did not necessarily address the technology cost issue, since the tariff was based on the avoided cost to the utility and not the actual cost of the CHP system. SGIP, which attempts to motivate customer adoption by providing incentives to reduce the actual cost of a system, may be complementary with an export tariff program with appropriate limitations. The intention would not be to provide an SGIP incentive to a technology that exports all or most of its power. Staff recommends a 25-percent limit on the amount of self-generated electricity that a system would be allowed to export.[44] Staff also notes that currently eligible SGIP technologies

[43] Wind technologies are currently eligible for net energy metering pursuant to PU CODE Section 2827, which staff does not consider export for sale on a net basis.

[44] Staff based the 25% limit on the New York State Energy Resources Development Agency's (NYSERDA's) CHP program, which allows systems to export up to 25% of their electricity to the grid and still qualify for incentives.

may benefit from being allowed to export incidental amounts of electricity to the grid:

- o Wind turbines are typically available in only a few sizes, and wind is a relatively unpredictable resource. Therefore, customers seeking to meet their entire electrical load may find that wind turbines produce slightly more electricity than the on-site load requires.
- o Energy storage may be able to provide additional value streams to the customer and to the grid by being able to export power to the grid. While the precise mechanisms for this export may not be fully developed yet, it might make sense to allow for room under the SGIP so that energy storage systems that do receive incentives can be fully utilized when and if those mechanisms are developed in the future.

- AB 2466 (Laird, 2008) – The Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program allows qualifying local governments to allocate bill credits from one or more eligible renewable distributed generation resources to multiple bill accounts of the same local government. These bill credits do not constitute a sale per se, and therefore staff recommends that the Commission clarify that eligible distributed generation resources participating in the AB 2466 program be allowed to receive SGIP incentives for the self-generation capacity necessary to serve the full loads of the designated benefitting accounts, not just the portion of the system serving on-site load at the generating account. This is distinct from the way the CSI treats its incentives. CSI limits incentives to on-site load only, and therefore a CSI system participating in RES-BCT is currently only eligible for incentives up to the load at the site where the generation is installed. Any excess generation installed to generate credits would not be eligible for CSI incentives. However, SGIP has no such size-to-load restriction, and therefore staff recommends that RES-BCT customers receive SGIP incentives for the full capacity (up to 1 MW, per the rules of RES-BCT) of the system—regardless of the load at the site where the generation is installed.

4.5.5 Energy Efficiency requirements

In the energy loading order,[45] the state of California has identified energy efficiency as the highest priority resource. As such, staff recommends that the Commission require SGIP customers to obtain an energy efficiency audit before receiving SGIP incentives for DER. Currently there is no energy efficiency requirement for SGIP projects.

The utilities or program administrators should provide audit tools appropriate to the size, facility complexity, and organizational sophistication of the participating customers. Additionally, certain non-utility provided audits may provide equivalent value in considering tradeoffs between and optimization of efficiency and on-site generation investments. The utilities/program administrators should collaborate with stakeholders and ED staff to develop guidelines for acceptable audit services. After an energy audit is performed, customers should submit a summary of the completed audit

[45] California's energy loading order is outlined in the interagency Energy Action Plan, http://www.cpuc.ca.gov/PUC/energy/Resources/Energy+Action+Plan/

recommendations, and identify which, if any, energy efficiency or demand response measures identified in the audit will be undertaken, and describe how this influences sizing of the self-generation system.

4.5.6 Maximum Reservation Hold Time

The SGIP currently allows a project to reserve and hold an incentive for up to 18 months from the time its application is submitted and reserved until the project is complete. Projects may request, and the PAs may grant, extensions to this 18-month timeline for certain reasons. Based on data in the SGIP queue, a significant number of SGIP projects have held reservations for longer than 18 months. These projects are holding up funds that could be used for other projects. The PAs have neither a consistent nor formalized process for granting extensions.

In order to understand this process and relieve the logjam of projects, staff recommends that the PAs should be required to submit a quarterly report listing all of the projects that have exceeded their 18-month reservation time and the reason for granting each extension. All projects should be limited to a maximum of two, six-month extensions, after which the reservation shall be automatically cancelled. Up until now, the maximum reservation hold time has been in the exclusive purview of the SGIP Program Administrators. However, recent concerns over budget availability elevate this issue to one of Commission-level interest, and staff recommends that the Commission intervene by seeking assurance that deadlines are being enforced. Staff welcomes comments on the best method for PAs to publicly report these projects which have been granted extensions.

4.5.7 Application Fees

The SGIP previously required application fees, as the CSI does today. These fees served several purposes: to support program administration, screen out applicants who did not fully intend to complete projects, and create a disincentive for perpetual re-application. Program administrators have noted that SGIP projects which are cancelled (often for failure to meet deadlines or produce adequate documentation) can simply re-apply the next day. This effectively re-sets the timeline at no penalty to the developer and creates a large amount of additional processing work on the part of the utilities. This additional effort increases administration costs of the SGIP and slows processing time. Staff welcomes comments on re-instituting an application fee, and what an appropriate fee would be – either as a percentage of system cost or a fixed amount.

4.5.8 Issues for Further Consideration

Below staff proposes several program modification ideas for discussion and further consideration. The proposed ideas represent more significant departures from the current SGIP framework, and therefore are not staff recommendations at this time. Staff is interested in receiving feedback on whether parties feel that any of these ideas have merit and should be considered by the Commission in the future. It is conceivable that one or more of the proposals could be integrated with the above-described program design modifications.

Wind Turbines and Coordination with ERP

Only two wind turbine projects, totaling 1,574 kW, have been completed and installed through SGIP since its inception. However, participation of wind projects has been much more robust in the California Energy Commission's (CEC) Emerging Renewables Program (ERP). The ERP provides incentives for small wind systems, while the SGIP provides incentives for larger wind systems.[46] At the end of 2009, ERP had provided incentives for 466 systems comprising approximately 2,900 kW of capacity.

Staff proposes a potential course of action for improving outcomes for distributed wind projects greater than 30kW:

- Consolidate wind turbine incentives for projects of all sizes into one program. Work with CEC to merge incentives for small wind and large wind into either the ERP or the SGIP.[47]
    - CEC has more experience with wind turbine projects through the ERP, and may be better able to target potential customers in this market than SGIP program administrators.
    - ERP and SGIP are completely separate programs with completely separate statutory budget authority. Implementing this recommendation would require significant coordination with - and agreement by - the CEC, as well as updated legislative direction.

ERP currently is funded by Public Goods Charge (PGC) funding, which is authorized only through January 1, 2012. Thus some kind of legislative

Budget Carve-out for Competitive Grants

Certain SGIP technologies are more commercially advanced than others. While the standard offer incentive structure employed historically in both the SGIP and CSI work well for more advanced technologies, it may not be the best mechanism for less commercially advanced technologies. Standard operating metrics and uniform cost, which are the basis for the standard offer incentive, can be difficult to pinpoint accurately for less mature technologies.

There could be consideration of a budget carve-out that established dedicated funds for a competitive grant program for less advanced technologies. This grant program could still focus only on commercial deployments, not R&D; however, it could target technologies in earlier stages of commercialization that might benefit from a more tailored incentive, in limited quantities, and combined with a higher level of technical support.

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[46] SGIP provides incentives for wind projects between 30kW and 5MW, while ERP provides incentives up to the first 30 kW for projects with a total size less than 50kW.

[47] Statutory funding for ERP expires at the end of 2011. If this funding is not reauthorized, the Commission should consider including incentives for small wind in SGIP.

In the near term, this program could include some advanced energy storage technologies and waste heat generation technologies. It may also include new applications of some of the other technologies such as fuel cells and CHP. This grant program could also be a venue for funding deployment of newer, emerging technologies, not yet considered in this program.

The implementation of such a program could possibly be coordinated with the CEC's PIER program. For example, the competitive grant component could possibly target technologies that have passed some PIER screen of commercial availability and technology performance validation. Such a program component would necessitate greater technical knowledge among both CPUC (or CEC) staff and utilities'/ program administrators' personnel. Comments are invited on both the merits of such an early-stage commercialization component and the feasibility of administering it.

5. Request for Comments

This proposal represents Energy Division staff recommendations based on analysis of historical SGIP data, SGIP measurement and evaluation studies, party comments in this proceeding, input received at the January 7, 2010 workshop, and publicly available information on distributed generation technologies.

The recommendations are intended to support the Commission's decision making process and do not represent the final word of the Commission. Staff anticipates and welcomes productive feedback and input from parties on the recommendations contained in this document. Staff has made every effort to explain the reasoning and analysis that has led to the specific recommendations in the proposal in order to facilitate party comments.

Specifically, parties are invited to comment on:

A) Technical performance aspects:

Microturbines: Parties are invited to comment as to whether a higher minimum efficiency requirement for microturbines, such as 72%, might be used to enable this technology to meet eligibility criteria.

Rich vs Lean Burn: Staff is not currently able to determine how realistic and or enforceable a different treatment of "rich" and "lean" burn engines would be. Staff invites comments on this issue.

Fuel Supply: Staff welcomes comments on the price (either in $/MMBtu or as an 'adder' to NG contract prices) and viability (i.e. how they could be verified, the benefits these contracts bring to California, etc) of biogas contracts are also welcomed.

Comments on minimum efficiency requirements for directed biogas contracts are welcomed.

Wind: Staff welcomes comments on non-financial barriers to wind adoption (i.e. tariff issues, NEM limits, siting) as well as realistic capacity factors of DG sites that are sited to onsite load and often not optimally sited for wind production.

Product Certification: Staff welcomes comments on the cost and time required for performance certification by third party laboratories.

AES Availability: Staff welcomes comments on a methodology for defining and determining "peak times" and "percentages of availability".

B) Financial performance aspects:

Parties are invited to comment on the assumptions, inputs, and methodology used to conduct this analysis. Any suggested changes should illustrate the effect on IRR(s).

Would an application fee be a significant barrier to projects? What is a reasonable fee (either flat or as a percent of total project cost) that would encourage developers to meet deadlines without being overly onerous? Would such a fee help manage the queue and facilitate advancement of the most viable projects?

Timeframe for Cost-effectiveness: Staff welcomes comment on whether the 2015 or 2020 date would be most relevant for the cost-effectiveness screen.

Fuel Cell Market: Staff welcomes comments on how, and if, the Commission should monitor the biogas fuel cell market and if the Commission should consider reducing the incentive for biogas fuel cells at a later date.

Capacity Factors: Staff welcomes comments on capacity factors (by technology) that would be used to determine the expected performance based payment calculation. Also, staff welcomes comments on what margin of lesser performance is reasonable to accept before not paying a PBI payment.

C) Additional ideas:

Wind Consolidation: Staff welcomes comments on the merits of whether the State should consider a consolidated program for projects, which is now split between the CEC and CPUC according to size.

Commercialization: Should there be a higher level of support for technologies further away from commercialization?

Allocation of funds by technology type: Staff welcomes comment on whether generating technologies which do not require fuel should be given a separate allocation of SGIP funds, or should combusting/catalyzing technologies be grouped with non-emitting technologies?

Appendix A - GHG Emissions Analysis Methodology

To determine whether current and proposed SGIP technologies would reduce GHG emissions, staff compared the expected lifecycle emissions for each DER technology to the emissions that would be avoided by that technology.

$$\text{Net Emissions} = \text{Avoided Emissions} - \text{Emissions Produced}_{DER}$$

- A positive Net Emissions result indicates that a DER technology avoids more emissions than it produces, thus reducing overall emissions. Technologies with a positive Net Emissions passed the screen.
- A negative Net Emissions result indicated that a DER technology produces more GHG emissions than it avoids. Technologies with a negative Net Emissions failed the screen.

The analysis only considered technologies that produce emissions from generation: either through use of a fossil fuel or through the use of electricity for charging, as in the case of energy storage. Renewable technologies and technologies operating solely on waste heat were deemed to produce zero emissions from generation and were not considered here.

The technologies considered in this analysis include natural gas-fueled technologies and energy storage technologies. This analysis relied on a number of assumptions about the operating characteristics of these technologies and the emissions profile of electricity and natural gas avoided.

The spreadsheet, "SGIP GHG Analysis – Public" shows all calculations. Assumptions and inputs can be varied by the user.

<u>Natural Gas-fueled DER – GHG Analysis Assumptions</u>
Natural gas technologies considered in this analysis include fuel cells, gas turbines, internal combustion (IC) engines, and microturbines. With the exception of fuel cells, the analysis only considered technologies operating in a combined heat and power (CHP) application, which was the SGIP requirement for natural gas-fueled combustion technologies when these technologies were included in the program previously. For fuel cells, staff considered both electric-only fuel cells and CHP fuel cells, which are both currently eligible for SGIP.

Avoided Emissions Factor Assumptions
Staff first looked at emissions from grid delivered electricity that would be avoided by DER. This "avoided emissions factor" represents the emissions produced when a MWh of electricity is consumed from the grid. This can also be thought of as the emissions that would be *avoided* when a MWh of electricity is generated by an alternative resource. For this analysis, staff considered the business as usual (BAU) avoided emissions factor used by ARB in the AB 32 Scoping Plan. ARB assumed an average avoided emissions factor of .437 TonneCO_2/MWh, which represents a weighted average of emissions rates from gas-fired generators online in California from 2002 to 2004. Although there are many different kinds of electricity generating resources in California, including nuclear and

renewables, gas-fired generators are those most likely to be turned on or turned off on the margin. Therefore, when considering an appropriate emissions factor for emissions avoided by an alternative resource, the emissions profile of gas-fired generators is most appropriate.

However, this emissions factor does not necessarily apply when a MWh of electricity is generated by customers using self-generation to offset their own load. The reason for this has to do with the fact that California's Renewables Portfolio Standard (RPS) requires utilities to generate 20% of the electricity required to serve customers with renewable power. When customers generate their own electricity, instead of purchasing that electricity from the utility, customers avoid a mix of gas-fired generation and zero emissions renewable generation that the utility would otherwise have to provide. Changing the emission factor to reflect the 20% RPS yields an electricity emission factor of .349 TonneCO_2/MWh, rather than the .437 TonneCO_2/MWh value used by ARB.

Staff used .349 TonneCO_2/MWh as the avoided GHG emissions factor for the *generating* technologies considered in this analysis. For energy storage technologies, which charge from the grid and discharge onto the grid at different times of day, different emissions factors were used. These are explained below.

Appendix A, Table 1: ARB Electricity Sector Emissions Assumptions

ARB Business as Usual (BAU) Avoided Emissions Rate	Avoided Emission Rate including 20% renewables used in this analysis
.437 TonneCO_2/MWh	.349 TonneCO_2/MWh

Emissions Produced Assumptions - Natural Gas DER

For each technology considered, staff used industry-supplied estimates for electrical efficiency, which appear in Table 2 below, along with documentation of the sources and assumptions. For CHP technologies, staff assumed a minimum overall efficiency of 62%, consistent with the California Energy Commission (CEC) guidelines for new, small CHP participating in the AB 1613 feed-in-tariff program.[48] Staff proposes the Commission apply the same minimum efficiency requirements in SGIP. If the CPUC adopted higher efficiency standards more technologies would qualify for SGIP. To calculate the useful heat recovered from CHP systems, staff calculated the heat recovery necessary to achieve an overall efficiency of 62%, given the electrical efficiency of each technology. While multiple CHP advocates assert that their technologies can achieve better than 62% overall efficiency, in order to make a determination that a technology will be GHG reducing pursuant to PUC Section 379.6 (b), the Commission should consider GHG emissions impacts based on a minimum efficiency requirement proposed for the program.

For each natural gas technology, the following assumptions[49] and conversions were used in this analysis:

[48] http://www.energy.ca.gov/2009publications/CEC-200-2009-016/CEC-200-2009-016-CMF.PDF
[49] Industry supplied assumptions for project life, capacity factor, and electrical degradation.

- Project Life - 10 years
- Capacity Factor - 80%
- Electrical Efficiency Degradation - 1% annually
  - For CHP technologies, overall system efficiency was held constant throughout the project life, so as electrical efficiency degraded, heat recovery was assumed to increase.
- Efficiency of avoided boiler (for CHP technologies) - 80%
- Conversion of natural gas to GHG emissions - ..05317 Tonne CO2E/MMBTU (conversion factor based on CO2E content of natural gas)
- Line losses added to grid electricity avoided – 7.8%

The following table shows the assumptions about the performance of each natural gas technology considered. Staff applied these assumptions to the GHG emissions calculation methodology described below to determine which technologies are expected to be GHG emissions reducing.

Appendix A, Table 2 Natural Gas DER Expected Performance Assumptions

Technology		Electrical Efficiency (HHV)	CHP Efficiency (minimum) (HHV)	GHG Reducing
Fuel Cells, Electric-Only[50]		51.6%	NA	Yes[51]
Fuel Cells, CHP[52]		37.9%	62.0%	Yes
Combustion Technologies, CHP[53]				
	Gas Turbines	29.0%	62.0%	Yes
	IC Engines (Rich Burn)	27.1%	62.0%	No
	IC Engines (Lean Burn)	35.0%	62.0%	Yes
	Microturbines	25.2%	62.0%	No

GHG emissions calculation methodology – Natural Gas DER

1. Calculate the *avoided emissions* associated with the grid electricity that the DG resource displaces over the project life.

[50] The electrical efficiency of electric-only fuel cells is based on Bloom Energy's ES 5000, which has a manufacturer reported fuel input requirement of .661 MMBTU/hour and an output of 100 kW. Assuming one hour of operation, the ES 5000 would produce 100 kWh or 341,200 BTU of electricity. Dividing this by the input yields an HHV efficiency of 51.6% http://www.bloomenergy.com/products/data-sheet/

[51] While the analysis found Bloom Energy's ES 5000 to be GHG reducing, there was insufficient data to prove that electric-only fuel cells are GHG reducing on a technology-wide basis. Therefore, Staff recommends potentially including electric-only fuel cells on a per product basis.

[52] The electrical efficiency for CHP fuel cells is based on manufacturer reported efficiency for the UTC Pure Cell 400 converted from Lower Heating Value (LHV) to Higher Heating Value (HHV). To convert to HHV, the LHV efficiency was divided by 1.108, which is the natural gas conversion factor used by the U.S. Department of Energy, http://hydrogen.pnl.gov/cocoon/morf/projects/hydrogen/datasheets/lower_and_higher_heating_values.xls.

[53] The electrical efficiencies and overall system efficiencies of CHP Gas Turbines, IC engines and Microturbines come from the California Clean Distributed Generation Coalition (CCDC) comments filed on December 15, 2009 in this proceeding, http://docs.cpuc.ca.gov/efile/CM/111520.pdf

Avoided Emissions$_{Electricity}$ = Avoided Generation (MWh) * Grid Emissions Factor (TonneCO_2E/MWh)

Where:

Avoided Generation (MWh) = DG Generation (MWh) + Line Losses Avoided (MWh)

Grid Emissions Factor = .349 TonneCO_2E/MWh

Line Losses Avoided (MWh) = DG Generation (MWh) / (1 – 7.8% Line Loss Factor)

2. *For CHP only*: Calculate the *avoided emissions* associated with boiler heat that a CHP DG resource displaces.

Avoided Emissions$_{Heat}$ = (Useful Heat Recovered (MMBTU) / 80% Boiler Efficiency) * .05317 TonneCO_2E/MMBTU[54]

Where:

Useful Heat Recovered (MMBTU) = (Total Fuel Input (MMBTU) * 62% efficiency) – (DG Generation (MWh) * 3.412 MMBTU/MWh[55])

3. Calculate the *emissions produced* by a DG resource over the project life by determining the total fuel consumed and converting that to emissions produced.

Emissions Produced$_{DG}$ = Fuel Input (MMBTU) * .05317 TonneCO_2E/MMBTU

4. Calculate the *net emissions impact* of the DG resource by subtracting the value in Step 3 from the sum of the values in Step 1 and 2.

Net Emissions = Avoided Emissions$_{Electricity}$ + Avoided Emissions$_{Heat}$ - Emissions Produced$_{DG}$

Energy Storage DER - GHG Analysis Assumptions

Energy storage technologies do not perform like other generating technologies and therefore the analysis of GHG impacts for energy storage had to be calculated slightly differently.

Staff assumed that energy storage technologies, regardless of whether they are coupled with a renewable DG technology, would charge primarily from the grid and primarily during off-peak hours. Staff also assumed that these storage technologies would be discharging exclusively during on-peak hours to help reduce a customer's peak energy and demand charges. Since the emissions profile of the grid differs significantly during

[54] Conversion factor based on GHG content of natural gas
[55] Conversion factor based on energy content of electricity

on-peak versus off-peak hours—with less efficient, higher emitting resources operating during peak hours and more efficient, lower emissions resources operating at night—this analysis used different emissions factors for charging and discharging of energy storage technologies.

For off-peak charging, staff assumed that the marginal generator on the grid would be a combined cycle gas turbine (CCGT). Therefore staff assumed that the emissions associated with charging would be based on the emissions of a CCGT with a heat rate of 6,917 Btu/kWh, which translates into an emissions factor of approximately .368 TonneCO_2/MWh. It is difficult to determine with certainty what the actual marginal generator on the grid will be at every off-peak hour when an energy storage facility would be charging. However, staff felt assuming that the marginal unit would be a CCGT was a conservative assumption. There may be times wind generation will be the marginal generating resource, especially as more wind connects to the grid. At such times, the emissions from charging energy storage might actually be zero, but this analysis assumed, .368 TonneCO_2/MWh to account for CCGT.

For on-peak discharging, staff assumed that the marginal generator on the grid would be a combustion turbine (CT) with a heat rate of 10,807 Btu/kWh which translates into an emissions factor of approximately .575 TonneCO_2E/MWh. Staff recognizes that this assumption is imperfect and that some hours of the year the marginal unit may be actually be a CCGT with a lower emissions factor. However, the marginal unit may be a less efficient peaking power plant with a higher emissions factor than a CCGT. A rate of .575 TonneCO_2E/MWh was determined to be a reasonable assumption and was used in this analysis. The most important consideration for this analysis is not the emissions factors themselves, but the difference between the emissions factor for charging and the emissions factor for discharging. Staff feels that the difference between the emissions factors used in this analysis is reasonably close to the actual difference in emissions factors from off-peak and on-peak hours, which is sufficient for this purpose.

Appendix A, Table 3: Grid Emissions Factors for Energy Storage[56]

Charging – Off peak	Discharging – On peak
.368 TonneCO_2/MWh	.575 TonneCO_2/MWh

Other assumptions used in this analysis include:

Appendix A, Table 4: GHG Analysis Assumptions, Energy Storage

	Round Trip Efficiency	Discharge Time	Annual Discharges	GHG Reducing
Energy Storage	80%[57]	4 hours	260[58]	Yes

- Efficiency Degradation - 1% annually

[56] Emissions factors calculated by dividing heat rates by .05317 Tonne CO2E/MMBTU
[57] 80% is the round trip efficiency required for energy storage projects seeking funding from the Department of Energy's American Recovery and Reinvestment Act (ARRA) grants program. Energy Division recommends the same standard be applied for SGIP.
[58] 260 days represents 5 days per week, 52 weeks per year

    - Round trip efficiency was assumed to degrade by 1% per year, resulting in a greater charging requirement to achieve the same discharge.
- Line losses – 7.8%
    - Line losses were assumed both in charging (increasing the electricity generation necessary for charging off-peak) and discharging (increasing the amount of electricity avoided on-peak).

GHG emissions calculation methodology – Energy Storage

1. Calculate the *emissions* associated with charging the energy storage technology during off-peak hours over the project life.

   $\text{Emissions}_{\text{Charging}}$ = (MWh used charging + Line Losses Incurred (MWh)) * .368 TonneCO_2/MWh

2. Calculate the *emissions avoided* when discharging an energy storage technology during peak hours over the project life.

   $\text{Emissions}_{\text{Discharging}}$ = (MWh discharged + Line Losses Avoided (MWh)) * .575 TonneCO_2/MWh

3. Calculate the *net emissions impact* of the energy storage by subtracting the value in Step 1 from the value in Step 2.

   Net Emissions = $\text{Emissions}_{\text{Discharging}} - \text{Emissions}_{\text{Charging}}$

Appendix B - Technology Cost Analysis Methodology

Staff conducted a simulated cash flow analysis for each of the technologies proposed for inclusion, except energy storage. Energy storage was analyzed separately and is explained in Appendix C.

The purpose of this cost analysis of proposed generation technologies was to the answer the following questions:

1. Do the proposed technologies require an incentive to achieve a reasonable return on investment for the customer?
2. What is the impact of SGIP incentives on customer payback period?

This analysis relied primarily on publicly available data on technology cost and performance. Where available, staff relied on data from historical SGIP projects. In other cases, data was drawn from publicly available resources that staff has made every effort to identify. Staff welcomes feedback on this analysis including all data inputs and assumptions.

The attached spreadsheet, "SGIP Cost Analysis – Public Dashboard" shows all calculations. Assumptions and inputs can be varied by the user.

Inputs and Assumptions

Installed Costs – Installed cost data for most technologies is based on the average cost of installed (i.e. completed) projects in the SGIP database[59] as of the end of 2009. SGIP data was available for wind turbines, fuel cells, gas turbines, IC engines, and microturbines.[60] For waste heat ORC engines and pressure reduction turbines, staff relied on cost data provided by TAS, Waste Heat Solutions, and Zeropex in comments in this proceeding.[61]

Renewable Fuel Clean-up Costs – To estimate the cost of fuel clean-up for renewable fuel projects (fuel cells and combustion technologies), staff did not rely on the installed cost data of renewable fuel projects reported in SGIP because of the uncertainty whether the SGIP data captures the full costs of renewable fuel clean-up for these projects. Some fuel may be cleaned-up off-site or by an external supplier, where any premium costs to clean-up would be reflected in the fuel sales price. Instead, staff used an estimate of fuel clean up equipment costs of $2,500/kW, which includes estimates for digester costs as well as post-digester fuel clean-up equipment costs. This number is based on conversations staff had with California Bioenergy. This cost estimate was added to the "non-renewable" installed cost of fuel cells and combustion projects to come up with a total installed cost for renewable fuel projects.

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[59] http://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-data-a-reports/doc_download/175-statewide-self-generation-incentive-program-data
[60] For CHP technologies, staff also received input from several manufacturers.
[61] http://docs.cpuc.ca.gov/published/proceedings/R0803008.htm

For renewable fuel projects, staff also assumed slightly higher operations and maintenance costs to account for ongoing costs associated with maintaining fuel clean-up equipment. These increased O&M costs were also provided by industry representatives in California. Consistent with these assumptions, staff assumed that there would be no cost of fuel for renewable fuel projects since the fuel feedstock is assumed to be a waste product that has no other value.[62]

Operations & Maintenance (O&M) costs – Staff relied on data provided by Itron Inc, the SGIP program cost-effectiveness evaluator, for O&M costs. This data will be publicly released in the upcoming SGIP cost-effectiveness evaluation, expected in later in 2010. In the case of multiple O&M costs for a given technology (based on size) the average of the two costs was used. However, in cases where the O&M cost for a given technology size was most representative of SGIP projects, that O&M cost was used and not the average. For example, in the case of fuel cell O&M costs, non-residential costs were used as these represent the majority of SGIP fuel cell installations.

Appendix B, Table 1: Technology Cost Assumptions[63]

Technology	Installed Cost ($/kW)	O&M ($/kWh)
Wind Turbine	$3,096	$0.008
Fuel Cell – Electric Only	$9,608	$0.020
Fuel Cell – Electric Only (Biogas)	$12,108	$0.040
Fuel Cell - CHP	$7,268	$0.030
Fuel Cell - CHP (Biogas)	$9,768	$0.054
Gas Turbine - CHP	$2,347	$0.020
Gas Turbine - CHP (Biogas)	$4,847	$0.054
Microturbine – CHP	$3,293	$0.020
Microturbine – CHP (Biogas)	$5,793	$0.086
Organic Rankine Cycle	$2,858	$0.010
Pressure Reduction	$3,488	$0.010

Metering Costs – Metering costs are based on the additional equipment required to monitor electricity generated, fuel input, and waste heat capture (when applicable) as required to calculate the hybrid-PBI described in this proposal. Note that these figures do not include any value for ongoing maintenance of metering equipment or provision of data to the program administrator, both of which are assumed to be negligible once the

[62] Staff's analysis presented here only considers renewable fuel projects where the renewable fuel is located on the same site as the generation. Staff considered the cost impact of directed biogas in analysis that is not presented here. The payback analysis for projects using directed biogas, which is almost identical to the analysis for projects using natural gas, is very sensitive to gas price. Due to the limited number of directed biogas contracts in California, obtaining reliable information about the cost of directed biogas proved difficult. Staff did not feel that it was appropriate to base its incentive analysis on limited information.
[63] Installed costs for natural gas-fueled MT, IC, GT, and FCs are the average installed cost of completed SGIP projects, on a $/kW basis, multiplied by the capacity for a given project. O&M costs were provided by Itron. For renewable-fueled technologies, a $2,500/kW adder was used based on discussions with California Bioenergy.

equipment is installed. Based on discussions with industry consultants, staff estimates metering costs as follows:

Net electricity output: $4,300
Waste heat capture: $17,000
Fuel consumption: $7,500

The analysis assumes that CHP applications require all three meters; electric-only fuel cells and biogas technologies do not require waste heat capture; and pressure reduction turbines, waste heat ORC, and wind turbines do not require waste heat capture or fuel consumption metering.

Salvage Value – Salvage value is not included in this analysis. Staff determined it could not accurately assess the salvage value of various technologies after their useful lifespan. Estimating the future values for technologies that are no longer operational would only serve to add subjectivity to the analysis as little data on salvage values exists. If included, this would increase the rate of return because the project owner would be able to sell the equipment for some additional revenue in the future.

Depreciation - Depreciation is not included in this analysis. Many technologies surveyed in this model would use a five-year Modified Accelerated Cost-Recovery System (MACRS) schedule. However, for simplicity, depreciation schedules and tax implications were left out of this analysis.

Federal Investment Tax Credit (ITC) - The federal ITC applies to most DER technologies proposed for inclusion in SGIP. The ITC is incorporated into the revenue stream as a single payment in year 1. This is based on the assumption that most projects will avail themselves of the grant in lieu of ITC that the federal government established in the American Recovery and Reinvestment Act (ARRA) of 2009. While the grant in lieu of the ITC expires at the end of 2010, the impact on customer payback should not differ materially.

The following technologies are eligible for a 30% ITC: fuel cells and renewable technologies including wind turbines and pressure reduction turbines. CHP technologies and biogas technologies are eligible for a 10% ITC.

Avoided Electricity Costs – The avoided cost of electricity for SGIP projects is based on the average retail cost of electricity for a commercial customer. Staff used PG&E's A-10 TOU primary rate to determine an avoided electricity cost of $0.117969/kWh – the average charge per kWh for the 2010 year. Staff only considered avoided electricity costs and did not consider the impact that distributed generation would have on customer demand charges. Applying a value for avoided demand charges is site and process-specific, and too complicated for the generic cost analysis. To the extent that an individual customer does avoid a portion or more of its electricity demand charge, then the customer payback and IRR would be higher than reflected in the staff analysis.

Utility Price Escalation - A figure of 2% is assumed in this analysis. This is based on California Energy Commission data on historical utility prices[64]. Between 1982 and 2008, utility prices in California increased approximately 2% annually. This analysis assumed the same annual price escalation for future years.

Natural Gas Costs – Staff used the natural gas price forecast from the 2009 MPR[65] to calculate the cost of natural gas for DG projects using natural gas. Natural gas prices, in $/MMBtu, are forecast through 2020 in the MPR. They are as follows:

Appendix B, Table 2: Natural Gas Price Assumptions

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
$ per MMBtu	6.20	7.04	7.24	7.36	7.50	7.66	7.81	7.97	8.13	8.29	8.45

Electrical Efficiency – For electrical conversion efficiencies for combustion technologies, staff relied on estimates provided by the California Clean DG Coalition in comments to this proceeding, as displayed in Table 3 below.[66] For fuel cells, staff relied on the original equipment manufacturer estimates published in technology specification sheets. This is the same information presented in Table 2.

Heat Recovery - Staff chose to apply the minimum CHP efficiency of 62% in the cost analysis for all CHP technologies. While many of these technologies can operate at higher efficiencies, this minimum efficiency, which staff used in its GHG analysis, and which staff proposes be the standard for SGIP technologies, is a conservative estimate for this cost analysis. If staff used higher heat recovery rates, which equipment manufacturers claim are possible, payback periods would be shortened and rates of return would increase.

Boiler Efficiency – Staff used this when calculating the avoided cost of natural gas, which is assumed to be a constant 80%.

[64] California Energy Commission, California State-Wide Weighted Average Retail Electricity Prices 1982 – 2008

[65] MPR California Gas Forecast (Nominal dollars) Public Utilities Code § 399.20 - 2009 Model

[66] Comments filed in R. 08-03-008, January 19, 2010.

Appendix B, Table 3: Electrical and Overall Efficiency Assumptions

Technology		Electrical Efficiency (HHV)	CHP Efficiency (minimum) (HHV)
Fuel Cells, Electric-Only[67]		56.1%	NA
Fuel Cells, CHP[68]		37.9%	62.0%
Combustion Technologies, CHP[69]			
	Gas Turbines	29.0%	62.0%
	IC Engines (Rich Burn)	27.1%	62.0%
	IC Engines (Lean Burn)	35.0%	62.0%
	Microturbines	25.2%	62.0%

Performance Degradation – All technologies decline in performance over time. In this analysis, kWh production decreases proportionally to performance degradation. It is assumed that any given technology will generate 100% of expected energy in the first year, and that this figure will begin to decline in year two. In the case of technologies which use an external fuel source, fuel consumption is held constant and energy generation is assumed to decline. Staff assumed 1% annual performance degradation for all technologies.

Capacity Factor - Capacity factor for base load technologies was assumed to be 80%. Capacity factor for wind was assumed to be 30%.

Methodology

The methodology for calculating the net present value, IRR, and simple payback of proposed SGIP technologies is described below. Staff began by estimating the electricity generation and (when applicable) heat recovery of each technology.

The electricity generated is the capacity (in kW) multiplied by the capacity factor (percentage of time online at full capacity) by the number of hours in a year. This amount of electricity is then multiplied by the avoided cost per kWh (based on PG&E's A-10 primary TOU rate) to show what a customer would have spent on the same amount of electricity in the absence of on-site generation, or the *value of avoided electricity*.

Natural Gas (NG) consumed is a function of a given technology's heat rate and the amount of kWh generated. In the case of technologies that do not require natural gas

[67] The electrical efficiency of electric-only fuel cells is based on Bloom Energy's ES 5000, which has a manufacturer reported fuel input requirement of .661 MMBTU/hour and an output of 100 kW. Assuming one hour of operation, the ES 5000 would produce 100 kWh or 341,200 BTU of electricity. Dividing this by the input yields an HHV efficiency of 51.6% http://www.bloomenergy.com/products/data-sheet/

[68] The electrical efficiency for CHP Fuel Cells is based on manufacturer reported efficiency for the UTC Pure Cell 400 converted from Lower Heating Value (LHV) to Higher Heating Value (HHV). To convert to HHV, the LHV efficiency was divided by 1.108, which is the natural gas conversion factor used by the U.S. Department of Energy, http://hydrogen.pnl.gov/cocoon/morf/projects/hydrogen/datasheets/lower_and_higher_heating_values.xls.

[69] The electrical efficiencies and overall system efficiencies of CHP Gas Turbines, IC engines and Microturbines come from the California Clean Distributed Generation Coalition (CCDC) comments filed on December 15, 2009 in this proceeding, http://docs.cpuc.ca.gov/efile/CM/111520.pdf

there is no consumption. Biogas is assumed to have the same energy content as natural gas.

In Combined Heat Power (CHP) applications, a portion of the heat generated in combustion is recovered for use. To solve for the amount of heat recovered, we begin with the heat rate (in Btu/kWh) of a given technology and multiply by the amount of kWh generated. This yields an amount of natural gas consumed in the process. A certain amount of the heat from combusting this natural gas is recovered; which varies based on the overall system efficiency of a technology. Removing the electrical generation from the system's overall efficiency shows the amount of heat recovered. This figure is adjusted based on the business-as-usual scenario, which in this case is an average boiler with 80% efficiency. Thus the avoided natural gas purchase is what would have been spent on natural gas to generate an equal amount of MMBtu in a boiler, or the *value of avoided natural gas.* As in natural gas cost calculations, the value of avoided natural gas is based on the MPR forecast price in a given year.

It should be noted that CHP applications using biogas are not required to capture any of the heat produced. To be conservative in the financial analysis, staff assumed that those biogas fueled CHP systems will not capture any available heat.

The cost of natural gas consumption is separated from operations and maintenance costs. It is calculated as the number of MMBtu used multiplied by the natural gas price (based on 2009 MPR forecast) for a given year. Due to the forecasted rise in natural gas prices, the cost of natural gas consumed increases every year. However, this is offset by the added value in avoided natural gas consumption (in CHP applications only).

O&M or warranty costs, provided by Itron to Energy Division staff in advance of their not yet completed cost-effectiveness evaluation , were converted to $/kWh. They remain constant throughout the lifetime of the project. This assumption will be vetted publicly later in fall 2010 when Itron presents its draft cost-effectiveness evaluation to the public.

Metering costs are assumed to remain constant and are not dependent on any variables or inputs in the model.

Incentives are assumed to be paid out over a six-year period with a bulk payment of 25% in year one, followed by equal payments in years two through six (assuming satisfactory performance and expected output). Investment tax credits are paid out in year one, it is assumed that developers have adequate tax appetite to take advantage of full ITC or are able to receive a grant-in-lieu-of ITC. The model initially calculates the ITC based on the capacity of the technology and percentage rebated. The ITC credit is allocated after rebates from the SGIP program are taken into account. For example, if the ITC is 30% for a given technology, this 30% is applied to the installed cost of the technology less SGIP incentives. The ITC is limited for certain technologies. Fuel cells, for example, receive a maximum of $3,000 per kW. To account for this, the model first calculates an initial ITC, and then looks for any limitations on incentive amounts. If the initial ITC is higher than the legal limit for a certain technology, the model will revert back to the legally allowed maximum ITC.

Cash flow is the net value of benefits (avoided electricity and or natural gas, plus any incentives and tax credits) less the net value of the costs (equipment purchase/installation, natural gas consumption, O&M, and metering). This cash flow figure is used for net present value, IRR, and payback period calculations. Though benefits and costs accrue at different times throughout the year, for purposes of simplicity the cash flow assumes all are received at the same time. Cumulative cash flow is simply the total net value of benefits less costs in a given year. For example, Year 2 cumulative cash flow is equal to the cash flow of Year 1 plus the cash flow of Year 2.

Net present value calculation uses the cumulative cash flow from year one as initial capital expenditure. The future benefits begin at year two, and are subject to effects of cash flow discounting. The discount rate used in the model is 5%. Though this will vary between developers and debt/equity financing arrangements, 5% was used as a median data point.

The break-even point function provides the point in time when cumulative cash flow is zero. It should be noted there is no discount used (e.g. this is simple payback).

<u>Toggles</u>
California Adder – This increases the incentive amount paid to a project by 20% per AB 2667, approved by the Governor on September 28, 2008. It is paid out in the first year in addition to the normal SGIP incentive. Thus it does not detract from the lump 25% payment in year one but is additional. In the case of calculating an ITC, the SGIP incentive and California adder are removed before applying the applicable rate.

Appendix C - Energy Storage Analysis

See attached document for Appendix C.

(END OF ATTACHMENT 1)

ATTACHMENT 2

Appendix C - Energy Storage Analysis

Advanced Energy Storage: Costs, Benefits and Policy Options

An Analysis of Customer-Side Technologies, Prepared for the California Public Utilities Commission

Susannah Churchill
May 2009

The author conducted this study as part of the program of professional education at the Goldman School of Public Policy, University of California at Berkeley. This paper is submitted in partial fulfillment of the course requirements for the Master of Public Policy degree. The judgments and conclusions are solely those of the author, and are not necessarily endorsed by the Goldman School of Public Policy (GSPP), by the University of California or by any other agency.

Abstract

Advanced energy storage (AES) includes a set of technologies capable of storing previously generated energy and releasing that energy in a controlled way at a later time, and can provide a host of benefits to the grid: it can provide emergency backup, reduce the need for peak generation capacity, provide ancillary services, facilitate demand response and help to integrate intermittent renewables. Many AES technologies are still under development, however, and little public information exists to help policymakers design appropriate support for AES deployment. This analysis, written for the California Public Utilities Commission, synthesizes information about AES benefits and lifecycle costs and uses an Excel-based optimization model to explore the customer economics of operating AES on the customer side of the meter, either with or without an onsite PV system. Policy recommendations include expanding the eligibility of an existing $2/watt AES incentive available through the Self-Generation Incentive Program to customer-side AES that operates on its own or in concert with onsite PV.

Acknowledgements and Disclaimers

A number of storage experts outside the CPUC provided invaluable input that informed my work. I would especially like to thank Janice Lin and Giovanni Damato at StrateGen Consulting for the use of their proprietary financial model and much of the data used as inputs, and for their support in using the model. Jim Eyer at Distributed Utility Associates answered many questions and kindly allowed me to cite valuable information from forthcoming reports. Mike Gravely at the California Energy Commission and Dan Rastler and Robert Schainker from EPRI provided valuable information about AES costs and benefits. Dan Kammen provided valuable insights and feedback throughout the drafting process. Thanks also CPUC staff including Molly Sterkel, Curtis Seymour and Jeanne Clinton for their feedback and support.

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Executive Summary

Advanced energy storage (AES) includes a set of technologies capable of storing energy and releasing that energy in a controlled way at a later time. AES is a versatile resource for the grid: it can act like generation, demand response, transmission or distribution depending on its location and application. This analysis aims to provide CPUC policymakers with information about AES benefits and costs and recommend policies for supporting optimal deployment of AES installed on the customer side of the meter, with a specific focus on whether a customer incentive for AES makes sense from a cost-based and/or value-based perspective.

Types of AES Benefits

The benefits of a given AES project may be diverse and accrue to many different stakeholders. The table below lists types of AES benefits and to whom they may accrue.

Types of AES Benefits and to Whom They May Accrue

Benefits to AES Owner	Benefits to Other Ratepayers and Society
• lower energy bills as demand is shifted off-peak • reliable back-up power • improved power quality • profits from selling AES resources into ancillary services and/or energy markets	• reduced need for peak generation capacity • more efficient use of renewable and other off-peak generation • reduced need for transmission and distribution capacity upgrades • transmission support and congestion relief • increased and improved availability of ancillary services • lower GHG and other emissions • lower future AES costs as market matures • jobs and other economic growth if industry locates in California

Valuation of AES Benefits

According a forthcoming study published by Sandia National Laboratories, the average economic value of three of the key societal benefits of customer-side AES systems – transmission and distribution upgrade deferral, generation capacity avoided, and transmission congestion relief -- comes to approximately $1.20 per watt. A study by the Electric Power Research Institute (EPRI) arrives at a similar value, though with different types of utility-side benefits measured.

Neither study includes certain key benefits listed above greater customer demand for renewable DG, positive impacts from reduced GHG emissions, lower future AES costs and in-state economic growth. Quantifying and monetizing the value of these benefits is beyond the scope of this study. However, it is reasonable to assume that in total, these additional benefits would be worth at least $.80/watt, bringing an accurate estimate of the societal value of customer-side AES systems to <u>at least $2 per watt installed</u>.

AES Lifecycle Costs and Installed Capacity

AES has many different applications and benefits, yet because of current energy market structure, distributed AES technologies are not able to monetize all the benefits that accrue in a particular installation, thus prohibiting rapid commercialization of these market-ready technologies. An AES system's size varies on two dimensions: power (how much electricity can be discharged at one time) and energy (how many hours can be discharged continuously). AES lifecycle costs are also impacted by system efficiency (how many useable kWh can be discharged compared to the amount charged) and by length of system life, which in turn is often dependent on how frequently and deeply the system is discharged. The table below summarizes a Sandia National Laboratories estimate of the lifecycle costs of various AES technologies assuming a 6-hour storage capacity.

Approximate $/kW Lifecycle Costs of Various AES Technologies at 6 Hours Storage Capacity, Converted from Sandia's $/kW-yr Estimates[1]

Technology	Lifecycle Cost ($/kW)
High-speed flywheel	8,962
Nickel cadmium battery	8,726
Vanadium redox flow battery	8,490
Asymmetric capacitor	7,457
Lithium ion battery	6,603
Zinc-bromine flow battery	5,660
Valve-regulated lead acid	5,283
Flooded cell lead acid	4,339
Sodium sulfur battery	4,056
Compressed air energy storage	3,301

It appears that significantly less than 50 MW of non-pumped hydro AES has been installed in the United States. Worldwide, total installed customer-side AES capacity appears to be no greater than 500 MW.

Modeling Results: Estimating AES Net Returns from the Commercial Customer's Perspective, With and Without PV

A proprietary optimization model developed by StrateGen Consulting was used to calculate the lifecycle net value of various types of AES systems from a commercial customer's perspective (based on total installed project cost, including equipment, installation, permitting and other related transaction cost). The data set used was limited primarily to one combination of load shape and TOU tariff structure, and it was assumed that an IRR of 8% is needed to make AES attractive to customers. Key modeling results include:

- Under an AES-only scenario with no AES incentive, only sodium sulfur batteries provide anything approaching an 8% IRR (at 6%), even under a

[1] See the Costs section of this report for the assumptions used in Sandia's lifecycle cost estimates.

'peaky' load shape. This implies that without an AES incentive, customer-side AES deployment is unlikely to increase significantly.

- When a $2/watt AES incentive applies, two technologies provide an 8% IRR or greater under an AES-only scenario (flooded-cell lead acid and sodium sulfur batteries), while two others provide a 5% IRR or greater. Given that PV is in high demand from California commercial customers and the PV-only IRR is less than 5% in these model runs, a $2/watt AES incentive may significantly boost customer demand for stand-alone AES.
- In combination with a PV system and assuming a 'peaky' load shape, only flooded-cell lead acid and sodium sulfur batteries causes the customer's IRR to increase compared with PV alone (each by approximately 1%), assuming current PV incentives and no AES incentive. This implies that some PV customers with similar load shapes would buy storage without an AES incentive as long as they made aware of its availability and benefits.
- With an AES incentive of $2/watt, the same two AES technologies bring the IRR of the PV-plus-storage system for the customer with the more peaky load shape to approximately 7.5%, approaching the 8% return that would be competitive with many other investments. Using two other, flatter commercial load shapes reduces the IRR in this scenario by up to 1.5%, but still provides greater returns to the customer than PV alone.

CPUC Policy Recommendations for Promoting Optimal Deployment of Customer-Side AES

The original white paper made several recommendations for future CPUC actions related to AES. These recommendations have been removed from this version of the white paper, and instead are replaced by the recommendations in the SB 412 staff proposal that appears above.

I. Introduction

A. Background

California policymakers face a host of challenges as they work to ensure reliable, affordable electricity for a growing population while moving away from reliance on fossil fuels. Total electricity demand and peak demand are growing quickly in California while state energy goals seek to increase generation from renewable sources and to modernize the grid so that demand can be more intelligently managed to account for the time-varying value of electricity. One reason why electricity planning and delivery is so challenging is that cheap and effective options for storing large amounts of power are limited. Without significant amounts of advanced energy storage (AES) acting as a 'shock absorber' for California's electricity system, supply and demand must be managed to match closely at any given moment, requiring expensive and inefficient investments in generation, transmission and distribution resources that may only be needed during times of highest demand. AES is a versatile resource for the grid: it can provide emergency backup, generation (spinning reserve) and ancillary services, facilitate demand response and help to integrate intermittent renewables into the grid. The value of the AES will depend heavily on its location and application.

As valuable as adding storage could be for California's power grid, many AES technologies are still early in their development, and existing commercial projects are in short supply worldwide. Global AES manufacturing capacity is still relatively small, estimated at less than 500 MW for all technologies;[2] worldwide AES installed capacity is less than 1 GW[3] (excluding pumped hydro, of which there is approximately 90 GW of installed capacity). Japan is the world's leader in AES deployment, with over 100 battery installations and about 300 MW operational. California policymakers are aware that proactively supporting the development of AES could be a smart strategy for meeting the state's long-term clean energy goals and maintaining system reliability, but little concrete information about AES costs and benefits is available to form a rational basis for policy action.

However, the market potential for AES in California could be very large given the wide range of benefits that AES could provide to a state with growing and peaky demand, increasing intermittency of supply and severe transmission constraints. Sandia National Laboratories estimated California AES market potential for energy and demand cost management at more than 7500 MW over ten years, with demand for avoided transmission congestion charges at 2900 MW and demand for ancillary services including area and voltage regulation at 800 MW over the same time period.[4]

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[2] MegaWatt Storage Farms Response to CPUC AES Data Request filed March 4 2009.

[3] Estimates from "The Potential of Wind Power and Energy Storage in California," Diana Schwyzer, Masters Thesis for Energy and Resources Group at UC Berkeley. November 2006. p. 22.

[4] James M. Eyer and Garth Corey. "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide; A Study for the DOE Energy Storage Systems Program." Draft Report. March 2009. See Appendix B for Sandia's estimates of market potential and assumptions.

B. Origin of This Analysis and Key Questions Addressed

This analysis was requested by Molly Tirpak-Sterkel, supervisor of the California Solar Initiative (CSI) and Distributed Generation (DG) programs in the CPUC's Energy Division. Energy Division CSI and DG staff were interested in learning more about AES in general and more specifically in the costs and benefits of deploying additional customer-side AES, particularly in conjunction with DG solar, and in what policies (including a customer incentive) might make sense for increasing customer-side AES deployment.

Several sections of this paper, including the beginning portions of the costs and benefits sections and the appendices listing policy options and technology descriptions, synthesize information about both customer-side and utility-side AES. The more quantitative portions narrow to a focus on customer-side AES, due to time constraints and because the CSI and DG team is most interested in customer-side applications.

The key questions addressed in this analysis include:

1) What is AES and what are the relevant technologies?

2) What kinds of benefits could be provided by increased AES deployment in California, and what does existing analysis say about how much customer-side AES benefits are worth?

3) What are AES current and future lifecycle costs, and how much installed capacity currently exists?

4) If CPUC wanted to create incentives for *customer-side* AES on its own or coupled with a PV system, what size incentive would be defensible from a value-based perspective (ie. commensurate with the value of AES to ratepayers or society) and from a cost-based perspective (ie. providing sufficiently attractive financial returns to the customer to significantly increase AES deployment)? What other actions should CPUC take to support optimal deployment of customer-side AES?

5) How much could deployment of *customer-side* AES reduce systemwide peak demand, assuming an incentive level appropriate from both a cost-based and value-based perspective?

C. Definition of AES

Advanced energy storage (AES) is used in this analysis to refer to a set of technologies capable of storing previously generated energy and releasing that energy in a controlled way at a later time. AES technologies may store electrical energy as potential, kinetic, chemical, thermal or electrical energy, and include various types of batteries, flywheels, electrochemical capacitors, compressed air storage, thermal storage devices and pumped hydroelectric power (a description and comparison of AES technologies is included as Appendix C).

Thermal energy storage, which converts electricity to heat or cold and releases the energy in thermal form as well, is not included in this analysis due to scope reasons. Hybrid and electric vehicles are also excluded from this analysis to keep the scope manageable, although such vehicles do fall under this definition of AES when used to store and discharge electricity back into the grid.

D. Recent State and Federal Policy Developments Relevant to AES

Policymakers within various California regulatory bodies are already at work gathering information about AES benefits and costs, supporting AES research and debating the merits of further policy support for AES.

The California Independent System Operator (CAISO) is developing a pilot program to study how various AES technologies might provide products for California's ancillary services markets, seeking via the program to identify and remove market barriers that currently make it difficult for AES to compete in the regulation market.

The California Energy Commission (CEC) has funded storage research and demonstration projects. On April 2, 2009, CEC held a workshop[5] asking stakeholders to provide information about why more utility scale energy storage technology systems are not being fielded throughout the state and nation, and what actions or policies California can consider to encourage or accelerate the fielding of more large, utility scale electricity energy storage systems in California in time to support the RPS goal of 33% by 2020. The State Legislature is considering the passage of AB 44 (Blakeslee), a bill that would direct the California Public Utilities Commission (CPUC) to develop appropriate new support for AES technologies.

In November 2008, the CPUC approved what may be the nation's first incentive for customer-side AES under the Self-Generation Incentive Program (SGIP), providing an incentive of up to $2/watt if the storage is coupled with SGIP-eligible DG renewables (currently small wind and fuel cells).[6] Ratepayer funding for demand response has also been made available via the California IOUs for thermal energy storage deployment. The California Legislature is currently considering a bill (AB 1536 by Assembly Member Blakeslee) that seeks to expand the role of AES in SGIP.

At the federal level, the Energy Independence and Security Act of 2007 directed the U.S. Department of Energy (DOE) allocated $295 million to supporting AES. One of the first major programs in this initiative is DOE's recently announced solicitation for utility-scale energy storage demonstration projects. In addition, Section 1302 of the American

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[5] See http://www.energy.ca.gov/2009_energypolicy/notices/2009-04-02_staff_workshop.html for CEC workshop notice.

[6] See CPUC Decision (D.) 08-11-044

Recovery and Reinvestment Act of 2009 appears to create the first US federal tax incentive for AES, providing a new 30% tax credit for investment in manufacturing facilities that produce equipment including "electric grids to support the transmission of intermittent sources of renewable energy, including storage of such energy." As of this writing, there do not appear to be any federal tax incentives for the deployment of AES; for example, the 30% investment tax credit for PV systems added to US code[7] by the Energy Improvement and Extension Act of 2008 appears to apply only to equipment that generates electricity, not equipment that stores it.

[7] Title 26, section 48, see http://www4.law.cornell.edu/uscode/26/usc_sec_26_00000048----000-.html

II. Benefits of AES Technologies

AES technologies can provide a broad range of benefits. As many storage experts and observers note, the fact that the benefits of one AES project may be diverse and accrue to many different stakeholders is one of the main barriers to developing storage markets. The value of a single AES installation is often divided between the customer or third party owning the AES system, utility shareholders, utility ratepayers, and society at large, so it is difficult for one set of stakeholders to capture enough of this value to outweigh the technologies' currently high costs, even if all these value streams are properly priced in the relevant markets. In addition, three different agencies oversee the design of market rules and tariffs for energy generation, transmission and ancillary services in California (CPUC, CAISO and FERC).

Sections A and B below describe the broad categories of AES benefits for a) the AES owner (which could be either a customer or a third party owning and operating the system) and b) all others who are not the AES owner, a group which I call here "ratepayers and society." Section C describes estimates from two public studies that quantify and monetize the value of various AES benefits; both studies arrive at similar valuations of some ratepayer benefits of customer-side AES. A number of AES benefits that accrue to ratepayers and Californians as a group, however, are missing from these two studies, making their estimates too low to be fully accurate.

A comprehensive methodology for quantifying and monetizing the full range of benefits, however, is beyond the scope of this paper; that task may be addressed via the Commission's cost-benefit methodology for distributed generation technologies and programs, in an AES-specific proceeding or some other Commission proceeding.

A. Potential Benefits to AES Owner

1. Energy bill savings from shifting demand to off-peak times: AES allows customers to change when they draw power from the grid to meet demand. For customers on time-of-use (TOU) rates (ie. who pay more for power during times of higher demand on the grid), AES allows energy arbitrage opportunities whereby the AES system charges during off-peak times and discharges when the cost of energy is high.

The economic value of this load-shifting to the customer will vary depending on their load shape and tariff, as well as on how much and at what times AES is used. Many commercial and industrial power customers in California have tariffs that consist of an energy charge, which is based on how many kilowatt-hours of energy have been used in a given time period, and a demand charge, which is based on the size of maximum demand within one month. Use of storage can reduce energy charges if the spread between on-peak and off-peak time of use rates is larger than the value of the energy that is wasted via storage's inefficiency. Larger savings will more likely come, however, from reduced demand charges, if AES reliably reduces the size of the customer's maximum demand peak in a given month. Customers with PV can use storage to mitigate the intermittency of the panels' power production, thereby reducing the customer's demand charge by making the PV output a more reliable method of reducing on-peak demand from the grid. (The value of customer-side AES to commercial customers both with and without PV is discussed in more detail in the Modeling Results section of this analysis.)

2. Reliable back-up power: AES technologies can provide customers with electricity for a period of hours when utility power is not available. These technologies are not a full substitute for a fossil fuel stand-by generator because they do not have they are too expensive to be designed to discharge for multiple days at once, but they can provide a lower-emissions, fuel-free source of back-up power for shorter outages. The value of backup power will be very specific to each end-user, since it will equal the value of the business losses that come from a power outage. Lawrence Berkeley National Laboratories estimated the annual cost for power interruptions to U.S. electricity consumers at $79 billion.[8]

3. Improved power quality: Some commercial and industrial customers' manufacturing or other processes are harmed if their power varies in frequency and voltage. AES can act like a system filter and eliminate these power quality inconsistencies. Again, the value of improved power quality will vary greatly by customer.

4. Profits from selling AES resources into ancillary services and/or energy markets: To the extent that AES owners are able under market rules to sell into ancillary services markets (discussed in more detail in the section below on societal benefits) or wholesale energy markets, they can profit from these services. Third-party owners of flywheels, for example, currently seek to sell into CAISO regulation markets for both Up and Down regulation (although many flywheels do not yet meet requirements for participation in these markets, a discussed later in this paper). A customer-side battery could also sell into the regulation or operating reserves markets during times when at least some of its capacity is not being used for shifting its own load, assuming there is a communications system capable of receiving signals from the grid operator's computer and responding within a minute or less by increasing or decreasing the output of the AES system.

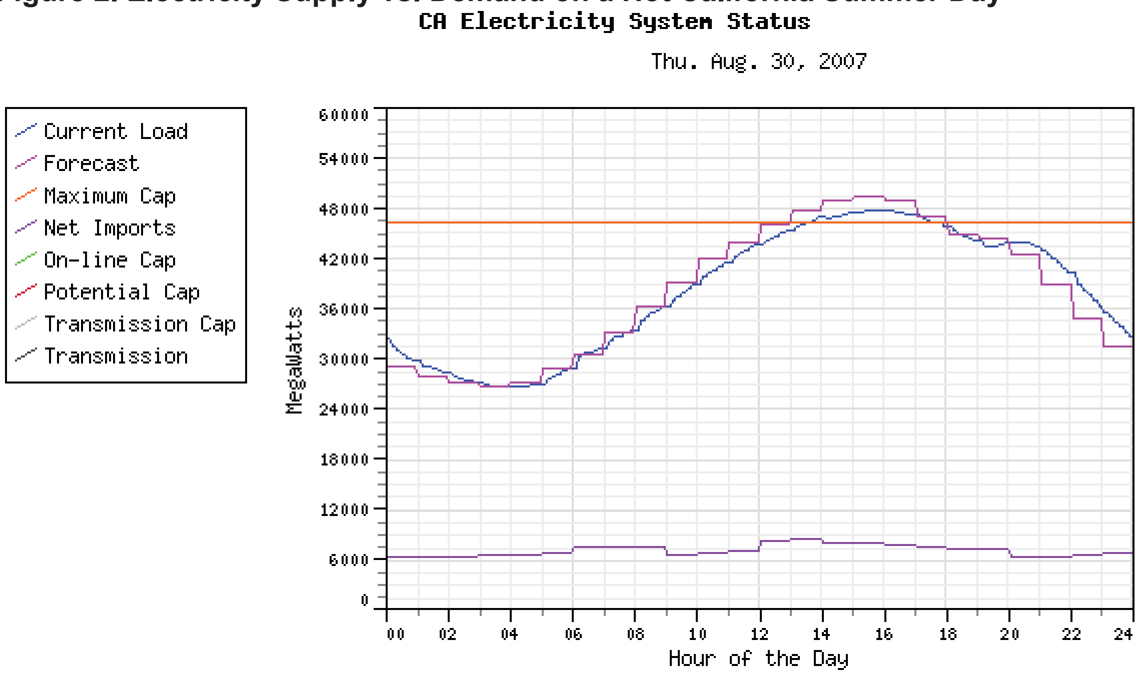
E3 shed some light on the likely profitability of AES selling into energy and ancillary services markets in their response to Energy Division's AES data request. E3 reported the results of a study that used 2006-07 data to analyze potential revenues for wholesale energy storage providers in several US markets (NYISO, PJM, ISO-NE and CAISO). The analysis found that even in markets with capacity payments, regulation markets account for at least 75% of expected revenues for wholesale energy storage, capacity payments provided about 5% (increasing to 22% in ISO-NE where capacity payments are higher), and wholesale energy arbitrage also provided only a limited percentage. In California, where there is currently no capacity-only market, energy arbitrage revenues from AES would provide an estimated 25% of revenues, and regulation would provide an estimated 75% of revenues.

[8] Kristina LaCommare and Joseph H. Eto. "Cost of Power Interruptions to Electricity Consumers in the United States (U.S.)" Lawrence Berkeley National Laboratories, February 2006.

B. Potential Benefits to Ratepayers and Society from Increased Deployment of AES

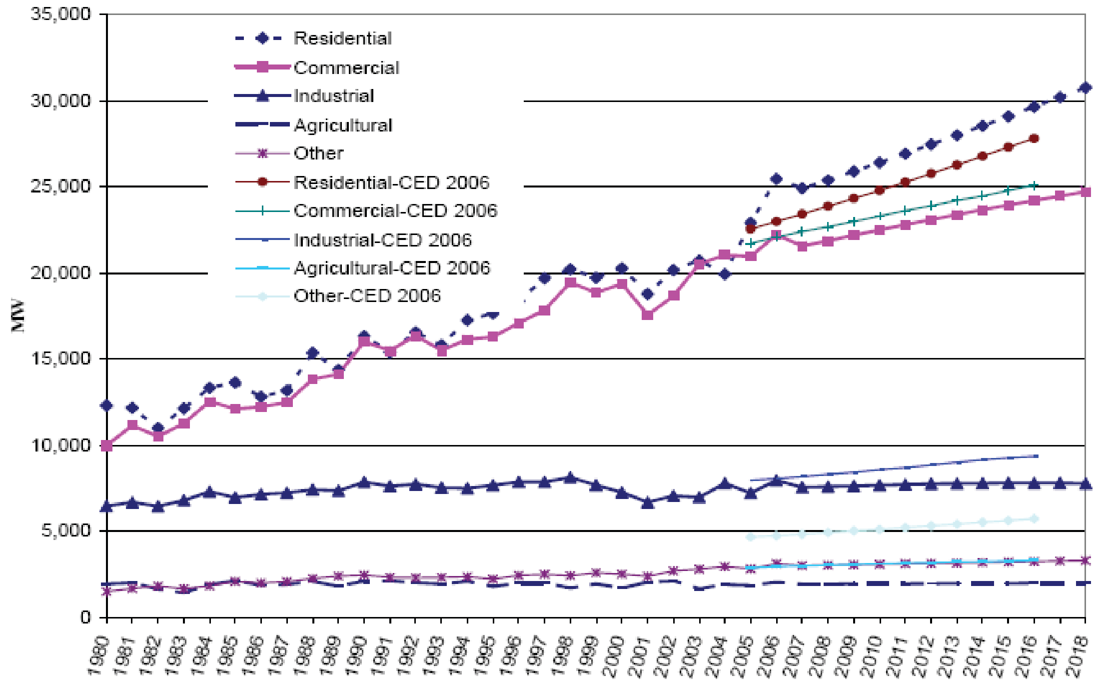
1. Reduced need for peak generation capacity: By allowing customers, utilities or power generators to store energy off-peak and discharge on-peak, storage provides an alternative to the construction and operation of new generation capacity and reserve capacity. Offsetting the need for new generation capacity is the more valuable of the two because reserve capacity tends to be from less expensive older, less efficient plants or "derated" generation facilities. Both kinds of capacity are needed only during times of high demand. The figure below shows the 'peakiness' of demand on a California summer day in California; note that on-peak demand is nearly twice as much as nighttime demand.

Figure 2. Electricity Supply vs. Demand on a Hot California Summer Day



Peak demand growth is a major concern for California electricity planners, exacerbated by the fact that populations in the hotter central and southern parts of the state are growing fastest. The California Energy Commission projects that average peak demand will grow by 1.3 - 1.4% annually between 2008 and 2018, with residential peak demand projected to grow at 1.9% annually (see figure below). The value of the avoided cost of peak generation capacity will continue to increase as peak demand grows and as carbon emissions become more expensive.

Figure 3. California Statewide Peak Demand by Sector (MW)



Source: "California Energy Demand 2008-1018, Staff Revised Forecast," California Energy Commission, November 2007. p.17. http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF

Reducing the need for growth in peak power capacity specifically associated with high penetration of renewables in California will be an important benefit of AES. Because solar and wind, for example, produce power during high-demand times but are intermittent (due to unpredictable factors like cloud cover and wind speeds), utilities will have to provide more peak power capacity to accommodate variations in renewable output unless storage can be used instead to firm and shape renewable generation.

To the extent that on-peak generation converts natural gas to electricity less efficiently than off-peak generation, reduced demand for peak generation capacity and energy also reduces demand for natural gas, thereby lowering natural gas prices.

2. More efficient use of renewable and other off-peak generation: California's clean energy and GHG emissions reduction goals will require a large increase in wind and other renewable electricity generation in coming decades, with an estimated 3000 MW of additional renewable generation needed to meet the 20% California RPS.[9] Wind in California tends to blow most strongly at night, and CAISO predicts a serious mismatch of load and generation in the off-peak hours of 11 pm to 6 am, including as much as 3000 to 5000 MW of excess off-peak capacity.[10] Rather than forcing renewable generators to curtail off-peak production, AES can allow excess wind and other off-peak energy to be stored and used during high-demand times (though AES efficiency losses would reduce

[9] CPUC RPS Quarterly Report, July 2008. p.4. http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf.
[10] CAISO Response to CPUC AES Data Request, filed March 4 2009.

the renewables facility's net output). For firming utility-scale renewable energy capacity, bulk energy storage is needed to absorb and store many hours of generation. Technologies like pumped hydro or compressed air energy storage (CAES) are relevant for bulk energy storage instead of technologies that provide short bursts of power, such as flywheels and supercapacitors, or more modular technologies appropriate for distributed applications, like batteries.

Renewable energy generators are permitted to include AES in their RPS bids in California. However, RPS rules do limit the amount of fossil fuels that can be used in a system, so some AES technologies (for example some forms of CAES) may be precluded. So far, few to no California RPS bids have included AES.[11] A few utility-scale PV projects in commercial operation in other countries including Japan[12] provide real-world examples of AES being used to firm large-scale renewable generation.

3. Reduced need for transmission and distribution capacity upgrades: AES can be used to maximize existing transmission and distribution (T&D) resources. For example, customer-side AES shifts demand off-peak, delaying the need for new T&D upgrades that would have been needed only to accommodate growth in peak demand. AES located at the transmission substation level can be dispatched by the utility to meet peak demand in a transmission-constrained region with power charged off-peak; American Electric Power is pioneering this application, using a 5 MW sodium sulfur battery to solve a transmission issue in Southern Texas.[13]

As discussed in a soon-to-be-published study from Sandia National Laboratories,[14] the value of T&D upgrade deferral varies greatly by location within California and is driven by the population density of the area, terrain, geology, weather, and the type and amount of T&D equipment involved. The study presents evidence that T&D marginal costs in California vary by a factor of seven among locations in the territories of the three large IOUs, and that the percentage of those costs that are related to peak demand during the summer can vary by up to 103%. The figure below displays the variation in weighted average annual T&D avoided cost, by climate zone, for the three major California utilities.

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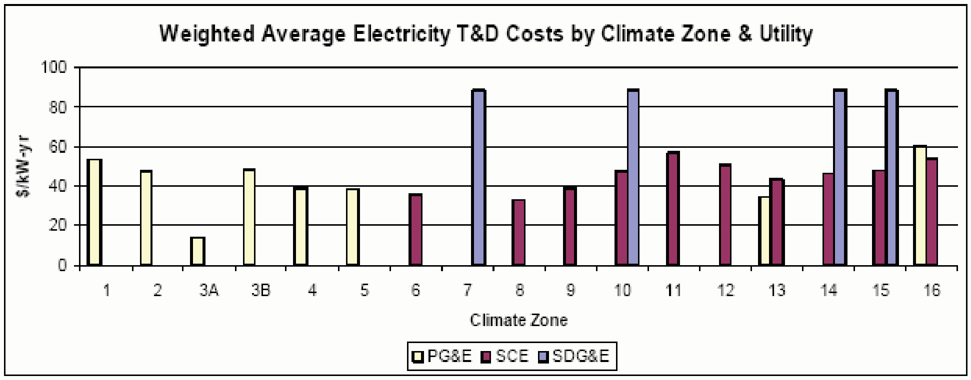
[11] Per communications with CPUC Energy Division RPS staff.

[12] See for example the 2 MW Wakkanai Solar Project, which uses sodium sulfur batteries to firm its solar output. Horizon Power is developing solar-diesel projects of more than 1 MW each, which will be combined with flywheel technology as storage, in Western Australia.

[13] "Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid," Electricity Advisory Committee, Dec 2008. p. 10.

[14] "Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage: A Study for the DOE Energy Storage Systems Program," Jim Eyer, Sandia National Laboratories. Forthcoming in 2009.

Figure 4. Weighted Average Annual T&D Avoided Cost for Large Investor-Owned Utilities in California[15]



Note: Climate Zone 3A includes San Francisco, East Bay, and Peninsula sub-areas, while 3B includes portions of Central Coast, Mission, and North Bay.

Source: Jim Eyer, "Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage: A Study for the DOE Energy Storage Systems Program," Sandia National Laboratories.

Similar results (expressed as $/kW installed instead of $/kW-yr) were published in The Energy Journal.[16] That study found that within PG&E's territory, 19% of distribution planning areas have zero T&D deferral value, while the average and maximum T&D deferral benefit values are $230/kW and $1,173/kW, respectively.[17]

4. Transmission support and congestion relief: AES can be used to improve T&D system performance by alleviating problems like voltage sag and unstable voltage. In addition, AES can help to avoid transmission congestion by discharging in congested areas at times of peak demand. For this purpose AES can be located either at the customer location or at an appropriate location on the transmission or distribution system. Note that as discussed above regarding T&D upgrade deferral, the range of values for T&D congestion relief between locations will be large.

5. Increased and improved availability of ancillary services: Ancillary services are services necessary to support the transmission of energy from generation resources to consumers, while maintaining the reliable operation of the transmission system. There are two primary types of ancillary services sold in California, both of which could be provided by AES: frequency regulation, which ensure the grid operates within an allowable range of interconnection frequencies, and operating reserves, which ensure that more energy can be added to the system within a short period of time to meet unexpected increases in demand or reductions on supply. Ancillary services account for 5–10% of

[15] The Sandia study noted above cites E3's 2004 Avoided Cost calculations as the source for this figure.

[16] The Sandia study noted above cites Energy Journal article: Woo, C., Lloyd-Zannetti, D. Orans, R. Horii, B. (Energy and Environmental Economics) and Heffner, G. (EPRI). *Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation.* The Energy Journal. 1995.

[17] Values expressed in 1999 dollars

electricity cost, or about $12 billion per year in the U.S., with 80% of that cost going to regulation.[18]

CAISO estimates that significant new regulation capacity will be needed to manage intermittent renewables under a 20% RPS: a November 2007 CAISO report estimated an increased need of up to 250 MW for "up" regulation and up to 500 MW for "down" regulation.[19]

Certain types of AES, including flywheels and supercapacitors, can be excellent regulation resources compared with more conventional regulation resources like hydro or combustion turbines because they can be dispatched very quickly and at high power. A 2008 study by the Pacific Northwest National Laboratory found that adding more fast-responding regulation resources could reduce CAISO's regulation procurement needs by as much as 40%.[20] Beacon Power notes that since Californians spent $109 million on Regulation Reserves in 2008, a 40% annual savings equals $43.6 million or about $0.018/kWh.[21]

6. Lower GHG and other emissions (and by extension lower cost of compliance for AB 32 and other environmental regulation): AES can reduce emissions by shifting on-peak energy use to off-peak. In California, relatively little baseload power comes from coal and much comes from hydroelectric and nuclear power, so off-peak generation generally has a cleaner emissions profile than largely gas-fired peak power. As renewables like wind increase as components of the off-peak power mix, the emissions benefits of AES will continue to grow.

AES is also a lower-emissions alternative for providing ancillary services. A study by KEMA found that regulation provided by a 20 MW flywheel AES system's created less than half the GHG emissions of equivalent regulation from a combined cycle gas turbine and less than three quarters of the emissions of a pumped hydro plant providing equivalent regulation.[22]

7. Lower future AES costs as market matures: As learning-by-doing, economies of scale and additional research and development spurred by increased demand allow AES manufacturers, integrators and installers to become more efficient, investments in AES deployment may reduce the costs of AES and related technologies in the future. Quantifying and monetizing the benefit of future cost reductions can be difficult, but policymakers often make the judgment that spurring market transformation in technologies with many positive externalities is worth some public investment.

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[18] "Vehicle-to-grid power fundamentals: Calculating capacity and net revenue." Kempton, Willett, and Jasna Tomić. Journal of Power Sources 144, no. 1 (June 1, 2005). P. 271.

[19] Clyde Loutan, David Hawkins et al. "Integration of Renewable Resources," California Independent System Operator, Nov 2007, p.7.

[20]Y.V. Makarov, S. Lu et al. "Assessing the Value of Regulation Resources Based on Their Time Response Characteristics." Pacific Northwest National Laboratory, June 2008.

[21] Beacon Power Response to CPUC AES Data Request, March 13 2009.

[22] Richard Fioravanti and Johan Enslin."Emissions Comparison for a 20 MW Flywheel-Based Regulation Plant." KEMA, January 2007.

8. Employment and other economic growth if industry locates in California: As more storage is deployed here, new jobs could be created in manufacturing and installation, boosting the state's economy and providing a new source of tax revenue.

C. Results from Existing Analyses Estimating Monetary Value of Societal AES Benefits

While many studies discuss the numerous benefits of AES qualitatively, few analysts have attempted to quantify or monetize the societal benefits associated with a kilowatt of AES capacity installed (that is, monetizing the benefits that accrue to everyone except the customer or other party who owns or operates the AES system). However, some estimates of these values will be needed as policymakers determine if incentives for AES deployment are cost-effective from a societal perspective. Discussed below are the results of two recent public studies attempting to monetize AES benefits; they both arrive at a societal benefit of approximately $1.20 per watt for customer-side AES with a 6-hour energy reservoir, although both studies leave out some relevant but difficult-to-quantify types of societal benefits.

Sandia Study

One public analysis, a 2004 report for DOE's Energy Storage Program by Sandia National Laboratories, estimated the net present value of ten years' worth of various utility-related AES benefits. The study estimated the value of various benefits in kW-yr and then added ten of those years together and discounted to present value. Jim Eyer, one of the report's authors, will be updating the 2004 numbers in a forthcoming report and has provided the more up-to-date estimates for this analysis, listed below in Table 1.[23] Sandia's assumptions are included in Appendix B.

[23] A shorthand way to convert the ten-year $/kW value to a $/kW-yr metric, assuming 2.5% escalation and a 10% discount rate, is to divide the $/kW value by 7.17.

Table 1. Estimated Benefits, Market Potential and Economic Impact for Energy Storage for 17 Applications

		Discharge Duration*		Benefit ($/kW)**		Potential (MW, 10 Years)		Economy ($Million)†	
#	Type	Low	High	Low	High	CA	U.S.	CA	U.S.
1	Electric Energy Time-shift	2	8	400	700	1,445	18,417	795	10,129
2	Electric Supply Capacity	4	6	359	710	1,445	18,417	772	9,838
3	Load Following	2	4	600	1,000	2,889	36,834	2,312	29,467
4	Area Regulation	15 min.	30 min.	785	2,010	80	1,012	112	1,415
5	Electric Supply Reserve Capacity	1	2	57	225	636	5,986	90	844
6	Transmission Support	2 sec.	5 sec.	192		1,084	13,813	208	2,646
7	Voltage Support	15 min.	1	400	800	722	9,209	433	5,525
8	Transmission Congestion Relief	3	6	31	141	2,889	36,834	248	3,168
9.1	T&D Upgrade Deferral 50th percentile	3	6	481	687	386	4,986	226	2,912
9.2	T&D Upgrade Deferral 90th percentile††	3	6	759	1,079	77	997	71	916
10	Substation Onsite Power	8	16	1,800	3,000	20	250	47	600
11	Time-of-Use Energy Cost Management	4	6	1,226		5,038	64,228	6,177	78,743
12	Demand Charge Management	5	11	582		2,519	32,111	1,466	18,695
13	Electric Service Reliability	5 min.	1	359	978	722	9,209	483	6,154
14	Electric Service Power Quality	10 sec.	1 min.	359	978	722	9,209	483	6,154
15	Renewables Energy Time-Shift	3	5	233	389	2,889	36,834	899	11,455
16	Renewables Capacity Firming	2	4	709	915	2,889	36,834	2,346	29,909
17.1	Wind Generation Grid Integration, Short Duration	10 sec.	15 min.	500	1,000	181	2,302	135	1,727
17.2	Wind Generation Grid Integration, Long Duration	1	6	100	782	1,445	18,417	637	8,122

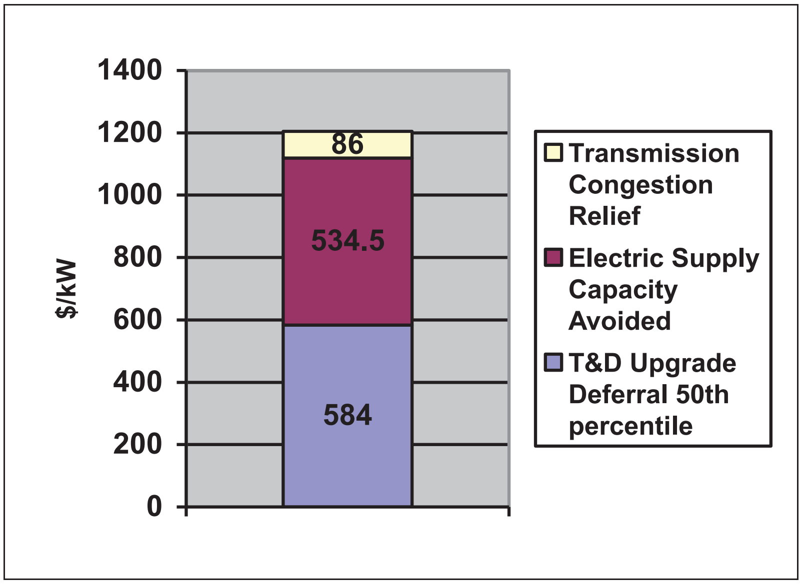
*Hours unless indicated otherwise. min. = minutes. sec. = seconds.
**Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.
†Based on potential (MW, 10 years) times average of low and high benefit ($/kW).
††Values are for one year. However, strorage could be used at more than one location, for similar benfits, during its life.

Source: Eyer, James M. and Garth Corey. "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide; A Study for the DOE Energy Storage Systems Program." Draft Report. March 2009.

5 below adds the average of the low-high values of the relevant categories of benefits developed by the Sandia study to estimate the total value per kW of some of the <u>societal</u> benefits of customer-side AES systems. (The customer would capture some of the other benefits including the value of energy time-shifting and demand charge management.) Figure 5 represents the value of some of the positive externalities of AES deployment for California ratepayers, and can be used as a basis for deciding what size ratepayer- or taxpayer-funded incentive might be appropriate for customer-side AES, though other types of benefits not quantified here should also be considered.

Since AES applications and benefits differ significantly depending on where on the system the technology is located, a different set of benefits would accrue from grid-connected AES or AES coupled with utility-scale renewables generation, and consequently a different size incentive might be appropriate.

Figure 5. Value of Some Societal Benefits of Customer-Side AES: Data from Sandia National Laboratories Study



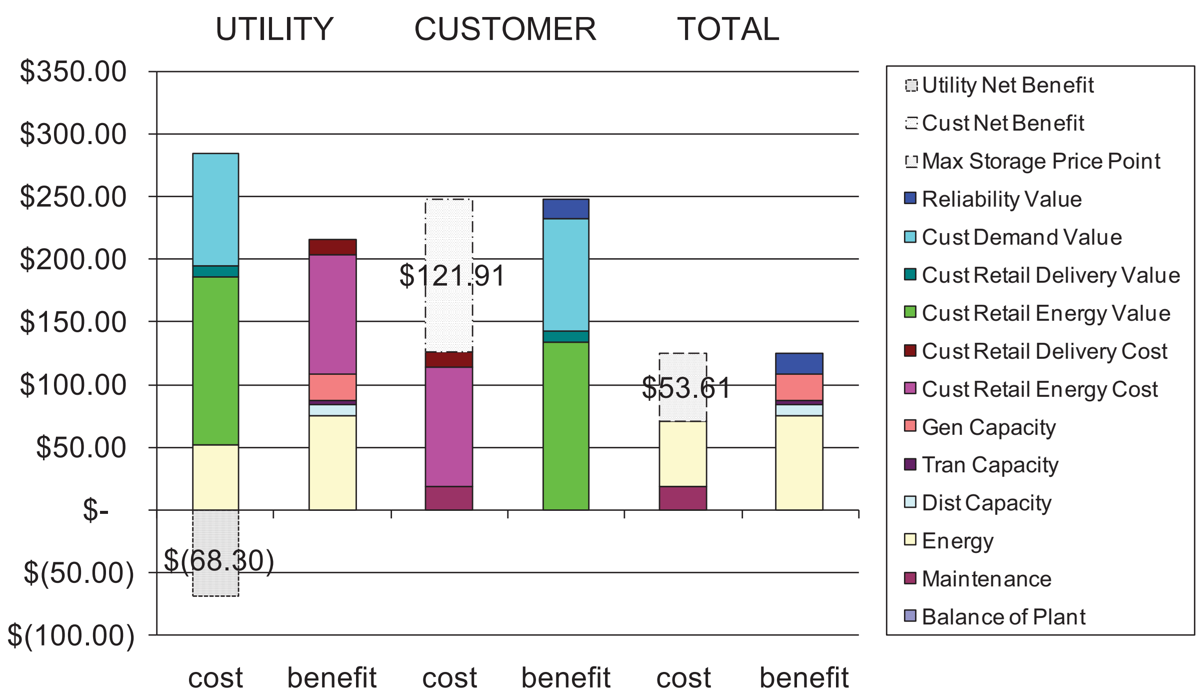
This summed value for quantified societal benefits of $1205/kW, or $1.20/watt, is very close to the value of ratepayer benefits found in the EPRI study discussed below when the EPRI values are converted from $/kWh to $/kW. Note that neither estimate takes into account the value of frequency regulation, a potentially highly valuable application of AES estimated at $1397/kW if the Sandia high and low values are averaged. It would not be accurate to add this value to the above sum because any given kW of customer-side AES cannot be used for energy and demand charge management and for regulation purposes at the same time (even assuming the customer has the two-way communication capabilities to be able to operate their AES system to provide regulation). If the customer sold some AES capacity into the frequency regulation market (see Appendix A for a discussion of how CAISO market rules might need to change to allow that to happen), the customer could recover the value of that societal benefit.

EPRI Study

In 2008, researchers produced a report for EPRI that sought to identify the market requirements, specifications, and functionality of distributed energy storage systems for a selected set of commercial sector buildings. The market scale and value of energy storage systems were estimated using a financial modeling tool[24] that can estimate the value of AES from utility, end-use customer and societal perspectives. The study focused on California and New York.

Below is a graph showing the results of the portion of the study focused on customer-side AES in San Francisco. It was assumed that the commercial customer with an 835 kW peak load was on a PG&E's TOU tariff, and that the AES system ran at 1500 cycles per year with 80% efficiency and with an 11-hour discharge. The utility side (ie. societal or ratepayer, not counting the customer) benefits sum to approximately $210 per kWh, as seen in the column second from left below. For a 6-hour system, which is our assumption for customer-side AES that can discharge continuously for full peak hours, this works out to $210 * 6 = $1260 in benefits per kW. As noted above, this value is close to Sandia's estimated $/kW value for customer-side AES used in a customer-side application. The assumptions used for EPRI's San Francisco customer-side AES section of the study are listed in Appendix B.

Figure 6. EPRI's San Francisco Energy Storage Valuation Tool Results (TOU Schedule with Fixed Dispatch)



Source: "Market Requirements and Opportunities for Distributed Energy Storage Systems in the Commercial Sector, Leveraging Energy Efficiency Initiatives." EPRI 2008

Neither Sandia's nor EPRI's estimates of the monetary value of societal AES benefits above include certain important but more difficult-to-quantify benefits of customer-side AES deployment such as:

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[24] EPRI EVAT 2.0. Product ID 1013749

- the value of displacing regulation and load-following services from thermal power plants with faster and more effective AES resources,
- the value of AES reducing the payback period for renewable DG systems and thus making renewable DG attractive to more customers,
- the value from the load-serving entity's perspective of reducing greenhouse gas emissions associated with peak electricity production,
- the value from society's perspective of reducing greenhouse gas emissions associated with peak electricity production, for example health, agricultural and water supply benefits,
- the value of reducing future AES and related technology costs by increasing capacity manufactured, and
- the value of new jobs and other economic growth created by additional AES manufacturing and installation in California.

Quantifying and monetizing the value of these benefits is beyond the scope of this study. However, it is reasonable to assume that in total, these additional benefits would be worth at least $.80/watt, bringing an accurate estimate of the societal value of customer-side AES systems to at least $2 per watt installed.

III. AES Lifecycle Costs and Estimates of Existing Installed Capacity

A. Background

Estimating the lifecycle costs of AES technologies deployed in California is difficult for several reasons. First, not many commercial AES projects exist worldwide and costs for demonstration projects are often not indicative of future costs, so there is little empirical information. Second, cost information is often closely guarded by companies who are in intense competition with each other. Third, permitting and other installation-related costs vary greatly by state, so it is difficult to predict total installed costs in California given that very few projects are located here. Fourth, there is little price uniformity due to the immaturity of the market; many companies trying to purchase AES systems note that price quotes for one type of AES system can vary wildly based on manufacturing company, volume ordered and timeline.

An AES system's size varies on two dimensions: power (how much electricity can be discharged at one time) and energy (how many hours can be discharged continuously). In addition, AES system costs are impacted by system efficiency (how many useable kWh can be discharged compared to the amount charged) and by length of system life, which in turn is often dependent on how frequently and deeply the system is discharged. All of these factors mean that an AES technology's cost cannot be meaningfully estimated independently of the way in which it is used.

AES lifecycle costs are made up of two basic components-- capital costs and operating and maintenance (O&M) costs. Information on capital costs has been estimated in a number of public analyses, while O&M cost estimates are more difficult to find. The most commonly used metric for AES costs is $/kW-yr, or how much a kW of capacity costs to own and operate for one year. This section reports capital and O&M cost information using primarily $/kW-yr as a metric, and also summarizes AES total lifecycle costs estimated by Sandia National Laboratories in $/kW and $/kWh discharged.

B. Capital Costs

AES capital costs are all the costs required to install the system, including 'balance of plant' costs such as the cost of power conversion electronics. Capital costs are a function of the system's power and the size of its reservoir of energy, and can be described by the following equation:

$$\text{Nominal \$/kW-yr}_{\text{Capital}} = \frac{\text{\$/kW (incl. BoP)} + (\text{\$/kWh} * \text{hours of storage in reservoir})}{\text{System life (years)}}$$

Table 2 below summarizes some recent public estimates of the capital cost components for various AES technologies. To find the total capital cost, the numbers below are plugged in to the above equation along with the number of storage hours needed. For example, if a customer wanted to buy a battery that could discharge for four continuous hours to supplement its PV system's peak-shaving capabilities, one would plug in 4 as the number of hours of storage in the reservoir.

Table 2. Estimates of Current AES Capital Cost Elements ($ per nominal kW and kWh), BoP Costs Included (except where noted), Operating & Replacement Costs Not Included

	Tech Type	EPRI 2008		Sandia July 2008		Sandia Feb 2008		Tiax		ESA website	
		$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW	$/kWh	$/kW
Batteries	Valve-regulated lead acid	350-400	450-550	200		200*	225			500-1000	400-900
	Flooded-cell lead acid	330-480	420-660	150		150	225	100-150		500-1000	400-900
	Nickel cadmium			600		600	225	500-600		800-3000	700-1500
	Zinc bromine flow			500		400	175	400-500		200-3000 (for all flow)	750-2900 (for all flow)
	Lithium ion			1333		500	175	Not avail yet		800-5000	1300-5000
	Sodium sulfur			450		250	150	250		300-1000	1000-2800
	Vanadium redox flow	280-450	425-1300	20kWh = 1800, 100 kWh= 600		350	205	350-500		200-3000 (for all flow)	750-2900 (for all flow)
	Nickel metal hydride			800				700-900			
	ZEBRA			800				600			
Capacitors	Asymmetric lead-carbon capacitors			625**	500**	500	400				
	Electrochemical capacitors	20,000 - 30,000	250-350		356					8000-10000 high power,	100-600 high power, 200-700

										100-400 low	low power
	CAES surface	200-250	700-800			120	600			40-100	700-900
Fly Wheels	High-speed flywheel	1340-1570	3360-3920	1000		1000	300			5000-7000	200-500
	Low-speed flywheel			380		380	280			1000-5000	3500-10000
	Pumped hydro	100-200	1500-2000							50-250	700-1500

** Jim Eyer, one of the report's authors, suggested via personal correspondence on 3/24/09 that the original report's per kWh cost estimate should be adjusted from 200 to 300, to correct for the need to oversize a VRLA battery to reduce damage from too many deep discharges*

*** data taken from "Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study. A for the DOE Energy Storage Systems Program," Schoenung and Hassenzahl, Sandia August 2003. SAND2003-2783. p. 22.*

Sources: EPRI 2008 = "Executive Summary: Electricity Energy Storage," by Robert Schainker, prepared for CPUC and CEC, March 24, 2009.

Sandia Feb 2008 = "Benefit-Cost Framework for Evaluating Energy Storage: A Study for the DOE Energy Storage Systems Program," by Schoenung and Eyer, Sandia Report SAND 2008-0978.

Sandia July 2008 = "Solar Energy Grid integration Systems – Energy Storage," by Ton, Hanley et al., Sandia Report SAND2008-4247.

Tiax = "Energy Storage: Role in Building-Based PV systems, Final Report for DOE," March 22, 2007, Tiax. Lists original equipment manufacturer costs per kWh only. Does not include balance of plant costs. Assumes 250 cycles per year.

ESA website = values estimated from ESA-developed graphs with large and irregular scales. ESA estimated cost rage for 2002 and expected values for the coming few years. http://www.electricitystorage.org/tech/technologies_comparisons_capitalcost.htm.

C. O&M Costs

AES O&M costs include the cost of buying the energy used to charge the system, fixed costs that do not depend on how much or often the system is used, and variable costs, the bulk of which are replacement costs. Many battery technologies lose effectiveness the more frequently and deeply they are discharged, meaning that the average length of an AES system's life (ie. how many cycles or years before it must be replaced) cannot be accurately determined independent of how often and how deeply it is discharged.

Operating costs can be calculated using the following equation:

Nominal $\$/kW\text{-}year_{O\&M}$ = ((cost of electricity during charging / efficiency) * average kWh charged per year) + fixed annual O&M /kW + ((variable O&M * kWh discharged per year)/kW)[25]

Table 3 below lists estimates from a 2003 Sandia report for the variables necessary for calculating AES O&M costs. The replacement frequency estimates assume that the system discharges 250 times per year (5 times per week for 50 weeks per year), which is close to our model's estimate 240 cycles per year for a customer-side AES system being used during business hours to reduce energy and demand charges. System life actually varies according to depth and frequency of discharge, as noted above; however, the below replacement frequencies can be considered reasonable estimates.

Table 3. Variables Affecting AES Operating Costs

[25] Since CAES systems use natural gas as a fuel, CAES operating costs are determined using a somewhat more complex equation: Nominal $\$/kW\text{-}year_{O\&M}$ = ((cost of electricity during charging / efficiency) * average kWh charged per year) + fixed annual O&M /kW + ((variable O&M * kWh discharged per year)/kW) + (generation heat rate x cost of natural gas)

	Tech Type	AC to AC Efficiency (%)	Replacement Cost ($/kWh capacity)	Replacement Frequency (years)	Fixed O&M ($/kW-yr)
Batteries	Valve-regulated lead acid	75	200	5	5
	Flooded-cell lead acid	75	150	6	15
	Nickel cadmium	65	600	10	25
	Zinc bromine flow	60	100	8	20
	Lithium ion	85	500	10	25
	Sodium sulfur	70	230	15	20
	Vanadium redox flow	70	600	10	20
	Nickel metal hydride	80*	No info	No info	No info
	ZEBRA	80-85*	No info	8.33	No info
Caps	Asymmetric lead-carbon capacitors	75**	625**	15**	5**
	Electrochemical capacitors	90	No info	No info	No info
CAES	CAES surface	79	0	None	10
Fly-wheels	High-speed flywheel	95	0	None	$1000/yr
	Low-speed flywheel	90*	No info	No info	No info
	Pumped hydro	87*	0	No info	No info

**data from "Energy Storage Technology Options and Applications Matrix," EPRI, emailed by Dan Rastler, or from ESA website at http://www.electricitystorage.org/tech/photo_lifeefficiency.htm.*
*** data from "Long vs. Short-Term Energy Storage: Sensitivity Analysis. A Study for the DOE Energy Storage Systems Program." Schoenung and Hassenzahl, Sandia July 2007. SAND2007-4253.*
All other data from "Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study. A for the DOE Energy Storage Systems Program," Schoenung and Hassenzahl, Sandia August 2003. SAND2003-2783.

Also important for estimating accurate AES lifecycle costs is the optimal depth of discharge for each technology. Batteries have varying levels to which their energy reservoir can be repeatedly discharged without significantly damaging the battery and requiring early replacement. Below is one public set of estimates of optimal depth of discharge and attendant cycle life by battery technology, developed by Tiax after conversations with various manufacturers and analysts.

Table 4. Optimal Depth of Discharge and Cycle Life for Some AES Technologies

	Tech Type	Optimal Depth of Discharge (%)	Attendant Cycle Life (# of cycles)
Batteries	Valve-regulated lead acid	40	1390
	Flooded-cell lead acid	40	1390
	Nickel cadmium	50	4000
	Zinc bromine flow	100	4000
	Lithium ion	Not packaged for this app	Not packaged for this app
	Sodium sulfur	90	4500
	Vanadium redox flow	60	10000
	Nickel metal hydride	70	4000
	ZEBRA	100	2000
	Asymmetric lead-carbon capacitors	No info avail	No info avail

Source: "Energy Storage: Role in Building-Based PV systems, Final Report for DOE," March 22, 2007, Tiax.

D. Estimates of Total Lifecycle AES Costs for Customer-Side AES

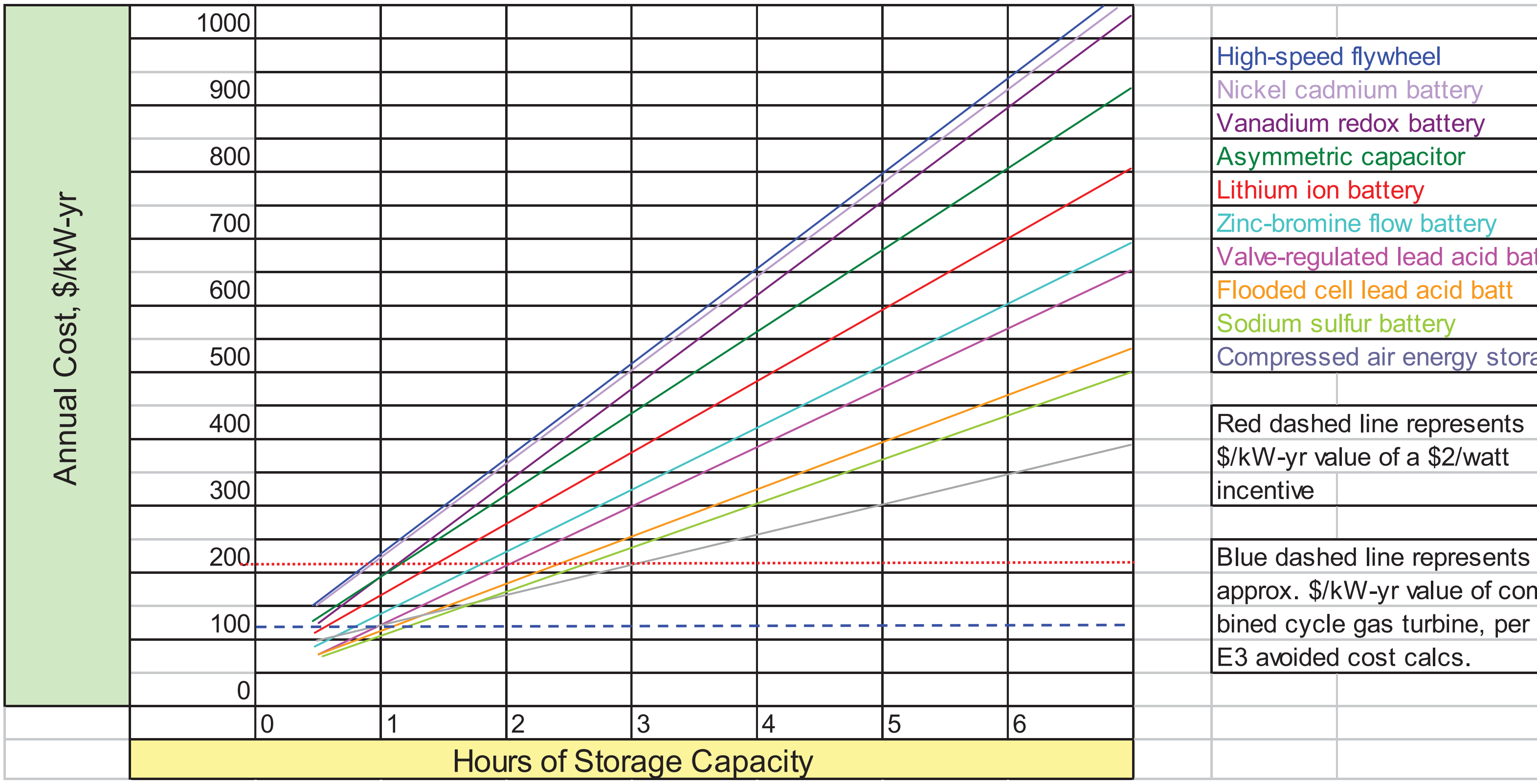
As noted above, estimating the total installed cost of an AES technology is a complex task, one that cannot be accomplished independent of knowing the size of the system's energy reservoir, the application and how often and deeply the system will be charged and discharged over its lifetime. While the above cost information includes AES technologies that can be used either at the customer site, on the grid or at the utility-scale generation site, the focus of this analysis is the costs and benefits of using AES on the customer side of the meter. At this time, batteries and capacitors are the only technologies that are both modular and long-lasting enough in duration to be used for this application; therefore the next sections of this analysis focus on estimating total installed costs for batteries and asymmetric lead-carbon capacitors and on modeling the economics of owning and operating these technologies from the customer's perspective.

1. Costs Expressed in $/kW-yr and $/kW

The figure below is based on a graph developed by Sandia National Laboratories showing the total levelized annual costs of various distributed AES technologies expressed in dollars per kilowatt-year. The original graph estimated cost only for up to 4 hours of storage, which has been extended that to 6 hours here to account for the length of discharge generally needed by a retail customer to fully offset peak energy and demand charges. These cost estimates include all capital and O&M costs, as well as payment on loans and interest for the up-front capital cost of a system. They take into account the varying efficiency and system lives of the differing technologies and assume 250 discharges per year, but do not appear to assume oversizing of systems in order to reduce wear and tear from deep discharges.

It should be noted that the graph below, developed in 2007, assumes a $600/kWh capital cost for vanadium redox flow batteries, which Sandia subsequently revised in a 2008 report[26] to $350/kWh based on updated cost information.

Figure 7. Sandia Total Levelized Annual Costs for Distributed Energy Storage Technologies, $/kW-yr



Source: "Long vs. Short-Term Energy Storage: Sensitivity Analysis. A Study for the DOE Energy Storage Systems Program." Schoenung and Hassenzahl, Sandia July 2007. SAND2007-4253. p. 23. Graph created by Sandia but extended to from 4 to 6 hours for this analysis.

To convert the above annual costs to $/kW values, one divides the $/kW-yr values by the carrying charge rate; the carrying charge rate used in the Sandia 2007 lifecycle cost analysis is 10.6%.[27] The red line in the figure above shows, for comparison with AES costs, the value of a $2/watt incentive using the same carrying charge rate of 10.6%. The blue dashed line shows the value of a CCGT, as listed in E3's avoided cost calculations.[28] The cost of building a combined cycle gas turbine is approximately $100/kW-yr, and the proposed installed cost of Edison's PV project is approximately $475/kW-yr.[29]

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[26] Susan Schoenung and James Eyer, "Benefit/Cost Framework for Evaluating Modular Energy Storage: A Study for the DOE Energy Storage Systems Program," Sandia February 2008. SAND2008-0978. p. 20.
[27] Susan Schoenung and William Hassenzahl, "Long vs. Short-Term Energy Storage: Sensitivity Analysis. A Study for the DOE Energy Storage Systems Program" Sandia National Laboratories, July 2007. SAND2007-4253. p. 15
[28] See E3 Electric Avoided Costs Update at http://www.ethree.com/cpuc_avoidedcosts.html
[29] Per cost estimates received from Energy Division staff.

The below table lists the approximate $/kW lifecycle costs of the technologies based on the values shown the graph above at 6 hours of storage capacity. For comparison, new peaking generation capacity (combustion turbine) costs approximately $1,500/kW while customer-side PV currently costs approximately $7,500-8,500/kW.

Table 5. Approximate $/kW Lifecycle Costs of Various AES Technologies at 6 Hours Storage Capacity, Converted from Sandia's $/kW-yr Estimates

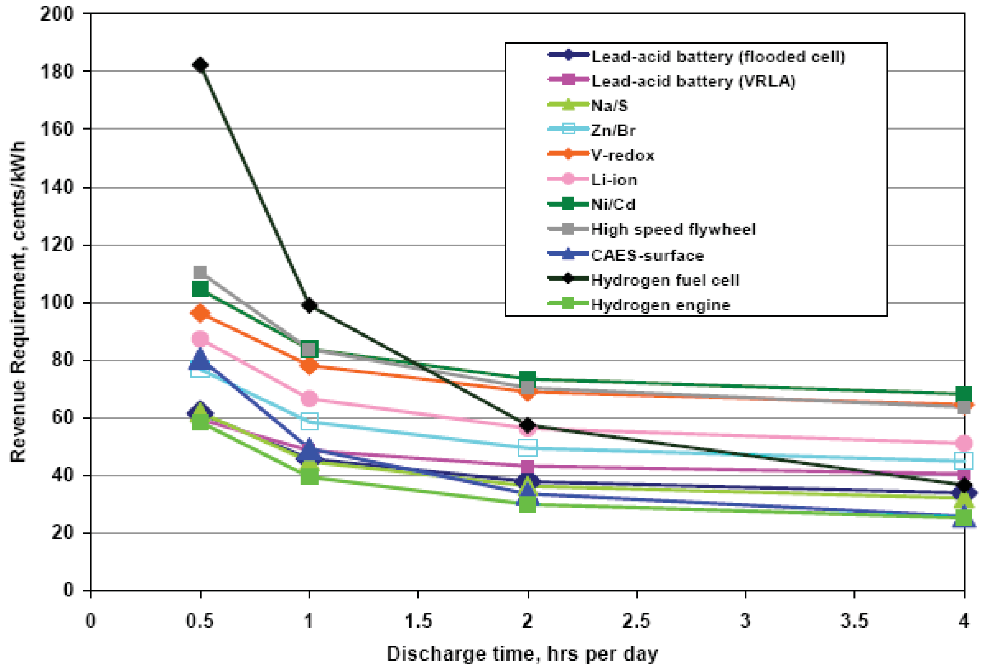
Technology	Lifecycle Cost ($/kW)
High-speed flywheel	8,962
Nickel cadmium battery	8,726
Vanadium redox flow battery	8,490
Asymmetric capacitor	7,457
Lithium ion battery	6,603
Zinc-bromine flow battery	5,660
Valve-regulated lead acid battery	5,283
Flooded cell lead acid battery	4,339
Sodium sulfur battery	4,056
Compressed air energy storage	3,301

Source: values calculated by dividing values in Sandia graph above by carrying charge rate of 10.6%

2. Costs Expressed in $/kWh Discharged

Sandia also developed the following graph to express distributed AES costs as a dollar per kWh revenue requirement for utilities. These are the costs of energy per kWh discharged from these systems; again, vanadium redox battery costs are estimated at the old $600/kW capital cost estimate. Since the cost curves become almost flat as more hours of storage are added, it can be assumed that the revenue requirements for 6 hours of storage are similar to the 4 hour estimates shown below.

Figure 8. Sandia Total Levelized Annual Costs for Distributed Energy StorageTechnologies



Source: "Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study. A for the DOE Energy Storage Systems Program," Schoenung and Hassenzahl, Sandia August 2003. SAND2003-2783. p. 42.

The economic assumptions used by Sandia to calculate the above annualized per kW-yr and per kWh costs are listed in the following table.

Table 6. Assumptions for Sandia 2003 AES Cost Estimates

Parameter	Value
General inflation rate	2.5%
Discount rate	8.5%
Levelization period	20 years
Carrying charge rate	12%
Fuel cost, natural gas	5 $/MBTU
Fuel cost escalation rate	0%
Electricity cost	5 ¢/kWh
Electricity cost escalation rate	0%
O&M cost escalation rate	0%

Source: "Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study. A for the DOE Energy Storage Systems Program," Schoenung and Hassenzahl, Sandia August 2003. SAND2003-2783. p. 36.

Figure 8 does not extend to 6 hours of storage. Below is a table converting Sandia's $/kW-yr cost estimates from Figure 7 to $/kWh discharged assuming 6 hours of storage capacity and 250 full cycles per year, which is Sandia's assumption and is close to the 240 cycles per year assumed in the modeling in later portions of this analysis. The conversion is calculated by dividing the $/kW-yr value by the number of kWh discharged per year. The value of a $2/watt AES incentive is included for comparison.

Table 7. Approximate $/kWh Discharged for Various AES Technologies at 6 Hours Storage Capacity, 250 Cycles per Year

Technology	Lifecycle Cost ($/kWh discharged)
High-speed flywheel	0.63
Nickel cadmium battery	0.62
Vanadium redox flow battery	0.60
Asymmetric capacitor	0.53
Lithium ion battery	0.46
Zinc-bromine flow battery	0.40
Valve-regulated lead acid	0.38
Flooded cell lead acid	0.31
Sodium sulfur battery	0.28
Compressed air energy storage	0.23
For comparison: $2/watt incentive	0.14

Source: values calculated by dividing the 6-hour $/kW-yr values in Table 5 above by 1500 hours per year. Original values from Sandia lifecycle costs shown in Figure 6.

E. AES Manufacturing Capacity and Total Installed Capacity

Few sources provide estimates of AES manufacturing capacity and total installed capacity; the below table summarizes available information. Significantly less than 50 MW of non-pumped hydro AES has been installed in the United States.[30] Worldwide, total installed customer-side AES capacity appears to be no greater than 500 MW and probably less, given that available information shows 55 MW of lead-acid batteries for UPS purposes and 270 MW of sodium sulfur batteries, and that the other technologies suitable for customer-side AES are all still early in their development.

Table 8. Estimated Total Installed Capacity of Various AES Technologies

Tech Type	Total Worldwide Installed Capacity (MW)
Valve-regulated lead acid	> 55 MW (valve-regulated plus flooded cell)
Flooded-cell lead acid	> 55 MW (valve-regulated plus flooded cell)
Sodium sulfur	280 MW
CAES surface	400 MW
Pumped hydro	90 GW

Source: ESA website, http://www.electricitystorage.org/tech/technologies

F. Predictions about Future Costs of Customer-Side AES

Little information is available estimating how the costs of various AES technologies will be impacted by increases in capacity manufactured or installed. Lead-acid and sodium-sulfur batteries, high-power flywheels, CAES and pumped hydro are all generally regarded as mature technologies whose costs are expected to decrease only moderately depending on additional capacity installed. However, nickel-metal hydride, ZEBRA and vanadium redox batteries are being manufactured in very small quantities and are expected by battery developers and analysts to come down significantly in cost with economies of scale. Lithium ion batteries, commonly used in consumer electronics but not yet commercialized for vehicle or larger-scale electricity storage applications, are the focus of large amounts of research and development funding for vehicle applications and are also projected to decrease significantly in cost as manufacturing capacity scales up. Owners of lithium ion batteries for stationary applications will benefit from cost reductions spurred by vehicle sector developments.

Table 9 below shows a DOE/Sandia estimate of current compared to future AES capital costs, developed by conversations with analysts and storage developers. However, any estimates of future AES cost reductions are bound to be very controversial.

[30] Estimate via personal communication with Dan Rastler of EPRI, April 7 2009.

Table 9. Current and Future Energy Storage System Capacity Costs

Technology	Current Cost ($/kWh)	10-yr Projected Cost ($/kWh)
Flooded Lead-acid Batteries	$150	$150
VRLA Batteries	$200	$200
NiCd Batteries	$600	$600
Ni-MH Batteries	$800	$350
Li-ion Batteries	$1,333	$780
Na/S Batteries	$450	$350
Zebra Na/NiCl Batteries	$800 [1]	$150
Vanadium Redox Batteries	20 kWh=$1,800/kWh; 100 kWh =$600/kWh	25 kWh=$1,200/kWh 100 kWh=$500/kWh
Zn/Br Batteries	$500	$250/kWh plus $300/kW [2]
Lead-carbon Asymmetric Capacitors (hybrid)	$500	<$250
Low-speed Flywheels (steel)	$380	$300
High-speed Flywheels (composite)	$1,000	$800
Electrochemical Capacitors [3]	$356/kW	$250/kW

Source: "Solar Energy Grid Integration Systems – SEGIS-ES." Dan Ton, Charles Hanley, Georgianne Peek and John Boyes. US Department of Energy and Sandia National Laboratories. SAND 2008-4247. p. 21.

In the absence of many available estimates of reductions in AES total future costs, it is reasonable to assume a decline in costs often observed in the electricity technology sector of 20% for every doubling of installed capacity.[31] In later sections of this analysis, I will use this 20% learning rate assumption to estimate cost reductions resulting from deployment spurred by incentives for customer-side AES.

G. Comparing Demand-Side AES Costs to the Costs of Energy Efficiency and Demand Response Technologies

Policymakers allocating ratepayer funding to support AES deployment will need to compare AES costs against the costs of other strategies for reducing peak demand, such as energy efficiency and demand response. At this time, CPUC has not verified costs per kW or kWh saved via the California IOUs' energy efficiency and demand response programs, so cost comparisons are not included in this analysis.

[31] Daniel Kammen. Committee on Science, United States House of Representatives. Hearing on the Future of University Nuclear Science and Engineering Programs. June 10, 2003.

IV. Modeling Results: Estimating AES Net Returns from the Commercial Customer's Perspective, With and Without PV

The customer-side AES cost information discussed in the previous section was used to model lifecycle costs via a proprietary financial model developed by StrateGen Consulting[32] that allows the user to calculate the net value of owning and operating various types of AES systems from a commercial customer's perspective.[33] The model predicts the net customer returns from using various types of batteries and capacitors to reduce energy and demand charges, and can estimate the impacts of various incentives on customer returns. Essentially, the StrateGen model computes the net benefits or costs of customer-side AES from the same perspective as the Participant Test used by the CPUC to assess the cost-effectiveness of energy efficiency and demand response programs, although it computes measures of returns like payback period and net present value rather than the benefit/cost ratio used by the CPUC tests.

This section begins with a conceptual discussion of how customer-side AES adds value for a customer with or without a customer-sited PV system. Next, the model's basic structure and assumptions are described. Next are the modeling results projecting the returns to customers using AES with and without a PV system and under various assumptions about incentives, tariffs and load shapes. Finally are some key policy-related takeaways from the results of this complex modeling effort

A. How AES Adds Value for Commercial Power Customers

In California, commercial and industrial customers (noted here simply as 'commercial customers') are required to be on time-of-use rates. A time-of-use customer's bill consists of an 'energy charge', which varies by the amount of energy consumed and what time of day and year it is taken from the grid, and a 'demand charge' based on the customer's maximum level of demand in a given month. The demand charge is meant to pass along the per-customer portion of the costs of the power generation and transmission and distribution capacity needed to ensure the customer's maximum power demand is met. In addition to providing backup power, customer-side AES can reduce a customer's energy and demand charges by charging during times when energy costs less and discharging during times when energy costs more, and by shifting the time of the customer's peak demand to an hour when demand charges are lower.

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[32] This Excel-based financial model is the private property of StrateGen Consulting and was built to help large power customers assess the economics of adding customer-side storage. The author of this analysis was given access to the model for this analysis after signing a personal non-disclosure agreement. The workings of the model are confidential, but StrateGen has given permission for any model outputs to be made public.

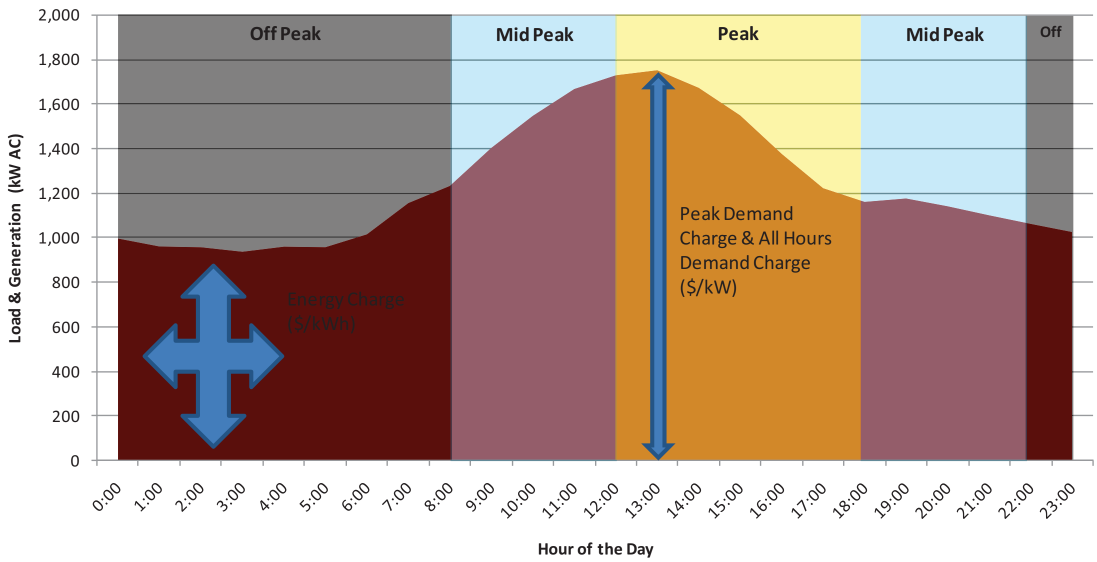
[33] Residential customers are likely to gain much less value from AES than larger customers since many are not on time of use rates, so they are not considered in this analysis.

The value of the energy arbitrage performed by AES will depend on the TOU energy price spread and on how much electricity is lost due to AES inefficiency. The value of the demand charge reduction will depend on the size of the on-peak demand charge, whether there is an off-peak demand charge and whether the AES system discharges with enough reliability to significantly lower peak demand every single day of the month—if AES does not reliably reduce load on each high-demand day, the monthly demand charge will not decrease.

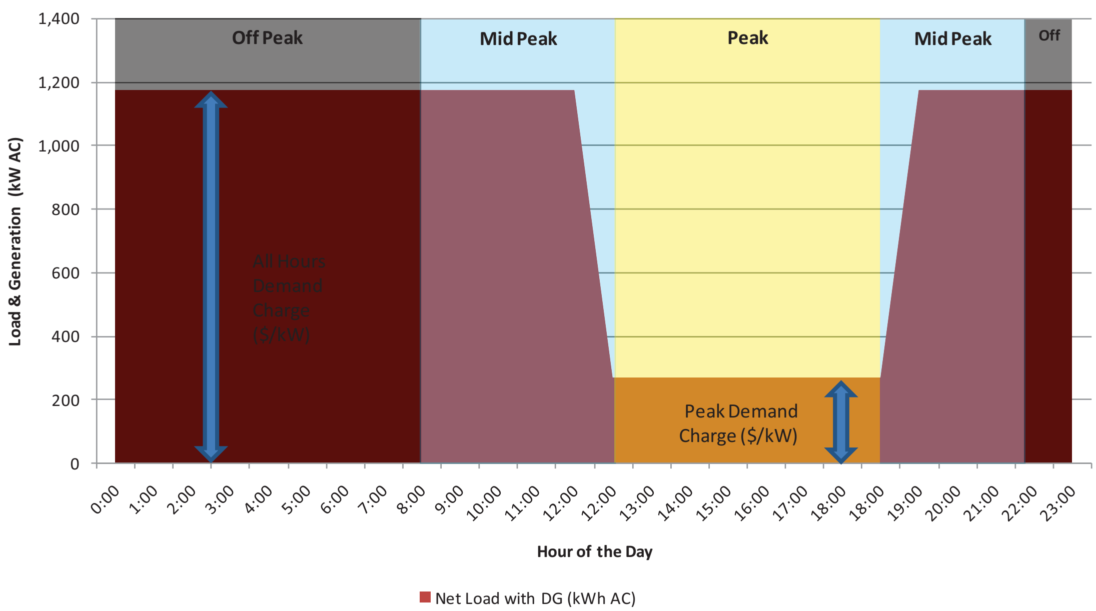
Figure 9 below provides a visual representation of how AES reduces energy and demand charges for a customer without a PV system.

Figure 9. AES Adds Value for Commercial Customer Without PV [34]

Summer Day in Orange County Baseline Load on SCE TOU8



Same Customer Using AES to Reduce Energy and Demand Charges



Source: "StrateGen AES Optimization Overview," StrateGen Consulting, March 2009.

AES adds even larger value for a TOU customer with PV compared to a customer without a PV system. This is for two reasons: first, efficiencies are gained when balance-of-plant costs can be shared between the PV and AES systems (most notably the cost of the inverter).[35] Second, AES and PV systems provide complementary peak-shaving

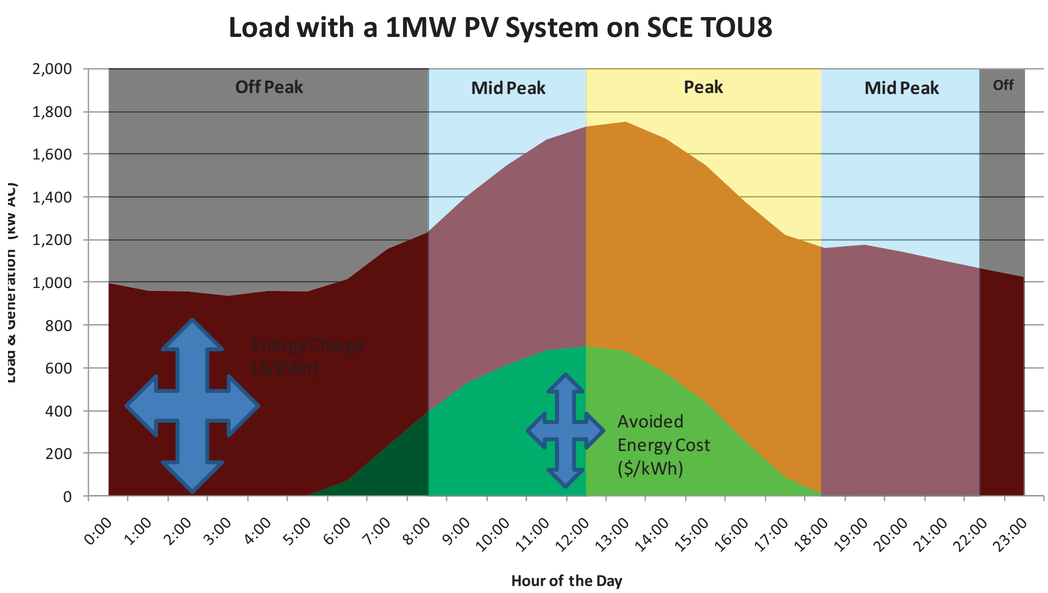
[34] Graphs from "Stratagen AES Optimization Overview," March 2009.

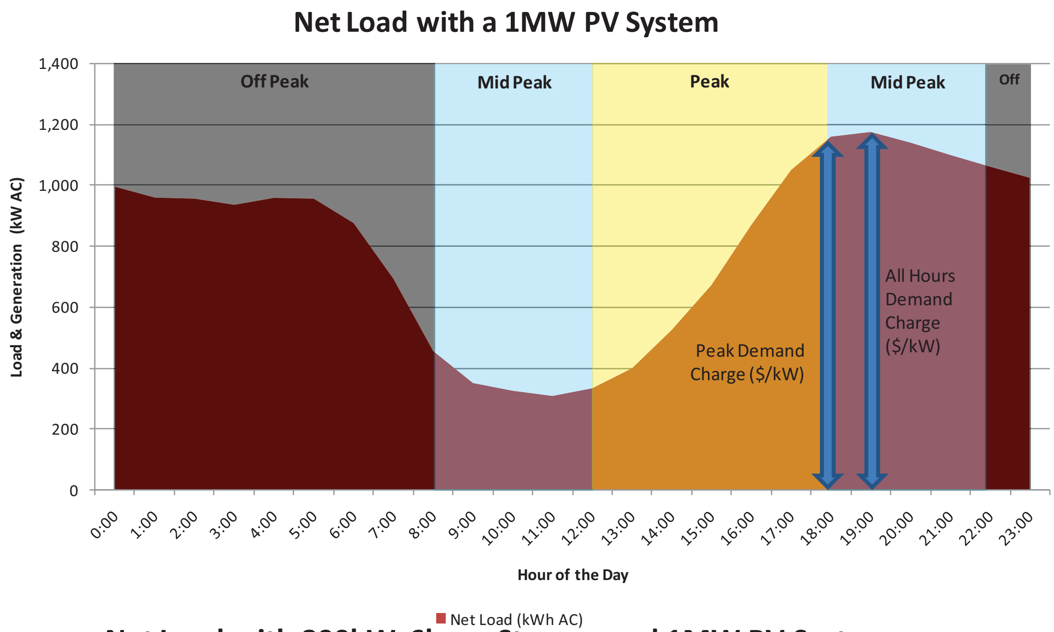
[35] "The Value of Distributed Electricity Storage to California Through Deployment with Solar Photovoltaics: Market Investigation, Preliminary Analysis and Recommendations for Extended Project," Kelsey Lynn, EPRI, March 2006.

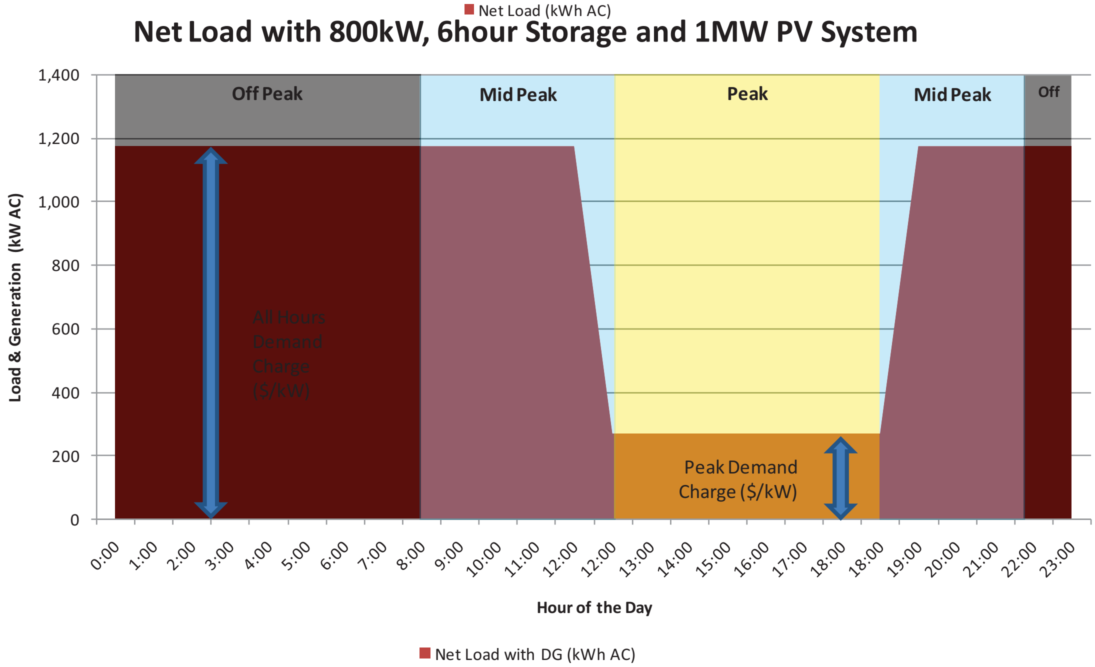
capabilities. PV generates significant output in the beginning of the typical on-peak demand period of noon to 6 pm, thereby reducing the amount of energy the AES system needs to discharge on-peak and reducing AES O&M costs compared to a customer without PV. Customer-side AES is capable of tailoring discharge levels to compensate for natural moment-to-moment dips in PV system output due to cloud cover or other factors, thereby firming PV's value as a means of deferring peak generation, transmission and distribution capacity. (Figure 10 below provides a visual representation of how AES reduces peak load for a customer with a PV system also meeting some of its peak load.)

A common misconception about AES in combination with PV is that the storage would primarily charge from the PV system. In fact, the storage system would charge from the PV system only when the PV system's output exceeds customer load (and when charging the PV output is a more profitable alternative to net energy metering, which is already an attractive option for the customer). The AES system would instead primarily charge from the grid off-peak and discharge on-peak to supplement the PV system's on-peak output.

Figure 10. AES Adds Value for Commercial Customer With PV
(continued on next page) [36]







Source: "StrateGen AES Optimization Overview," StrateGen Consulting, March 2009.

Some advocates of storage[37] state that that adding AES has the additional benefit of incenting owners of existing PV systems to boost the PV system's afternoon output by re-angling their systems to maximize their total output. Apparently many solar installations have been 'de-rated' due to the way CSI incentives are paid; the PV systems have been angled to maximize output at peak times but as a result, total system output is reduced. If AES supplants the benefit of de-rating by allowing load-shifting, then adding storage could boost overall PV output. While this benefit was not included in the financial

[37] Powergetics Data Response to CPUC AES Data Request, March 4 2009.

modeling done here, it should be explored in future analysis about the benefits of storage plus PV.

B. StrateGen Consulting's AES Optimization Model and Assumptions for Inputs

StrateGen's model was developed as a tool for estimaing the net customer returns for commercial customers of using various types of customer-side AES technologies as a load-shifting strategy; the model allows for analysis using AES full lifecycle costs, not just capital costs. (The model assumes that the AES system is not selling into ancillary services markets.) It allows inputs for the following variables:

- AES cost components and performance parameters (including efficiency and allowable depth of discharge)
- size of AES system (kW and kWh)
- customer hourly load shape and size
- tariff structure
- number of days the AES system is operated per month
- financial specifications (including discount rate and rate of inflation) and
- years of project life and incentive types (including tax credits or incentives per kW or kWh discharged) and levels.

Based on the inputs entered by the user, the model optimizes the AES system's timing and length of charge and discharge so as to minimize the combination of energy and demand charges and operating costs and thereby maximize net benefits to the customer. It takes the load shape of the peak-demand day from each month and makes the simplifying assumption that each day of that month in which the systems is running will have the same load shape as the peak day; since the AES system is having to work harder that usual on that peak day, this is a conservative assumption regarding AES profitability. The model then computes monthly and yearly energy and power savings and combines those with system costs to present 3 metrics of cost-effectiveness: internal rate of return (IRR), net present value (NPV), and simple payback period. (Note that the model does not include a value for the AES benefit associated with backup power, since that value will vary with the value of goods or services lost.)

The model allows users to examine the value of customer-side AES that is either used on its own or in conjunction with a PV system; a typical PV system's output can be entered into the model and factored into the customer's net load profile.

Below are descriptions of the various inputs used in the modeling for this analysis, first summarized in a table and next discussed in more detail by type of input.

Table 10. Summary of Assumptions and Inputs

Type of Input	Input
AES and PV Cost Components and Performance Parameters	AES costs taken from Costs section, averaged when estimates differ; PV $7.50/watt installed
Customer Load Shape and Size	Actual load data from high school in northern California, PG&E territory; ~950 kW peak
Sizes of AES and PV Systems	AES-only model runs: 400 kW * 6 hrs AES-plus-PV model runs: 200 kW * 6 hrs AES, 300 kWp PV
Tariff Structure & Number of Days AES Operated Per Month	SCE TOU 8, PG&E E-19, SDG&E Schedule AL-TOU. PG&E used for most model runs. Systems operate 20 days per month.
Financial Specifications	8% discount rate, 4.5% electricity escalation rate, 3% inflation
Years of Project Life	25
Incentive Types and Levels	AES: no incentive or $2/watt capacity-based PV: $0.15/kWh PBI and 30% federal ITC

AES and PV Cost Components and Performance Parameters

This analysis uses the cost and performance information for various types of batteries and capacitors laid out in the Costs section as AES cost inputs for the model. Nickel metal hydride and ZEBRA batteries were excluded because, as the estimates from the Costs section show, adequate capital cost or O&M cost information for those battery types was not available. However, those two battery types have some of the highest $/kWh capital cost components, making them unlikely to show positive financial returns. Other technology types beside batteries and asymmetric lead-carbon capacitors were not included in the modeling because due to their energy and power capabilities, they are not appropriate for customer-side use. (Asymmetric lead-carbon capacitors are still under development but are showing promise as multi-hour storage.)[38]

Where there are differing estimates of capital cost components in Table 2 in the Costs section, the estimates are averaged, excluding the ESA estimates from the average because they were so imprecise. O&M cost and performance inputs were taken from 3 and Table 4 in the Costs section. Sandia's annual levelized total installed cost estimates from Figure are not used as model inputs because the model needs capital cost inputs in order to compute net costs/benefits correctly.

For the storage-plus-PV model runs, the total installed PV cost for commercial customers with systems of 100-500 kW is assumed to be $7.50/watt, as estimated in a recent report from Lawrence Berkeley National Labs.[39] To simulate the efficiencies gained when

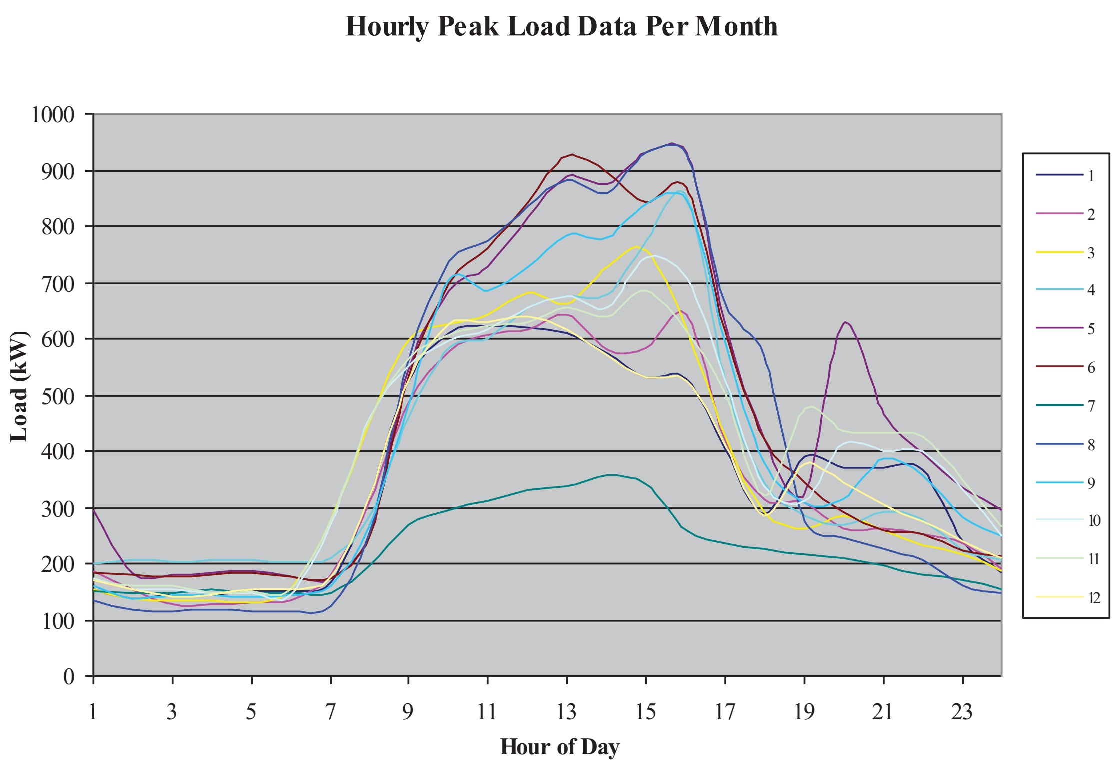
[38] Susan Schoenung and James Eyer. "Long vs. Short-Term Energy Storage: Sensitivity Analysis. A Study for the DOE Energy Storage Systems Program," Sandia National Laboratories, July 2007. SAND2007-4253. Appendix A.
[39] Ryan Wiser, Galen Barbose and Carla Peterman, "Tracking the Sun: The Installed Costs of Photovoltaics in the US from 1998-2007," by Lawrence Berkeley National Laboratories. February 2009. p.11

balance of plant costs can be shared, the cost of the inverter needed for the AES system is reduced by half for the AES-plus-PV model runs. The remaining AES inverter cost is due to the fact that while the AES system, being smaller, could use much of the PV system's inverter, a rectifier will still be needed to allow AES to both charge and discharge.[40] Since inverters cost about $0.35 per watt, AES capital costs are reduced by $175/kW in these scenarios, a total reduction of $35,000 per battery since each AES system in the storage-plus-solar scenarios are modeled at a size of 200 kW.

Customer Load Shape and Size

The load profile (ie. the variation in the customer's demand versus time) used in the model is generated using actual hourly load data from a high school in PG&E's territory. The high school has a fairly 'peaky' load with a maximum of approximately 950 kW in summer months, peaking at around 4 pm. This peaky load shape is typical for schools. The figure shows the high school's load profiles on its highest-demand day of each month.

Figure 11: **High School Load Shape Used in Model**



In the sensitivity analysis at the end of this section, two other load shapes are examined: a large retailer and a warehouse-like distribution center. While the high school does appear to have an especially peaky load shape, thereby making AES especially valuable for load-shifting, it should be noted the school also has low electricity usage at the school during the summer months of July, December and January.

[40] Per personal communication with Giovanni Damato, StrateGen, Monday April 27 2009.

Sizes of AES and PV Systems

The model allows the user to vary the size of the system in relation to the customer's peak demand in order to optimize profitability. For the high school without PV model runs, I use an AES system size of 400 kW * 6 hours (2400 kWh); this is on the larger side of what a customer with a 950 kW peak demand might choose, so the estimates of financial returns will be conservative. I use a smaller AES system size of 200 kW for the AES-plus-PV model runs, since the AES system will be load-shifting as a supplement to the PV system.

For the model runs for the customer with PV, I assume the PV system is sized at 300 kW. In the model, the system must be sized to avoid net metering any generation, because an excess of PV output would mean the modeling would be complicated by whether the excess PV output should be used to charge the AES system or fed back into the grid.

Tariff Structure & Number of Days AES Operated Per Month

I ran the model using one current TOU tariff each from SCE, PG&E and SDG&E. These tariffs are commonly used by commercial customers, including those with PV. Below is information about the three tariffs used in the model.

Table 11. Tariffs Used in AES Optimization Model

Tariff Type:	Commercial	Commercial	Commercial
Name:	**SCE TOU-8**	**PG&E E-19 Non-FTA**	**SDG&E Schedule AL-TOU**
Utility:	SCE	PG&E	SDG&E
Location:	Southern California	Northern California	Southern California
Class:	general, large	general, medium	general, large
Demand Range:	>500 kW	500-1,000 kW	500kW-12MW
Service Size:	<2 kV	<2.4 kV	<2kV
Service Type:	Bundled Service	Bundled Service	Bundled Service
Net Metering:	Annual	Annual	Annual
Export Tariff:	Null Export Tariff	Null Export Tariff	Null Export Tariff
Updated:	1/1/2008	10/1/2008	9/1/2008
Energy Charges ($/kWh)			
Summer Peak	0.1101	0.1438	0.1838
Summer Shoulder	0.0902	0.0987	0.1002
Summer Off Peak	0.0641	0.0803	0.0776
Winter Peak	-	-	0.1207
Winter Shoulder	0.0922	0.0879	0.1102
Winter Off Peak	0.0668	0.0775	0.0844
Demand Charges ($/kW/month)			
Summer All Hours	10.77	6.90	11.18
Summer Peak	15.23	12.30	10.81
Summer Shoulder	5.14	2.80	-
Summer Off Peak	-	-	-
Winter All Hours	10.77	6.90	11.18
Winter Peak	-	-	3.80
Winter Shoulder	-	1.00	-
Winter Off Peak	-	-	-

Since many commercial customers have low to no demand on weekends, I ran the model assuming the AES system runs one full cycle each business day every month of the year, which works out to 20 * 12 = 240 cycles per year. (Note the assumption here that the AES system is being used for load-shifting purposes only; if the system were also selling regulation or other ancillary services during times when its load-shifting application was not interrupted, the returns to the customer would presumably be greater.)

Financial Specifications

Below are the base case inputs I used for various financial assumptions. The 8% discount rate is only applied when calculating the NPV, not the IRR or payback period. Because an 8% discount rate is always assumed, an IRR of 8% will return an NPV of 0; I use the IRR 8%/NPV 0 breakeven point as a benchmark for what the average commercial customer would require in order to be interested in installing an AES system. If the IRR is much lower than 8%, a customer would be likely to find a number of more profitable projects in which to invest their money.

Table 12. Financial Specifications Used in AES Optimization Model

Financial Specifications	Input
Installation Year	2010
Discount Rate	8.0%
General Inflation	3.0%
Electricity Price Escalation Rate	4.5%
O&M Inflation	3.0%
Income Taxes	
Marginal Federal Tax Rate	35.00%
Marginal State Tax Rate	8.84%
Combined Marginal Federal & State Tax Rate	40.75%
Storage Depreciation Method	7yr MACRS

Years of Project Life and Incentive Types and Levels

I assume a 25 year project life in all cases, based on the typical length of a PV system life. Incentive types allowed in the model include an incentive based on a percentage of capital costs, a capacity-based incentive ($/kW installed), a performance-based incentive ($/kWh discharged) federal or state investment tax credits.

For the storage-plus-PV model runs, I always assume that the commercial customer receives a $0.15/ kWh PV incentive in annual installments over 5 years, a 30% federal investment tax credit for the PV system and a 50% federal depreciation basis reduction (which means that with a 30% ITC, 15% of the PV system's cost may not be expensed for federal tax purposes). In the sections below, I refer to this combination of existing PV incentives as "PV incentives." (In reality, the level of state-level PV incentive provided varies according to what IOU incentive step is in effect when the system is installed. Fifteen cents per kWh is PG&E's current CSI step applicable to commercial customers, while SCE and SDG&E currently provide $0.22/kWh for commercial customers. Many PV systems already installed in California also received a larger incentive, so a $0.15/kWh incentive assumption is conservative.)

I vary the assumptions for AES incentives, looking at scenarios with no incentive, a $2/watt capacity-based incentive and the level of capacity-based incentive needed to reach an 8% IRR. I assume the federal ITC for solar does not extend to storage, though it is possible that the IRS may in the future determine that solar is eligible for the ITC as part of a PV system.

C. Model Results: Without PV

Using the above-listed information as base case inputs, the table below lists the IRR, NPV and payback periods with the operation of various types of AES by a high school in PG&E territory that does not generate renewable energy onsite. Also included are the

IRR assuming a $2/watt AES incentive, and the level of AES incentive needed to create an 8% IRR/NPV of 0.

Table 13. Financial Returns of Customer-Side AES Technologies for High School Without PV, 6 Hours of Storage, 2400 kWh Capacity, PG&E TOU E-19 Tariff

	Technology Type	Capital Costs[41] ($/kWh, $/kW)	IRR w/out Incentive (%)	NPV* w/out Incentive ($)	Simple Payback w/out Incentive (years)	IRR & NPV Assuming a $2/watt AES Incentive (%, $)		AES Incent Needed to Attain 8% IRR / NPV 0 ($/kW)
						IRR	NPV	
Batteries	Valve-regulated lead acid	292, 363	NA	-710,579	NA	NA	-132,039	3,208
	Flooded-cell lead acid	208, 383	NA	-441,472	NA	8	-2,554	2,012
	Nickel cadmium	583, 225	NA	-1,296,749	NA	NA	-857,831	5,909
	Zinc bromine flow	450, 175	1	-477,451	22	7	-38,533	2,182
	Lithium ion	917, 175	NA	-1,660,647	NA	NA	-1,221,728	7,567
	Sodium sulfur	317, 150	6	-144,381	12	17	294,537	658
	Vanadium redox flow	380, 534	NA	-953,684	NA	NA	-514,846	4,346
Caps	Asymmetric lead-carbon capacitors	500, 450	NA	-620,291	NA	5	-181,772	2,828

*8% discount rate applied for NPV only

As the numbers show above, the sodium sulfur battery is the only technology that comes close to an 8% IRR without an incentive. This suggests that assuming this customer is representative of the commercial customer class, and assuming PG&E's TOU tariff and today's AES costs, all the other technologies would be poor investments as a load-shifting strategy for this customer class absent an incentive. However, assuming an incentive level of $2/watt, three technologies would either approach or exceed an 8% IRR (flooded cell lead acid, zinc bromine flow and sodium sulfur).

Notable in the above table are the low IRRs of VRLA, nickel cadmium and VRB batteries given their capital costs are not enormous in relation to other technologies. The reason is that all of these technologies have relatively high replacement costs, as can be seen in the O&M costs table in the Costs section of this analysis.

Next is a table showing that the impact of using the SCE or SDG&E TOU tariffs instead of PG&E's is somewhat substantial, measuring about $0.75/ watt difference at a

[41] These capital costs are averages of the different capital cost estimates listed in Table 2 of the Costs section.

maximum. This supports my later conclusion that tariff structure does indeed impact AES profitability, and that TOU tariff structures should be designed to reflect the true value of customer-side AES use.

While SCE's tariff appears to be between the two others in terms of "AES-friendliness" (with PG&E least AES-friendly and SDG&E the most), I use only PG&E's tariff going forward in my model runs because demand for solar is highest in PG&E's territory, making it important to examine the size of AES incentive needed for PG&E's commercial customers. Since later portions of this section compare stand-alone AES and AES-with-PV cost-effectiveness using the model, both the with- and without-PV model analysis must use the same IOU tariff.

Table 14. Level of Capacity-Based Incentive Under Varying IOU TOU Tariffs Needed to Produce an 8% IRR/NPV of 0 for Various Customer-Side AES Technologies for High School Without PV, 6 Hours of Storage, 2400 kWh Capacity

	Technology Type	PG&E E19 Non-FTA: Incentive Needed for 8% IRR / NPV* 0 ($/kW)	SCE TOU-8: Incentive Needed for 8% IRR / NPV* 0 ($/kW)	SDG&E Schedule AL-TOU: Incentive Needed for 8% IRR /NPV* 0 ($/kW)
Batteries	Valve-regulated lead acid	3,208	2,945	2,602
	Flooded-cell lead acid	2,012	1,748	1,547
	Nickel cadmium	5,909	5,615	5,449
	Zinc bromine flow	2,182	1,780	1,612
	Lithium ion	7,567	7,285	7,062
	Sodium sulfur	658	284	-82
	Vanadium redox flow	4,346	3,995	3,763
Caps	Asymmetric lead-carbon capacitors	2,828	2,436	1,981

*8% discount rate applied for NPV only

D. Model Results: With PV

Next, I used the model to look at how financial returns change when commercial customers using PV systems add storage in order to load-shift and/or firm their PV output. The below table shows the financial returns for the same high school customer with PV assuming the above-described PV incentives and tax credits, plus with storage with no incentive, compared with the financial returns from a PV system alone. (It does not make sense to goal seek for an AES incentive that brings the PV-storage combination system to an 8% IRR because that would mean part of the AES incentive would in effect be used to subsidize the PV system.)

To simulate the reduction in total balance of plant costs when the two systems run in combination, I reduce the cost of the inverter needed for the AES system by half. Since inverters cost about $0.35 per watt, I reduce the AES capital costs by $175/kW in these scenarios.

Table 15. Financial Returns of Customer-Side AES Technologies for High School With 300 kW PV, PV Incentives Included, 6 Hours of Storage * 200 kW Capacity, No Storage Incentives, PG&E TOU E-19 Tariff

	Technology Type	Capital Costs[42] ($/kWh, $/kW)	IRR w/out AES Incentive (%)	NPV* w/out AES Incentive ($)	Simple Payback w/out AES Incentive (years)	For Comparison: PV with No Storage (%, $, years)		
						IRR	NPV	Pay
Batteries	Valve-regulated lead acid	292, 188	4.6	-404,281	16	4.8	-283,127	15
	Flooded-cell lead acid	208, 208	5.7	-268,886	14	4.8	-283,127	15
	Nickel cadmium	583, 50	2	-735,333	22	4.8	-283,127	15
	Zinc bromine flow	450, NA	4.8	-407,639	15	4.8	-283,127	15
	Lithium ion	917, NA	1.9	-897,402	19	4.8	-283,127	15
	Sodium sulfur	317, NA	5.8	-263,360	13	4.8	-283,127	15
	Vanadium redox flow	380, 359	2.9	-585,151	21	4.8	-283,127	15
Caps	Asymmetric lead-carbon capacitors	500, 275	4.2	-491,979	18	4.8	-283,127	15

*8% discount rate applied for NPV only

The information in the table above shows that with current AES cost levels and no AES incentive, two AES technologies moderately improve the profitability of distributed solar for this customer: flooded cell lead acid batteries and sodium sulfur batteries. This outcome makes sense given that earlier model outputs show that many of the technologies have small or even negative IRRs for this application once full lifecycle costs are factored in. Flooded-cell lead acid and sodium sulfur batteries each increase the customer's IRR by a little less than 1% and reduce the payback period by at most 2 years.

Next we look at how the financial returns for customers with PV and storage change if we add a $2/watt AES incentive, compared with PV (plus incentives) on its own. As the table below shows, a $2/watt AES incentive brings the customer's total IRR close to 8% using two AES technologies: flooded-cell lead acid and sodium sulfur batteries. VRLA and zinc bromine flow batteries both have an IRR of over 6% in combination with PV in this scenario as well.

[42] These capital costs are averages of the different capital cost estimates listed in 2 in the Costs section, minus $175/kW due to sharing inverter cost with PV system.

Table 16. Financial Returns of Customer-Side AES Technologies for High School With 300 kW PV, PV Incentives Included, 6 Hours of Storage * 200 kW Capacity, $2/Watt AES Incentive, PG&E TOU E-19 Tariff

	Technology Type	Capital Costs[43] ($/kWh, $/kW)	IRR with AES Incentive (%)	NPV* with AES Incentive ($)	Simple Payback with AES Incentive (years)	For Comparison: PV with No Storage (%, $, years)		
						IRR	NPV	Pay
Batteries	Valve-regulated lead acid	292, 188	6.3	-184,822	13	4.8,	-283,127	15
	Flooded-cell lead acid	208, 208	7.5	-49,427	10	4.8,	-283,127	15
	Nickel cadmium	583, 50	3.3	-515,874	17	4.8,	-283,127	15
	Zinc bromine flow	450, 0	6.4	-188,180	12	4.8,	-283,127	15
	Lithium ion	917, 0	3	-677,943	20	4.8,	-283,127	15
	Sodium sulfur	317, 0	7.6	-43,901	10	4.8,	-283,127	15
	Vanadium redox flow	380, 359	4.5	-365,692	15	4.8,	-283,127	15
Caps	Asymmetric lead-carbon capacitors	500, 275	5.7	-272,520	11	4.8,	-283,127	15

*8% discount rate applied for NPV only

E. Summary Comparison of Customer Financial Returns: Differing Combinations of Solar, Storage and Incentives

Below is a summary table showing the financial returns that result from combinations of solar and storage systems with and without an AES incentive, all of which have been displayed separately in the sections above.

[43] These capital costs are averages of the different capital cost estimates listed in Table 2 of the Costs section, minus $175/kW since inverter costs are shared with PV system.

Table 17. Summary of Financial Returns of Customer-Side AES Technologies for High School, PG&E TOU E-19 Tariff, Under Varying Incentive Level Assumptions and With/Without PV

	Technology Type	AES Without Incentive (%, $)		AES Only With $2/watt Incentive (%, $)		PV w/ Incentives, No AES (%, $)		PV w/ Incentives, AES With No Incentive (%, $)		PV w/ Incentives, AE $2/watt Incentive (%, $)	
		IRR	NPV*	IRR	NPV*	IRR	NPV*	IRR	NPV*	IRR	NPV*
Batteries	Valve-regulated lead acid	NA	-710,579	NA	-132,039	4.8	-283,127	4.6	-404,281	6.3	-184,8
	Flooded-cell lead acid	NA	-441, 472	8	-2,554	4.8	-283,127	5.7	-268,886	7.5	-49,42
	Nickel cadmium	NA	-1,296,749	NA	-857,831	4.8	-283,127	2	-735,333	3.3	-515,8
	Zinc bromine flow	1	-477,451	7	-38,533	4.8	-283,127	4.8	-407,639	6.4	-188,1
	Lithium ion	NA	-1,660,647	NA	- 1,221,728	4.8	-283,127	1.9	-897,402	3	-677,9
	Sodium sulfur	6	-144,381	17	294,537	4.8	-283,127	5.8	-263,360	7.6	-43,90
	Vanadium redox flow	NA,	-953,684	NA	-514,846	4.8	-283,127	2.9	-585,151	4.5	-365,6
Ca	Asymmetric lead-carbon capacitor	NA,	-620,291	5	-181,772	4.8	-283,127	4.2	-491,979	5.7	-272,5

*8% discount rate applied for NPV only

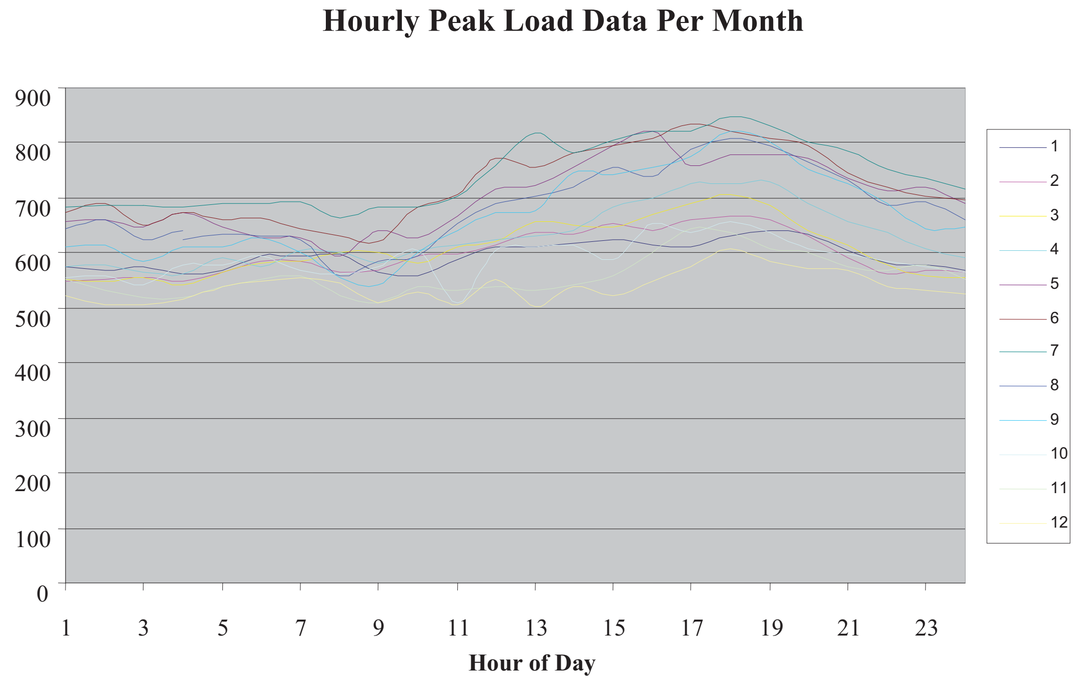
The model also allows a look at how customer savings with AES or AES-plus-PV break down between energy and demand charge savings. Under the storage only scenarios, more than 95% of savings came from demand charges for all AES technologies. (The value of charging off-peak is offset by the AES system's round-trip inefficiencies.) Under the storage-plus-PV scenarios, savings from demand charges go down to between 40 and 45% for all AES technologies, since the AES system has to discharge (and therefore charge) significantly less due to PV generation.

F. Sensitivity Analysis: Varying Load Shape

The profitability of customer-side AES systems will of course be impacted by number of factors; additional analysis should be undertaken to see what kind of impact results from varying incentive levels and types, tariff structures, power pricing and other factors (see the last recommendation below for a list of key parameter). One key parameter examined here is the load shape; how do the returns to the customer change when two additional load shapes are used instead of the high school's?

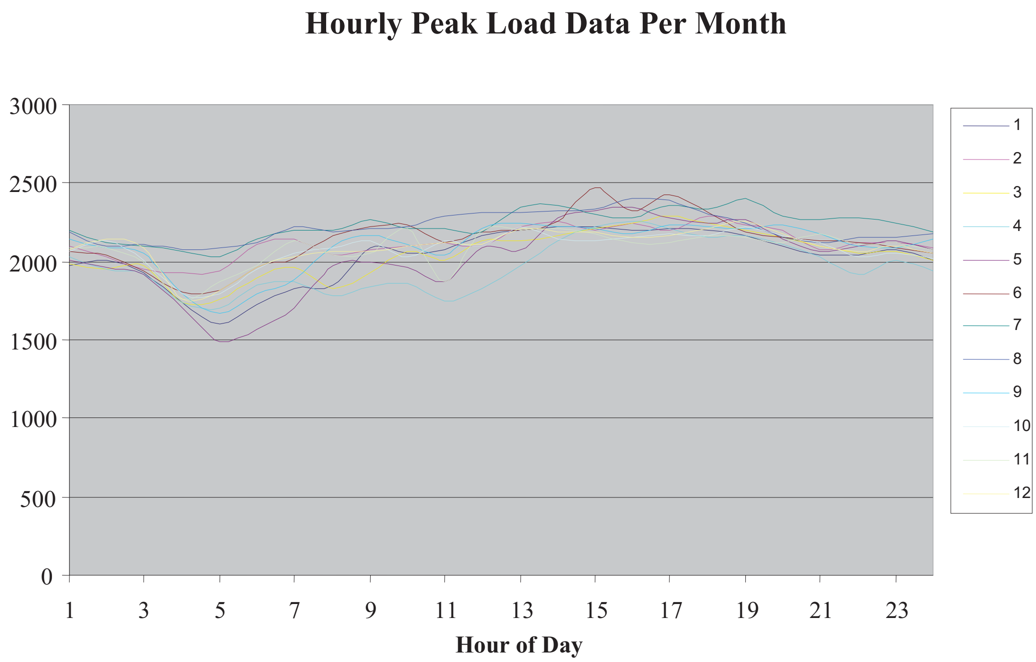
The first load shape used in the sensitivity analysis is for a large retail store located in SCE territory. As shown in the figure below, the retailer's peak demand is about 100 kW less than the high school's at approximately 850 kW, and it is considerably flatter throughout the day.

Figure 12: Large Retailer Load Shape Used in Model



The second load shape used in the sensitivity analysis is for a large warehouse-like, non-refrigerated retail distribution center in SCE territory. The distribution center's demand is also fairly flat and much larger than the other two customers, peaking at about 2500 kW. So that the AES and PV systems continue to be approximately the same in proportion to the load size, I increase the size of the AES and PV systems in the original analysis by a factor of 2.6 for the distribution center model runs.

Figure 13: **Large Distribution Center Load Shape Used in Model**



The table below shows how the variation in load shapes impacts the returns to AES in combination with PV, assuming a $2/watt AES incentive as well as existing PV incentives. Future research should focus on how varying load shapes affect customer returns for stand-alone AES and for AES-plus-PV without any AES incentive; there was not time enough to examine those scenarios in this analysis. Note that the NPVs in the rightmost column are bound to be much more negative because the distribution center's load, AES and PV systems are larger; the IRR is therefore the better comparison between load profiles.

For comparison with the returns to the retailer and distribution center with AES-plus-PV listed in the table below: the PV-only returns to the retailer are IRR= 4.8% and NPV = $-283,127, and the PV-only returns to the distribution center are IRR=4.8% and NPV= $-736,131. In other words, the IRR from adding a PV system on its own stays much the same across load shapes.

Table 18. Financial Returns of Customer-Side AES Technologies for Varying Load Shapes With PV, 6 Hours of Storage, $2/Watt AES Incentive and Current PV Incentives, PG&E TOU E-19 Tariff

	Load Shape & Technology Type	High School (%, $)		Retailer (%, $)		Distribution Center (%, $)	
		IRR	NPV*	IRR	NPV*	IRR	NPV*
Batteries	Valve-regulated lead acid	6.3	-184,822	4.8	-326,040	4.7	-873,417
	Flooded-cell lead acid	7.5	-49,427	6.0	-190,645	5.9	-521,388
	Nickel cadmium	3.3	-515,874	1.8	-641,849	1.6	-1,703,253
	Zinc bromine flow	6.4	-188,180	5.2	-309,255	5.1	-842,369
	Lithium ion	3	-677,943	1.6	-815,285	1.5	-2,157,387
	Sodium sulfur	7.6	-43,901	6.5	-153,854	6.4	-435,064
	Vanadium redox flow	4.5	-365,692	2.9	-492,830	2.7	-1,318,578
	Asymmetric lead-carbon capacitor	5.7	-272,520	4.5	-390,518	4.4	-1,054,745

*8% discount rate applied for NPV only

The above results show that the retailer and the distribution center load shapes have similar returns from AES in combination with PV, and on average, the IRR of the flatter load shapes is about 1 - 1.5% less than for the high school with a more peaky load shape. With a flatter load shape, an AES system has to work harder to discharge on-peak kilowatt hours, and the all-hours demand charge will be relatively high because the customer started with a relatively large amount of off-peak demand.

Nonetheless, with a $2/watt AES incentive and under all three load shapes, flooded-cell lead acid and sodium sulfur batteries both provide IRRs of at least 6%, and zinc bromine flow batteries increase the IRR compared with stand-alone PV's return of 4.8%.

G. Policy-Related Conclusions from this Section

Key policy-related takeaways from this section include:

- This modeling effort estimates customer financial returns from customer-side AES and PV assuming only one set of tariffs, one set of PV incentives and three large commercial load shapes, and not including some relevant AES benefits. The NPV and IRR values listed for AES and PV in this analysis should be viewed within the context of this limited set of scenarios and data only. A more in-depth analysis of the customer economics of installing customer-side AES is needed to better assess appropriate incentive levels (in addition to a financial analysis of a variety of AES technologies and applications from the utility's perspective), including analysis varying these parameters:

  - load profiles (using load shapes of varying flatnesses both with and without PV),
  - tariff structures, with a special focus on the impacts of critical peak pricing,
  - lifecycle AES costs,
  - the size of the AES and PV systems relative to the customer's peak load,
  - availability of other AES incentives including the federal 30% solar investment tax credit,
  - energy bill savings stemming from any associated GHG emissions reductions once GHG emissions are priced in California, and
  - revenues from selling into ancillary services markets, once the necessary two-way communications are available.

- Under an AES-only scenario with no AES incentive, only sodium sulfur batteries provide anything approaching an 8% IRR (at 6%), even under a 'peaky' load shape. This implies that without an AES incentive, customer-side AES deployment is unlikely to increase significantly.

- When a $2/watt AES incentive applies, two technologies provide an 8% IRR or greater under an AES-only scenario (flooded-cell lead acid and sodium sulfur batteries), while two others provide a 5% IRR or greater. Given that PV is in high demand from California commercial customers and the PV-only IRR is less than 5% in these model runs, a $2/watt AES incentive may significantly boost customer demand for stand-alone AES.

- In the AES-only scenario, the incentive needed to return an 8% IRR under SDG&E's TOU commercial tariff was as much as $0.75/watt lower than under PG&E's TOU commercial tariff. This implies that tariff structure does indeed impact AES profitability, and that designing TOU tariff structures to reflect the true value of customer-side AES use will be an important strategy for optimal AES deployment.

- In combination with a PV system and assuming a 'peaky' load shape, only flooded-cell lead acid and sodium sulfur batteries cause the customer's IRR to increase compared with PV alone (each by approximately 1%), assuming current AES costs and PV incentives and no AES incentive. This implies that some PV customers with similar load shapes would buy storage without an AES incentive as long as they made aware of its availability and benefits.

- With an AES incentive of $2/watt, the same two AES technologies (flooded cell lead acid and sodium sulfur) bring the IRR of the PV-plus-storage system to approximately 7.5%, approaching the 8% return that would be competitive with many other investments.

- Under the storage only scenarios, more than 95% of savings come from demand charges for all AES technologies, while under the storage-plus-PV scenarios, savings from demand charges represent between 40 and 45% of total savings.

- With an AES incentive of $2/watt, the same two AES technologies bring the IRR of the PV-plus-storage system for the customer with the more peaky load shape to approximately 7.5%, approaching the 8% return that would be competitive with many other investments, while zinc bromine flow batteries bring the return to 6.4%. Using two other, flatter commercial load shapes reduce the IRRs for the various AES technologies by up to 1.5%, but these three technologies provide greater returns to the customer than PV alone for all three load shapes.

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Appendix A: Summary of Party Responses to CPUC AES Data Request Regarding Policies Needed to Remove Barriers to AES Deployment

CPUC Energy Division's AES data request was issued on the DG and RPS proceeding email listserves in February 2009. Responses were received on March 4, 2009. Respondents included E3, CAISO, Megawatt Storage Farms, CCSE, Greensmith, Powergetics, Expansion Energy, Southwest Solar Technologies, Beacon Power, IREC, PG&E, and SCE; respondents who made the recommendation are listed in parentheses, though the list of parties supporting in parentheses may not be complete. The data request asked for a variety of information including information on AES costs, but this appendix seeks to organize and summarize the policy recommendations only. Note that a number of the recommendations are changes under the purview of CAISO, FERC or other agencies and not at CPUC.

A. Modify market participation rules in CA regulation, capacity, and retail energy markets to better allow AES to participate

1. Make CAISO ancillary services market rules more flexible so that AES can more fully participate: Using data from 2006 and 2007, E3 analyzed potential revenues for wholesale energy storage providers in several US markets (NYISO, PJM, ISO-NE and CAISO); E3 provided some public results of this analysis in their response to our AES data request. The analysis found that even in markets with capacity payments, regulation markets account for at least 75% of expected revenues for wholesale energy storage, capacity payments provided about 5% (increasing to 22% in ISO-NE where capacity payments are higher), and wholesale energy arbitrage also provided only a limited percentage. In California, where there is currently no capacity-only market, energy arbitrage revenues from AES would provide an estimated 25% of revenues, and regulation would provide an estimated 75% of revenues.

E3 asserts that many existing ISO market rules are designed with large dispatchable generation resources in mind and preclude or limit participation by AES. E3 proposes in particular two changes to CAISO market rules to improve AES revenues in regulation and capacity/RA markets. The first is to allow AES to bid less than 1 hour of energy in capacity/RA and regulation markets. The second is to reduce minimum bid size in the regulation market to less than 1 megawatt. With these changes, owners of smaller AES projects would be incented to provide valuable regulation and capacity resources to the grid.

E3's analysis estimates that if CAISO changed the two above rules, the net present value of AES would go from a current maximum of $766/kWh of energy storage capacity to a maximum of $1800/kWh. Assuming this is value is less than the delta between AES installed system cost and the value of energy arbitrage (energy arbitrage estimated by E3 to be worth $185/kWh in CA), then additional incentives will be needed to make AES ownership cost-effective.

2007 CAISO NPV $/kWh of energy storage value at increasing ratio of kWh energy storage/kW capacity ratios, 1 hour energy requirement vs 15 minute energy requirement.

Below are two figures from E3's analysis.

Figure 14. E3: 2007 CAISO NPV $/kWh of Energy Storage Value at Increasing Ratio of kWh Energy Storage/kW Capacity Ratios, 1 hour Energy Requirement vs. 15 minute Energy Requirement

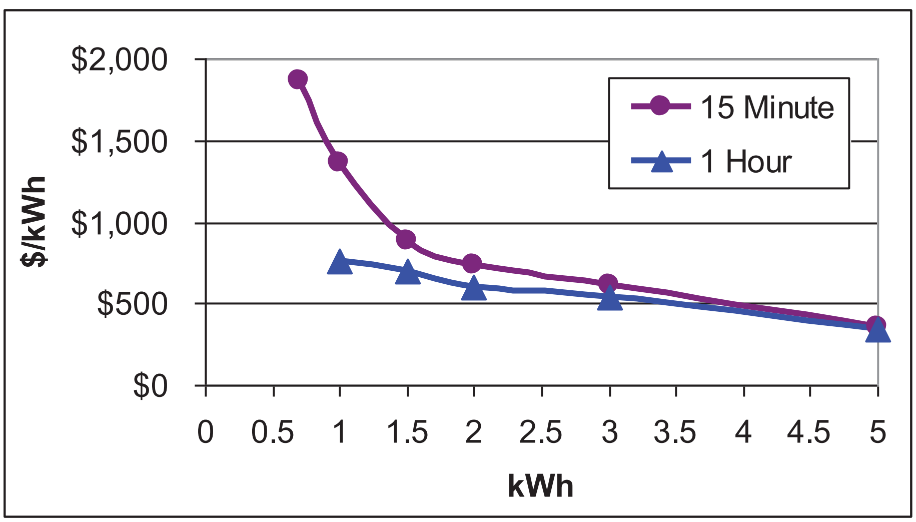
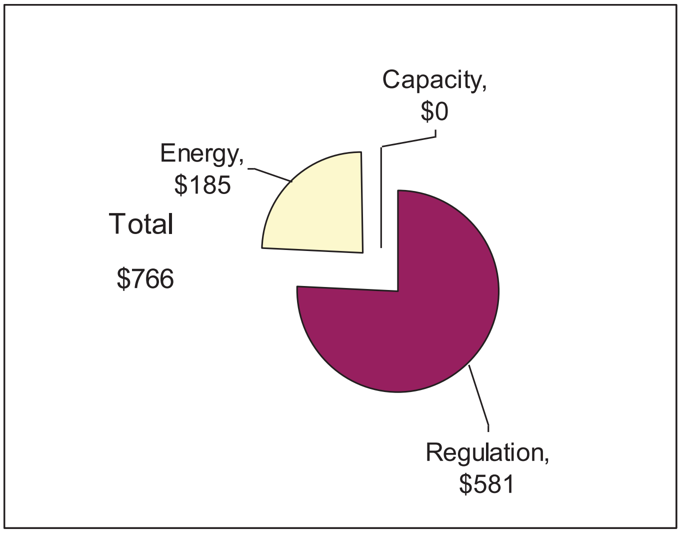


Figure 15. E3: 2007 CAISO 1 MW, 1 MWh, 60 min Energy Requirement, NPV $/kWh of Energy Storage Value



2. CPUC should work with CAISO to ensure that capacity and RA markets are both designed to allow AES projects of varying sizes to bid in. (E3)

3. AES projects are capital-intensive, and thus often need financing, which is hard to get without long-term contracts to show to lenders. But there is currently no market for long-term contracts for regulation, only a spot market. MegaWatt advocates that the CAISO develop a long-term forward market for regulation. (MegaWatt Storage Farms)

4. Allow IOUs to ratebase AES investments as generation investments and T&D investments (CAISO)

5. Streamline the siting and interconnection rules for both distributed and bulk AES projects. Only Powergetics provided details about existing problems with siting and interconnection, however. (PG&E, Powergetics, Expansion Energy)

- Powergetics advocates that the CPUC develop a rule requiring utilities to allow AES and DG systems to connect at the meter socket, stating that this would greatly simplify interconnection.

6. CPUC should explicitly ensure that Rule 21 interconnection standards apply to interconnection of AES devices as well as generation, stating that this change would allow for reduced cost and complexity for AES owners. It is possible, however, that such a change could instead increase AES installation costs by adding new requirements for paperwork, inspection fees, preplanning submittals and utility signoffs. (Greensmith)

B. Improve efficiency of pricing in CA ancillary services, capacity/RA, and retail energy markets so AES owners and investors receive more efficient deployment signals.

1. Require time-of-use rates for all customers including residential. TOU rates provide a signal to shift energy use to times when the value of the energy is lower, and are an essential first requirement for AES to make economic sense for a customer. (GreenSmith)

2. Revise customer tariffs to more accurately reflect the time-varying value of electricity, so customers are incented to use storage to manage energy costs (ie create a new optional tariff that makes energy and demand charge differentials greater in TOU metering).

GreenSmith recommends including in the optional tariff a high TOU price differential, a capacity payment and a payment for any ISO-dispatchable charging or discharging.

3. Change CPUC's capacity counting rules to incent firming of intermittent renewables. Specific changes are a) resources with low capacity factors get correspondingly lower RA credit and b) prices in the bilateral capacity/RA market are not capped at the current CPUC waiver price of $40/kw-year but are allowed to rise to the actual value of capacity (IREC, Greensmith).

C. Coordinate with FERC to ensure full cost recovery given that AES has both T&D and generation value

1. FERC rules prevent AES from being placed in the transmission ratebase, even though AES provides an efficient alternative to adding T&D capacity. FERC should allow AES to be ratebased and should allow independent AES owners to be on an equal footing with IOUs in developing AES as a T&D resource. (MegaWatt Storage Farms)

D. Allow an increased rate of return for utilities who invest in AES

1. If FERC will not allow AES investment to be recovered in transmission rates or will not set rates high enough to spur AES development, CPUC should consider increasing IOUs' rate of return for investment in generation or ancillary services to compensate. (CAISO)

2. Allow cost recovery of IOU AES pilot projects that can assess the real-world value of various kinds of AES to ratepayers. IOUs have submitted requests for cost recovery of AES pilot projects as part of their demand response programs; the Commission should work to approve such programs quickly. (CAISO, PG&E, Southwest Solar Technologies, Expansion Energy, GreenSmith)

E. Develop incentives for 1) customer-side and/or 2) utility-side AES.

1. Customer-side AES Incentive Proposals:

a. Create incentives to support stand-alone AES that is coupled with existing and/or new renewable DG, meaning the AES does not have to be directly connected to the DG system but must be at the same customer location. This will allow for cheaper installation of AES with existing DG systems, since rewiring the existing DG can be expensive, and will allow the customer to structure the system in the way that makes most financial sense. (Powergetics)

b. incentives could be structured as capacity-based, performance based or as a feed-in tariff. feed-in tariff. Beacon Power suggests FIT for fast regulation, 1.5 cents per kilowatt service hour.

2. Utility-side AES Incentive Proposals:

a. Well-designed ratepayer incentives for investment in and installation of supply-side AES could be warranted because many AES benefits accrue to ratepayers, and because incentives will drive market transformation and lower future AES deployment costs.

F. Instead of an incentive, create IOU purchasing requirements for AES, similar to an RPS for AES

1. MegaWatt Storage Farms advocates for an IOU or LSE requirement to purchase or sign contracts for 5% of capacity from low-emissions AES by 2020 (but with no specific requirement to be coupled with any one set of technologies). A storage portfolio standard has the benefits of guaranteeing large increases in installed AES capacity, avoiding the need to arrive at a specific incentive level that monetizes all the benefits of storage, allowing competition to drive AES costs down and providing revenue streams via PPAs that will reduce risk for AES investors.

G. CPUC should explicitly place AES as a high priority in the loading order and require IOUs to fully integrate storage into their long-term planning processes, considering AES as a key resource type.

1. In their data responses, many parties emphasized the need for AES to become a central resource in IRP, especially given the wide range of benefits that AES can provide to the grid. (Megawatt Storage Farms)

Appendix B: Assumptions Used In Sandia and EPRI Studies Cited in Benefits Section

1) Assumptions Used in Eyer, James M., Corey, Garth. "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide; A Study for the DOE Energy Storage Systems Program." Draft Report. March 2009.

Table 19. Assumptions Used by Sandia to Develop AES Benefit Values

#	Type	Benefit ($/kW)* Low	High	Note
1	Electric Energy Time-shift	400	700	Low: 80% eff., 2¢/kWh VOC, 4 hours. High: 80% efficiency, 1¢/kWh VOC, 5.5 hours.
2	Electric Supply Capacity	359	710	Low: Mid/Peak Duty Cycle C.T. costing $50/kW-year. High: Combined Cycle costing $99/kW-year.
3	Load Following	600	1,000	Low: Simple Cycle C.T., $20/MW per hour service price. High: Combined Cycle, $50/MW per service hour price.
4	Area Regulation	785	2,010	Low: $25/MW per hour, 50% capacity factor. High $40/MW per hour, 80% capacity factor. For up *and* down regulation.
5	Electric Supply Reserve Capacity	57	225	Low: $3/MW per hour, 30% capacity factor. High $6/MW per hour, 60% capacity factor.
6	Transmission Support	192		Based on DOE/EPRI storage report[14].
7	Voltage Support	400	800	Low: prevent 1 outage lasting 1 hour over 10 years. High: prevent 2 outages lasting 1 hour over 10 years. Storage = 5% of load.
8	Transmission Congestion Relief	31	141	Based on CAISO congestion prices in 2007.
9.1	T&D Upgrade Deferral 50th percentile	481	687	Low: upgrade factor 0.25, high upgrade factor = 0.33.
9.2	T&D Upgrade Deferral 90th percentile	759	1,079	Same as above.
10	Substation Onsite Power	1,800	3,000	Based on cost for standard storage solution.
11	Time-of-Use Energy Cost Management	1,226		Based on PG&E's A6 time-of-use tariff. Six hours of storage discharge duration.
12	Demand Charge Management	582		Based on PG&E's A6 time-of-use tariff. Six hours of storage discharge duration.
13	Electric Service Reliability	359	978	Low: $20/kWh * 2.5 hours per year avoided outages for 10 years. High: 10 Years of UPS Cost-of-ownership (present value).
14	Electric Service Power Quality	359	978	Low: avoided PQ-related cost, 10 years. High: 10 Years of UPS Cost-of-ownership (present value).
15	Renewables Energy Time-Shift	233	389	Low: bulk wind generation. High: baseload RE generation.
16	Renewables Capacity Firming	709	915	Low: for fixed orientation distributed PV. High: for bulk wind generation.
17.1	Wind Generation Grid Integration, Short Duration	500	1,000	Though the estimated *benefit* is relatively high; a modest amount of storage (<0.1 kW) is needed per kW of wind generation.
17.2	Wind Generation Grid Integration, Long Duration	100	782	Low: avoid 1 outage in 10 years from wind gen. shortfall. High: high estimate of benefit for reduced transmisison congestion.

*Lifecycle, 10 years, 2.5% escalation, 10.0% discount rate.

Table 20. Assumptions Used by Sandia to Develop Maximum Market Potential

#	Type	Maximum Market Potential (MW, 10 Years) CA	U.S.	Note
1	Electric Energy Time-shift	1,445	18,417	10% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
2	Electric Supply Capacity	1,445	18,417	Same as above.
3	Load Following	2,889	36,834	Total load following = 20% of peak load, 20% of that, maximum, served by storage.
4	Area Regulation	80	1,012	Per CEC/PIER study involving Beacon Power flywheel storage for regulation.
5	Electric Supply Reserve Capacity	636	5,986	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
6	Transmission Support	1,084	13,813	1.5% of peak demand, per EPRI/DOE report.
7	Voltage Support	722	9,209	5% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
8	Transmission Congestion Relief	2,889	36,834	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
9.1	T&D Upgrade Deferral 50th percentile	386	4,986	T&D upgrade needed for 7.7% of peak load. Of that, a maximum of 50% of qualifying peak load is served by storage. Storage = 3.0% of peak load, on average.
9.2	T&D Upgrade Deferral 90th percentile	77	997	
10	Substation Onsite Power	20	250	2.5 kW per system
11	Time-of-Use Energy Cost Management	5,038	64,228	67% of peak load is assumed to be in-play. 1%/yr storage adoption rate.
12	Demand Charge Management	2,519	32,111	33% of peak load is assumed to be in-play. 1%/yr storage adoption rate.
13	Electric Service Reliability	722	9,209	10% of peak load is assumed to be in-play, 10% of that, maximum, served by storage.
14	Electric Service Power Quality	722	9,209	Same as above.
15	Renewables Energy Time-Shift	2,889	36,834	20% of peak load is assumed to be in-play, 20% of that, maximum, served by storage.
16	Renewables Capacity Firming	2,889	36,834	Same as above.
17.1	Wind Generation Grid Integration, Short Duration	181	2,302	10.0% of peak load is in play. Add storage equal to as much as 2.5% of that amount for intermittency.
17.2	Wind Generation Grid Integration, Long Duration	1,445	18,417	10% of peak load from wind gen., Add storage to a maximum of 20% of that.

The term "in-play" indicates the portion of maximum market potential that is assumed to be

2) Assumptions used in *Market Requirements and Opportunities for Distributed Energy Storage Systems in the Commercial Sector,* Leveraging Energy Efficiency Initiatives. EPRI, Palo Alto, CA 2008.

Table 21. Assumptions Used in EPRI Study

INPUT	UNITS	VALUE(S)	ASSUMPTIONS
On/Off-Peak Energy Costs, Delivery Cost	$/kWh	$0.14/kWh On-Peak, $0.08 /kWh Off-Peak, $0.01/kWh Delivery	Customer uses Time-of-Use rates before and after ES; Tariff prices averaged to meet model structure
Monthly Demand Cost	$/kW-month	$14/kW-month	Average cost for demand used throughout the year; no separation of on/off-peak demand
Expected Demand Charge Reduction	Percentage (%)	19%	In the customer analysis, SF office buildings showed a 30 percent decrease in demand charges when using a 200 kW storage system in a 200,000 sq ft building (~835 kW after improving lighting efficiency)
Reliability Value	$/kWh unserved	$12/kWh unserved	The values for a backup diesel engine generator ($500/kW, $15/kW-yr) were spread over 15 years, assuming 4 unserved hours/year
Outages	Number of events; Duration	2 outage events per year, with an average 2-hour duration	Although outage events are unpredictable, they are assumed to last 2 hours and occur twice a year

Appendix C: Descriptions of AES Technologies

This appendix provides a discussion of how various customer- and utility-side AES technologies work, notes examples of existing projects and provides comparisons of the technologies' benefits and drawbacks.

A. Descriptions of Technologies and Examples of Existing Projects

Batteries[44]

Batteries have the potential to span a broad range of energy storage applications. Battery systems for electricity storage use the same principles as batteries used, for example, in automobiles, but in much larger and higher power configurations. Energy storage systems based upon batteries can be portable, and the utility industry is familiar with them. Batteries are a proven technology in widespread use, including limited application to electrical energy storage in systems greater than 5 MW. Japan currently has more than 55 installations of batteries for storage.

Banks of conventional lead-acid batteries have been applied to stabilize electrical systems by rapidly providing extra power and by keeping voltage and frequency stable. However, they wear out relatively quickly when they are charged and discharged frequently. A number of flow battery systems, for example zinc-bromine and vanadium redox, have seen field trials. Flow battery systems store electrolytes outside the battery and circulate them through the battery cells as they are needed. The battery electrodes provide a substrate for chemical reactions and do not participate in them. Thus, flow batteries are long-lived. Nickel metal hydride (NiMH) batteries also show promise for storage applications but they have lower energy densities and are vulnerable to overcharging.

In recent years, lithium-ion (Li-ion) batteries have enjoyed tremendous popularity in commercial devices such as cell phones and laptop computers due to their high energy density (2-3 times that of nickel-cadmium batteries and up to 4 times that of lead-acid batteries). The higher energy density of Li-ion batteries and their relatively long lifetimes make them cost-effective, but the technology has not yet been proven safe on the scale needed for electricity storage.

The major challenges in using batteries for electrical storage are to make them both affordable and long-lived. Commercially available battery systems are not adequate for long-term (>10 years) use. Manufacture of batteries requires handling a variety of chemicals and may pose safety and environmental issues.

Flywheels

A conventional flywheel stores energy as the kinetic energy of a massive disk spinning on a metal shaft. The amount of energy stored depends upon the linear speed of rotation and the mass of the disk. First-generation flywheels, typically manufactured from steel, increased the mass while maintaining rim speeds on the order of 50 m/s. The introduction

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[44] Descriptions of batteries, flywheels, SMES and electrochemical capacitors from "Challenges of Electricity Storage Technologies: A Report from the APS Panel on Public Affairs Committee on Energy and Environment," May 2007. http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf.

of fiber-composite materials enabled second-generation flywheels to reach rim speeds of 800-1000 m/s. These higher-speed machines are limited by the expansion of the rim, which can be as much as 1-2% at high speeds. The expanding rim separates from the rest of the flywheel. They also experience bending resonances and other dynamical instabilities.

Third-generation flywheels, currently under development, combine high mass with high power. For example, the JY-60 Fusion Test Facility in Japan, a 200 MW system is composed of six flywheels, each with a 6.6 m diameter. One flywheel weighs 1,100 tons, reaches rotation speeds of 420-600 revolutions per minute and the rim of the flywheel travels up to 65.7 meters per second. An example is the Pentadyne ASD Voltage Support Solution from the Pentadyne Power Corporation. It offers 120 kW of power for 20 seconds of discharge. The total system weight is half a ton, the rotation speed is 50,000 rpm, and the maximum tip speed is about 800 m/s. One system utilizes a magnetically levitated ring design that resolves many of the design flaws in first- and second-generation flywheels. Using a ring as the rotator eliminates the expansion failure. In addition, the magnetic fields can be adjusted to control the rotational instabilities that arise at high speeds. These systems currently exist as prototypes only.

Short discharge time flywheels are suitable for stabilizing voltage and frequency, while longer duration flywheels may be suitable for damping load fluctuations. However, the high cost and limited capacity of first- and second-generation flywheels has greatly limited the implementation of this technology. A flywheel farm approach could be advantageous for larger-scale energy storage. Current technology could allow forty 25 kW flywheels to operate at 1 MW for 1 hour in one facility.

Superconducting Magnetic Energy Storage (SMES)

A SMES is an inductor with superconducting windings. Energy is added or extracted from the magnetic field of the inductor by increasing or decreasing the current in the windings. At steady state, the superconducting windings dissipate no energy, and energy may be stored indefinitely with low loss. The main parts in a SMES are motionless, which results in high reliability and low maintenance. However, superconductors also require refrigeration systems that introduce energy losses and do contain moving parts. (New designs involving pulse tubes have no moving parts.) Power can be discharged almost instantaneously with high power output for a brief period of time with less loss of power than for other technologies. Discharge times of seconds or less have been demonstrated in currently available systems.

Today, several megawatt-level units are used to stabilize voltage and frequency, especially at manufacturing plants requiring ultra-clean power, such as microchip fabrication facilities. As a DOE/BPA demonstration project, a 10 MVA (Megavolt-amperes) SMES device was used to stabilize the 900 mile, alternating current connection between two power companies, BPA and Southern California. It is possible to network several SMES systems or to build larger single coils to increase the energy available. While larger SMES coils look attractive on paper from the perspectives of physics and economics, they produce large magnetic forces that must be contained. A 24 kV SMES magnet has been tested at Florida State University, as a research system. Containment costs of the high magnetic fields associated with large currents may be a cost driver. Various solutions have been proposed, such as constructing the coils underground to transmit the outward force to bedrock, wrapping the coils in steel, or using toroidal geometries. The main challenge to SMES is reducing the overall cost of the system. Current technology relies on low temperature superconductors, which require expensive cryogenics. Advances in high-temperature superconductivity will play an important role in moving towards less expensive cryogenics and lower conductor costs. Fortunately, cryogenic costs are falling. However, at this time, the costs of high-temperature superconducting components far outweigh possible savings in cryogenics.

Electrochemical Capacitors

Electrochemical capacitors, also known as electric double-layer capacitors, store energy in the form of two oppositely charged electrodes separated by an ionic solution. The energy is stored by charge separation as ions are attached to the electrodes to store energy and released as the ions go back into solution. Because of the increase in stored energy with the increase of electrode surface area, research has focused on the development of high surface area electrodes. *Symmetric* capacitors with activated carbon electrodes are the most widely implemented system. However, much higher energy limits are predicted when one of the electrodes is replaced by a battery-like electrode, for example lithium-titanium-oxide spinel or lead oxide. Such capacitors may have higher operating voltages and greater tolerance to exceeding their design voltage. They also seem to offer packaging and manufacturing advantages that defer costs. These *asymmetric* capacitors have greater promise for applicability to large stored-energy applications than their symmetric counterparts.

Generally, capacitors are suitable for short-duration applications like providing backup power during brief interruptions. Advanced capacitors are excellent for stabilizing voltage and frequency. By proper networking, they could possibly be used for longer time-scale applications. Electrochemical capacitors provide high power density, and their performance does not depend upon temperature. They live through charge/discharge cycles with extremely low maintenance, and have projected lifetimes up to 20 years. This technology is slowly being deployed for some applications. Siemens has developed a storage system that utilizes capacitors to capture and store braking energy of trains, and this concept has been considered for use in automobile technology as well. Although a successful demonstration project of a large 1 MJ, 100 kW uninterruptible power supply (UPS) system using electrochemical capacitors for bridging power was carried out by EPRI Power Electronics Application Center in 2003, experts argue that there is more fundamental research to be done before capacitors are ready for wide scale testing. Although capacitors are more capable than batteries for at least some applications, they are more expensive. Improved high-speed manufacturing methods for capacitor cell fabrication or the development of cheaper electrode materials could reduce the costs.

Pumped Hydroelectric Storage[45]

Pumped hydro storage facilities include two vertically-separated reservoirs. Incoming electricity is used to pump water from the lower reservoir to the upper reservoir. To recover the electricity, water is allowed to flow back downhill, powering a generator on the way. The pumping and generation can be accomplished by a single reversible turbine/generator, or by separate components. The flow of water between the reservoirs can be either under- or above-ground. Advantages of pumped hydro storage include its low operating cost and the fact that the pump and turbine can be sized separately (unless a reversible turbine/generator is used). Disadvantages include its high capital cost; the environmental impacts of the reservoirs; and the fact that many areas lack suitable geography (in particular, the necessary elevation difference).

Dozens of large pumped hydro facilities exist worldwide. Total capacity is about 90 GW, which dwarfs the capacities of other large-scale storage technologies.

Compressed Air Energy Storage[46]

Compressed air energy storage (CAES) plants use off-peak electricity to compress air into an air store reservoir. When electricity is needed, the air is withdrawn, heated by a fuel or from the plant's compressor "waste" heat, and run through expansion turbines to drive an electric generator. If fuel is used to heat the stored air, the CAES plant burns about one-third the premium fuel of a conventional combustion turbine and thus produces about one-third the pollutants (e.g., CO2, NOx) per kWh generated. The compressed air can be stored in several types of underground media including porous rock formations, depleted natural gas/oil fields, and caverns in salt or rock formations. When using underground geologic formations to store the air, long hours of energy can be stored cost-effectively, and such plants are much less expensive than pumped hydroelectric plants to build. The compressed air can also be stored in above ground or near surface pressured air pipelines (including those used to transport high pressure natural gas), but due to cost concerns, such above ground air store plants can only store about 2 to 4 hours of energy cost-effectively.

A 290-MW, 4 hour CAES plant has been in operation in Huntorf, Germany since December 1978 and uses two man-made solution mined salt caverns to store the air. In the 1970's through the 1990's, EPRI sponsored numerous technical and economic studies to determine the technical feasibility and economic viability of deploying CAES in the United States. These studies found that approximately three-fourths of the United States has geology potentially suited for siting reliable underground air storage CAES systems.

Alabama Electric Cooperative built, with EPRI assistance, the first U.S. based CAES plant, which came online in June 1991. This plant uses a first generation design, has a

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[45] "The Potential of Wind Power and Energy Storage in California," Diana Schwyzer, Masters Thesis for Energy and Resources Group at UC Berkeley. November 2006. p. 33.

[46] "New Utility Scale CAES Technology: Performance and Benefits (Including CO2 Benefits)," by Robert B. Schainker (EPRI, USA, rschaink@epri.com), Michael Nakhamkin (ESPC), Pramod Kulkarni (CEC) and Tom Key (EPRI). Available at http://www.energystorageandpower.com/pdf/epri_paper.pdf

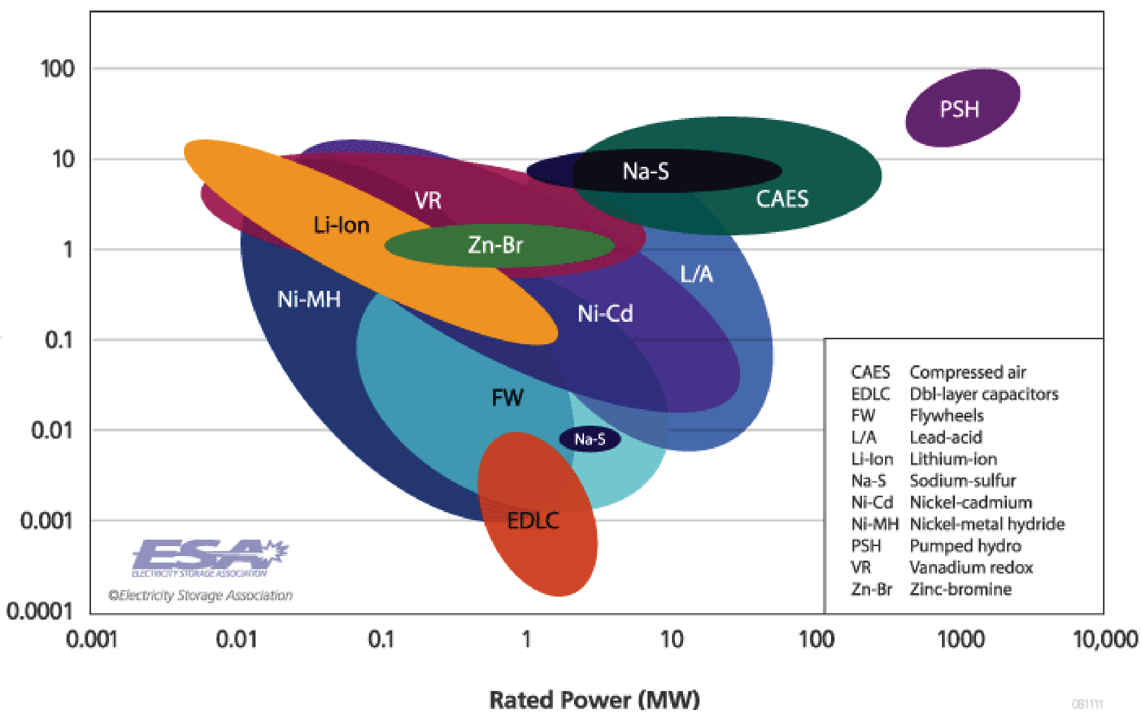
power capacity of 110 MW and its underground air store reservoir is sized to produce this power output for a maximum continuous time duration of about 26 hours.

There was one major design difference between the German and Alabama CAES plants. The Alabama plant had an exhaust gas heat exchanger in it (i.e., a recuperator, using combustion turbine jargon) , which reduced the plants fuel consumption by 25% to heat the air after it came out of the storage reservoir. The German and Alabama plants are relatively complex, requiring a lot of different types of rotating turbomachinery. They have a cost today in the range of $700/kW to $800/kW, which in some cases limits their commercial attractiveness.

B. Capabilities of Different AES Technologies

As discussed above, AES technologies differ greatly in their functions and applications. Below is a graphic developed by the Electricity Storage Association showing the relationship of the different technologies' potential for power (how much electricity can be released at one time) and energy (how many hours can be discharged continuously).

Figure 16. Energy and Power Capabilities of Various AES Technologies



Source: ESA website, http://electricitystorage.org/tech/technologies_comparisons_ratings.htm

(END OF ATTACHMENT 2)

ATTACHMENT 3

Appendix A: SGIP Staff Proposal GHG Analysis Workbook, Page 1

Input Assumptions for SB 412 GHG Analysis

Avoided GHG Emissions Rate	
CHP	**349**
Storage (Charging)	**368**
Storage (Discharging)	**567**

T&D Line Losses	**7.8%**

Conversion Factors	117	lbs. CO2 Equivalent/MMBTU
	0.05317	Tonne CO2E/MMBTU

Avoided GHG Emissions Rate Background		
Description	**Avoided GHG from Grid**	**Source**
	Kg/MWh	
BAU Avoided Emission Rate including 20% renewables (applicable to demand side programs)	**349**	**AB 32 Scoping Plan, modified by CPUC staff for customer generation**
ARB BAU Avoided Emission Rate	437	AB 32 Scoping Plan
Gas CCGT Emissions factor	368	MBCS staff review of AB 32 Scoping Plan Goals (from E3 GHG calculator)
Gas CT Emissions factor	575	MBCS staff review of AB 32 Scoping Plan Goals (from E3 GHG calculator)
Other	0	User defined

Natural Gas Fueled Distributed Generation

Generator Assumptions

Capacity Factor	80%
Electrical Efficiency Degradation	1%

Technology	Capacity (MW)	Electrical Efficiency (HHV)	CHP Efficiency - AB 1613 (HHV)	GHG Reducing (Y/N)	Industry Est. CHP Efficiency (Reference Only)
Electric-only Fuel Cells	0.100	51.6%	0.0%	Yes	0
Fuel Cell CHP	1.000	37.9%	62.0%	Yes	NA
Gas Turbine	10.000	29.0%	62.0%	Yes	68.7%
Rich Burn Engine	0.100	27.1%	62.0%	No	81.0%
Lean Burn Engine	0.800	35.0%	62.0%	Yes	79.0%
Microturbine	0.065	25.2%	62.0%	No	71.5%
Combustion CHP Average	2.741	29.4%	62.0%	Yes	75.3%

Grid/Avoided Boiler Assumptions

GHG Emissions Factor (E)	349	Kg/MWH
T&D losses	7.8%	
Avoided Boiler Efficiency	80%	

Electric-only Fuel Cells

		Capacity	Electrical Efficiency*	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Electric-only Fuel Cells	1	0.1	51.6%	0.0%	6,612	701	59	760	265	4,634	0.05317	246	0	0.0%	0	19
	2	0.1	51.1%	0.0%	6,679	694	59	752	263	4,634	0.05317	246	0	0.0%	0	16
	3	0.1	50.6%	0.0%	6,747	687	58	745	260	4,634	0.05317	246	0	0.0%	0	14
	4	0.1	50.1%	0.0%	6,815	680	58	738	257	4,634	0.05317	246	0	0.0%	0	11
	5	0.1	49.6%	0.0%	6,884	673	57	730	255	4,634	0.05317	246	0	0.0%	0	8
	6	0.1	49.1%	0.0%	6,953	666	56	723	252	4,634	0.05317	246	0	0.0%	0	6
	7	0.1	48.6%	0.0%	7,023	660	56	716	250	4,634	0.05317	246	0	0.0%	0	3
	8	0.1	48.1%	0.0%	7,094	653	55	708	247	4,634	0.05317	246	0	0.0%	0	1
	9	0.1	47.6%	0.0%	7,166	647	55	701	245	4,634	0.05317	246	0	0.0%	0	(2)
	10	0.1	47.1%	0.0%	7,238	640	54	694	242	4,634	0.05317	246	0	0.0%	0	(4)
SubTotal (Sample Project		0.100	49.3%	0.0%	6,921	6,701	567	7,268	2,536	46,340	0.05317	2,464	0	0.0%	0	72
1 MW		1	49.3%	0.0%	6,921	67,009	5,669	72,678	25,365	483,397	0.05317	24,640	0	0.0%	0	725

***Electrical efficiency for electric-only fuel cells must be greater than or equal to 50.1% (HHV) in order for electric-only fuel cells to be GHG reducing.**

Fuel Cell CHP

		Capacity	Electrical Efficiency	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Fuel Cell CHP	1	1	37.9%	62.0%	9,000	7,008	593	7,601	2,653	63,074	0.05317	3,354	15,194	38.8%	1,010	309
	2	1	37.5%	62.0%	9,091	6,938	587	7,525	2,626	63,074	0.05317	3,354	15,434	39.2%	1,026	298
	3	1	37.2%	62.0%	9,183	6,869	581	7,450	2,600	63,074	0.05317	3,354	15,670	39.5%	1,042	288
	4	1	36.8%	62.0%	9,276	6,800	575	7,375	2,574	63,074	0.05317	3,354	15,905	39.9%	1,057	277
	5	1	36.4%	62.0%	9,369	6,732	570	7,301	2,548	63,074	0.05317	3,354	16,137	40.2%	1,073	267
	6	1	36.1%	62.0%	9,464	6,665	564	7,228	2,523	63,074	0.05317	3,354	16,366	40.6%	1,088	257
	7	1	35.7%	62.0%	9,560	6,598	558	7,156	2,497	63,074	0.05317	3,354	16,594	40.9%	1,103	247
	8	1	35.3%	62.0%	9,656	6,532	553	7,085	2,472	63,074	0.05317	3,354	16,819	41.2%	1,118	237
	9	1	35.0%	62.0%	9,754	6,467	547	7,014	2,448	63,074	0.05317	3,354	17,042	41.6%	1,133	227
	10	1	34.6%	62.0%	9,852	6,402	542	6,944	2,423	63,074	0.05317	3,354	17,262	41.9%	1,147	217
SubTotal (Sample Project		1.000	36.2%	62.0%	9,421	67,009	5,669	72,678	25,365	630,738	0.05317	33,538	162,423	40.4%	10,796	2,622
1 MW		1	36.2%	62.0%	9,421	67,009	5,669	72,678	25,365	630,738	0.05317	33,538	162,423	40.4%	10,796	2,622

Gas Turbine

		Capacity	Electrical Efficiency	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Gas Turbine	1	10	29.0%	62.0%	11,766	70,080	5,929	76,009	26,527	824,527	0.05317	43,842	272,094	46.5%	18,085	770
	2	10	28.7%	62.0%	11,884	69,379	5,869	75,249	26,262	824,527	0.05317	43,842	274,485	46.7%	18,244	663
	3	10	28.4%	62.0%	12,004	68,685	5,811	74,496	25,999	824,527	0.05317	43,842	276,852	46.9%	18,401	558
	4	10	28.1%	62.0%	12,126	67,999	5,753	73,751	25,739	824,527	0.05317	43,842	279,196	47.1%	18,557	454
	5	10	27.9%	62.0%	12,248	67,319	5,695	73,014	25,482	824,527	0.05317	43,842	281,516	47.3%	18,711	351
	6	10	27.6%	62.0%	12,372	66,645	5,638	72,283	25,227	824,527	0.05317	43,842	283,813	47.5%	18,864	248
	7	10	27.3%	62.0%	12,497	65,979	5,582	71,561	24,975	824,527	0.05317	43,842	286,087	47.7%	19,015	147
	8	10	27.0%	62.0%	12,623	65,319	5,526	70,845	24,725	824,527	0.05317	43,842	288,338	47.9%	19,165	47
	9	10	26.8%	62.0%	12,751	64,666	5,471	70,137	24,478	824,527	0.05317	43,842	290,567	48.1%	19,313	(52)
	10	10	26.5%	62.0%	12,879	64,019	5,416	69,435	24,233	824,527	0.05317	43,842	292,773	48.3%	19,459	(150)
SubTotal (Sample Project		10.000	27.7%	62.0%	12,315	670,090	56,689	726,779	253,646	8,245,274	0.05317	438,424	2,825,722	47.4%	187,814	3,036
1 MW		1	27.7%	62.0%	12,315	67,009	5,669	72,678	25,365	824,527	0.05317	43,842	282,572	47.4%	18,781	304

Rich Burn Engine

		Capacity	Electrical Efficiency*	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas - GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Rich Burn Engine	1	0.1	27.1%	62.0%	12,590	701	59	760	265	8,823	0.05317	469	3,079	47.9%	205	1
	2	0.1	26.8%	62.0%	12,718	694	59	752	263	8,823	0.05317	469	3,103	48.1%	206	(0)
	3	0.1	26.6%	62.0%	12,846	687	58	745	260	8,823	0.05317	469	3,127	48.3%	208	(1)
	4	0.1	26.3%	62.0%	12,976	680	58	738	257	8,823	0.05317	469	3,150	48.4%	209	(2)
	5	0.1	26.0%	62.0%	13,107	673	57	730	255	8,823	0.05317	469	3,174	48.6%	211	(3)
	6	0.1	25.8%	62.0%	13,239	666	56	723	252	8,823	0.05317	469	3,197	48.8%	212	(4)
	7	0.1	25.5%	62.0%	13,373	660	56	716	250	8,823	0.05317	469	3,219	49.0%	214	(5)
	8	0.1	25.3%	62.0%	13,508	653	55	708	247	8,823	0.05317	469	3,242	49.2%	215	(6)
	9	0.1	25.0%	62.0%	13,645	647	55	701	245	8,823	0.05317	469	3,264	49.3%	217	(7)
	10	0.1	24.8%	62.0%	13,782	640	54	694	242	8,823	0.05317	469	3,286	49.5%	218	(8)
SubTotal (Sample Project)		0.100	25.9%	62.0%	13,178	6,701	567	7,268	2,536	88,234	0.05317	4,692	31,841	48.7%	2,116	(39)
1 MW		1	25.9%	62.0%	13,178	67,009	5,669	72,678	25,365	882,336	0.05317	46,916	318,413	48.7%	21,164	(388)

****CHP efficiency must be equal to or greater than 62.7% for Rich Burn Engines in order for these technologies to be GHG reducing at given electrical efficiencies***

Lean Burn Engine

		Capacity	Electrical Efficiency	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas - GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Lean Burn Engine	1	0.8	35.0%	62.0%	9,749	5,606	474	6,081	2,122	54,654	0.05317	2,906	14,757	41.5%	981	197
	2	0.8	34.7%	62.0%	9,847	5,550	470	6,020	2,101	54,654	0.05317	2,906	14,948	41.9%	994	188
	3	0.8	34.3%	62.0%	9,947	5,495	465	5,960	2,080	54,654	0.05317	2,906	15,137	42.2%	1,006	180
	4	0.8	34.0%	62.0%	10,047	5,440	460	5,900	2,059	54,654	0.05317	2,906	15,325	42.5%	1,019	172
	5	0.8	33.6%	62.0%	10,148	5,385	456	5,841	2,039	54,654	0.05317	2,906	15,510	42.8%	1,031	163
	6	0.8	33.3%	62.0%	10,251	5,332	451	5,783	2,018	54,654	0.05317	2,906	15,694	43.0%	1,043	155
	7	0.8	33.0%	62.0%	10,355	5,278	447	5,725	1,998	54,654	0.05317	2,906	15,876	43.3%	1,055	147
	8	0.8	32.6%	62.0%	10,459	5,226	442	5,668	1,978	54,654	0.05317	2,906	16,056	43.6%	1,067	139
	9	0.8	32.3%	62.0%	10,565	5,173	438	5,611	1,958	54,654	0.05317	2,906	16,235	43.9%	1,079	131
	10	0.8	32.0%	62.0%	10,671	5,122	433	5,555	1,939	54,654	0.05317	2,906	16,411	44.1%	1,091	123
SubTotal (Sample Project)		0.800	33.5%	62.0%	10,204	53,607	4,535	58,142	20,292	546,544	0.05317	29,061	155,949	42.9%	10,365	1,596
1 MW		1	33.5%	62.0%	10,204	67,009	5,669	72,678	25,365	683,180	0.05317	36,327	194,937	42.9%	12,957	1,995

Microturbine

		Capacity	Electrical Efficiency*	Total System Efficiency (CHP only)**	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Microturbine	1	0.065	25.2%	62.0%	13,540	456	39	494	172	6,168	0.05317	328	2,270	49.2%	151	(5)
	2	0.065	24.9%	62.0%	13,676	451	38	489	171	6,168	0.05317	328	2,285	49.4%	152	(5)
	3	0.065	24.7%	62.0%	13,815	446	38	484	169	6,168	0.05317	328	2,301	49.5%	153	(6)
	4	0.065	24.5%	62.0%	13,954	442	37	479	167	6,168	0.05317	328	2,316	49.7%	154	(7)
	5	0.065	24.2%	62.0%	14,095	438	37	475	166	6,168	0.05317	328	2,331	49.9%	155	(7)
	6	0.065	24.0%	62.0%	14,237	433	37	470	164	6,168	0.05317	328	2,346	50.0%	156	(8)
	7	0.065	23.7%	62.0%	14,381	429	36	465	162	6,168	0.05317	328	2,361	50.2%	157	(9)
	8	0.065	23.5%	62.0%	14,527	425	36	460	161	6,168	0.05317	328	2,375	50.3%	158	(9)
	9	0.065	23.3%	62.0%	14,673	420	36	456	159	6,168	0.05317	328	2,390	50.5%	159	(10)
	10	0.065	23.0%	62.0%	14,821	416	35	451	158	6,168	0.05317	328	2,404	50.6%	160	(11)
SubTotal (Sample Project		0.065	24.1%	62.0%	14,172	4,356	368	4,724	1,649	61,676	0.05317	3,279	23,378	49.9%	1,554	(77)
1 MW		1	24.1%	62.0%	14,172	67,009	5,669	72,678	25,365	948,861	0.05317	50,454	359,659	49.9%	23,905	(1,184)

**Electrical efficiency must be equal to or greater than 28.2% in order for CHP to be GHG reducing at 62% overall efficiency*

***CHP efficiency must be equal to or greater than 63.9% for Microturbines in order for these technologies to be GHG reducing at given electrical efficiencies*

Combustion CHP Average

		Capacity	Electrical Efficiency	Total System Efficiency (CHP only)	Heat Rate (calculated)	Generation	T&D Avoided	Total Electricity Avoided	Emissions Avoided (E)	Fuel Input	Natural Gas GHG Conversion	Emissions Produced	Heat Recovered	Heat Recovery Rate	Emissions Avoided (H)	Net Emissions Reduction
Technology	Year	MW	%	%	BTU/kWh	MWh	MWh	MWh	Tonne CO2E	MMBTU	Tonne/MMBTU	Tonne CO2E	MMBTU	MMBTU	Tonne CO2E	Tonne CO2E
Combustion CHP Average	1	2.74125	29.4%	62.0%	11,606	19,211	1,625	20,836	7,272	222,964	0.05317	11,856	72,691	46.2%	4,831	246
	2	2.74125	29.1%	62.0%	11,724	19,019	1,609	20,628	7,199	222,964	0.05317	11,856	73,347	46.4%	4,875	218
	3	2.74125	28.8%	62.0%	11,842	18,828	1,593	20,421	7,127	222,964	0.05317	11,856	73,995	46.6%	4,918	190
	4	2.74125	28.5%	62.0%	11,962	18,640	1,577	20,217	7,056	222,964	0.05317	11,856	74,638	46.8%	4,961	161
	5	2.74125	28.2%	62.0%	12,082	18,454	1,561	20,015	6,985	222,964	0.05317	11,856	75,274	47.0%	5,003	133
	6	2.74125	28.0%	62.0%	12,204	18,269	1,546	19,815	6,915	222,964	0.05317	11,856	75,904	47.3%	5,045	105
	7	2.74125	27.7%	62.0%	12,328	18,086	1,530	19,617	6,846	222,964	0.05317	11,856	76,527	47.5%	5,086	77
	8	2.74125	27.4%	62.0%	12,452	17,906	1,515	19,420	6,778	222,964	0.05317	11,856	77,144	47.7%	5,127	50
	9	2.74125	27.1%	62.0%	12,578	17,727	1,500	19,226	6,710	222,964	0.05317	11,856	77,755	47.9%	5,168	22
	10	2.74125	26.9%	62.0%	12,705	17,549	1,485	19,034	6,643	222,964	0.05317	11,856	78,360	48.0%	5,208	(5)
SubTotal (Sample Project		2.741	28.1%	62.0%	12,148	183,689	15,540	199,228	69,531	2,229,643	0.05317	118,556	755,634	47.1%	50,224	1,198
1 MW		1	28.1%	62.0%	12,148	67,009	5,669	72,678	25,365	813,367	0.05317	43,249	275,653	47.1%	18,322	437

Appendix A: SGIP Staff Proposal GHG Analysis Workbook, Page 6

Storage Minimum Performance Outcomes

Storage Assumptions

Round Trip Efficiency (min.)	70.00%	
Charge/Discharge Time	4	hours
Operation Days	260	/year
Performance Degradation	1%	

Grid Assumptions

GHG Emissions Factor (Charge)	368	Kg/MWH
GHG Emissions Factor (Disch.)	567	
T&D losses (all times)	7.8%	

Technology	Capacity	Charging	Line Losses (Charging)	Net Generation, Charging	Net Emissions Produced	Discharging	Line Losses (Discharging)	Net Generation, Discharging	Net Emissions Avoided	Annual Net Emissions Reduction
Year	MW	MWh	MWh	MWh	Tonne CO2E	MWh	MWh	MWh	Tonne CO2E	Tonne CO2E
Energy Storage										
1	1	1486	126	1,611	593	1,040	88	1,128	640	47
2	1	1486	126	1,611	593	1,030	87	1,117	633	40
3	1	1486	126	1,611	593	1,019	86	1,106	627	34
4	1	1486	126	1,611	593	1,009	85	1,094	621	28
5	1	1486	126	1,611	593	999	85	1,084	614	21
6	1	1486	126	1,611	593	989	84	1,073	608	15
7	1	1486	126	1,611	593	979	83	1,062	602	9
8	1	1486	126	1,611	593	969	82	1,051	596	3
9	1	1486	126	1,611	593	960	81	1,041	590	(3)
10	1	1486	126	1,611	593	950	80	1,030	584	(9)
Total	1	14,857	1,257	16,114	5,930	9,944	841	10,786	6,115	185

Round trip efficiency for energy storage must be greater than or equal to 67.9% in order for energy storage to be GHG reducing.

(END OF ATTACHMENT 3)

ATTACHMENT 4

Note: All inputs and assumptions should be manipulated on this tal

Inputs - Technology Specific		Cost		Federal Investment Tax Credit			Expected Performance			
Technology	Sample System Size (kW)	Installed Cost ($/kW)	O&M ($/kWh)	ITC (%)	Maximum ITC ($/kW)	ITC Eligible Size	Electrical Efficiency	Total System Efficiency	Capcity Factor	Incentive Amount ($/kW)
Wind Turbine	387	$3,096	$0.008	30%			NA	NA	20%	$ -
Fuel Cell - Electric Only	100	$9,608	$0.020	30%	$3,000	> 0.5 kW	46.0%	46.0%	80%	$ -
Fuel Cell - Electric Only (Biogas)	100	$12,108	$0.040	30%	$3,000	> 0.5 kW	46.0%	46.0%	80%	$ -
Fuel Cell - CHP	400	$7,268	$0.030	30%	$3,000	> 0.5 kW	41.2%	62.0%	80%	$ -
Fuel Cell - CHP (Biogas)	400	$9,768	$0.054	30%	$3,000	> 0.5 kW	41.2%	41.2%	80%	$ -
Gas Turbine - CHP	1000	$2,347	$0.020	10%		< 50 MW	29.0%	62.0%	80%	$ -
Gas Turbine - CHP (Biogas)	1000	$4,847	$0.054	10%		< 50 MW	29.0%	29.0%	80%	$ -
Microturbine - CHP	165	$3,293	$0.020	10%	$200		25.2%	62.0%	80%	$ -
Microturbine - CHP (Biogas)	165	$5,793	$0.086	10%	$200		25.2%	25.2%	80%	$ -
IC Engine - CHP	800	$2,322	$0.020	10%		< 50 MW	35.0%	62.0%	80%	$ -
IC Engine - CHP (Biogas)	800	$4,822	$0.054	10%		< 50 MW	35.0%	35.0%	80%	$ -
Organic Rankine Cycle	100	$2,858	$0.010	0%			NA	NA	80%	$ -
Pressure Reduction	100	$3,488	$0.010	30%			NA	NA	80%	$ -

Renewable Fuel Clean Up ($/kW)
$2,500.00

Inputs - General	
Incentive Payment in 1st Year	25%
Incentive Payment Period (yrs)	5
California Adder?	Yes
Discount Rate (%)	5%
Avoided electricity price ($/kWh)	$0.12
Electricity price escalation (%/yr)	2%
Metering Cost - Tariff related ($/yr)	$1,439
Metering Cost - Electricity output ($)	$4,300
Metering Cost - Waste heat ($)	$17,000
Metering Cost - Fuel input ($)	$7,500
NG Cost ($/MMBtu)	$6.20
Hours of operation/yr	8,760
Performance degradation (%/yr)	1%
Avoided Boiler efficiency	80%
kW per Btu	3412
% of incentive paid for 1st MW	100%
% of incentive paid for 2nd MW	50%
% of incentive paid for 3rd MW	25%

Outputs			
Technology	Expected IRR (%)	Simple Payback (years)*	NPV ($)
Wind Turbine	9.50%	9.66	$948,652
Fuel Cell - Electric Only	-13.78%	#REF!	-$429,149
Fuel Cell - Electric Only (Biogas)	-8.98%	#REF!	-$466,359
Fuel Cell - CHP	-8.81%	#REF!	-$1,010,713
Fuel Cell - CHP (Biogas)	-6.48%	#REF!	-$1,182,442
Gas Turbine - CHP	13.47%	6.04	$727,227
Gas Turbine - CHP (Biogas)	2.78%	8.93	-$395,359
Microturbine - CHP	-1.55%	#REF!	-$136,583
Microturbine - CHP (Biogas)	-11.91%	#REF!	-$549,218
IC Engine - CHP	15.98%	5.62	$762,415
IC Engine - CHP (Biogas)	2.81%	8.92	$1,978,345
Organic Rankine Cycle	33.04%	3.83	$400,641
Pressure Reductior	49.72%	2.98	$477,571

* "#REF!" indicates that the technology will not break even during the expected lifetime.

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Technology Type	Microturbine - CHP	Installed Cost ($)	$572,218
Capacity (kW)	165	Installed Cost ($/kW)	$3,293
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.020
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	25.2%
Incentive Payment in 1st Year	25%	System efficiency	62.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$8.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	13540
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	1,156,320	1,144,757	1,133,309	1,121,976	1,110,756	1,099,649	1,088,652	1,077,766	1,066,988	1,056,318
Value of avoided electricity	**$136,410**	**$137,747**	**$139,097**	**$140,460**	**$141,836**	**$143,226**	**$144,630**	**$146,047**	**$147,479**	**$148,924**
NG Consumed (MMBtu)	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657
Heat recovered (MMBtu)	5,762	5,704	5,647	5,591	5,535	5,479	5,425	5,370	5,317	5,263
Heat recovery rate (%)	49.20%	48.71%	48.22%	47.74%	47.26%	46.79%	46.32%	45.86%	45.40%	44.94%
Avoided NG consumption (MMBtu)	7,202	7,130	7,059	6,988	6,918	6,849	6,781	6,713	6,646	6,579
Value of avoided NG	**$44,653**	**$50,196**	**$51,106**	**$51,433**	**$51,888**	**$52,465**	**$52,957**	**$53,502**	**$54,030**	**$54,542**
Cost of NG Consumed	-$97,072	-$110,224	-$113,356	-$115,234	-$117,426	-$119,931	-$122,280	-$124,785	-$127,290	-$129,795
O&M Costs	-$23,126	-$22,895	-$22,666	-$22,440	-$22,215	-$21,993	-$21,773	-$21,555	-$21,340	-$21,126
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
California Adder	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
ITC	**$33,000**									
Cash Flow	($508,593)	$53,384	$52,742	$52,780	$52,643	$52,327	$52,095	$51,769	$51,439	$51,105
Cumulative Cash Flow	($508,593)	($455,208)	($402,466)	($349,686)	($297,043)	($244,715)	($192,620)	($140,851)	($89,411)	($38,306)

Net Present Value		**-$136,583**
IRR		**-1.55%**
Break Even (yrs)	**#REF!**	

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Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	IC Engine - CHP	Installed Cost ($)	$1,886,305
Capacity (kW)	800	Installed Cost ($/kW)	$2,322
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.020
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	35.0%
Incentive Payment in 1st Year	25%	System efficiency	62.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	9749
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	5,606,400	5,550,336	5,494,833	5,439,884	5,385,485	5,331,631	5,278,314	5,225,531	5,173,276	5,121,543
Value of avoided electricity	**$661,381**	**$667,863**	**$674,408**	**$681,017**	**$687,691**	**$694,431**	**$701,236**	**$708,108**	**$715,048**	**$722,055**
NG Consumed (MMBtu)	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657
Heat recovered (MMBtu)	14,757	14,610	14,464	14,319	14,176	14,034	13,894	13,755	13,617	13,481
Heat recovery rate (%)	41.54%	41.12%	40.71%	40.30%	39.90%	39.50%	39.11%	38.72%	38.33%	37.95%
Avoided NG consumption (MMBtu)	18,447	18,262	18,080	17,899	17,720	17,543	17,367	17,193	17,022	16,851
Value of avoided NG	**$114,369**	**$128,566**	**$130,896**	**$131,735**	**$132,898**	**$134,376**	**$135,637**	**$137,032**	**$138,385**	**$139,697**
Cost of NG Consumed ($)	-$338,871	-$384,783	-$395,714	-$402,273	-$409,925	-$418,670	-$426,868	-$435,613	-$444,359	-$453,104
O&M Costs	-$109,325	-$108,232	-$107,149	-$106,078	-$105,017	-$103,967	-$102,927	-$101,898	-$100,879	-$99,870
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	**$188,631**									
Cash Flow	($1,400,359)	$301,975	$301,001	$302,962	$304,208	$304,731	$305,639	$306,190	$306,756	$307,340
Cumulative Cash Flow	($1,400,359)	($1,098,384)	($797,383)	($494,421)	($190,212)	$114,519	$420,157	$726,347	$1,033,103	$1,340,442

Net Present Value	**$762,415**
IRR	**15.98%**
Break Even (yrs)	**5.62**

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Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Gas Turbine - CHP	Installed Cost ($)	$2,375,890
Capacity (kW)	1,000	Installed Cost ($/kW)	$2,347
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.020
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	29.0%
Incentive Payment in 1st Year	25%	System efficiency	62.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	11766
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	7,008,000	6,937,920	6,868,541	6,799,855	6,731,857	6,664,538	6,597,893	6,531,914	6,466,595	6,401,929
Value of avoided electricity	$826,727	$834,829	$843,010	$851,271	$859,614	$868,038	$876,545	$885,135	$893,809	$902,569
NG Consumed (MMBtu)	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456
Heat recovered (MMBtu)	27,211	26,938	26,669	26,402	26,138	25,877	25,618	25,362	25,108	24,857
Heat recovery rate (%)	46.48%	46.01%	45.55%	45.10%	44.65%	44.20%	43.76%	43.32%	42.89%	42.46%
Avoided NG consumption (MMBtu)	34,013	33,673	33,336	33,003	32,673	32,346	32,023	31,702	31,385	31,072
Value of avoided NG	$210,882	$237,058	$241,355	$242,902	$245,047	$247,772	$250,097	$252,669	$255,164	$257,584
Cost of NG Consumed ($)	-$511,228	-$580,491	-$596,983	-$606,877	-$618,421	-$631,614	-$643,983	-$657,176	-$670,369	-$683,562
O&M Costs	-$136,656	-$135,289	-$133,937	-$132,597	-$131,271	-$129,958	-$128,659	-$127,372	-$126,099	-$124,838
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$237,589									
Cash Flow	($1,778,816)	$354,667	$352,007	$353,260	$353,529	$352,798	$352,562	$351,817	$351,067	$350,314
Cumulative Cash Flow	($1,778,816)	($1,424,149)	($1,072,142)	($718,882)	($365,353)	($12,555)	$340,007	$691,824	$1,042,891	$1,393,206

Net Present Value	$727,227
IRR	13.47%
Break Even (yrs)	6.04

Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Fuel Cell - CHP	Installed Cost ($)	$2,936,198
Capacity (kW)	400	Installed Cost ($/kW)	$7,268
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.030
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	41.2%
Incentive Payment in 1st Year	25%	System efficiency	62.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	8282
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	2,803,200	2,775,168	2,747,416	2,719,942	2,692,743	2,665,815	2,639,157	2,612,766	2,586,638	2,560,772
Value of avoided electricity	$330,691	$333,931	$337,204	$340,509	$343,846	$347,215	$350,618	$354,054	$357,524	$361,027
NG Consumed (MMBtu)	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216
Heat recovered (MMBtu)	4,829	4,781	4,733	4,685	4,639	4,592	4,546	4,501	4,456	4,411
Heat recovery rate (%)	35.37%	35.02%	34.67%	34.32%	33.98%	33.64%	33.30%	32.97%	32.64%	32.31%
Avoided NG consumption (MMBtu)	6,036	5,976	5,916	5,857	5,798	5,740	5,683	5,626	5,570	5,514
Value of avoided NG	$37,424	$42,069	$42,832	$43,106	$43,487	$43,971	$44,383	$44,840	$45,282	$45,712
Cost of NG Consumed ($)	-$143,938	-$163,439	-$168,082	-$170,868	-$174,119	-$177,833	-$181,315	-$185,030	-$188,745	-$192,459
O&M Costs	-$84,096	-$83,255	-$82,422	-$81,598	-$80,782	-$79,974	-$79,175	-$78,383	-$77,599	-$76,823
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$880,859									
Cash Flow	($1,945,497)	$127,867	$128,092	$129,709	$130,993	$131,939	$133,072	$134,042	$135,023	$136,018
Cumulative Cash Flow	($1,945,497)	($1,817,630)	($1,689,538)	($1,559,829)	($1,428,836)	($1,296,897)	($1,163,825)	($1,029,783)	($894,760)	($758,742)

Net Present Value	-$1,010,713
IRR	-8.81%
Break Even (yrs)	#REF!

Cost Forecasts	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Fuel Cell - Electric Only	Installed Cost ($)	$972,601
Capacity (kW)	100	Installed Cost ($/kW)	$9,606
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.020
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	46.0%
Incentive Payment in 1st Year	25%	System efficiency	46.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	7418
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	700,800	693,792	686,854	679,986	673,186	666,454	659,789	653,191	646,659	640,193
Value of avoided electricity	$82,673	$83,483	$84,301	$85,127	$85,961	$86,804	$87,654	$88,514	$89,381	$90,257
NG Consumed (MMBtu)	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	-$32,230	-$36,596	-$37,636	-$38,260	-$38,987	-$39,819	-$40,599	-$41,431	-$42,262	-$43,094
O&M Costs	-$14,016	-$13,876	-$13,737	-$13,600	-$13,464	-$13,329	-$13,196	-$13,064	-$12,933	-$12,804
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	$0									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$291,780									
Cash Flow	($657,633)	$31,572	$31,489	$31,829	$32,071	$32,217	$32,421	$32,580	$32,746	$32,920
Cumulative Cash Flow	($657,633)	($626,061)	($594,572)	($562,743)	($530,672)	($498,455)	($466,034)	($433,454)	($400,708)	($367,788)

Net Present Value		-$429,149
IRR		-13.78%
Break Even (yrs)	#REF!	

Cost Forecasts	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

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Technology Type	Microturbine - CHP (Biogas)	Installed Cost ($)	$984,718
Capacity (kW)	165	Installed Cost ($/kW)	$5,793
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.086
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	25.2%
Incentive Payment in 1st Year	25%	System efficiency	25.2%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	13540
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	1,156,320	1,144,757	1,133,309	1,121,976	1,110,756	1,099,649	1,088,652	1,077,766	1,066,988	1,056,318
Value of avoided electricity	$136,410	$137,747	$139,097	$140,460	$141,836	$143,226	$144,630	$146,047	$147,479	$148,924
NG Consumed (MMBtu)	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657	15,657
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Costs	-$99,444	-$98,449	-$97,465	-$96,490	-$95,525	-$94,570	-$93,624	-$92,688	-$91,761	-$90,843
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$98,472									
Cash Flow	($879,519)	$37,859	$40,193	$42,531	$44,872	$47,217	$49,567	$51,920	$54,279	$56,641
Cumulative Cash Flow	($879,519)	($841,660)	($801,467)	($758,936)	($714,064)	($666,847)	($617,280)	($565,359)	($511,081)	($454,439)

Net Present Value		-$549,218
IRR		-11.91%
Break Even (yrs)	#REF!	

Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	IC Engine - CHP (Biogas)	Installed Cost ($)	$3,858,305
Capacity (kW)	800	Installed Cost ($/kW)	$4,822
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.054
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	35.0%
Incentive Payment in 1st Year	25%	System efficiency	35.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	9749
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	5,606,400	5,550,336	5,494,833	5,439,884	5,385,485	5,331,631	5,278,314	5,225,531	5,173,276	5,121,543
Value of avoided electricity	$661,381	$667,863	$674,408	$681,017	$687,691	$694,431	$701,236	$708,108	$715,048	$722,055
NG Consumed (MMBtu)	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657	54,657
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Costs	-$302,746	-$299,718	-$296,721	-$293,754	-$290,816	-$287,908	-$285,029	-$282,179	-$279,357	-$276,563
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$388,631									
Cash Flow	($3,169,278)	$366,706	$376,248	$385,824	$395,436	$405,083	$414,768	$424,490	$434,252	$444,053
Cumulative Cash Flow	($3,169,278)	($2,802,572)	($2,426,324)	($2,040,500)	($1,645,064)	($1,239,980)	($825,212)	($400,722)	$33,530	$477,582

Net Present Value	$1,978,345
IRR	2.81%
Break Even (yrs)	8.92

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Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Gas Turbine - CHP (Biogas)	Installed Cost ($)	$4,875,890
Capacity (kW)	1,000	Installed Cost ($/kW)	$4,847
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.054
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	10.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	29.0%
Incentive Payment in 1st Year	25%	System efficiency	29.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	11766
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	7,008,000	6,937,920	6,868,541	6,799,855	6,731,857	6,664,538	6,597,893	6,531,914	6,466,595	6,401,929
Value of avoided electricity	$826,727	$834,829	$843,010	$851,271	$859,614	$868,038	$876,545	$885,135	$893,809	$902,569
NG Consumed (MMBtu)	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456	82,456
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Costs	-$378,432	-$374,648	-$370,901	-$367,192	-$363,520	-$359,885	-$356,286	-$352,723	-$349,196	-$345,704
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$487,589									
Cash Flow	($3,970,245)	$458,742	$470,670	$482,640	$494,655	$506,714	$518,820	$530,973	$543,174	$555,426
Cumulative Cash Flow	($3,970,245)	($3,511,503)	($3,040,834)	($2,558,193)	($2,063,539)	($1,556,824)	($1,038,005)	($507,032)	$36,142	$591,568

Net Present Value	-$395,359
IRR	2.78%
Break Even (yrs)	8.93

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Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Fuel Cell - CHP (Biogas)	Installed Cost ($)	$3,936,198
Capacity (kW)	400	Installed Cost ($/kW)	$9,768
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.054
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	41.2%
Incentive Payment in 1st Year	25%	System efficiency	41.2%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	8282
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	2,803,200	2,775,168	2,747,416	2,719,942	2,692,743	2,665,815	2,639,157	2,612,766	2,586,638	2,560,772
Value of avoided electricity	$330,691	$333,931	$337,204	$340,509	$343,846	$347,215	$350,618	$354,054	$357,524	$361,027
NG Consumed (MMBtu)	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216	23,216
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Costs	-$151,373	-$149,859	-$148,360	-$146,877	-$145,408	-$143,954	-$142,514	-$141,089	-$139,678	-$138,282
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$1,180,859									
Cash Flow	($2,606,260)	$182,633	$187,405	$192,193	$196,998	$201,822	$206,664	$211,526	$216,408	$221,307
Cumulative Cash Flow	($2,606,260)	($2,423,627)	($2,236,222)	($2,044,029)	($1,847,031)	($1,645,209)	($1,438,544)	($1,227,018)	($1,010,612)	($789,305)

Net Present Value		-$1,182,442
IRR		-6.48%
Break Even (yrs)	#REF!	

Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Fuel Cell - Electric Only (Biogas)	Installed Cost ($)	$1,222,601
Capacity (kW)	100	Installed Cost ($/kW)	$12,108
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.040
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electrical efficiency	46.0%
Incentive Payment in 1st Year	25%	System efficiency	46.0%
Incentive Payment Period (yrs)	5	Electricity cost ($/kWh)	0.12
Discount Rate (%)	5.00%	Metering Cost ($/yr)	$1,439
Degradation (%/yr)	1.00%	Hours of operation/yr	8,760
Utility price escalation (%/yr)	2.00%	NG Cost ($/MMBtu)	$6.20
Capacity Factor	80.00%	Boiler Efficiency	80%
California Adder?	Yes	Heat Rate	7418
		kW per Btu	3412

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	700,800	693,792	686,854	679,986	673,186	666,454	659,789	653,191	646,659	640,193
Value of avoided electricity	$82,673	$83,483	$84,301	$85,127	$85,961	$86,804	$87,654	$88,514	$89,381	$90,257
NG Consumed (MMBtu)	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198	5,198
Heat recovered (MMBtu)	0	0	0	0	0	0	0	0	0	0
Heat recovery rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avoided NG consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0
Value of avoided NG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost of NG Consumed ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Costs	-$28,032	-$27,752	-$27,474	-$27,199	-$26,927	-$26,658	-$26,392	-$26,128	-$25,866	-$25,608
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	$0									
Metering Cost - Fuel consumption	-$7,500									
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$300,000									
Cash Flow	($881,199)	$54,292	$55,388	$56,489	$57,595	$58,707	$59,824	$60,947	$62,076	$63,210
Cumulative Cash Flow	($881,199)	($826,907)	($771,519)	($715,031)	($657,436)	($598,729)	($538,905)	($477,958)	($415,883)	($352,673)

Net Present Value		-$466,359
IRR		-8.98%
Break Even (yrs)	#REF!	

Cost Forecasts											
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Pressure Reduction	Installed Cost ($)	$353,100
Capacity (kW)	100	Installed Cost ($/kW)	$3,488
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.010
Incentive Amount - 2nd MW ($/kW	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electricity cost ($/kWh)	$0.12
Incentive Payment in 1st Year	25%	Metering Cost ($/yr)	$1,439
Incentive Payment Period (yrs)	5	Hours of operation/yr	8,760
Discount Rate (%)	5.00%		
Degradation (%/yr)	1.00%		
Utility price escalation (%/yr)	2.00%		
Capacity Factor	80.00%		
California Adder?	Yes		

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	700,800	693,792	686,854	679,986	673,186	666,454	659,789	653,191	646,659	640,193
Value of avoided electricity	**$82,673**	**$83,483**	**$84,301**	**$85,127**	**$85,961**	**$86,804**	**$87,654**	**$88,514**	**$89,381**	**$90,257**
O&M Costs	-$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
SGIP Incentive Payment	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
California Adder	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
ITC	**$105,930**									
Cash Flow	($177,244)	$89,052	$89,870	$90,696	$91,530	$92,373	$93,223	$94,082	$94,950	$95,826
Cumulative Cash Flow	($177,244)	($88,192)	$1,677	$92,374	$183,904	$276,277	$369,500	$463,583	$558,533	$654,359

Net Present Value	**$477,571**
IRR	**49.72%**
Break Even (yrs)	**2.98**

Cost Forecasts											
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NG	6.2	7.04	7.24	7.36	7.5	7.66	7.81	7.97	8.13	8.29	8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Organic Rankine Cycle	Installed Cost ($)	$307,100
Capacity (kW)	100	Installed Cost ($/kW)	$2,858
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.010
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	0.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electricity cost ($/kWh)	$0.12
Incentive Payment in 1st Year	25%	Metering Cost ($/yr)	$1,439
Incentive Payment Period (yrs)	5	Hours of operation/yr	8,760
Discount Rate (%)	5.00%		
Degradation (%/yr)	1.00%		
Utility price escalation (%/yr)	2.00%		
Capacity Factor	80.00%		
California Adder?	Yes		

Year	1	2	3	4	5	6	7	8	9	10
Electricity generated (kWh)	700,800	693,792	686,854	679,986	673,186	666,454	659,789	653,191	646,659	640,193
Value of avoided electricity	**$82,673**	**$83,483**	**$84,301**	**$85,127**	**$85,961**	**$86,804**	**$87,654**	**$88,514**	**$89,381**	**$90,257**
O&M Costs	-$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008	$7,008
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300									
Metering Cost - Waste heat	-$17,000									
SGIP Incentive Payment	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
California Adder	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
ITC	**$0**									
Cash Flow	($254,174)	$89,052	$89,870	$90,696	$91,530	$92,373	$93,223	$94,082	$94,950	$95,826
Cumulative Cash Flow	($254,174)	($165,122)	($75,253)	$15,444	$106,974	$199,347	$292,570	$386,653	$481,603	$577,429

Net Present Value	**$400,641**
IRR	**33.04%**
Break Even (yrs)	**3.83**

Cost Forecasts

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.50	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

Technology Type	Wind Turbine	Installed Cost ($)	$3,719,802
Capacity (kW)	1,200	Installed Cost ($/kW)	$3,099
Incentive Amount - 1st MW ($/kW)	$0	O&M or Warranty Cost ($/kWh)	$0.008
Incentive Amount - 2nd MW ($/kW)	$0	ITC (%)	30.0%
Incentive Amount - 3rd MW ($/kW)	$0	Electricity cost ($/kWh)	$0.12
Incentive Payment in 1st Year	25%	Metering Cost ($/yr)	$1,439
Incentive Payment Period (yrs)	5	Hours of operation/yr	8,760
Discount Rate (%)	6.00%		
Degradation (%/yr)	1.00%		
Utility price escalation (%/yr)	2.00%		
Capacity Factor	20.00%		
California Adder?	Yes		

Year	1	2	3	4	5	6	7	8	9	10	11
Electricity generated (kWh)	2,102,400	2,081,376	2,060,562	2,039,957	2,019,557	1,999,361	1,979,368	1,959,574	1,939,978	1,920,579	1,901,373
Value of avoided electricity	$248,018	$250,449	$252,903	$255,381	$257,884	$260,411	$262,963	$265,541	$268,143	$270,771	$273,424
O&M Costs	-$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768
Metering Cost - Tariff Based	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
Metering Cost - Electricity output	-$4,300										
SGIP Incentive Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California Adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	$1,115,701										
Cash Flow	($2,376,790)	$264,779	$267,232	$269,710	$272,213	$274,740	$277,292	$279,870	$282,472	$285,100	$287,753
Cumulative Cash Flow	($2,376,790)	($2,112,013)	($1,844,781)	($1,575,070)	($1,302,857)	($1,028,117)	($750,824)	($470,955)	($188,483)	$96,617	$384,370

Net Present Value	$948,652
IRR	9.50%
Break Even (yrs)	9.66

Cost Forecasts										
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NG	$6.20	$7.04	$7.24	$7.36	$7.60	$7.66	$7.81	$7.97	$8.13	$8.29	$8.45
Electricity	$0.1180	$0.1203	$0.1227	$0.1252	$0.1277	$0.1302	$0.1329	$0.1355	$0.1382	$0.1410	$0.1438

12	13	14	15	16	17	18	19	20
1,882,359	1,863,536	1,844,900	1,826,451	1,808,187	1,790,105	1,772,204	1,754,482	1,736,937
$270,690	$267,983	$265,303	$262,650	$260,024	$257,423	$254,849	$252,301	$249,778
$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768	$15,768
-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439	-$1,439
$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0
$285,019	$282,312	$279,632	$276,979	$274,353	$271,752	$269,178	$266,630	$264,107
$669,389	$951,701	$1,231,333	$1,508,312	$1,782,665	$2,054,417	$2,323,595	$2,590,225	$2,854,332

(END OF ATTACHMENT 4)