Public Interest Energy Research (PIER) Program

INTERIM/FINAL PROJECT REPORT

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Prepared for: California Energy Commission

Prepared by: DNV KEMA Energy & Sustainability

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Energy Storage Cost-effectiveness Methodology and Preliminary Results is the interim report for the Technical Support on Energy Storage Use Case and Cost-effectiveness Analysis project (contract number 500‐11‐029, work authorization number 3 conducted by DNV KEMA Energy and Sustainability. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

This report describes a model-based methodology to quantitatively evaluate energy storage cost-effectiveness for five Use Cases: Frequency Regulation, Comparative Portfolio, Distribution Substation Capacity Deferral, Distribution Connected Photovoltaic Integration, and Demand-Side Customer Bill Reduction. The basis for evaluating cost-effectiveness is described and preliminary cost-effectiveness findings are presented. For each of the five Use Cases evaluated, the preliminary results indicate energy storage is cost effective for a subset of assumptions for a range of benefits versus range of costs. The five Use Cases and the need to develop and demonstrate cost-effectiveness evaluation methodologies were products of the California Public Utilities Commission Energy Storage Order Instituting Rulemaking proceeding R.10-12-007 (CPUC ES OIR). The analytic work described in this report was prepared in support of the CPUC ES OIR. Appendices to this report include detailed "Input" and "Results" data spreadsheets from the modeling performed for the five Use Cases evaluated and presented in this report.

Keywords: energy storage, cost-effectiveness, use cases, energy markets, Ancillary services markets, T&D deferral, demand charge reduction, PV integration

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EXECUTIVE SUMMARY

In 2010, the California Legislature enacted Assembly Bill (AB) 2514 (Skinner, Chapter 7.7, Statutes of 2010), directing the California Public Utilities Commission (CPUC) to:

- Open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems.
- By October 1, 2013, adopt an energy storage procurement target, if determined to be appropriate, to be achieved by each load serving entity (LSE) by December 31, 2015, and a second target to be achieved by December 31, 2020.
- Consider a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.

In this task, DNV KEMA Energy and Sustainability (DNV KEMA) supported the CPUC staff and the California Energy Commission (Energy Commission) staff in their assessment of the cost-effectiveness of energy storage for Phase II of the AB 2514 proceedings. This effort was conducted through the technical support contract of the California Energy Commission with DNV KEMA.

To support the proceedings, the cost-effectiveness of energy storage was intended to be evaluated across a number of scenarios group by (1) Transmission Connected Energy Storage, (2) Distribution Level Energy Storage, and (3) Demand Side (Customer Side) Energy Storage. The DNV KEMA study team was asked to support this effort due to the modeling tools that DNV KEMA had developed to assess such applications.

Challenges to Assessing Energy Storage

Assessing the viability of storage presents a unique set of challenges. “Electricity Storage” is comprised of a group of technologies that vary in stages of development from traditional to advanced systems. In addition, the performance characteristics of these multiple technologies vary from power (short duration) to energy (long duration), and also have differences in efficiencies, costs, as well as the number of discharge cycles specific technologies can perform. Finally, when sited at certain locations of the grid, the devices can often perform multiple tasks or solve multiple problems. Each of these issues presents a unique set up challenges when assessing the technology. As Federal and State agencies continue to assess these challenges, the notion that simplified approaches to valuing storage are not adequate and in fact, may even lead to incorrect results.

It is for these reasons that DNV KEMA developed the set of tools utilized for this study. For each area of the grid – wholesale, transmission, distribution, and end-use - our models are based on tools that run simulations of actual applications and grids in order to evaluate the potential of the application. Each of the tools DNV KEMA developed to evaluate the specific Use Cases are governed by guidelines of:

(1) Assessments need to be conducted at the fidelity necessary to ensure storage is accurately assessed from all perspectives - Accuracy and fidelity is essential for acceptance of results by the broad, diverse stakeholder groups participating valuation processes

(2) All benefits of storage need to be taken into account - Limiting the benefits streams or not accounting for the multiple-application potential of storage technologies may lead to false conclusions

(3) Benefits Assessments must be Realistic - Real world constraints, non-linearities, and points of diminishing returns must be recognized and factored into calculations

Phase II Evaluation Effort

The CPUC initiated the Energy Storage Order Initiating Rulemaking proceeding R.10-12-007[1] *(ES OIR) to satisfy the terms of California Assembly Bill AB 2514. In general, the goal the ES OIR is to,"… establish a record for decision making in R.10-12-007 to satisfy the terms of AB 2514 (PUC Section 2836) with regard to establishing potential energy storage procurement targets for load-serving entities (LSEs)."*[2]

Requirements that needed to be met by the CPUC as specified in AB 2514, included:

(1) Open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems.
(2) By October 1, 2013, adopt energy storage procurement targets, if determined to be appropriate, to be achieved by each LSE by December 31, 2015, and a 2nd target to be achieved by December 31, 2020.
(3) Ensure that the energy storage system procurement targets and policies that are established are technologically viable and cost effective.

CPUC ES OIR Phase 1 and Phase 2 Output

As noted in the third bullet above, Cost-effectiveness is one of two tests that must be met for establishment of any energy storage procurement target. DNV KEMA, working in collaboration with CPUC Staff, Energy Commission Staff, and ES OIR Stakeholder representatives, (1) developed methodologies to evaluate storage's cost-effectiveness and (2) performed example cost-effectiveness evaluations on a subset of the priority Use Cases identified in Phase 1 of the ES OIR.

Study Scope

The technical studies described in this report address the first of the several policy topics identified in the ES OIR Scoping Memo,

1. **Cost-effectiveness [emphasis added]**

[1] http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

[2] Agenda for Energy Storage Procurement Workshop, CPUC, January 14, 2013

2. Market Needs
3. Barriers
4. Ownership model
5. Procurement target, if necessary

CPUC Staff's Phase 2 Interim Report further discussed and noted the limitation of existing cost-effectiveness methodologies relative to the complexity of energy storage, and thus the current limited ability to address the question of cost-effectiveness of energy storage in specific applications. The CPUC Staff's Phase 2 report further proposed use of DNV KEMA modeling tools to support the development of a methodology to support evaluation of storage cost-effectiveness.

Areas of Analysis for DNV KEMA

The Phase 2 Interim Report identified seven Priority Use Cases. From those use-cases, five Use Cases were evaluated in this study. The related general categories (bolded text below) that the five Use Cases fall under are:

A. **Transmission Connected Energy Storage**
   1) Ancillary Services Storage, Frequency Regulation Only
   2) Comparative Portfolio of Storage Resource Additions (for evaluating system level impacts)
B. **Distribution Level Energy Storage**
   3) Substation sited storage, for substation capacity upgrade deferral
   4) Distribution circuit sited storage, for photovoltaic (PV) related circuit upgrade avoidance and load growth related substation capacity deferral
C. **Demand Side (Customer Side) Energy Storage**
   5) Customer Bill Reduction

The evaluation was conducted through an interactive, iterative process, where stakeholders were updated on a weekly basis to discuss "data" as well as the numbers used in the analysis effort. DNV KEMA appreciated the time and effort provided by the stakeholder team members such as Electric Power Research Institute (EPRI), California Energy Storage Alliance (CESA), the Energy Commission, and the CPUC for their comments throughout the process.

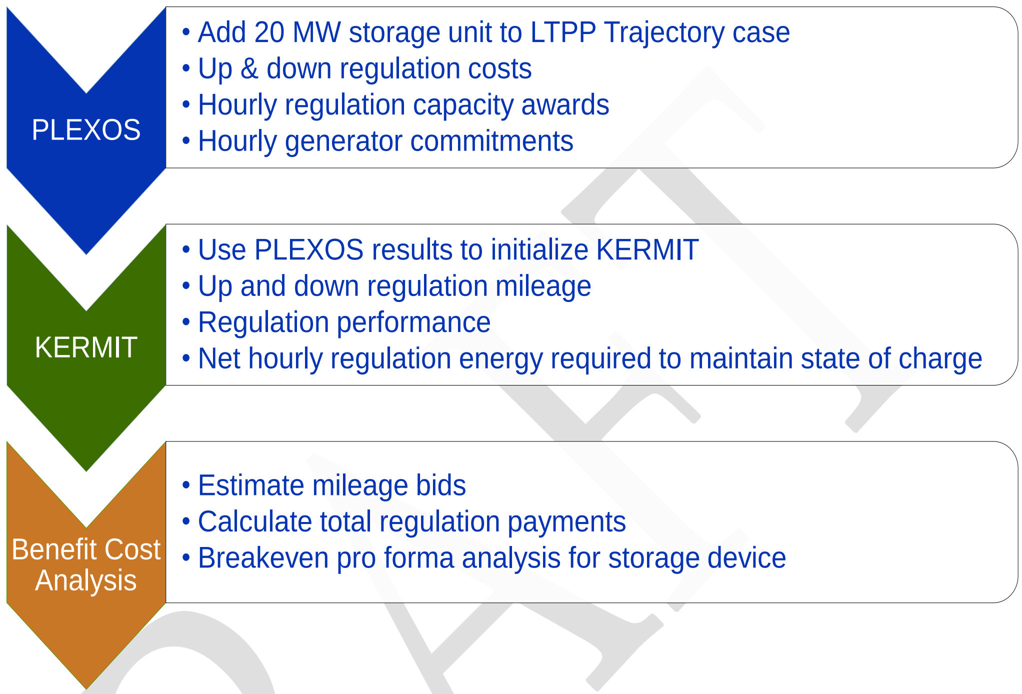
Methodology

Each of the Use Cases evaluated by DNV KEMA required model-based insight to adequately address the question of cost-effectiveness. For example,

- For market-based Use Cases, the market revenue based value for providing Frequency Regulation under a Pay For Performance regime cannot be quantified without a means to estimate the benefit-factor associated with sub-hourly storage system performance, and requires a sub-hourly resolution. High resolution production simulation modeling using PLEXOS® (PLEXOS) with DNV KEMA Renewable Market Integration Tool (KERMIT) was used to estimate the potential revenue stream in a future market scenario that includes Pay for Performance.

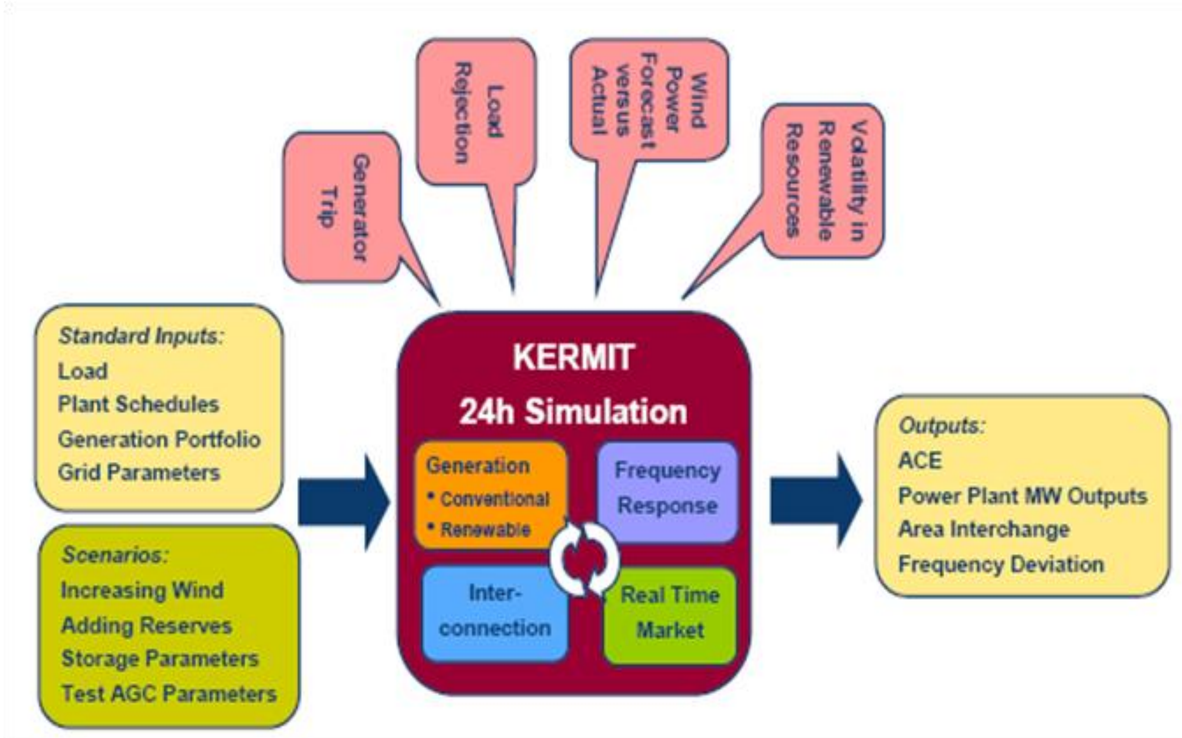
Below is an example of our modeling approach and an overview of KERMIT:

Figure 1: Modeling Approach



Source: DNV KEMA Energy & Sustainability

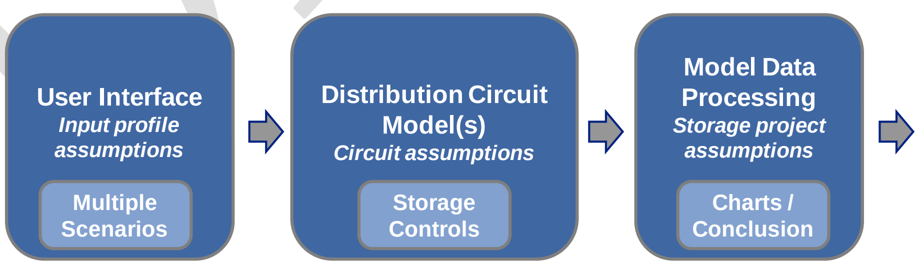
Figure 2: KERMIT Overview



Source: DNV KEMA Energy & Sustainability

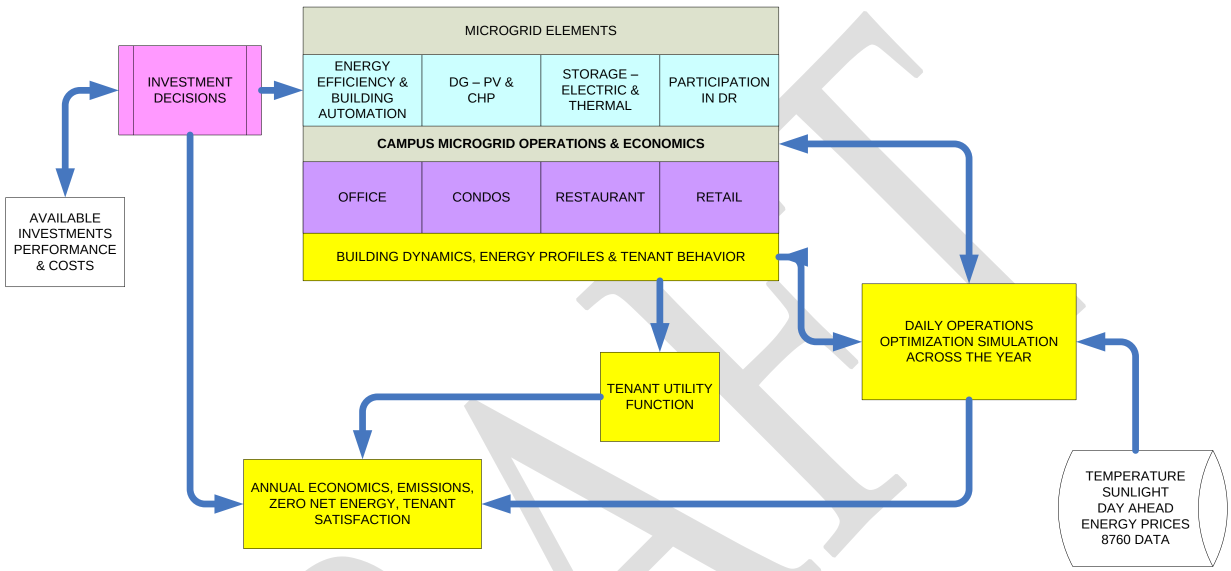
- For distribution capacity deferral storage Use Cases, the efficacy of a given energy storage system to mitigate a distribution level overload or voltage control issue is dependent on the interaction between the storage system and the attributes of the electric power system it will connect to. Load flow simulation modeling using DNV KEMA's Energy Storage Distribution Valuation tool (ESBAM) with Open Distribution System Simulator (OpenDSS) was used.

Figure 3: A Brief Graphical Description of ES-BAM



- For demand-side use cases, the customer savings due to bill reduction required the ability to calculate the specific amount of demand reduced and energy shifted against a sample demand shape that has enough detail to adequately estimate the electric bill impacts. When other customer-side assets like PV are introduced, the control of energy storage within the model also required substantial controls logic (implemented via linear programing optimization) to answer the deceptively simple question - by how much can electric bill charges be reduced through a given storage system. DNV KEMA's Microgrid Optimization (MGO) tool was used in the case.

Figure 4: A Brief Graphical Description of the MGO Tool



Source: DNV KEMA Energy & Sustainability

Cost-effectiveness Evaluation Conclusions

For each of the five Use Cases evaluated, the preliminary results indicate energy storage is cost effective for a subset of assumptions for a range of benefits versus range of costs. The value basis for these preliminary findings are market revenue potential versus storage cost, avoided transmission and distribution (T&D) investment versus storage cost, and customer bill savings versus storage cost. In each case evaluated, the cost-effectiveness cross over, or breakeven point, depended on the value side of the equation being at the upper end of the assumed value range, and the storage cost being at the lower end of the assumed cost range.

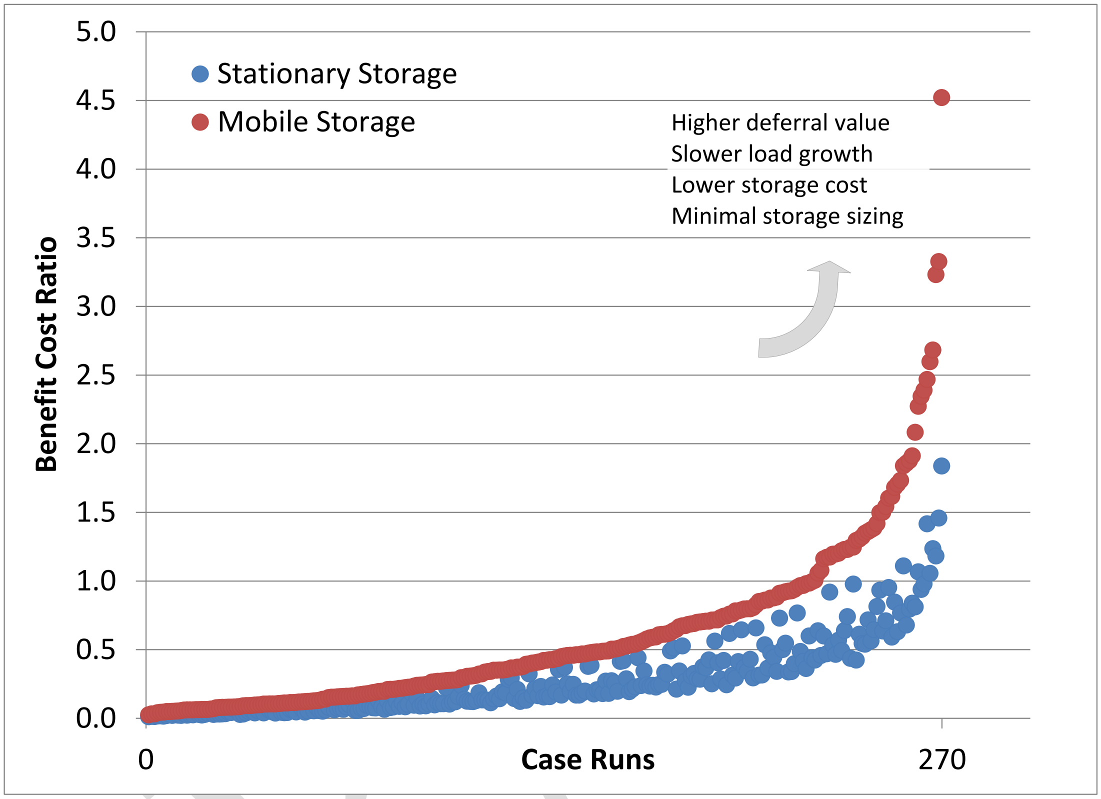
Table 1: Summary Table of the Benefits-Costs for Scenarios for Regulation Markets

	Asset Type	Capex ($/kW)	Regional Price Multiplier	Performance Multiplier	Benefit to Cost
Base Case	Battery	$750	1	1	1.09
	Flywheel	$1,500	1	1	0.66
2x Regulation Price	Battery	$750	2	1	2.18
	Flywheel	$1,500	2	1	1.33
P4P Performance Score	Battery	$750	1	0.9	0.98
	Flywheel	$1,500	1	0.9	0.6

Source: DNV KEMA Energy & Sustainability

For substation sited energy storage, shown below in the benefit to cost chart, upgrade deferral is the primary value benefit when other applications such as ancillary services and/or renewable integration are not considered.

Figure 5: Benefits-Costs for Substation-Sited Energy Storage

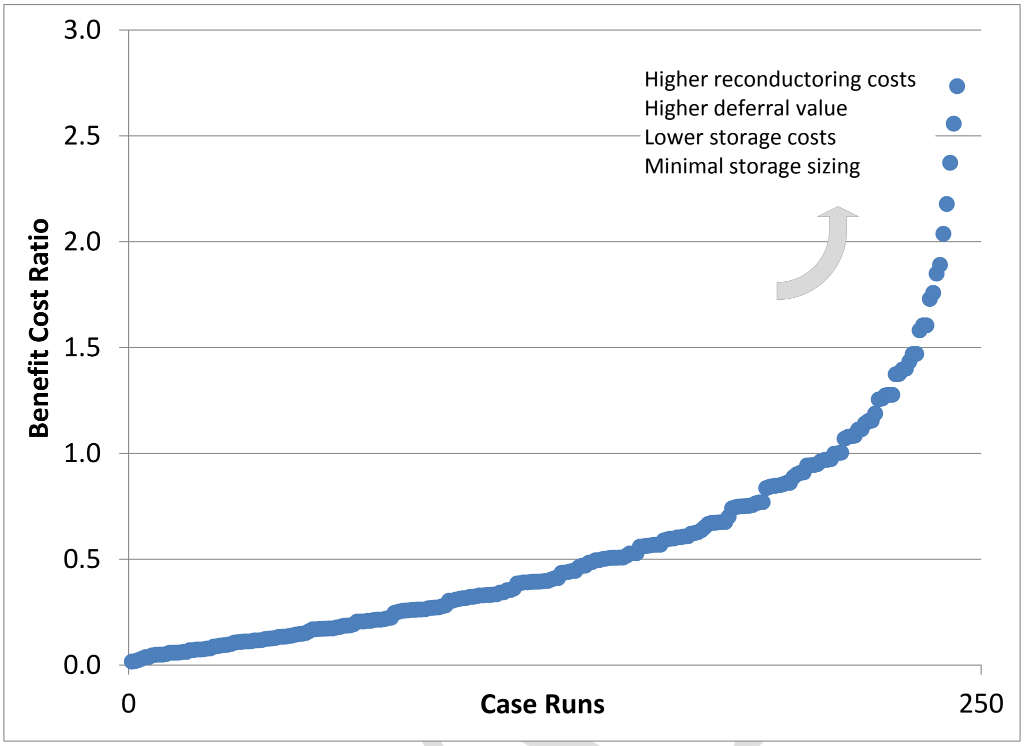


Source: DNV KEMA Energy & Sustainability

Higher deferral costs, lower battery costs, and the ability to move across multiple sites in sequence can result in positive net values for this application. Larger sizes can allow for longer deferral periods, but add cost without much value if duration or capacity is in excess of system load management needs. Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

For distributed storage for PV integration, cost effective cases were found when re-conductoring costs were high. Sizing storage greater than the line limit needs increases costs with small incremental benefit, resulting in non-economic cases. Upgrade avoidance, including re-conductoring and avoided regulator costs accounted for the majority of benefit value. Loss savings were found to be only a small portion of overall benefit. The break-even case reflects a correctly sized battery with high re-conductoring costs, low deferral value, and medium range storage costs. Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

Figure 6: Benefits-Costs for Substation-Sited Energy Storage for Distributed Storage for PV Integration



Source: DNV KEMA Energy & Sustainability

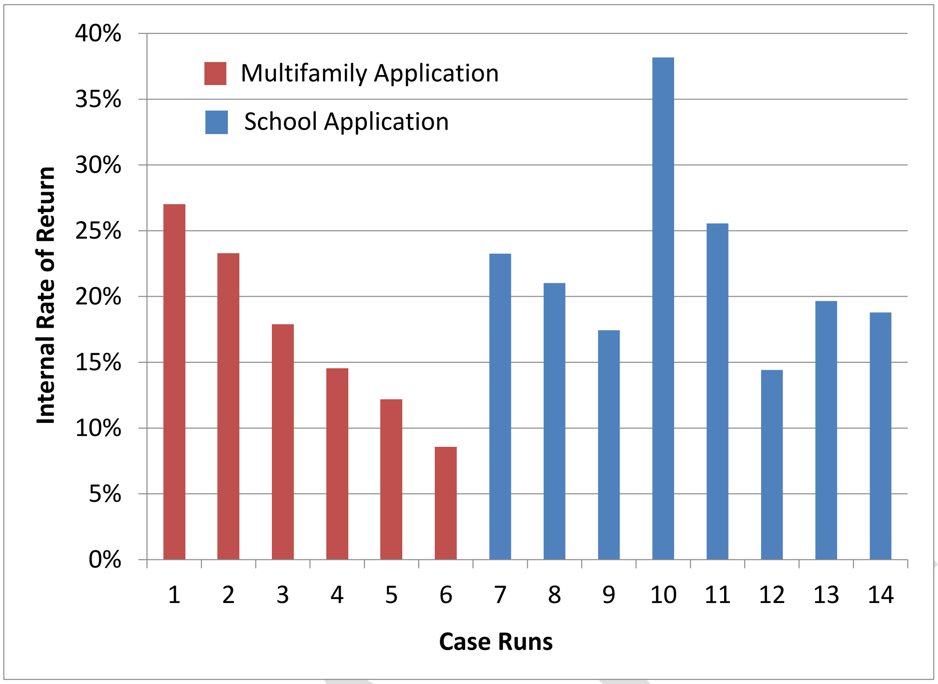
For the common area meter scenario, tariff switching gives an estimated Internal Rate of Return (IRR) of around 17%, while maintaining the facility on the same tariff gives an estimated IRR of around 7.5%.

For the school scenario, the best simulated IRR for a combined installation of solar PV and storage is around 17%. The scenario with only storage installation in the school has an estimated IRR of 11%.

The primary findings from the customer use case analysis are as follows:

Customer owned and operated storage is cost-effective for facilities with high peak demand to base load ratio, under tiered time-of-use (TOU) tariffs with high demand charges. In these cases, the current Self Generation Incentive Program (SGIP) incentives played a significant role in storage cost-effectiveness.

Figure 7: Internal Rate of Return for Multifamily and School Applications



Source: DNV KEMA Energy & Sustainability

Limitations to Evaluation Energy Storage Cost-effectiveness

Modeling limitations prevented quantified model-based Cost-effectiveness evaluation of several prioritized Use Case scenarios identified in the ES OIR Phase 2 prioritization of Use Cases, include,

1) Multiple-use Use Case scenarios where there were applications that bridged customer and utility side of the meter

2) Generator co-located Use case scenarios where the storage modifies attributes of a generator's output and the storage is not directly delivering services to the grid.

Chapter 1:

Introduction

DNV KEMA applied a model-based analytic methodology to quantitatively evaluate energy storage cost-effectiveness for five Use Cases: Frequency Regulation, Comparative Portfolio, Distribution Substation Capacity Deferral, Distribution Connected photovoltaic (PV) Integration, and Demand-Side Customer Bill Reduction. The basis for evaluating cost-effectiveness, the methodology applied, the assumptions used and preliminary cost-effectiveness findings for the five Use Cases are presented in this report.

Each of the Use Cases evaluated by DNV KEMA required model-based insight to adequately address the question of cost-effectiveness. For example,

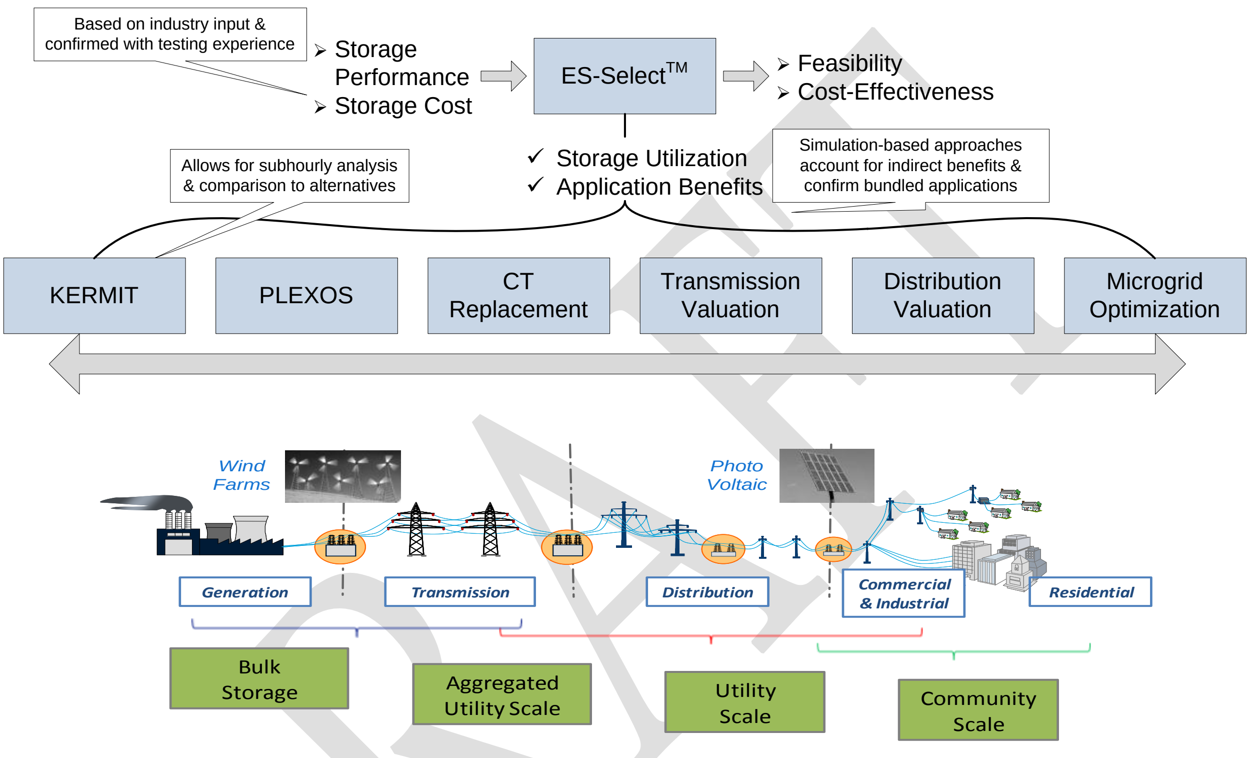
- For bulk storage market-based Use Cases, the market revenue based value for providing Frequency Regulation under a Pay For Performance regime cannot be quantified without a means to estimate the benefit-factor associated with sub-hourly storage system performance, and requires a sub-hourly resolution. High resolution production simulation modeling using PLEXOS with DNV KEMA Renewable Market Integration Tool (KERMIT) tool was used to estimate the potential revenue stream in a future market scenario that includes Pay for Performance.

- For distribution capacity deferral storage Use Cases, the efficacy of a given energy storage system to mitigate a distribution level overload or voltage control issue is dependent on the interaction between the storage system and the attributes of the electric power system it will connect to. Load flow simulation modeling using DNV KEMA's Energy Storage Distribution Valuation tool (ESBAM) with Open Distribution System Simulator (OpenDSS) was used as a means to quantify the amount of electric system overload mitigation and/or voltage support provided by a given storage system, and thus act as an effective wires-solution upgrade deferral/avoidance measure to establish a project-specific avoided cost value.

- For demand-side use cases the customer savings due to bill reduction required the ability to calculate the specific amount of demand reduced and energy shifted against a sample demand shape that has enough detail to adequately estimate the electric bill impacts. When other customer-side assets like PV are introduced, the control of energy storage within the model also required substantial controls logic (implemented via linear programing optimization) to answer the deceptively simple question - by how much can electric bill charges be reduced through a given storage system. DNV KEMA's Microgrid Optimization (MGO) tool was used to perform both the storage use optimization against an annualized demand shape to lower customer electric bill charges.

Storage systems are capable of performing multiple applications that can accrue a number of benefits. In addition, these benefits can vary depending where the device is located on the grid, or are revealed when the proper time scaled and fidelity is used when assessing the application. Hence, for this analysis, the study group utilized multiple models to evaluate the five (5) use cases. Figure 8 shows how different models used depending on where the device is located. In the figure, the DNV KEMA Energy Storage-Select Tool (ES-Select) is referenced as that tool was used to guide the pricing employed in the analysis.

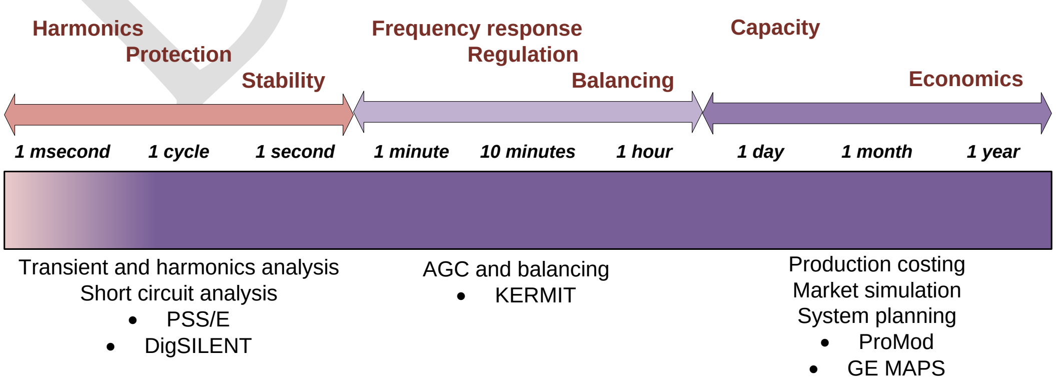
Figure 8: Representation of which Tools Map Specific Locations on the Grid



Source: DNV KEMA Energy & Sustainability

Figure 9 shows the time dimension factor required in modeling certain location on the grid such as wholesale applications, where "common" tools in use today had a "gap" the times between one minute and one hour.

Figure 9: Mapping of Time Fidelity Required with Current Tools



Source: DNV KEMA Energy & Sustainability

The modeling tools the study team used for this study is discussed in detail in the evaluation of the five Use Cases further described and discussed in later chapters describing each Use Case.

The five Use Cases and the need to develop and demonstrate cost-effectiveness evaluation methodologies were products of the California Public Utilities Commission (CPUC) Energy Storage Order Instituting Rulemaking proceeding R.10-12-007 (ES OIR). This proceeding and the initiating Assembly Bill AB 2514 legislation are key background and are discussed next.

California Public Utilities Commission Energy Storage Proceeding

The CPUC initiated the Energy Storage Order Initiating Rulemaking proceeding R.10-12-007[3] (ES OIR) to satisfy the terms of California Assembly Bill AB 2514. In general, the goal the ES OIR is to,"… establish a record for decision making in R.10-12-007 to satisfy the terms of AB 2514 (PUC Section 2836) with regard to establishing potential energy storage procurement targets for load-serving entities (LSEs)."[4]

California Assembly Bill AB 2514, Skinner Energy Storage, was signed into law September 29, 2010, and states,

"The Legislature finds and declares all of the following:

> (a) Expanding the use of energy storage systems can assist electrical corporations, electric service providers, community choice aggregators, and local publicly owned electric utilities in integrating increased amounts of renewable energy resources into the electrical transmission and distribution grid in a manner that minimizes emissions of greenhouse gases.
>
> (b) Additional energy storage systems can optimize the use of the significant additional amounts of variable, intermittent, and off-peak electrical generation from wind and solar energy that will be entering the California power mix on an accelerated basis.
>
> (c) Expanded use of energy storage systems can reduce costs to ratepayers by avoiding or deferring the need for new fossil fuel-powered peaking powerplants and avoiding or deferring distribution and transmission system upgrades and expansion of the grid.
>
> (d) Expanded use of energy storage systems will reduce the use of electricity generated from fossil fuels to meet peak load requirements on days with high electricity demand and can avoid or reduce the use of electricity generated by high carbon-emitting electrical generating facilities during those high electricity demand periods. This will have substantial cobenefits from reduced emissions of criteria pollutants.
>
> (e) Use of energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities will reduce emissions of carbon dioxide and criteria pollutants.

[3] http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

[4] Agenda for Energy Storage Procurement Workshop, CPUC, January 14, 2013

(f) There are significant barriers to obtaining the benefits of energy storage systems, including inadequate evaluation of the use of energy storage to integrate renewable energy resources into the transmission and distribution grid through long-term electricity resource planning, lack of recognition of technological and marketplace advancements, and inadequate statutory and regulatory support."[5]

Requirements to be met by the CPUC as specified in AB 2514 include:

- Open a proceeding to determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems.
- By October 1, 2013, adopt energy storage procurement targets, if determined to be appropriate, to be achieved by each LSE by December 31, 2015, and a 2nd target to be achieved by December 31, 2020.
- Ensure that the energy storage system procurement targets and policies that are established are technologically viable and cost effective.

Energy Storage Proceeding Phase 1 and Phase 2 Output

As noted in the third bullet above, Cost-effectiveness is one of two tests that must be met for establishment of any energy storage procurement target. DNV KEMA, working in collaboration with CPUC Staff, Energy Commission Staff, and ES OIR Stakeholder representatives, 1) developed methodologies to evaluate storage's cost-effectiveness and 2) performed example cost-effectiveness evaluations on a subset of the priority Use Cases identified in Phase 1 of the ES OIR. ES OIR Phase 1 and 2 provide the framework for assessing cost-effectiveness, and the specific applications in the form of Use Cases to be considered for determining cost-effectiveness. The Phases of the ES OIR is described in the ES OIR Scoping Memo.[6]

The prior Stakeholder-process information developed during ES OIR Phase 1 and 2 are inputs for DNV KEMA's subsequent tasking to develop a cost-effectiveness evaluation methodology and apply the methodology to a subset of the Stakeholder-prioritized Energy Storage Use Cases. This report outlines the five Use Cases evaluated by DNV KEMA, describes the basis for evaluating cost-effectiveness, describes the methodology applied to quantitatively evaluate cost-effectiveness, and summarizes the preliminary cost-effectiveness findings from use of the methodology. Appendices to this report include detailed "Input" and "Results" spreadsheets from the modeling performed for the example cost-effectiveness evaluations discussed in this report.

Study Scope

The technical studies described in this report address the first of the several policy topics identified in the ES OIR Scoping Memo,

[5] http://www.leginfo.ca.gov/pub/09-10/bill/asm/ab_2501-2550/ab_2514_bill_20100929_chaptered.pdf

[6] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M029/K555/29555784.PDF

6. **Cost-effectiveness [emphasis added]**
7. Market Needs
8. Barriers
9. Ownership model
10. Procurement target, if necessary

CPUC Staff's Phase 2 Interim Report further discussed and noted the limitation of existing cost-effectiveness methodologies relative to the complexity of energy storage, and thus the current limited ability to address the question of cost-effectiveness of energy storage in specific applications. The CPUC Staff's Phase 2 report further proposed use of DNV KEMA modeling tools to support the development of a methodology to support evaluation of storage cost-effectiveness, "The DNV KEMA model is called Energy Storage Select (ES-Select), but it would be used in combination with other KEMA models or programs (KERMIT, Storage Distribution Tool, and Storage Peaker Tool, in particular). Based on input from various parties, Staff proposes that both ESVT and ES Select models may provide useful – if not determinative – analysis for certain Use Cases, or for an assessment of system level impacts of a portfolio of storage resource additions."[7]

[7] "Energy Storage Phase 2 Interim Staff Report", CPUC Energy Storage Proceeding R.10-12-007, CPUC Staff, January 4, 2013, p. 20

Chapter 2:

Cost-effectiveness Evaluation Methodology

Use Cases For Model Based Evaluation

The Phase 2 Interim Report listed seven Priority Use Cases identified. From those use-cases, several were selected for study by DNV KEMA with the goal of implementing a model-based cost-effectiveness evaluation process using the above noted DNV KEMA analytic tools. The five Use Cases evaluated in this study, and the related general categories (bolded text below) that the five Use Cases fall under are:

Transmission Connected Energy Storage

1) Ancillary Services Storage, Frequency Regulation Only
2) Comparative Portfolio of Storage Resource Additions (for evaluating system level impacts)

Distribution Level Energy Storage

3) Substation sited storage, for substation capacity upgrade deferral
4) Distribution circuit sited storage, for PV related circuit upgrade avoidance and load growth related substation capacity deferral

Demand Side (Customer Side) Energy Storage

5) Customer Bill Reduction

In each case, the ability to evaluate the potential cost-effectiveness of Energy Storage is limited by:

- inability to estimate market based revenue streams for a storage project (merchant or utility self-provided asset) including the new Pay for Performance market rules,
- inability to quantify storage's potential T&D capacity upgrade deferral or avoidance impact, or
- inability to estimate storage's potential to deliver customer savings for a load shape and onsite generator(PV) output modified and managed by a storage asset

To overcome these limitations, DNV KEMA applied three software tools that mapped to the location of the storage systems Use Cases listed. The mapping of the DNV KEMA tools to the general categories is:

- **Transmission Connected Energy Storage**
  PLEXOS with KERMIT, for production simulation and market simulation

- **Distribution Level Energy Storage**

ESBAM with OpenDSS, for electrical distribution performance (loading and voltage) impacts

- **Demand Side Energy Storage**
  Microgrid Optimization Tool (MGO) for estimating storage use based customer bill savings through load shape management for demand charge reduction plus storage for shaping PV output to minimize customer energy costs

These software tools were described at the December 3, 2012 ES OIR Workshop[8]. These models are described further below in this report in context of their use to evaluate the cost-effectiveness of storage for the Use Cases studied.

Energy Storage Applications' Benefits Basis

The measure of cost-effectiveness for the Use Cases that are project-specific (all but the Comparative Portfolio Use Case) is: the ratio of benefit versus cost is larger than 1, for the net present value (NPV) of the positive (benefits) and negative (costs) cash flows for a 20 year project life. The following sections of this Chapter discuss the major components of benefit and cost for the general categories of Use Cases. The following Chapters present the specific details on the assumed or derived benefits and costs, and the resulting NPV of whether the benefits versus is smaller than, larger than or equal to 1.

Market Revenues

For the Transmission Connected category Use Case, the primary benefit used in the cost-effectiveness modeling and evaluation is market revenue. For the Frequency Regulation Only Use Case modeled, the form of market revenue quantified as a 'benefit' is market-based payment for provision of Regulation Up (RegUp) and Regulation Down (RegDown) services sold into the California Independent System Operator (CAISO) market. For the timeframe modeled (first project year is 2020), Pay For Performance was added to the compensation model for the Frequency Regulation services revenues. ***The modeling challenge solved by DNV KEMA in this study was the calculation of the market revenue $/MegaWatthour (MWh) hourly payment stream***. Production simulation was used to determine the dispatch and related hourly base clearing price for RegUp and RegDown payments for a sample set of days that were then extrapolated for a representative year's 8760 market hours.

The KERMIT tool was then used for the inter-hour resolution needed to estimate the associated Pay for Performance Benefit Factor applied to the Production Simulation (production cost based) RegUp and RegDown base clearing prices. While there are other compensation schemes proposed and present within Storage-based Power Purchase Agreement (PPA) term sheets today, we did not include any supplemental revenue streams for which there are not yet clear

[8] http://www.cpuc.ca.gov/NR/rdonlyres/B2251C13-57AF-4443-A826-76D85D43E579/0/CPUCDNVKEMAModelAssessment12032012WorkshopFinal.pdf

investment recovery mechanisms. These potential additional services not considered in modeling the Frequency Only Use Case include: provision of volt-ampere reactive (VAR) to the local Participating Transmission Owner (PTO), blackstart capability, or fixed revenue streams via PPA to an LSE who wants to hedge market risk for their Ancillary Services costs. The specific modeling implemented to quantify this benefit, and the modeling results, are discussed below in Chapter 3.

Transmission and Distribution Avoided Costs

For the Distribution Level Energy Storage category Use Cases, the primary benefits used in the cost-effectiveness modeling and evaluation are transmission and distribution (T&D) upgrade deferral (annual carrying charge for the upgrade deferral period) and T&D upgrade avoidance (first-year T&D installed cost avoided). A range of T&D Unit costs per several industry references cited in the detailed discussion in Chapters 5 and 6. ***The modeling challenge solved by DNV KEMA in this study was the verification of mitigation of 1) substation overload (deferral benefit) and the years that an assumed storage system size would be effective and 2) mitigation and permanent removal of circuit section overload (full Avoided Cost of upgrade) due to a non-load-growth caused circuit overload.*** In this study, the circuit overload was caused by installation of relatively large 1.5 megawatt (MW) PV system installed on a primary distribution circuit lateral. To solve this modeling challenge, load flow simulation was applied to an 8760 hour load shape to test the efficacy of a range of assumed storage system sizes. Load flow was needed to verify that the assumed storage sizing solved the problem it was intended for. There are several secondary benefits calculated in terms of system performance, but which are not carried forward as part of the financial benefits due to no existing clear means to monetize these benefits. These secondary benefits (‘with’ versus ‘without’ storage performance benefits) calculated in the load flow solution include, energy (I^2R and I^2X) loss reduction, reduction in voltage regulation device switching, and reduction in the steady state voltage range. While hourly resolution for the load flow simulations was adequate for assessing steady state voltage performance, the transient voltage concern per the Distribution Level Storage PV Integration Use Case would require a higher time resolution and dynamic-capable electric system model to 1) capture the PV intermittency related impact on transient voltages and 2) test the efficacy of a transient-response-speed (10’s ms) capable storage system.

Customer Savings

For the Demand Energy Storage category Use Cases, the primary benefit used in the cost-effectiveness modeling and evaluation is customer electric bill reduction through removal or reduction of Demand Charges applicable to some general commercial and industrial rate categories, and shifting PV output to reduce energy related bill charges. ***The modeling challenge solved by DNV KEMA in this study was the ability to quantify the amount of demand reduction feasible and associated cost savings for an assumed storage system modifying 1) a given customer demand load profile against 2) a specific electric rate Tariff.*** On-site PV was also included in several sensitivities which was added to the bill minimization optimization scheme by using available storage capacity to shift PV output for energy savings and account for any coincident reduction in net load demand. Given that the benefits for this

Use Case are strictly from the perspective of the retail customer, retail customer incentives also enter into the 'benefits' calculation as a reduction in capital expenditure (CAPEX) initial investment cost. Three incentive programs are included in the cost-effectiveness NPV of benefit-cost calculation:

1) The California Self Generation Incentive Program (SGIP), applicable to storage
2) The California Solar Initiative (CSI), applicable to PV, for the Use Case sensitivities that include customer-sited PV
3) The Federal Investment Tax Credit (FITC), applicable to storage and PV, for the Use Case sensitivities that include customer-sited PV

The specific modeling implemented to quantify this benefit, and the modeling results, are discussed below in Chapter 7.

System Benefits

This Use Case's benefit is not related to a specific storage asset or project, but rather the benefit basis is the impact to system level metrics as solved in a production simulation simulation. The modeled system benefits estimated through comparing a portfolio without-storage and a portfolio with-storage include:

- Total quantity of monitored emissions, including nitrogen oxide (NOx) and carbon dioxide (CO_2)
- Total cost of serving energy ($) and the average cost of energy ($/MWh)
- Number of conventional gas-fired unit starts
- Total fuel used to serve load

Energy Storage Technologies' Costs Basis

Storage Technologies Capital and Operations Expenditure Assumptions

ES-SELECT was our basis for capital expenditure (CAPEX) and operating expenditure (OPEX) assumptions for the storage technologies used in the modeled Use Cases. Show ES-Select table with CAPEX ranges for the technologies. Note that dollar per kiloWatt ($/kW) and stated duration is how the cost is characterized. $/kWh can be calculated from these two metrics.

Table 2 summarizes the cost that were used in the analysis. First, convention is to described the storage technologies in terms of $/kW over how many hours. It is understood that some stakeholders prefer to view storage cost in terms of $/kWh. In our analysis, this number was simply derived from the "duration" that was assigned to each of the technologies.

Table 2: Summary of Storage Costs from DNV KEMA's ES-Select

Technology Type	Cost ($/kW)		
	Low	Medium	High
Lithium-Ion (Energy) - 2 hours	2,700	3,500	4,200
Lithium-ion (Power) - 1 hour	675	875	1,050
Advanced Lead Acid - 4 hours	3,000	3,900	4,850
Technology Type	**Cost ($/kWh)**		
	Low	Medium	High
Lithium-Ion (Energy) - 2 hours	1,350	1,750	2,100
Lithium-ion (Power) - 1 hour	675	875	1050
Advanced Lead Acid - 4 hours	750	975	1,212.50

Source: DNV KEMA Energy & Sustainability

The number's themselves were provided by utilizing data from DNV KEMA's ES-Select tool. This tool was utilized because the tool is also utilized by Sandia National Lab and is listed, open to the public on the Energy Storage webpage of the lab. Hence, the numbers are accepted by the Department of Energy. In addition, ES-Select uses a range on public data on each of the technologies that is in its database. The team gratefully acknowledges the stakeholder teams that also provided cost numbers for the analysis. The study team compared and weighed all information that was brought to the process and in some cases, used that information to select the cost of the technologies from the ES-Select range to conduct analysis.

Chapter 3:

Use Case Overview

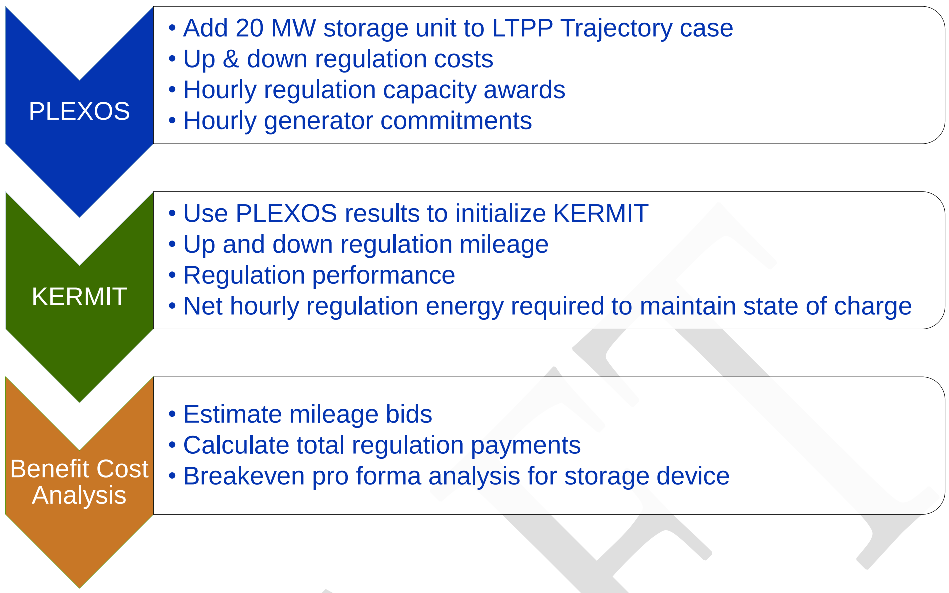
This use case examines the cost-effectiveness and breakeven costs of a single 20 MW 5 MWh storage device participating in CAISO frequency regulation markets. The CPUC 2020 Long Term Procurement Plan (LTPP) 33% Renewable Portfolio Standard (RPS) Trajectory case PLEXOS model is used to estimate the annual revenue stream for a storage device in the year 2020. The 2020 annual revenue stream is then used as the basis for a 20 year pro forma evaluation of the 20 MW storage device installed in the year 2015.

Modeling the Use Case

An overview of the modeling approach for the Regulation Only use case is in Figure 10. PLEXOS, described in more detail below, was used to produce hourly energy and ancillary service commitments that minimize system production costs from the set of assets in the LTPP Trajectory case. The hourly commitments were fed into KERMIT to simulate second to second operation of the 20 MW battery providing regulation. The PLEXOS model is then used to estimate hourly costs of energy and regulation. KERMIT is used to estimate how well the storage unit performed in providing regulation and the MW-miles of work the storage did while providing regulation (two new market elements required by Federal Energy Regulatory Commission Order 755). In addition, KERMIT simulates and estimates the imbalance energy required for the storage unit to maintain its state of charge (SOC) at 50% according to CAISO specifications.

The benefit cost analysis is a pro-forma style analysis that estimates break-even capital costs for the 20 MW, 5 MWh storage device based on a 20 year revenue stream from CAISO regulation market and listed project financing assumptions. In addition, system benefits are estimated by determining the change in California production costs estimated by PLEXOS for the simulations with and without the storage device. Sensitivity analyses examining the influence of the primary factors are reported as well.

Figure 10: Overview of Frequency Regulation Use Case Modeling Approach



Source: DNV KEMA Energy & Sustainability

Storage Services Modeled

The storage unit modeled is a fast responding storage device appropriate for providing regulation. The specific parameters and the behavior of the plant can be considered representative of a battery device (detailed later in this chapter) although the operating characteristics are also representative of a flywheel, pumped hydro, or other fast acting storage device. The battery is assumed to be able to participate in both Up and Down regulation markets but not in any other market. CAISO requires storage devices participating as a Regulation Energy Managed device to maintain their state of charge at 50% every 5 minutes. This is because the real time energy market is supposed to “clear” the regulation market by redispatching the system so the energy procured in the energy markets is equal to load. In doing so, all regulation capacity is available each time the real time energy dispatch for CAISO is executed.

The roundtrip efficiency of a storage device is less than 100% meaning that some amount of energy is lost when a battery is charged and discharged. Ideally regulation signals are zero net energy over a long time frame (hours) and in reality they tend to be unless an abnormal event occurs (such as a generator tripping offline). As a result, storage devices participating in regulation markets will regularly need to procure and sell energy in the real time market to maintain a 50% SOC. Over a period of a day to a year this results in a net cost born by the storage device because a storage device typically needs to buy more energy than it sells in the real time market.

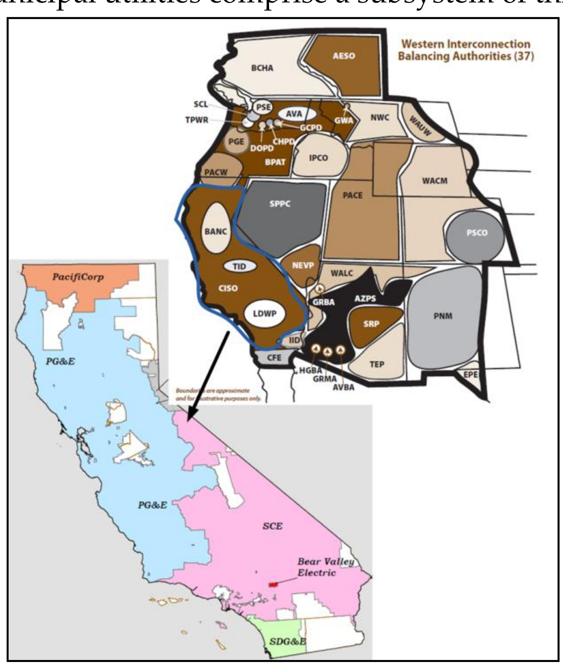
Implementing the Use Case in PLEXOS and KERMIT

PLEXOS is a unit commitment and production costing software program developed and marketed by Energy Exemplar. Every two years the CPUC reviews the Investor Owned Utilities (IOUs) procurement plans through a LTPP proceeding. For the 2010 LTPP, the CPUC coordinated with CAISO, Energy Commission, Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), major California stakeholders, and Energy and Environmental Economics (E3) to develop detailed production cost models of California based on the IOUs proposed procurement plans with the purpose to examine reliability and resource needs for California under 5 major scenarios for future growth and policy development under a 33% RPS. The LTPP 33% Trajectory case serves as the model framework for the Frequency Regulation use case and more information about this model can be found on the CPUC LTPP website and downloaded from CAISO's website.

Again, the purpose of using PLEXOS is to simulate the operation of California's grid in future years and estimate the following:

- Hourly energy production from the portfolio of generators in the Trajectory case
- Hourly assignments of ancillary services based on avoided opportunity costs
- Hourly energy imports / exports to other Western Energy Coordinating Council (WECC) entities and regions
- Hourly energy and ancillary service costs for each utility and municipality within California
- Hourly energy and ancillary service costs for the major WECC regions outside of California

The CPUC LTPP 33% RPS Trajectory Case PLEXOS model has 2,492 generators distributed among 46 nodes that represent the WECC. Modeling most of the intricacies of WECC is required due to the high dependence of California on imports (and exports under certain future scenarios). As a result, the CAISO system and municipal utilities comprise a subsystem of this model. No changes were made to the model except one storage device was added as a non-marginal unit to provide regulation.



KERMIT is an analysis tool used to simulate sub-hourly system operations as well as system frequency and interchange deviations. Each generator within CAISO is modeled using either Institute of Electrical and Electronics Engineers (IEEE)-approved non-linear dynamic system models or proprietary non-linear dynamic system models developed by DNV KEMA when IEEE models were non-existent.

KERMIT has been used either for or by five Independent System Operators (ISOs) / Regional Transmission Owners (RTOs) in the United States plus three in Europe as well as numerous islands and utilities. KERMIT is calibrated for each system to ensure the system dynamics are appropriately modeled and representative. Part of the calibrating process is to compare the output of KERMIT versus actual observed system behavior for key metrics in the seconds and minutes after a large generator has tripped offline.

The hourly data produced by PLEXOS is an input to KERMIT to simulate a 24-hour period on a second by second time resolution. A subset of days was then selected and simulated in PLEXOS and KERMIT and the results were extrapolated to produce an annual estimate. Ideally the subset of days is selected to statistically represent the distribution of results of the primary metric of importance. In this instance, the LTPP Trajectory Case was simulated for the entire 2020 year and the daily regulation costs for CAISO were calculated. The distribution of daily regulation costs provided the initial distribution for the sampling to produce the subset of days to examine in higher fidelity. In total, 15 days were selected from the distribution and their average daily regulation costs are within 1% of the average daily regulation cost simulated for CAISO using the LTPP Trajectory Case. The list of days can be found in Table 3.

Table 3: List of Days and Regulation Costs for Base Case

Day Selected	Base Case Regulation Cost
8-Jan	$216,656
9-Mar	$209,396
24-May	$172,629
7-Jun	$196,052
21-Jun	$218,979
24-Jun	$596,745
9-Jul	$272,402
13-Aug	$168,472
31-Oct	$183,734
19-Dec	$194,781

Source: DNV KEMA Energy & Sustainability

Summary of Inputs

Financial and Market Assumptions Inputs

The primary inputs assumed for the financial and market analyses are listed in Table 4. The values are consistent with the values used by Electric Power Research Institute (EPRI) in their analyses and compiled by California Energy Storage Alliance (CESA).

Table 4: Summary of Primary Financial Assumptions

Financial Specs	
Overnight CAPEX ($/kWh)	$1,015
Replacement Costs ($/kWh)	$250
Replacement Cost Reduction	2%
Yearly O&M ($/kWh)	$15.25
AS Price Escalation	3%
Inflation Rate	3%
Discount Rate	8%

Source: DNV KEMA Energy & Sustainability

Storage Technology Assumptions Inputs

The primary inputs and characteristics assumed for the storage are listed in Table 5 and represent a fast acting battery storage device. The following assumptions were also made:

- A pay for performance regulation market exists as it is implemented today
- Storage devices participating as a Regulation Energy Managed device must procure or sell energy to maintain a 50% SOC
- The storage device provides regulation as a non-marginal unit

Table 5: Summary of Primary Operational Assumptions for Storage Device

Operational Specs	
Power Capacity (MW)	20
Energy Capacity (MWh)	5
Efficiency (%)	83%
Battery Yearly Degredation	3%
Up Regulation Performance	91%
Down Regulation Performance	97%
Replacement Schedule (years)	3

Source: DNV KEMA Energy & Sustainability

Sensitivity Alternatives

A number of sensitivities analyses were conducted to examine the influence of the storage and financial inputs assumed. An additional scenario with flywheel specific financial and operational parameters was also examined.

Battery technology scenario

Sensitivities analyses were performed for the following parameters: efficiency, discount rate, replacement costs, and energy capacity. Each sensitivity analysis involved varying the specific input parameter by the following percentages: 50%, 75%, 150%, and 200%. Note that 100% represents the base value listed in the respective table.

Another sensitivity also examined in the evaluation is the doubling of CAISO regulation costs to examine how influential regulation costs are to the analysis.

Flywheel technology scenario

The performance data of the battery device was used as the basis of the flywheel technology scenario. To represent a flywheel instead of a battery, the operating and financial input parameters of the pro forma analysis were changed to reflect a flywheel specific device. The operational and financial specifications are listed in Table 6.

Table 6: Operational and Financial Specifications

Operational Specs	
Power Capacity (MW)	20
Energy Capacity (MWh)	5
Efficiency (%)	81%
Yearly Degredation	0%
Up Regulation Performance	98%
Down Regulation Performance	95%
Replacement Schedule (years)	3

Financial Specs	
Overnight CAPEX ($/kW)	$1,500
Debt	50%
Replacement Costs ($/kWh)	$0
Replacement Cost Reduction	0%
Yearly O&M ($/kWh)	$15.25
AS Price Escalation	3%
Inflation Rate	3%
Discount Rate	8%

Source: DNV KEMA Energy & Sustainability

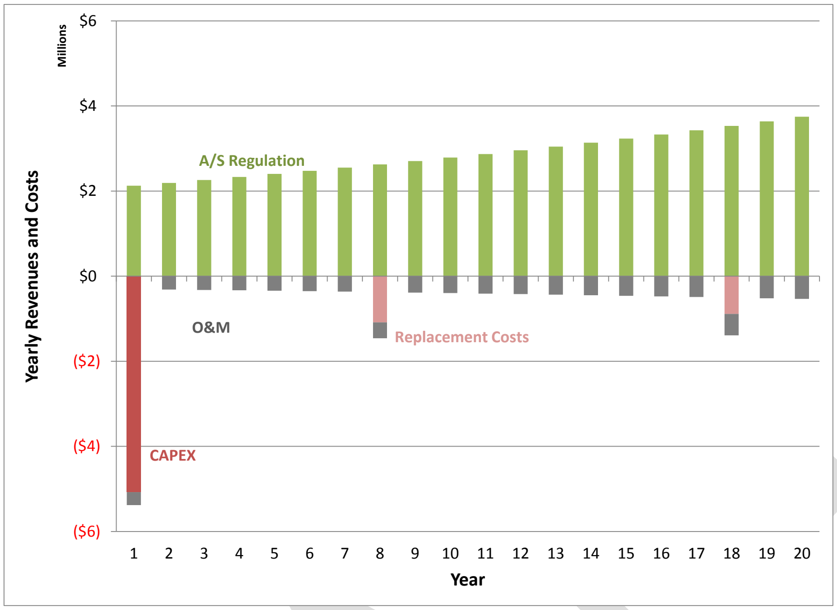
Use Case Modeling Preliminary Results

Unit Specific Results

For the base case of values listed in Tables 2, the breakeven cost (a benefit-cost ratio of 1) for a 20 MW, 5MWh storage device participating in CAISO regulation markets from 2015 to 2035 is $17.6 million. This represents an $882/kW ($3528/kWh) cost for the device. Any storage devices with costs below this level are even more cost competitive and any devices with costs higher are estimated to be not cost effective. For example, a battery storage device with a capital cost of $600 per kW is estimated to have a 20 NPV of $7.50 million whereas a battery storage device with a capital cost of $1,000 per kW is estimated to have a 20 NPV of ($3.14) where the parenthesis represent a negative value.

The 20 year annual pretax revenues and costs for the storage device are graphed in Figure 11Error! Reference source not found.. A large capital expenditure in year 1 is the construction and installation of the storage device using 50% debt. Annual loan payments are then made to pay down the remaining principal on the loan at an interest rate of 6.18% over the 20 year life. Operations and maintenance (O&M) costs and imbalance energy costs represent the other two annual costs incurred by the storage device. Every 10 years the entire battery stack is replaced because of the annual reduction in energy capacity due to cycle life degradation. Depicted in green are the annual revenue generated by providing regulation capability grown or reduced by 3% from the 2020 estimate.

Figure 11: Chart of 20 Year Revenues



Source: DNV KEMA Energy & Sustainability

The breakeven cost, that is benefit cost ratio (BCR) of 1, for a flywheel storage device is $6.44 million ($965/kW or $3,860/kWh) and the BCR for a flywheel with a capital cost of $1,500 is 0.66. This is a 9.4% increase in breakeven capital cost compared to the battery storage device indicating higher capital cost projects are feasible. This is because the flywheel device has lower variable O&M costs and does not need to replace a battery stack every 10 years.

Table 7: Summary of BCR Results for Scenarios

	Asset Type	Capex ($/kW)	Regional Price Multiplier	Performance Multiplier	Benefit to Cost
Base Case	Battery	$750	1	1	1.09
	Flywheel	$1,500	1	1	0.66
2x Regulation Price	Battery	$750	2	1	2.18
	Flywheel	$1,500	2	1	1.33
P4P Performance Score	Battery	$750	1	0.9	0.98
	Flywheel	$1,500	1	0.9	0.6

Source: DNV KEMA Energy & Sustainability

If regulation costs are twice what they were estimated to be using the LTPP Trajectory Case model, then the breakeven cost for a battery storage device participating in the CAISO regulation market is $40.78 million ($2,039/MW or $8,156/MWh). This is a 232% % increase compared to the base case results. Using the capital costs CESA provides, the BCR for a battery is 2.18 and 1.33 for a flywheel.

From an operations point of view, the most important factor determining the breakeven cost is the performance of the storage device as that determines what fraction of the approximately $3 million the storage device is able to obtain. If the performance of the storage device is reduced by 10% (from 98% to 88% for up regulation performance and from 95% to 86% for down regulation performance) then the BCR decreases by 0.11 for a battery and 0.06 for a flywheel. The break-even cost decreases by 14%.

Chapter 4:

Transmission ES, Comparative Portfolio

Use Case Overview

The comparative portfolio use case examines two simplified future resource portfolio scenarios by comparing and contrasting the differences in electricity production (for example commitment decisions, imports, renewable curtailment, emissions) and production costs (for example net cost to load, CA generation cost, import/export prices, Ancillary Service prices) of each scenario in meeting a modified net load profile.

Modeling the Use Case

Two resource portfolios built to meet future capacity needs are examined. The two scenarios examined are:

A. Only new, fast acting gas combined cycle gas turbines (CCGTs) and CTs are built to meet future capacity needs;
B. Combination of fast acting gas plants (CCGTs and CTs) and storage plants (medium and short duration) are built to meet future capacity needs

Scenario A is a reasonable representation of the current trajectory of new capacity additions in California and the United States given the recent steep decline in gas prices and the relatively cheap capital costs of gas plants and reduced permitting lag times as compared to the capital costs of other conventional generators. Scenario B represents an alternative option to Scenario A in that it represents a future trajectory of new capacity additions of new fast acting gas plants and fast storage devices / plants.

Storage Services Modeled

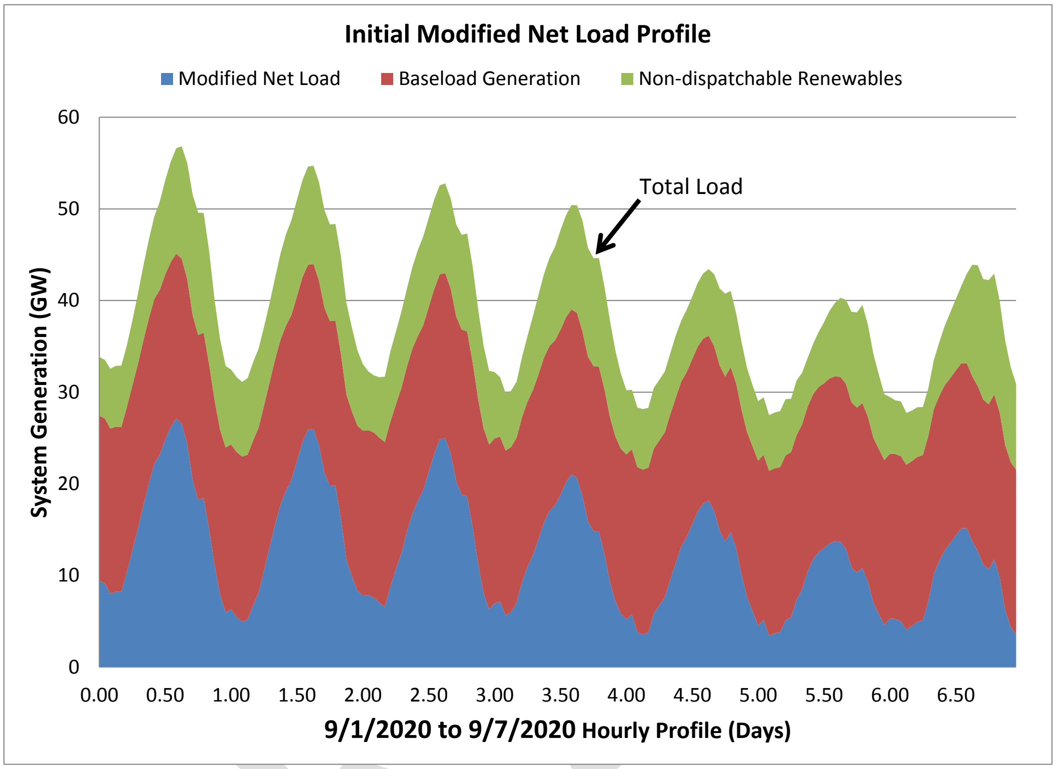
In this analysis, hourly energy and ancillary service costs for scenarios A and B are modeled using PLEXOS. Each resource portfolio (scenarios A and B) are used to meet a modified net load profile. The modified net load profile for hour “” is defined as follows:

$$\text{Modified Net Load Profile}_i = \text{Load}_i - \text{non-dispatchable renewable generation}_i - \text{baseload generation}_i$$

In essence, inflexible generation whether it is non-dispatchable renewable energy or energy from large baseload plants is removed from the load profile to produce the modified net load profile. An example of the components removed from the load profile to get a modified net load profile is shown for the first week in September in Figure 12.

Note that a constant level of baseload generation is removed from each monthly profile. The baseload level is set at the minimum level of the net load profile (load minus non-dispatchable renewables) – 100 MW (offset constant). The offset constant is used to adjust the monthly average of the modified net load profile. Initially the offset constant is set at 100 MW to keep the modified net load profile positive for all time periods. A sensitivity analysis removes this constraint to examine the effect of over-generation events (periods where the modified net load profile is less than zero).

Figure 12: Modified Net Load Profile



Source: DNV KEMA Energy & Sustainability

Implementing the Use Case in PLEXOS

A simplified PLEXOS model was built for the comparative portfolio use case. The model consists of one large region where all of the assets in scenarios A and B reside. This large region is interconnected to a large external region which it can import and export power up to the interconnection limits. Interconnection limits are set to the maximum import and export capabilities of California in the LTPP Trajectory Case. A stacked import and export cost curve is used to value imports and exports each hour and the values used are representative of import and export costs estimated for California using the LTPP Trajectory Case.

The ancillary services included in each scenario are load following, regulation, and spinning reserve. The hourly ancillary service requirements for each ancillary service product are determined in a manner consistent with CAISO's procurement of each product type. It is assumed the storage devices can provide any ancillary service product.

Four months of modified net load profile were used to compare portfolios A and B. The four months examined are January, March, July, and September. The modified net load profiles were developed using the load and renewable profiles used in the LTPP Trajectory Case model.

Portfolio Models

CT and CCGT, Case A Portfolio

For scenario A, only two types of gas plants will be considered. One will be a highly flexible CT plant, such as a LMS100, and the other will be a CCGT representing a highly flexible CCGT plant, such as a Siemens Flex-Plant CCGT. Table 8 summarizes the operational specifications for the LMS100 and CCGT units. The amount of LMS100 and CCGT capacity added to scenario A is equal to the maximum modified net load value divided by the nameplate capacity of each generator and rounded up to the nearest integer. The reasoning behind this formula is that the model should not be capacity constrained in order to find the lowest production cost value for a given net load profile and set of asset characteristics.

Table 8: Operational Specifications of a LMS100 and CCGT Base Turbine

LMS100 Base Specifications		
Nameplate Capacity	100	MW
Heat Rate	8,628	BTU/kWh
Efficiency	40%	%
Ramp Rate	4	MW/min
Total Overnight CAPEX	$1,535	$/kW
Variable O&M	$4.17	$/MWh
Fixed O&M	$17.40	$/kW-yr
Start-up Fuel Requirement	2.8	MMBtu/MW
Start-up Cost	$1,725	$/start
Minimum Operating Level	40%	% of Nameplate Capacity
Fuel Cost	$6.16	$/MMBtu
GHG Adder	$36.65	$/MMBtu

CCGT Base Specifications		
Nameplate Capacity	500	MW
Heat Rate	6,940	BTU/kWh
Efficiency	49%	%
Ramp Rate	25	MW/min
Total Overnight CAPEX	$1,372	$/kW
Variable O&M	$3.02	$/MWh
Fixed O&M	$8.30	$/kW-yr
Start-up Fuel Requirement	2.8	MMBtu/MW
Start-up Cost	$8,624	$/start
Minimum Operating Level	40%	% of Nameplate Capacity
Fuel Cost	$6.16	$/MMBtu
GHG Adder	$36.65	$/MMBtu

Source: DNV KEMA Energy & Sustainability

In this analysis, hourly energy and ancillary service costs for scenarios A and B are modeled using PLEXOS. Each resource portfolio (scenarios A and B) are used to meet a modified net load profile. The modified net load profile for hour “” is defined as follows:

CT, CCGT and Energy Storage, Case B Portfolio

Scenario B is a replica of scenario A with three types of storage added and capable of providing energy arbitrage, hourly ramping capability, and spinning and regulation reserve. Table 9 summarizes the three types of storage units included in scenario B and their operational characteristics.

Table 9: Type of Storage and Operational Parameters

Storage Asset	Application	Example Type	Nameplate Capacity	Energy Capacity	Ramp Rate Down (MW/min)	Ramp Rate Up (MW/min)	Min Operating Level (% of Nameplate Capacity)	Efficiency
Short Duration	Ancillary services such as frequency regulation	Flywheel or Li-Ion Battery	20	1	5,000	5,000	5%	83%
Medium Duration	Hourly flexibility useful for ramping events	CAES	100	4	100	40	10%	83%
Long Duration	Energy arbitrage	Pumped hydro	300	12	300	300	15%	82.5%

Source: DNV KEMA Energy & Sustainability

The storage devices capable of energy arbitrage are 300 MW storage devices with 12 hours of stored energy capacity. The ramping units are 100 MW storage devices with 4 hours of energy capacity. The spinning and regulation reserve units are 20 MW storage devices with 1 hour of energy capacity. The number of energy arbitrage devices added was calculated by the following formula:

of 300 MW storage devices = (max value of the net load - the min ave daily modified net load value)/300 + 1

The number of 100 MW storage devices for ramping was calculated by the following formula:

of 100 MW storage devices = maximum 3 hour ramp observed during the 4 month period / 100 + 1

The number of 20 MW storage devices for regulation and spinning reserve was calculated by the following formula:

of 20 MW storage devices = (max of hourly spinning capacity + max of regulation capacity) / 20 + 1

Sensitivities

Table 10 lists the six sensitivity cases examined for the comparative portfolio use case. The six cases examine the six key variables that critically determine the results.

Table 10: Listing of Use Cases Examined

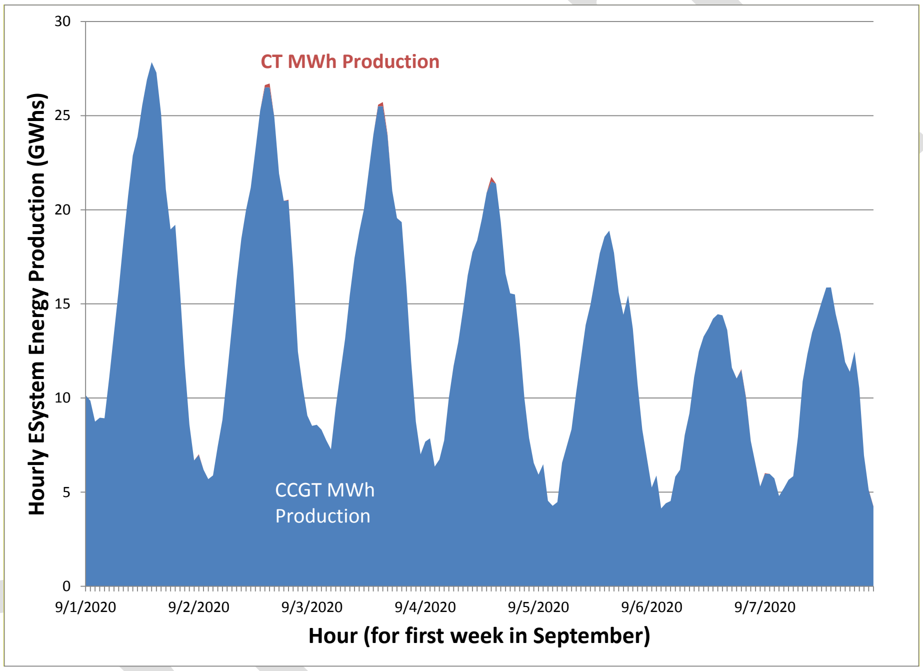
Sensitivity Case	Moniker	Low Value	Base Value	High Value	Step Increment	Number of runs	Description
1	Regulation Capacity	50%	100%	200%	25%	7	Vary amount of capacity reserved for regulation
2	Gen Maximum Heat Rate	50%	100%	200%	25%	7	Change heat rate of the CCGTs and CTs at max load
3	Startup Costs	50%	100%	200%	25%	7	Change startup costs for each type of gas generator
4	Fuel Costs	50%	100%	200%	25%	7	Change the cost of natural gas to examine range of fuel costs
5	Gen Heat Rate Slope	50%	100%	200%	25%	7	Change the fuel consumption slope of the gas generators
6	Baseload Offset Value	-300%	100%	500%	100%	9	Vary the amount of baseload generation removed from the net load profile

Source: DNV KEMA Energy & Sustainability

System Impacts Preliminary Results

Figure 13 and Figure 14 are stacked area graphs detailing the hourly production from the class of asset (CCGT and CT for Case A; CCGT, CT, and storage for Case B). As seen in Figure 13, CCGTs produce the majority of the hourly energy and the CT assets operate as peaker units. The CTs operate for 1 to 3 hours a day and at most 7 CTs operate at once whereas at most 279 CCGTs operate at once. CCGTs provide 99.91% of the energy to meet the annual modified net load while CTs provide the remaining 0.09% energy.

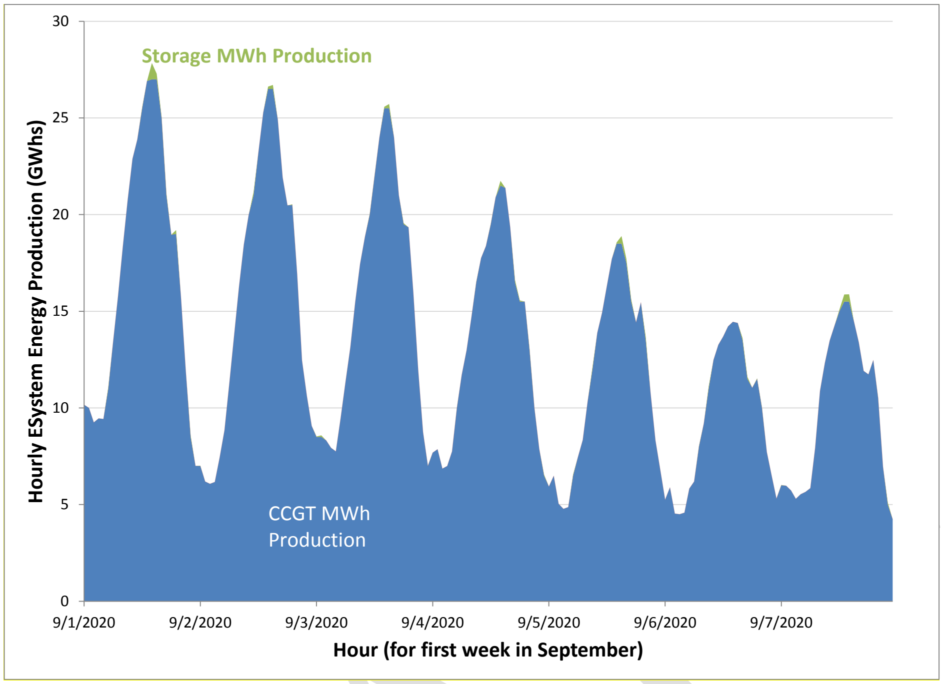
Figure 13: Dispatch of CCGT and CT Assets for Case A for the First Week of September



Source: DNV KEMA Energy & Sustainability

As seen in Figure 14, adding storage to Case A eliminates the use of the CTs for the month of September. In fact, storage eliminated the use of CTs for June, September, and December simulations and reduced the use of CTs for March. In March CTs provided 333 MWh of energy which is reduced from 5,517 MWhs CTs provided in March in Case B. In total, CCGTs provide 99.48% of the total energy, storage provides 0.52%, and CTs provides less than 0.01%.

Figure 14: Hourly Dispatch of CCGT, and Storage Assets for Case B for the First Week of September



Source: DNV KEMA Energy & Sustainability

Table 11 reports the monthly and annual results for the base case implementations of Case A and Case B. The annual benefit estimated by introducing storage into an all gas portfolio is $0.37 per MWh and the range of monthly benefits is $0.26 to $0.46 per MWh. This translates to a total benefit of $8.64 million. The source of the majority of the benefits is due to reduced fuel costs of the CTs. The second leading cause of reduction is a reduced number of startups (more efficient utilization of generation). Although introducing storage does not only produce benefits. There are costs associated with introducing storage, namely increased generation from the CCGT assets to charge the storage assets and to true up lost energy due to inefficiencies.

Table 11: Summary Results for the Four Months Simulated and Estimated Annual Results

	Base Case Results ($Mlns)		Difference	Difference
	Case A	Case B	($Mlns)	($/MWh)
March	$330.62	$329.96	($0.66)	($0.45)
June	$378.30	$377.92	($0.38)	($0.26)
September	$359.62	$359.08	($0.54)	($0.34)
December	$282.58	$282.00	($0.58)	($0.46)
Annual	$5,404	$5,396	($8.64)	($0.37)

Source: DNV KEMA Energy & Sustainability

The spring and winter months realize the highest benefit savings of the four months simulated. This corresponds with the months with the steepest modified net load shapes (low daily load factors) indicating that the production cost benefits of storage increase as the modified net load becomes peakier (or load factor declines).

Table 12 lists the range of results for the sensitivity analyses. The factor with the most influence is fuel costs as varying fuel costs from 50% to 200% produced the widest range in results. Estimated benefits ranged from $0.20 per MWh to $0.64 per MWh by adjusting fuel costs. The second most important factor affecting the results is the heat rate of the generators. More benefits can be realized when storage is introduced to systems with more inefficient generators. The least contributing factor to the results is the slope of the generators heat rate.

Table 12: Scenario Analysis Results

Scenario	Sensitivity Results ($/MWh) Low	Base	High
Regulation Adjustment	($0.39)	($0.37)	($0.36)
Generator Maximum Heat Rate	($0.31)	($0.37)	($0.41)
Startup Costs	($0.40)	($0.37)	($0.35)
Fuel Costs	($0.20)	($0.37)	($0.64)
Generator Heat Rate Slope	($0.35)	($0.37)	($0.39)

Source: DNV KEMA Energy & Sustainability

Chapter 5:

Distribution ES, Substation Capacity Deferral

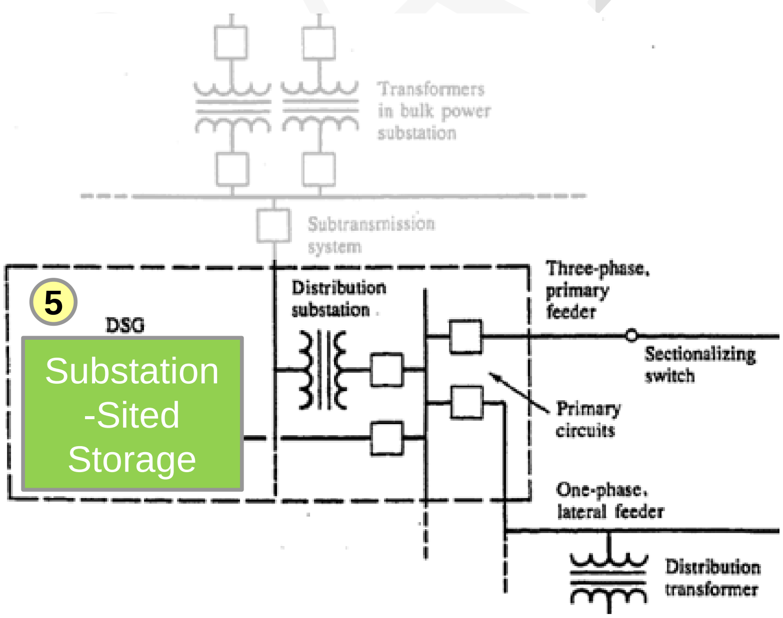
Use Case Overview

Substation-sited distributed energy storage can be employed by a utility for:

1. deferring substation equipment upgrades by shaving system peak demand
2. providing Volt/VAR support
3. reducing substation transformer losses

Figure 15, below, illustrates how energy storage is sited in this use case. The storage device is located on the secondary side of the substation transformer. Therefore, real and reactive output power from the storage device reduces power flow through the substation transformer to serve the distribution circuit. This in turn also reduces the voltage drop and losses across the substation.

Figure 15: Substation-sited Energy Storage



Source: DNV KEMA Energy & Sustainability

Of the above applications, substation upgrade deferral is the primary application for this use case. The substation upgrade deferral reflected here is the delayed investment of additional substation transformer capacity. Storage enables this deferral by reducing substation transformer peak loading during the hours of the years for which the respective equipment would have been overloaded without energy storage. In addition to peak shaving, the storage device can output reactive power to reduce voltage drops and losses across the substation transformer. Lastly, by reducing peak demand overloads on the substation transformed, the useful life of the substation transformer can be extended.

Modeling the Use Case

Electric System Model

The cost-effectiveness of storage for this use case is evaluated based on engineering modeling. In particular, the costs and benefits account for system-wide impacts, observed via time series power flow simulation. In addition, the modeling results guide assumptions and evaluate the degree to which storage can meet the stated applications (at different storage sizes, for example) For this use case, the model simulates power flow over a sample multi-phase distribution test feeder, the publicly available IEEE 123 Node Test Feeder.[9] Simulation results for these systems are obtained using DNV KEMA's distribution energy storage valuation tool, ES-GRID.[10]

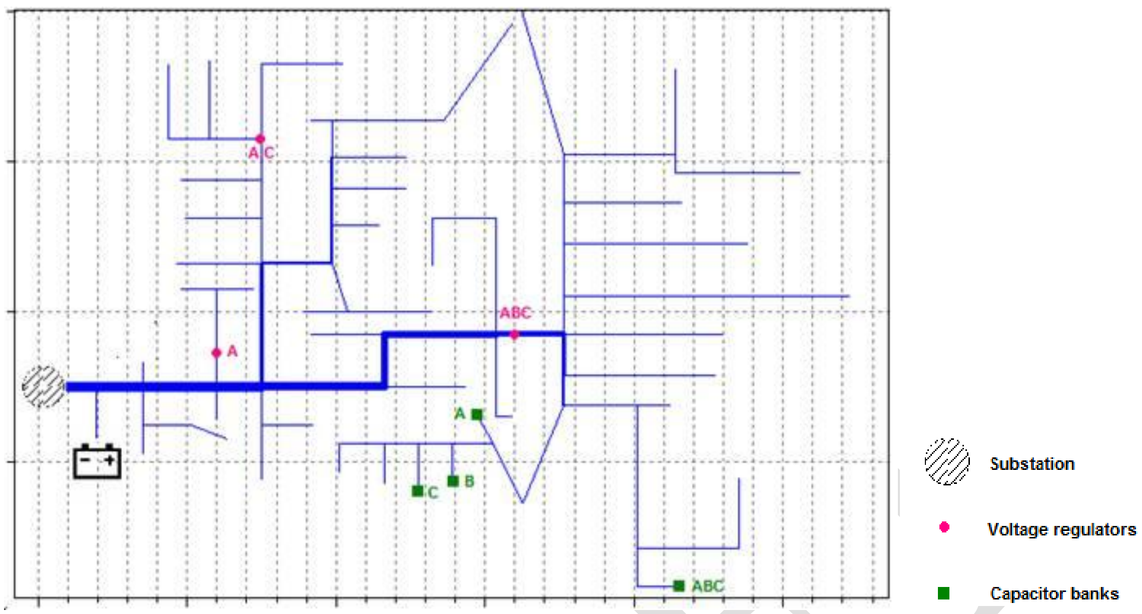
In the IEEE 123 Node Test Feeder, system loads are specified as peak real and reactive demand. To create hourly load profiles from these spot loads, each load in the network was assigned to one of three load classes and assigned an hourly planning load profiles. The three load classes included residential, commercial, and industrial. Loads were assigned to classes based on their connection, single- versus three-phase, and their magnitude. Lastly, the substation transformer was rated at 5,000 kVA and the load profiles were set such that the simulation year's peak demand represented 90% of maximum nameplate loading of the substation.

The energy storage device is sited at the substation. Figure 16, below, illustrates the placement of storage device on the IEEE 123 Node Test Feeder.

[9] "IEEE 123 Note test Feeder," IEEE Power Engineering Society, Power System Analysis, Computing and Economics Committee, Distribution System Analysis Subcommittee.

[10] Prior to its current name of "ES-Grid", DNV KEMA's modeling tool was named "ESBAM." They are one and the same. Any references to ESBAM in earlier rulemaking documents or presentations, such as materials presented during the stakeholder workshop, also apply to ES-Grid.

Figure 16: IEEE 123 Node Test Feeder with Energy Storage placed at Substation



Source: DNV KEMA Energy & Sustainability

Energy Storage Controls Model

The objective of real power storage dispatch controls for this use case is a reduction of peak substation demand. Although the real power controls are not designed specifically to target voltage effects, they can mitigate some voltage issues by reducing the voltage drop over the substation transformer. The problem is formulated as a discretized deterministic dynamic programming model. Using base case simulation results, as well as battery specifications and constraints, the model computes hourly dispatch of the storage device. Storage reactive power controls are implemented using a controller which regulates storage reactive power output as a proportion of the total substation reactive power demand and the real power output of the storage. Reactive power controls further improve circuit voltage by providing Volt/Var support and mitigating low voltage constraint violations.

Summary of Inputs

To evaluate the financial impact of energy storage in this use case, the following benefit and cost elements are evaluated:

- Substation upgrade deferral. This benefit represents the ability to delay substation transformer upgrades for one or more years. An annual fixed charge rate is calculated and applied to the total installed cost of the upgrade and valued as a benefit for to the number of years deferral is possible with storage. The number of years that the substation upgrade is deferred is calculated by counting the number of years between the time that peak demand exceeds 90% of circuit capacity in the base and test cases.

- Distribution loss reduction. Changes in system losses are calculated via engineering simulations. Annual time series data for electricity wholesale prices are used to estimate the value of loss changes. Some configurations slightly increase losses though others decrease losses.

Energy storage costs considered in the analysis include:

- Investments cost of storage. The storage unit's capital cost is calculated as a function of the size of the unit and the battery type. During the analysis period, storage units are replaced based on estimated actual life. Storage actual life is calculated as a function of the number of charge/discharge half-cycles and the amount of energy that is charged/discharged in each half-cycle, and its calendar life. (The engineering simulation tracks storage charges and discharges). A fixed charge rate is used to levelize the total cost.

- Cost of replacement. The cost of replacing storage at the end of its actual life is assumed to be a fraction of initial investment cost. The number of replacements during the project analysis period depends on the storage actual life.

- Operation and maintenance cost. Annual operation and maintenance costs are assumed to be proportional to storage power capacity.

- Cost of electricity. This cost element is defined as the cost of energy to charge the battery. A set of electricity wholesale price time series data is used to approximate the cost of electricity.

- Moving cost. This cost reflects the cost to move a mobile storage unit to another circuit for additional deferral benefit, but at a new circuit.

Additional financial input assumptions reflect common values used across the analyses associated with ES OIR study effort. Table 13, below, identifies the financial assumptions used in this use case.

Table 13: General Financial Assumptions

General inflation rate* (prior to and post 2020)	2.00%
Electricity price escalation rate (prior to 2020)	1.00%
Electricity price escalation rate (post 2020)	2.00%
Percent financed with equity	50.00%
Percent financed by debt	50.00%
Cost of equity	11.47%
Cost of debt	6.18%
Property tax rate	1.10%
Insurance	0.40%
Weighted Average Cost of Capital	7.57%
Federal income tax rate	35%
State income tax rate	8.84%

*All prices are inflated from 2013 to 2020 and from 2020 to 2040 with a 2% inflation rate.

Source: DNV KEMA Energy & Sustainability

To evaluate the cost-effectiveness of storage under a range of scenarios, varying cost and benefit values were assigned to key financial parameters and scenarios were developed by taking a combination of these values. Table 14, below, presents key sensitivity values.

Table 14: Key Sensitivity Values

Variable	Li-Ion	Advanced Lead Acid
Energy Storage Size (MW)	0.5, 1, 2	0.5, 1, 2
Energy Storage Duration (hrs)	2, 4	4
2013 Storage Cost ($/kW)	2,700; 3,500; 4,200	3,000; 3,900; 4,850
2020 Deferral Value ($/kW)	70, 309, 538	70, 309, 538
Load Growth Rate (%)	1%, 2%, 6%	1%, 2%, 6%

Source: DNV KEMA Energy & Sustainability

Use Case Modeling Preliminary Results

Engineering Results

Table 15, below, summarizes the engineering analysis results for IEEE 123 Node Feeder. The results provided for the "base case," represent the distribution system performance without energy storage. The columns to the right present distribution system performance with energy storage. Each column represents performance for the same distribution system but with the corresponding size and duration of energy storage installed. The engineering analysis results illustrate the ability of energy storage to reduce system peak load and mitigate voltage exceptions. The results also identify the impact of energy storage on system losses and equipment wear-and-tear. For this case, the equipment monitored was the load tap changer, and the number of tap changes was counted.

In the spreadsheet which accompanies this report, hourly annual profiles are provided for key variables of the analysis, all provided as three-phase real and reactive power, including: (1) substation demand, (2) battery site power injection, and (3) tap change operations of voltage regulation equipment.

Table 15: Summary Results With and Without Energy Storage

Metric	Base case	500 kW, 2 HR	500 kW, 4 HR	1000kW, 2HR	1000kW, 4HR	2000kW, 2HR
Peak demand (kVA)	4,523	4,323	4,195	4,247	3,957	3,957
Maximum real power demand	4,049	3,901	3,744	3,795	3,538	3,549
Maximum reactive power	2,017	1,960	1,914	1,918	1,822	1,822
Total energy demand (MWh)	18,906	18,958	18,960	19,011	19,067	19,155
Total Losses (MWh)	406	405	405	406	407	408
Tap changes (#)	6,541	7,077	7,079	7,113	7,033	6,451
Maximum voltage (p.u.)	1.0520	1.0461	1.0462	1.0462	1.0463	1.0463
Overvoltage events (#)	10	0	0	0	0	0
Minimum voltage (p.u.)	0.9728	0.9688	0.9691	0.9692	0.9685	0.9685
Undervoltage events (#)	0	0	0	0	0	0

Source: DNV KEMA Energy & Sustainability

Financial Results

Drawing from the results of the engineering analysis, a cash flow analysis was then calculated for multiple scenarios, using combinations of the key sensitivities shown in Table 14 above. The cash flows and computed benefit cost ratios for all scenarios can be found in the spreadsheet which accompanies this report. Five illustrative runs are shown in Table 16 below.

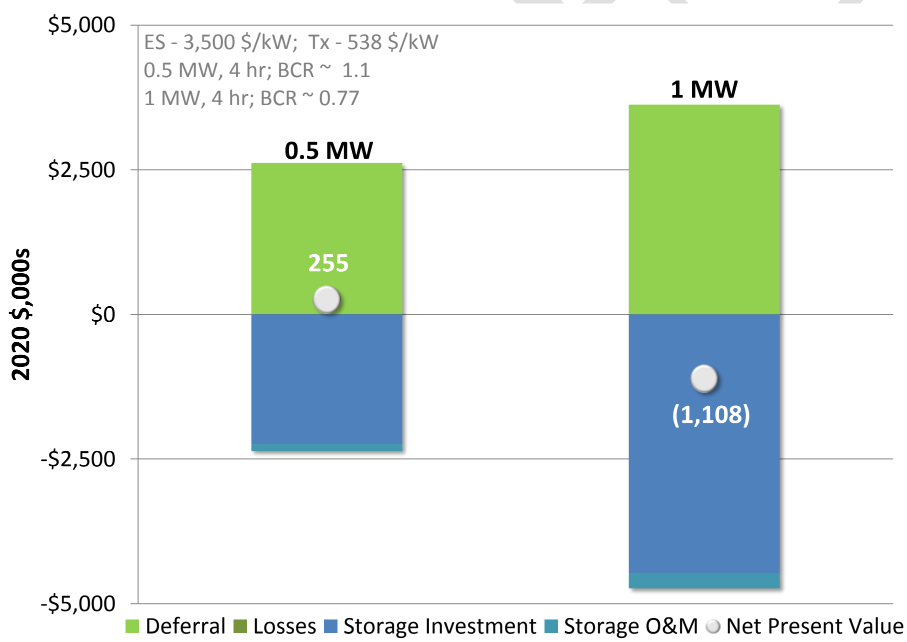
Table 16: Select Financial Results

Scenario #	Size	Deferral Value	Sites	Load Growth	Benefits	Costs	NPV	BCR
178	0.5 MW 4 hr	$538/kW	Single	1%	2,617	-2,362	255	1.11
205	1 MW 4 hr	$538/kW	Single	1%	3,627	-4,735	-1,108	0.77
175	0.5 MW 4 hr	$309/kW	Single	1%	1,503	-2,362	-859	0.64
175	0.5 MW 4 hr	$309/kW	Multiple	1%	2,854	-2,703	150	1.06
179	0.5 MW 4 hr	$538/kW	Single	2%	1,498	-2,362	-864	0.63

Source: DNV KEMA Energy & Sustainability

Figure 17, below, depicts the BCR for case 178 on the left and case 205 on the right. The first of these cases illustrates that the use of storage for deferral at a single location was cost-effective where alternative costs were high and the battery was 'optimally' sized. Regarding optimal sizing, as shown with scenario 205, a larger size than the 0.5 MW required for deferral adds cost with little incremental value.[11]

Figure 17: Benefits, Costs and NPV for Scenarios 178 and 205



Source: DNV KEMA Energy & Sustainability

The rate of load growth also affects the cost-effectiveness of an investment. In particular, the slower the load growth, the longer the storage can defer a substation investment. Figure 18 illustrates the differences in cost-effectiveness under a 1% load growth assumption, on the left (Scenario 178) and under a 2% load growth assumption, on the right (Scenario 179).

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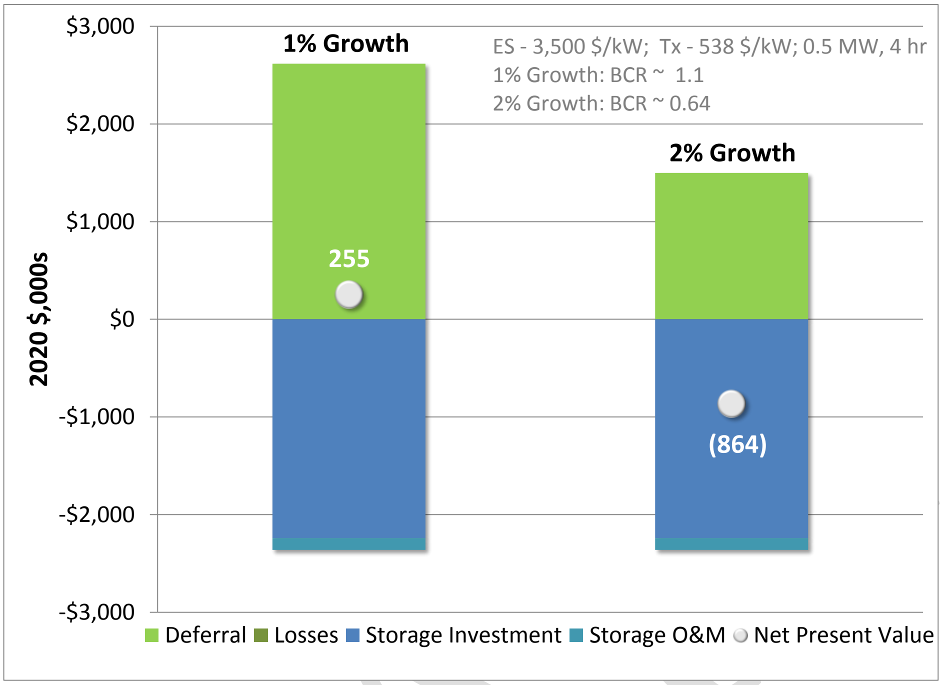
[11] Additional value might include reliability benefits, for example. However, such benefits were not included in the economic valuation here.

Figure 18: Benefits, Costs and NPV for Scenarios 178 and 179

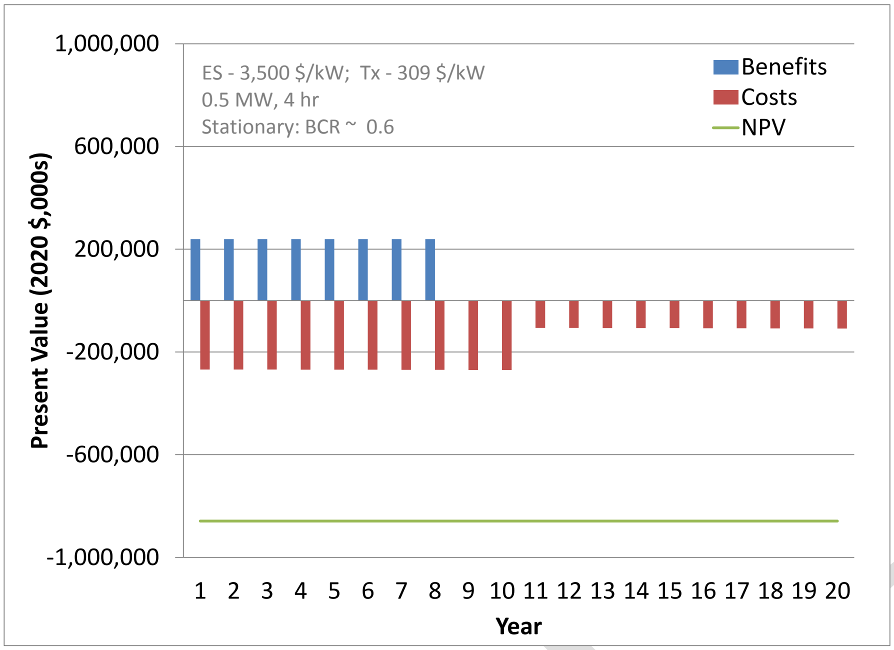


Source: DNV KEMA Energy & Sustainability

The use of mobile energy storage can further increase the cost-effectiveness of energy storage for deferral. In particular, the number of years in which the deferral benefit may be realized is increased by moving the energy storage device to a new circuit when the load growth on the present circuit exceeds the peak shaving capabilities of the unit.[12] Cash flow analyses for Scenario 175, a mobile case and a stationary case, are shown in Figure 19 and Figure 20 below. These cases demonstrate how the additional years of deferral benefit enabled with mobile storage can make storage cost effective where it might not have been cost-effective at a single site. Figure 19 shows the stationary case with a negative net present value (NPV), and ure 21 shows the same case but with mobile storage, which has a positive NPV.

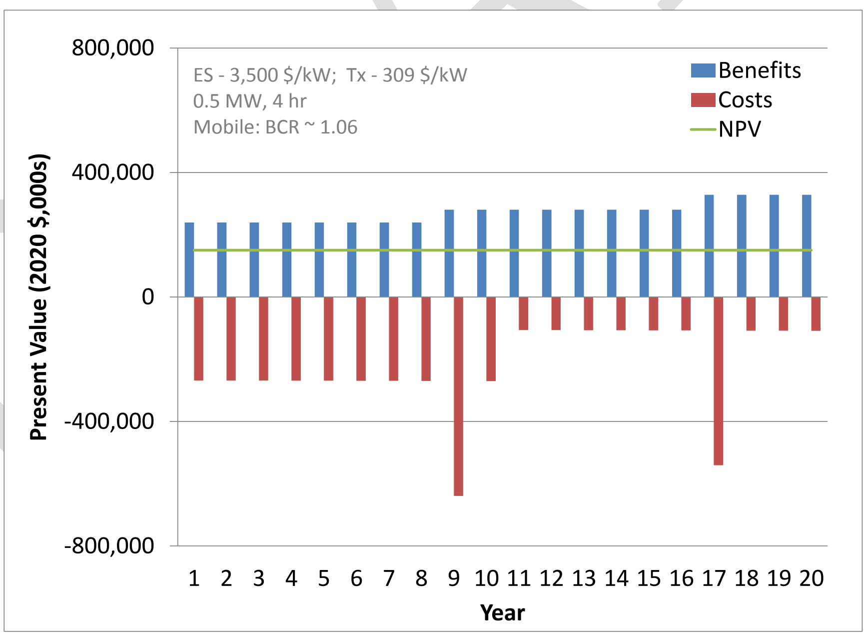
[12] For this analysis, additional circuits are modeled as having the same characteristics as the original circuit. In addition, the analysis places a limit on the number of moves – up to three. Furthermore, a cost is incurred per move.

Figure 19: Cash Flow for Scenario 175 – Single Site, Stationary Storage Deferral Example



Source: DNV KEMA Energy & Sustainability

Figure 20: Cash Flow for Scenario 175 – Multiple Site, Mobile Storage Deferral Example



Source: DNV KEMA Energy & Sustainability

Furthermore, mobile energy storage enables cases with lower alternative deferral costs to be cost-effective. For example, the mobile version of Scenario 175 has a deferral value of $309/kW whereas the cost-effective stationary case noted above, Scenario 178, has a deferral value of $538/kW for the same energy storage cost ($3,500/kW) and size (0.5 MW with 4 hours).

Summary of Results

The findings of the substation sited distributed energy storage use case are summarized below:

1. *Deferral is the primary value benefit for the substation sited energy storage when other applications ancillary services or renewable integration are not considered.*
    - Losses can decrease or increase, depending on the storage size and system set-up, but the cost and benefits of losses tend not to have significant effect on overall cost-effectiveness.

2. *The ability to move storage across multiple sites can increase deferral value for an incremental cost lower than the price of a new unit.*

3. *Higher deferral costs, lower battery costs, and the ability to move across multiple sites in sequence can result in positive net values for this application.*

4. *Larger sizes can allow for longer deferral periods, but can also add cost without much value if duration or capacity is in excess of system load management needs.*

Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

Chapter 6:

Distribution ES, PV Integration Use Case

Use Case Overview

Energy storage can be employed by utilities to facilitate the integration of photovoltaic (PV) generation and mitigate possible negative impacts on the distribution system by:

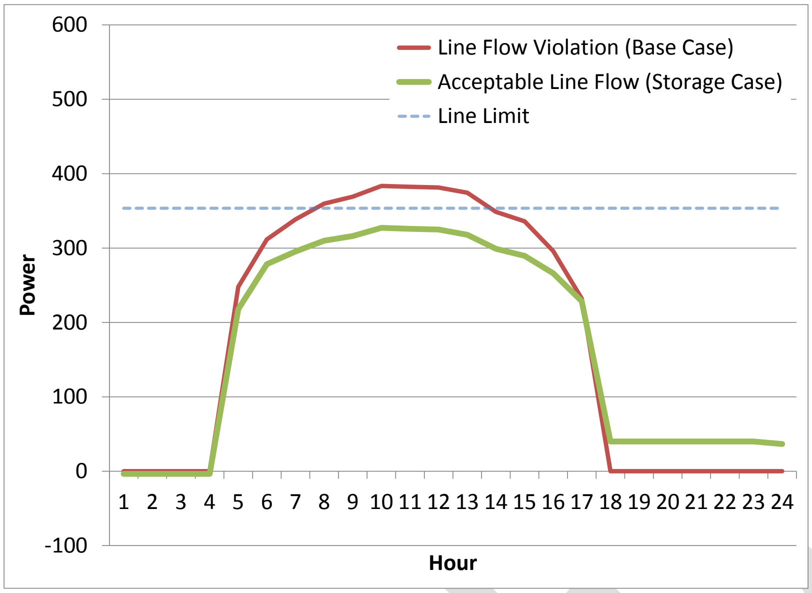
1. avoiding system upgrades required for PV integration
2. mitigating voltage fluctuations at the primary distribution side resulting from intermittent distributed PV generation
3. reducing distribution system losses through improved utilization of distributed generation
4. deferring upgrade of substation equipment by time-shifting peak PV generation to coincide with system load peak

In the use case presented here, the avoided system upgrade is reflected as an avoided investment to re-conductor distribution equipment that would have become overloaded in the presence of reverse power flows from downstream PV generation. Energy storage is presented as an alternative to this equipment upgrade. This avoided upgrade is the primary application of this use case. In addition, energy storage can mitigate voltage fluctuations and violations that might arise from PV production intermittency, resulting from changing environmental conditions, and non-concurrence of system load peak and PV output. Mitigation of voltage fluctuations can also benefit the system by reducing the wear-and-tear on distribution equipment that manages feeder voltage. The controls modeled here are not designed specifically to target voltage effects, but operations are assessed to observe any opportunistic benefit obtained. Lastly, charging the energy storage devices during periods of high PV output enables time-shifting of generation to better coincide with the system load peak. This application of storage can firm up the peak reductions obtained from renewable distributed generation and therefore enable deferral of substation equipment.

Figure 21 and Figure 22, below, present daily simulation results to illustrate how energy storage enables the avoided system upgrade benefit and the deferral benefit stated above.

In Figure 21, the red line represents the line flow violation that would have occurred without energy storage. The green line represents the line flow with energy storage, which is within the line limit.

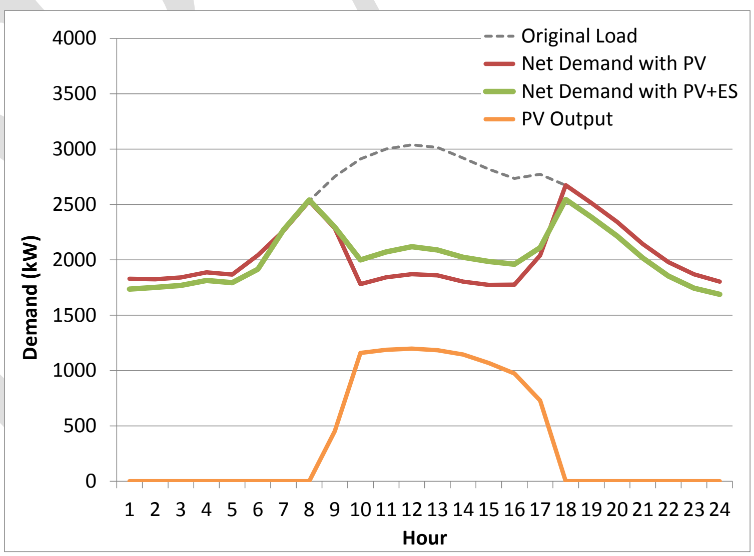
Figure 21: Charging Energy Storage Reduces Power Flow from PV Generation Site



Source: DNV KEMA Energy & Sustainability

In Figure 22, the green line represents net energy demand at the substation with energy storage in combination with the downstream PV. The red line represents net energy demand without energy storage and downstream PV only. The dotted grey line represents original demand without PV production. With energy storage, the maximum net demand at the substation is lower and occurs slightly later than the case without energy storage.

Figure 22: Substation Peak Load is Reduced Through Time-Shift of the PV Generation



Source: DNV KEMA Energy & Sustainability

Modeling the Use Case

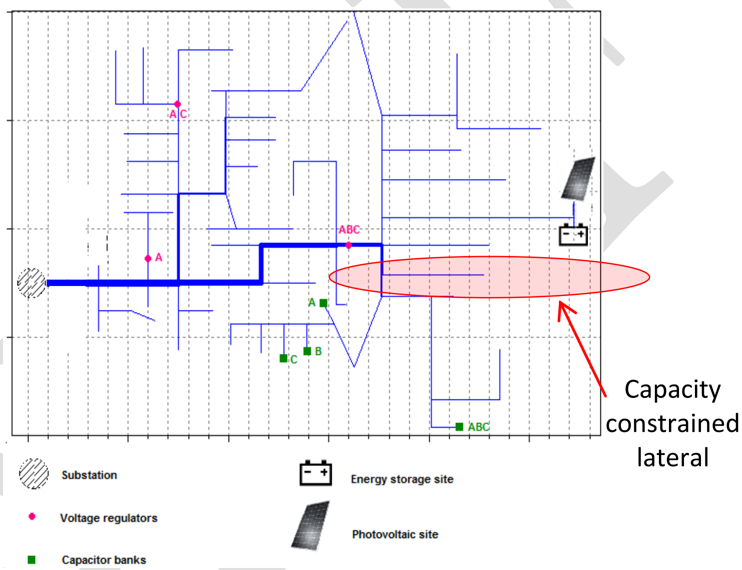
PV Model

In this use case, the distributed PV generation is modeled as a single, 1,500 kW, utility-owned three-phase PV generator. This engineering model can be representative of either (1) a single, large-scale PV generator, or (2) an aggregate of multiple downstream PV generators.

The output profile of the PV generator is modeled using solar irradiance data collected from the National Renewable Energy Laboratory (NREL) using a measurement site in Southern California.[13] This solar irradiance data was converted to total power output of the generator[14].

The energy storage device is co-located with the PV generator, interconnected at the primary distribution level. Figure 14 illustrates the placement of the PV and ES on the sample feeder. The engineering model for the PV integration case is based the IEEE 123 Node Test Feeder, as described in detail below.

Figure 23: IEEE 123 Node Test Feeder with Downstream PV and Co-located Energy Storage



Source: DNV KEMA Energy & Sustainability

Electric System Model

The system is modeled using sample hourly planning load profiles. The substation transformer is rated at 5,000 kVA substation. To demonstrate the voltage issues which arise on distribution feeders with intermittent generation, the test feeder was modified to increase the length of all distribution lines by a factor of 1.5.

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[13] Specifically, this site is Loyola Marymount University, University Hall, Los Angeles, California. Available online at: http://www.nrel.gov/midc/lmu/

[14] http://users.cecs.anu.edu.au/~Andres.Cuevas/Sun/help/PVguide.html

The PV unit and energy storage device is placed on the IEEE 123 Node Test Feeder at the end of a three-phase capacity constrained lateral which branches off the circuit's main three-phase feeder. The conductor for the lateral section between the PV generation and the main feeder is modeled as a Sparrow #2 conductor. This conductor size was selected to create a case where there would be an overload condition on the lateral. The total length of this lateral was set to be 1.1364 miles. A #2 conductor is commonly found on primary distribution circuits. A per-phase real power transfer limit of 354 kW is assumed for the constrained lateral. In Figure 23, above, the capacity-limited lateral is highlighted.

Energy Storage Controls Model

The objective of real power storage dispatch controls for this use case is a reduction of reverse power flow exceeding the constrained lateral capacity. Although the real power controls are not designed specifically to target voltage effects, they can mitigate some voltage issues by controlling PV output intermittency. The problem is formulated as a discretized deterministic dynamic programming model. Using base case simulation results, as well as battery specifications and constraints, the model computes hourly dispatch of the energy storage device. Storage reactive power controls are implemented using a controller which regulates energy storage reactive power output as a proportion of the total substation reactive power demand and the real power output of the energy storage unit. Reactive power controls further improve circuit voltage by providing Volt/Var support and mitigating low voltage constraint violations.

Summary of Inputs

To evaluate the financial impact of energy storage in this use case, the following benefit and cost elements are evaluated:

- Avoided cost of upgrade. This represents a one-time avoided cost of an upgrade which entails re-conductoring. The value is achieved where storage can maintain the critical lateral power flow within its capacity limit.
- Avoided cost of voltage regulator installation. An added voltage regulator installation is assumed as a one-time cost in the first year of analysis, and is avoided if energy storage can eliminate all voltage exception events.
- Substation upgrade deferral. This represents the benefit of delaying a substation transformer upgrade, as calculated in Chapter 5. The difference here is that the benefit attributed to energy storage is the difference between what is achievable with PV alone versus with energy storage and PV. The number of years that a substation upgrade is deferred is calculated by counting the number of years between the time that peak demand exceeds 90% of circuit capacity in the base and test cases.
- Distribution loss changes. Annual time series data for electricity wholesale prices are used to compute value of loss changes.

Energy storage costs considered in the analysis include:

- Investments cost of storage. The storage unit's capital cost is calculated as a function of the size of the unit and the battery type. During the analysis period, storage units are replaced based on estimated actual life. Storage actual life is calculated as a function of the number of charge/discharge half-cycles and the amount of energy that is charged/discharged in each half-cycle, and its calendar life. (The engineering simulation tracks storage charges and discharges). A fixed charge rate is used to levelize the total cost.
- Cost of replacement. The cost of replacing storage at the end of its actual life is assumed to be a fraction of initial investment cost. The number of replacements during the project analysis period depends on the storage actual life.
- Operation and maintenance cost. Annual operation and maintenance costs are assumed to be proportional to storage power capacity.
- Cost of electricity. This cost element is defined as the cost of energy to charge the battery. A set of electricity wholesale price time series data is used to approximate the cost of electricity.

Table 17 below shows the general financial assumptions used in this use case.

Table 17: General financial assumptions

General inflation rate* (prior to and post 2020)	2.00%
Electricity price escalation rate (prior to 2020)	1.00%
Electricity price escalation rate (post 2020)	2.00%
Percent financed with equity	50.00%
Percent financed by debt	50.00%
Cost of equity	11.47%
Cost of debt	6.18%
Property tax rate	1.10%
Insurance	0.40%
Weighted Average Cost Of Capital (WACC)	7.57%
Federal income tax rate	35%
State income tax rate	8.84%

*All prices are inflated from 2013 to 2020 and from 2020 to 2040 with 2% inflation rate.

Source: DNV KEMA Energy & Sustainability

To evaluate the cost-effectiveness of storage under a range of scenarios, varying cost and benefit values were assigned to key financial parameters and scenarios were developed by taking a combination of these values. These key sensitivity values can be seen in Table 18, below.

Table 18: Key Sensitivity Values

Variable	Li-Ion	Advanced Lead Acid
Energy Storage Size (MW)	0.5, 1, 2	0.5, 1, 2
Energy Storage Duration (hrs)	2, 4	4
2013 Storage Cost ($/kW)	2,700; 3,500; 4,200	3,000; 3,900; 4,850
Cost of Re-Conductoring ($/mile)	40,000; 1 million; 1.75 million	40,000; 1 million; 1.75 million
2020 Deferral Value ($/kW)	70, 309, 538	70, 309, 538
Load Growth Rate (%)	1%, 2%, 6%	1%, 2%, 6%

Source: DNV KEMA Energy & Sustainability

Use Case Modeling Preliminary

Engineering Results

Table 19, below, summarizes the engineering analysis results for IEEE 123 Node Feeder with PV generation. The results provided for the "base case," represent the distribution system performance with PV and without energy storage. The columns to the right present distribution system performance with energy storage. Each column represents performance for the same distribution system but with the corresponding size and duration of energy storage installed. The engineering analysis results illustrate the ability of energy storage to mitigate overloads of the capacity constrained lateral, eliminate both high and low voltage exceptions, reduce system losses, reduce system peak demand, and reduce voltage regulation tap changed operations.

In the spreadsheet which accompanies this report, hourly annual profiles are provided for key variables of the analysis, all provided as three-phase real and reactive power, including: (1) substation demand, (2) capacity limited lateral line flow, (3) PV site power injection, (4) battery site power injection, and (5) tap change operations of voltage regulation equipment.

Table 19: Summary Results for Distribution System Performance with PV, and With or Without Energy Storage

Metric	Base case	500 kW, 2 HR	500 kW, 4 HR	1000kW, 2HR	1000kW, 4HR	2000kW, 2HR
Peak real power demand (kW)	4,369	4,341	4,341	4,259	4,259	4,145
Line capacity overload (Hours)	662	46	0	0	0	0
Maximum line flow (kW)	405	369	341	341	332	332
Total energy demand (MWh)	16,422	16,453	16,464	16,508	16,511	16,646
Total Losses (MWh)	605	581	568	572	568	622
Tap changes (#)	10,706	10,198	9,998	10,002	9,990	11,723
Maximum voltage (p.u.)	1.0568	1.0522	1.0492	1.0492	1.0473	1.0703
Overvoltage events (#)	123	11	0	0	0	356
Minimum voltage (p.u.)	0.94487	0.94699	0.94699	0.95178	0.95178	0.94433
Undervoltage events (#)	172	35	24	0	0	30

Source: DNV KEMA Energy & Sustainability

Financial Results

Drawing on the results of the engineering analysis, a cash flow analysis was then run for several scenarios using combinations of the key sensitivities shown in Table 18 above. The cash flows and computed benefit cost ratios for all scenarios can be found in the spreadsheet which accompanies this report. Six illustrative runs are shown in Table 20 below.

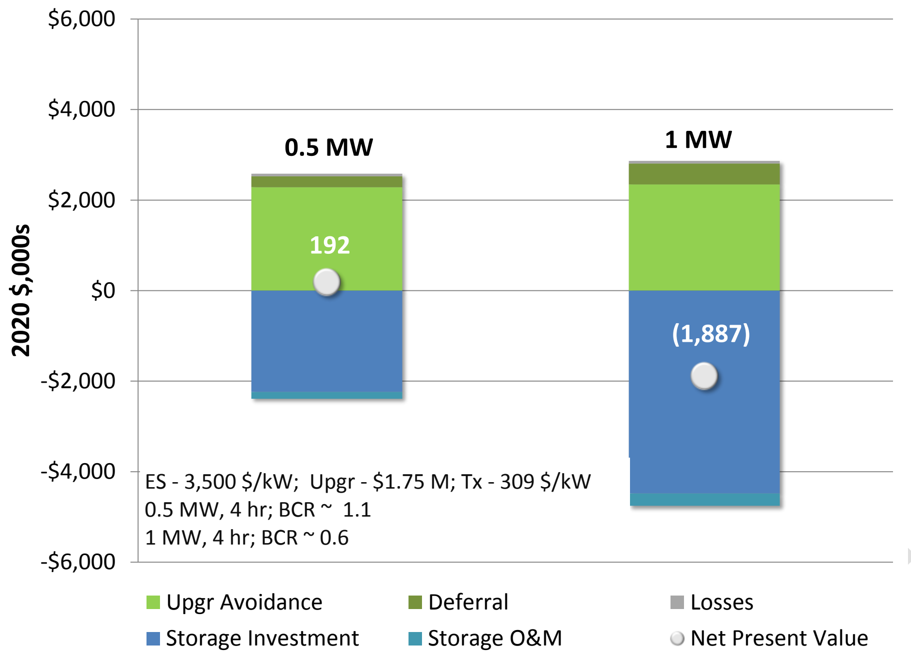
Table 20: Select Financial Results

Scenario #	Size	Deferral	Benefits	Costs	NPV	BCR
150	0.5 MW 4 hr	$309/kW	2,584	-2,392	192	1.1
177	1 MW 4 hr	$309/kW	2,867	-4,753	-1,887	0.6
138	0.5 MW 4 hr	$70/kW	2,399	-1,880	519	1.3
153	0.5 MW 4 hr	$538/kW	2,761	-2,392	369	1.2
147	0.5 MW 4 hr	$70/kW	2,399	-2,392	7	1.0

Source: DNV KEMA Energy & Sustainability

Error! Reference source not found. illustrates a cost-effective case, Scenario 150 on the left. The majority of the benefits are due to avoided re-conductoring upgrades. Additional benefit comes from substation upgrade deferral and some loss reduction. Larger energy storage investment, illustrated with Scenario 177 on the right, shows a slight increase in value. However, the case is not cost-effective as the incremental cost of sizing energy storage beyond the re-conductoring avoidance application is greater than the incremental benefits.

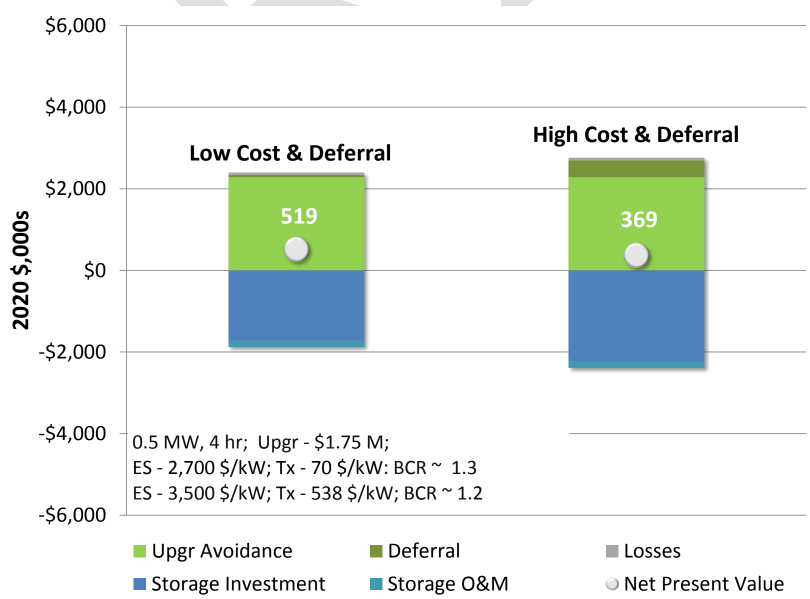
Figure 24: Cost, Benefits and NPV for Scenarios 150 and 177



Source: DNV KEMA Energy & Sustainability

Though re-conductoring is the primary benefit of this application, higher substation upgrade costs (and therefore higher deferral values) enable cost-effective cases with higher energy storage costs. Figure 25 illustrates two cases that are cost-effective, one with lower energy storage cost and deferral value (Scenario 138 on the left) and the other with higher energy storage cost and deferral value (Scenario 153 on the right).

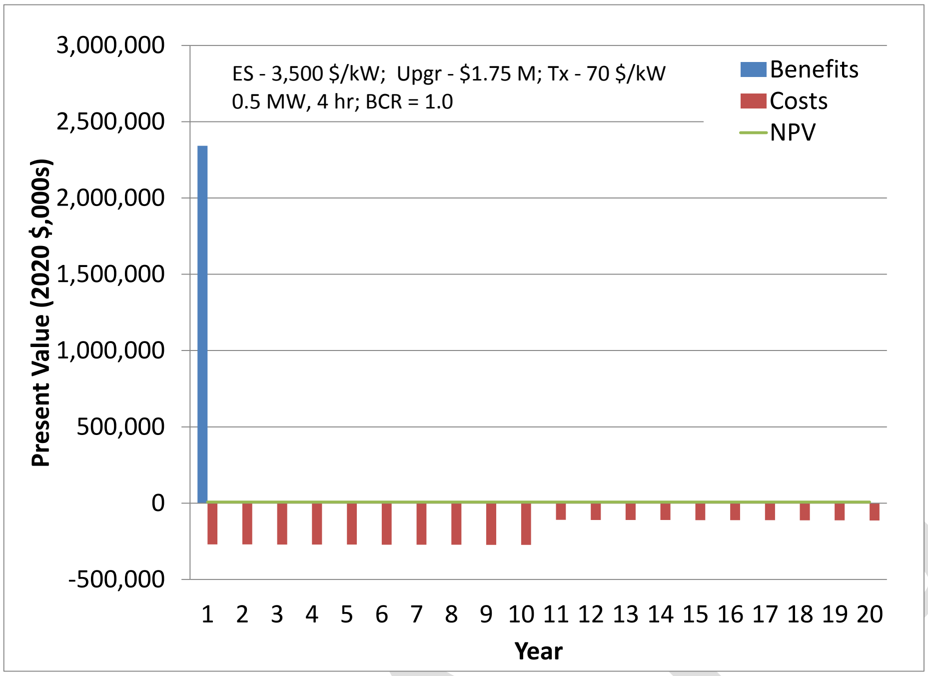
Figure 25: Cost, Benefits and NPV for Scenarios 138 and 153



Source: DNV KEMA Energy & Sustainability

Figure 26 presents the cash flow for a break-even case with high re-conductoring costs.

Figure 26: Cash Flow for Scenario 144, A Break-Even Example



Source: DNV KEMA Energy & Sustainability

Summary of Results

Cost effective cases were found to exist when re-conductoring costs were high. Sizing storage greater than the line limit needs increases costs with small incremental benefit, resulting in non-economic cases. Upgrade avoidance, including re-conductoring and avoided regulator costs accounted for the majority of benefit value. Loss savings were found to be only a small portion of overall benefit. Break-even case reflects a correctly sized battery with high re-conductoring costs, low deferral value, and medium range storage costs. Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

The findings of the PV integration use case are summarized below:

1. *Energy storage can facilitate PV integration while enabling additional potential system operational benefits*
   - Energy storage has potential to improve power quality, shift PV production, and mitigate line and equipment overloads
   - Isolated instances of high investment requirements are cost-effective for the values considered in these cases

2. *Due to its modularity and performance capabilities, energy storage can enable PV deployment in areas previously deemed infeasible/constrained*

- It appears that energy storage can feasibly connect large, remote PV production sites that might be difficult to configure through traditional means
- Energy storage provides additional capacity and ensures consistent production from PV

3. *Energy storage can provide deferral benefit by shifting PV production*
    - The modeled cases demonstrate that energy storage can shift PV production to better cover peak load
    - This has the net effect of deferring equipment upgrades by extending the ability of substation equipment to satisfy feeder net load

4. *The interaction between energy storage and PV reduces the deferral benefit of storage from cases where PV is not present*
    - Because PV can address large portion of the deferral capacity requirement, a smaller portion of the benefit can be attributed to energy storage for a similar sized unit
    - PV production pushes the need for energy storage deferral services out farther in time, lowering the net present value due to time value of money

Chapter 7:

Demand Side Customer Bill Reduction

The demand side customer use case evaluates the benefits to utility customers for storage devices located behind-the-meter. The storage device is owned and operated by the customer. Benefits are accrued by using storage for reduction in electric energy costs through time arbitrage of energy and reduction in peak demand charges by shaving the peak load of the facility.

Use Case Overview

- The use case focuses on buildings or facilities under commercial time of use rates to draw storage benefits from energy arbitrage. The primary input assumptions for the demand use case are as follows: Time horizon of financial analysis – 15 years
- Customer facilities evaluated – Common area meter of multi-family residence, school
- Location of customer facility – San Diego, CA
- Tariffs evaluated– SDGE AL-TOU, SDGE A
- Technologies – Solar PV, high power Lithium Ion (Li-Ion) storage

Modeling the Use Case

The modeling methodology and input assumptions are listed below:

Storage Services Modeled

The high level storage services modeled are:

- Energy arbitrage
- Peak shaving
- Solar PV time arbitrage

The benefits are derived by simulating hourly storage operation one day at a time over the time horizon of financial analysis. The inputs to the simulation consist of hourly forecasts of facility electric demand, energy prices, PV production (where applicable) and monthly demand charges. The simulations model the following storage operational regimes:

- Peak shaving to attain a pre-specified demand
- Co-minimization of energy and demand costs to maximize bill reduction

Facility asset upgrades occur on the first year, 2013. The primary simulation assumptions are shown in Table 21.

Table 21: Customer Use Case Storage Simulation Assumptions

Parameter	Unit	Value
Simulation time horizon	years	15
Year of upgrade / installation	Year #	1
Number of simulated days per year	#	365
Time period of optimization	hours	1
Time horizon of optimization	hours	24

Source: DNV KEMA Energy & Sustainability

Peak shaving operation is modeled to generate customer bill reduction by switching from a commercial tariff rate (SDGE AL-TOU) with demand charges to a residential tariff rate (SDGE A) without demand charges.

Implementing the Use Case in Microgrid Optimization Tool

The DNV KEMA MGO tool models the optimal operation of the battery based on the tariff adopted for the load. The optimization is deterministic, i.e. it assumes that the storage operator has perfect apriori information of hourly facility demand, PV production, energy and demand costs. Load forecasts for each year after the base year are generated by applying a constant escalation factor of 0.3%. Similarly, energy and demand costs are escalated at a constant rate of 3% per year. For the scenario where storage is operated to shift the customer to a different tariff structure, a screening algorithm is used to determine whether the installed devices have sufficient capacity to limit demand to comply with tariff switching requirements for all hours of the year.

The hourly optimization is performed over 24 hour periods. At the beginning of each day, the storage state of charge is reset to zero. The physical characteristics of solar PV, storage and load are modeled as constraints of the optimization problem. The objective function to be minimized is the sum of the total energy cost over the 24 hour period and a characterization of the demand cost. Based on the day-ahead forecasts, each day of the month is ranked on the maximum projected demand of the day. The demand cost represented in the objective function is the monthly demand charge divided by the peak demand rank for the day.

The hourly operational results are aggregated to calculate savings and costs over each year.

Summary of Inputs

The input details for the customer use case are as follows:

Financial and Rates Inputs

The input tariffs are shown in Table 22 and the primary financial parameters are detailed in Table 23. The demand charges under the AL-TOU tariff is split up by peak demand charge and the non-coincident demand charge. Three sensitivities on storage costs are considered: 1. Low - $3,000/KW; 2. Medium - $3,500/KW, High - $4,500/KW. The numbers here denote 2013$.

- The incentive inputs are categorized as follows: Direct rebates on capital expenditure: Energy storage rebates under the SGIP, solar PV rebates under the CSI program
- Direct tax rebate: For solar PV, the Federal Income Tax Credits (FITC) comprise of 30% tax credit on the remainder of capital expenditure after CSI rebates. If the customer installation has solar PV and storage, and the net yearly charging energy of the storage device is at-least 75% of the net yearly PV production, the customer is eligible for at-least 75% of FITC rebate on the remainder of capital expenditure on storage after SGIP rebates. If the net yearly charging energy of the storage device is less than 75% of the net yearly PV production, the customer is not eligible for any FITC rebate on storage.
- Tax deduction from accelerated depreciation: Solar PV and storage are assumed to be under 5 year accelerated depreciation program for tax deductions.

Table 22: Input Tariff Rates in 2013 for Customer Use Case

SDGE A tariff rates			
	Energy Charge	Demand Charge	Service fee ($/Mth)
Jan	$158.99	$0.00	$9.26
Feb	$158.99	$0.00	$9.26
Mar	$158.99	$0.00	$9.26
Apr	$158.99	$0.00	$9.26
May	$198.95	$0.00	$9.26
Jun	$198.95	$0.00	$9.26
Jul	$198.95	$0.00	$9.26
Aug	$198.95	$0.00	$9.26
Sep	$198.95	$0.00	$9.26
Oct	$158.99	$0.00	$9.26
Nov	$158.99	$0.00	$9.26
Dec	$158.99	$0.00	$9.26
Energy charge escalation rate (%/year)	3.00%		
Demand charge escalation rate (%/year)	3.00%		

SDGE AL-TOU tariff rates												
	Peak hours		Mid peak hours		Off peak hours		Energy Charge ($/MWhr)			Peak	NonCI	Service
	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend	Peak	Semipeak	Offpeak	Demand	Demand	fee
Jan	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Feb	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Mar	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Apr	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
May	11-18	0-0	06-11, 18-20	0-0	22-06	00-23	$104.22	$83.01	$61.22	$14.00	$16.76	$58.22
Jun	11-18	0-0	06-11, 18-20	0-0	22-06	00-23	$104.22	$83.01	$61.22	$14.00	$16.76	$58.22
Jul	11-18	0-0	06-11, 18-20	0-0	22-06	00-23	$104.22	$83.01	$61.22	$14.00	$16.76	$58.22
Aug	11-18	0-0	06-11, 18-20	0-0	22-06	00-23	$104.22	$83.01	$61.22	$14.00	$16.76	$58.22
Sep	11-18	0-0	06-11, 18-20	0-0	22-06	00-23	$104.22	$83.01	$61.22	$14.00	$16.76	$58.22
Oct	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Nov	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Dec	17-20	0-0	06-17, 20-22	0-0	22-06	00-23	$99.68	$90.53	$67.39	$4.97	$16.76	$58.22
Energy charge escalation rate (%/year)	3.00%											
Demand charge escalation rate (%/year)	3.00%											

Source: DNV KEMA Energy & Sustainability

Table 23: Cost, Financial and Incentive Inputs for Customer Use Case

Parameter	Unit	Value
Storage technology	—	High energy Li-Ion
Rated power	KW	5, 50
Discharge duration at rated power	hours	2
Round trip storage efficiency	%	87.0%
Round trip inverter efficiency	%	94.0%
Installed cost of storage	2013$/KW	Low: 3,000 Med: 3,500 High: 4,500
Storage system O&M cost	2013$/KW	$20
Engineering life of storage	years	15
Engineering life of inverter	years	15
Battery initial energy level	%	0.0%
PV Installation cost (full cost)	2013$/KW	$5,440
PV Installation cost (only panels)	2013$/KW	$3,260
PV Calendar life	years	20
PV Derating factor	%/year	1.5%
PV O&M cost	2013$/KW	$25
Storage O&M escalation rate	%	2.0%
Solar PV O&M escalation rate	%	2.0%

Source: DNV KEMA Energy & Sustainability

Storage and PV Technology Assumptions Inputs

The characteristics of solar PV and high power Li-Ion storage unit are shown in Table 24. The engineering degradation of storage is not taken into account in this analysis since it is assumed that the cycling intensity for peak reduction and time arbitrage does not warrant replacing either the storage or inverter before the 15 year duration. Accordingly, there is no benefit attributed from salvage value of the storage system.

Table 24: Characteristics of Solar PV and Storage

Parameter	Unit	Value
Round trip storage efficiency	%	87.0%
Round trip inverter efficiency	%	94.0%
Engineering life of storage	years	15
Engineering life of inverter	years	15
PV Calendar life	years	20
PV Derating factor	%/year	1.5%
Capacity factor of PV in installation year (without derating or losses)	%	23.92%

Source: DNV KEMA Energy & Sustainability

Customer Load Assumptions Inputs

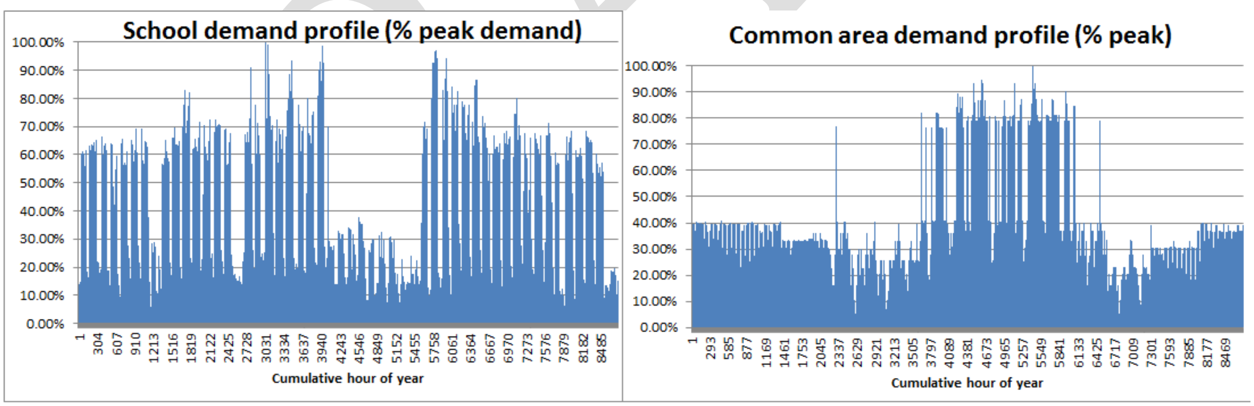
For a customer facility to be a good candidate for the installation of electric storage systems under the benefit criteria evaluated, the demand profile should satisfy the following criteria: 1. High ratio between peak demand and base load and, 2. High variability in the demand. Table 25 shows the main inputs parameters for the load, and Figure 27 shows the base year hourly profiles for the customer load of the two facilities.

Table 25: Customer Facility Assumptions

Parameter	Unit	Value
Peak demand of common area meter load (2013)	KW	21.0
Peak demand of school (2013)	KW	900.0
Standard deviation of common area load	%	17.96%
Standard deviation of school load	%	19.10%
Standard deviation of temperature	%	11.67%
Load increment rate	%/year	0.30%

Source: DNV KEMA Energy & Sustainability

Figure 27: Demand Profiles for School and Common Area Meter



Source: DNV KEMA Energy & Sustainability

Scenario and Sensitivity Alternatives

The two facilities have been selected for two different storage operational paradigms as categorized below

Common area load for multi-unit residential building

A customer can enroll in the residential SDGE A rate if the peak demand for the previous twelve consecutive months is less than 20 KW. The peak demand in 2013 for the common area load of multi-family residence is assumed to be slightly higher and the applicability for combined solar PV and storage systems for tariff switching is evaluated.

IN this case, the storage unit and solar PV are dc-coupled, sharing the same inverter. It is assumed that the storage system installation covers the interface and electricals. As such, only the cost of solar panels is attributed to the combined installation.

The installed capacities are configured such that the net output of the combined system is never greater than the facility load. Hence, installation of a net-meter is not required. The hourly simulation results are screened to verify compliance to the net production and storage FITC requirement assumptions.

Two sensitivities are evaluated for this scenario: 1. The peak demand of the facility is 21 KW in 2013 and a 10 KW combined installation is sufficient to switch the load to the A-tariff throughout the 15 year period and, 2. The peak demand of the facility is 22.5 KW in 2013 and a 10 KW combined installation cannot curtail the peak demand below 20 KW. In this case, the storage unit operates to minimize energy charges through demand reduction and time arbitrage. Scenario numbers 1 and 2 in Table 23 details the primary inputs for the common area meter load scenario.

School

For the scenarios evaluated on the school, the solar PV and storage devices have separate inverters and net-metering is allowed. The customer is on the commercial AL-TOU tariff and remains on the same tariff for the duration of analysis. Sensitivities on this scenario include a combined installation of solar PV and storage and an installation of only storage. Different sizes of installations are also evaluated. Scenario numbers 3 – 6 in Table 26 details the sensitivities on the school scenario.

Table 26: Main Input Parameters for Customer Use Case Scenarios

Perturbation parameters	Unit	Sensitivity runs											
Facility Type	-	Common Area Meter	Common Area Meter	Common Area Meter	Common Area Meter	Common Area Meter	Common Area Meter	School	School	School	School	School	School
Installed capacity of PV	KW	5	5	5	5	5	5	50	50	50	0	0	0
Installed capacity of storage	KW	5	5	5	5	5	5	50	50	50	50	50	50
Installed duration of storage	KWhr	10	10	10	10	10	10	100	100	100	100	100	100
Cost of storage	$/KW	$3,000	$3,500	$4,500	$3,000	$3,500	$4,500	$3,000	$3,500	$4,500	$3,000	$3,500	$4,500
Peak demand in base year (2013)	KW	21.0	21.0	21.0	22.5	22.5	22.5	900.0	900.0	900.0	900.0	900.0	900.0
Demand increment rate (per year)	%/year	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Percent financed by debt	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Discount rate	%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%

Source: DNV KEMA Energy & Sustainability

Use Case Modeling Preliminary Results

The results of the customer use case evaluations are detailed in Table 27. For the common area meter scenario, tariff switching gives an estimated Internal Rate of Return (IRR) of around 17%, while maintaining the facility on the same tariff gives an estimated IRR of around 7.5%.

For the school scenario, the best simulated IRR for a combined installation of solar PV and storage is around 17%. The scenario with only storage installation in the school has an estimated IRR of 11%.

The primary findings from the customer use case analysis are as follows:

1. Customer owned and operated storage is cost-effective for facilities with high peak demand to base load ratio, under tiered TOU tariffs with high demand charges
2. Current SGIP incentives are critical to storage cost-effectiveness.

Table 27: Input Parameters and Financial Results for Different Customer Use Case Scenarios

Sc #	Scenario Characteristics				Installation			Incentives					Financial Results	
	Configuration	Customer type	Primary function	Storage cost ($/KW)	Facility Peak Demand (KW)	Installed Storage (KW, KWhr)	Installed PV	SGIP	CSI	FITC PV	FITC Storage	Acc dep	IRR	NPV
1	Storage and Solar PV dc-coupled	Common area meter of multi-family residence	Demand reduction to shift to different tariff	Low - $3000/KW	21	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	27.03%	$13,363
				Med - $3500/KW									23.29%	$12,110
				High - $/4500/KW									17.90%	$9,602
2	Storage and Solar PV dc-coupled	Common area meter of multi-family residence	Demand and energy charge reduction	Low - $3000/KW	22.5	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	14.55%	$4,692
				Med - $3500/KW									12.17%	$3,438
				High - $/4500/KW									8.56%	$931
3	Storage and Solar PV ac-coupled	School	Demand and energy charge reduction	Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	YES	YES	YES	YES	23.26%	$164,918
				Med - $3500/KW									21.02%	$152,382
				High - $/4500/KW									17.43%	$127,310
4	Only Storage	School	Demand and energy charge reduction	Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	NA	NA	No	YES	38.18%	$91,391
				Med - $3500/KW									25.56%	$75,215
				High - $/4500/KW									14.41%	$42,864

Source: DNV KEMA Energy & Sustainability

Chapter 8:

Generation Co-Located Storage

Two Use Cases for the general category of Generator Co-Located storage where identified in the CPUC ES OIR Phase 1 and Phase 2 Stakeholder process, VER Co-Located Storage and Conventional Generator Co-Located storage. These were not selected in CPUC ES OIR Phase 2 for detailed cost-effectiveness modeling. However, the unique aspects and relevance to California warrant a brief discussion of these forms of thermal energy storage technology that can enhance forms of generation present in California's resource mix: Concentrating Solar Power and Gas Fired Generation with co-located thermal energy storage.

Turbine Inlet Cooling with Thermal Energy Storage

TIC-TES Co-Located Generation & Storage Resource Description

The first Case Study for Conventional Generator Co-Located storage is Turbine Inlet Cooling with Thermal Energy Storage. This is a system where an inlet cooling system is coupled with a traditional natural gas generator in order to improve the output characteristics of the power plant.

How Turbine Inlet Cooling Works

Combustion turbines are sensitive to inlet air temperatures. As outside air temperature rises, the generation output of combustion turbines will decrease. The reason for this is because as air temperature increases, the density of the air decreases. Less dense air has less mass which equates to less power output. For a typical combustion turbine, this output degradation starts to occur as air temperature increases past its ISO ambient temperature design point, often around 60 degrees Fahrenheit, and steadily degrades by about 15-25% as the outside air temperature increases to temperatures around 100 degrees Fahrenheit.[15]

Cooling the inlet air counters the impact of hot weather generation output. A Chiller based cooling typically provides 45 to 50 degree inlet air to a combustion turbine and allows the device "reclaim" the lost output. Turbine Inlet Air cooling systems are not new and have a proven track record of performance.

Impact of Adding Energy Storage

In order for this system to operate, chiller systems are used. Systems can be designed to operate coincident to the hot periods of the day. However, this can create an additional load to the overall system to drive the chillers. When combined with thermal storage, or simply

[15] (source, DN Tanks, http://www.turbineinletcooling.org/webinars/TICAWebinar5_021313TES.pdf)

producing the chilled water or ice during off-peak hours and storing the chilled water or ice, additional benefits are captured. These benefits are (1) providing an "on-demand" increase or decrease in generator output of up to 20%, (2) shifting the chiller load to off-peak periods, and (3) reducing net capital cost and capacity of the chiller plant

The addition of storage versus providing the chilling need real time expands the potential to enhance the operational flexibility of gas generation to add another resource for ramp-rate response, and potentially provide Automatic Generation Control (AGC) tracking via modulating the cooling effect via a large stored or 'buffered' amount of thermal energy that is decoupled from real-time generation production. This is a new concept that DNV KEMA has conceptually discussed with several technical leaders in the TIC field. Though there are few current applications of the concept to allow for a more complete assessment of these additional benefits, these benefits could be explored in advance of field experience by implementing these performance characteristics into a production simulation model and testing the impacts through simulation.

Shifting the parasitic load of chilled water/ice will lower cost of production for the host generation plant. From a system perspective, this shift in the parasitic load to off-peak improves overall system load factor. The potential aggregate off-peak load in California for storing thermal cooling for gas plant TIC is substantial, and this form of off-peak load could help several system level challenges including:

- Providing load for otherwise curtailed off-peak wind energy production
- Mitigating severe evening system aggregate load ramp-down events

Just on the basis of cost to install such systems, Chillers with Thermal Energy Storage (TES), not only provides Turbine Inlet Cooling (TIC), it also provides energy storage, either on the supply-side or on the demand-side of the electric meter. Compared to the other energy storage options, such as Pumped Hydroelectric (PH), Compressed Air Energy Storage (CAES), Advanced Electro-chemical Batteries, Mechanical Flywheels and Superconducting Magnetic Energy Storage (SMES), TES coupled with TIC may be a least cost option (Andrepont 2012).[16]

Concentrated Solar Power with Thermal Energy Storage

For concentrating solar power with thermal energy storage, (CSP-TES), DNV KEMA is performing modeling of CSP-TES for a separate Energy Commission Project[17]. That project report has not been issued, but information describing CSP-TES technology and interim modeling results are provided as an informational reference point on potential benefit value of adding TES to CSP.

[16] *"Turbine Inlet Cooling – A valuable tool to increase electric energy production,"* Turbine Inlet Cooling Association White Paper, March 2012

[17] Optimizing Concentrated Solar Thermal Storage Systems, Energy Commission Contract # 500-10-064

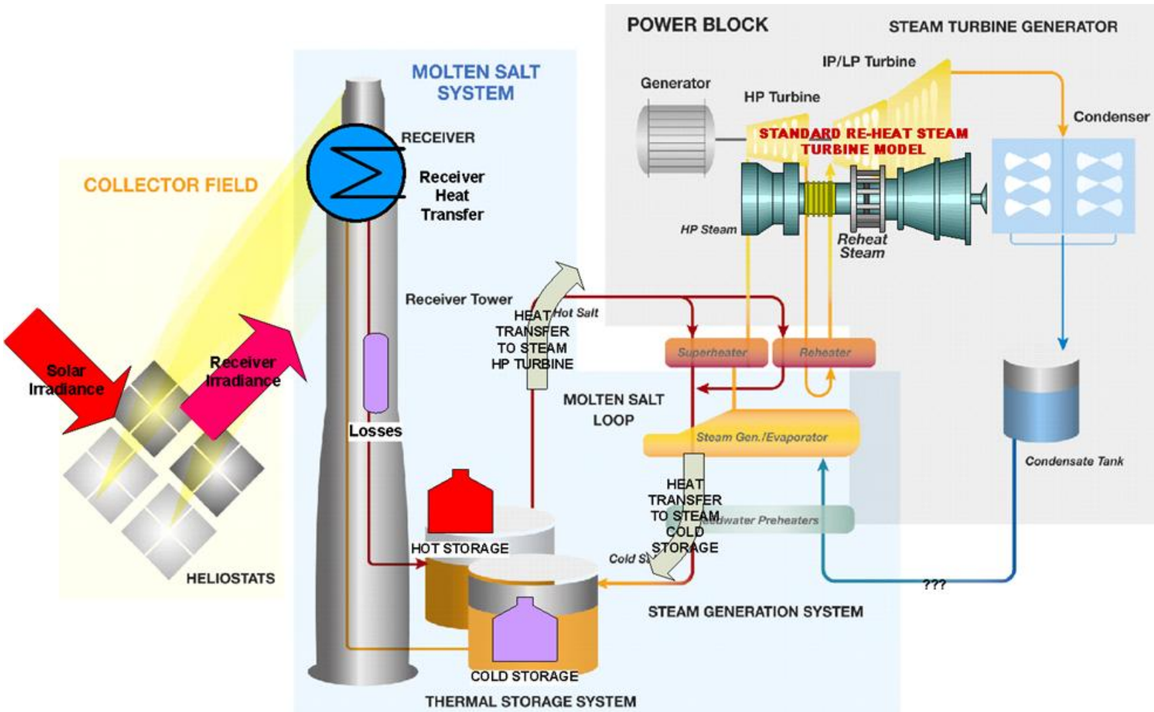
Concentrating Solar Power technologies are gaining ground in California and around the world. Three major approaches within CSP systems are parabolic troughs, solar towers, and dish Stirling technology. Advancements in the technologies for collecting and transferring heat have made CSP more competitive with other renewable generation and CSP plants ranging in capacity from 50MW to 400MW are in operation or under construction primarily in the US (CA, NV, AZ), Spain and South Africa.

Thermal storage systems have the potential to greatly enhance the grid dispatch and electricity market characteristics of concentrated solar power installations, especially in California, which is a world leader in solar energy capacity. Concentrating solar power (CSP) coupled with thermal energy storage (TES), if successfully configured and controlled, could potentially be deployed as a substitute for conventional generation or pumped hydro, with benefits in reliability, emissions, and peak generation. It is the thermal energy component that provides the flexibility to enable the system to potentially access such markets or applications. Many of the benefits of coupled CSP-TES systems to the California grid and markets are understood only on a qualitative level. With end-to-end system modeling, this study aims to quantify a number of potential benefits to the California grid and market from adding substantial amounts of thermal energy storage to existing and future CSP installations.

CSP-TES Co-Located Generation & Storage Resource Description

For evaluating CSP-TES plant performance in KERMIT, a model of CSP-TES based on the technologies operational today, namely a CSP tower model coupled with two-tank molten salt thermal energy storage, was developed. In this CSP model concept, the heat transfer fluid (HTF) is molten salt. Molten salt, at 290°C (554°F) is pumped from a "cold" storage tank through the receiver where it is heated to 565°C (1,049°F) and then into a "hot" tank for storage. When power is needed from the plant, the HTF is pumped from the “hot” tank to a steam generating system for a conventional Rankine-cycle turbine/generator system and then on to the "cold" storage tank and eventually cycled to the receiver again for heating. **Error! Reference source not found.** provides a schematic of the CSP-TES power plant modeled in KERMIT.

Figure 28: Schematic of CSP-TES modeled in KERMIT



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With this plant model, the dynamics and response of the CSP-TES plant to control signals such as schedule, real time dispatch and Area Control Error (ACE), can be evaluated and its output linked to system performance. In a later phase of this project the performance of CSP-TES, using detailed thermodynamic models of several CSP and TES technologies, will be tested against this prototype.

Impact of Adding Energy Storage to CSP

A CSP plant coupled with thermal energy storage (TES) has the ability to provide firm energy and ancillary services and follow a day-ahead schedule, hence behave like a flexible and dispatchable, yet renewable, resource. Furthermore, while adding energy storage to other renewable sources is a possibility today, typically in the form of a battery, thermal storage is can be considered as a cost effective approach if the CSP plant is already being constructed. In such cases, the thermal storage component is a minor addition to the overall cost of the full system. As such, CSP plants coupled with TES, or CSP-TES, may provide unique opportunities and benefits to the California grid. **Error! Reference source not found.** provides a summary of potential system-level benefits to California from added CSP-TES capacity.

Table 28: Potential Benefits of CSP-TES

Renewable Integration Issue	Benefit of CSP-TES	Value
Flexibility & Reliability	Lower variability	Avoided cost for procuring regulation and reserves
	Firm schedules	Avoided cost incurred by forecast error Replacing peaking capacity
	Ancillary services Regulation Reserves Ramp management	Avoided emissions cost Avoided cycling cost Avoided cost of ramping Regulation capacity
	Black start	Cost of black start capability
	Governor response	Lesser burden on conventional units
	System inertia	Transient stability
Renewables Curtailment	On-site firming of renewables	Avoided cost of transmission upgrade from Solar Resource Area
	Production to match demand	Avoided curtailment of renewable energy Avoided loss of PTC
Portfolio & Planning	Dispatchable capacity Flexible capacity	High capacity factor to count towards RA requirements Avoided capacity cost
	Lower exposure to fluctuating gas prices	Avoided risk premium for future gas price and volatility
	Cost effective storage	Installed cost vs. other storage options
	Water conservation	Lower water use if replacing water intensive generation

Source: DNV KEMA Energy & Sustainability

Chapter 9:

Conclusions & Recommended Future Research

Cost-effectiveness Evaluation Conclusions

This report described the model-based methodology used to quantitatively evaluate energy storage cost-effectiveness for five Use Cases: Frequency Regulation, Comparative Portfolio, Distribution Substation Capacity Deferral, Distribution Connected PV Integration, and Demand-Side Customer Bill Reduction . For each of the five Use Cases evaluated, the preliminary results indicate energy storage is cost effective for a subset of assumptions for a range of benefits versus range of costs. The value basis for these preliminary findings are market revenue potential versus storage cost, avoided T&D investment versus storage cost, and customer bill savings versus storage cost. In each case evaluated, the cost-effectiveness cross over, or breakeven point, depended on the value side of the equation being at the upper end of the assumed value range, and the storage cost being at the lower end of the assumed cost range.

Limitations to Evaluation Energy Storage Cost-effectiveness

Modeling limitations prevented quantified model-based Cost-effectiveness evaluation of several prioritized Use Case scenarios identified in the ES OIR Phase 2 prioritization of Use Cases, include,

3) Multiple-use Use Case scenarios where there were applications that bridged customer and utility side of the meter
4) Generator co-located Use case scenarios where the storage modifies attributes of a generator's output and the storage is not directly delivering services to the grid.

Suggestions for Additional Research

Current modeling tools do not cover scenarios that include both customer-savings/energy use optimization and grid-performance models. This lack of an integrated model limits the ability to quantitatively assess the feasibility, impacts, and ultimately the cost-effectiveness of Demand Side energy storage applications when there is the option of utility access for control and dispatch, as one of the multiple services feasible from a Demand-Side asset. The Demand Side modeling (MGO software) and Distribution modeling (ESBAM software) used for this study can be extended to address energy storage multi-use scenario where 1) services cross both sides of the meter and 2) the grid-side benefit comes from aggregated demand-side energy storage dispatched by a utility to deliver a system level benefit. The combining of the two modeled perspectives (customer side and utility side) is a recommended follow-on research effort that would build on the modeling used for this study.

The lack of models for co-located generation + storage is being addressed for the CSP-TES Use Case discussed in Chapter 8.1. But, this modeling limitation remains for TIC-TES. Enhancing Production Simulation modeling (PLEXOS with KERMIT) as used for this project and more generally for California resource planning is a recommended follow research effort that would build on the modeling used for this study.

APPENDIX A:

Original Use Case Statements from CPUC ES OIR Stakeholders

- Transmission Connected ES Use Case(s), http://www.cpuc.ca.gov/NR/rdonlyres/3E556FDB-400D-4B24-84BC-CD91E8F77CDA/0/TransmissionConnectedStorageUseCase.pdf

- Distribution (Distributed) Energy Storage Use Case(s), http://www.cpuc.ca.gov/NR/rdonlyres/85723CE4-A503-499F-804F-DC7BA8E9B991/0/DistributedEnergyStorageUseCaseSubstation.pdf

- Demand-Side Energy Storage, Customer Sited Use Case(s), http://www.cpuc.ca.gov/NR/rdonlyres/2676F607-09DC-411E-8E2C-67149D81C8E0/0/DSMUseCaseCustomerSide.pdf

- Comparative Portfolio Use Case

APPENDIX B:

Use Case Modeling Input and Output Data Spreadsheets

APPENDIX C:

Acronyms and Definitions

Acronyms

AB	Assembly Bill
ACE	Area Control Error
AGC	Automatic Generation Control
BCR	Benefit cost ratios
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CESA	The California Energy Storage Alliance
CPUC	California Public Utilities Commission
CPUC ES OIR	California Public Utilities Commission Energy Storage Order Instituting Rulemaking proceeding R.10-12-007
CSI	California Solar Initiative
CSP-TES	Concentrating Solar Power with Thermal Energy Storage
CT	Combustion Turbine
DNV KEMA	DNV KEMA Energy and Sustainability
E3	Energy & Environmental Economics
EPRI	Electric Power Research Institute
ES	Energy storage
ESBAM	DNV KEMA's Energy Storage Distribution Valuation tool
ES-Select	DNV KEMA Energy Storage-Select Tool
FITC	Federal Income Tax Credits
HTF	Heat transfer fluid
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-owned utilities
IRR	Internal Rate of Return
ISO	Independent System Operator
KERMIT	DNV KEMA Renewable Market Integration Tool
kW	KiloWatt
Li-Ion	Lithium-ion
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MGO	Microgrid Optimization tool
MW	MegaWatt
MWh	MegaWatt-Hour
NPV	Net Present Value
NREL	National Renewable Energy Laboratory

O&M	Operations and maintenance
OPEX	Operating Expenditure
OpenDSS	Open Distribution System Simulator
PG&E	Pacific Gas & Electric
PIER	Public Interest Energy Research
PLEXOS	PLEXOS®
PPA	Power Purchase Agreement
PTO	Participating Transmission Owner
PV	Photovoltaic
RD&D	Research, Development and Demonstration
RegDown	Regulation Down
RegUp	Regulation Up
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Owners
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SOC	State of Charge
T&D	Transmission and Distribution
TOU	Time of Use
VAR	volt-ampere reactive
WACC	Weighted Average Cost of Capital
WECC	Western Energy Coordinating Council