

FINAL REPORT

Advanced Phasor-based Control of Energy Storage Micro-grids

ESTCP Project EW19-5163

DECEMBER 2019

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REPORT DOCUMENTATION PAGE			<i>Form Approved</i> <i>OMB No. 0704-0188</i>		
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1. REPORT DATE (DD-MM-YYYY) 12-16-2019		2. REPORT TYPE ESTCP Final Report		3. DATES COVERED (From - To) 02/08/19 - 09/19/19	
4. TITLE AND SUBTITLE Advanced Phasor-based Control of Energy Storage Microgrids			5a. CONTRACT NUMBER W912HZ-19-C-0008		
			5b. GRANT NUMBER		
			5c. PROGRAM ELEMENT NUMBER		
6. AUTHOR(S) David H. Altman, Benjamin Robistow (Raytheon), Ann Yu (Customized Energy Solutions)			5d. PROJECT NUMBER EW19-5163		
			5e. TASK NUMBER		
			5f. WORK UNIT NUMBER		
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) Raytheon Integrated Defense Systems, Tewksbury, MA			8. PERFORMING ORGANIZATION REPORT NUMBER EW19-5163		
9. SPONSORING / MONITORING AGENCY NAME(S) AND ADDRESS(ES) Environmental Technology Certification Program 4800 Mark Center Drive, Suite 16F16 Alexandria, VA 22350-3605			10. SPONSOR/MONITOR'S ACRONYM(S) ESTCP		
			11. SPONSOR/MONITOR'S REPORT NUMBER(S) EW19-5163		
12. DISTRIBUTION / AVAILABILITY STATEMENT Distribution Statement A					
13. SUPPLEMENTARY NOTES					
14. ABSTRACT This project investigated the use of advanced phasor-based control to maximize the performance and reliability benefits of Li-ion energy storage within a DoD installation microgrid.					
15. SUBJECT TERMS					
16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT Unclassified	b. ABSTRACT Unclassified	c. THIS PAGE Unclassified	Unclassified	126	David H. Altman
					19b. TELEPHONE NUMBER (include area code) 508-490-2720

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ACRONYMS AND ABBREVIATIONS

ACE	Area Control Error
ACT	Active Control Technology
AF	Asset Framework
AFB	Air Force Base
ANGB	Air National Guard Base
ARB	Air Reserve Base
BESS	battery energy storage system
BoP	Balance of Plant
BTM	behind-the-meter
CAISO	California ISO
CBP	Capacity Bidding Program
CES	Customized Energy Solutions
CES	Customized Energy Solutions
C-HIL	Controller Hardware-in-the-Loop
CoMETS	Competitive Market Evaluation Tools for Storage
CSR	Capacity Storage Resource
DCM	Demand Charge Management
DERMS	Distributed Energy Resource Management Systems
DoD	Department of Defense
DR	Demand Response
DRs	Distributed Resources
EPE	El Paso Electric
ESR	Energy Storage Resource
ESS	Energy Storage System
FERC	Federal Energy Regulatory Commission
HMI	Human-Machine Interface
IA	information assurance
IC	Integrating Controller
ICAP	Installed Capacity
IFOM	In-Front-of-the-Meter
ISA	Interconnection Service Agreement
ISO/RTO	Independent System Operators/Regional Transmission Organizations
IT	Information Technology
kW	kilowatt
LFP	Lithium Iron Phosphate

Li-ion	Lithium Ion
LMP	Locational Marginal Price
LoG-RT	Loss-of-Grid Ride-Through
LSR	Load Shift Resource
MITT-LL	MIT Lincoln Labs
MTBF	Mean Time Between Failure
MTTF	Mean Time to Failure
MW	Megawatt
MWh	Megawatt hours
NAS	Naval Air Station
NB	Naval Base
NGR	Non-Generating Resources
NMC	Lithium Nickel Manganese Cobalt Oxide
NPV	net present value
O&M	Operation and Maintenance
Pax	Patuxent
PCS	Power Conversion System
PDP	Peak Demand Period
PDR	Proxy Demand Resource
PFP	Pay for Performance
PMU	Phasor Measurement Unit
PoI	Point of Interconnect
POs	Performance Objectives
REM	Regulation Energy Management
RMF	Risk Management Framework
RPM	Reliability Pricing Model
SC	Scheduling Coordinator
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SOC	State-of-Charge
TOU	Time-of-Use
UPS	Uninterruptible Power Supplies
WMPA	Wholesale Market Participation Agreement

ACKNOWLEDGEMENTS

This report is the result of efforts of multiple individuals across three companies: Raytheon Integrated Defense Systems, Customized Energy Solutions, and PXiSE Energy Solutions.

Raytheon Integrated Defense Systems contributors were David Altman and Benjamin Robistow

Customized Energy Solutions contributors were Pramod Kulkarni, Ann Yu, Chad Dixon, and Gabriel Gomez

PXiSE Energy Solutions contributors were Chuck Wells, Rex Motes, David Jeon, and Leonardo Proserpi

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ABSTRACT

INTRODUCTION AND OBJECTIVES

ESTCP project EW19-5163 studied the use of Li-ion Energy Storage Systems (ESS) coupled with advanced phasor-based microgrid control technology to improve the economics, reliability and performance of DoD installation microgrids.

A combination of techno-economic and reliability analysis was performed for conceptual energy storage enhanced microgrids at five different DoD installations. We considered Li-ion Energy Storage System (ESS), with sizes ranging from 100kW to over 3000kW, and durations ranging from 1-6hrs of total storage. The ESS, as well as other components in the microgrid, were controlled by PXiSE's Active Control Technology (ACT) phasor-based microgrid controls. Controller Hardware-in-the-Loop (C-HIL) testing was performed to evaluate ACT performance based upon IEEE 2030.8 Microgrid Controller Testing standard requirements.

Three overarching objectives were defined to address reliability, economics, and technical feasibility of the approach. These overarching objectives served as the basis of 8 detailed performance objectives that were addressed via reliability and techno-economic analysis, and C-HIL testing.

TECHNOLOGY DESCRIPTION

Li-ion batteries were chosen due to their low cost, acceptable cycle life, and versatility. These batteries were used as part of an ESS that included an inverter capable of grid-forming and dynamic transfer to ride-thru un-planned outages. When combined with appropriate switching, this can enable elimination of dedicated UPS units in favor of more cost effective multi-function ESS units.

The microgrid designs analyzed use PXiSE's ACT high speed microgrid controls to exploit the dynamic response characteristics of the ESS and allow decoupled control of real and reactive power. PXiSE's control improves reliability by allowing multiple grid forming ESS units that are undersized in lieu of one larger unit, and economics by allowing precise control of power at multiple points in the microgrid to simultaneously satisfy multiple value stacking objectives.

PERFORMANCE AND COST ASSESSMENT

Analysis was used to determine the reliability of the proposed storage enhanced microgrid configurations at five DoD installations. C-HIL testing was used to evaluate the ability of the PXiSE ACT controls to realize control assumptions made in the reliability and techno-economic analysis. Economically optimized energy storage enabled microgrid designs were identified for all installations that could meet the required reliability. These designs reduced energy security costs (\$/kW protected load) 6% to 169% through grid-tied operations, and by eliminating UPS units and diesel generators. C-HIL testing was performed with ACT controls, successfully completing 17 microgrid control and operation tests based on IEEE 2030.8 requirements.

STUDY CONCLUSIONS AND OUTCOMES

Our Phase I study concludes that short duration Li-ion energy storage can be used in a DoD installation microgrid to improve reliability with significantly reduced cost vs. an all-diesel microgrid. Techno-economic analysis showed that value stacking market participation functions is most important, followed by UPS elimination. Reliability analysis showed that 1-2 diesel generators can be cost effectively eliminated. C-HIL testing showed that PXiSE's ACT controls can enable key functionalities assumed the techno-economic and reliability analyses regarding renewable integration, multi-ESS microgrid reliability, and value stacking.

EXECUTIVE SUMMARY

INTRODUCTION

ESTCP project EW19-5163 studied the use of Li-ion Energy Storage Systems (ESS) coupled with advanced phasor-based microgrid control technology to improve the economics, reliability and performance of DoD installation microgrids.

Two Li-ion chemistries were considered: Lithium Nickel Manganese Cobalt Oxide (NMC), typically supplied by Samsung SDI or LG Chem, and Lithium Iron Phosphate (LFP), typically supplied by Powin or BYD. Either battery type would be employed as part of a DynaPower Energy Storage System (ESS), with sizes ranging from 100kW to over 3000kW, and durations ranging from 1-6hrs of total storage.

These batteries, as well as other components in the microgrid, are controlled by PXiSE's Active Control Technology (ACT) phasor-based microgrid controls. PXiSE's ACT combines high speed synchrophasor-based measurements, closed loop feedback control with real / reactive power decoupling, and cost function-based system operation optimization.

A combination of techno-economic and reliability analysis was performed for conceptual energy storage enhanced microgrids at five different DoD installations. Techno-economic analysis was performed to optimize net life cycle costs associated with deployment and operation of the energy storage enhanced microgrid. Reliability analyses were performed for each installation to determine critical load coverage probability for islanding through outages up to 168hrs with varying storage sizes, durations, number of ESS units, ESS mean time between failures (MTBF), and numbers of removed diesel generators.

One of the underlying assumptions of the reliability analysis is that all available renewable energy in any hour can be used, provided it does not exceed system kWh capacity. This is not typically a valid assumption in diesel generation-based microgrids, but can be for grid-forming inverter-based microgrids. However, unlike networked diesels, grid forming inverters represent a single point of failure and can reduce reliability. To address this potential shortcoming, the EW19-5163 microgrid concepts use PXiSE's ACT controls to enable energy storage to be divided into multiple units with the capability to back each other up in the event of ESS failure.

Similarly, one of the underlying assumptions of the techno-economic analysis was that the energy storage can be used for any grid-tied use case in any hour, and that some use cases can be performed in the same hour. To realize this assumption, the EW19-5163 microgrid concepts use PXiSE's ACT to control energy storage and other Distributed Energy Resources (DER) to manage power and energy flows at appropriate points in the microgrid to simultaneously satisfy the criteria associated with each grid-tied use case.

To evaluate the efficacy of the PXiSE ACT controls in providing the aforementioned capabilities, Controller Hardware-in-the-Loop (C-HIL) testing was performed using a modified version of the C-HIL facility and models being used on ESTCP project EW-201606. Tests were performed using a test plan developed through a collaboration between Raytheon and MIT-Lincoln Labs (MIT-LL) to address IEEE 2030.8 Microgrid Controller Testing standard requirements.

OBJECTIVES

There were three overarching objectives of EW19-5163 defined to address reliability, economics, and technical feasibility of using advanced phasor control and Li-ion energy storage in a DoD installation microgrid. The comparative baseline was defined by ESTCP as a microgrid employing a set of networked diesel generators. Baseline microgrids for each installation are depicted in Figures 3-7 in the body of this report.

- 1) Quantify improved reliability performance relative to a baseline diesel microgrid analysis
- 2) Define an economic operational concept that supports cost-effective implementation
- 3) Test PXiSE ACT microgrid controls to validate functions that enable 1) and 2)

These overarching objectives served as the basis of 8 performance objectives that were addressed via reliability and techno-economic analysis of energy storage microgrid concepts at five DoD installations, and Controller Hardware-in-the-Loop (C-HIL) testing of PXiSE ACT controls.

Reliability Performance Objectives

- 1) Provide operation with reliability $\geq$ the all diesel baseline microgrid to meet 100% of installation critical and ride-thru load
- 2) Provide operation with reliability $\geq$ the all diesel baseline microgrid at 100% installation critical and ride-thru load to meet 130% of installation critical and ride-thru load
- 3) Provide operation with reliability $\geq$ the all diesel baseline microgrid at 100% installation critical and ride thru load to meet 10% and 30% of installation critical and ride-through load when no diesel fuel is available

Techno-economic Performance Objectives

- 1) Reduce net life-cycle costs of deployment and operation (corresponding to technical objective 1 above) relative to the all diesel baseline microgrid

Controller Hardware-in-the-Loop Testing Objectives

- 1) Demonstrate transitions & stable islanded operation using an “under-sized” grid-forming ESS, complemented by an ESS receiving high-speed PQ commands
- 2) Quantify the ability to reduce fuel utilization and ESS throughput / cycling through high speed control
- 3) Illustrate the ability to ride-thru failure of a grid forming ESS during islanding using a redundant ESS with Loss of Grid Ride-Through (LoG-RT) capability
- 4) Quantify the ability to provide improved microgrid demand management capability at the Point of Interconnect (PoI) through more effective utilization of available DERs

ENERGY STORAGE TECHNOLOGY(IES) AND DOD INSTALLATIONS SELECTED FOR MODELING

EW19-5163 considered Li-ion batteries as part of an integrated ESS. Li-ion batteries were chosen due to their low cost, acceptable cycle life, and versatility to support various grid-tied use cases to produce economic benefits. Their low capital cost (<\$400/kWh) enables short duration Li-ion storage systems cost competitive with both comparably sized diesel generators and Uninterruptible Power Supplies (UPS), including the inverter and balance of plant (BoP).

Li-ion batteries were used within a DynaPower ESS that included an inverter capable of grid-forming and dynamic transfer to support LoG-RT. As demonstrated in prior projects, (e.g., EW-201242), grid-forming inverters are a proven solution to incorporate renewables within a microgrid, improving reliability and reducing fuel consumption. As is being demonstrated on EW-201606, DynaPower's dynamic transfer technology enables LoG-RT to seamlessly accommodate un-planned outages. When combined with appropriate switching, this can enable elimination of dedicated UPS units in favor of more cost effective multi-function ESS units.

To optimally control the ESS and other DERs, the microgrid designs considered in this study use PXiSE's ACT microgrid controls. PXiSE's ACT provides high speed control capability to exploit the dynamic response characteristics of the ESS and allow decoupled control of real and reactive power. Specifically, PXiSE's control improves reliability by allowing the use of multiple grid forming ESS units that are undersized in lieu of one larger unit. It also improves economics by allowing precise control of power at multiple points in the microgrid to simultaneously satisfy multiple value stacking objectives.

Five different installations were investigated for the project:

- 1) Fort Bliss – New Mexico / Texas
- 2) Holloman Air Force Base (AFB) – New Mexico
- 3) March Air Reserve Base (ARB) – California
- 4) Naval Air Station (NAS) Patuxent (Pax) River – Maryland
- 5) Naval Base (NB) Ventura County – California

Fort Bliss was specified by ESTCP, the other four installations were selected based on their local market characteristics and/or tariff information at the time of the project proposal.

MODELING METHODOLOGY

Three types of modeling were pursued in this project. First, techno-economic analysis was performed to determine the economically optimal size and duration of the energy storage by considering various combinations of grid-tied use cases. Then reliability analysis was conducted to determine critical load coverage probability vs. islanding duration.

The optimized size of the energy storage from the economic analysis determined the number of UPS units that could be eliminated. The reliability analysis then determined the number of diesel generators that could be eliminated. UPS and diesel generator reductions were then incorporated into the techno-economic analysis to arrive at the final cost results.

Techno-economic Analysis

Techno-economic analysis was done by Customized Energy Solutions (CES) using their Competitive Market Evaluation Tool for Storage (CoMETS) tool. The analysis considered a variety of behind and in front of the meter use cases which varied with location. Storage size and duration were optimized for the most economically favorable use case(s) for each installation.

Reliability Analysis

Reliability analysis was conducted by Raytheon using a custom model based on an NREL-developed, ESTCP provided, probabilistic methodology to determine critical load coverage probability vs. islanding duration. An energy storage dispatch strategy was implemented within the model that sought to use energy storage to minimize the number of generators required to meet the critical load for each islanding duration. Numerous cases were run to vary ESS size, duration, quantity of units comprising the total storage, and MTBF.

Controller Hardware-in-the-Loop (C-HIL)

C-HIL testing was performed to evaluate the performance of the PXiSE ACT controls by modifying a model of the Otis Air National Guard Base Microgrid developed under EW-201606¹. This entailed dividing the ESS model used on EW-201606 into two half-size units, and providing a PXiSE ACT controller access to simulated relay phasor data and DER control interfaces. Testing was performed for four groups of tests that represented a subset of the IEEE 2030.8 testing performed on EW-201606 using the baseline Raytheon-developed control solution. These tests were chosen specifically to enable testing of the aforementioned performance objectives 5-8.

PERFORMANCE ASSESSMENT

Performance assessment was comprised of two parts: 1) reliability analysis for the proposed storage enhanced microgrid configurations at each of the five installations, and 2) C-HIL testing evaluating the ability of the PXiSE ACT controls to provide the aforementioned capabilities required to realize the assumptions made in the reliability and techno-economic analysis.

Reliability Assessment

Table 1 summarizes the reliability analysis performance assessment results. As noted previously, the storage size and duration were the result of the techno-economic optimization, and the numbers of generators removed where the maximum possible while meeting the 100% Critical Load Reliability requirement. None of the configurations provided appreciable coverage at 130% Critical Load – this is not surprising since the number of generators was minimized for the 100% critical load profile. Most configurations provided >24hrs coverage for 10% and 30% Critical Load Reliability (without generators). Fort Bliss was the exception, due to high critical load and relatively small storage size driven by relatively poor grid-tied economics. NB Ventura achieved 3hrs at the 30% critical load requirement; however, the periods where the load coverage probability fell below the requirement were marginal, limited by storage MTBF. A follow-up analysis showed that by increasing MTBF, >24hrs of coverage would be achieved with the same storage size.

¹ The EW-201606 C-HIL model / hardware was used to cost effectively test ACT functionality with existing DERs

Table 1. Summary of Reliability Results

	Fort Bliss	Holloman AFB	March ARB	NAS Pax River	NB Ventura
Storage Size	1700kW	2400kW	2400kW	29400kW	2500kW
Storage Duration	1hr	2hr	1hr	1hr	1hr
# Diesel Generators	7 (1 removed)	7 (2 removed)	3 (1 removed)	10 (2 removed)	9 (1 removed)
# UPS	4 (none removed)	4 (9 removed)	0 (all removed)	0 (all removed)	0 (all removed)
100% Critical Load Reliability	>168hrs above requirement	>168hrs above requirement	>168hrs above requirement	>168hrs above requirement	>168hrs above requirement
130% Critical Load Reliability	<1hr above requirement	<1hr above requirement	4hrs above requirement	3hrs above requirement	<1hr above requirement
10% Critical Load Reliability*	>24hrs above requirement	>24hrs above requirement	>24hrs above requirement	>24hrs above requirement	>24hrs above requirement
30% Critical Load Reliability*	<1hr above requirement	>24hrs above requirement	>24hrs above requirement	>24hrs above requirement	3hrs above requirement

* No diesel generators

Although in a few instances it may have been possible to reduce the number of required generators further with increased storage size or duration, in general eliminating more than two generators was economically problematic.

UPS units, on the other hand, were easy to eliminate, provided the design could be implemented in a way that would provide equivalent functionality to the existing UPS. To achieve this, our results assume that storage is implemented using multiple modular ESS units that can be co-located with critical load requiring ride-thru. This is possible because of the grid-forming capabilities of our ESS approach, and control capabilities of PXiSE ACT microgrid controls.

Controller Hardware-in-the-Loop Assessment

C-HIL testing to address performance objectives 5-8 was performed in four test groups mapped into the IEEE 2030.8 standard using the test plan that was developed for EW-201606.

Test Group 1 included nine tests addressing transitions to and from islanding. In general, to pass the test, any microgrid controller, and, in particular, the PXiSE ACT controller would need to execute the scenario without tripping protective relays that would result in a partial or complete failure of the microgrid. Planned islanding tests were performed under heavy import and heavy export conditions. Un-planned islanding tests were also performed for heavy import and export, each un-planned islanding event was divided into 3 sub-tests for each condition (auto-reconnect nominal SoC loss-of-grid ride-thru, loss-of-grid ride-thru with low or high ESS SoC). PXiSE ACT controls successfully completed all of these tests. The re-connection test was also completed successfully by the PXiSE ACT control without incident. Notably, the PXiSE ACT controls were able maintain wind turbine production during all transitions, which represents an improvement over the baseline where shutting down and re-starting was required to avoid tripping the turbine.

Test Group 2 included 5 tests addressing steady-state islanding performance. The tests evaluated the ability of the PXiSE ACT controls to react to variations in DER outputs, and to optimize DER dispatch strategies to maximize microgrid efficiency and reliability. Success was achieved by not tripping protective relays that would cause the microgrid to partially or totally fail, and increasing islanding efficiency and reliability relative to the base case from EW-201606. DER variation tests included varying ESS output frequency and voltage, wind turbine power output (kW) and generator power output (kW). All of these tests were completed successfully. Notably, the independent reactive power control capability enabled by the PXiSE controller enabled faster ramping of the diesel generator, avoiding a reverse kVAR fault observed in the baseline. Steady state islanding efficiency and reliability testing was completed, but as of the writing of this draft report the comparable baseline results have not yet been collected for comparison. This will be updated in the final submission.

Test group 3 included two tests evaluating the ability of the PXiSE ACT controls to support “redundant ride-thru” by using the non-grid forming ESS to take over grid forming responsibilities in the event the grid-forming ESS fails. Success was defined as maintaining load coverage during and following the failure of the primary grid forming ESS while charging or discharging. Both tests were successful demonstrating that multiple grid forming ESS units can back each other up in a microgrid similar to the way a networked set of diesel generators works.

Test group 4 included one test to evaluate the ability of the PXiSE ACT controls to manage power flow within the microgrid during grid-tied operation using multiple DERs to meet a particular power control objective. This test represents a scenario where demand management is a continuous need, and maybe complicated by variable renewable generator performance and potentially conflict with other ongoing economic use cases (e.g., frequency regulation). This test was again completed successfully by the PXiSE ACT controls, demonstrating the ability of the PXiSE ACT controls to manage power flow using multiple ESS units and other DERs.

COST ASSESSMENT

Table 2 summarizes results from techno-economic optimization for current pricing data. Most notably, columns E and J show the annualized net cost per kW protected critical load for both the baseline and storage-enhanced microgrids. Column E is the summation of columns A-D and column J is the summation of columns A-D and F-I. In general, market participation provided the greatest benefits, followed by UPS elimination, and then diesel generator elimination. NAS Pax River achieved the best results, realizing a profitable microgrid by value stacking frequency regulation, demand response (DR), and demand charge management (DCM). Holloman AFB showed the second best results through DR, DCM, and retail arbitrage. March ARB and NB Ventura produced comparable results, combining DCM, DR, retail arbitrage, and spinning reserve. We note that better economics could have been achieved by performing frequency regulation in CAISO; however, CAISO rules would require the storage to be connected in front of the meter in a way that would very limiting and likely be impractical for a DoD installation microgrid. Fort Bliss showed the least favorable results. This was primarily the result of the limited market participation options available (DCM and retail arbitrage), and the high base load of the facility combined with the tariff resulting in small addressable demand charges. A small benefit was obtained through these functions and elimination of a diesel generator.

Table 2. Summary of Cost Results

	Peak Critical Load (kW)	Diesel Gensets (A)	UPS (B)	Microgrid (C)	DR & Peak Shaving Savings (D)	Annual Net Cost of Protecting each KW of Peak Critical Load (E)	Energy Storage (F)	DCM & Wholesale Revenues (G)	Diesel Genset Considered Obsolete because of Storage (H)	UPS Considered Obsolete because of Storage (I)	Annual Net Cost of Protecting each KW of Peak Critical Load with Storage (J)	ES Size (kW)	ES Duration (hr)
Holloman AFB	5996	\$49	\$22	\$36	(\$10)	\$98	\$35	(\$51)	(\$11)	(\$16)	\$55	2400	2.7
March ARB	600	\$121	\$52	\$243	\$0	\$416	\$192	(\$240)	(\$30)	(\$52)	\$286	2400	1.3
NAS Patuxent River	8014	\$49	\$22	\$36	(\$10)	\$98	\$176	(\$330)	(\$8)	(\$22)	(\$86)	29400	1.3
NAS Patuxent River	8014	\$49	\$22	\$36	(\$10)	\$98	\$23	(\$64)	(\$8)	(\$16)	\$33	3000	1.3
Naval Base Ventura County	4003	\$57	\$23	\$54	\$0	\$135	\$30	(\$42)	(\$8)	(\$23)	\$91	2500	1.3
Fort Bliss	12507	\$47	\$18	\$18	\$0	\$83	\$7	(\$5)	(\$6)	\$0	\$78	1700	1.3

STUDY CONCLUSIONS AND OUTCOMES

In summary, our Phase I study concludes that state of the art short duration Li-ion energy storage can be used in a DoD installation microgrid to improve reliability with significantly reduced cost vs. an all-diesel microgrid. The techno-economic analysis showed that value stacking market participation functions is most important, followed by UPS elimination. Reliability analysis showed that 1-2 diesel generators can be cost effectively eliminated if appropriately storage is included in the design. C-HIL testing showed that PXiSE's ACT controls can enable multiple "undersized" ESS units realize an inverter grid-forming microgrid. This outcome validates key assumptions in the techno-economic and reliability analyses regarding renewable integration, multi-ESS microgrid reliability, and value stacking. These results motivate follow-on work to demonstrate a Li-ion ESS and ACT phasor control-based microgrid.

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1.0 INTRODUCTION

ESTCP project EW19-5163 studied the use of Li-ion Energy Storage Systems (ESS) coupled with advanced phasor-based microgrid control technology to improve the economics, reliability and performance of DoD installation microgrids.

Two Li-ion chemistries were considered: Lithium Nickel Manganese Cobalt Oxide (NMC), typically supplied by Samsung SDI or LG Chem, and Lithium Iron Phosphate (LFP), typically supplied by Powin or BYD. Either battery type would be employed as part of a DynaPower Energy Storage System (ESS), with models ranging from 100kW - 3000kW and durations ranging from 1-6hrs of total storage.

These batteries, as well as other components in the microgrid are to be controlled by PXiSE's Active Control Technology (ACT) microgrid controls. PXiSE's ACT combines high speed synchrophasor-based measurement, closed loop feedback control with real / reactive power decoupling, and cost function-based system operation optimization.

Techno-economic analysis was performed to optimize net life cycle costs associated with deployment and operation of the energy storage enhanced microgrid. These results were compared to baseline microgrid techno-economic results (without energy storage) performed by ICF and provided by ESTCP.

Reliability analyses were performed for each installation to determine critical load coverage probability for microgrid islanding through outages up to 168hrs. These analyses were performed for the baseline microgrid (without energy storage), and for multiple energy storage enhanced microgrid designs. Analyses were performed for ESTCP-provided critical load profiles, a 130% critical load profile, and with 10% and 30% critical load profiles with no fuel.

Controller Hardware-in-the-Loop (C-HIL) testing was performed to evaluate the ability of the PXiSE ACT microgrid controls to provide unique capabilities that would improve system reliability and economic performance. Testing was performed in accordance with IEEE 2030.8 guidance, using a modified version of the C-HIL set-up and model developed for ESTCP project EW-201606.

1.1 BACKGROUND

As described in ESTCP FY 2019 Broad Agency Announcement: Topic B9², "DoD is the largest single consumer of energy in the United States. Installations are dependent on a commercial grid that is vulnerable to disruption due to aging infrastructure, severe weather, and physical- and cyber-attacks. Major power outages are growing in number and severity in the United States, and military bases often experience increased frequency and longer duration outages than typical utility customers because many bases are located in outlying areas.

² <https://www.serd-estcp.org/Funding-Opportunities/ESTCP-Solicitations/BAA-Proposal-Instructions/FY19-ESTCP-BAA-EW-Topic-B9-Energy-Storage>

There is growing concern whether military bases can maintain critical functions during outages that last for days or weeks, as opposed to hours. DoD is actively pursuing the deployment of microgrid technologies to provide improved energy security for longer durations. Additional discussion and analysis of microgrids at military installations can be found in the report *Power Begins at Home*³. DoD also has been working with the private sector to develop renewable generation assets on military installations. Although of value to improving energy security in some circumstances, they cannot be relied on as a backbone of an energy security solution in the absence of energy storage. Given DoD's energy security requirements, its plans to deploy microgrids, and its existing and planned deployment of renewables, the potential to use energy storage to provide a better and more cost-effective energy security solution is significant."

A number of military and commercial projects have demonstrated the technical feasibility and operational advantages of microgrids. However, microgrids are costly and complex to develop, deploy, and maintain, requiring significant engineering and capital investment. These cost challenges are confounded by the need to significantly oversize generation assets to achieve N+1 redundancy with adequate coverage. Fortunately, energy storage provides a "swiss army knife" for improving microgrid performance. Its functional diversity enables value stacking across diverse microgrid designs, markets, and locations. Its dynamic response capabilities can be used to improve microgrid coverage and duration, and minimize service disruptions by providing ride-through capability. However, to realize these benefits, energy storage must be properly specified and controlled in conjunction with other microgrid Distributed Energy Resources (DERs).

This program investigates the use of advanced phasor-based control to maximize the performance and reliability benefits of state-of-the-art Li-ion energy storage within a DoD installation microgrid. This combination was selected for its ability to improve microgrid coverage, duration, availability and reliability through precise control of small redundant storage systems.

1.2 OBJECTIVE OF THE DEMONSTRATION

There are three overarching primary objectives of EW19-5163 defined to address reliability, economics, and technical feasibility of using advanced phasor control and Li-ion energy storage in a DoD installation microgrid.

- 1) Quantify improved reliability performance relative to baseline analysis enabled by phasor control + energy storage

The first objective was to quantify the reliability advantages associated with including energy storage relative to an all-diesel microgrid. This was done by calculating probability of critical load coverage vs. islanding / outage duration for preferred system configurations, and comparing with a baseline requirement based on an all-diesel microgrid.

- 1) Define an economic operational concept that supports cost-effective implementation

³ <https://noblis.org/wp-content/uploads/2017/11/Power-Begins-at-Home-Noblis-Website-Version-15.pdf>

The second objective was to optimize and quantify the economics associated with implementing energy storage within a microgrid relative to an all diesel microgrid. This was done by optimizing the size and use cases for the energy storage to maximize its economic value. The results were compared to the baseline (all diesel) microgrid analysis performed by ICF for ESTCP.

1) Test PXiSE ACT microgrid controls to substantiate key benefits

The third objective was to demonstrate and validate unique functionality and capabilities that are provided by the PXiSE ACT microgrid controls that are needed to realize the assumptions of our reliability and techno-economic analysis and thereby improve microgrid reliability and economics. This was done by performing Controller Hardware-in-the-Loop (C-HIL) testing of the PXiSE ACT microgrid controls.

To pursue these three objectives, our project considered Li-ion batteries as part of an integrated ESS. We chose Li-ion batteries due to their low cost, acceptable cycle life, and versatility to support various grid-tied use cases to produce economic benefits. The capital costs of a 1 and 2hr Li-ion ESS are valued \$600 and \$1000/kW, respectively. This is similar to the \$600-1100/kW provided by ESTCP for capital costs of standby diesel generation. As such, Li-ion energy storage could be used to displace generators for short term operation with lower net cost.

We used these Li-ion batteries within a DynaPower ESS that included an inverter capable of grid-forming and dynamic transfer to support Loss of Grid Ride-Thru (LoG-RT). As demonstrated in prior projects, (e.g., EW-201242), grid-forming inverters are a proven solution to maximize the ability to incorporate renewables within a microgrid, which improves reliability and reduces fuel consumption. As is being demonstrated on EW-201606, dynamic transfer provides a means to seamlessly accommodate un-planned outages. This can help enable elimination of Uninterruptible Power Supplies (UPS), eliminating their O&M costs, and capital expense for new construction.

To optimally control the ESS and other DERs, we employ PXiSE's ACT microgrid controls. We chose this technology for its high speed control capability that is well suited to exploit the dynamic response characteristics of our ESS. Specifically, PXiSE's control improves reliability by allowing the use of multiple "under-sized" grid forming ESS units in lieu of one larger unit. It improves economics by allowing precise control of power at multiple points in the microgrid to satisfy multiple simultaneous value stacking objectives.

Five different installations were investigated for the project:

- 1) Fort Bliss – New Mexico / Texas
- 2) Holloman Air Force Base (AFB) – New Mexico
- 3) March Air Reserve Base (ARB) – California
- 4) Naval Air Station (NAS) Patuxent (Pax) River – Maryland
- 5) Naval Base (NB) Ventura County – California

1.3 REGULATORY AND MARKET DRIVERS

With Order 841 issued on February 15, 2018, the Federal Energy Regulatory Commission (FERC) directed regional grid operators (ISO/RTO) to remove barriers for energy storage to participate in the wholesale markets. Prior to the order, some ISO/RTOs have allowed energy storage participation in selective wholesale markets – most notably, Frequency Regulation – by designating special resource types or registering storage as both a generator and a load. While some aspects of the compliance filings from the regional grid operators still limit energy storage participation⁴, the FERC order implicitly recognized energy storage’s role in building a more flexible grid to support renewable energy integration. Removing barriers to wholesale market participation opens up multiple revenue streams for energy storage projects, stabilizing the returns on such projects to attract more investments.

The existing rules at the CAISO are largely in compliance with Order 841 with the exception of minimum size requirement. While it is in compliance, the CAISO does not currently allow behind-the-meter (BTM) energy storage participation into the Frequency Regulation wholesale market, significantly reducing the potential revenues for such projects. There is a possibility that the CAISO may open up BTM participation into Frequency Regulation once it better understands how the BTM load shift product works while such participation may adversely affect the Frequency Regulation market price.

To comply with Order 841, PJM has altered the definition of Energy Storage Resource (ESR) and Capacity Storage Resource (CSR) to include all storage technologies and allow storage to offer into wholesale markets and serve retail load. PJM has informed stakeholders, within the 841 compliance filing development process, that the Installed Capacity (Capacity Offer MW) for CSRs is limited to the output that can be sustained for a period of 10 hours. Storage resources are able to offer in as both an ESR and CSR in order to provide Energy/Ancillary Services and Capacity. The ESR participation model will accommodate the bi-directional capability of energy storage; ESR Offer Curves may include negative MW values to reflect an entire, bi-directional dispatchable range of a storage resource.

With the focus of Order 841 on ESR participation in RTOs/ISOs, the opportunity for ESRs in the regulated utility territory of El Paso Electric Company remains largely in the area of demand charge reduction or load shifting for retail customers. El Paso Electric has been successful in procuring energy storage as part of its recent planning process⁵ at the utility level but any release of customer specific programs that include ESRs remain to be seen.

Despite falling under the jurisdiction of El Paso Electric Company, Fort Bliss (TX) and Holloman AFB (NM) have different electricity rate structures and fall under the jurisdiction of their respective states. The largest difference between tariff rate structures of the two sites is the quality of service delivered to each site and comes in two types- firm and interruptible power service.

⁴ See, for example, analyses from Energy Storage Association (ESA), <http://energystorage.org/news/esa-news/energy-storage-association-unveils-initial-assessment-regional-grid-operator>

⁵ El Paso Electric 2019 press release summarizing procurement of a mix of resources including 100MW of storage: <https://www.epelectric.com/about-el-paso-electric/article/plans-to-add-hundreds-of-mws-of-solar-energy-battery-storage-by-2023>

The full load at Holloman AFB is served by firm service while the load at Fort Bliss is split between a base level of firm service (under 44,000kW) and interruptible service for any demand above this amount. The interruptible rate is subject to curtailment at the discretion of EPE when emergency conditions exist but the impact of this is reflected in a lower demand charge range rate (\$2.22 /kW vs \$20.21/kW for the firm demand portion). The opportunity for storage to reduce demand charges is larger in the Holloman AFB case with its higher demand charges (\$19.57/kW) for the peak period.

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2.0 TECHNOLOGY DESCRIPTION

2.1 TECHNOLOGY OVERVIEW

This program investigated two technologies: PXiSE's (pronounced "Pice") Active Control Technology (ACT) microgrid controls, and DynaPower's IPS/CPS and MPS Li-ion Energy Storage Systems (ESS).

2.1.1 PXiSE Active Control Technology (ACT)

PXiSE's ACT is an advanced phasor-based control technique rooted in substation automation and smart grid applications where Phasor Measurement Unit (PMU) data is used to monitor transmission system performance. In microgrid applications, PXiSE's ACT uses PMU data to perform feedback control of DERs, with consideration for their power / energy capabilities, and speed of response.

PXiSE's ACT combines high speed measurement, closed loop feedback control with real / reactive power decoupling, and cost function-based system operation optimization. Time synchronized PMU data, commonly available in modern relays, is used to obtain information on power and energy flows within the microgrid up to sixty times per second. ACT collects this data from key points in the microgrid and uses it to make real-time PQ dispatch decisions in order to manage load / generation balance during islanding using multiple DERs. PQ dispatch decisions are made using a patented method of simultaneously controlling DERs to cost-function defined objectives, with consideration for their different response dynamics and communication protocols. Dispatch commands to fast and slower responding DERs are partitioned using digital filters based on response speed to achieve stable islanding.

During grid-tied operation, ACT provides the capability to engage in a broad variety of functions employing the available DER ranging from demand management and energy shifting to power quality support and frequency regulation. It incorporates a demand scheduler that can be updated every 15 minutes to optimize DER dispatch objectives, and can incorporate real-time weather data from the internet to project renewable generation.

To reliably achieve high speed control functions PXiSE's ACT employs OSISoft PI System software for configuration and to capture, analyze, visualize, and store real-time data. High-speed data processing takes place outside of the PI System to avoid incremental control system latency. PXiSE has integrated ACT with a variety of inverters, including DynaPower, Ideal Power, and Sungrow, and it can accept a variety of protocols including Modbus, DNP3, OPC, and IEC61850 GOOSE. It is designed to be compliant with the IEEE 2030 microgrid controller standards. Data transmission requirements are within the capabilities of modern networks, including allowance for security device latencies (required network bandwidth of 100MBps).

2.1.2 DynaPower Li-ion Energy Storage System

The energy storage technology considered on this program is derived from DynaPower's CPS/IPS and MPS family of Li-ion ESSs. DynaPower offers these Li-ion ESS solutions from 100kW – 3MW using a variety of Li-ion cells. An example system is the IPS-2200, which was designed for grid connected use and provides 2MW/2MWh of storage. The IPS-2200 employs a 2.2MW Power Conversion System (PCS), LG Chem JP3 platform Li-ion battery racks, and Balance of Plant (BoP) hardware including enclosures, battery management, protection, and air cooling (HVAC).

Newer versions of the IPS-2200 are in pre-production and include the CPS-i-1500 and CPS-i-3000, which provide up to 1500kW and 3000kW for 1, 2, 4, or 6hr duration, respectively. Smaller MPS-i systems designed for behind the meter operation are available at 100, 250 and 500kW for 1, 2, 4, and 6hr duration. These employ DynaPower's MPS-125, MPS-250, or MPS-500 inverters and Samsung SDI batteries. We have chosen to focus on this family of energy storage system solutions in part due to its modularity and scalability. Both Samsung SDI and LG Chem provide racked NMC Li-ion cells with comparable cost and performance. This allows us to customize the overall energy storage configuration to suit installation needs at the minimum cost. In addition to Samsung / LG Chem NMC batteries, we considered Powin and BYD LFP batteries, which can offer advantages for longer duration applications.

2.2 ADVANTAGES AND LIMITATIONS OF THE TECHNOLOGY

2.2.1 PXiSE Active Control Technology (ACT)

PXiSE's ACT provides unique capabilities to maximize the performance and reliability benefits of energy storage within a DoD installation microgrid. It's ability to rapidly collect load and generation data and make real-time PQ dispatch decisions allows optimal management of load / generation balance during islanding using multiple DERs. Dispatch partitioning allows fast responding DERs (such as inverter-based storage) to compensate for rapid variations in renewable generation and system demand. Multiple fast responding DERs can be coordinated to support microgrid load, which enables the use of multiple modular "under-sized" ESSs in lieu of a single grid-forming ESS sized to support the islanded load. This provides redundancy and improves reliability without the need to modify off-the-shelf ESS controls.

ACT's ability to decouple real and reactive power control enables each to be controlled independently, improving voltage and frequency control, thus enhancing power quality. Precise control of load / generation balance can provide a means for the microgrid to manage demand at the microgrid Point of Interconnect (PoI). This enables multi-DER (microgrid level) demand management, and enables seamless transition to and from islanded operation.

OSISoft's PI system, which serves as the foundation of ACT, is recognized as the premier software in the real-time data management field and is used by most utility companies worldwide, as well as in the water, gas, steel, pharmaceuticals, and mining and minerals industries. The OSISoft PI Asset Framework (AF) is a standard part of the PI System and is used for configuring the ACT system to reduce integration time. The configurable Human-Machine Interface (HMI) and data historian capabilities inherent to the OSISoft PI system enable a complete microgrid control solution, including Supervisory Control and Data Acquisition (SCADA) functionality, with embedded analytics.

Since ACT uses existing relay PMU data and communication techniques compatible with modern off the shelf DER controls, it can be a software-only solution. High reliability, high speed, communication and control is assured through redundant control hardware, and supported by extensive experience in highly sensitive transmission automation applications.

The primary limitation associated with PXiSE's ACT approach is its reliance on high speed sensing and control to obtain the aforementioned benefits. One of the objectives of the C-HIL testing described later in this report was to obtain experience with ACT to see if communications intermittencies or latencies were problematic and impaired the ability of ACT to provide the sought benefits. As described in Section 6.2, ACT performed as expected throughout the testing despite the use of Modbus/TCP to transmit and receive the data. This suggests that communications latency sensitivities are not a fatal flaw to the technology. Moreover, if high speed communication is not available, ACT has the ability to revert to a SCADA mode of operation which does not require it. A SCADA mode of operation is what is used by most other microgrid control systems, including Raytheon's controls on EW-201242 and EW-201606.

2.2.2 DynaPower Li-ion Energy Storage System

DynaPower's family of ESS's employ their line of advanced inverters to provide features that are critical to maximize the benefits of energy storage in microgrids. Highly capable grid-forming algorithms, dynamic transfer, and black start capability are all standard.

DynaPower's inverters provide a means to integrate with PXiSE's high speed control by accepting analog PQ commands, this has been demonstrated in prior commercial development. The high ramp rate capabilities of DynaPower's inverters and small time to stabilize at a new power output are both critical to maximizing the benefits that can be provided by the fast PXiSE PQ control. DynaPower's dynamic transfer functionality can be integrated with a static transfer switch to reduce islanding transition time to as little as 20ms. This is likely to be critical in enabling the elimination of UPSs for some critical load applications with connected Information Technology (IT) equipment.

DynaPower's IPS/CPS and MPS ESS product lines provide a fully-integrated ESS solution, incorporating an Integrating Controller (IC) to coordinate Battery Management System, BoP, and Power Conversion System (PCS) operation. It also includes electrical and thermal protections in the form of fuses, breakers, contactors, temperature monitoring and fire detection / suppression. DynaPower's battery enclosures are of a standard design, and the remainder of their BoP equipment is largely commercial off the shelf, including HVAC units for battery air cooling.

While there are many emerging storage technologies that show promise to exceed the performance and economics of Li-ion, at present Li-ion, and specifically Samsung SDI and LG Chem, hold a substantial portion of the energy storage system market share. Aggressive cost reduction has allowed these manufacturers to offer racked battery solutions at low cost. Current pricing for a complete (battery racks, HVAC, enclosure) DC system is <\$400/kWh. The flexibility inherent to using Samsung, LG Chem batteries in modular enclosures allows ESS power and energy to optimize life cycle cost and resiliency benefit. Field experience and volume have matured design tools and enabled these suppliers to offer performance guarantees for specific designs and use cases. These factors have established the commercial viability of Li-ion ESS technology and make them the most common selection of large energy storage developers.

Our hypothesis entering the Phase I study was that employing a low cost and mature battery technology will lead to the most cost effective potential Phase II demonstration focused on validating the microgrid performance, economic, and reliability benefits enabled by energy storage through Active Control.

2.3 RISKS ASSOCIATED WITH THE TECHNOLOGY

1. Maturity:

PXiSE Energy Solutions, LLC was formed in 2016 by Sempra Energy (Sempra) after successful joint development efforts with OSIsoft and has to-date focused on supporting grid integration of large scale renewables, behind-the-meter microgrids, and utility Distributed Energy Resource Management Systems (DERMS). Today, Sempra Energy is the majority owner of PXiSE with Mitsui & Co., Ltd. a minority owner. The original underlying technology was developed as a joint effort between Sempra and OSIsoft along with consultants hired by Sempra. A significant contributor to the technology development effort is Charles Wells, formerly from OSIsoft, who has decades of relevant experience and a holder of several patents on decoupled real and reactive power control. Another significant contributor is Prof. de Callafon who has several years of experience in real-time control and manages a research laboratory on Synchrophasor Grid Monitoring and Automation (SyGMA) laboratory at University of California San Diego.

Since forming and commencing commercialization activities, PXiSE has completed a demonstration project at the former Sempra Renewables-owned 24MW Auwahi Wind farm mated to an 11 MW 4.4 MWh LiFePo4 battery energy storage system (BESS) on Maui, and multiple commercial deployments (e.g., 58MW Copper Mountain Solar Installation in Boulder City Nevada, 200MW Great Valley Solar near Fresno California, over 150MW of solar projects for IEnova in Mexico). In the Distributed Energy Resource Management (DERMS) space, PXiSE is actively deploying its platform on Australian utility Horizon Power's system to ultimately serve ~40 microgrids and up to 50,000 DERs. PXiSE has also completed building-level microgrid demonstration projects at the Sempra Energy Headquarters in San Diego, CA and a commercial winery microgrid in Sonoma, CA. Thus, for commercial microgrid applications the TRL of PXiSE's ACT technology is high (TRL6+).

However, this study effort aside, PXiSE, to date, has not done any work with the DoD or to meet DoD user-specific needs. On the other hand, PXiSE's ACT technology has evolved from pre-commercial with activities focused on demonstration projects to the development of integrated commercial solutions, as illustrated by the project on Australian utility Horizon Power's system. Residual risk coming into this project resided largely in ACT integration and validating microgrid specific performance and reliability capabilities, which was the subject of our Phase I C-HIL testing. As described in Section 6.2, these tests with the PXiSE ACT solution were successful, advancing the TRL to 5 for the desired DoD installation microgrid functions. Additional efforts are also needed to assess and determine whether additional work is needed to incorporate cybersecurity features to pass DoD RMF risk assessment. The primary concern associated with this is the possibility that features intended to improve security may impact the ability to achieve reliable high speed communications.

DynaPower's ESS and inverter technology is advanced with respect to microgrid functions, but also a well-established mature product (TRL9). We are currently using a CPS-2000 for grid-forming and LoG-RT on EW-201606, targeting >90% renewable penetration and <60ms LoG-RT transition time from grid-tied to islanded operation. Their IPS/CPS and MPS storage system designs have been fielded in multiple different configurations. DynaPower has previously successfully integrated with PXiSE to support its high speed PQ control. As an outcome of this study activity we envision specific microgrid instantiations that include control functions that have not yet been demonstrated. As such, while the stand-alone maturity of the DynaPower product is high (TRL9), its integrated use for specific control functions we anticipate needing in future demonstrations is lower, ranging from TRL4-5.

2. Performance and Safety Risks:

As discussed above, the performance risks associated with our approach pertain largely to control integration, microgrid application-specific design, and introduction of new features required to satisfy DoD specific information assurance (IA) / cyber-security considerations. These risks could be substantially burned down through C-HIL testing specific to a follow-on microgrid design. It would be important that the C-HIL testing were as high fidelity as possible, including IA networking components that will be used in the design. As mentioned earlier, NMC and LFP chemistries were considered for the DynaPower ESS. These chemistries require fire suppression for safety; however, the designs and performance of these fire suppression systems for these specific chemistries are well established. As such, the safety risk is judged to be low.

3. Sourcing:

The hardware required to realize the system designs considered in this study is entirely off-the-shelf, with customization as required to suit application-specific needs. As mentioned previously, PXiSE's ACT is a software centric-solution and does not require any special purpose hardware. As such, ACT is implemented using standing industrial PC computing platforms, relays, and associated components. Networking is done using standard switches, routers, and firewalls. Sourcing of these hardware components is straightforward and simple. Similarly, DynaPower's ESS solutions are built using commercially available components. Li-ion battery racks are provided by leading commercial manufacturers, such as Samsung SDI, LG Chem, Powin, and BYD. Inverters are built using off the shelf components to standard product designs. The ESS enclosure and BoP hardware is either off the shelf, or built to a custom DynaPower design requirements for a standard product.

4. Scalability:

A major advantage of the approach pursued under this project is its scalability. The availability of ESSs ranging from 100kW – 3MW and durations from 1-6 hours covers a massive amount of application space. Moreover, the advanced features previously discussed are available in all DynaPower products across power levels and durations.

The ability to use PXiSE's ACT to synchronize control of many units that are sized and sited (located) to suit specific microgrid design considerations is a significant advantage. Ultimately, specifics pertaining to load distribution and priority, existing electrical infrastructure capabilities and condition, and equipment siting / integration constraints will play a major role in determining the specific implementation for any of the sites considered in this study. The modular / scalable nature of DynaPower's ESS technology and capability of PXiSE's ACT microgrid controls provides a means to easily account for these considerations and implement a site-specific design that will provide optimal performance, reliability, and economics.

3.0 PERFORMANCE OBJECTIVES

Table 3 captures Performance Objectives (POs) for this project. For brevity, results are shown as meets (green) or does not meet (red). Blue indicates that the results significantly exceeded the objective.

3.1 RELIABILITY PERFORMANCE OBJECTIVES

POs 1-3 were evaluated for each installation using reliability analysis, details are found in Section 6.1. System sizing was done to optimize performance against PO1. PO2 and PO3 were evaluated as “alternative technical scenarios” without modification to the system design.

The objective of PO1 was to determine if there are reliability benefits associated with incorporating energy storage into a DoD microgrid relative to using an all diesel design with N+1 diesel generators. This was done by calculating the probability that the microgrid (baseline and energy-storage enhanced) would be able to supply the ESTCP-provided critical load for each installation for an up to a 7 day (168hr) outage that could start on any day of the year. To meet this performance objective, the ESS-enhanced microgrid must provide an equivalent or higher probability of supporting the critical load for durations lasting up to 168 hours. This criteria was met for all five installations with varying energy storage configurations and number of eliminated diesel generators.

The objective of PO2 was to determine whether the addition of energy storage would allow the microgrid to support critical loads that are 130% higher than the baseline. The energy storage enhanced microgrid design that was simulated for PO1 was re-simulated with 130% of the critical load used to evaluate PO1. Like PO1, success was defined by maintaining equivalent or higher probability of supporting the 130% critical load for durations lasting up to 168hrs. This criteria was not met for any of the installations. This was not a surprising outcome since the configuration analyzed had been optimized to minimize the number of diesel generators required to meet the 100% critical load case.

The objective of PO3 was to determine whether the addition of energy storage would allow the microgrid to support 10% or 30% of the critical load when no diesel generators are available. The energy storage enhanced microgrid design that was simulated for PO1 was re-simulated with 10% and 30% of the critical load used to evaluate PO1 and no available diesel generation. Like PO1, success was defined by maintaining equivalent or higher probability of supporting the 10% or 30% critical load for durations lasting up to 24 hours. This criterial was met for all installations for the 10% critical load, and all installations except Fort Bliss and Naval Base Ventura for the 30% critical load. Fort Bliss did not meet this requirement because of the relatively small amount of energy storage that was used relative to 10% critical load. Naval Base Ventura marginally did not meet this criteria due to reduced load coverage probability for shorter outage durations. However, increasing energy storage MTBF changes this outcome.

3.2 NET COST PERFORMANCE OBJECTIVE

PO4 was evaluated for each installation using techno-economic analysis, details are found in Section 7.0. The objective of PO4 was to determine whether the addition of energy storage to a DoD microgrid could support reduced net cost (per kW of critical load) relative to the baseline all diesel microgrid. To determine this metric, techno-economic analysis was performed to determine the annual net cost of protecting each kW of peak critical load for the energy storage-enhanced microgrid design. This result was compared to the baseline analysis performed by ICF for ESTCP. Success was defined as realizing a net cost (per kW of critical load) with storage that is at or below level of baseline microgrid for both current and future volatile scenarios. This criteria was met for all installations.

3.3 MICROGRID CONTROL PERFORMANCE OBJECTIVES

POs 5-8 were evaluated using C-HIL testing, details are found in Section 6.2. The objective of POs 5-8 were to test the ability of PXiSE's ACT microgrid controls to provide the functionality required to realize an inverter grid forming-based microgrid with multiple "undersized" ESS units. POs 5-7 assessed islanded control functionality, PO8 assessed grid-tied control functionality.

The objective of PO 5 was to demonstrate that the ACT control could transition to and from, and achieve stable islanded operation using an "under-sized" (relative to peak critical load) grid-forming ESS, complemented by a second ESS receiving high-speed PQ commands. To determine this metric, testing was performed using a modified version of the C-HIL model and system used for the Otis ANGB microgrid developed under EW-201606. Success was defined by completing 5 tests based on IEEE 2030.8 requirements without causing equipment to trip offline. All 5 tests were successfully completed with the microgrid under ACT control.

The objective of PO 6 was to demonstrate that the ACT control could quantifiably reduce fuel utilization and ESS throughput / cycling through control of the modified Otis ANGB configuration relative to the baseline case with Raytheon's IPEM control. Success was defined by demonstrating a relative improvement on both metrics (projected fuel consumption and reduced ESS thru-put). As of the writing of this report, testing was completed for a 4 hour scenario using PXiSE ACT controlled has been accomplished, but baseline testing for the same scenario is not yet completed. This will be updated in a future revision to this report.

The objective of PO 7 was to illustrate the ability to ride-through failure of a grid forming ESS during islanding using a redundant ESS that supports Loss of Grid Ride-Through (LoG-RT). Testing was again performed using the modified Otis ANGB C-HIL system and model. Success was defined by demonstrating the system could ride-thru a grid-forming ESS failure by using the redundant ESS. This test was successfully completed with the microgrid under ACT control.

The objective of PO8 was to quantify the ability to provide improved microgrid demand management capability at the Point of Interconnect (PoI) through more effective utilization of available DERs. Testing was again performed using the modified Otis ANGB C-HIL system and model. Success was defined by demonstrating the system could maintain constant power flow at the Point of Interconnect (PoI) in the presence of wind generation and load variability. This test was successfully completed with the microgrid under ACT control.

Table 3. Performance Objectives and Results

Performance Objective	Metric	Requirements	Success Criteria	Results		
1. Reliability to Meet 100% of Installation Critical and Ride-through Load	Critical and ride-through load served during outage (that can begin at any time)	Performance measured for outages of any duration between 1 hour and 168 hours	Meets or exceeds reliability probability curve from baseline microgrid specifically for 24- and 168-hour outages. Compares favorably with baseline microgrid at other outage durations under 168 hours.	Fort Bliss		
				Holloman AFB		
				March ARB		
				NAS Pax River		
				NB Ventura		
2. Reliability to Meet 130% of Installation Critical and Ride-through Load		Fort Bliss <1				
			Holloman <1hr			
			March ARB 4hr			
			NAS Pax River 3hr			
			NB Ventura <1hr			
3. Reliability to Meet 10% and 30% of Installation Critical and Ride-through Load when no Diesel Fuel is Available		Performance measured for outages of any duration between 1 hour and 24 hours	Proportion of critical and ride-through load served (probabilisticly). No minimum standard.		10%	30%
	Bliss			>24	<1	
	Holloman			>24	>24	
	March			>24	>24	
	Pax			>24	>24	
	Ventura			>24	3	
4. Net Life-cycle Costs of Deployment and Operation (corresponding to technical objective 1 above)	Calculate per methodology distributed with baseline microgrid data and results	Net cost (per kW of critical load) is at or below level of baseline microgrid in current and future volatile scenarios	Fort Bliss			
			Holloman AFB			
			March ARB			
			NAS Pax River			
			NB Ventura			
5. Demonstrate transitions & stable islanded operation using an “under-sized” grid-forming ESS, complemented by a ESS receiving high-speed PQ commands	Demonstrate unique control capabilities provided by PXiSE ACT via C-HIL test	Perform testing with Otis ANGB microgrid C-HIL model and facility with 2x ESS units at ½ the size of the baseline design	Complete planned and unplanned transitions to and from islanding without tripping protective relays	Testing completed without tripping relays – improved ride-thru performance for wind turbine vs. baseline controls		
Testing completed for PXiSE controls, comparison to baseline pending						
6. Quantify the ability to reduce fuel utilization and ESS throughput / cycling through high speed control			Complete planned and unplanned transitions to and from islanding without tripping protective relays	Testing completed without tripping relays		
7. Illustrate the ability to ride-through failure of a grid forming ESS during islanding using a redundant ESS with Loss of Grid Ride-Through (LoG-RT) capability				Demonstrated ability to maintain power flow at PoI while compensating for wind and load variability and maintaining SoC of ESS units within acceptable range		
8. Quantify the ability to provide improved microgrid demand management capability at the Point of Interconnect (PoI) through more effective utilization of available DER		Control power flow at PoI with varying wind generation and load				

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4.0 FACILITY/SITE DESCRIPTION

Five installations were simulated in this effort using data supplied by ESTCP. For each site, hourly data including load profiles, solar PV production, real time energy prices, day ahead energy prices, synchronized reserve prices, and regulation prices were provided and used to support techno-economic and reliability analysis. Capital and annual O&M costs for diesel generators and UPSs were used to calculate cost savings opportunities when the introduction energy storage enabled their removal. Electricity bill components were used to determine behind the meter cost savings. Since no electrical drawings were provided, each installation was modeled using a simplified “single bus” representation. This means that the analysis assumed that any generator can support any load in the installation.

4.1 FACILITY/SITE LOCATION AND RELEVANT CHARACTERISTICS

This project examined Fort Bliss, Holloman Air Force Base (AFB), March Air Reserve Base (ARB), Naval Air Station (NAS) Patuxent (Pax) River, and Naval Base (NB) Ventura County. These installations were selected by examining behind the meter (based largely on tariff), in front of the meter (based largely on market), and capital / O&M (UPS and generator) cost avoidance opportunities. Installations with high time-of-use energy cost differences, large demand charges, and time of use demand charges were viewed as providing best behind the meter opportunity. Installations in de-regulated markets where storage, and solar + storage are supported by market rules and more highly valued were favored over regulated markets where a lack of transparency and accessibility may limit opportunity.

Fort Bliss – Texas and New Mexico

Fort Bliss was specified by ESTCP as a mandatory installation to study. Inspection of the tariff initially suggested that there may be opportunity for storage due to large differences in summer time-of-use energy costs and high demand charges. However, this did not pan out due to the high load and load-dependent demand charges and oversubscribed demand response program. Fort Bliss’s utility, El Paso Electric, is regulated and vertically integrated, which limited economic opportunity. Fort Bliss has substantial existing PV and moderate PV capacity to critical load ratio, which suggested good potential to extract improved islanding resiliency from combining storage with existing solar PV.

Holloman Air Force Base (AFB) – New Mexico

Holloman Air Force Base (AFB) featured similar summer time-of-use energy cost differences to Fort Bliss and also features relatively high demand charges. Also serviced by El Paso Electric (regulated and vertically integrated), market opportunities were limited to behind the meter costs savings measures, retail arbitrage, and demand response. The large PV installation at Holloman AFB provided intriguing potential for resiliency enhancement with storage, as it comprises 83% of the critical load.

March Air Reserve Base (ARB) – California

March Air Reserve Base (ARB) features moderate differences in time of use energy costs and high summer on-peak demand charges that vary with time-of-use, depending on rate. Serviced by Southern California Edison, March ARB is located in the CAISO de-regulated market. CA has strict emission controls requirements that severely restrict the use of diesel generators, increasing the relative value of solar + storage in demand response. The combination of behind the meter and in-front of the meter opportunities made March ARB an intriguing option from an economic standpoint. From a resiliency perspective, March ARB is also attractive due to its existing 400kW of solar PV, which could cover 67% of the peak critical load. It also features the highest ratio of critical load requiring ride-thru to critical load at 58%.

Naval Air Station (NAS) Patuxent (Pax) River – Maryland

NAS Pax River is located in the PJM market where energy storage has had significant economic success in the frequency regulation markets⁶. PJM has the highest on-peak frequency regulation requirement of the ISO/RTOs (700MW) and has historically featured the highest average regulation market clearing prices⁷. Market saturation and changes to PJM's energy storage-specific RegD signal to address structural market issues have precipitated a downturn in the market, especially for very short duration storage⁸. However, for new projects where flexibility remains to add energy and explore multiple value streams, such as regulation and arbitrage⁹, there could be notable opportunity. Also, while not currently featuring on-site PV, NAS Pax River may be very well suited for an economically viable solar + storage microgrid project.

Naval Base (NB) Ventura County – California

Naval Base Ventura County is also serviced by Southern California Edison and exists in the de-regulated CAISO market. Moreover, it resides in a location where there is a known capacity shortage, making it likely that both behind and in-front of the meter opportunities should be notable and forthcoming. It has notable existing PV; however, the PV to critical load ratio is relatively low (33%).

The two installations that were not selected for investigation were NAS Corpus Christi and Westover ARB. NAS Corpus Christi was not selected due to its low, time invariant energy prices and demand charges and limited opportunity for energy storage in ERCOT. Westover ARB was not selected for similar tariff considerations, as well as the fact that it is supplied by a vertically integrated utility (Chicopee Electric Light).

⁶ B. Xu, et al., "A Comparison of Policies on the Participation of Storage in U.S. Frequency Regulation Markets," Proceedings of the Power and Energy Society General Meeting (PESGM), 17-21 July 2016 Boston, MA, USA

⁷ "RTO/ISO Regulation Market Comparison", available online at <https://www.pjm.com/-/media/.../20160413-item-03-rto-iso-benchmarking.ashx>

⁸ T. Lee, "Exploring Frequency Regulation Market Transformation," Kleinman Center for Energy Policy, University of Pennsylvania School of Design, July 27, 2017

⁹ Salles, Mauricio BC, et al. "Potential Arbitrage Revenue of Energy Storage Systems in PJM." *Energies* 10.8 (2017): 1100.

4.2 FACILITY/SITE ASSUMPTIONS AND INITIAL CONDITIONS

As a result of the economic modeling effort, three different storage system solutions were evaluated in the reliability analysis. Figure 1 depicts the MPS-i-250, which was selected as a modular building block that could be co-located with critical loads requiring ride-thru to replace 250kVA UPS installations.

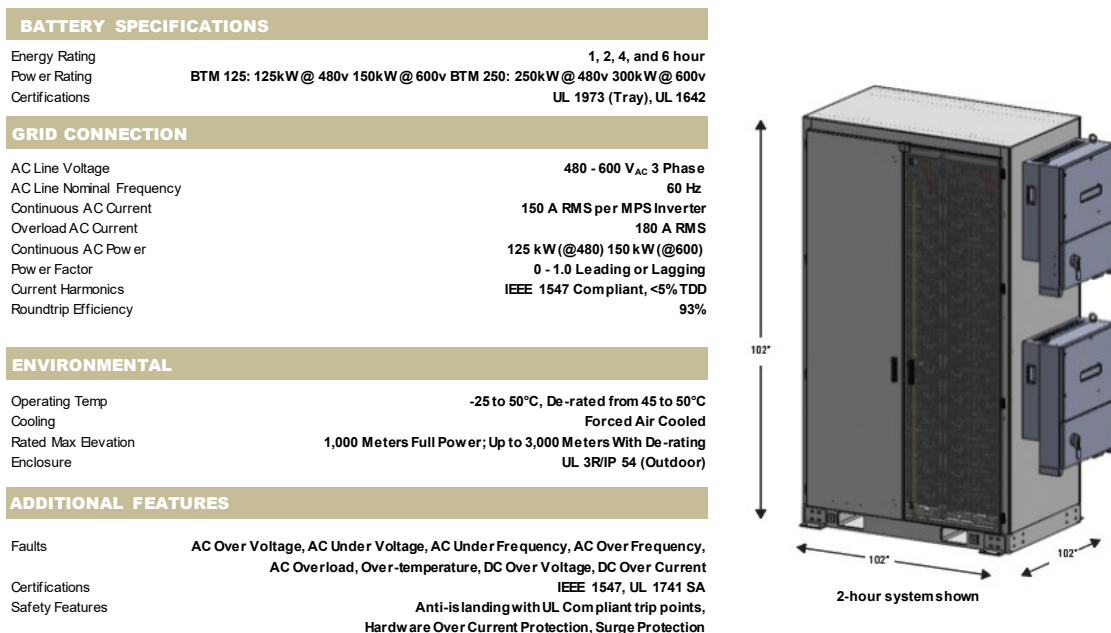


Figure 1. MPS-i-250 Energy Storage System

Figure 2 depicts the CPS-i-3000, which, along with its half-size version (CPS-i-1500) was evaluated for the larger proposed energy storage installations.

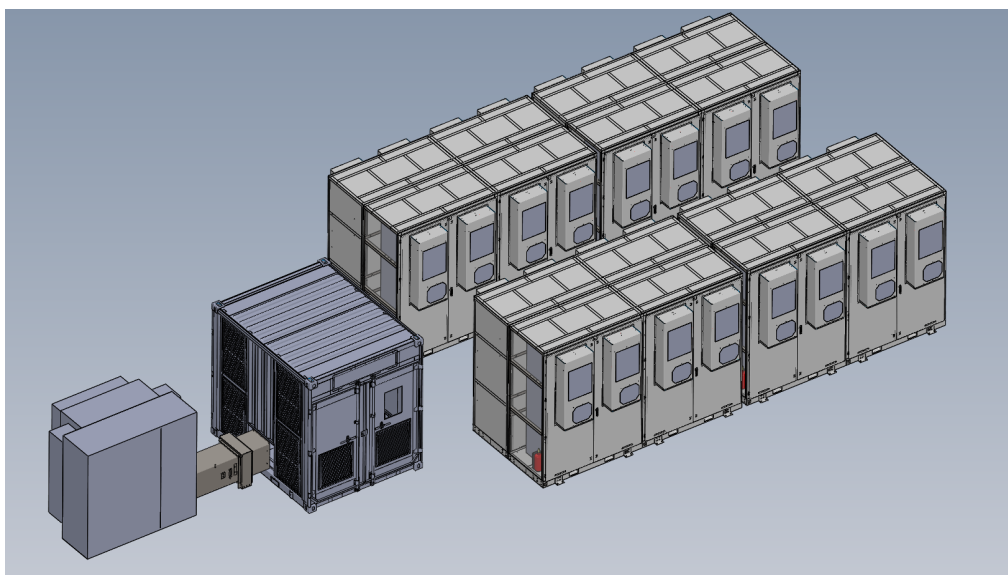


Figure 2. CPS-i-3000 Energy Storage System

Both of these systems are fully integrated, using battery supplier (Samsung for MPS-i-250, LG Chem for CPS-i models) battery racks and BMS, and DynaPower inverters and integrating controllers. Battery racks are air cooled by redundant HVAC units, improving reliability. Each battery has a lifespan of 2500 full depth of discharge cycles from 0 to 100% SoC with average round trip efficiency of 90%.

Operations and maintenance costs for these systems were taken from a recently issued O&M contract on a \$/kW-year basis. The O&M costs considered quarterly site visits (with routine inspection and testing), 5 and 10 year overhaul visits, preventative maintenance and downtime prevention spares, remote monitoring, a 10 year warranty, and a 95% availability guarantee.

Reliability for these units is difficult to quantify due to a lack of well documented field data for fully integrated systems. DynaPower warranty claim data on 450MW of fielded equipment indicates a failure rate of 0.05/MW-year. For a 3MW system like the CPS-i-3000, this equates to a mean time to failure (MTTF) of 6.67 years, or 58,400 hours. This failure rate is lower than the literature predictions for complete Li-ion ESS, but this maybe the result of including a mix of inverter-only and integrated energy storage system products. For integrate Li-ion energy storage, Chatzinikolaou et al. indicates converter MTTFs 31,125hrs (1MW) and Li-ion battery string MTTFs (1MWh) between 1468 and 4255hrs, dependent on design specifics¹⁰. The converter MTTF value is significantly lower than DynaPower's field data. Chatzinikolaou's battery string failure rates suggest that converter reliability could be skewing the DynaPower data. Arifujjaman predicts ESS MTBF as high as 8 years for a 1MW/500kW Li-ion battery for frequency regulation application¹¹. In both the Chatzinikolaou and Arifujjaman's papers, the calculated MTTF and MTBF are very design specific. Replicating either reliability calculation would require design details that are not currently available. Therefore, a mid-range value of 1895hrs taken from reference 9 was used in the reliability analysis, and a sensitivity analysis was performed sensitivity of system performance to ESS MTTF/MTBF. As will be shown in the reliability analysis (Section 6.1), the strategy of dividing the total ESS capacity into multiple units can mitigate the possibility of ESS failures due to insufficient MTTF/MTBF.

The following figures depict the microgrid configurations considered for each installation. Two configurations are shown: baseline, and "energy storage enhanced". Multiple "energy storage enhanced" options were analyzed varying storage size, duration, and number of units. The configuration shown reflects the result of the storage size and duration optimization analysis. The number of units used to comprise the total storage was selected to improve reliability and enable straightforward UPS elimination.

¹⁰ Chatzinikolaou, Efstratios and Rogers, Daniel J. "A Comparison of Grid-Connected Battery Energy Storage System Designs". IEEE Transactions on Power Electronics, 6913. September 2017.

¹¹ Arifujjaman, Md. "A comprehensive power loss, efficiency, reliability and cost calculation of a 1 MW/500 kWh battery based energy storage system for frequency regulation application". Elsevier. pp. 158-169. 24 April 2014.

Fort Bliss

Figure 3 depicts the configuration for Fort Bliss. The economic analysis did not favor the use of large quantities of energy storage at Fort Bliss on market participation grounds, and as such the optimum configuration included a small amount of energy storage (1700kW / 1hr). The total energy storage size was not sufficient to eliminate any of the 2000kVA UPS. However, including the storage did allow the elimination of 1 diesel generator.

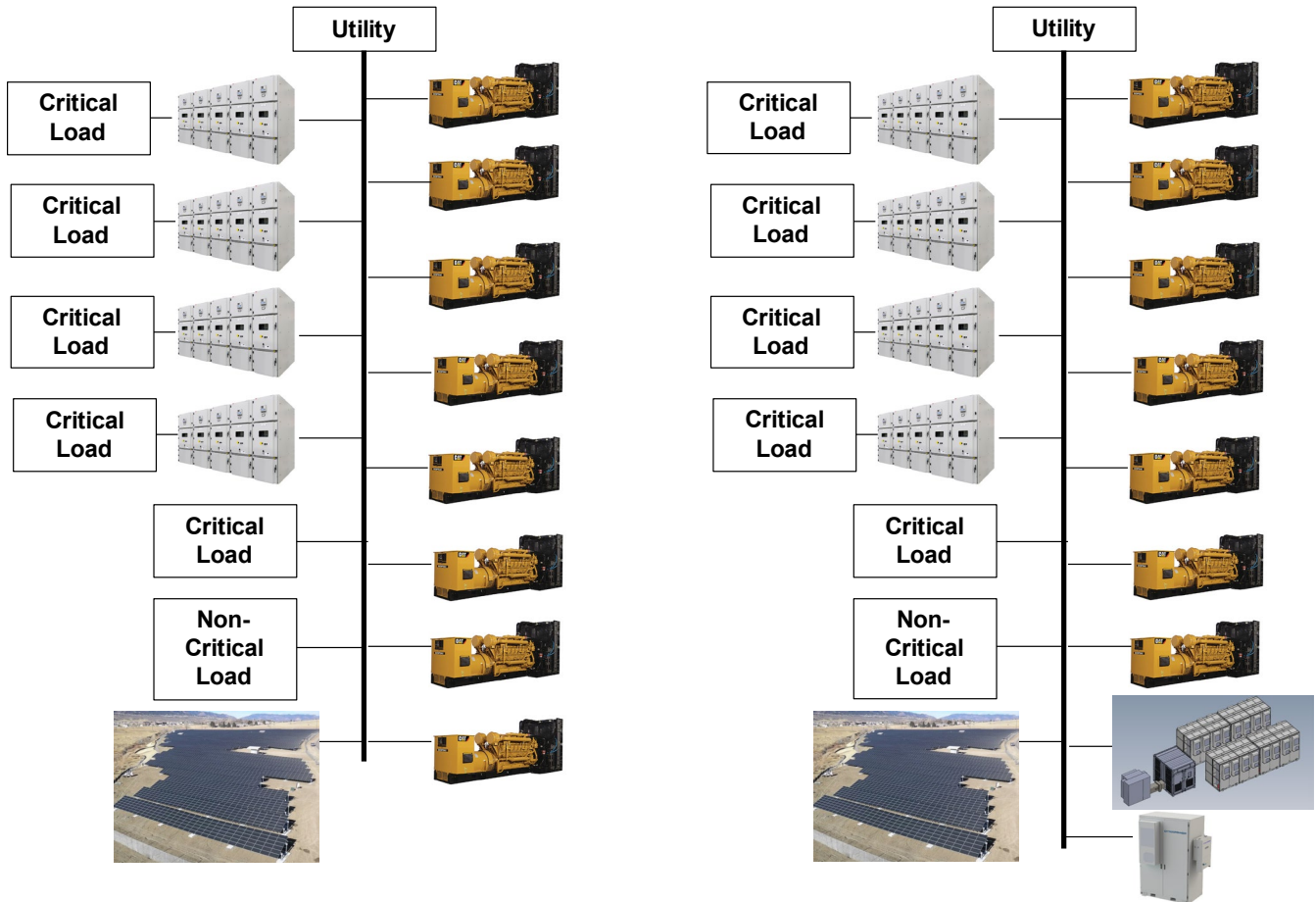


Figure 3. Baseline and Energy Storage Enhanced Microgrid for Fort Bliss

Holloman AFB

Figure 4 depicts the configuration for Holloman AFB. The economic analysis at Holloman was more favorable than Fort Bliss and resulted in an ESS sizing that was smaller than the peak critical load that requires ride-thru (2400kW vs. 3000kW). 9 of the 15 total 250kVA UPSs were replaced by 250kW ESSs in this design concept, leaving 4 UPS. The reliability analysis predicts that 2 diesel generators can be removed, which improved the economics.

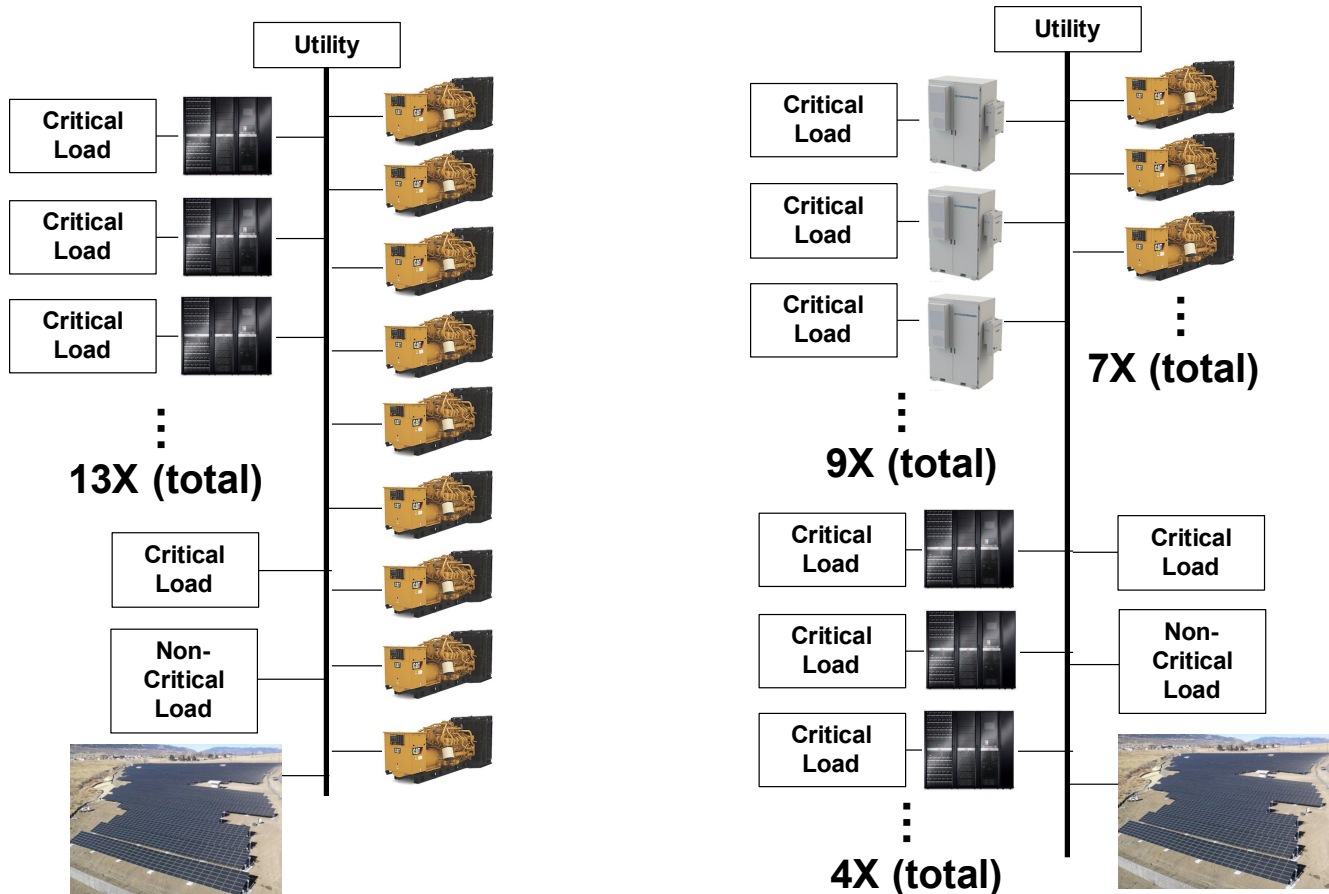


Figure 4. Baseline and Energy Storage Enhanced Microgrid for Holloman AFB

March ARB

Figure 5 depicts the configuration for March ARB. The economic analysis at March ARB resulted in an ESS sizing that was larger than the peak critical load that requires ride-thru (2400kW vs. 350kW). All 3 for the 250kVA UPSs were replaced by 250kW ESSs, complemented by additional 250kW and 1500kW units. The reliability analysis predicts that 1 diesel generator can be removed, which further improved the economics.

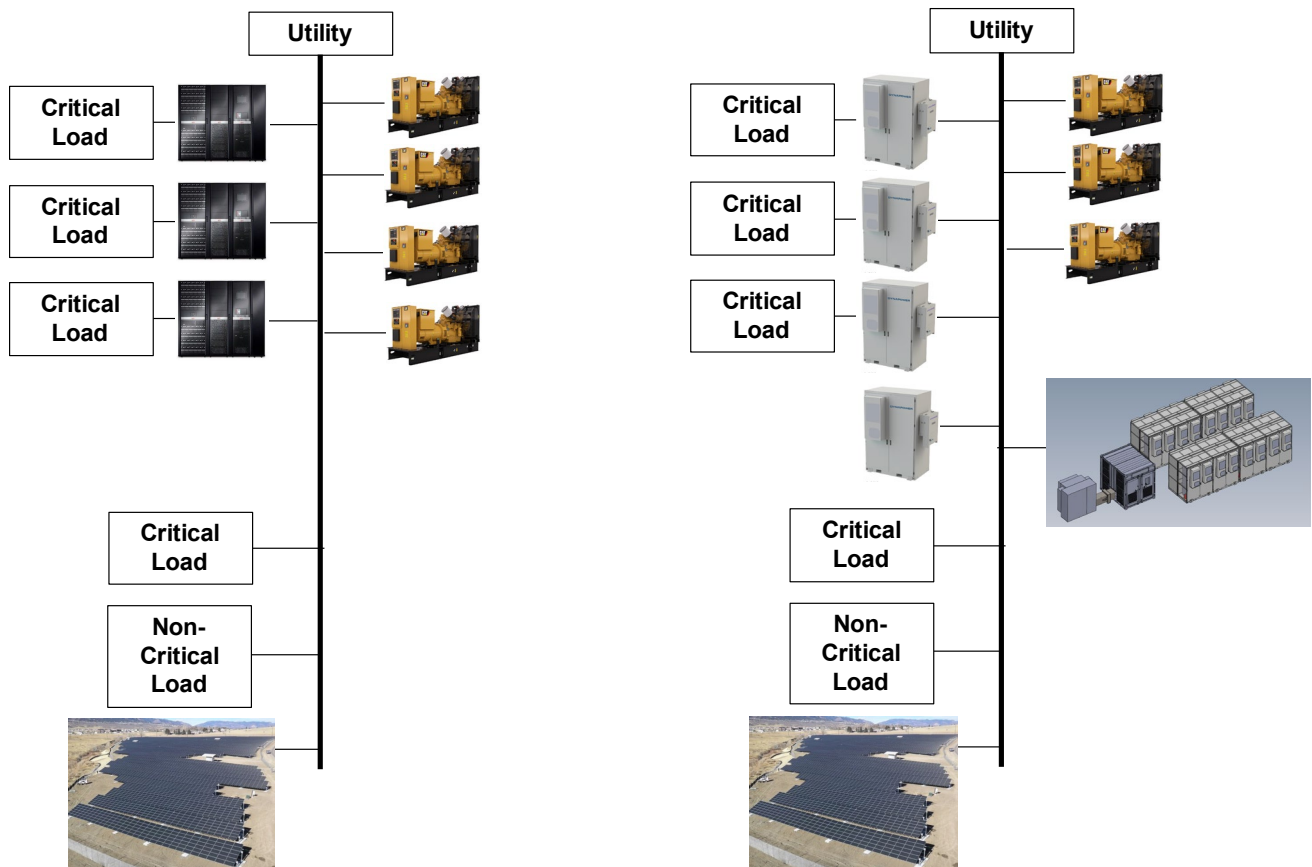


Figure 5. Baseline and Energy Storage Enhanced Microgrid for March ARB

NAS Pax River

Figure 6 depicts the configuration for NAS Pax River. The economic analysis at NAS Pax River resulted in an ESS sizing that was substantially larger than the peak critical load that requires ride-thru (29400kW vs. 4000kW). All 17 of the 250kVA UPSs were replaced by 250kW ESSs, and a 25MW large scale energy storage (8x 3000kW) unit was also included. The reliability analysis predicts that 2 diesel generators can be removed, which improved the economics. At ESTCP's request, an alternate configuration was also analyzed with 3MW of energy storage. This system could be implemented by replacing 12 of 17 UPSs with 250kW ESSs.

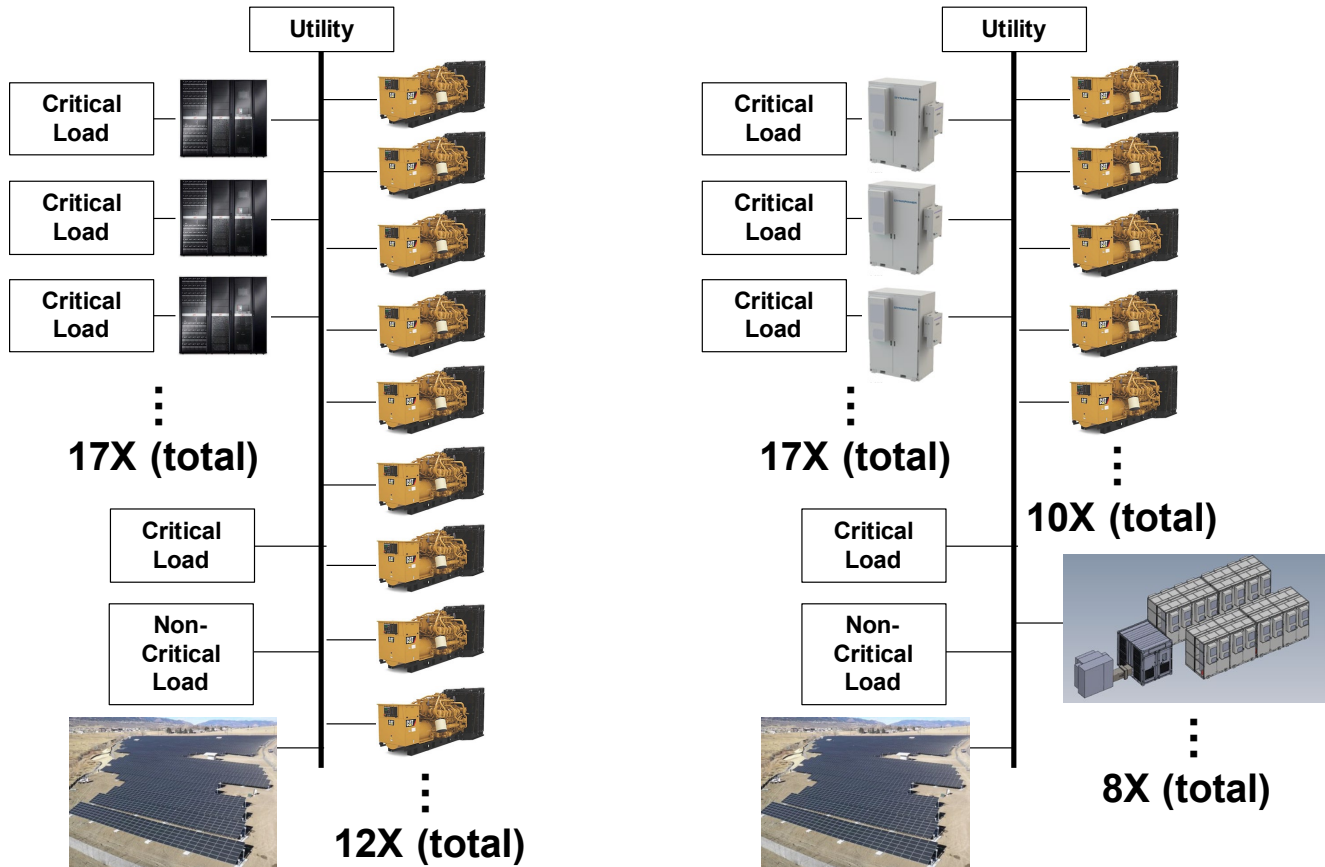


Figure 6. Baseline and Energy Storage Enhanced Microgrid for NAS Pax River

Naval Base Ventura

Figure 7 depicts the configuration for Naval Base (NB) Ventura. The economic analysis at NB Ventura resulted in an ESS sizing that was incrementally larger than the peak critical load that requires ride-thru (2500kW vs. 2250kW). All 9 of the 250kVA UPSs were replaced by 250kW ESSs, and one additional 250kW ESS was also included. The reliability analysis predicts that 1 diesel generator can be removed, which improved the economics.

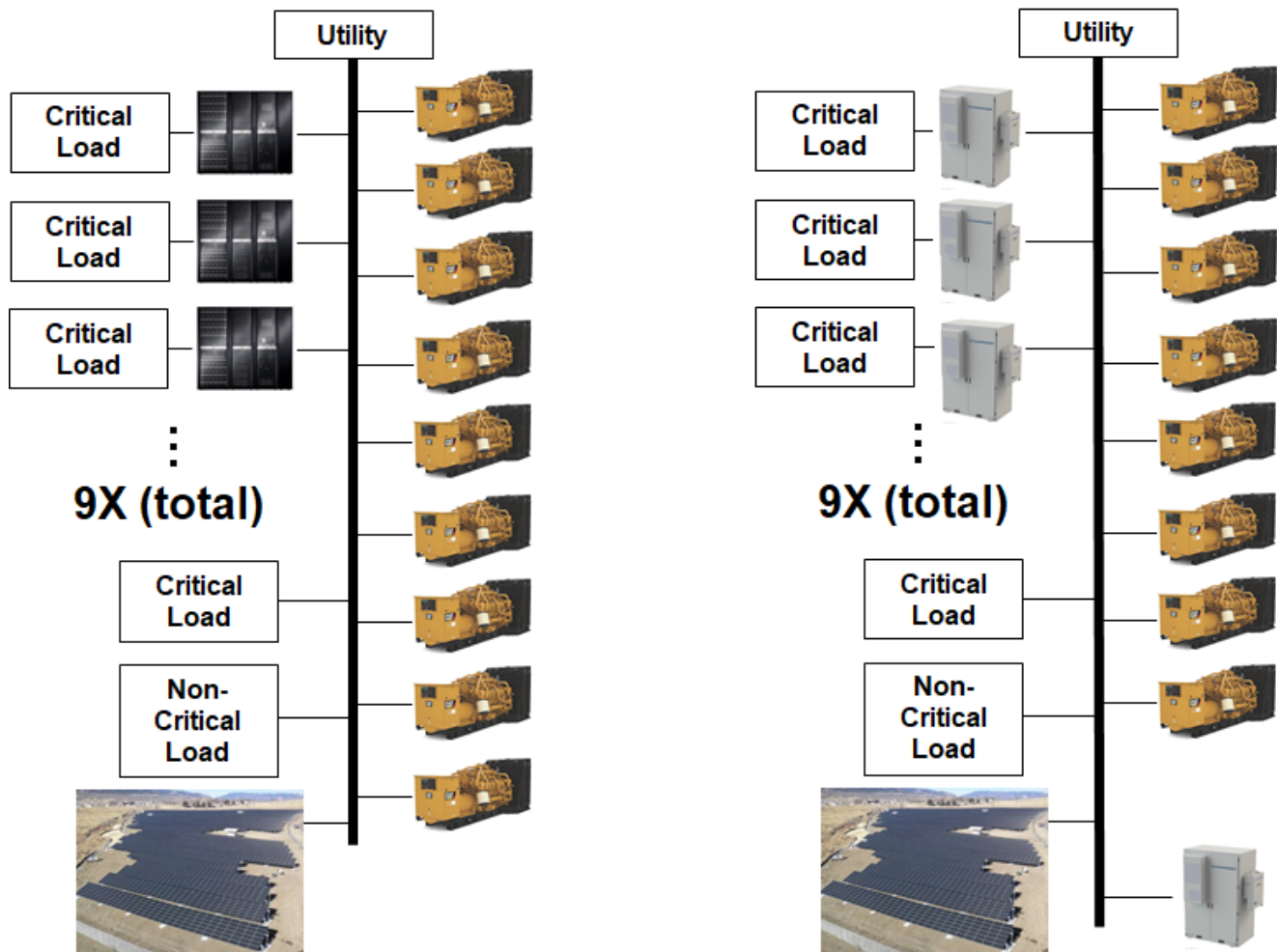


Figure 7. Baseline and Energy Storage Enhanced Microgrid for Naval Base Ventura

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5.0 METHODOLOGY

5.1 CONCEPTUAL METHODOLOGY

The overall methodology taken for the techno-economic and reliability analysis is shown in Figure 8. First, techno-economic analysis was performed to determine the optimal size and duration of the energy storage by considering various combinations of grid-tied use cases. The analysis was done by Customized Energy Solutions (CES) using their Competitive Market Evaluation Tools for Storage (CoMETS) tool and ESTCP-provided inputs. ESS parameters were specified as noted in Section 4.2.

Once the total economically optimal size and duration of the storage was known, reliability analysis was conducted to evaluate the 100% critical load coverage probability for a single ESS configuration with MTBF = 1895hrs. A dispatch strategy was implemented within the model to use energy storage to minimize the number of diesel generators required to support a particular islanding duration. Numerous cases were run varying ESS size from 1/4 – 4x the economic optimum, and duration from 1 to 6 hours. These analyses were performed for configurations eliminating 1-3 diesel generators. The results of these analyses determined the number of diesel generators to remove for each installation. They also assessed whether deviations from the economically optimized configuration (size or duration) were merited on reliability improvement grounds by cost effectively enabling elimination of additional generators or UPS.

With the optimized storage and number of diesel generators determined, additional cases were run with varying energy storage MTBF (for a single ESS configuration) and with total energy storage capacity broken into up to 5 modular units. These analyses were used to understand the impact of varying ESS MTBF, and to evaluate the reliability impact of breaking the storage into multiple units.

Based on these outcomes, the “energy storage enhanced” configurations shown in Figures 3-7 were determined. When possible, we used multiple ESS units as direct replacements for existing UPS and would be co-located with critical load requiring ride-thru. We chose this approach because it maximizes the chance that our UPS replacement approach would be feasible in a real system, and because it results in a microgrid design that is inherently more flexible and scalable than using a single, large ESS. It is important to note that this approach works because of PXiSE’s unique control technology, which allows precise control of these numerous small ESS units. Once all UPS were replaced, the remainder of the energy storage was implemented using larger ESS unit(s).

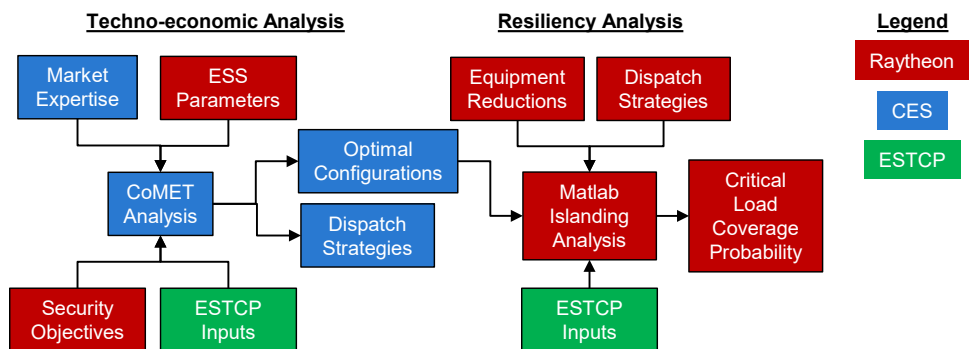


Figure 8. Overall Methodology Used to Perform Analysis

5.2 REVIEW OF BASELINE MICROGRID MODELING

5.2.1 Reliability Analysis

The goal of our baseline modeling was to match the data provided by ESTCP, ensuring that our model was consistent. As exemplified by the NAS Pax River results in Figure 9, when modeling the peak critical load profile we were able to reproduce the provided results precisely. However, when modeling the variable load profile our results vary from that provided by ESTCP. After investigation, we determined that the differences stem from the way the two simulations treat situations where generator supported critical load reduces with increasing duration. Our method assumed the number of generators required at any duration “d” was the maximum required to reach that duration. The ESTCP method assumed the number of generators required at any duration “d” was based on the critical load at that time step. However, the ESTCP method also included the cumulative probability of successfully reaching that time step, whereas our approach did not. The net effect is that the ESTCP predicts higher probability due to time steps where the required number of generators are reduced which our analysis does not take credit for. Figure 9 also shows variable load results that are typical, as our model consistently under-predicted the ESTCP provided results. Additional baseline performance comparisons are shown in Appendix A3.

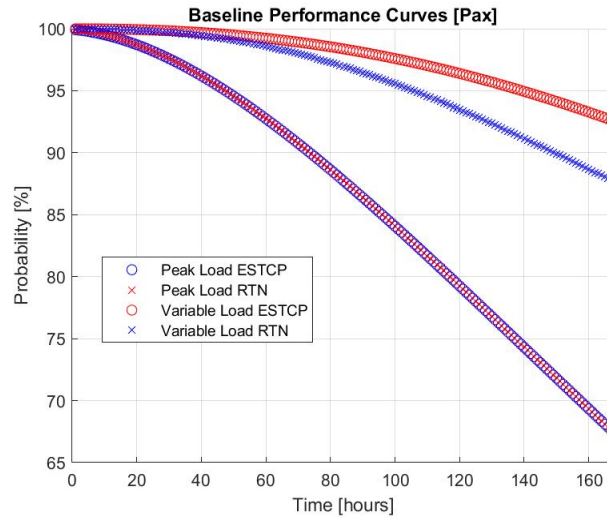


Figure 9. NAS Pax River Baseline Reliability Results

5.2.2 Techno-economic Analysis

The CES|CoMETs focuses on the economic benefits of storage-enabled installations. To this end, the techno-economic analysis performed using CES|CoMETs focused on analyzing the benefits of storage by comparing the benefit-to-cost ratio of adding storage to the provided baseline microgrid analysis. We therefore did not replicate the ESTCP-provided baseline, but did use the provided outcomes (see Table 2, Table 20 columns A-E) in our storage enhanced microgrid analysis. We assumed that solar PV was a sunk cost, as it either already existed at the site, or would be built as a standalone project on its own financial merits independent of the microgrid.

5.3 STORAGE-ENABLED MICROGRID MODELING

5.3.1 Reliability Modeling

In order to properly align with the baseline provided by ESTCP, our storage-enabled microgrid reliability modeling utilized a modified version of the methodology provided in the white paper “Calculating the Reliability of a Backup System¹²”. ESTCP guidance provided in “Emergency Diesel Generator Reliability for ESTCP Modeling¹³” and “PV System Reliability for ESTCP Modeling¹⁴” established the probability of failure to start and probability of failure to run using the provided mean time between failure (MTBF) for diesel generators and solar PV.

There were two methods by which energy storage increased reliability in our model. First, energy storage dispatch logic was set to minimize the number of generators that are needed to support the critical load for any given outage duration. For each time step the model would assess whether the energy storage possessed the power and energy capability to reduce the number of required generators for that hour. If it did, storage was deployed to maintain the number of required generators at or below that of the prior time step. The fewer generators required to maintain load coverage probability for a particular duration outage, the higher the load coverage probability. The above dispatch logic also provided the benefit of reducing generator runtime. By running the generators for less hours, the probability of having more generators available for longer duration outages is improved.

A key assumption that drove the model was that during a given hour of the outage the required load could be supplied by the available generation online regardless of required ramp rate or renewable penetration. This condition allowed for quick charging of the energy storage when it did not have sufficient energy to reduce the number of generators, and full utilization of all available PV production for all time steps where ESS SoC was below 100%. It is important to note that these assumptions necessitate a grid forming inverter-based microgrid design. Diesel microgrids cannot accommodate high penetration renewables with the possibility of reverse power flow, and are sensitive to high ramp rate transients (e.g., passing clouds).

To incorporate energy storage into the model we had to determine proper way of calculating and including its reliability similar to what ESTCP had provided in the aforementioned white paper for the diesel generator-only configuration. We determined that energy storage reliability would be modeled in the same manner as the diesel generators using matrices of probabilities rather than running a separate Monte Carlo. Using this method we created a separate matrix for energy storage reliability and combined the probabilities as independent variables occurring at the same time. It was determined that the probabilities were independent because the failure of a generator does not affect the failure of the energy storage. Potential energy storage failures therefore impacted any time step where energy storage was used to reduce the number of generators. We assumed an MTBF of 1895 hours as a mid-range value for MW-scale, 1hr duration Li-ion storage based on literature¹⁵, see Section 4.2 for additional information on energy storage reliability.

¹² Ericson, S. “Calculating the Reliability of a Back-up Power System,” 6 May 2019

¹³ “Emergency Diesel Generator Reliability for ESTCP Modeling”, 4 April, 2019

¹⁴ “PV System Reliability for ESTCP Modeling, 3 April, 2019

¹⁵ Chatzinikolaou, E and Rogers, D.J, “A Comparison of Grid-Connected Battery Energy Storage System Designs,” IEEE Transactions on Power Electronics, Vol 32, No. 9, 9 Sept 2017

5.3.2 Techno-economic Analysis

Building on the baseline microgrid analysis ICF performed, we investigated how adding energy storage to the microgrid could enhance reliability or maintain similar reliability level at a lower cost by allowing the energy storage to provide other economic services. Similar to allowing the diesel generators to provide emergency demand response and peak shaving in the baseline cases, the energy storage assets were modeled to provide a variety of site-related or wholesale energy market services to improve the return on such investment. Solar photovoltaic systems are installed at the sites and considered as part of the microgrids. However, their sizes are small relative to the loads and all solar generation was assumed to directly offset the load. The net load (load – solar generation) was therefore used in the analysis. Additional inputs and modeling assumptions are documented in Appendix A4.

As the example shown in Table 4, the net cost of protecting peak critical load at Holloman AFB in the baseline case was \$98/kW ($A+B+C+D = E$) whereas the net cost was reduced to \$53/kW ($E+F+G+H+I = J$) with the storage-enabled microgrid. The reduction was two-fold: capital and operational costs of some diesel and UPS units were eliminated because the proposed energy storage system can replace the diesel and UPS in its bridging functionality in the islanded mode, and the additional site-related savings and wholesale revenues energy storage system could bring in.

Table 4. Comparison of Contributors to Net Cost of Microgrid

Holloman AFB	Peak Critical Load (kW)	Diesel Gensets (A)	UPS (B)	Microgrid (C)	DR & Peak Shaving Savings (D)	Annual Net Cost of Protecting each KW of Peak Critical Load (E)	Energy Storage (F)	DCM & Wholesale Revenues (G)	Diesel Genset Considered Obsolete because of Storage (H)	UPS Considered Obsolete because of Storage (I)	Annual Net Cost of Protecting each KW of Peak Critical Load with Storage (J)
Baseline Microgrid	5996	\$49	\$22	\$36	(\$10)	\$98	N/A	N/A	N/A	N/A	N/A
Storage-enabled Microgrid	5996	\$49	\$22	\$36	(\$10)	\$98	\$33	(\$51)	(\$11)	(\$16)	\$53

CES's proprietary modeling suite CES|CoMETS (Competitive Market Evaluation Tools for Storage) was used to conduct the economic benefits analyses. CES|CoMETS has been utilized extensively in analyzing storage projects across the U.S. for commercial developers. A full list of customers can be found in Appendix A2. A brief description of the method is as follows

Step 1: Based on the load duration curve of each site, a storage system configuration was chosen as a starting point for the analysis. The load duration curve was constructed by ranking the hourly load of the site. If there is a sharp tip at the beginning of the curve, meaning that the load is “peaky”, the site is usually a good candidate for installing storage for demand charge management purposes.

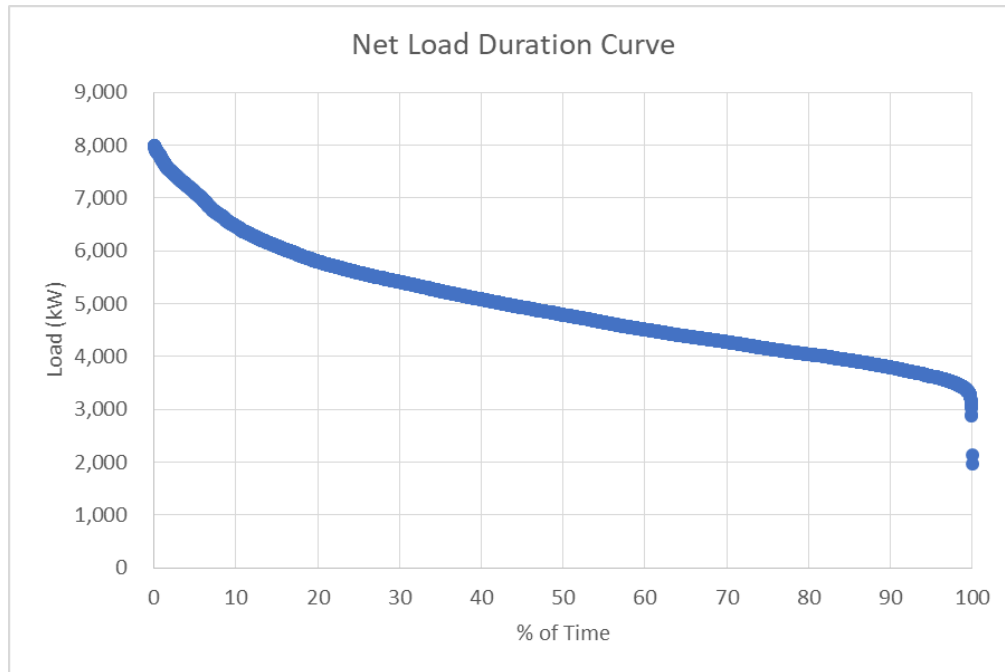


Figure 10. Sample Net Load Duration Curve from Site

Step 2: With load profile, utility tariff, and wholesale market prices as inputs, CoMETS examined the inputs for each of the 8760 hours in a year to determine how the storage system should be used. It prioritized the most valuable services, which were demand charge management and retail energy arbitrage for most sites. When the storage was not being used for these services, it could be utilized in the wholesale market (if applicable) or for any other facility/utility services to try to earn more revenue.

Step 3: The annual revenue was calculated once the optimal combination of services were determined for each hour. CoMETS kept track of the State-of-Charge (SoC) of the storage system to ensure that the suggested service for the next hour was possible. If there was not sufficient energy or head room to charge in the storage, CoMETS would reduce the projected revenues proportionally. The revenue for the subsequent 20 years were calculated based on inflation or price forecasts of each service. The financial details and a net present value (NPV) were calculated from the annual revenues (see Figure 11 and Figure 12).

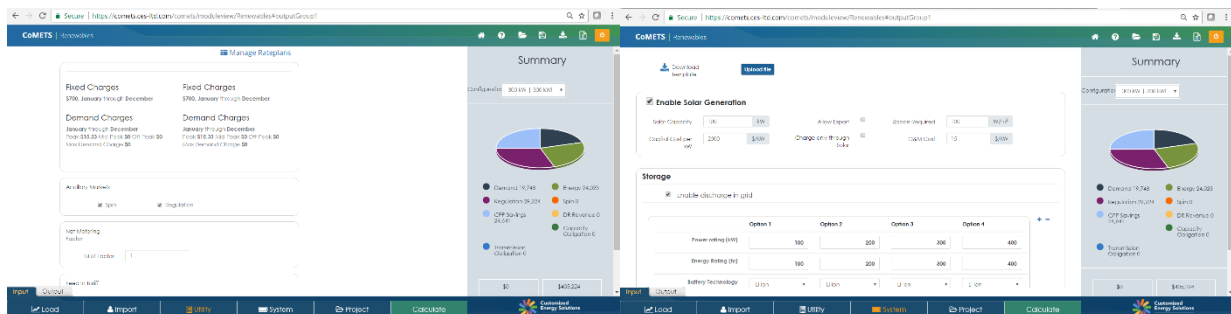


Figure 11. Sample Inputs for CoMETS BTM Module

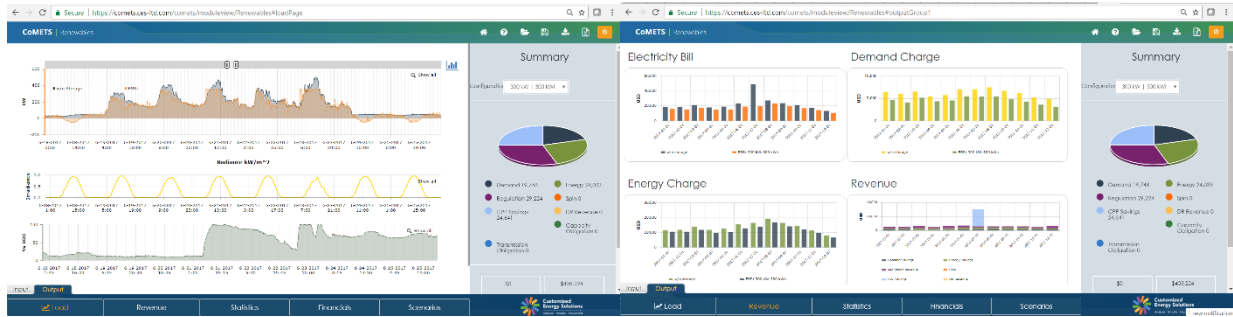


Figure 12. Sample Outputs for CoMETS BTM Module

Step 4: The analyses in steps 2 and 3 were iterated with a different storage configuration in either power or duration or a different price scenario. Multiple storage configurations and price scenarios were analyzed. The resulting NPVs were listed together to determine the optimal storage configuration for the site. Moreover, to ensure the site reliability functions are met with the storage systems, a 33% additional energy was added to the cost of the storage system. In other words, the storage system was assumed to operate in an SOC range of 25% to 100%.

In the economic benefit analysis for storage, various services the energy storage can provide were considered. Table 5 summarizes the services considered and how they were applicable for each site. For example, while PJM allows participation in the Frequency Regulation market from behind-the-meter storage resources, the CAISO does not. Revenues from Frequency Regulation were therefore not considered for the PDR case for March ARB and NB Ventura County located within the CAISO territory. The details of the services are described later in section 7.1.

Table 5. Energy Storage Services for Each Site

Grid Domain	Service	Applicable Bases
Site-related Services	Demand charge management	S1. Holloman AFB S2. March ARB S5. NAS Patuxent River S6. NB Ventura County S7. Fort Bliss
	Retail energy arbitrage	S1. Holloman AFB S2. March ARB S6. NB Ventura County S7. Fort Bliss
	Utility demand response program	S1. Holloman AFB S2. March ARB S5. NAS Patuxent River S6. NB Ventura County
Wholesale Market Services	Wholesale energy arbitrage	S2. March ARB (CAISO) S5. NAS Patuxent River (PJM) S6. NB Ventura County (CAISO)
	Frequency regulation	S5. NAS Patuxent River (PJM)
	Spinning reserve	S2. March ARB (CAISO) S5. NAS Patuxent River (PJM) S6. NB Ventura County (CAISO)

ESTCP project EW-201606 utilized Controller Hardware-in-the-Loop (C-HIL) testing of the Otis Air National Guard Base (ANGB) microgrid to support development and integration of microgrid controls. The C-HIL model, and some of the control hardware used for this testing was leveraged in this project to allow testing of PXiSE's Active Control Technology (ACT) microgrid controls. In coordination with MIT-LL, EW-201606 developed a test plan to address IEEE 2030.8-2018 IEEE Standard for the Testing of Microgrid Controllers¹⁶ requirements. A subset of the tests defined in this plan were run to demonstrate specific functionality that was enabled by the PXiSE ACT controls. Tested microgrid operations included steady-state islanding, unplanned islanding, grid reconnection, and grid-tied operations. Testing was performed using measured variable load and wind turbine generation profiles.

Single-line diagram of a power system for a study on a high-speed disconnect. The diagram shows a 24.9 kV Bourne Feeder connected to a bus with a 751A SEL circuit breaker. A Phasor Measurement Unit (PMU) is located at bus 1, which is also the location of a high-speed disconnect. A transformer connects bus 1 to bus 2, which is connected to two ESS units. Another transformer connects bus 1 to bus 4, which is connected to a Wind Turbine. A third transformer connects bus 1 to bus 6, which is connected to a 1.3 MVA Genset and a Critical Load. A fourth transformer connects bus 1 to bus 5, which is connected to an East Feeder Load. A legend identifies symbols for Power Meter, PMU, Transformer, Inverter, and Genset.

¹⁶ IEEE 2030.8-2018 IEEE Standard for the Testing of Microgrid Controllers

The second change was to ensure that the relay data that was being modeled could be converted to phasor data that was required by IEEE C37.118 IEEE Standard for Synchrophasor Measurements and Communication¹⁷ and sent to the PXiSE ACT. Per the C37.118 IEEE standard, this data should be sent to PXiSE ACT using the native C37.118 protocol to fully use the high-speed control capabilities of the PXiSE ACT controller. However, due to limitations with the current relay simulation capabilities within the Typhoon modeling environment, we elected to send data via a Modbus/TCP connection. We note that improved C37.118 modeling capability is being introduced in Q4 2019 and would be used in any future testing.

¹⁷ IEEE C37.118 IEEE Standard for Synchrophasor Measurements and Communication

6.0 PERFORMANCE ASSESSMENT

6.1 RELIABILITY ASSESSMENT

Reliability assessment was performed for each installation to evaluate the impact of Energy Storage (ES) size (kW), duration (number of hours of charge / discharge capability at rated kW size), number of ESS units, and MTBF on probability of critical load coverage with 1, 2 and (if appropriate) 3 diesel generators removed. Size variations (1/4 to 4x) were performed about the nominal economically optimized value determined by CES. Durations of 1-6 hours were considered. Number of ESS units were varied from 1-5 to comprise the total nominal storage size (kW) determined by CES for the optimal duration (kWh).

NAS Patuxent River

Figure 14 shows the impact of varying size and duration when removing 1 diesel generator. All considered sizes provide acceptable results with an ESS MTBF of 1895hrs and duration of 1hr. This indicates that economically optimized storage size is larger than is required for reliable operation with “N-1” generators and therefore SoC can be as low as 25% at the beginning of the outage. Increasing duration from 1-6 hours had a minimal effect. Note that the drop in reliability at the beginning of the outage is caused by energy storage failures when attempting to reduce the number of required generators.

In the early time steps of the simulation, the dispatch control logic employs the energy storage to a greater extent in an attempt to minimize the number of diesel generators required to obtain a particular islanding duration. When energy storage is dispatched, critical load coverage probability is determined by multiplying the probability the required number of diesel generators are operating with the probability the dispatched storage is operating. As run time increases, probability of failure to run goes up for both the diesels and energy storage, causing the critical load coverage probability to drop. As the required number of generators increases to its maximum for the total outage, storage is used less frequently and becomes less of a factor in total critical load coverage probability.

This effect goes away when the number of required generators has increased to the point where energy storage plays a significantly reduced role. This effect can be mitigated by increasing the ESS MTBF, or by dividing the ESS capacity into multiple smaller units that provide graceful degradation. This is illustrated in Figure 17.

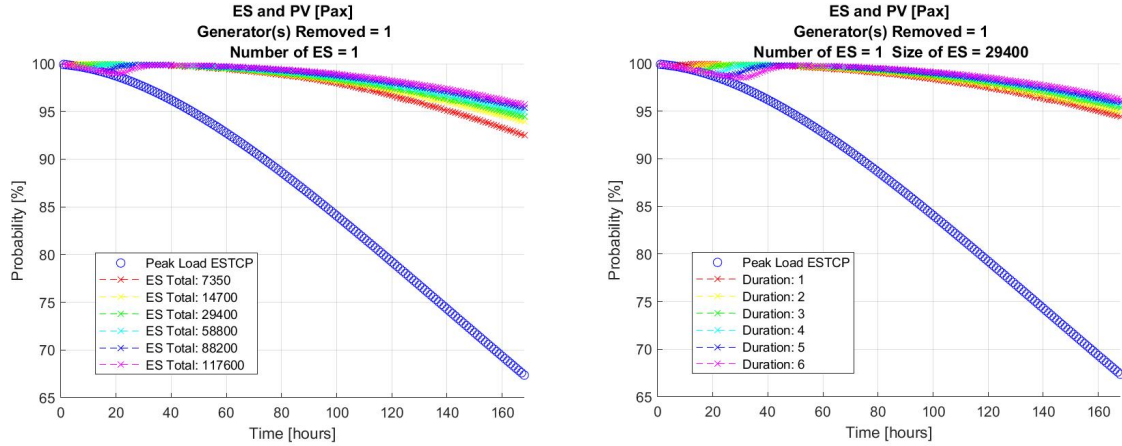


Figure 14. NAS Pax River Reliability Results – “N” Generators, Varying Size and Duration

Figure 15 shows the impact of varying size and duration when removing 2 diesel generators. ESS duration and MTBF are held constant with prior results. Reliability is reduced vs. “N” generators, but all considered sizes again provide acceptable results. Similarly, increasing duration from 1-6 hours once again had minimal effect. In addition to the results shown in Figure 15, we performed analyses of the NAS Pax River system with a 3MW energy storage system and 2 generators removed. The results showed decreased reliability relative to the 29.4MW system, but still over the ESTCP requirement. These plots are located in Appendix A3.

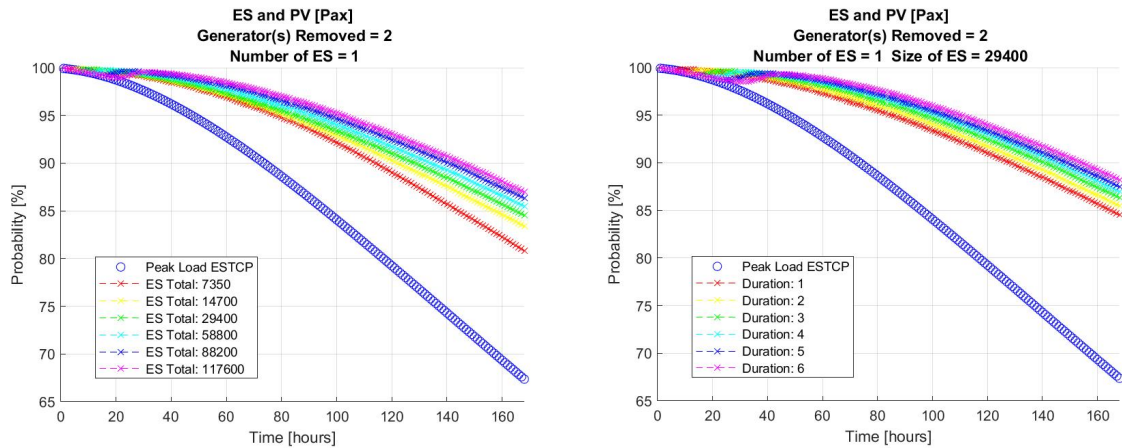


Figure 15. NAS Pax River Reliability Results – “N-1” Generators, Varying Size and Duration

Figure 16 shows the impact of varying size and duration when removing 3 diesel generators. Again, ESS duration and MTBF are held constant. As can be seen, removing a 3rd generator results in excessive failures even if the total storage capacity is doubled relative to the economic optimum. Between 4x and 6x the economic optimum must be used to enable elimination of the 3rd generator. Alternatively, increasing storage duration to >5hr can also enable elimination of the 3rd generator. Therefore, both options require increasing the kWh capacity ~5x that of the economic maximum, which is not economically justifiable or practical.

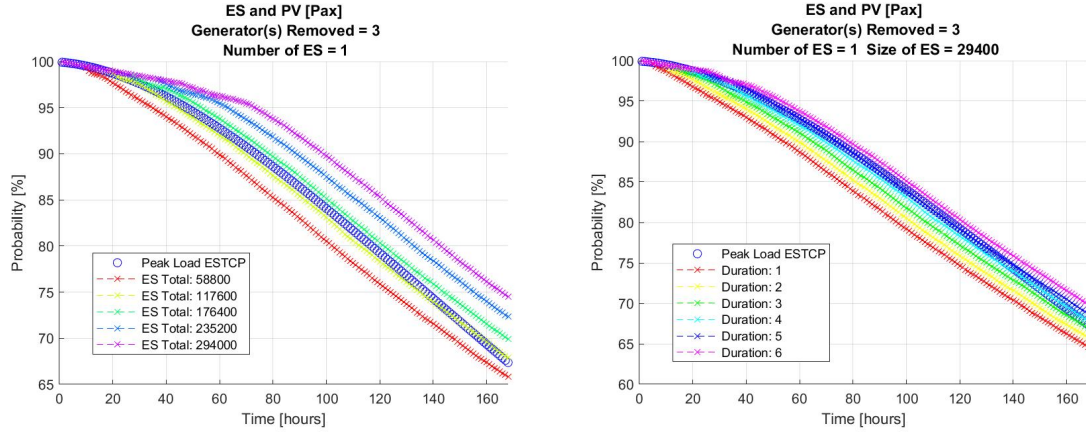


Figure 16. NAS Pax River Reliability Results – “N-2” Generators, Varying Size and Duration

Figure 17 shows the impact of MTBF and the number of storage units that are used to comprise the total energy storage size. As can be seen, when 1 energy storage unit is used with a low MTBF (<2000hrs) it compromises performance early in the simulation by increasing probability of failure when the minimum quantity of generators required is low. This is improved by increasing MTBF, or by dividing the total storage into multiple smaller units.

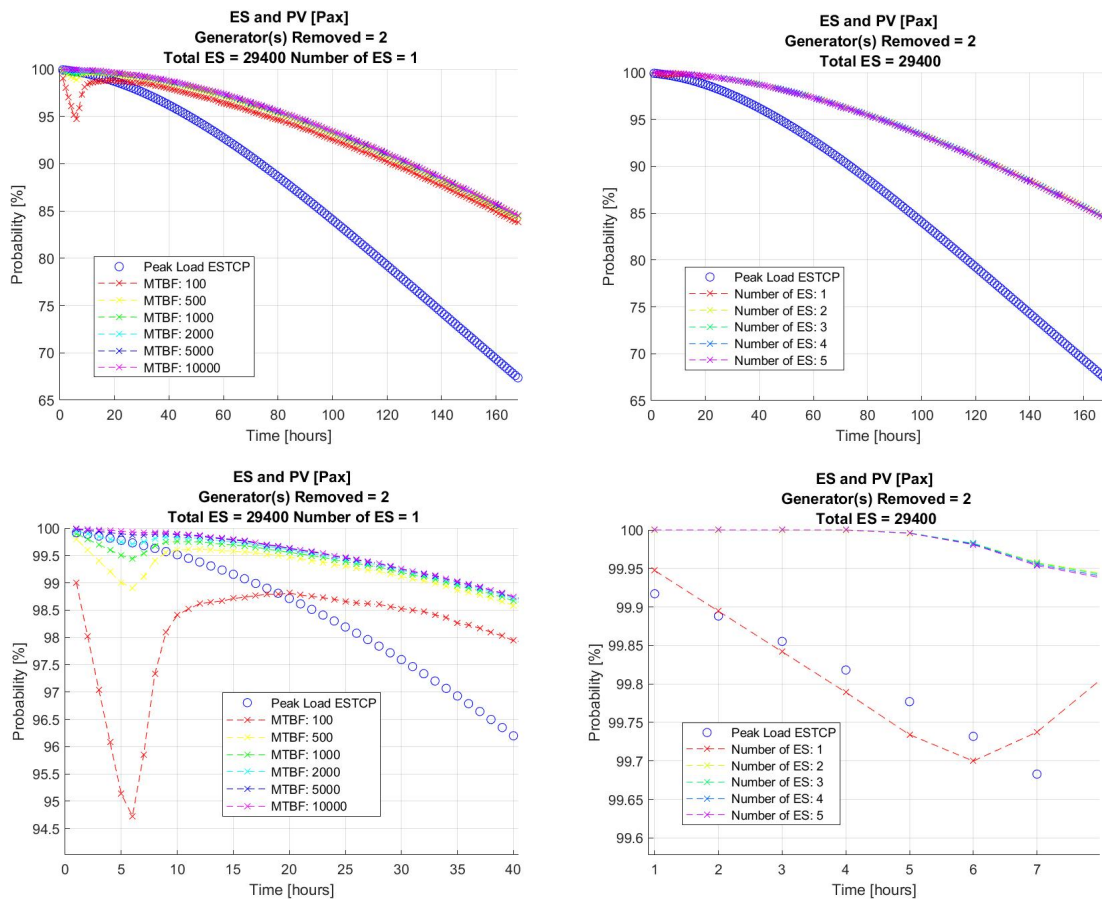


Figure 17. AS Pax River Reliability Results – “N-1” Generators, Varying MTBF and ESS Units

Figure 18 shows reliability performance at 130% of critical load with optimized N-1 (2 generator removed) configuration. The system is able to maintain the critical load coverage probability over the requirement for 3 hours. This limited duration is likely due to the fact that there is generally not enough generation available with N-1 (or fewer) generators given the relatively low production of the solar PV compared to the magnitude of the critical load.

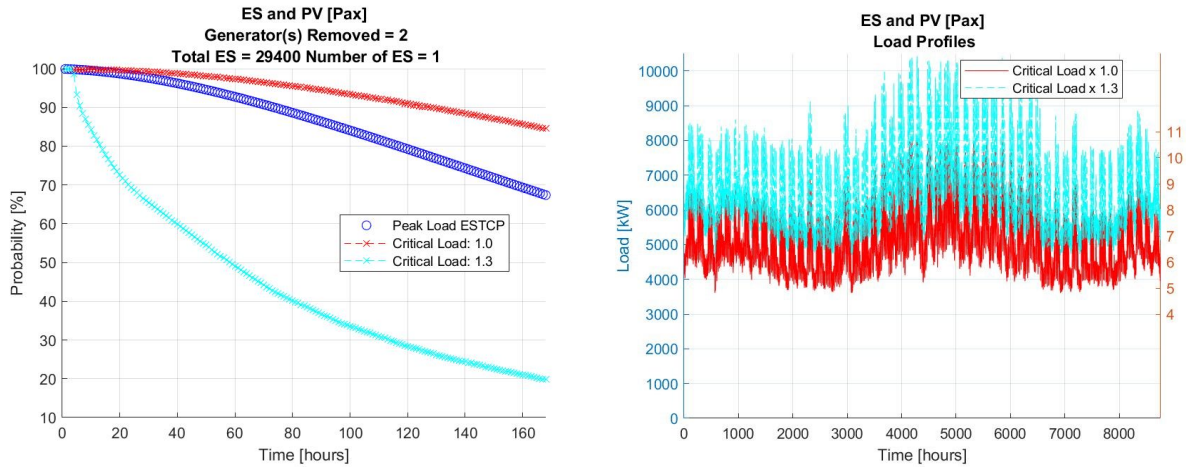


Figure 18. NAS Pax River Reliability Results – “N-1” Generators, 130% Critical Load

Figure 19 shows reliability performance at 10% and 30% of critical load with no diesel generators. The large size of the storage, coupled with adequate solar PV production for the reduced load is able to maintain acceptable load coverage throughout the duration of the outage. The simulation was re-run with a 3MW energy storage system. These plots, located in Appendix A3, showed that the 3MW system can also meet both the 10% and 30% critical load for the full outage duration.

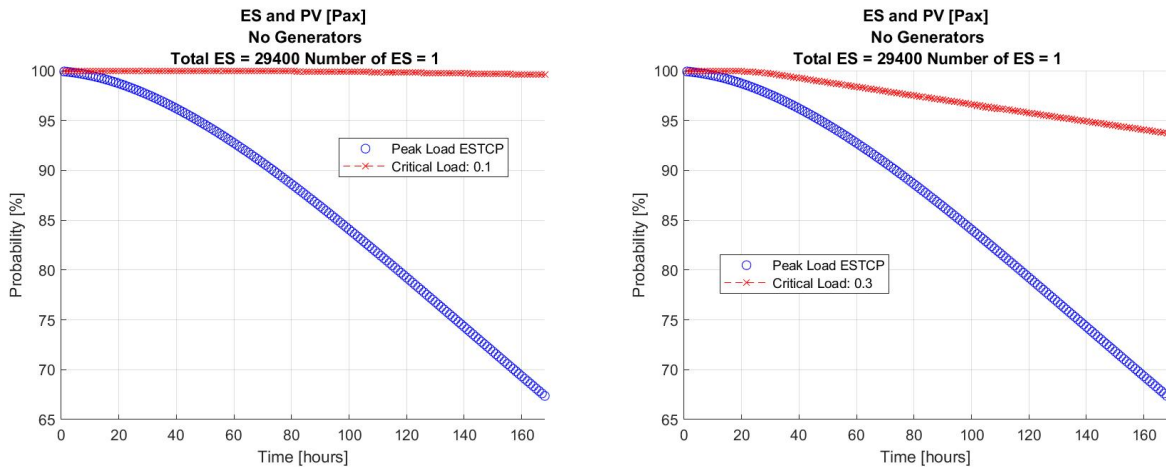


Figure 19. NAS Pax River Reliability Results – No Generators, 10 and 30% Critical Load

Holloman AFB

For Holloman AFB, we determined that we could remove 2 diesel generators and meet the reliability requirement. Figure 20 shows this with varying energy storage size (2hr duration) and duration assuming MTBF = 1895hrs. All considered sizes provide acceptable results, indicating that economically optimized storage size is again large enough to allow 25% SoC at the start of the outage. Increasing duration from 1-6 hours also had a minimal effect. Figures that capture performance with “N” and “N-2” generators, as well as MTBF and varying ESS unit quantities are located in Appendix A3.

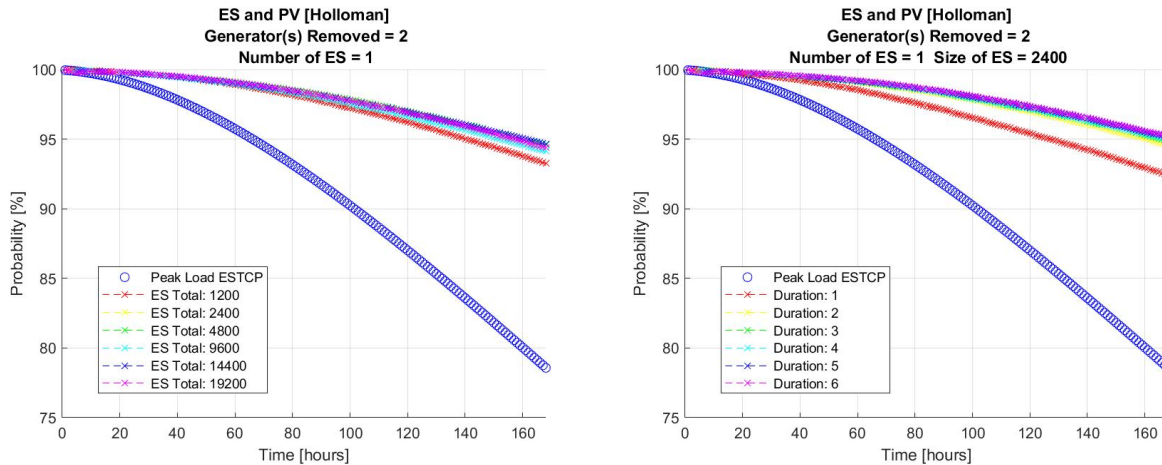


Figure 20. Holloman AFB Reliability Results – “N-1” Generators, Varying Size and Duration

Figure 21 shows reliability performance at 130% of critical load with optimized N-1 (2 generator removed) configuration. Despite the large amount of PV, the performance of the system falls incrementally below the ESTCP requirement in the first hour, presumably due to the MTBF of the energy storage.

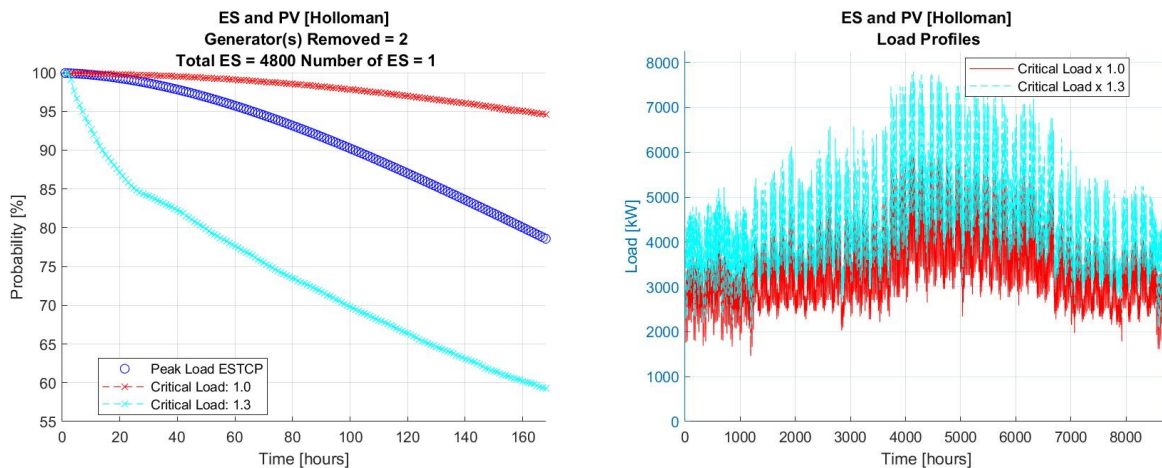


Figure 21. Holloman AFB Reliability Results – “N-1” Generators, 130% Critical Load

Figure 22 shows reliability performance at 10% and 30% of critical load with no diesel generators. The high solar PV production with adequately sized storage is able to maintain load coverage throughout the duration of the outage.

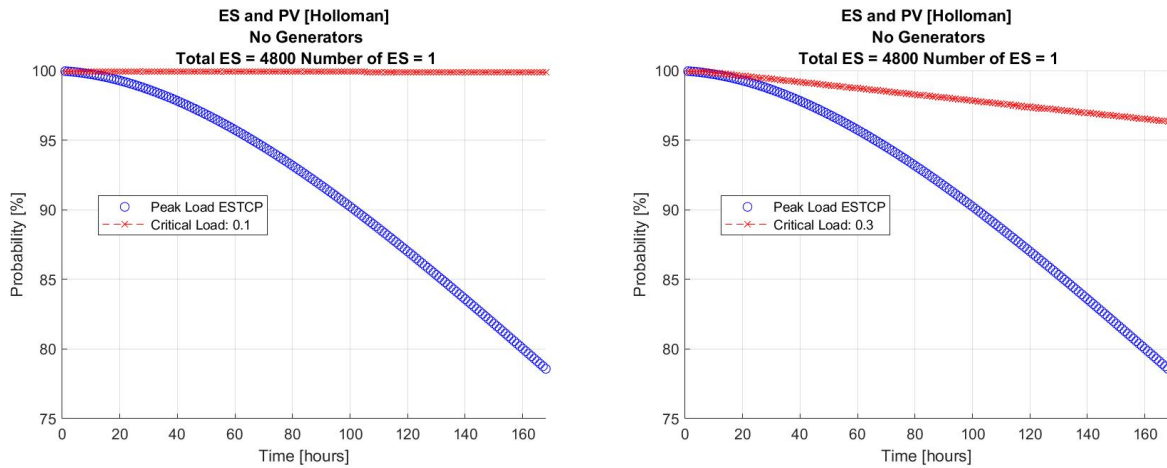


Figure 22. Holloman AFB Reliability Results – No Generators, 10% and 30% Critical Load

March ARB

For March ARB, we determined that we could remove 1 diesel generator and meet the reliability requirement. Further generator elimination was limited by the high performance of the baseline. Figure 23 shows this with varying energy storage size and duration. Early ESS failures play a large role in the results – this is also the result of the ESTCP baseline performance being very good relative to the other installations. Early ESS failures make a single ESS configuration fail the reliability requirement unless its MTBF was >10,000hrs. It is unclear whether this can be achieved. However, splitting the ESS into two (or more) units with the nominal ESS MTBF value of 1895hrs provided acceptable results. Varying MTBF and number of ESS unit plots illustrating this are in Appendix A3.

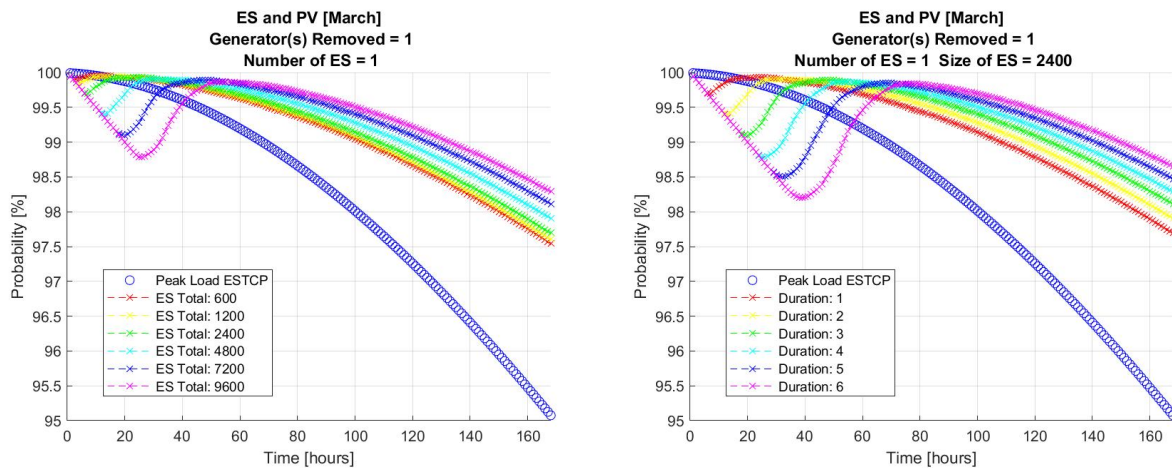


Figure 23. March ARB Reliability Results – “N” Generators, Varying Size and Duration

Figure 24 shows reliability performance at 130% of critical load with optimized N (1 generator removed) configuration. With 1 energy storage system the load coverage probability falls below the requirement in the first hour. However, if the storage is split into 5 units as intended in the design, the system is able to maintain critical load coverage over the ESTCP requirement for 4 hours (see Appendix A3).

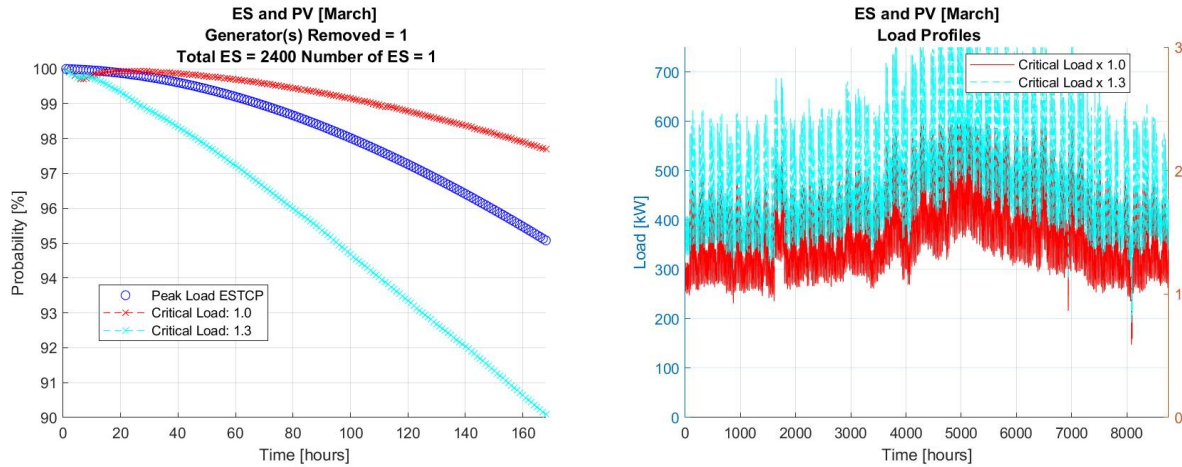


Figure 24. March ARB Reliability Results – “N” Generators, 130% Critical Load

Figure 25 shows reliability performance at 10% and 30% of critical load with no diesel generators. The high solar PV production with adequately sized storage is able to maintain load coverage throughout the duration of the outage. However, as shown in the plots, it is necessary to split the storage into multiple smaller units to avoid falling below the requirement in the early hours of the outage.

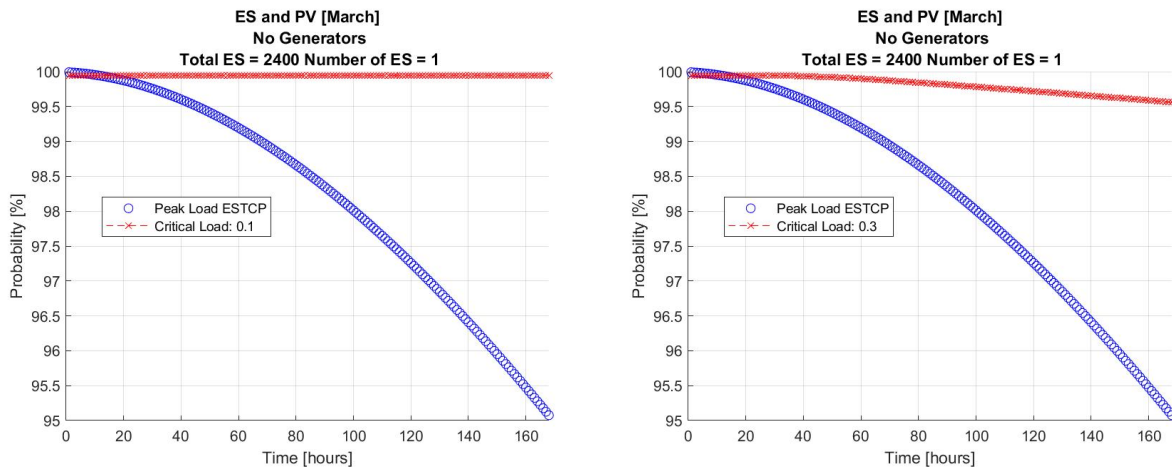


Figure 25. March ARB Reliability Results – No Generators, 10 and 30% Critical Load

Fort Bliss

For Fort Bliss, we determined that we could remove 1 diesel generator and meet the reliability requirement. Figure 26 shows this with varying energy storage size and duration. All considered sizes provide acceptable results, indicating that economically optimized storage size is again large enough to provide starting SoC flexibility. Increasing duration from 1-6 hours again also had a minimal effect. Figures that capture performance with “N-1” generators, as well as MTBF and varying ESS unit quantities are located in Appendix A3. These results show that by increasing duration to >2hrs an additional generator can be removed.

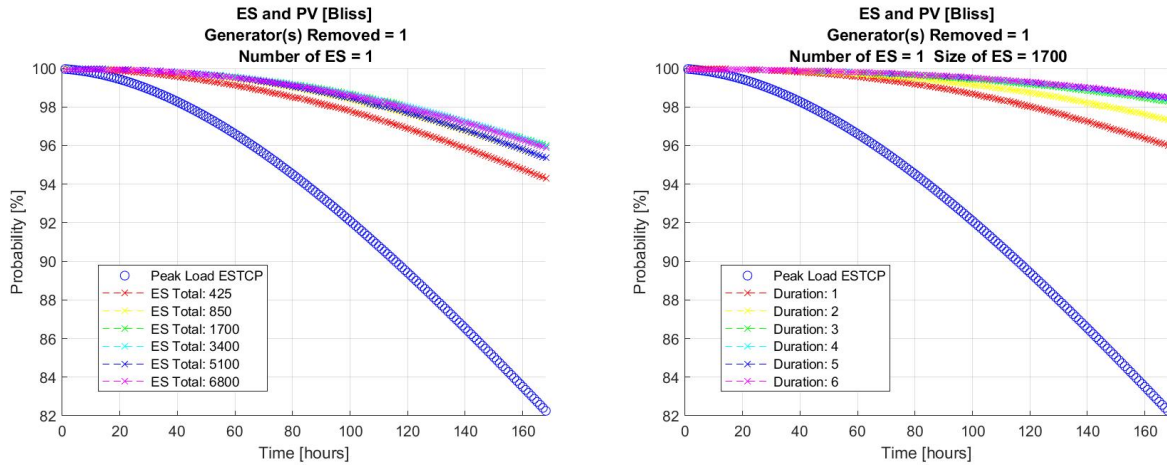


Figure 26. Fort Bliss Reliability Results – “N” Generators, Varying Size and Duration

Figure 27 shows reliability performance at 130% of critical load with optimized N (1 generator removed) configuration. The small amount of storage relative to peak critical load results in critical load coverage falling below the ESTCP requirement in <1 hour.

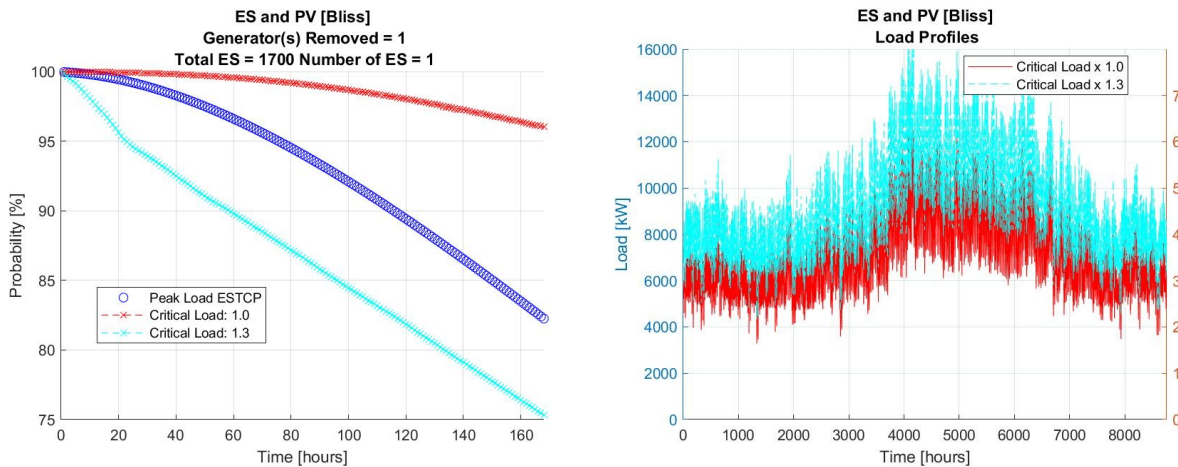


Figure 27. Fort Bliss Reliability Results – “N” Generators, 130% Critical Load

Figure 28 shows reliability performance at 10% and 30% of critical load with no diesel generators. The 10% critical load result provides performance above the requirement for the full outage duration, but the 30% critical load result shows no coverage. The former reflects the high PV production with adequate sizing, the latter is not surprising given the relatively high critical load and small quantity of storage. It is likely the 30% critical load case could be supported if the storage size and/or duration were increased, but this is not supported by the economics.

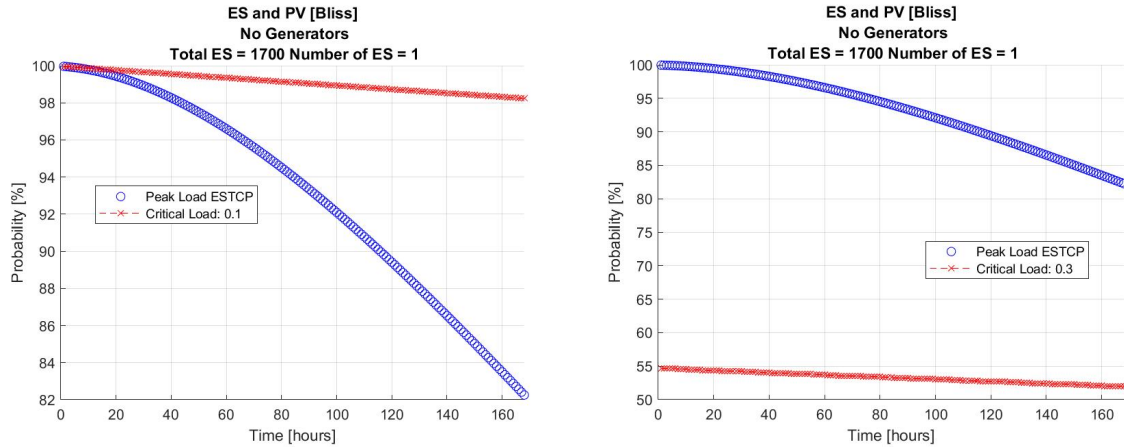


Figure 28. Fort Bliss Reliability Results – No Generators, 10% and 30% Critical Load

Naval Base Ventura

For Naval Base Ventura, we determined that we could remove 1 diesel generator and meet the reliability requirement. Figure 29 shows this with varying energy storage size and duration. Note that the “dip” in probability at the beginning of the curve causing failures is due to energy storage failures that are addressed by breaking the storage into multiple units as shown in the Appendix plots. With this taken into account, all considered sizes provide acceptable results, indicating that economically optimized storage size is again larger than is required for reliable operation with “N” generators. Increasing duration from 1-6 hours had a minimal effect. Figures that capture performance with “N-1” generators, as well as MTBF and varying ESS unit quantities are located in Appendix A3.

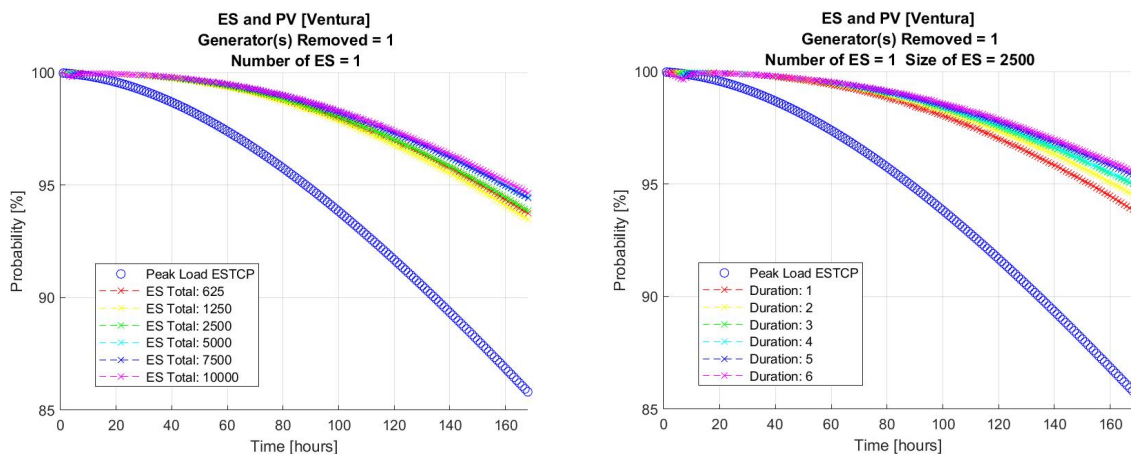


Figure 29. Naval Base Ventura Reliability Results – “N” Generators, Varying Size and Duration

Figure 30 shows reliability performance at 130% of critical load with optimized N (1 generator removed) configuration. The results show that the critical load coverage is maintained above the requirement for <1 hour.

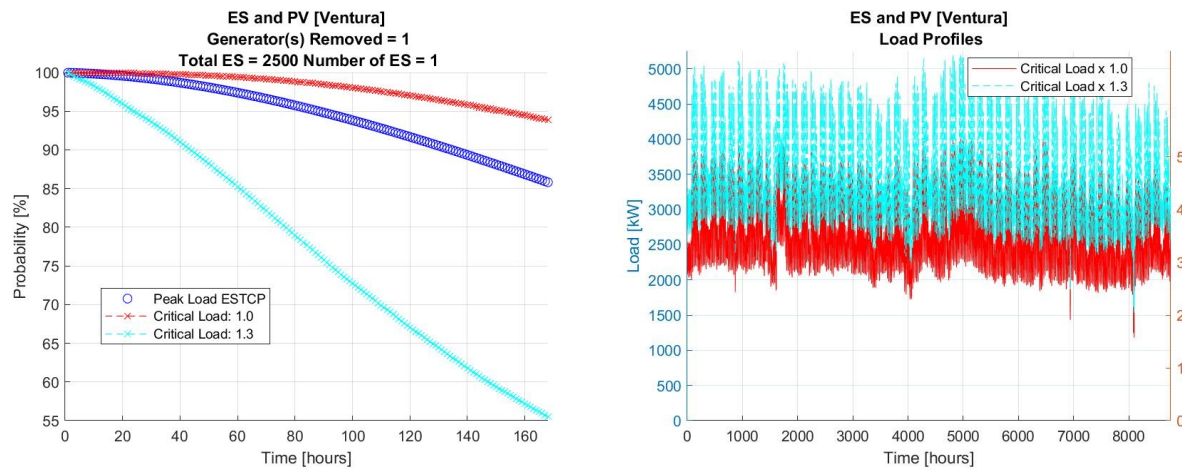


Figure 30. NB Ventura Reliability Results – “N” Generators, 130% Critical Load

Figure 31 shows reliability performance at 10% and 30% of critical load with no diesel generators. The 10% case passes, the 30% marginally falls below the requirement. This result relates to the MTBF of the energy storage used in the simulation. An additional simulation was performed with 2x increased MTBF (3790hrs vs. 1895hrs), this produced result that met the requirement for the full duration.

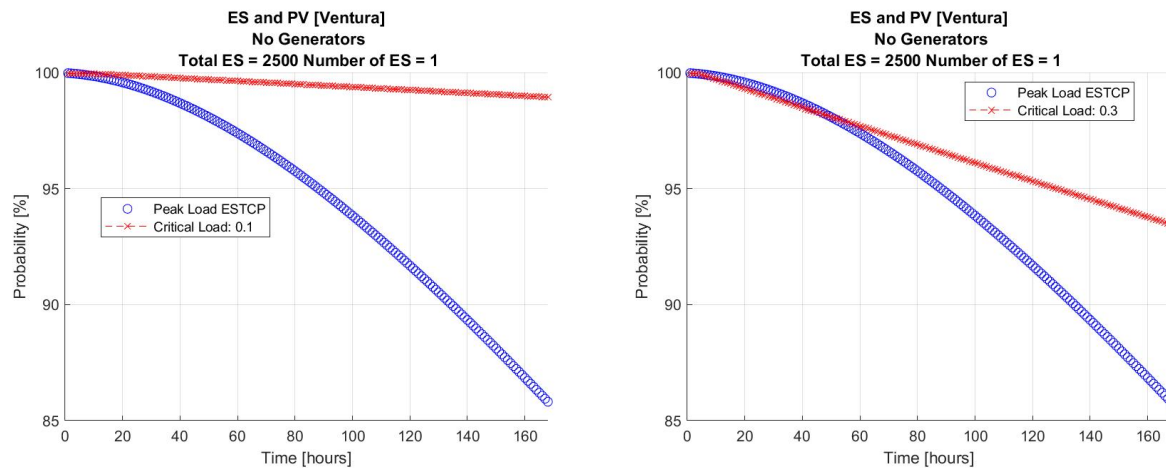


Figure 31: NB Ventura Reliability Results – No Generators, 10% and 30% Critical Load

6.2 CONTROLLER HARDWARE-IN-THE-LOOP (C-HIL) ASSESSMENT

C-HIL assessment involved testing to demonstrate multiple performance objectives noted in Section 3.0. These objectives were mapped into the IEEE 2030.8 standard test structure using the test plan that was developed for EW-201606 by Raytheon and MIT-LL. Based on this mapping, we grouped the tests into 4 different test groups described below.

Test Group 1

Test Group 1 involved testing transitions to and from islanding under varying power import and export conditions with low and high ESS SoC to match the worst case scenario. In general, to pass the test, any microgrid controller, and, in particular, the PXiSE ACT would need to execute the scenario without tripping protective relays that would result in a partial or complete failure of the microgrid. The following section describes the outcomes of those tests with test numbering that maps to the EW-201606 test plan. Detailed test conditions and example results for each test described are located in Appendix A3.

Test 5.1.1 tested the ability of the PXiSE ACT controller to perform planned islanding under heavy power import conditions. Test 5.1.2 was similar to 5.1.1, except testing was performed under heavy power export conditions. The PXiSE ACT controller successfully completed both of these tests without tripping any protective relays by discharging or charging the two ESS units to compensate for the heavy power export or import leading up and following the planned transition. Notably, the PXiSE ACT controller was able to execute the planned transitions without shutting down and re-starting the wind turbine as is done in the current control scheme on EW-201606. This would be of benefit to microgrid operation since the wind turbine is currently required to ramp back-up following the transition, resulting in lost wind production and increased diesel fuel consumption when once transitioned to microgrid mode.

Tests 5.2.1.1-5.2.1.3 tested the ability of the PXiSE ACT controller to perform un-planned islanding under heavy power export conditions. Test 5.2.1.1 tested un-planned islanding with automatic re-connect. This scenario represents short term disturbances in grid power quality. Test 5.2.1.2 tested un-planned islanding with loss of grid ride-thru. This scenario represents an unplanned grid outage. Test 5.2.1.3 tested loss of grid ride-thru under low ESS SoC conditions. This test is the same as 5.2.1.2, except under low SoC conditions where the energy storage will be challenged to maintain the load shortly after transitioning. The PXiSE controller was able to successfully complete all of these tests without tripping any relays within the system during the transition. This was a noteworthy outcome, especially considering un-planned transitions universally result in tripping the wind turbine offline in the current system design. This requires the microgrid to start the diesel generator immediately following an outage since it takes the turbine 20 minutes to re-initialize when it is tripped offline. When using PXiSE ACT controls, the turbine rides-thru the unplanned outage and the 20min of wind production is reclaimed, reducing diesel generator run time.

Tests 5.2.2.1-5.2.2.3 repeat the results from the 5.2.1 unplanned transition test sequence, except under heavy power import conditions. 5.2.2.1 and 5.2.2.2 are identical to 5.2.1.1 and 5.2.1.2, except for the heavy power import during the time of the transition. Test 5.2.1.3 is conducted under high (as opposed to low) energy storage SoC conditions, this challenges the control system to take action to avoid over charging the energy storage. As was the case for all 5.2.1 tests, the PXiSE ACT controls are able to complete all 5.2.2 tests successfully without tripping protective relays.

The aforementioned benefit of maintaining wind production through an un-planned outage is maintained.

Test 5.3.1 tested the ability of the PXiSE ACT controller to re-connect to the grid from islanding operation and considered scenarios where a feature that would enable automatic re-connect was enabled or disabled. The PXiSE ACT controls were able to successfully re-synchronize the system with the grid and re-connect without tripping any protective relays. Similar to the planned and un-planned disconnect, it was able to achieve this without curtailing the wind turbine.

Test Group 2

Test Group 2 involved testing steady-state islanding performance. The tests evaluated the ability of the PXiSE ACT controls to react to variations in DER outputs, and to optimize DER dispatch strategies to maximize microgrid efficiency and reliability. Success in the former tests was defined as maintaining stable microgrid operation through the variations without tripping any protective relays that would cause the microgrid to partially or totally fail. Success in the latter test required the islanding efficiency and reliability of the system to be improved relative to the base case from EW-201606. Detailed test conditions and example results for each test described are located in Appendix A3.

Tests 4.2.1.1a and 4.2.1.1b entailed varying operating set points of the grid forming energy storage system during islanding to ensure the PXiSE ACT controls could manage the impacts of off-nominal voltage and frequency within the microgrid. Test 4.2.1.1a varied the nominal frequency provided by the grid forming ESS from 59.5 to 60.5Hz in 0.1Hz steps. Test 4.2.1.1b varied the nominal voltage provided by the grid-forming ESS from 0.95 p.u. to 1.05 p.u. in 0.01 p.u. steps. The PXiSE ACT controls were able to successfully complete these tests without tripping any protective relays.

Tests 4.2.1.2 entailed varying wind turbine production from 0.166 p.u. to 1 p.u. in 0.166 p.u. steps to verify the ability of the PXiSE ACT controls to react to variations in wind turbine production. The PXiSE ACT controls were successfully able to manage the variations in wind turbine production by charging or discharging the second (non-grid forming) ESS to avoid tripping any protective relays.

Test 4.2.1.3 entailed varying production of the diesel generator to show that the PXiSE controller could control the base loading of the diesel generator. This was accomplished without incident.

Test 4.2.1.4 entailed evaluating nominal steady state islanding performance and was performed using measured wind generation and load data collected on EW-201606. The testing was completed for 1.5 total hours. Diesel generator power and time were recorded and used to calculate fuel consumption. Total ESS throughput, defined as kWh that enter and leave the ESS was recorded for each ESS. The objective of the test was to demonstrate reduced fuel consumption and ESS throughput relative to the baseline control strategy. As of the writing of this report, we have not yet been able to re-do the same scenario tested for the PXiSE controls with the base case controls. This will be addressed in a future revision to this report.

Test Group 3

Test 4.2.2.1 evaluated the ability of the PXiSE ACT controls to support “redundant ride-thru” by using a non-grid forming ESS to take over grid forming responsibilities in the event the primary grid-forming ESS trips offline. Success was defined as maintaining load coverage during and following the failure of the primary grid forming ESS. Detailed test conditions and example results for each test described are located in Appendix A3.

PXiSE ACT controls were successfully able to demonstrate the redundant ride-thru capability by managing the voltage and frequency of the microgrid through the transition from the primary to the back-up ESS for grid forming. This outcome was significant, in that it shows that multiple grid forming ESS units can be used to back each other up in a microgrid similar to the way a networked set of diesel generators works.

Test Group 4

Test group 4 introduced an entirely new test that was not considered in the EW-201606 IEEE 2030.8 test plan. The purpose of this test was to evaluate the ability of the PXiSE ACT controls to manage power flow within the microgrid during grid-tied operation using multiple DERs to meet a particular power control objective. This test represents a scenario where demand management is a continuous need, and may be complicated by variable renewable generator performance and potentially conflict with other ongoing economic use cases (e.g., frequency regulation). As is noted in Section 7.0, demand management was a critical economic function for all installations. Therefore, it is critical that the PXiSE ACT controls can continuously manage demand at the point of interconnect of the microgrid, since any significant lapses would compromise an entire month's worth of demand charge savings.

This test was performed by using real-data load and generation profiles for load and the wind turbine for 1.5 hours. The results from the test show that the PXiSE ACT was able to use the ESS units to compensate for fluctuations in the wind turbine output to reduce power flow variations at the PoI. It was also able to start and run the generator to increase ESS SoC while simultaneously continuing to compensate for wind turbine production variability.

In summary, C-HIL testing results indicate that the PXiSE ACT controls are capable of meeting all defined performance objectives thus far evaluated, with one pending. These results validate key assumptions in our reliability and techno-economic analysis. Specifically, the results show that PXiSE ACT control allows multiple “undersized” grid forming ESS units to support islanded operation, including under conditions where the one that is currently grid forming fails. It also allows multiple DERs to be used to control power flow in the microgrid during grid-tied operation. Lastly, the testing shows general compliance with IEEE 2030.8 requirements for the evaluated microgrid configuration.

Finally, it is worth noting that voltage and power transitions during islanding are influenced by the underlying dynamics of the C-HIL model. Managed communication between the voltage source inverter and protective relays/breakers at point of interconnect can be used to accompany the PXiSE ACT to further reduce such voltage and power transitions, as is recommended by PXiSE in its designs featuring on-premise equipment. Such managed communication were not available due to over-the-internet communication between PXiSE ACT and the C-HIL model during testing.

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7.0 COST ASSESSMENT

7.1 COST DETAILS

For each site, various use cases were analyzed. A use case refers to a combination of services the storage can provide. Such use cases differ from site to site based on the utility structure and the wholesale market the site locates in.

March ARB and NB Ventura County: CAISO

In the CAISO territory, energy storage can participate in CAISO's wholesale market mainly through two resource types: Proxy Demand Resource (PDR) for behind-the-meter installations and Non-Generating Resources (NGR) for in-front-of-the-meter installations. See Table 6 for the comparison between the two resource types.

Table 6. Comparison between PDR and NGR at the CAISO

Proxy Demand Resource (PDR)	Non-Generating Resources (NGR)
Proxy Demand Response (PDR) is a market participation model that enables 3rd parties to bid demand response into the CAISO market independent of the Load Serving Entity for load curtailment in wholesale Energy and Ancillary Services markets. Behind-the-Meter (BTM) energy storage can participate in the market as a PDR. PDR – Load Shift Resource (PDR-LSR) is a market participation model that allows for a bidirectional dispatch product that rewards PDRs for increasing consumption during negative pricing (i.e., oversupply events). Available Fall 2019. *Storage in a microgrid can participate as a PDR for demand response and load-shifting purposes; cannot participate in the Regulation market.	Grid-scale, In Front-of-the-Meter (IFOM) energy storage that operates as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by an MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy. ▪ If registered as Regulation Energy Management (REM) resource, need to have at least 15 minutes of continuous energy and can only sell into Regulation market. ▪ If registered as non-REM resource, need at least 60 minutes of continuous energy and can sell into all markets.

The CAISO has not yet specified the resource type for energy storage as part of a microgrid. The storage assets at March ARB and NB Ventura County were therefore modeled both as PDRs and NGRs to compare the potential benefits. As a PDR, the storage could be used for customer-sided services such as demand charge management but could not participate in wholesale Frequency Regulation. On the other hand, it could participate in Frequency Regulation as an NGR but could not provide any customer-sided services, including reliability-related ones.¹⁸

¹⁸ For more information on the comparison between NGR and PDR, refer to, <http://www.caiso.com/Documents/ParticipationComparison-ProxyDemand-DistributedEnergy-Storage.pdf>

The specific use cases considered assuming storage as a PDR are presented in Table 7. In each use case, the services are presented in the order of priority. For example, in Use Case 1, the storage was first used to manage demand charges, and then for energy arbitrage based on the TOU rate. For the remaining hours, it participated in the Spinning Reserve wholesale service. The priorities are assigned assuming that for a PDR resource, the storage should provide the site-related services first, and participate in wholesale services when it is available. Within the site-related services, demand charge management (DCM) usually brings in more revenues than retail energy arbitrage; DCM therefore is prioritized. For the wholesale services, various use cases were considered including single or multiple services. For each hour, CES|CoMETS optimizes for revenues depending on the participating services. The storage asset was modeled to be used for one optimal service for any given hour.

Table 7. Use Cases for Storage as a PDR in CAISO

<i>Use Case #</i>	Description
<i>P1</i>	Demand Charge Management > Retail Energy Arbitrage > Spinning Reserve
<i>P2</i>	Demand Charge Management > Wholesale Energy Arbitrage
<i>P3</i>	Demand Charge Management > Retail Energy Arbitrage > Wholesale Energy Arbitrage > Spinning Reserve
<i>P4</i>	Demand Charge Management > Retail Energy Arbitrage > Demand Response Program > Spinning Reserve

Use case 4 combining demand charge management, retail energy arbitrage, demand response and spinning reserve wholesale service had the best net present value across all storage configurations (see Table 8). While the earnings from the other revenue streams were similar, adding the demand response program significantly increased the revenue. As noted earlier, the demand response program was modeled after the SCE CBP even though March ARB does not currently participate in the program.

Table 8. Comparison across Use Cases for 2400kW/1.3hr Storage System for March ARB

<i>Use Case</i>	NPV	IRR	Demand Charge Management	Retail Energy Arbitrage	Wholesale Energy Arbitrage	Spinning Reserve	Demand Response
<i>P1</i>	\$195,878	7.3%	\$1,140,759	\$499,937	\$0	\$861,441	\$0
<i>P2</i>	(\$869,592)	-1.1%	\$1,140,759	(\$66,482) ¹⁹	\$362,389	\$0	\$0
<i>P3</i>	\$276,572	7.9%	\$1,140,759	\$494,470	\$130,967	\$816,634	\$0
<i>P4</i>	\$577,907	9.8%	\$1,140,759	\$418,013	\$0	\$844,811	\$480,582

*Revenues and costs calculated for 20 years of project life.

¹⁹ In this use case, the storage system is effectively charging with retail energy to sell into the wholesale market, hence the negative value in the retail energy arbitrage service. The algorithm restricts such sales only during times when the wholesale prices are higher than the retail rate.

The PDR analysis was carried out for a wide variety of storage configurations for each use case and for various price scenarios. The primary findings are as follows,

- A. At the time ESTCP gathered data for the analysis, there were only 3-month worth of Spinning Reserve prices for 2018. Beginning in 2018, the CAISO permanently increased the amount of Spinning Reserve procurement, resulting in much higher Spinning Reserve prices. The higher Spinning Reserve prices continued into 2019 with seasonal variation. Since the revenue from the Spinning Reserve service was a considerable part of the total revenue, the historical 2018 Spinning Reserve prices were used in the analysis. The projected revenue was significantly higher when the 2018 historical Spinning Reserve prices were used (see Table 9).

Table 9. Comparison of Optimal Storage Configurations across Price Scenarios

Wholesale Spinning Reserve Prices	Wholesale Energy Price	Use Case	NPV	IRR	Optimal Storage Capacity (kW)	Optimal Duration (hr)
<i>ESTCP Data</i>	Current Scenario	P4	\$236,979	8.7%	1400	1
	Future Scenario	P4	\$239,255	8.7%	1400	1
<i>2018 historical prices</i>	Current Scenario	P4	\$577,907	9.8%	2400	1
	Future Scenario	P4	\$512,507	9.0%	2700	1

*Revenues and costs calculated for 20 years of project life.

- B. Across all storage configurations, the one-hour duration configuration had the best return on investment (see Figure 32). This is because of the lower cost of the 1-hour systems. While the longer-duration systems could shave off more demand charges and participate for more hours in the wholesale services, the incremental revenue could not match the additional costs.

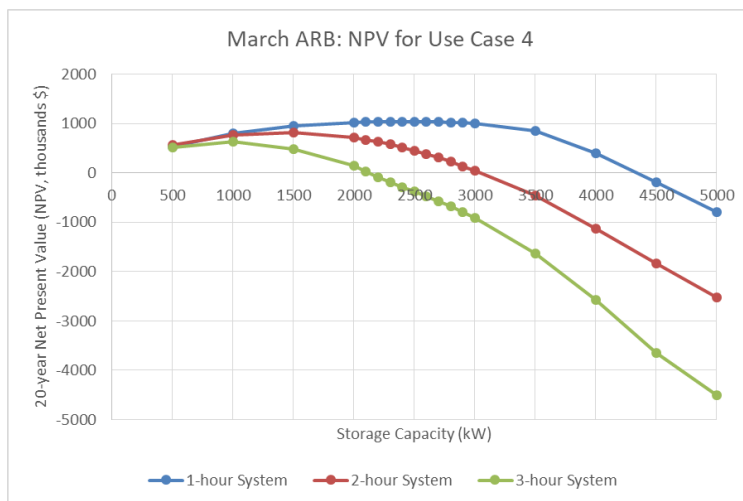


Figure 32. NPV Comparison for Various Storage Duration at March ARB

As an NGR participating in the CAISO's wholesale services, the storage can provide energy, Frequency Regulation, Spinning and Non-Spinning Reserves services. Table 10 shows the use cases analyzed for storage as an NGR. In each use case, depending on the participating services and the resource's SOC, CES|CoMETS optimizes for revenue for each hour.

Table 10. Use Cases for Storage as NGR in CAISO

Use Case #	Description
<i>N1</i>	Wholesale Energy Arbitrage, Spinning Reserve
<i>N2</i>	Wholesale Energy Arbitrage, Frequency Regulation
<i>N3</i>	Frequency Regulation

When modeled as an NGR, the storage is treated as a resource independent of the microgrid. Its size is only constrained by the local interconnection. For a given duration, the wholesale revenues are proportional to the capacity of the storage. The optimal size in the PDR analysis (2400kW/1hr) is therefore used to compare results across resource types. Table 11 shows the modeled revenues from each service in various use cases.

Table 11. Comparison across Use Cases for a 2400kW/1.3hr Storage System (NGR)

Use Case	NPV	IRR	Wholesale Energy Arbitrage	Frequency Regulation	Spinning Reserve
<i>N1</i>	(\$1,531,713)	-13.8%	\$437,400	N/A	\$0 ²⁰
<i>N2</i>	\$5,282,774	32.0%	\$80,386	\$7,171,502	N/A
<i>N3</i>	\$6,320,235	36.4%	N/A	\$8,266,497	N/A

*Revenues and costs calculated for 20 years of project life.

It is obvious from the modeled results that frequency regulation revenue is the main driver of storage participating as a NGR. The frequency regulation signal in the CAISO does not require a long-duration storage. In use case 2, for example, a longer duration storage would show more participation in energy arbitrage and less in frequency regulation, resulting in an overall less favorable NPV because of the higher cost of the longer-duration storage (see Table 12).

²⁰ While use case 1 focused on wholesale energy arbitrage and spinning reserve services, the revenue for spinning reserve for the 2000kW/1hr battery was \$0 because the storage must continuously provide energy for 1 hour to qualify for the spinning reserve service. When the efficiency losses were factored in, the 1hr storage never had enough energy to provide spinning reserve service. A longer duration storage would qualify for the service. The use case for longer duration storage was modeled but not shown in the report.

Table 12. Revenue Comparison for Different Durations of Storage at 2400kW for March ARB

Storage Duration	Use Case	NPV	IRR	Wholesale Energy Arbitrage	Frequency Regulation
1.3hr	N2	\$5,282,774	32.0%	\$80,386	\$7,171,502
2.6hr	N2	\$2,789,853	15.4%	\$423,836	\$6,177,970
3.9hr	N2	\$693,466	7.8%	\$730,736	\$5,454,244

*Revenues and costs calculated for 20 years of project life.

While storage used as an NGR was modeled to earn significantly more revenues than storage modeled as a PDR, the main revenue stream was from Frequency Regulation. However, NGR operation would require the energy storage to be directly connected to the utility, significantly limiting the design options to incorporate it within an installation microgrid. It would also prevent the use of the storage in performing behind the meter functions, limiting flexibility. It is therefore recommended that for the time being storage at the two sites participate as PDRs in the CAISO market to provide implementation flexibility and open up multiple revenue streams including demand charge management, retail and wholesale energy arbitrage, demand response programs and spinning reserve. It is possible that CAISO might open up the Frequency Regulation market to the PDR resources although such proposal has been postponed multiple times due to technical issues²¹. If it happens, the additional Frequency Regulation revenue stream will significantly change and improve the economics of energy storage as a PDR.

Holloman AFB

The El Paso Electric (EPE) territory, a vertically integrated utility, does not offer the wholesale revenue opportunities present in CAISO or PJM, but does allow for energy storage to be used for demand charge management and retail arbitrage behind the meter.

Two use cases were investigated adding energy storage to the Holloman AFB site: 1) Demand Savings plus Retail Arbitrage and 2) Demand Savings plus Retail Arbitrage, with Demand Response.

Holloman AFB has the possibility for participating in a limited demand response program which was recently approved by the EPE for their New Mexico territory²². The DR program still lacks some detail for participation and will be run with a limited size and budget as a similar (and already

²¹ See, for example, issue paper for Energy Storage and Distributed Energy Resources (ESDER) initiative, phase 3, accessible here: <http://www.caiso.com/Documents/IssuePaper-EnergyStorageandDistributedEnergyResourcesPhase3.pdf>

²² The approved DR efficiency program for New Mexico can be found here: https://www.epelectric.com/files/html/Energy_efficiency/Annual_Reports/NMPPRC_Case_No_18-00116-UT.pdf. Note that since many of the details are lacking, the Texas version of the DR program was used as a proxy. The Texas manual for the EPE Load Management Program can be found here: https://www.epelectric.com/files/html/Energy_efficiency/Energy_Efficiency_Program_Manuals/2018_Program_Manuals/2018_Load_Management_Program_Final.pdf

fully subscribed) DR program in their Texas territory. The addition of the DR revenue stream in the second use case offers additional revenue but is still overshadowed by the revenue potential of demand charge reduction.

The specific use cases considered are presented in Table 13. In each use case, the services are presented in the order of priority. For example, in Use Case 1, the storage was first used to manage demand charges, then for energy arbitrage based on the TOU rate.

Table 13. Use Cases for Storage at Holloman Air Force Base

<i>Use Case #</i>	Description
<i>1</i>	Demand Charge Management > Retail Energy Arbitrage
<i>2</i>	Demand Charge Management > Retail Energy Arbitrage > Demand Response

The economic analysis of both use cases are presented in Table 14. The demand charge management service brings in the majority of the revenue while the demand response program slightly improves the return on investment of the project.

Table 14. Comparison for Revenue Streams across Use Cases

<i>Use Case</i>	NPV	IRR	Demand Charge Management	Retail Energy Arbitrage	Demand Response	Optimal Storage Capacity (kW)	Optimal Duration (hr)
<i>1</i>	\$1,504,043	14.7%	\$3,734,602	\$171,793	\$0	2500	1
<i>2</i>	\$1,992,723	13.2%	\$4,873,937	\$234,123	\$1,044,348	2400	2

*Revenues and costs calculated for 20 years of project life.

Fort Bliss

Fort Bliss, with a footprint on the Texas side of the border, has similar opportunities for participating in demand charge management and retail arbitrage from behind the meter. The DR program in the Texas EPE territory is not a current option for Fort Bliss, as it is oversubscribed and it is not clear how EPE will open it up further in the near future. This limited the number of use case to a single one in this analysis, demand charge management with retail energy arbitrage.

Table 15. Use Case Considered for Fort Bliss

<i>Use Case #</i>	Description
<i>1</i>	Demand Charge Management > Retail Energy Arbitrage

In contrast to Holloman AFB, analysis on Fort Bliss showed NPVs that were largely negative for the use case studied (see Table 16). To narrow down the potential root cause of the difference in economics of the two sites, a comparison of the net load distribution curves of the two sites (Figure 33) was first analyzed. As shown in the figure, Fort Bliss and Holloman AFB share a similar shape, with neither standing out as drastically ‘peakier’ than the other and making it less likely that load patterns have a large play in the economics of the Holloman AFB model.

Table 16. Comparison across Use Cases for 1700kW/1.3hr Storage Configuration

<i>Use Case</i>	NPV	IRR	Demand Charge Management	Retail Energy Arbitrage
<i>1</i>	(\$319,481)	2.6%	\$1,312,136	\$1,982

*Revenues and costs calculated for 20 years of project life.

By taking a closer look at the two-part (firm and interruptible) energy demand charge structure at the Fort Bliss site (introduced in section 1.3), it appears financial impact of the storage’s ability to reduce incremental demand during the peak period is lessened drastically because of the lower demand charge rate (\$2.22/kW) of each kW above 44,000kW. For reference, the entire load during the six hours of the summer peak period is above the 44,000kW threshold, where the lower \$2.22kW rate is applied. In contrast, the ESR in the Fort Holloman case offsets a demand charge of \$19.57/kW for each hour of the on peak period since it has a one-part demand charge structure and allows the battery to avoid a higher demand charge cost.

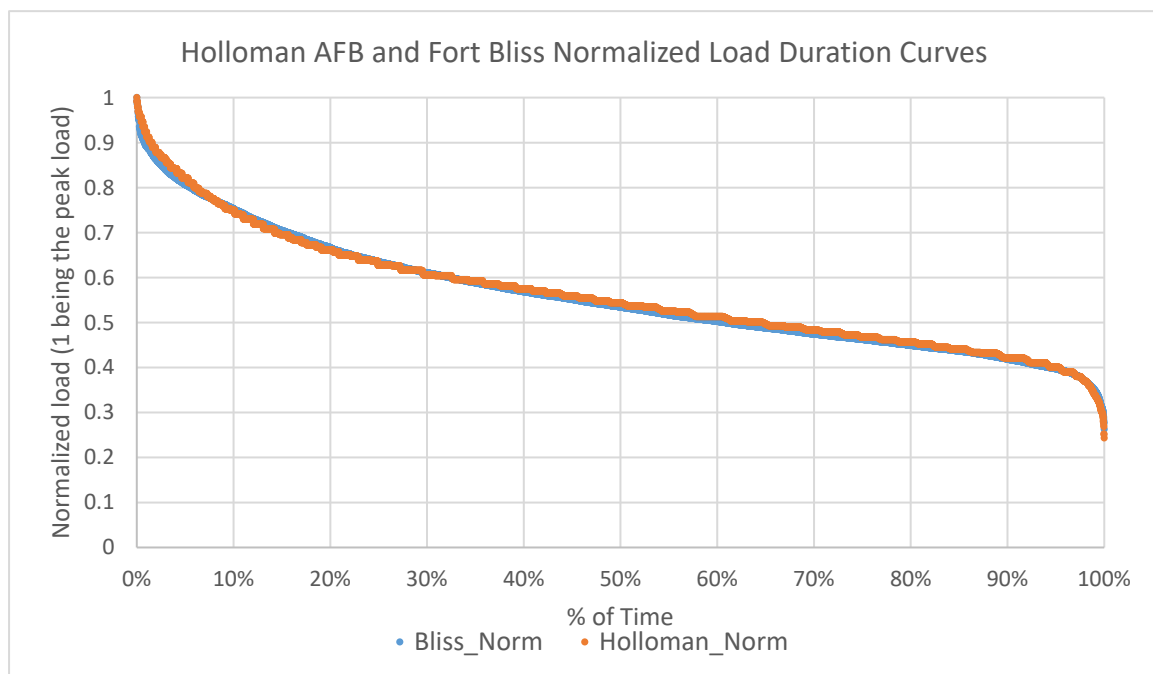


Figure 33. Comparison of Net Load Duration Curve between Holloman AFB and Fort Bliss

NAS Patuxent River: PJM

PJM allows behind-the-meter (BTM) energy storage resources to participate by registering as a Demand Response (DR) resource. All resources participating in DR programs, without an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement (WMPA), must not inject energy onto the grid²³. Demand Response resources in PJM can offer all wholesale services that they are technically capable of providing which includes, but is not limited to, Capacity Demand Response, Frequency Regulation, and Synchronized (Spinning) Reserve. The storage asset at NAS Patuxent River, in addition to providing customer-sided services such as Demand Charge Management, was modeled for participation in the Capacity market, the Frequency Regulation market, the Synchronized Reserve market, and the Energy market.

The specific use cases considered assuming storage as a Demand Response resource are presented in Table 17. In each use case, the services are presented in the order of priority in order to preserve the greatest value stream. For example, in Use Case 1, the storage was first used to manage demand charges, then to participate in the Synchronized Reserve wholesale market. Note that unlike the sites described earlier, NAS Patuxent is not on a TOU rate schedule; there is therefore no revenue stream from retail energy arbitrage. The economic analysis results of each use case are summarized in Table 18.

Table 17. Use Cases for Storage at NAS Patuxent River

<i>Use Case #</i>	Description
<i>1</i>	Demand Charge Management > Demand Response Program > Synchronized Reserve
<i>2</i>	Demand Charge Management > Demand Response Program > Frequency Regulation
<i>3</i>	Demand Charge Management > Demand Response Program > Wholesale Energy Arbitrage > Synchronized Reserve

Table 18. Comparison across Use Cases for 29400kW/1.3hr Storage Configuration

<i>Use Case</i>	NPV	IRR	Demand Charge Management	Wholesale Energy Arbitrage	Synchronized Reserve	Frequency Regulation	Capacity Demand Response
<i>1</i>	(\$16,747,960)	-7.3%	\$6,980,238	N/A	\$2,913,292	N/A	\$1,962,173
<i>2</i>	\$21,624,006	16.8%	\$6,980,238	N/A	N/A	\$42,254,591	\$1,962,173
<i>3</i>	(\$18,460,714)	-9.8%	\$6,980,238	\$1,212,690	\$1,528,208	N/A	\$1,962,173

*Revenues and costs calculated for 20 years of project life.

²³ NAS Patuxent River does not have in Interconnection Service Agreement or a Wholesale Market Participation Agreement, therefore, the site cannot inject energy back onto the grid.

As described earlier in Step 4, the analysis was carried out for a wide variety of storage configurations for each use case and for various price scenarios. The primary findings are as follows:

- A. Use case 1 utilizes Demand Charge Management (DCM), Synchronized Reserve, and Capacity Demand Response (DR) participation²⁴, which in PJM, is based on the output that can be maintained over a 10-hour period.²⁵ In use case 1, the priority for the utilization of the storage is based on preserving the highest per hour value, Demand Charge Management, while reserving requisite MWh capacity for additional revenue streams such as Synchronized Reserve and Capacity Demand Response²⁶. ESTCP provided details on NAS Patuxent River's current Capacity Market participation including 6 total DR Event Hours per year, \$250 Energy payments for DR events, and varying levels of Capacity payments. CES utilized these assumptions, and the Future Volatile Capacity Price of \$226/MW-day, in determining the potential Capacity revenues for the 29,400kW/1hr storage configuration within use case 1.
- B. Use case 2 combines Demand Charge Management and Frequency Regulation. This use case has the best NPV of all NAS Patuxent River use cases (see Table 18) due to the Frequency Regulation market participation, however, it may also have the greatest risk²⁷. In order to realize the greatest value for this case, the first priority for the battery is to provide Demand Charge Management (DCM) (even though the greatest overall value comes from Frequency Regulation market participation). DCM participation is the greatest value because it has the highest per hour value compared to Frequency Regulation.
 - Frequency Regulation participation is lucrative, however, in order to realize its full value the ESS must be in the market for a copious amount of hours. Due to the burden of continuous participation, DCM participation actually provides a greater per hour value as compared to Frequency Regulation. To ensure sufficient participation in a DCM event, the ESS is charged in the preceding hour, subject to the maximum power

²⁴ The exact Capacity Demand Response program suggested for this analysis would be Load Management Capacity Only.

²⁵ There are no current Day-Ahead Must Offer Requirements for Capacity Demand Response resources, therefore, the burden of participation in this market is based on PJM testing requirements and a limited number of "Performance Assessment Intervals" that PJM uses to ensure Capacity resources can serve reliability needs. PJM generally has an oversupply of energy resources and has not incurred a long-term shortage event since 2014.

²⁷ Since PJM created the 2-signal (RegA & RegD) Frequency Regulation market in 2012, they have been trying and, in some cases, succeeding in changing the structure and operation of assets offering into this market. Most notably, in January 2017, PJM altered the RegD signal from a 15-minute, energy neutral signal to a 30-minute energy neutral signal which caused many battery resources to reduce their capability (offering less MWs) or face severe performance and cell degradation. A settlement conference was convened to resolve issues stakeholders raised with these changes and this conference has reached the final chapter. Pending FERC approval, PJM will pay affected batteries for the loss of capability/degradation and in exchange, affected parties agree not to protest any future PJM filing that moves the PJM Frequency Regulation market to a single, non-energy neutral regulation signal. PJM eluded to this future "Regulation Market Enhancement Filing" within the settlement offer and terms but has not provided any more details or timeline for this filing. Thus, CES does not have enough information to include the potential impact of the Regulation Market Enhancement Filing within the modeling results.

(kW) of ESS, discharged during the event hour(s), and recharged in the post-event hour. Thus, the ESS is only needed for 4 – 5 hours of the day (1 hour to charge – 2-3 hours of discharge to shave the peak – 1 hour to recharge). In the hours that the battery is not providing Demand Charge Management, it is participating in the Frequency Regulation Market or providing Capacity Demand Response.

- C. Use case 3 is similar to use case 1, however, it also evaluates Wholesale Energy Arbitrage as a revenue stream. Due to the relatively consistent LMPs in PJM, the forecasted revenue that can be achieved through Wholesale Energy Arbitrage is less than the revenue that can be achieved by using the same ESS MWh in the Synchronized Reserve market. In the dataset provided by ESTCP, there were current and future volatile prices for the Day-Ahead Energy market, Real-Time Energy market, and the Capacity market. The projected revenue was slightly higher when the future volatile Capacity and Energy market prices were considered (see Table 19).

Table 19. Comparison of NAS Pax River Optimal Storage Configuration across Price Scenarios – Use Case 2

Capacity Price	Wholesale Energy Price	Wholesale Synchronized Reserve Prices	Use Case	NPV	IRR
Current Scenario	Current Scenario	ESTCP Data	2	\$21,624,006	16.8%
Future Scenario	Future Scenario		2	\$22,316,092	17.1%

*Revenues and costs calculated for 20 years of project life.

- D. Across all storage configurations, the one-hour duration configuration had the best NPV (see 34). This is because of the lower cost of the 1-hour systems. While the longer-duration systems could shave off more demand charges and participate for more hours in the wholesale services, the incremental revenue could not match the additional costs.

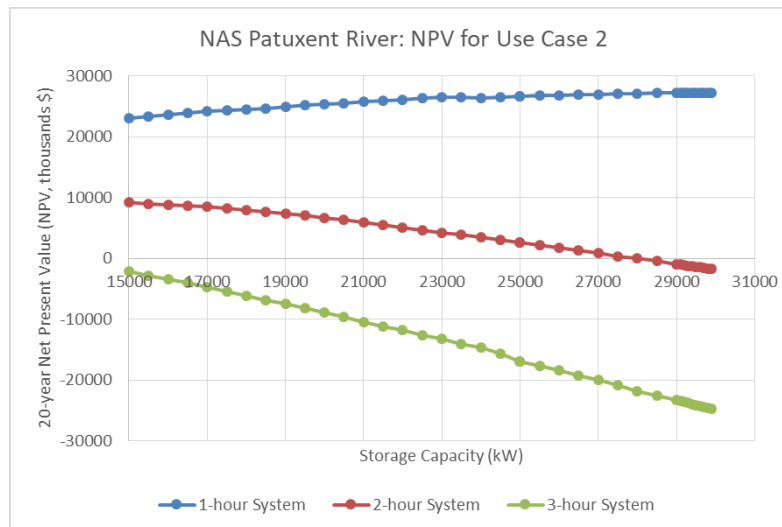


Figure 34. NPV Comparison of Various Storage Duration at NAS Patuxent River Site

While the 29.4MW storage system shows the optimal NPV, concerns were raised that (1) such a large system might adversely affect the PJM Frequency Regulation market, and that (2) it is not practical to install such a big system all at once. Barring a major market change, it is unlikely that an increase of 29.4 RegD MWs would degrade the Regulation Clearing Prices substantially as Regulation prices are driven primarily by the Lost Opportunity Cost of Gas units that offer, and are co-optimized, between Regulation (RegA) and Energy. To address the second concern, additional analysis for a 3MW²⁸ storage system was performed. The economics are summarized in Table 21.

Table 20. Comparison across Use Cases for 3000kW/1.3hr Storage Configuration

<i>Use Case</i>	NPV	IRR	Demand Charge Management	Wholesale Energy Arbitrage	Synchronized Reserve	Frequency Regulation	Capacity Demand Response
1	\$269,704	7.5%	\$2,491,504	N/A	\$479,584	N/A	\$200,222
2	\$6,526,666	34.7%	\$2,491,504	N/A	N/A	\$7,766,610	\$200,222
3	\$424,632	8.3%	\$2,491,504	\$387,297	\$228,431	N/A	\$200,222

*Revenues and costs calculated for 20 years of project life.

It's worth noting that for Use Case 2, the demand charge management savings and frequency regulation revenues were not proportional between 3MW and 29.4MW storage sizes. The algorithm prioritizes demand charge management, finding the amount of peak demand that can be shaved off depending on the size of the storage. For the 3MW system, the amount of peak demand that can be shaved off was smaller, resulting in the system participating in Frequency Regulation for more hours²⁹ and a relatively higher revenue.

Summarized Results and Analysis

As discussed earlier in Section 5.0, energy storage is added to the microgrid to enhance reliability or maintain similar reliability level at a lower cost by allowing the energy storage to provide other economic services. The optimal configurations of energy storage, together with its costs and economic benefits are summarized in Table 22 based on current pricing data. The blue section of the table is from the ICF base case. The orange section details the cost and economic and reliability benefits of storage on a dollar per kilowatt of peak critical load basis. The green section is the optimal storage configuration for each site.

²⁸ The choice of a 3MW/1.3hr system is somewhat arbitrary, although it is roughly 10% of the optimal 29.4MW case. In the presentation *Isolating the Energy Resiliency Contributions and Costs of Storage in Military Microgrids* (Energy Exchange, August 20-22, 2019, Denver, CO), Craig Schultz from ICF suggested a 2.4MW/3MWh system for the NAX Patuxent River site.

²⁹ When compared with the 29.4MW system, the 3MW system participated in Frequency Regulation for almost twice as much time (4712 out of 8760 hours for 29.4MW versus 8329 hours for 3MW). The replacement cycle for the 3MW system was therefore much shorter, at around 5 years. Such replacement costs were reflected in Table 23.

Table 21. Net Cost of Protecting Critical Load with Storage-Enabled Microgrids

	Peak Critical Load (kW)	Diesel Gensets (A)	UPS (B)	Microgrid (C)	DR & Peak Shaving Savings (D)	Annual Net Cost of Protecting each KW of Peak Critical Load (E)	Energy Storage (F)	DCM & Wholesale Revenues (G)	Diesel Genset Considered Obsolete because of Storage (H)	UPS Considered Obsolete because of Storage (I)	Annual Net Cost of Protecting each KW of Peak Critical Load with Storage (J)	ES Size (kW)	ES Duration (hr)
Holloman AFB	5996	\$49	\$22	\$36	(\$10)	\$98	\$35	(\$51)	(\$11)	(\$16)	\$55	2400	2.7
March ARB	600	\$121	\$52	\$243	\$0	\$416	\$192	(\$240)	(\$30)	(\$52)	\$286	2400	1.3
NAS Patuxent River - 29.7MW	8014	\$49	\$22	\$36	(\$10)	\$98	\$176	(\$330)	(\$8)	(\$22)	(\$86)	29400	1.3
NAS Patuxent River - 3MW	8014	\$49	\$22	\$36	(\$10)	\$98	\$23	(\$64)	(\$8)	(\$16)	\$33	3000	1.3
Naval Base Ventura County	4003	\$57	\$23	\$54	\$0	\$135	\$30	(\$42)	(\$8)	(\$23)	\$91	2500	1.3
Fort Bliss	12507	\$47	\$18	\$18	\$0	\$83	\$7	(\$5)	(\$6)	\$0	\$78	1700	1.3

It's worth noting that for the best performing site, NAS Patuxent River, the annual net cost of protecting peak critical load with a storage-enabled microgrid is negative. As discussed earlier, the primary revenue stream for the modeled 29.4MW storage was from Frequency Regulation in PJM. The negative cost means that the storage asset more than pays for itself as a merchant asset participating in Frequency Regulation that has little to do with maintaining reliability for NAS Patuxent River.

Results Discussion: Net Costs

The cost assumptions and cost matrix of the storage-enabled microgrids for each site are summarized in and Table 23 and Appendix A4. The treatment of these costs are in following with the ESTCP-provided cost framework which considered “hard” equipment and O&M costs. Additional non-equipment/O&M and “soft” costs that were not considered in the baseline or this analysis are discussed in Section 7.2. Note that the system installation and O&M costs shown here are in addition to the baseline microgrid costs determined by ESTCP. The baseline microgrid costs include microgrid controls, communications, and electrical infrastructure modifications.

Table 22. Modeling Cost Assumptions

Cost Components	Inputs	Rationale
a. System Installation Costs (2020)	Storage (DC System): \$400/kWh – inclusive of batteries, enclosure, and all balance of plant (e.g., HVAC, fire suppression) PCS/Inverter: \$200/kW	Based on developer information from recent project analyses. These costs are for lithium-ion batteries but not with any specific battery chemistry. There could be small variations depending on the battery chemistry. Raytheon also received a quote of similar costs from DynaPower including availability guarantee related spares.
b. System O&M	\$7.5/kW-year	Costs provided based on current O&M pricing from DynaPower, includes preventative maintenance (PM), PM spares, monitoring, 10 year extended warranty, and a 95% availability guarantee
c. Annual percentage escalation for storage O&M after Year 1	2.2%	Per ESTCP inputs
d. Energy storage component replacement	\$200/kWh At Year 10	Based on developer information from recent project analyses. Some may choose to supplement part of the storage capacity every 3 or 5 years, but the present value of the replacement costs are similar.

The rainflow analysis method for battery storage degradation³⁰ was used to calculate the equivalent full depth-of-discharge cycles to determine when the energy storage components should be replaced. For each use case at each site, the SoC profile of the storage system was logged; smaller cycles were accumulated into larger ones to calculate the full depth of discharge equivalent cycles. Table 24 shows the full depth of discharge cycles for the optimal use case for each site using such method.

Table 23. Equivalent Cycles for the Optimal Use Case Using Rainflow Analysis Method

	Holloman AFB	March ARB	NAS Patuxent River	NB Ventura County	Fort Bliss
Full Depth-of-Discharge Equivalent Cycles per Year	104	245	209	253	72

Based on discussions with Dynapower that the storage systems quoted are capable of more than 3000 cycles, a replacement period of 10 years is therefore sufficient.

Table 24. Summary of Net Costs of Storage-Enabled Microgrids for Each Site (Current Pricing)

	e. Changes to Electricity Bill ³¹	f. Net Incremental Revenues from Market or Utility Program Participation ³²	g. Year 1 Incremental Costs or Savings ³³		h. Net Life-Cycle Costs or Savings ³⁴	
			Ttl	\$/kW	Ttl	\$/kW/yr
Holloman AFB	(\$445,344)	\$91,051	\$2,609,735	\$435	(\$1,992,723)	(\$17)
March ARB	(\$135,901)	\$115,554	\$1,559,796	\$2,600	(\$577,907)	(\$48)
NAS Patuxent River	(\$493,369)	\$3,855,019	\$17,608,636	\$2,197	(\$21,624,006)	(\$135)
Naval Base Ventura County	(\$165,955)	\$126,441	\$1,597,625	\$399	(\$951,402)	(\$12)
Fort Bliss	(\$114,571)	\$0	\$1,161,512	\$93	\$319,481	\$1

*Revenues and costs calculated for 20 years of project life.

³⁰ See how the method is implemented in, for example, M. Chawla, R. Naik, R. Burra, H. Wiegman, "Utility energy storage life degradation estimation method", IEEE Conference on Innovative Technologies for an Efficient and Reliable Electricity Supply, pp. 302-308, 2010. Each battery manufacturer has different cycle life v.s. depth of discharge range curve: one 0-100% cycle usually degrades the battery more than ten 0-10% cycles. Absent of such specific information from the battery manufacturer, a simpler approach was used to add up ten 0-10% cycles into one 0-100% cycle, which slightly overestimated cycle counts per year and underestimated battery life.

³¹ Annualized present value calculated based on equal savings per year across the 20 years of the project life, or the PMT function in Excel. Negative value meant reduced electricity bill. These include reduced demand charges and savings from retail energy arbitrage. For use cases where retail energy arbitrage was not a service considered, the energy charge often increased to charge the storage for other services.

³² Annualized present value calculated based on equal revenues per year across the 20 years of the project life. Positive value meant incremental revenues from market or utility programs.

³³ Positive value meant costs whereas negative value meant savings. The Year 1 incremental costs consist of storage capital cost (one-time), operating cost, savings from electricity bill and incremental revenues from market and utility program participation from Year 1.

³⁴ Positive value meant costs whereas negative value meant savings. This is the net present value of the 20-year life of the storage project.

The same net cost matrix using prices from the Future Volatile scenario is summarized in Table 26. In the ESTCP data provided, there was a Future Volatile scenario (as opposed to Current scenario) for Day-Ahead and Real-Time energy prices for March ARB, NAS Patuxent River and Naval Base Ventura County. However, for all three sites, the best use cases did not involve wholesale energy arbitrage, which could change the revenue streams drastically using the Future Volatile scenario prices. Instead, when Future Volatile scenario prices were used, the revenue streams changed only slightly because the storage was charged using Real-Time energy prices.

Table 25. Summary of Net Costs of Storage-Enabled Microgrids for Each Site (Future Volatile Pricing)

	e. Changes to Electricity Bill	f. Net Incremental Revenues from Market or Utility Program Participation	g. Year 1 Incremental Costs or Savings		h. Net Life-Cycle Costs or Savings	
			Ttl	\$/kW	Ttl	\$/kW/yr
March ARB³⁵	(\$143,158)	\$127,728	\$1,765,470	\$2,942	(\$512,507)	(\$43)
NAS Patuxent River	(\$493,369)	\$3,915,358	\$17,554,836	\$2,191	(\$22,316,092)	(\$139)
Naval Base Ventura County	(\$166,428)	\$125,359	\$1,598,168	\$399	(\$944,416)	(\$12)

*Revenues and costs calculated for 20 years of project life.

Results Discussion: Incremental Revenues

As discussed earlier in section 5.1, various services were considered for each base depending on its location, applicable tariff and utility programs.

Grid Domain	Service	Applicable Bases
Site-related Services	Demand charge management	S1. Holloman AFB S2. March ARB S5. NAS Patuxent River S6. NB Ventura County S7. Fort Bliss
	Retail energy arbitrage	S1. Holloman AFB S2. March ARB S6. NB Ventura County S7. Fort Bliss
	Utility demand response program	S1. Holloman AFB S2. March ARB S5. NAS Patuxent River S6. NB Ventura County
Wholesale Market Services	Wholesale energy arbitrage	S2. March ARB (CAISO) S5. NAS Patuxent River (PJM) S6. NB Ventura County (CAISO)
	Frequency regulation	S5. NAS Patuxent River (PJM)
	Spinning reserve	S2. March ARB (CAISO) S5. NAS Patuxent River (PJM) S6. NB Ventura County (CAISO)

³⁵ The optimal storage size for March ARB under the Future Volatile scenario was 2700kW/1hr, instead of 2400kW/ 1hr under the Current scenario. The revenue streams and costs therefore changed proportionally to the optimal size change.

The details of each service and how it varies across the sites are described as follows.

Demand Charge Management (Peak Demand Shaving or Shifting)

The local utility charges the site a demand charge based on the highest average electricity demand over any 15-minute interval in a billing cycle. For example, if the load at a facility reaches an average of 10,000kW over one 15-minute period in a given month, the demand charge for that month under SCE's TOU-8 Option A schedule would be 10,000kW at \$8.77/kW, or \$87,700. In this analysis, the highest hourly load of each month was used to calculate the demand charges. In the economic benefits modeling, the energy storage system was assumed to be preparing for the peak load periods so that it can effectively reduce the demand charges for the given month.

Retail Energy Arbitrage (Time-of-use energy savings on electricity bill)

For sites under Time-of-Use (TOU) rates, the local utility specifies an on-peak and an off-peak rate where the electricity costs are different. The energy storage was modeled to charge during off-peak times and discharge to offset load during on-peak times to reduce the cost of electricity for the site.

Emergency Demand Response Program

The local utility devices Demand Response (DR) programs for loads to participate in during high system load, constrained grid condition periods.

The Southern California Edison (SCE) Capacity Bidding Program (CBP)³⁶ that Naval Base Ventura County participates in pays participants a capacity payment ranging from \$1.38/kW to \$19.53/kW depending on the month. During a DR event, the participants would be called upon to reduce their consumption by the bid-in capacities for any duration that could last between 1 and 6 hours. During the DR events, the site receives an energy payment at \$250/MWh. There is a penalty for non-performing participants. In the economic modeling, the storage was assumed to bid into the program at a capacity that would sustain the output for 6 hours to avoid penalty. It was assumed that the DR events would occur during the 50 days with the highest Locational Marginal Price (LMP) with a randomly selected duration between 1 and 6 hours. CoMETS then tracked the SOC of storage as the DR events occurred and evaluated its effectiveness in participating in the program. While the March ARB site does not currently participate in a DR program, a DR program similar to SCE's Capacity Bidding Program (CBP) was constructed to evaluate the impact to its revenues.

For the El Paso Electric the high-level details of the EPE's DR program for sites in New Mexico have been approved by the utility commission with EPE outlining high level participating levels and incentive dollar amounts though the program still lacks a fully detailed participation manual similar to the one released for the Texas EPE demand response program. The EPE Texas DR program requirements were used as a proxy for the upcoming NM DR program since the published total financial incentive amounts and total MW participation numbers fall in the same ballpark.

³⁶ See the details of the CBP at: <https://www1.sce.com/NR/sc3/tm2/pdf/ce293.pdf>

The parameters used for modelling the DR revenue stream were adopted from the following excerpt from the EPE Texas Load Management Program³⁷:

The Program will be in effect during the Peak Demand Period (“PDP”), which is from June 1, 2018 through September 30, 2018. PDP is defined as weekdays from 1:00 p.m. to 7:00 p.m. Mountain Daylight Time (MDT). Project Sponsors are required to demonstrate load availability by participating in one scheduled curtailment at the beginning of the PDP. Thereafter, Project Sponsors may be called upon up to four more unscheduled times per program year for a maximum of 15 hours per year, including the scheduled curtailment (each, a “Curtailment”). For each Curtailment, upon notice, the Project Sponsor will have one hour to reduce their load by the Contracted Amount. The Project Sponsor shall monitor load reduction during Curtailments. During a Curtailment, the Project Sponsor will reduce load by at least the Contracted Amount. EPE will not be obligated to pay a Project Sponsor for verified Demand Savings that exceed the amount of the contracted Curtailable kW demand. At their discretion, EPE may choose to pay an incentive for this excess demand should funding become available. The Project Sponsor will then receive an incentive payment at the end of the PDP, calculated as a maximum of \$48 per kW for the average reduction of all Curtailments during the PDP (“Incentive Payment”).

For the NAS Patuxent River site, the storage resources located behind a customer meter (that cannot inject) are considered by PJM to be Demand Response (DR). PJM allows Demand Response resources with load reduction capability of >100 kW to bid into their Capacity Market or Reliability Pricing Model (RPM). Demand Response Capacity Sell Offers are limited to a resource’s Installed Capacity (ICAP) which, for limited energy resources, is based on the MW of reduction that can be sustained for 10 continuous hours. During a PJM Capacity event or Performance Assessment Interval, the participants would be called upon to reduce their consumption by the bid-in capacities for any duration that could last between 1 and 10 hours. During these Capacity events, the site receives an energy payment at \$250/MWh. The PJM Capacity Market, that NAS Patuxent River currently participates in, pays participants a capacity payment ranging from \$85/MW-day to \$97/MW-day depending on the auction.

PJM’s Capacity Performance construct, also known as Pay for Performance (PFP), which went into effect on June 1, 2018, allows Capacity resources to incur performance rewards / penalties if they provide Energy and/or Reserves less than / greater than their Capacity obligation during “Performance Assessment Intervals,” which are triggered whenever there is a shortage of reserves. The last Performance Assessment Interval was assessed by PJM in 2014. Currently, no battery Capacity Storage Resources have cleared in any RPM auction. Under-performance penalties are high and start at \$3,000/MWh of energy/reserve shortfall (and increase in subsequent years), and are capped at monthly and annual values.

SMECO Retail Electric Service Tariff Rider DR-GSD, LP defines a utility demand response program that NAS Patuxent River may be eligible to participate in, however, a financial analysis for this program was not included in the CES|CoMETs models. Participation in the SMECO demand response program would jeopardize more lucrative revenue streams and savings

³⁷ See more details of the program at:

https://www.epelectric.com/files/html/Energy_efficiency/Energy_Efficiency_Program_Manuals/2019_Program_Manuals/2019_Load_Management_Manual.pdf

opportunities such as Frequency Regulation and Demand Savings. Also, the NAS Patuxent River is already participating in PJM's Capacity market. Attempting to participate in both PJM's Capacity Market and SMECO's Demand Response program simultaneously could be problematic as it may cause issues with measurement and verification as well as "double-dipping" concerns.

Wholesale Energy Arbitrage

Wholesale energy arbitrage refers to charging or discharging the energy storage system based on the wholesale energy price signal. Whereas the retail energy price stays consistent throughout the summer/winter season or remains constant for the entire on/off-peak periods, wholesale energy prices change on an hourly or 5-minute basis. Under existing rules in the CAISO and in PJM, behind-the-meter energy storage resources can reduce load or increase consumption based on wholesale energy prices. March ARB, Naval Base Ventura County and NAS Patuxent River were modeled with participation in the wholesale energy arbitrage.

Frequency Regulation

Frequency Regulation is a wholesale market service that the system operator, an ISO or RTO, utilizes to balance its second-to-second energy supply and demand. The ISO or RTO procures this service from generators and distributed generation resources. Under existing rules, PJM allows Frequency Regulation participation from behind a customer's retail delivery point where as the CAISO does not.

PJM operates real-time only Ancillary Services market for Frequency Regulation. Under existing rules in PJM, behind-the-meter energy storage resources can provide Frequency Regulation. NAS Patuxent River was modeled with participation in the Frequency Regulation market, specifically RegD, receiving payments based on wholesale market prices whenever the storage was not providing other services. In order to maintain any necessary reliability benefits from the installation of energy storage, the market participant may be required to de-rate the offer MW in order to maintain the necessary SOC floor.

PJM's RegD signal is a 30-minute energy neutral signal that requires a 2-second response. PJM's uses Frequency Regulation to control the Area Control Error (ACE) with a two-signal approach for dispatching Regulation resources: 1) a slow Regulation signal designed for traditional resources with limited ramping capability (RegA signal), and 2) a fast energy-neutral dynamic Regulation signal (RegD signal) designed for fast-ramping Regulation technologies, such as batteries, that can respond nearly instantaneously to system imbalances. Typical revenues for storage resources providing RegD in PJM's Frequency Regulation market are between \$16-18/MW per hour.

Spinning Reserve

The ISO/RTO must maintain a sufficient amount of operating reserves to be able to recover from the loss of the largest single system contingency. To this end, both the CAISO and PJM procure synchronized capacity to provide Spinning Reserve (called Synch Reserve in PJM). Under existing rules in CAISO and PJM, behind-the-meter energy storage resources can provide Spinning Reserve. March ARB, Naval Base Ventura County and NAS Patuxent River were modeled with participation in the Spinning Reserve market, receiving payments based on wholesale market prices whenever the storage was not providing other services.

Based on their ability to respond in near real-time, PJM considers battery storage resources as synchronized to the grid, thus enabling them to provide Synchronized Reserves. To participate in PJM's Synchronized Reserve market, a resource must be capable of responding to a PJM Synchronized Reserve event notification within 10 minutes. Resources can participate in the Synchronized Reserve market in an amount equal to their response capability within the 10-minute window that can be sustained for a period of 30 minutes.

7.2 COST DRIVERS

Only the storage system cost drivers are discussed below, including significant hard and soft costs required to install the storage systems and integrate them within the microgrid, cost of complying with the DoD specified Risk Management Framework (RMF) and the cost of interconnecting with the utility and the ISO.

As discussed in section 7.1, the system installation costs considered in CES|CoMETS were \$400/kWh for a DC-connected storage system, and \$200/kW for the Power Conversion Systems (PCS). The installation costs modeled did not include,

- 1) Interconnection costs: The microgrid must be connected with the electrical grid to supply power at the appropriate transmission or distribution level. These costs include installing and connecting transformers and protective relays to the utility or ISO interconnection specification. The interconnection costs are to enhance the capability of the connected grid to absorb the exported power at a certain voltage/current without adversely affecting the grid's reliability and safety. Such costs vary with the site and its utility/ISO's engineering specifications, and should generally be included under the EPC costs.
- 2) Communication costs: If a site participates in the wholesale market, a communication link with the ISO dispatch center or with a scheduling coordinator must be established. Such communications equipment uses the MOD/DNP bus protocols, often through a dedicated line. While the communications system may not cost too much, meeting the DoD's Risk Management Framework (RMF) would add extra costs. This would include hardware/software security controls. These costs are site-specific.
- 3) Scheduling Coordinator/Management Fees: Contracting with a Scheduling Coordinator (SC) who acts an agent to enable market participation. Per ISO and FERC requirements, the generating resource or microgrid owner or operator either itself be a certified SC or hire an organization that is certified to be one. A SC makes the bids on behalf of the microgrid for pre-determined services (e.g. frequency regulation) to participate in the market. Upon execution of the bid, the SC makes the settlement of payment form the ISO to the owner/operator of the asset or enables recovery of penalty in case of default. This is recurring monthly cost that could range from \$10,000 or more depending on the asset size and the extent to which the SC is involved with in managing the asset and determining the bids etc.

Additionally, there are soft costs that include,

- Engineering design costs for integrating the energy storage system with the rest of the microgrid.
- Costs for the interconnection application and permission to connect with the utility/ISO grid.
- Permitting costs from the local jurisdiction (may not apply to DoD facilities) to install and operate energy storage.

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8.0 STUDY CONCLUSIONS AND OUTCOMES

In summary, this Phase I study concludes that state of the art Li-ion energy storage coupled with phasor-based control can be used in a DoD installation microgrid to improve reliability with significantly reduced cost vs. an all-diesel microgrid.

For each of the five installations modeled, an “energy storage enhanced” microgrid design concept was identified capable of meeting the 100% critical load profile with improved load coverage probability vs. the all-diesel microgrid baseline. Most of the final configurations provided >24 hours of coverage at 10% and 30% critical load, with Fort Bliss being the notable exception due to the relatively small amount of storage driven by market participation economics. NB Ventura achieved 3hrs at the 30% critical load requirement; however, the periods where the load coverage probability fell below the requirement were marginal, limited by storage MTBF. A follow-up analysis showed that by increasing MTBF, >24hrs of coverage would be achieved with the same storage size. None of the facilities could sustain the 130% critical load for appreciable durations, with NAS Pax River and March ARB achieving the best results at 3hr and 4hrs, respectively. This was an expected outcome, with configuration optimized for 100% critical load coverage there was simply not enough available generation.

The net cost per kW critical load for the aforementioned microgrid design concepts was reduced by between 6% and 169%. This was enabled by market participation, followed by UPS elimination, and then diesel generator elimination. NAS Pax River produced the best economic results, achieving a profitable microgrid design with a net cost of -\$86/kW protected load (188% reduction). Holloman AFB (44% reduction), NB Ventura County (32% reduction), and March ARB (31% reduction) also showed significant cost improvements. Fort Bliss provided the least benefit at 6% reduction.

C-HIL testing results demonstrated the ability of the PXiSE ACT microgrid controls to perform unique functions required to realize key assumptions in the reliability and techno-economic analysis. Specifically, the C-HIL results showed that multiple ESS units could be used in a grid forming inverter-based microgrid, and that these ESS units can back each other up in a similar fashion to networked diesel generators. In addition, the C-HIL results showed that PXiSE ACT can provide precise control of power flow in the presence of variable generation and load by controlling ESS and other DERs. This function is critical to all installations, as demand charge management was universally found to be the highest priority grid-tied function.

Other key conclusions were as follows:

- 1) Positive economics associated with employing storage in a DoD installation microgrid are derived primarily (45-91% of total benefit) from market participation. Value stacking multiple use cases optimized on an hour-by-hour basis provides the best results, especially for locations where each use case can provide significant and comparable value (e.g., CAISO locations).
- 2) Elimination of UPS in favor of multi-function ESS can provide supplementary benefits to complement market participation (6-32% of total benefit). However, the implementation must support equivalent functionality to the UPS, which may dictate co-locating the energy storage with the load and/or integrating with suitably high-speed switching to enable acceptable power quality during transitions.

- 3) Elimination of 1-2 diesel generators provides incremental economic benefits (2-14% of total benefit), but is not a driver of economic results unless capital and O&M cost reductions are the primary drivers of cost savings (as is the case for Fort Bliss where generator elimination accounts for 55% of the total benefit). Elimination of >2 diesel generators becomes economically impractical due to the large quantity of storage required.
- 4) For Li-ion, short duration (1-2 hour) storage is preferred over long duration storage. The incremental benefits obtained via increasing storage duration do not offset the additional costs.
- 5) Demand charge management was found to be the highest value (\$/hr) single market participation mechanism and was prioritized at all five installations.
- 6) Frequency regulation was found to be the highest overall value (\$) market participation mechanism and was substantially responsible for the outcomes of the NAS Pax River analysis. It also provided the best economic outcomes for both CAISO installations (March ARB, NB Ventura County). However, current CAISO market rules are a significant impediment and practically preclude the use of installation microgrid energy storage for frequency regulation.
- 7) The ESS MTBF required to ensure the reliability of a single, centralized ESS does not compromise microgrid reliability benefits can vary from 1000 to 10,000 hours. Insufficient data exists from manufacturers and in the literature to conclude whether 10,000hrs MTBF can be met. However, dividing the energy storage into multiple units with a modest MTBF of 1895hrs was found provide acceptable results.
- 8) The control capabilities of PXiSE's ACT demonstrated advantages over the baseline SCADA control. Specifically, it enabled the wind turbine to ride-thru planned and unplanned transitions, and accommodated increased generator ramp rates. These benefits support increased islanding efficiency and reliability.

9.0 REFERENCES

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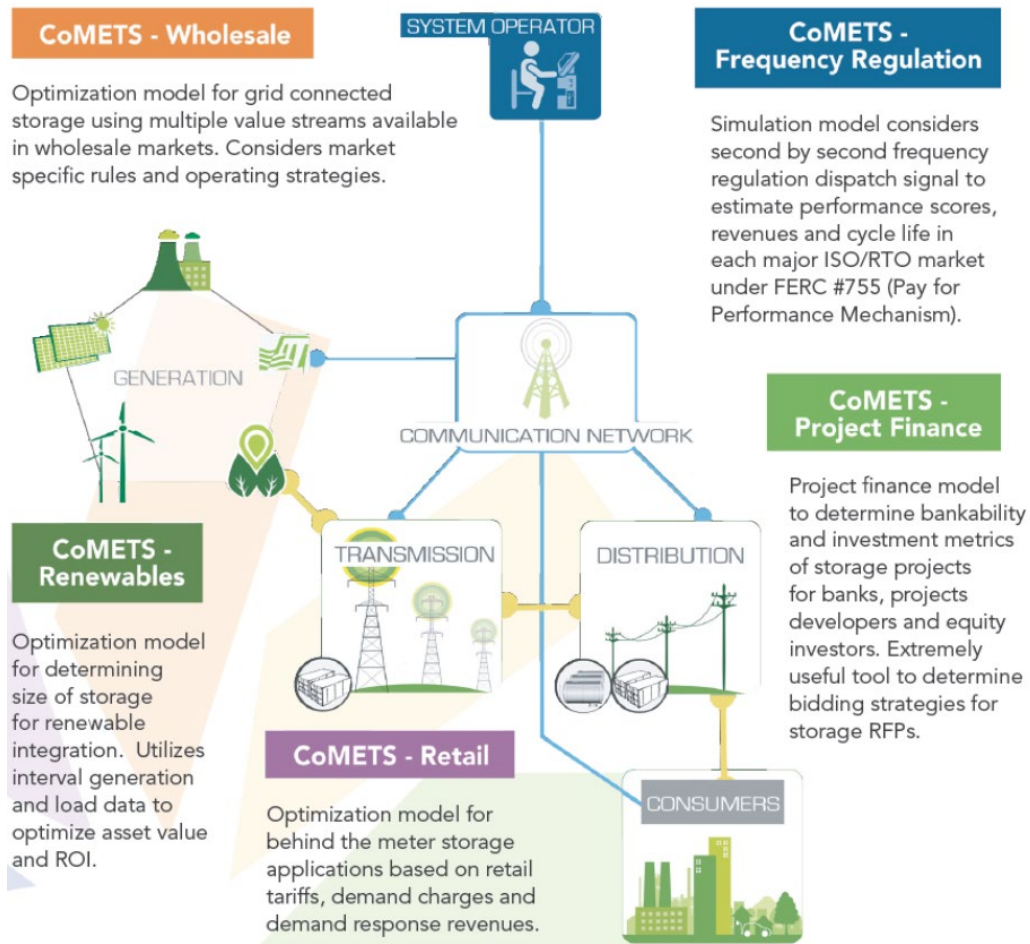
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A2. METHODOLOGY APPENDIX

CoMETS Overview

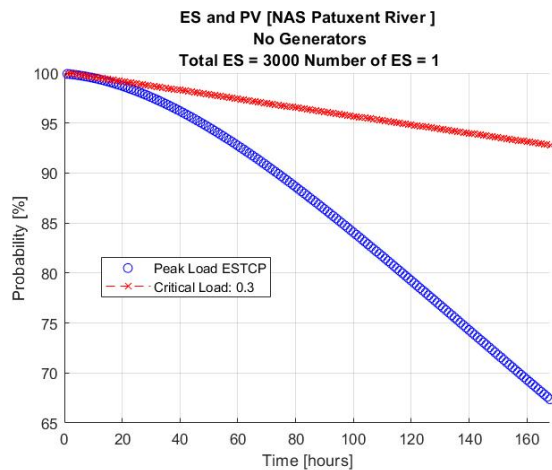
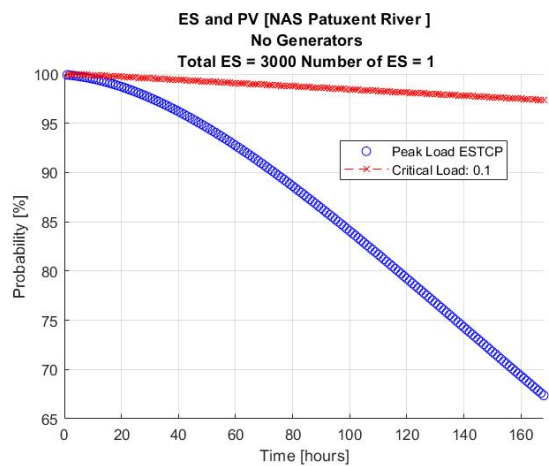
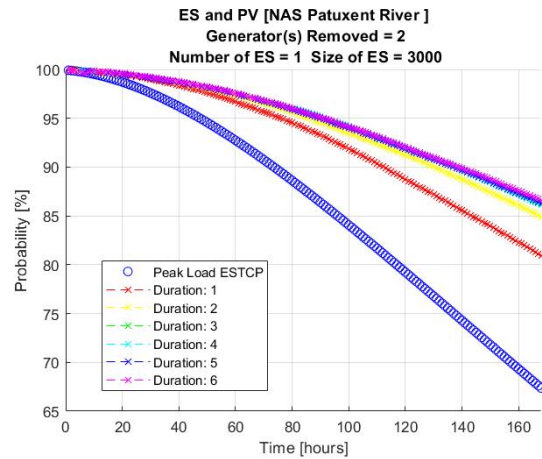
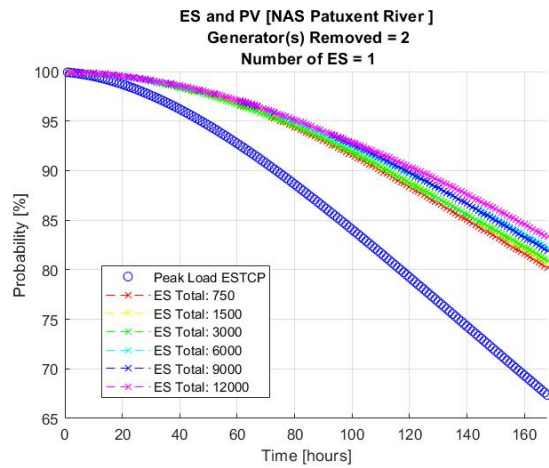
Competitive Markets Evaluation Tools for Storage (CoMETS) is a suite of software models using Matlab and Python that help technology and project developers evaluate and optimize energy storage resources for grid-connected and behind-the-meter storage applications. The CoMETS model include consideration of wholesale energy and ancillary services products, demand response, retail demand charge reduction and retail arbitrage among other revenue sources. CoMETS consists of modules that allow modeling of revenue options/bill savings for a single service or in combination with several other services (use cases), while ensuring their mutual compatibility. CoMETS models the economics of market participation for microgrids consisting of multiple loads, generators (renewable and fossil) and energy storage systems.

Customized Energy Solutions' (CES) development of CoMETS is informed by its 20-year experience of analyzing the wholesale energy storage markets across the US and scheduling conventional and renewable generation, demand response, and energy storage for the wholesale markets. Based on CES's experience managing 225 MW of energy storage assets, the CoMETS is built based on real market conditions and how to optimize in the real world. The underlying assumptions in the model are continuously being updated to reflect the changing rules at the utility, RTO/ISOs and the FERC. Such capability is unique to CoMETS because CES has a staff of 30 attending or monitoring ISO/utility/FERC meetings to keep abreast of the rules on regular basis. Past and current CoMETS customers include Pacific Gas and Electric (PG&E), Eaton, Mitsubishi Heavy Industries (MHI), Mitsubishi Research Institute (MRI), Invenergy, Exelon Corporation, Siemens Gamesa, Enel Green Power, Starwood Capital, Innolith, Industria Energy, Ameren, 174 Power Global, NEC Energy Solutions, International Renewable Energy Agency (IRENA), and American Railroad Energy Storage (ARES).

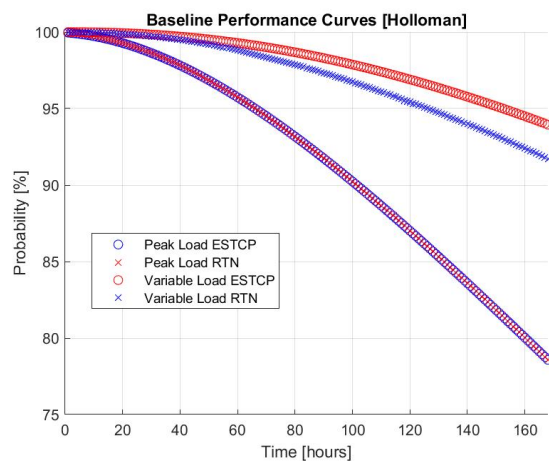


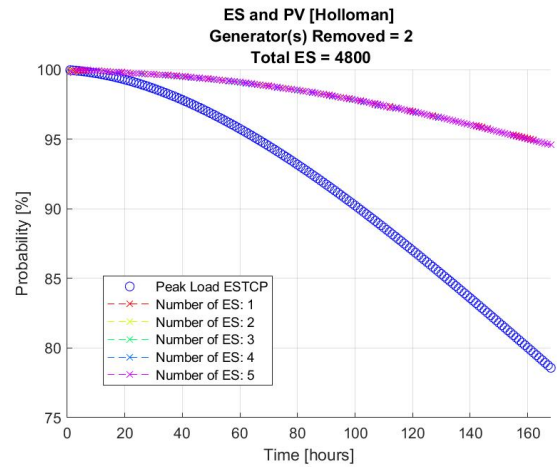
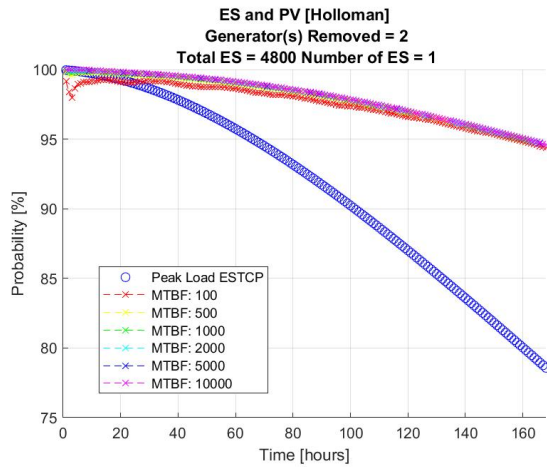
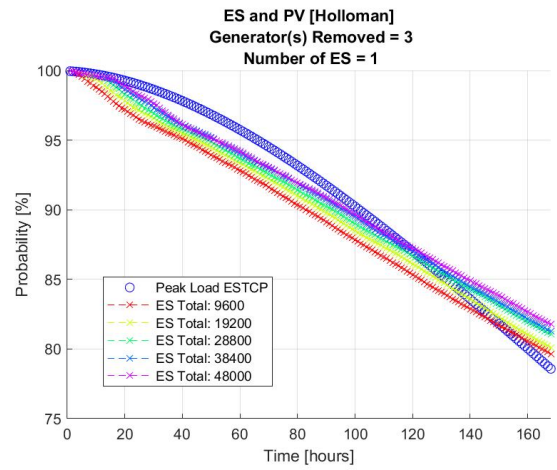
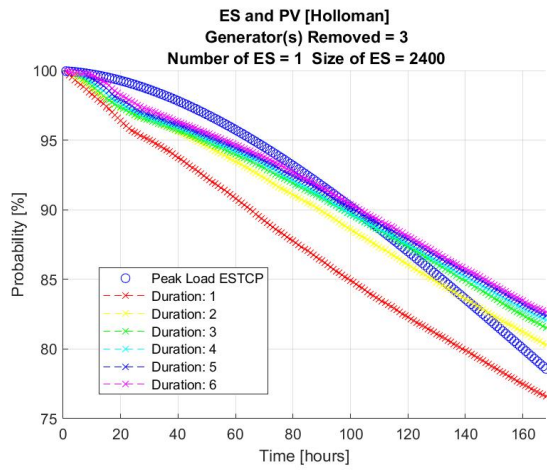
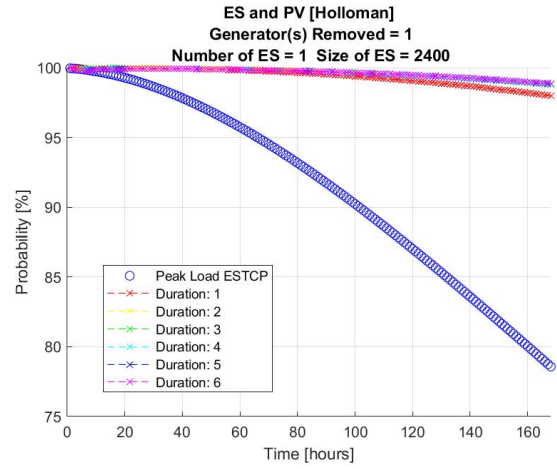
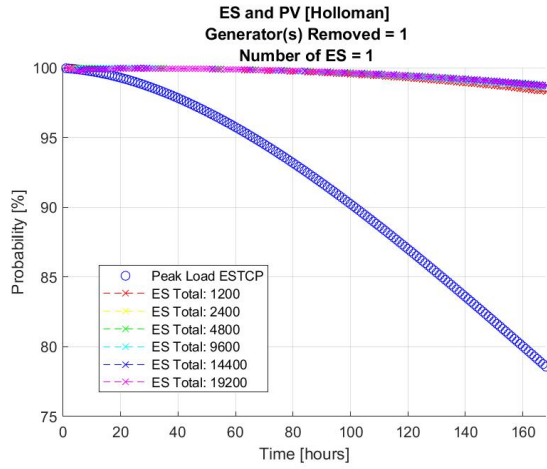
A3. PERFORMANCE APPENDIX

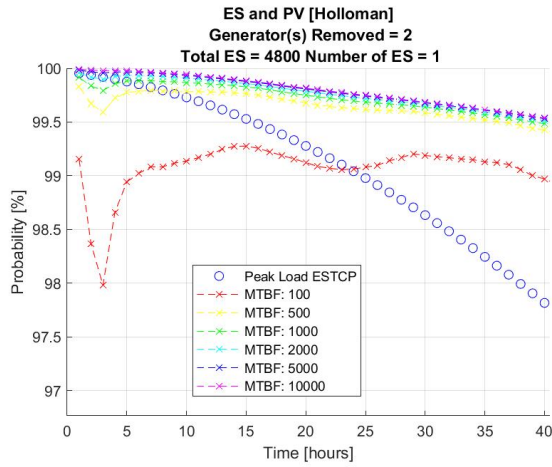
Additional Reliability Results: NAS Pax River



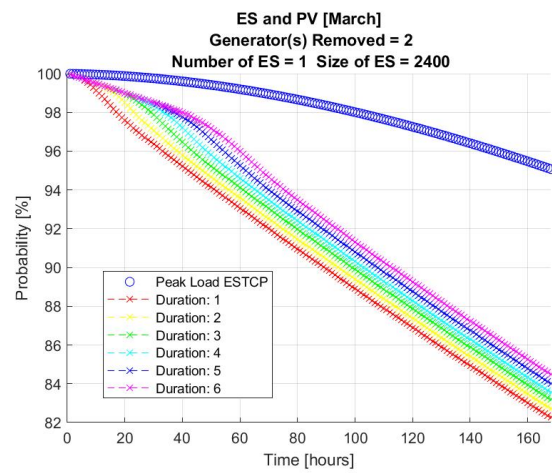
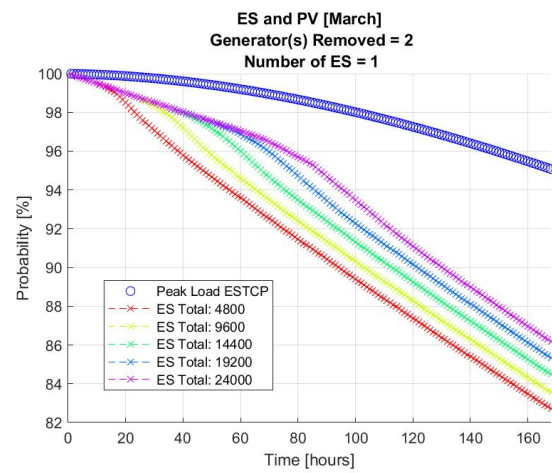
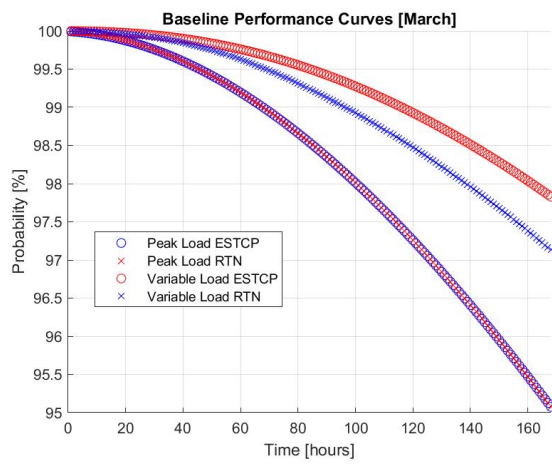
Additional Reliability Results: Holloman Air Force Base

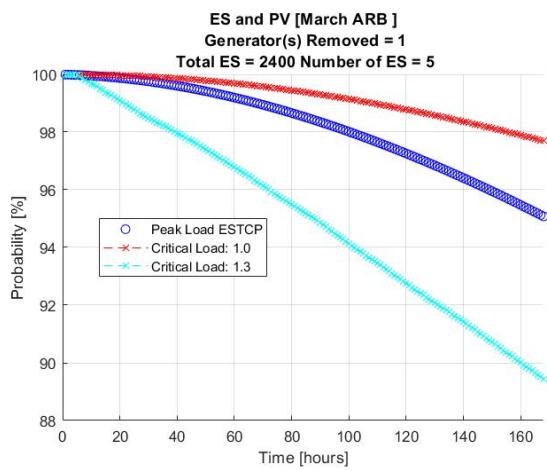
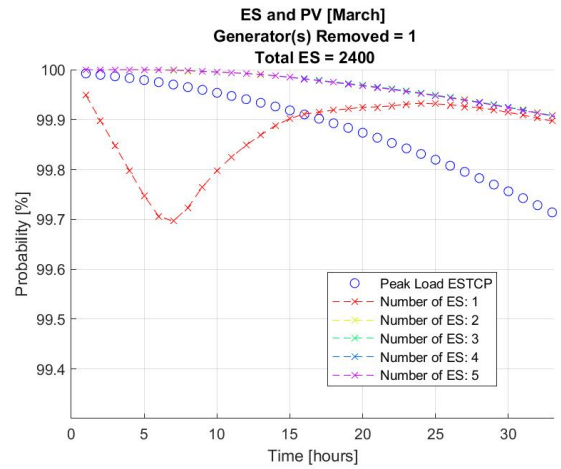
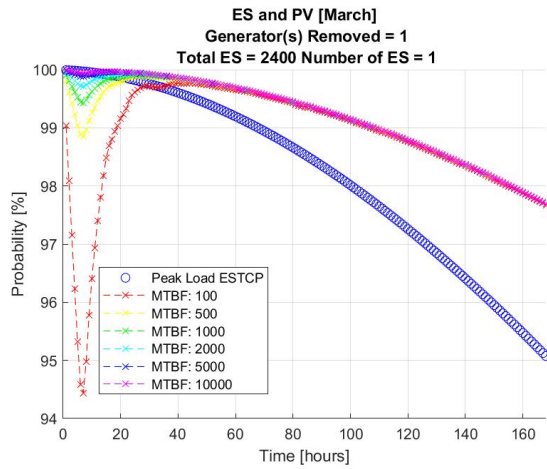




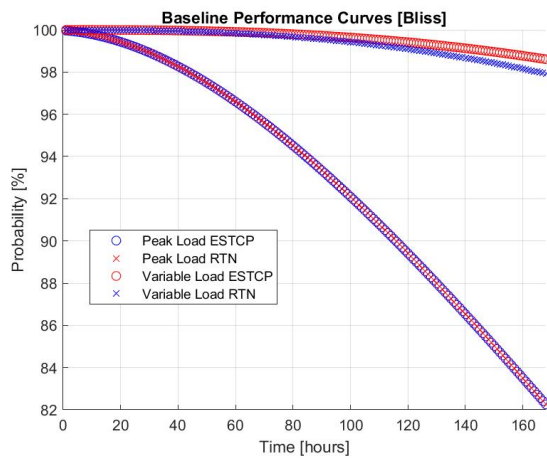


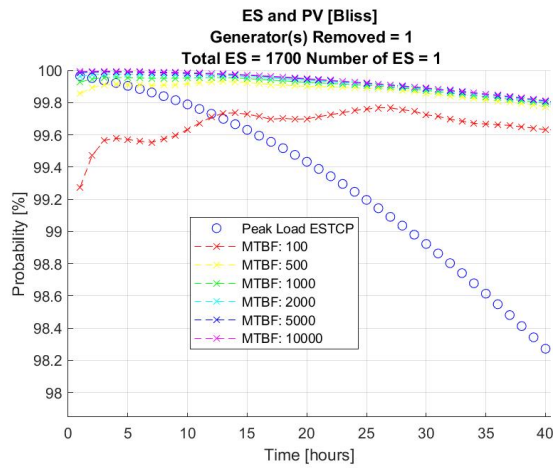
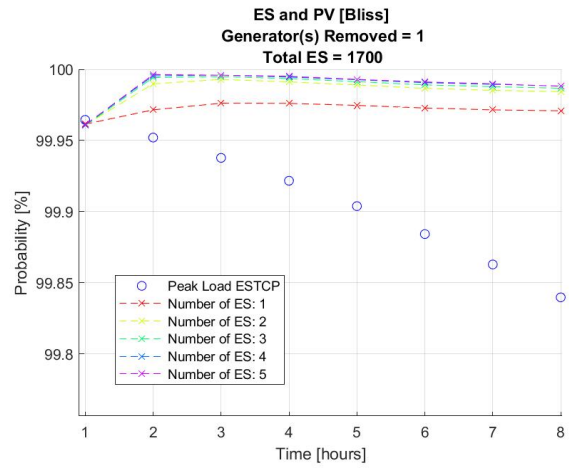
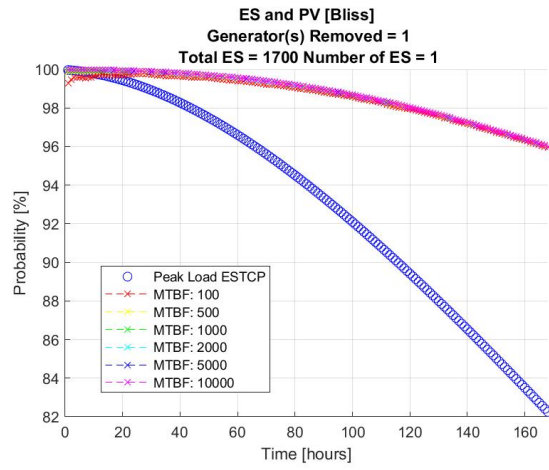
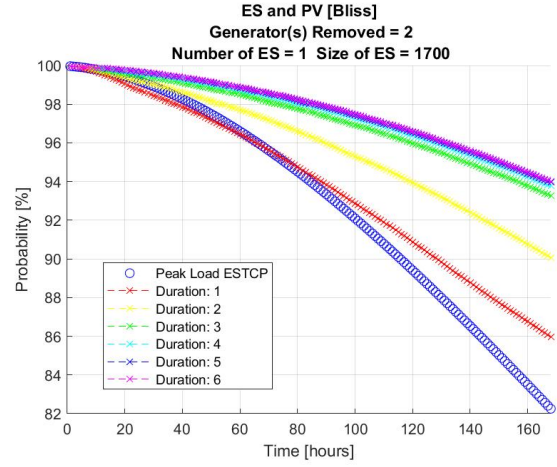
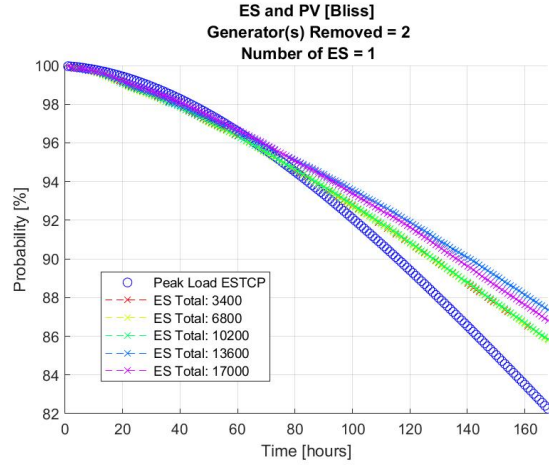
Additional Reliability Results: March Air Reserve Base



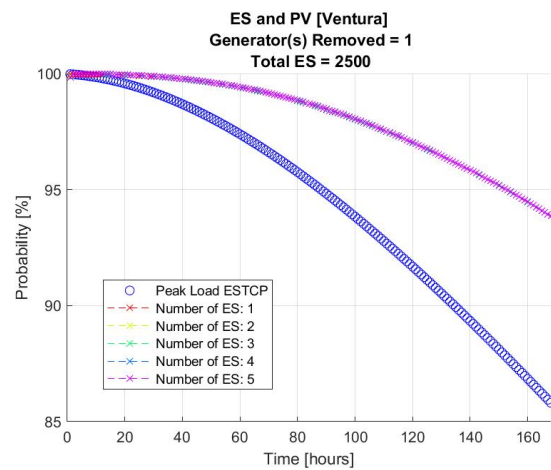
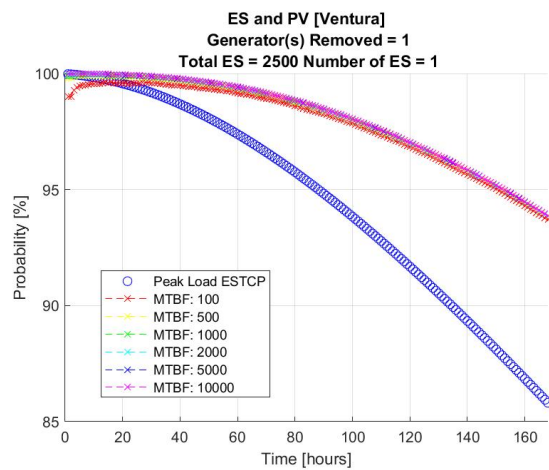
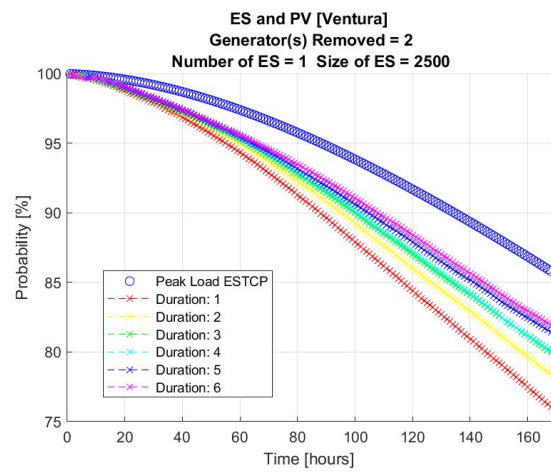
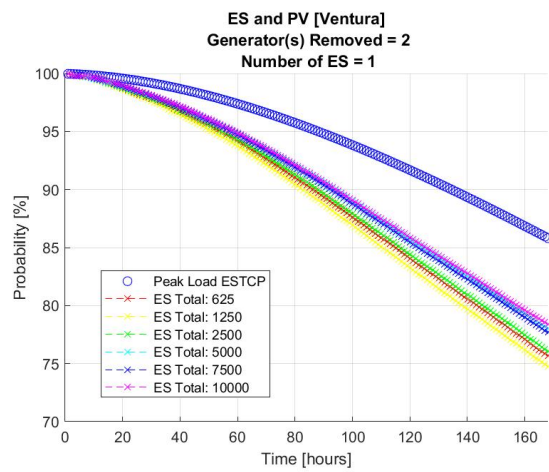
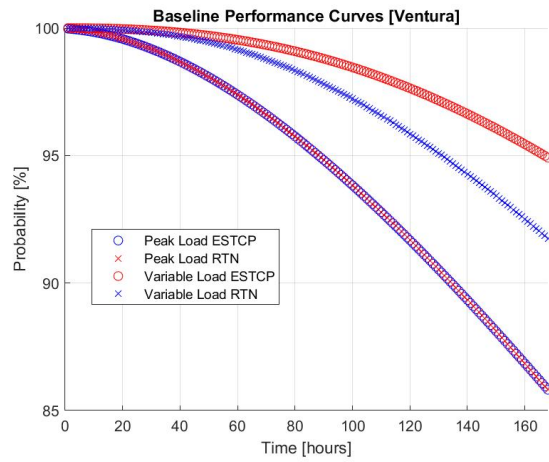


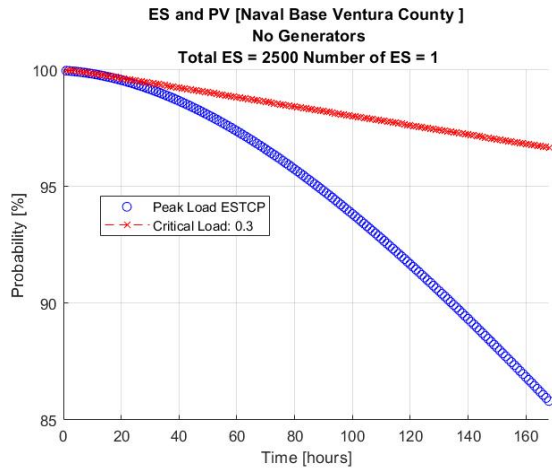
Additional Reliability Results: Fort Bliss





Additional Reliability Results: Naval Base Ventura

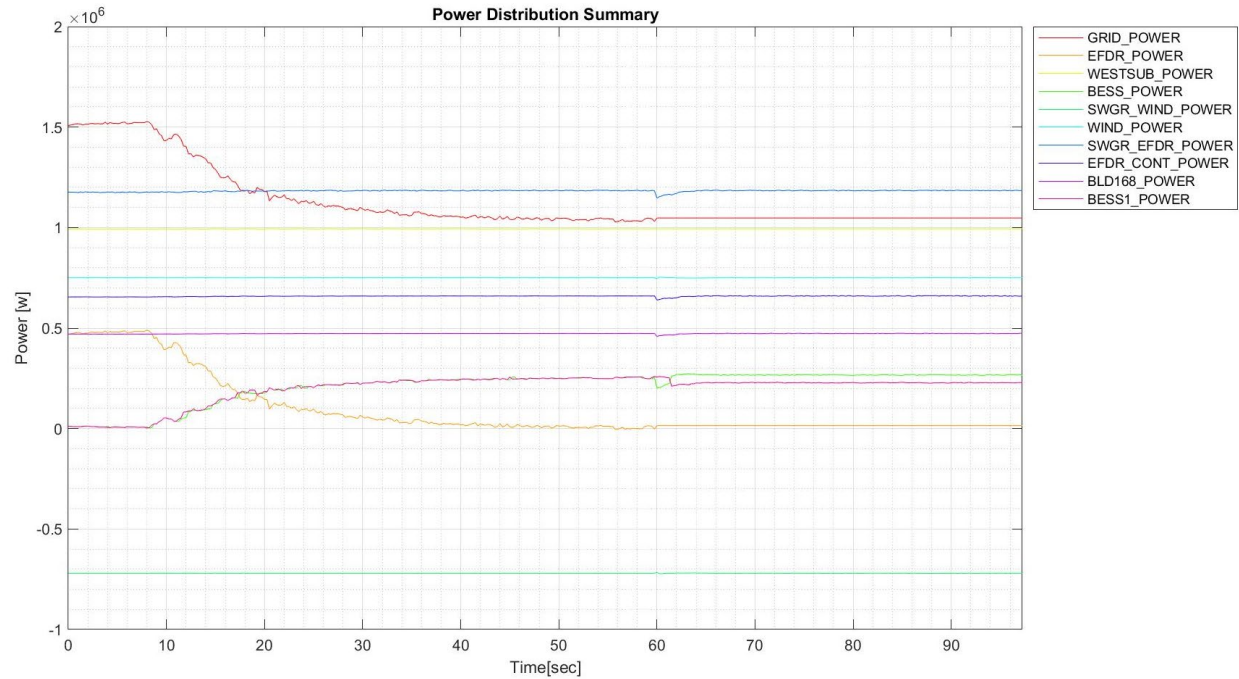




Test 5.1.1 Planned Islanding – Heavy Power Import

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Receive Island Command The system starts grid connected and is importing the majority of the power required for the EFDR Load (Non-Critical + Critical Loads) from the Utility. PXiSE commands the system to enter Microgrid mode. ESS #1 will be in Grid-Forming and ESS #2 will be in Grid-Following	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify ESS picks up Microgrid load and opens HSDS 2. Ensure system remains stable utilizing V/F for ESS #1 and PQ commands for ESS #2 from PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	0.5			
GEN Output	0.0			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	1.0			
Critical Load	1.0			
Non EFDR	0.5			

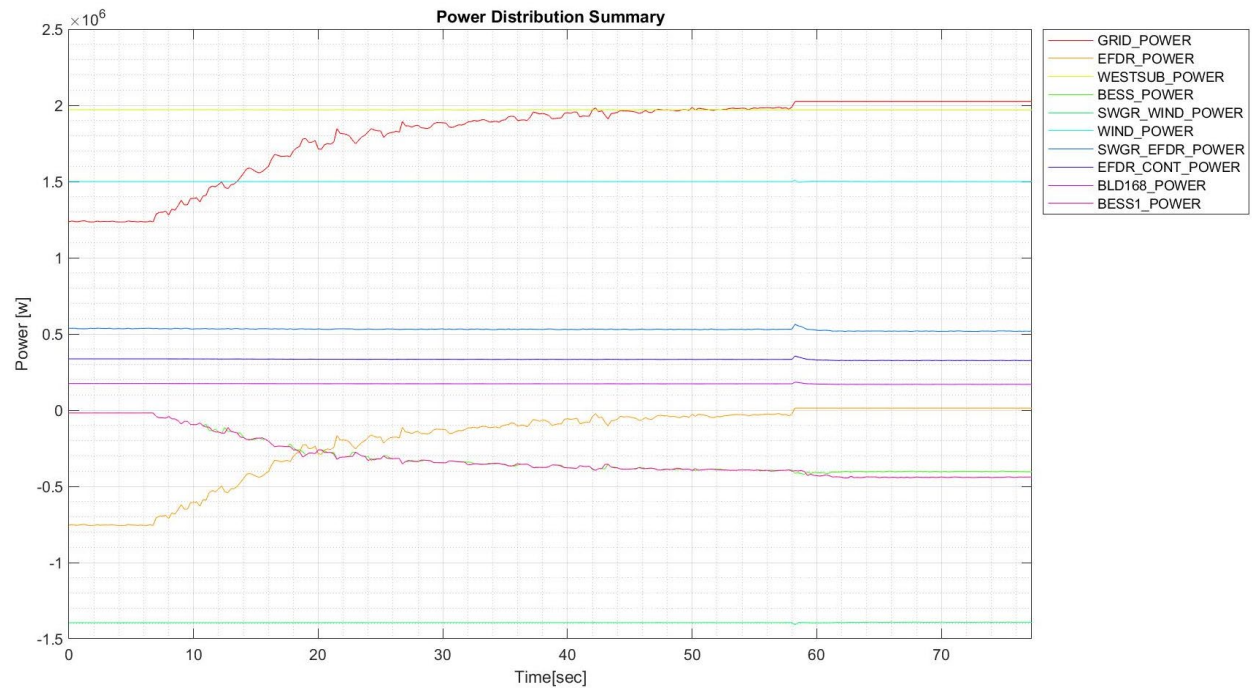
Test 5.1.1 Power Distribution vs. Time. Islanding occurs at t = 60s



Test 5.1.2 Planned Islanding - Heavy Power Export

Component	State	TestDescription	Metric	Pass/Fail Criteria
HSDS	Closed	Receive Island Command The system starts grid connected and is generating more power than the power required for the EFDR Loads (Non-Critical + Critical Loads). PXiSE commands the system to enter Microgrid mode. ESS #1 will be in Grid Forming and ESS #2 will be in Power Control mode	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify ESS picks up Microgrid load and opens HSDS 2. Ensure system remains stable utilizing V/F for ESS #1 and PQ commands for ESS #2 from PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	1.0			
GEN Output	0.0			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	0.5			
Critical Load	0.5			
Non EFDR	1.0			

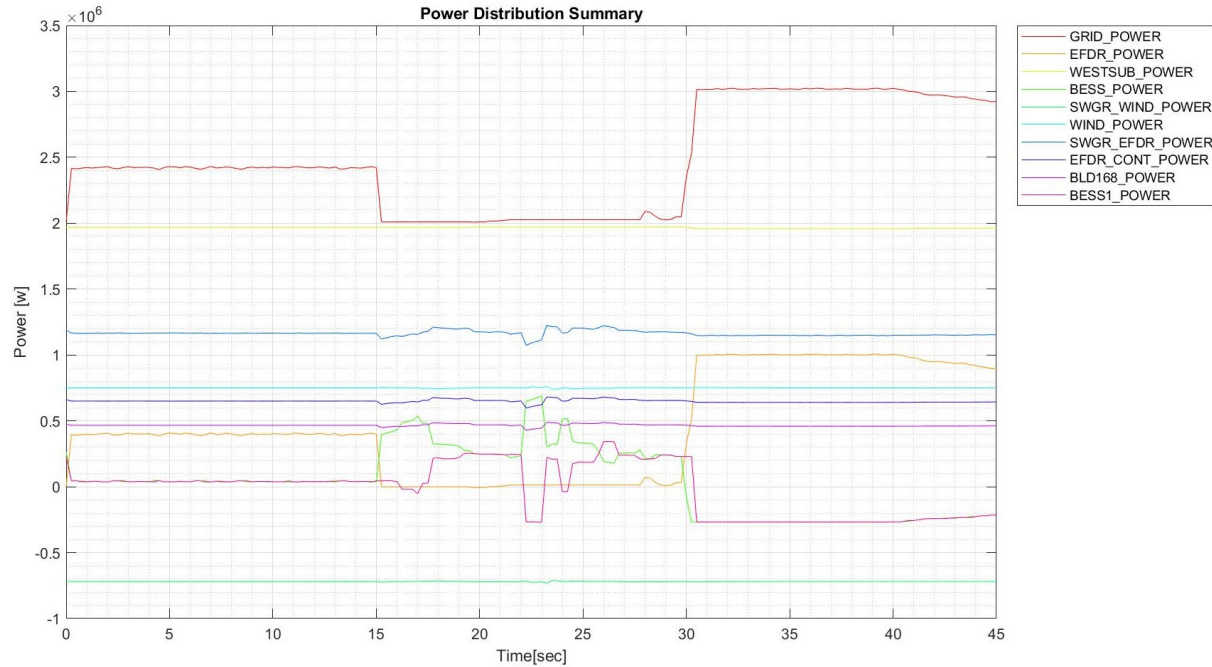
Test 5.1.2 Power Distribution vs. Time. Islanding occurs at t = 58s



Test 5.2.1.1 Unplanned Islanding – Auto Reconnect

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, Auto-Reconnect RTN will control the circuit breaker positions via the HIL SCADA 1. Trip CB2 (52 EFDR) 2. Re-close CB2 (52 EFDR) prior to emergency timer time-out	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. ESS PCU detects loss of grid 2. Transitions to LoG-RT 3. ATS starts Timer 4. Detects Grid Ok Status 5. System transitions back to grid-tied 6. Genset does not start/parallel 7. System remains stable using PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	1.0			
GEN Output	0.0			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	0.1			
Critical Load	0.1			
Non EFDR	1.0			

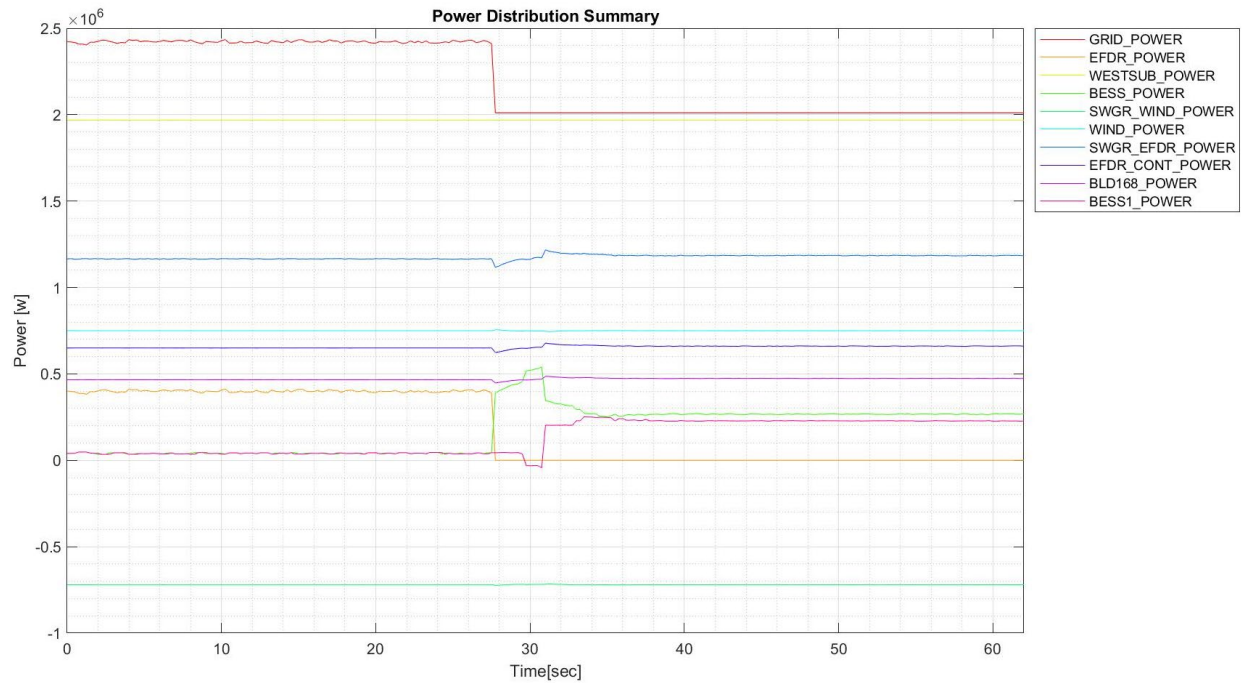
Test 5.2.1.1 Power Distribution vs. Time. Islanding occurs at t = 15s, Reconnection at 30s



Test 5.2.1.2 Unplanned Islanding – LoG RT

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, LoG-RT The system starts grid connected with Critical , and Non-Critical Loads within their allowable ranges. Generator is online but not Paralleled until needed. RTN trips CB2 simulating a Loss of Grid and transitions into Microgrid mode. * Re-run test throughout the allowable ranges of the Loads and Generator	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify ESS picks up Microgrid load 2. Ensure system remains stable utilizing PQ commands from PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	1.0			
GEN Output	Varies			
ESS #1 SOC	50 %			
ESS #2 SOC	50 %			
Noncritical Load	Varies			
Critical Load	Varies			
Non EFDR	1.0			

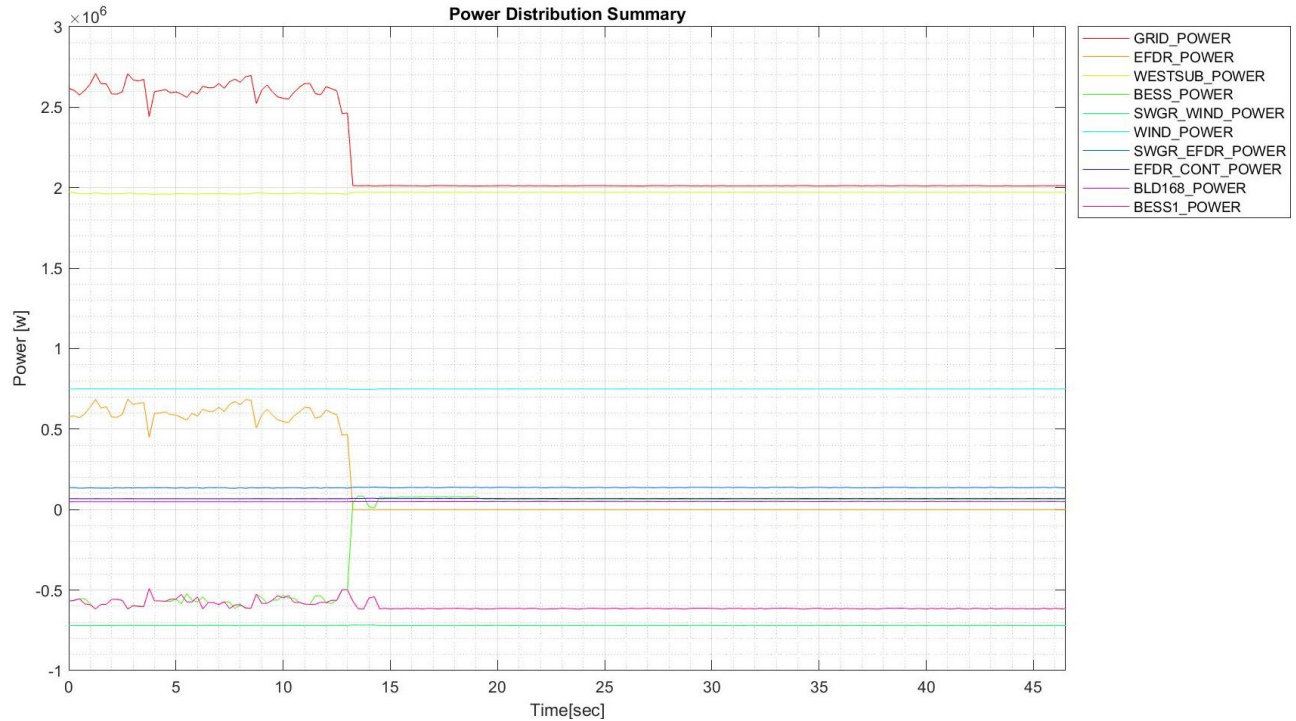
Test 5.2.1.2 Power Distribution vs. Time. Islanding occurs at t = 28s



Test 5.2.1.3 Unplanned Islanding - Low SoC

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, Low SoC	<u>Measurements:</u>	1. Verify ESS picks up Microgrid load 2. Ensure system remains stable utilizing PQ commands from PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ	The system starts grid connected with Critical , and Non-Critical Loads within their allowable ranges.	1. Vrms 2. Real Power 3. Reactive Power 4. Frequency	
ESS #2 Mode	PQ			
WT Mode	Connected	Generator is online but not Paralleled until needed.	Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	
WT Output	0.5			
GEN Output	0.0	ESS #1 and ESS #2 are brought to their lower limit of operation		
ESS #1 SOC	30 %	CB2 is tripped simulating a Loss of Grid and transitions into Microgrid mode.		
ESS #2 SOC	30 %			
Noncritical Load	0.1	* Re-run test to determine failure conditions		
Critical Load	0.1			
Non EFDR	1.0			

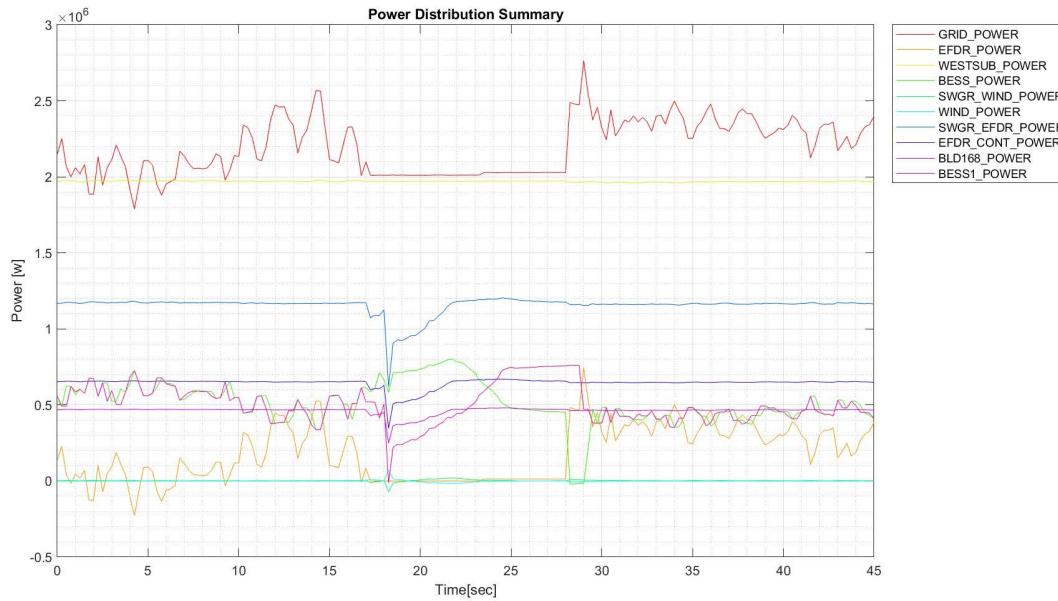
Test 5.2.1.3 Power Distribution vs. Time. Islanding occurs at t = 13s



Test 5.2.2.1 Unplanned Islanding – Auto Reconnect

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, Auto-Reconnect RTN will control the circuit breaker positions via the HIL SCADA 1. Trip CB2 (52 EFDR) 2. Re-close CB2 (52 EFDR) prior to emergency timer time-out	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. ESS PCU detects loss of grid 2. Transitions to LoG-RT 3. ATS starts Timer 4. Detects Grid Ok Status 5. System transitions back to grid-tied 6. Genset does not start/parallel 7. System remains stable using PXISE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	0.5			
GEN Output	0.0			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	1.0			
Critical Load	1.0			
Non EFDR	1.0			

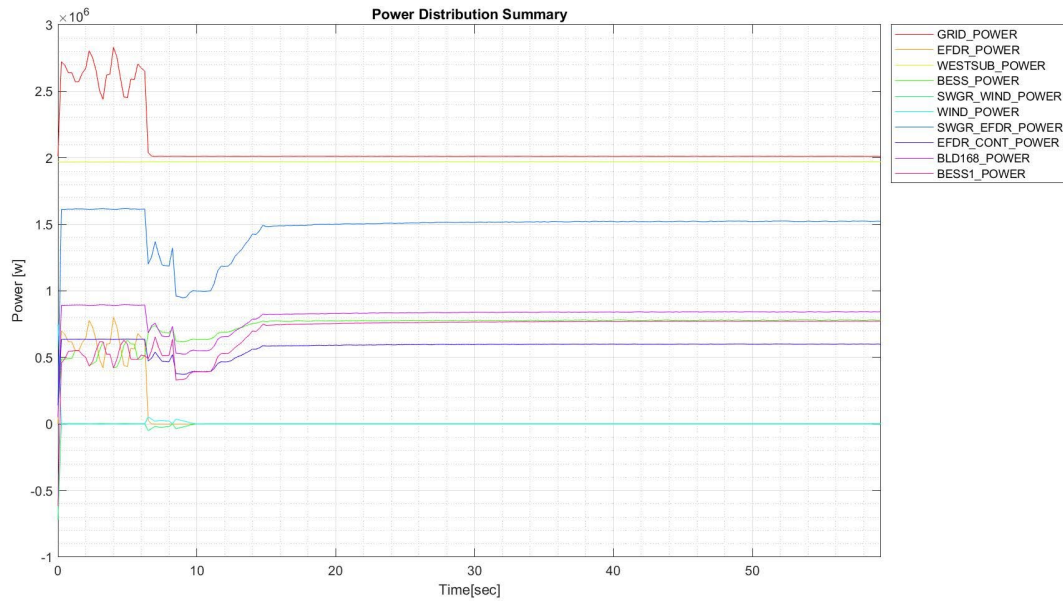
Test 5.2.2.1 Power Distribution vs. Time. Islanding occurs at t = 18s, Reconnection at t = 26s



Test 5.2.2.2 Unplanned Islanding – LoG RT

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, LoG-RT The system starts grid connected with Critical , and Non-Critical Loads within their allowable ranges. Generator is online but not Paralleled until needed. CB2 is tripped simulating a Loss of Grid and transitions into Microgrid mode. * Re-run test throughout the allowable ranges of the Loads and Generator	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify ESS picks up Microgrid load 2. Ensure system remains stable utilizing PQ commands from PXISEACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	0.5			
GEN Output	Varies			
ESS #1 SOC	50 %			
ESS #2 SOC	50 %			
Noncritical Load	Varies			
Critical Load	Varies			
Non EFDR	1.0			

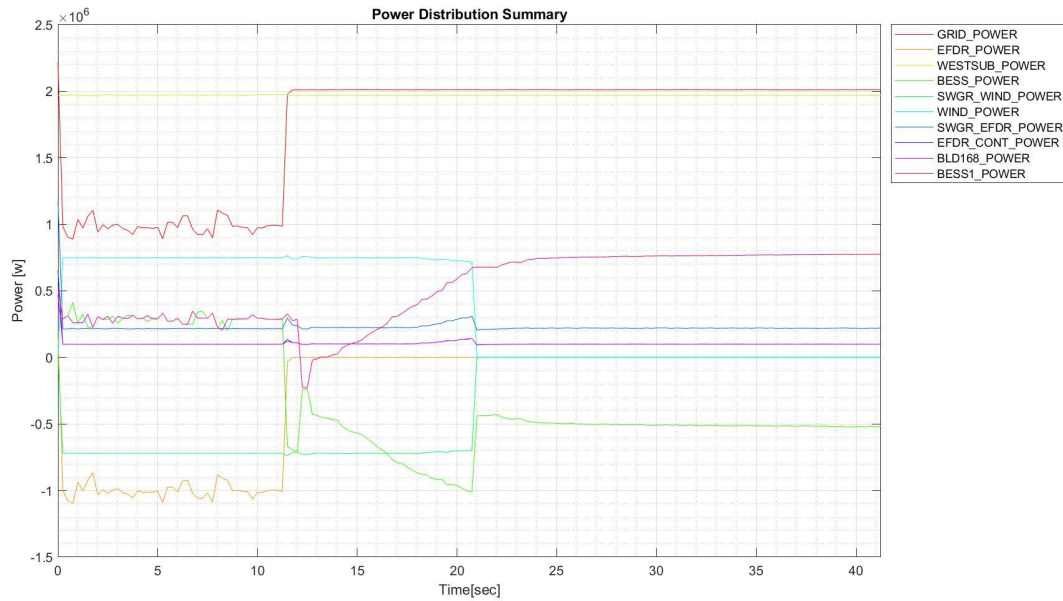
Test 5.2.2.2 Power Distribution vs. Time. Islanding occurs at t = 3s



Test 5.2.2.3 Unplanned Islanding - High SoC

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Unplanned POI disconnection, High SoC	<u>Measurements:</u>	
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ	The system starts grid connected with Critical , and Non-Critical Loads within their allowable ranges.	1. Vrms 2. Real Power 3. Reactive Power 4. Frequency	1. Verify ESS picks up Microgrid load
ESS #2 Mode	PQ			
WT Mode	Connected	Generator is online but not Paralleled until needed.	Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	2. Ensure system remains stable utilizing PQ commands from PXISE ACT
WT Output	0.5			
GEN Output	0.0	ESS #1 and ESS #2 are brought to their upper limit of operation		
ESS #1 SOC	68 %	CB2 is tripped simulating a Loss of Grid and transitions into Microgrid mode.		
ESS #2 SOC	68 %			
Noncritical Load	1.0			
Critical Load	1.0	* Re-run test to determine failure conditions		
Non EFDR	1.0			

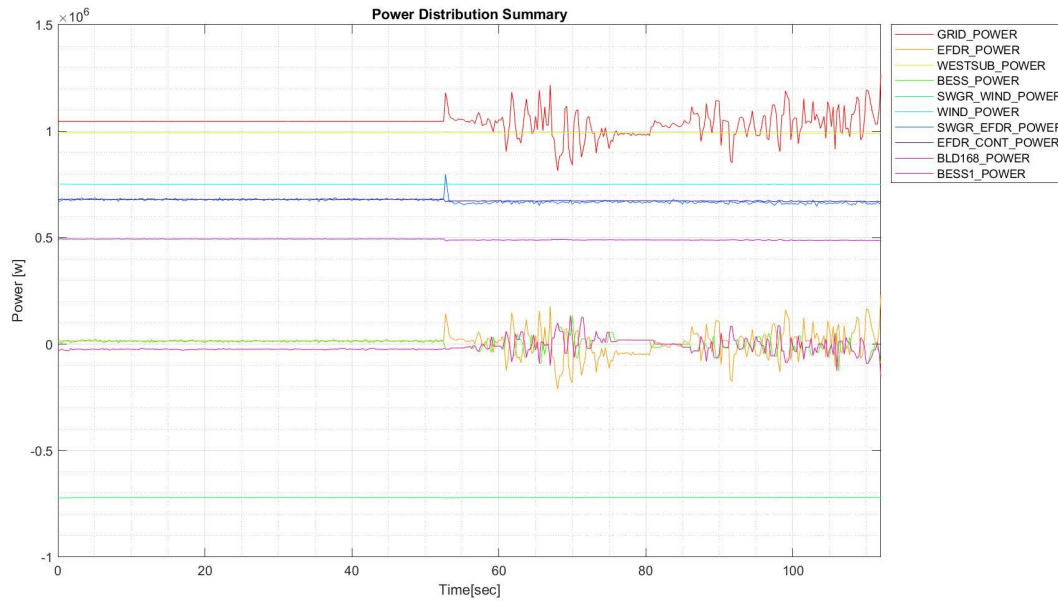
Test 5.2.2.3 Power Distribution vs. Time. Islanding occurs at t = 11s



Test 5.3.1.1 Reconnection Test

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	Receive Island Command The system starts in Microgrid mode. RTN commands the system to enter Grid-tied mode. ESS #1 will be in V/F mode and ESS #2 will be PQ mode	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify successful transition into Grid-tied operations 2. Ensure system remains stable utilizing PQ commands from PXISEACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	V/F			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	0.5			
GEN Output	0.0			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	1.0			
Critical Load	1.0			
Non EFDR	0.5			

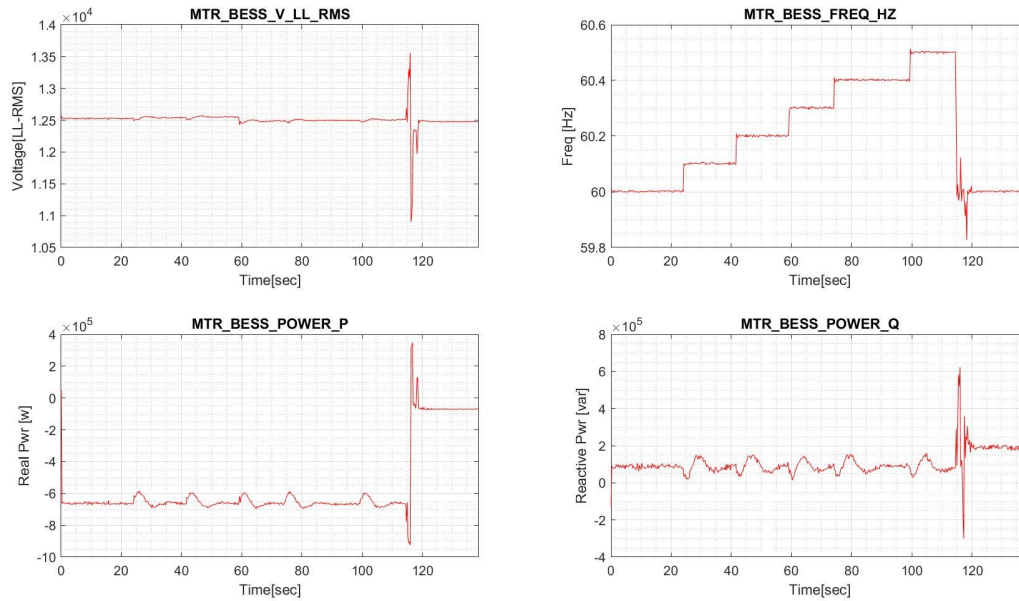
Test 5.3.1.1 Power Distribution vs. Time.



Test 4.2.1.1a Changing ESS Frequency

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	ESS Frequency Offset	Measurements:	
CB2 Status	1 0			
ATS Mode	Paralleled			
ESS #1 Mode	VF			
ESS #2 Mode	PQ	The system starts in Microgrid mode.	1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify the system remains stable under the varying frequency 2. Ensure system remains stable utilizing PQ commands from PXiSE ACT
WT Mode	Connected	PXiSE commands the ESS #1 (Grid-Forming) to have an offset frequency of 59.5 Hz to 60.5 Hz in 0.1 Hz Steps		
WT Output	Varied			
GEN Output	0.72	Wind turbine 0kW output increasing by 500 kW to maximum of 1500kW		
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	Varied	Non-critical load and critical load will minimum for part 1 and maximum for part 2		
Critical Load	Varied			
Non EFDR	1.0			

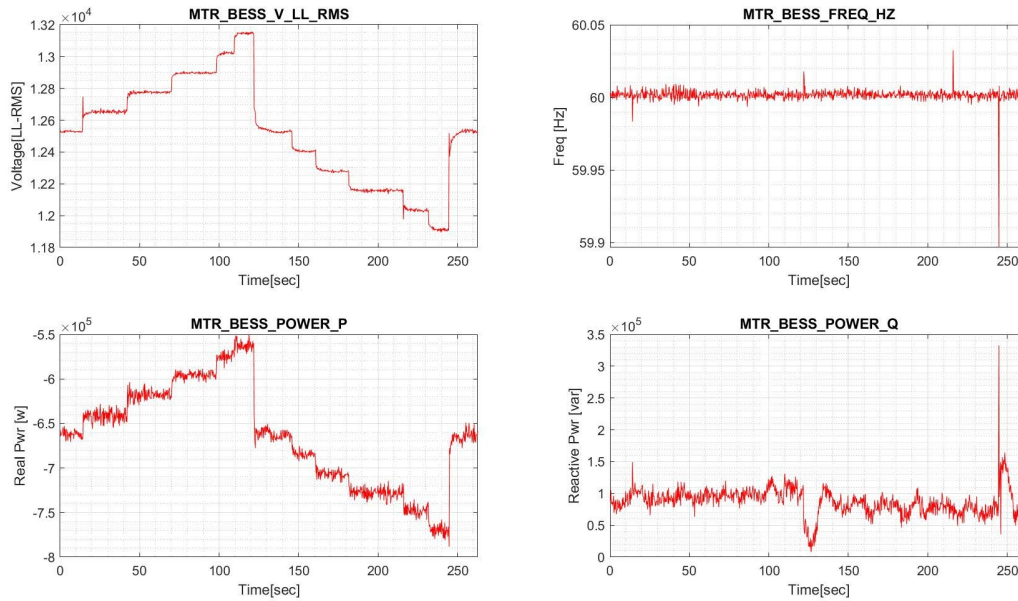
Test 4.2.1.1a Grid forming ESS meter measurements



Test 4.2.1.1b Changing ESS Voltage

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	ESS Voltage Offset The system starts in Microgrid mode. PXiSE commands the ESS #1 (Grid-Forming) to have an offset voltage of 0.95 p.u. to 1.05 p.u. in 0.01 p.u. Steps	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify that the system remains stable under the varying voltage 2. Ensure system remains stable utilizing PQ commands from PXiSE ACT
CB2 Status	1 0			
ATS Mode	Paralleled			
ESS #1 Mode	VF			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	Varied			
GEN Output	0.72			
ESS #1 SOC	50%			
ESS #2 SOC	50%			
Noncritical Load	Varied			
Critical Load	Varied			
Non EFDR	1.0			

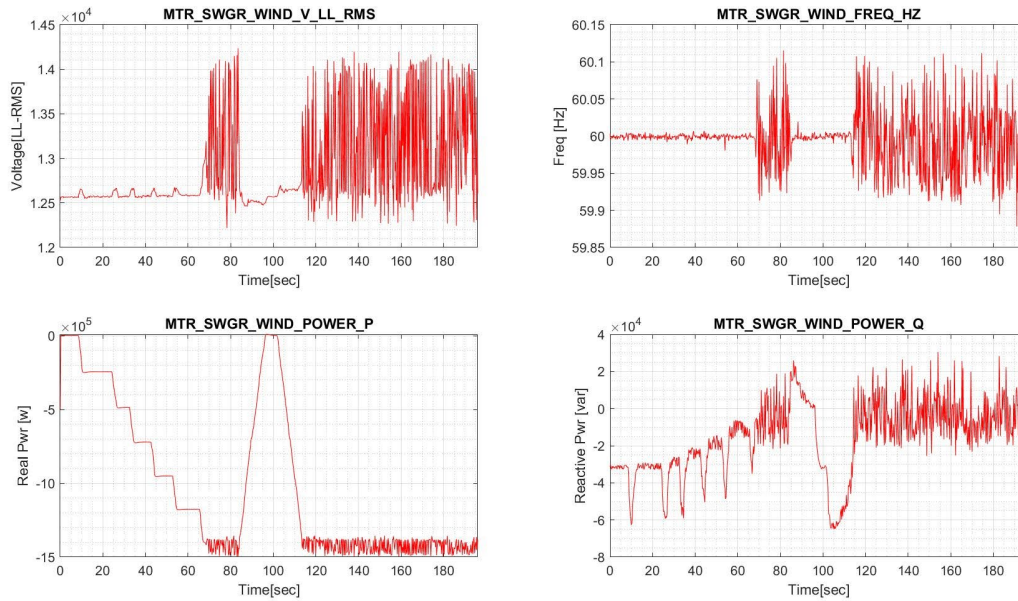
Test 4.2.1.1b Grid forming ESS meter measurements



Test 4.2.1.2 Changing Wind Turbine Power Set Point

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	Wind Turbine Control	Measurements:	
CB2 Status	1 0			
ATS Mode	Paralleled	The system starts in Microgrid mode.	- Vrms - Real Power - Reactive Power - Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	- Verify that the system remains stable under the varying ESS SoC - Ensure system remains stable utilizing PQ commands from PXiSE ACT
ESS #1 Mode	VF	PART 1:		
ESS #2 Mode	PQ	RTN ensures the ESS #1 and ESS #2 hold a high SoC		
WT Mode	Connected			
WT Output	Varied	Monitor PQ control of DERs at the upper limit.		
GEN Output	0.72	PART 2:		
ESS #1 SOC	Varied	RTN ensures the ESS #1 and ESS #2 hold a low SoC		
ESS #2 SOC	Varied			
Noncritical Load	Varied	Monitor PQ control of DERs at the lower limit.		
Critical Load	Varied			
Non EFDR	1.0			

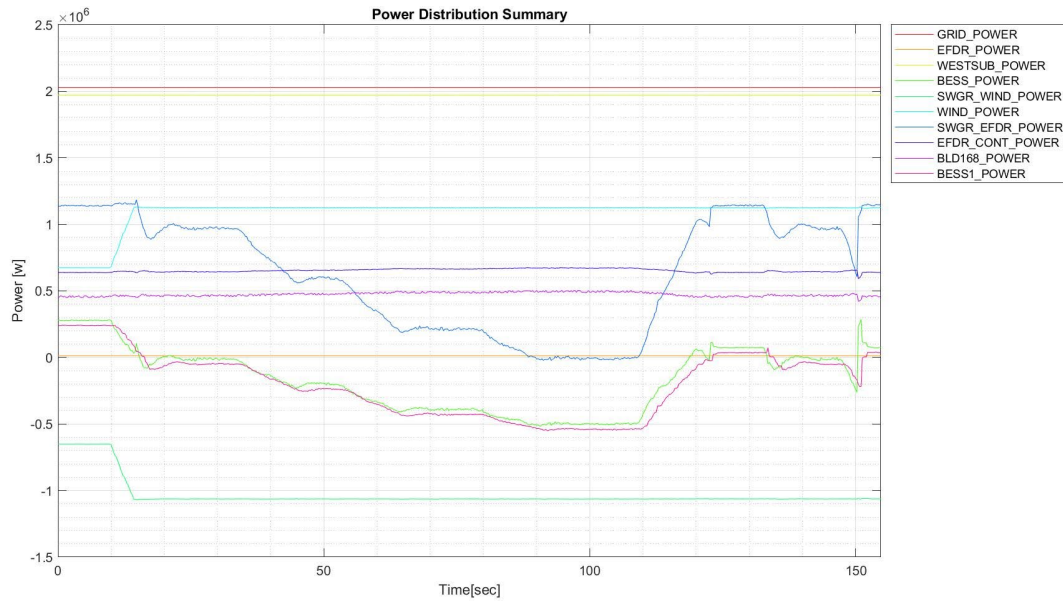
Test 4.2.1.2 Wind turbine meter measurements



Test 4.2.1.3 Changing GENSET Power Set Point

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	GENSET Control	Measurements:	
CB2 Status	1 0			
ATS Mode	Paralleled			
ESS #1 Mode	VF	PART 1: RTN ensures the ESS #1 and ESS #2 hold a high SoC	- Vrms - Real Power - Reactive Power - Frequency	Verify that the system remains stable under the varying ESS SoC
ESS #2 Mode	PQ			
WT Mode	Connected	Monitor PQ control of DERs at the upper limit.	Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	Ensure system remains stable utilizing PQ commands from PXiSE ACT
WT Output	0.75			
GEN Output	Varied	PART 2: RTN ensures the ESS #1 and ESS #2 hold a low SoC		
ESS #1 SOC	Varied			
ESS #2 SOC	Varied	Monitor PQ control of DERs at the lower limit.		
Noncritical Load	Varied			
Critical Load	Varied			
Non EFDR	1.0			

Test 4.2.1.3 Power Distribution vs. Time.



Test 4.2.1.4 Nominal Steady State Islanded

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Open	DER Control The system starts in Microgrid mode. System runs for TBDhrs, Micro-grid controller manages ESS#1 SoC	Measurements: 1. Generator run time vs. load (calculated fuel consumption) 2. ESS#1 throughput 3. ESS#2 throughput	1. System maintains stable islanding for complete test duration.
CB2 Status	1 0			
ATS Mode	Normal			
ESS #1 Mode	VF			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	0.5			
GEN Output	0			
ESS #1 SOC	Varied			
ESS #2 SOC	Varied			
Noncritical Load	Varied			
Critical Load	Varied			
Non EFDR	1.0			

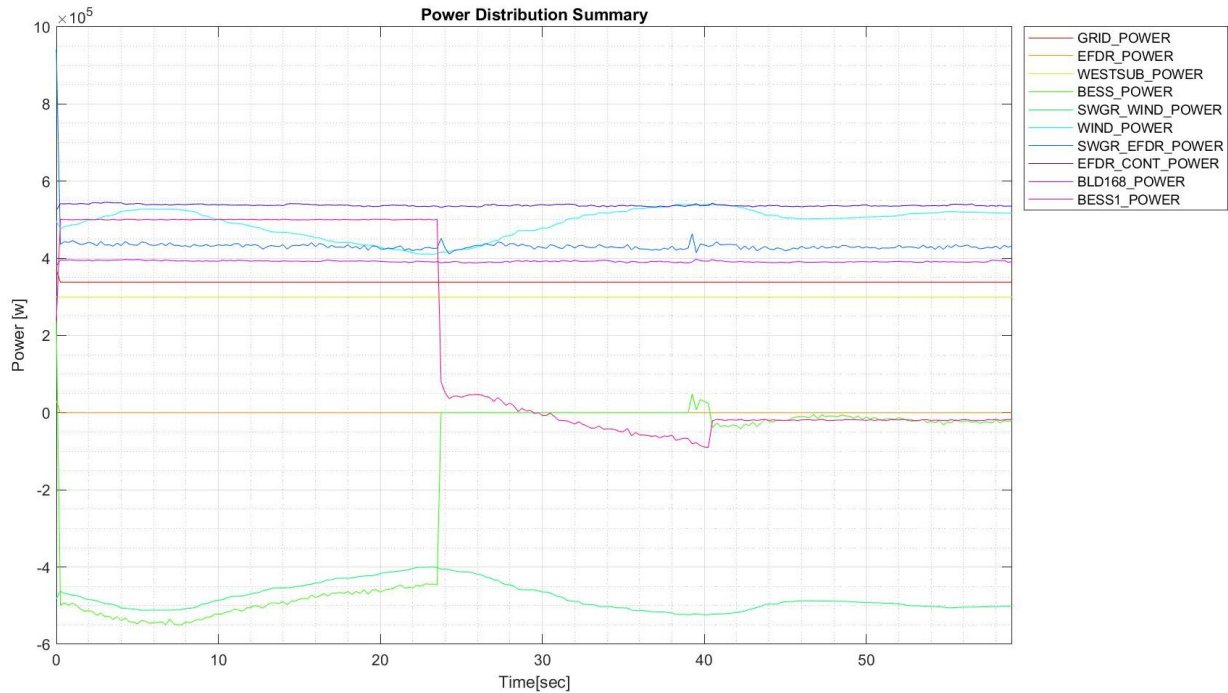
Test 4.2.1.4 Power Distribution vs. Time.



Test 4.2.2.1 Redundant ESS Inverter Control

Component	State		Test Description	Metric	Pass/Fail Criteria
HSDS	Open		ESS	Measurements:	1. Verify that the system remains stable under the varying ESS SoC 2. Verify the proper transition of the second inverter into grid-forming mode of operation 3. Ensure system remains stable utilizing PQ commands from PXISE ACT
CB2 Status	1	0			
ATS Mode	Paralleled		PART 1:		
ESS #1 Mode	Vf		RTN ensures the ESS #1 and ESS #2 hold a high SoC		
ESS #2 Mode	PQ		Trip the simulated Battery System		
WT Mode	Connected				
WT Output	0.0		Monitor PQ control of DERs at the upper limit.		
GEN Output	0.32		Ensure that Measurements for Settling Time and Over/Under Voltages are recorded		
ESS #1 SOC	Varied			PART 2:	
ESS #2 SOC	Varied		RTN ensures the ESS #1 and ESS #2 hold a low SoC		
Noncritical Load	Varied		Trip the simulated Battery System		
Critical Load	Varied		Monitor PQ control of DERs at the lower limit.		
Non EFDR	1.0				

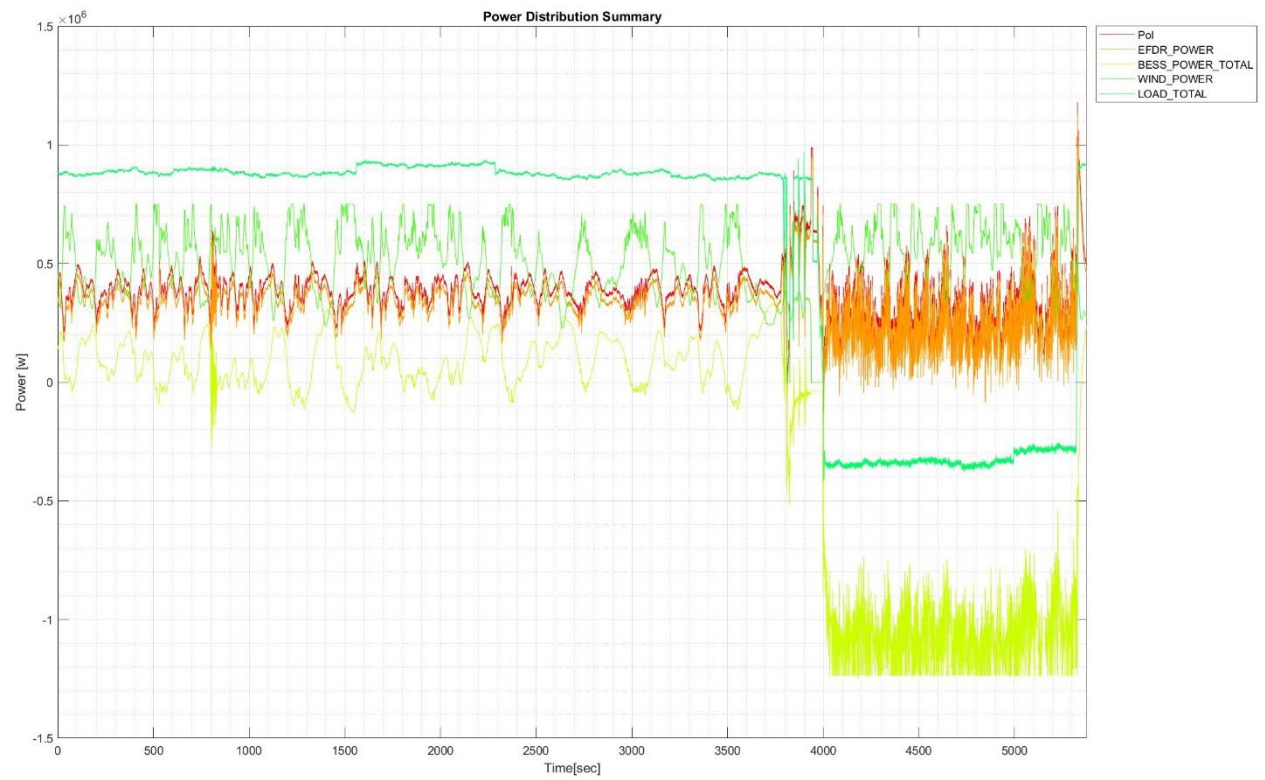
Test 4.2.2.1 Power Distribution vs. Time. Grid forming BESS fails at t = 22s and is reconnected at t = 40s



Test Group 4 Grid Tied Demand Management

Component	State	Test Description	Metric	Pass/Fail Criteria
HSDS	Closed	Grid-Tied Demand Management The system starts Grid-tied. RTN will start variable load profiles and variable wind turbine generation profile PXiSE ACT will control all system DERs to maintain a constant power flow at PCC	Measurements: 1. Vrms 2. Real Power 3. Reactive Power 4. Frequency Ensure that Measurements for Settling Time and Over/Under Voltages are recorded	1. Verify that the system remains stable under varying Non-EFDR Loads 2. Ensure system remains stable utilizing PQ commands from PXiSE ACT
CB2 Status	Closed			
ATS Mode	Normal			
ESS #1 Mode	PQ			
ESS #2 Mode	PQ			
WT Mode	Connected			
WT Output	Varied			
GEN Output	Varied			
ESS #1 SOC	Varied			
ESS #2 SOC	Varied			
Noncritical Load	1.0			
Critical Load	1.0			
Non EFDR	0.05			

Test Group 4 Power Distribution vs. Time.



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A4. COST APPENDIX

Modeling Assumptions

<i>Storage Assumptions</i>		
<i>Technology</i>	Li-ion	
<i>Round Trip Efficiency</i>	90%	
<i>SOC Low</i>	0%	
<i>SOC High</i>	100%	
<i>Unit Cost for PCS</i>	200	\$/kW
<i>Unit Cost for Storage</i>	400	\$/kWh
<i>Replacement Cost</i>	50% of initial CapEx	at year 10
<i>System Availability</i>	95%	
<i>Battery Warranty</i>	10	years
<i>Project</i>		
<i>Life</i>	20	years
<i>Discount Rate</i>	6%	
<i>Market</i>		
<i>Annual Inflation Rate for Retail and Wholesale Electricity Prices, Demand Charges, DR programs, Spinning/Synchronized Reserve Prices</i>	2.2%	
<i>Forecast for Frequency Regulation</i>	CES Forecast for PJM and CAISO	

The load duration curve for each site is included here for reference.

