Long-Duration Energy Storage: Resiliency for Military Installations

Jeffrey Marqusee, Dan Olis, Xiangkun Li, and Tucker Oddleifson

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
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NREL/TP-5C00-87646
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NREL wishes to thank Justin Briggs of Antora Energy for providing his time and expertise to allow NREL to properly model their system. We also wish to thank Tim Tetreault of DoD's Environmental Security Technology Certification Program for his support, which allowed NREL to model multiple military installations. Finally, we wish to thank ARPA-E for their leadership in long-duration energy storage and providing the financial support for this project.

List of Acronyms

AC	alternating current
AFB	Air Force Base
ATB	Annual Technology Baseline
BESS	battery energy storage system
CFE	carbon-free energy
CHP	combined heat and power
DC	direct current
DER	distributed energy resource
DoD	U.S. Department of Defense
EDG	emergency diesel generator
EPA	U.S. Environmental Protection Agency
ITC	investment tax credit
LDES	long-duration energy storage
MACRS	modified accelerated cost recovery system
MMBtu	million British thermal units
NAS	Naval Air Station
NB	Naval Base
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PV	photovoltaics
RTE	round-trip efficiency
SOC	state of charge
TPV	thermophotovoltaics
TRL	technology readiness level

Executive Summary

This report provides a quantitative techno-economic analysis of a long-duration energy storage (LDES) technology, when coupled to on-base solar photovoltaics (PV), to meet the U.S. Department of Defense's (DoD's) 14-day requirement to sustain critical electric loads during a power outage and significantly reduce an installation's carbon footprint. The LDES modeled is Antora Energy's battery energy storage system (BESS). It is currently at a technology readiness level (TRL) of 7 and not ready for full-scale deployment. To support decisions on the value of near-term demonstrations, this analysis looked at the potential value of Antora Energy's BESS if deployed in the future.

Antora Energy's BESS stores thermal energy in inexpensive carbon blocks. To charge the battery on a military base, power from the grid or an on-base solar PV will resistively heat the carbon blocks to temperatures up to or exceeding 1,000°C. To discharge energy, the hot blocks are exposed to thermophotovoltaic (TPV) panels that are like traditional solar panels but specifically designed to efficiently use the heat radiated by the blocks. In addition, the BESS can directly dispatch thermal energy. It is worth noting that Antora has also developed a BESS that outputs only heat, which will be commercially deployed at industrial sites starting in 2025. Two versions of the BESS that could dispatch electricity as well as heat were modeled, one that would be available in the mid- term (the "Intermediate" BESS) and one that could be available in the long-term (the "Goal" BESS). The Intermediate BESS's costs are approximately twice as much as the Goal costs, and the Intermediate TPVs have a reduced conversion efficiency leading to a system-level AC-to-AC round-trip efficiency (RTE) of 38% vs. 48% for the Goal system.

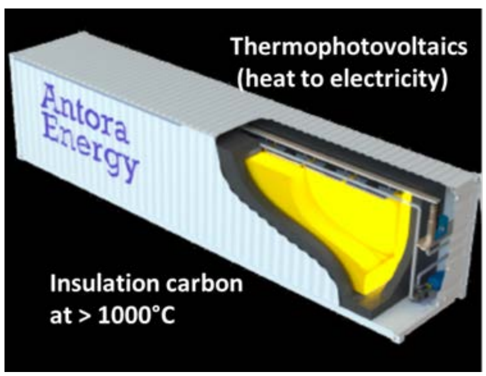

Figure ES-1. Antora Energy's BESS

The techno-economic modeling was done using the National Renewable Energy Laboratory's (NREL's) REopt® model. REopt was modified to model Antora Energy's BESS and used in an iterative approach to find cost-effective resilient solutions. To model Antora Energy's BESS, three key changes to the public version of REopt were required. First, the charging and discharging rates had to be decoupled so that the charging rate was not constrained to equal the discharging rate. Second, the daily loss of stored energy (thermal) needed to be included in the model. Finally, the BESS needed to be modeled like a combined heat and power system that can dispatch both electricity and heat.

NREL selected three installations (Table ES-1) representative of many military installations to assess the costs and benefits of using Antora Energy's BESS coupled to an on-base PV system to provide energy resilience. They cover three military services and are in different states, with sufficient land to potentially site a large PV system. This analysis used these three installations to illustrate the potential value of LDES, not to design or recommend a solution for these installations. Details of existing energy assets and site-specific constraints were not considered.

Table ES-1. Military Installations

Installation	State	Military Service	Size (acres)
Fort Bliss	Texas	Army	1,100,000
Patuxent River Naval Air Station (NAS)	Maryland	Navy	52,000
Holloman Air Force Base (AFB)	New Mexico	Air Force	13,800

The three sites represent very different total and critical electric loads. Table ES-2 provides information on the three installations' electric loads as modeled.

Table ES-2. Military Installations' Electric Loads

Installation	Average Electric Load (kW)	Peak Electric Load (kW)	Critical Load %
Fort Bliss	37,806	67,605	18.50%
Patuxent River NAS	21,444	33,958	23.5%
Holloman AFB	9,009	15,990	37.5%

Installations' dependence on diesel fuel represents a significant vulnerability. Many installations do not have the volume of diesel stored on base to meet a 14-day outage and are dependent on receiving supplies from off-base during a grid outrage. During long-duration outages, DoD has experienced failures of the off-base supply chain.

The characteristics of Intermediate systems that can achieve greater than a 95% survival probability at the end of a 14-day outage are listed in Table ES-3.

Table ES-3. Intermediate Diesel-Fuel-Free Systems

Installation	PV (MW_{DC})	BESS (MW)	BESS (hours)	CO_2 Reduction	20-Year Net Present Value (NPV)
Fort Bliss	59	16.0	45.6	29%	+$30.6 million
Patuxent River NAS	69	8.4	96.2	50%	+$24.3 million
Holloman AFB	26	6.3	62.9	49%	+$4.7 million

All the systems have positive 20-year NPVs, meaning they save money. The systems all require large utility-scale solar PV, whose costs and savings generated are included in the NPV. The required BESS are large, multimegawatt batteries with multiday durations. Each system also provides a large reduction in the carbon footprint of the electricity consumed by the base. They do this using local on-base resources and thus contribute to DoD's goals of both procuring 100% carbon-free energy (CFE) on an annual basis and at least 50% of demand matched to CFE regional supply on an hourly basis. Higher levels of CO_2 reduction can be achieved if desired with an increase in system costs.

These diesel-fuel-free mid-term systems are not vulnerable to interruptions in the diesel supply and provide a higher resiliency than diesel-based systems even when there is an unlimited diesel supply. Figure ES-2 compares the survival probability as a function of grid outage duration of an N+1 redundant[1] diesel-based microgrid with a mid-term Antora Energy BESS coupled to on-base solar PV at Fort Bliss.

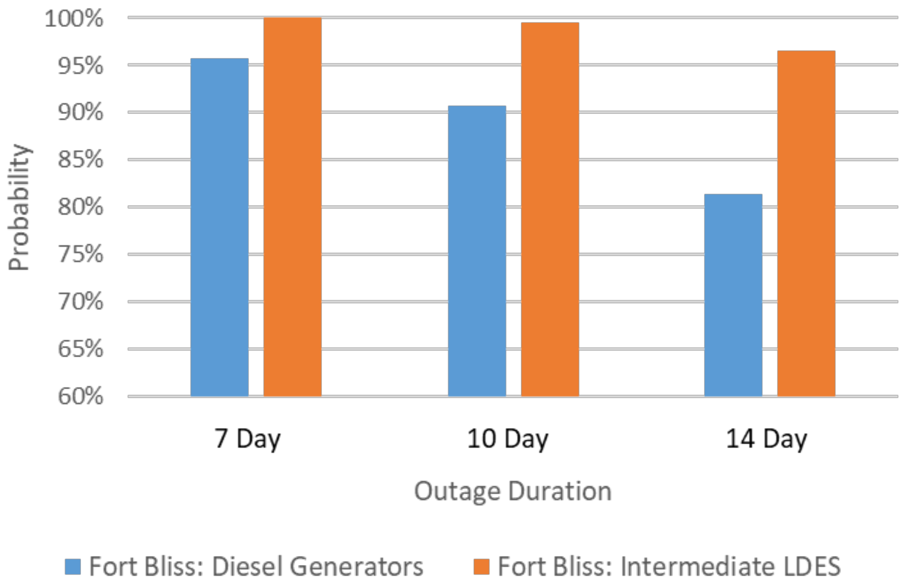

Figure ES-2. Fort Bliss resiliency comparison

The diesel-fuel-free LDES system outperforms the traditional diesel-based system and provides a large net saving that can be used to pursue third-party financing. Similar results for Patuxent River NAS and Holloman AFB are presented in the body of the report. In the longer term, further reductions in the costs and improvements in RTE, would lead to the Goal system. If this occurs, the savings would approximately double.

In summary, our study found that Antora Energy's BESS coupled to on-base utility-scale solar PV can in the future:

- Meet DoD's electric energy resilience requirements with a higher reliability than typically found in diesel-fueled systems.
- Provide resiliency without use of diesel fuel, thus eliminating the risk and vulnerability associated with the diesel fuel supply chain during a long-duration grid outage.
- Have a lower life cycle cost than traditional diesel-based microgrid systems.
- Be cost-effective by providing the required distributed energy resources at a positive NPV and thus potentially funded through a third-party mechanism.
- Provide a large reduction in CO_2 as a side benefit of its resiliency design.
- Economically replace a portion of natural gas used for thermal loads and further reduce an installation's CO_2 footprint.

[1] An N+1 system has one additional generator than is required to meet the peak load.

Accomplishing these benefits requires multimegawatt BESS with multiday durations coupled to utility-scale solar PV. The ability to provide these cost and performance benefits is due to multiple factors:

- The continued rapid decline in PV costs allows for utility-scale PV to be economically attractive at many locations. These declines are expected to continue, which will further increase the positive NPV in the future.
- The emergence of low-cost storage per kilowatt-hour allows for affordable multiday energy storage durations.
- The ability to charge more rapidly than discharging allows the battery to exploit available excess solar PV production during an outage.
- Critical loads being a fraction (20% to 40%) of total loads provides opportunity for a much larger PV system to support grid-tied loads than would be justified by the critical load, as well as provide large sources of cost savings from grid-tied operations.
- Availability of large tracts of land on DoD installations allows DoD to site utility-scale solar PV on the installation.

Our analysis provides strong support for the future value of Antora Energy's BESS for military installations and moving forward with near-term field demonstration(s) on military installations. Although the primary motivation for the development of Antora Energy's BESS was to provide heat and power to industry and support the electric grid, it has significant potential value as a behind-the-meter asset to meet DoD's installation energy needs.

The energy resilience market in DoD offers opportunities to accelerate the commercialization and deployment of LDES technologies. DoD is large enough to provide companies an early customer whose value proposition makes it less cost sensitive than the front-of-the-meter market. The DoD market can play the role it has in many technology domains and allow LDES to mature rapidly and drive costs down in time to meet the commercial needs of the future electric grid.

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1 Introduction

1.1 Background

Stationary energy storage provides many value streams. It can be deployed in front of the meter in support of the grid or behind the meter to provide direct value for a customer. Both locations can contribute significantly to energy resiliency. In front of the meter, it provides support to the grid to avoid grid outages and behind the meter it provides power to critical loads when the grid goes down. The future of the stationary energy storage market will depend on the development of emerging technologies, their costs, and the markets for their services (1). Today the market is dominated by lithium-ion (Li-ion) battery energy storage systems (BESS) of 1- to 6-hour duration and pumped hydroelectric storage for long-duration storage.

The Advanced Research Projects Agency–Energy (ARPA-E), though its Duration Addition to electricitY Storage (DAYS) program (2), has invested in long-duration energy storage (LDES) systems with a focus on meeting the future needs of the grid. One such technology, developed by Antora Energy (3), stores thermal energy in carbon blocks. The carbon blocks are heated through resistive heating and discharged through thermophotovoltaic (TPV) panels. Antora Energy's BESS offers a potential cost-effective, large-scale stationary storage system that can deployed on the scale of megawatts with durations up to 100 hours. Initial products are expected to be 24-hour systems.

The current default solution for energy resiliency at U.S. Department of Defense (DoD) installations relies on emergency diesel generators (EDGs). This is often accomplished by single stand-alone generators tied to individual buildings. But with increasing frequency, diesel generators are networked and serve as the primary distributed energy resource (DER) for a microgrid (4). Today, hybrid systems are being planned that rely on EDGs, Li-ion BESS, and on-base solar photovoltaic (PV) systems. Although these hybrid systems offer many advantages, they are still dependent on the supply of diesel fuel to meet DoD's 14-day (5) islanding requirement (6) (7). An active mid-size to large military base, supported only by EDGs, requires on the order of 100,000 to 300,000 gallons of diesel fuel to power its critical loads for 14 days. The cost of sustaining this large volume of diesel is significant, and many military bases choose to rely on off-base suppliers of diesel. Unfortunately, during long-duration grid outages, external diesel supplies are often not provided. The risk associated with the diesel supply chain is of great concern to DoD.

LDES is recognized as a potential solution for future grid stability as renewable energy penetration increases, but the cost per kilowatt-hour must be low for widespread adoption. In addition, uncertainty in future market demands inhibits the commercialization of LDES technologies (8). It has been recognized that LDES "may also provide enhanced resiliency at the level of a (micro)grid or single building" (9). DoD in the next several years plans to invest significant funding into deploying new energy resilience solutions for its installations. LDES offers DoD a potentially unprecedented opportunity to eliminate or significantly reduce its installations' dependence on diesel fuel, as well as the risk and vulnerability inherent in that supply chain. The energy resilience market in DoD offers opportunities to accelerate the commercialization and deployment of LDES technologies. The DoD market is large enough to provide companies an early customer whose value proposition makes it less cost sensitive than the front-of-the-meter market. By providing additional services such as energy resilience and decarbonization, DoD could represent an early market whose value streams justify deploying LDES at a higher cost than utilities and other grid management organizations might be able to justify. It can serve as a steppingstone into the civilian backup power market, which even a decade ago was more than 170 GW in the United States (10), of which over 85% was provided solely by emergency generators (11). The DoD market can play the role it has in many technology domains and allow LDES to mature rapidly and drive costs down in time to meet the commercial needs of the future electric grid (12).

1.2 Report's Purpose

At present, little to no analysis has been published on the costs and benefits of LDES to provide behind-the-meter energy resilience services. By examining the costs and benefits of Antora Energy's BESS coupled to an on-base solar PV system within a microgrid, we provide a proof point for the role of LDES being deployed behind the meter for energy resilience in general, and specifically quantify it for DoD installations. This report provides a quantitative techno-economic analysis of the ability of Antora Energy's BESS, coupled to on-base solar PV, to meet DoD's 14-day requirement to sustain critical electric loads during a power outage. Antora Energy's BESS is currently at a technology readiness level (TRL) of 7 and today is not ready for full-scale deployment. To support decisions on the value of near-term demonstrations, this analysis looked at the potential value of Antora Energy's BESS if deployed in the future.

This work assesses the performance and life cycle costs of optimized systems of different DER combinations that are integrated into a microgrid on a DoD installation. Only the costs of the DERs are considered, under the assumption that the costs of a microgrid will be approximately the same independent of the types and sizes of the DERs. Thus, the cost differential for various solutions will be due to the cost differential of the selected DERs. Resilience performance comparisons are made by looking at the performance of LDES-based solutions within a microgrid to the standard of an N+1 redundant microgrid of EDGs (13). Only microgrid configurations are considered, because building-tied systems alone cannot meet DoD's requirements (14).

The results and conclusions in this report represent the independent analysis and assessment of the team at the National Renewable Energy Laboratory (NREL). NREL held multiple conversations with Antora Energy to understand the technology but conducted this study independent of Antora Energy.

2 Antora Energy BESS Technology

Antora Energy's BESS stores thermal energy in inexpensive carbon blocks. To charge the battery, power from the grid or on-base solar PV will resistively heat the carbon blocks to temperatures up to or exceeding 1,000°C. To discharge energy, the hot blocks are exposed to TPV panels that are like traditional solar panels but specifically designed to efficiently use the heat radiated by the blocks. In addition, the BESS can directly dispatch the thermal energy.

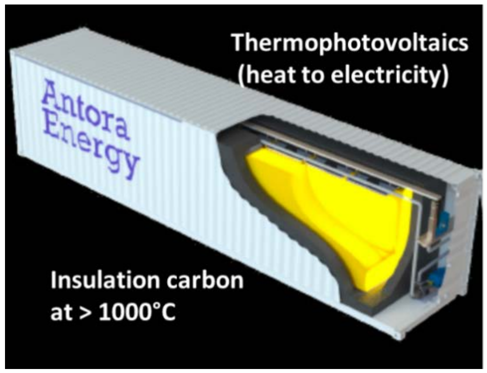

Figure 1. Antora Energy's BESS

NREL worked with Antora Energy to estimate the costs and performance of Antora Energy's BESS. The estimates used in this report were developed by NREL based on conversations with Antora Energy. Antora Energy's BESS is currently under development and is at a TRL of 7. It is presently undergoing beta testing. NREL chose to model two versions of the BESS: one that would be available in the mid- term (the "Intermediate" BESS) and one in the long-term that achieves lower cost and higher performance goals (the "Goal" BESS). The Intermediate BESS costs approximately twice as much as the Goal BESS, and the Intermediate TPV has a reduced conversion efficiency leading to AC-to-AC round-trip efficiency (RTE) of 38% vs. 48% for the Goal system. Both versions have more than a 20-year lifetime, and the only replacement of components is the inverter. Information on the cost and performance metrics for these two versions can be found in Appendix A.

NREL's model for Antora Energy's BESS is illustrated in Figure 2.

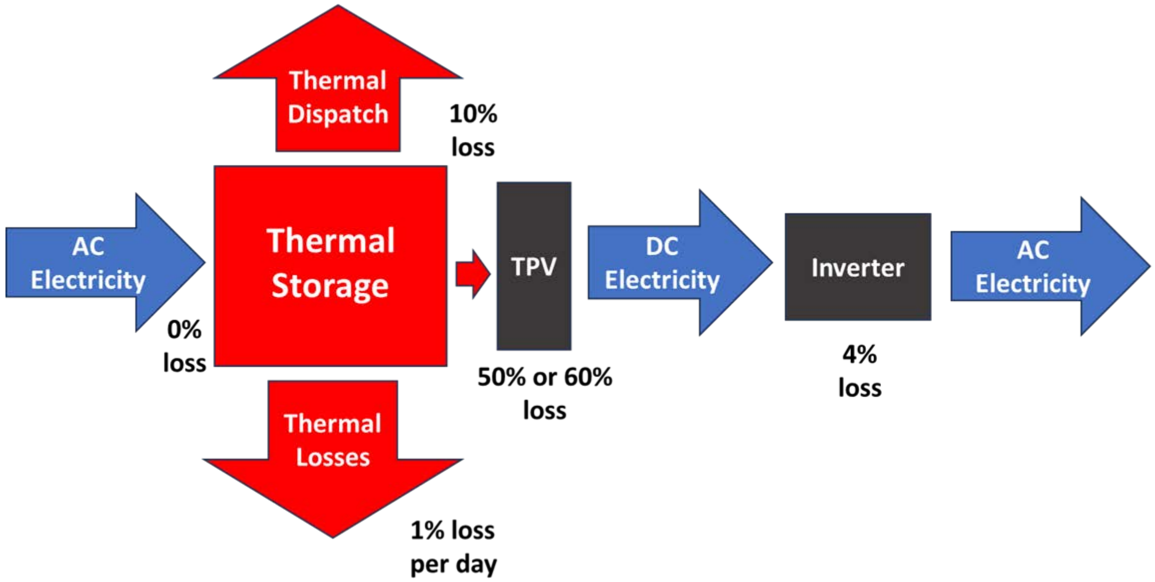

Figure 2. Model of Antora Energy's BESS

Because the AC electric power is used to resistively heat the carbon blocks, there is no need to rectify the power and therefore no related conversion losses. Antora Energy's BESS has only a unidirectional inverter and does not require a bidirectional inverter used in electrochemical batteries. Two different TPV efficiencies are listed in Figure 2, corresponding to the Intermediate and Goal configurations.

Antora Energy's BESS has several important attributes that should be recognized:

- Energy and power are decoupled. Because energy is stored as thermal energy and power is produced by TPV, the energy (kilowatt-hours or duration hours[2]) and power (kilowatts) are independent. This allows the independent optimization of the two BESS size attributes.
- Charging is decoupled from discharging limits. Because charging does not use the inverter and is done through resistive heating, the limit on the rate of energy charging is many times the discharging limit. This allows the BESS to store all excess solar PV energy not consumed by the load. This eliminates curtailment of the solar PV while grid tied and islanded.
- Energy storage or duration is scalable and affordable. Because energy storage capacity or duration is solely dependent on the volume of carbon blocks, it can easily be increased without significant costs. This allows the BESS to have durations of multiple days at an affordable price.
- The BESS is inherently safe. There is no potential of thermal runaway, so the BESS can be deployed without safety concerns.
- The BESS has a long lifetime and is anticipated to have low sustainment costs. The subsystems apart from the inverter all have long lifetimes and require very little maintenance. The TPV component in principle should have a long lifetime like solar PV

[2] Duration in hours refers to the number of hours the BESS can dispatch power at its maximum rate.

modules and concentrating solar PV modules. At present there is no empirical data to support this assumption (see Appendix C).

- The BESS has a low AC-to-AC RTE of 38% to 48%, compared to Li-ion BESS. This limits the BESS's applications to cases requiring long-duration storage. It is not likely to compete with Li-ion BESS for short-duration applications. Li-ion BESS have AC-to-AC RTEs of 85% and lower costs per kilowatt.

Other emerging LDES technologies are in development. Many have power and energy scales decoupled, in that the cost driver for increasing energy is unrelated to the power cost driver. This allows one to independently select the energy scale (kilowatt-hours) and power (kilowatts). Flow batteries are the most mature LDES. They have higher RTEs than Antora Energy's BESS, typically about 60%, and can have higher charging rates than discharging rates. Today, their charging rates are twice their discharging rates. Antora Energy's BESS can charge greater than 3 times the discharging rate, so it is less constrained on storing any available energy. Flow battery energy costs are much higher, and it is difficult to see how they could achieve an affordable multiday duration. Iron Air BESS (15) are currently being demonstrated. They have a similar RTE to Antora Energy's BESS and have similar low-cost, long-duration storage. Their charging rates are constrained to equal their discharging rates due to the use of a bidirectional inverter. Finally, there are other thermal storage BESS that may share many of the attributes of Antora Energy's BESS described here.

3 Modeling Methodology

The techno-economic modeling was done using NREL's REopt platform (16). REopt was modified to model Antora Energy's BESS and used in an iterative approach to find cost-effective resilient solutions.

3.1 REopt Model

REopt (17) (18) is a techno-economic model used to optimize energy systems for microgrids and other applications. The model is used to optimize the integration and operation of behind-the-meter DERs. It is formulated as a mixed-integer linear program that determines the optimal selection, sizing, and dispatch strategy of various DERs such that electrical and thermal loads are met at every time step at the minimum life cycle cost subject to potential constraints. For this project, EDGs, utility-scale solar PV, Li-ion BESS, Antora Energy's BESS, and a natural gas boiler are modeled. Figure 3 illustrates the structure of REopt.

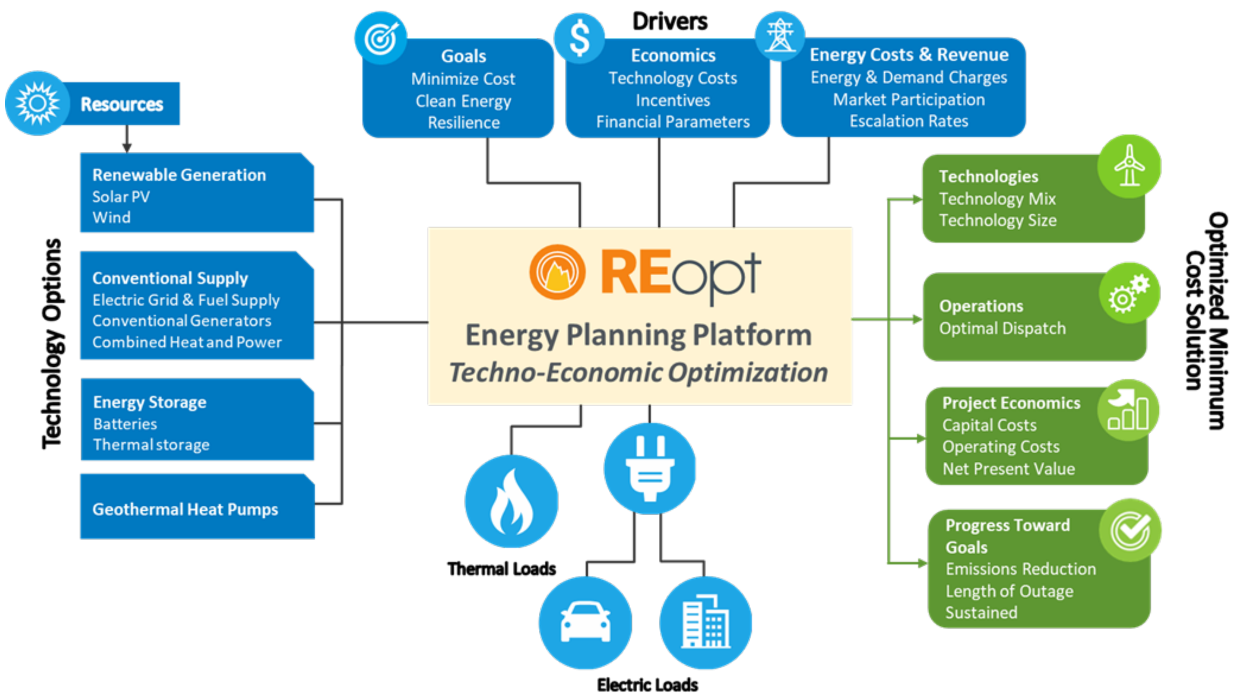

Figure 3. REopt model

We used REopt to find the lowest-cost solution that could meet all critical loads during a defined grid outage. The current REopt resiliency optimization code allows one to find the lowest-cost solution that meets a single outage that starts and ends at a specific date and time.[3] The optimized solution can then be analyzed to understand its resilience performance for all outages starting across the year (8,760 outage start times). Hourly total and critical electric loads were input to represent loads at different military installations (see Appendix D). The loads are based on actual hourly load data provided by each installation but modified, for security reasons, to mask the real hourly load data. The modifications have no impact on the results. For one

[3] The next publicly released version of REopt will allow users to consider up to four different outage times at once.

installation, a realistic hourly thermal load was developed based on thermal loads for similar locations, scaled to the annual thermal energy consumption expected for the installation.

Two issues cannot be treated by the current publicly available REopt tool. To conduct realistic modeling of the baseline installation at military diesel-based microgrids requires considering the reliability of EDGs (13) (14). A Markovian matrix methodology (13) and empirical data (19) were integrated into an internal version of REopt to address this issue. This technique will be available in the next publicly released version of REopt. In addition, to model Antora Energy's BESS required three key modifications of the public version of REopt. First, the charging and discharging rates had to be decoupled so that the charging rate was not constrained. Second, the daily loss of stored energy (thermal) needed to be included in the model. Finally, the BESS needed to be modeled like a combined heat and power (CHP) system that can dispatch both electricity and heat.

3.2 Modeling Approach

There are two key metrics that determine the value of different DER configurations. The first is energy resilience performance as measured by the survival probability. DoD's installation energy resilience goal is maintaining electric power for all critical loads up to 14 days in the event of a grid outage (5). No backup power system has a 100% probability of providing power. Power may not be provided because of limited fuel availability, equipment failures, insufficient DER capacity, or poor solar conditions. The survival probability is the cumulative probability that the system will meet all critical loads averaged over all possible outage start times throughout the year as a function of the grid outage duration. We compare the LDES microgrid-based survival probability to an EDG N+1 redundant microgrid system. The second key metric is the net present value (NPV) of the system of DERs. A negative NPV implies a life cycle cost, while a positive NPV implies a life cycle saving. We compare this NPV to that of a diesel-based microgrid with an economically optimized solar PV system that does not provide any resiliency but is selected purely for economic benefits. The costs of distribution upgrades needed to support a microgrid are not considered, because these would be identical for both LDES- and diesel-based microgrids. The costs of designing and installing the microgrid components are also not included because they should be very similar for the two cases.

Our modeling goal was to determine if an LDES-based solution could provide a cost-effective, highly resilient solution. Given that currently non-LDES solutions do not provide military installations a 100% survival probability over a 14-day outage (14) (6), requiring an LDES-based solution to achieve 100% is unrealistic. There is a trade-off between survival probability and costs (i.e., NPV). Higher survival probability, closer to 100%, can always be achieved by increasing the sizes of the DERs but often at a significant cost.

Our approach was to use the modified version of REopt in an iterative fashion. We calculated the cost-optimal DER configuration to survive a single outage starting at the peak hourly load. The survival probability was then calculated using REopt's outage simulator (18), which calculated the survival probability assuming a uniform distribution of outage start times throughout the year. We examined two objectives: requiring a 95% survival probability and a 98% survival probability at the end of a 14-day outage. If the results did not yield a survival probability greater than 95% or 98%, we increased the duration of the single outage and reran REopt. This process was iterated until a solution that met our preselected survival probability goal was achieved. At each iteration, REopt finds the solution with a minimum life cycle cost that meets the single-outage resilience constraint. No attempt was made to do an exhaustive search on the outage duration constraint, but rather to find an example solution that met our criteria for the survival probability at the end of a 14-day outage. The outage duration was simply increased by a day or a large fraction of a day at each iteration.

A key input metric that is required by REopt is the minimum state of charge (SOC) of the BESS while grid tied. The BESS is allowed to drop to zero SOC during a grid outage. In typical techno-economic modeling of a Li-ion BESS, the minimum SOC is usually set to 20% (18). This value is chosen to avoid shortening the lifetime of the Li-ion BESS. Antora Energy's BESS has no issues associated with discharging to an SOC of 0%, but if it is at or near a 0% SOC when a grid outage starts at night, it will be unable to satisfy the critical load. In addition, the large energy storage expected to be required to meet DoD resiliency goals will result in a BESS that has no need to use most of its SOC while grid tied to yield economic value. A higher minimum SOC will lead to a higher survival probability at 14 days, and a lower SOC minimum will lead to a higher NPV due to greater flexibility while grid tied. Figure 4 illustrates this trade-off between NPV and the 14-day survival probability at Fort Bliss, constrained to meet a single 7-day outage starting at the hourly maximum peak load.

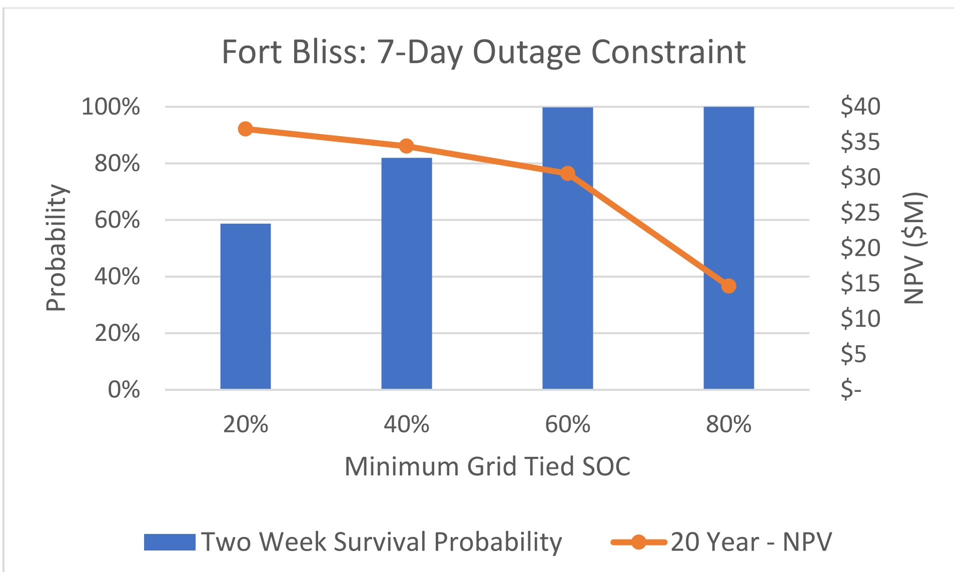

Figure 4. Impact of minimum BESS SOC

These results represent systems optimized by the REopt model. The trade-off between economics and resilience performance is clear. The loss of grid-tied revenue is reflected in the NPV's modest decline as one increases the minimum SOC from 20% to 60% but declines rapidly past this level. The improvement in resilience performance increases significantly as one goes from a minimum SOC of 20% to 60%, but levels out at that point. The reason for this behavior can be understood by looking at the BESS SOC. Figure 5 shows a histogram of the SOC while grid tied at Fort Bliss when the minimum SOC is constrained to 60%.

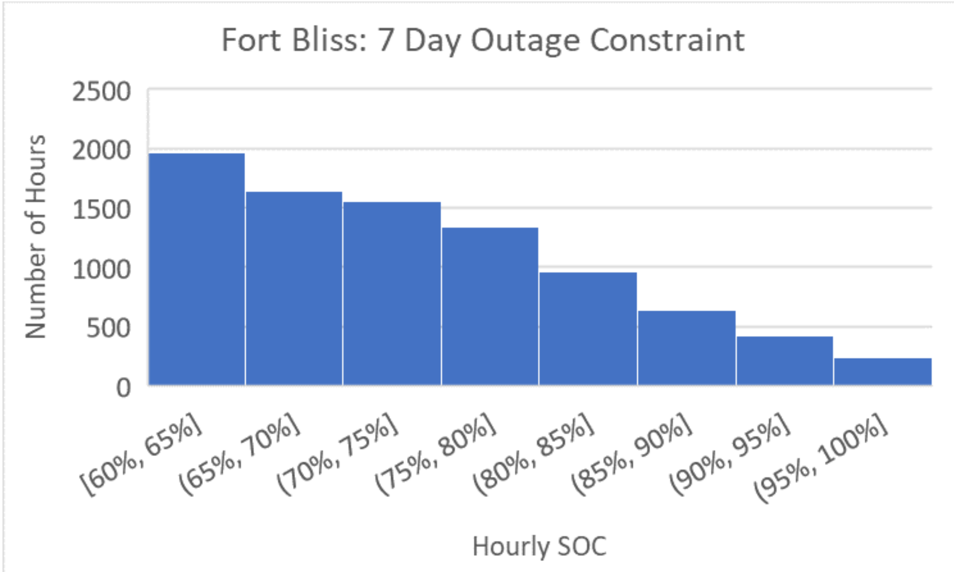

Figure 5. Hourly SOC statistics

The average SOC is 74%, and less than 3% of the hours are at the minimum SOC of 60%. Thus, a constraint of a 60% minimum SOC has a small impact on the NPV when compared to lower minimum SOCs, but more than 74% of the hours have SOCs less than 80% when optimized for economically efficient dispatch. Thus, the NPV drops sharply, as shown in Figure 4, as the minimum SOC is set to 80%. Based on these types of results we choose to set the minimum SOC for Antora Energy's BESS at 60% when grid tied. During an outage, Antora Energy's BESS can discharge all its energy if needed.

4 DoD Installations

DoD's installations are essential for U.S. national security. Installations support the maintenance and deployment of weapons systems and the training and mobilization of combat forces, and they perform support functions for overseas operations. In addition to their combat support role, DoD installations play an important role for homeland defense and the national response to emergencies.

Energy is essential for DoD's installations, and DoD is dependent on electricity and natural gas to power their installations. In fiscal year 2022 (20), DoD's installations consumed more than 200,000 million Btu (MMBtu) and spent $3.96 billion to power, heat, and cool buildings.

Typical mid-size to large active military installations' peak electric loads range from 10 to 90 MW, and their critical electric loads range from approximately 15% to 35% of the total electric load. Figure 6 illustrates conditions seen on seven different mid-size to large military installations.

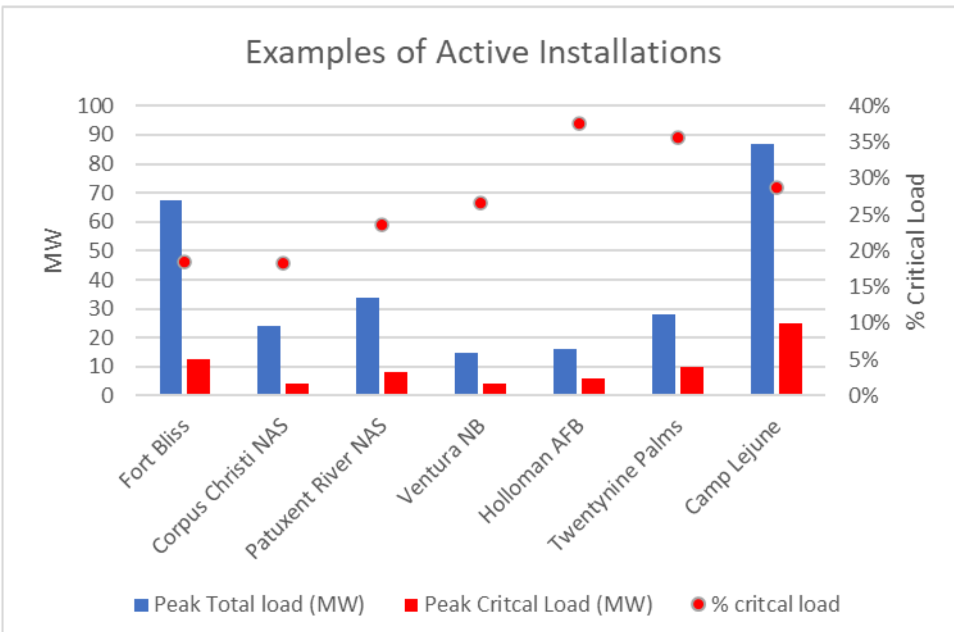

Figure 6. Electric load characteristics on DoD installations.

AFB: Air Force Base; NAS: Naval Air Station; NB: Naval Base.

NREL selected three installations (Table 1) representative of many military installations to assess the costs and benefits of using Antora Energy's BESS coupled to an on-base PV system to provide energy resilience. They cover three military services, are in different states, and have sufficient land to potentially site a large PV system. This analysis used these three installations to illustrate the potential value of LDES, not to design or recommend a solution for these installations. Details of existing energy assets and site-specific constraints were not considered.

Table 1. Military Installations

Installation	State	Military Service	Size (acres)
Fort Bliss	Texas	Army	1,100,000
Patuxent River NAS	Maryland	Navy	52,000
Holloman AFB	New Mexico	Air Force	13,800

The three sites represent very different electric loads and percentages of that load that are critical. Table 2 provides information on the three installations' electric loads as modeled. Hourly electric load profiles are provided in Appendix D. These load profiles are based on real electric load data from the three installations but have been slightly modified for security reasons. The results presented in this report are not impacted by those changes.

Table 2. Military Installations' Electric Loads

Installation	Average Electric Load (kW)	Peak Electric Load (kW)	Critical Load (%)
Fort Bliss	37,806	67,605	18.50%
Patuxent River NAS	21,444	33,958	23.5%
Holloman AFB	9,009	15,990	37.5%

To assess the value of Antora Energy's BESS to support thermal loads as a CHP system, a thermal load profile was created for Patuxent River NAS. This thermal profile was developed based on other locations where data were available and scaled to conditions for Patuxent River NAS. The modeled thermal load has a peak of 114 MMBtu/h and a total annual thermal load of 303,092 MMBtu. Details on this thermal load profile can be found in Appendix D.

5 Baseline Results

The cost and performance of an LDES-based system needs to be assessed relative to current practice. A common baseline for energy resilience is to consider the performance of an N+1 redundant network of EDGs (6) within a microgrid. In both this baseline and the LDES-based systems we consider only the costs and revenues from the DERs. Any upgrades to the distribution system to allow a microgrid should be identical. We assume the design and engineering costs of the microgrid, and its controller and communication system will also be comparable. So, the cost differential between a baseline system and an LDES-based solution will be due to the life cycle costs of the DERs. The life cycle costs of these DERs are dependent on how they are used and the approach for supplying the diesel fuel required. To make a balanced cost comparison, we also calculate the life cycle costs of deploying solar PV that provides no resilience value. On-base solar PV can provide substantial revenue even if it provides no resiliency value.

An N+1 redundant network of EDGs was selected for each installation. The size of the individual EDGs was constrained to common commercially available sizes. The specific size was selected to minimize EDG costs and maximize resiliency performance. All EDG networks are sized to ensure that *N* EDGs have a capacity greater than the maximum critical load. Table 3 provides information on the size, number, and total capacity of the EDGs modeled for each installation.

Table 3. Installation EDGs

Installation	Individual EDG Size	Number of EDGs	Total Capacity
Fort Bliss	2 MW	8	16 MW
Patuxent River NAS	1.5 MW	7	10.5 MW
Holloman AFB	2 MW	4	8 MW

Assuming unlimited diesel fuel, this network of EDGs will meet the critical load unless two or more units fail or are not in service (13). NREL and the Army Corps of Engineers Power Reliability Enhancement Program (PREP) have recently compiled and analyzed data on the reliability of EDGs commonly used on military installations (21) (19). Three metrics define an EDG's reliability (13):

- Failure to start probability = number of failures to start/number of attempts to start.
- Availability = (lifetime − time offline due to repairs and maintenance)/lifetime.
- Mean time to failure = total runtime/number of failures while running.

Table 4 shows the mean value based on large empirical data sets for well-maintained EDGs (21). Poorly maintained EDGs have much worse reliability.

Table 4. EDG Reliability Metrics

Reliability Metric	Values
Failure to start	0.94%
Availability	99.5%
Mean time to failure	1,100 hours

The cumulative probability of meeting 100% of the critical load during an outage averaged over all possible times in the year an outage can start is called the survival probability (13). It depends on the number of EDGs, the reliability metrics, and the hourly critical load profile. Figure 7 shows the expected performance of an N+1 network of EDGs as defined in Table 3 and Table 4 given the installation load profiles provided in Appendix D over a grid outage lasting from 1 hour to 336 hours (14 days).

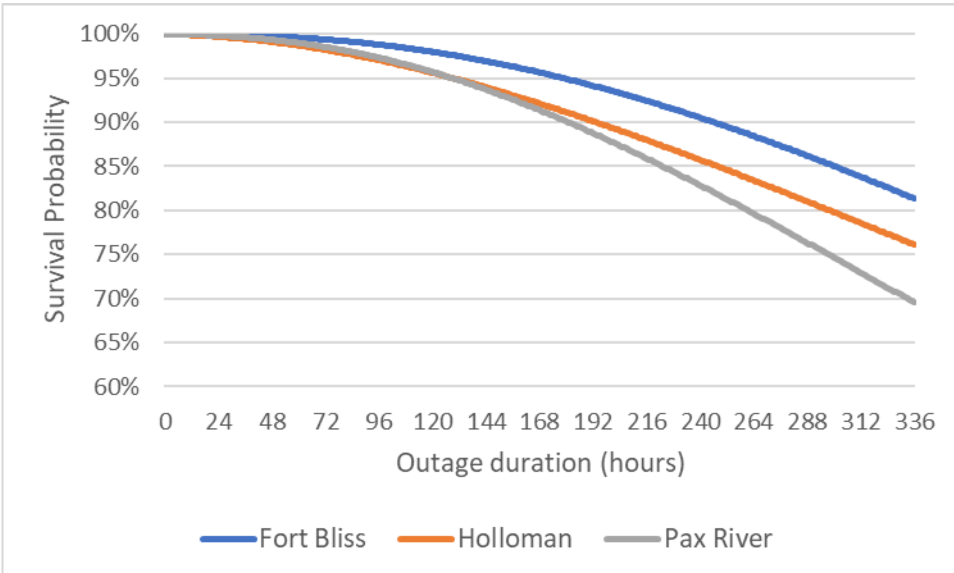

Figure 7. Survival probability for an N+1 network of EDGs

The survival probability differs between installations because the number of EDGs and hourly load profiles are different. Even well-maintained EDGs with unlimited diesel fuel reserves have only a 70% to 80% probability of meeting the critical load by the end of a 14-day outage. Interruptions in the vulnerable diesel supply chain leads to even worse energy resiliency performance.

The life cycle cost of such a system depends on how the diesel fuel is supplied and paid for. There are three possibilities: off-site supplies are provided, sufficient on-site storage exits to meet a 14-day outage and its sustainment is budgeted separately, or new on-site storage of sufficient size to meet a 14-day outage is constructed. Only the third possibility requires dedicated funding beyond the cost of diesel used during an outage. In this case the capital costs include the cost of the centralized tanks ($1.80/gallon (22)) and the first fill ($3.00/gallon). The sustainment costs are the tank maintenance ($1.07/gallon/year) and fuel polishing. Fuel polishing is required every year to prevent diesel fuel from going bad. It typically varies in price from $1.00/gallon/year to $3.00/gallon/year. We have assumed a cost of $2.00/gallon/year. Table 5 shows the expected tank size and the added capital and sustainment costs for each installation.

Table 5. On-Base Dedicated Central Diesel Storage

Installation	Central Diesel Storage	Capital Costs	Sustainment Costs
Fort Bliss	220,000 gallons	$1.056 million	$0.675 million/year
Patuxent River NAS	150,000 gallons	$0.720 million	$0.461 million/year
Holloman AFB	100,000 gallons	$0.480 million	$0.307 million/year

If dedicated central diesel storage must be procured and sustained, its cost will add $8.5 million to $12.4 million over the 20-year life cycle. Obviously, there are cases that could be hybrid of the three diesel delivery options, but for most bases, to avoid the risk of an interruption during a grid outage, storing and maintaining a 14-day supply of diesel fuel will cost many millions of dollars.

The operation of the EDGs while grid tied depends on federal and state environmental regulation as well as local electricity markets. The U.S. Environmental Protection Agency (EPA) regulates generators under the New Source Performance Standards and requires emergency generators to meet Tier IV standards to run while grid tied. This adds an additional capital cost of $150/kW (23) for the size of generators being considered. In addition, local and state air permits are required for operating EDGs while grid tied. States may institute additional generator testing and permitting requirements independent of EPA based on air pollutants including CO_2. Fort Bliss cannot run EDGs while grid tied even if they are Tier IV. California does not allow EDGs to run while grid tied. Maryland and New Mexico will consider applications for running EDGs grid tied if they meet Tier IV standards. These regulations may change in the future as many states begin to restrict use of diesel generators to help meet climate change goals. If EDGs are allowed to run while grid tied, there are two economic benefits: the EDGs can be used for peak shaving, and they can be enrolled in local emergency demand response programs, usually through a curtailment service provider.

For comparison with an LDES-based solution, we have considered cases where there are no dedicated costs for central diesel storage and the EDGs only run during a grid outage. Table 6 shows the 20-year NPV (or costs in this case) based on the systems described in Table 3 for each installation. The NPVs for all possible EDG scenarios are provided in Appendix B.

Table 6. Emergency Diesel Generator Life Cycle Costs

Installation	20-Year NPV
Fort Bliss	−$17.21 million
Patuxent River NAS	−$11.30 million
Holloman AFB	−$8.61 million

The life cycle costs of the EDGs range from $8.61 million to $17.21 million, not including any costs for centralized diesel storage. These costs do not include the costs for microgrid-related components, as these costs are considered comparable for all systems considered.

On-base solar PV can provide revenue, although without energy storage it provides limited resiliency value. To provide a balanced comparison of an LDES/solar PV system we have calculated the NPV of grid-tied solar that can offset the costs of the EDGs. Assuming a solar PV deployment in 2026, Table 7 shows the 20-year NPV of utility-scale solar on each installation assuming third-party ownership. The sizing of the solar PV was determined to be the most cost-effective. The solar PV provides power only to the base and does not participate in any external markets.

Table 7. Solar PV Life Cycle Costs

Installation	PV Size (kW_{DC})	Required Acres	20-Year NPV
Fort Bliss	26,586	160	$6.08 million
Patuxent River NAS	44,706	268	$31.82 million
Holloman AFB	12,165	73	$5.49 million

These estimates assume there is no land area constraint. The sizes of solar PV for installations like Fort Bliss or Hollman AFB are not an issue, but available land may place a size constraint for installations like Patuxent River NAS. If only 100 or 200 acres of land were available, the largest solar PV that could be deployed at Patuxent River NAS would provide a 20-year NPV of $16.35 million or $29.02 million, respectively.

6 LDES Results

Using the approach described in Section 3, we calculated the cost and performance of different LDES-based systems and compared them to the baseline results described in Section 5 for the three installations described in Section 4. First, we discuss potential solutions for energy resiliency that are diesel fuel independent. In this section we evaluate the cost and performance of both the mid-term (Intermediate) and long-term (Goal) Antora Energy BESS. In the next section we discuss a hybrid system, which includes a small dependence on EDGs only for Antora Energy's mid-term BESS. In the final subsection, we examine the potential of using the mid-term system to also support thermal loads at a base like Patuxent River NAS. In all these calculations we assume the cost of solar PV per kW is the expected cost in 2026 and calculate a 20-year NPV. Continued expected decline after 2026 in solar PV costs and a longer NPV period leads to even higher positive NPV results.

These results are based on REopt optimizations found over a continuous sizing search space. It is expected that commercial systems from Antora Energy will be available only in certain discrete increments of power and duration and not necessarily the fractional power and duration listed here. The results shown are not significantly changed if the system power and duration are constrained to projected commercial sizes. In addition, in all cases we do not consider the potential revenue from participation in real-time or day-ahead energy markets. The future value of LDES in these energy markets is very uncertain and involves cybersecurity risks that DoD would need to overcome. This may be a valuable opportunity in the future, and the costs and benefits should be considered as the markets mature.

6.1 Fuel-Independent Energy Resiliency

Dependence on large quantities of diesel fuel represents an important vulnerability for military installations. Many installations do not have the volume of diesel stored on base to meet a 14-day outage. They are dependent on receiving supplies from off-base during a grid outrage that surpasses their on-base storage capacity. During long-duration outages DoD has experienced failures of the off-base supply chain (24) (25).[4]

Mid-Term Opportunities (Intermediate)

Assuming Antora Energy's BESS Intermediate costs and performance described in Section 2 and Appendix A, we find that a cost-effective energy resilience solution can be designed. The required survival probability at the end of a 2-week outage is a site-specific decision. There is a direct trade-off between costs and survival probability. One can continually increase the performance of the system to achieve higher and higher survival probability, but it comes at a modest cost increase. Figure 8 illustrates this trade-off for Fort Bliss.

[4] Based on private communications with military installation public works offices.

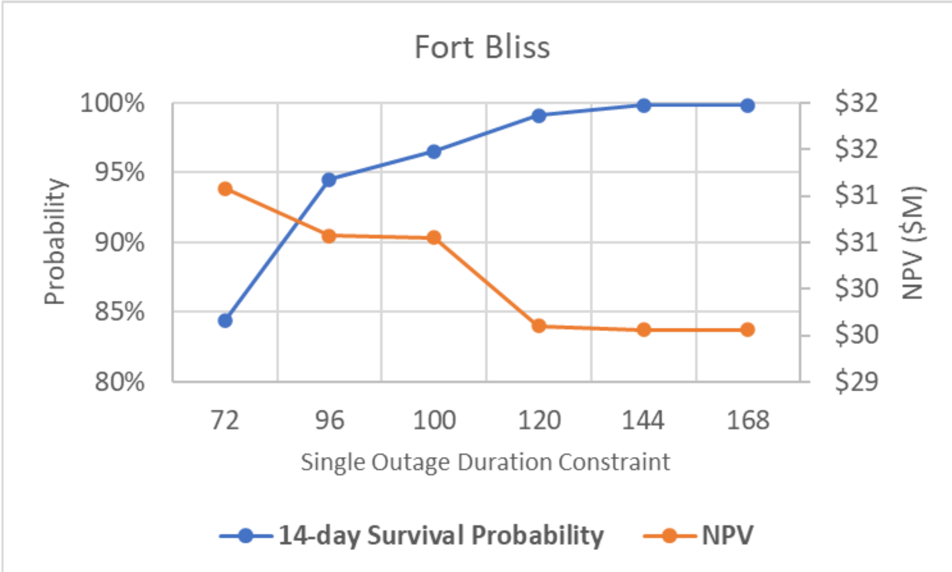

Figure 8. Cost versus performance trade-off

Operationally, we increase the system's performance by increasing the single-outage duration constraint (hours) in REopt. The results for the 14-day survival probability reflect the system's performance averaged over all outage start times. The NPV decreases and the 14-day survival performance increases as we increase the hours for the single-outage duration constraint in the REopt optimization. Both plateau at approximately 120 hours. In this section we report the results requiring a greater than 95% survival probability at the end of a 14-day outage. The 95% survival probability is assuming that the solar PV and Antora BESS are 100% reliable but the PV is intermittent. As discussed in Appendix C, utility-scale solar PV is very reliable, and Antora Energy's BESS is expected to be reliable, but no empirical data to support this later assumption are currently available. Both the PV and Antora Energy's BESS are expected to have large mean times to failure relative to a 2-week outage, and thus, if operational at the start of a grid outage, will not fail during a grid outage of 1 hour to 2 weeks. Both systems' availability at the start of a grid outage are expected to be approximately 99%. Including a non-perfect reliability would decrease the reliability of the fuel-independent system survival probability by a few percent. The baseline diesel system has a survival probability of 70% to 80% assuming diesel is 100% available. Thus, the diesel-fuel-free systems are expected to have a much higher resiliency than traditional diesel-based systems even if their non-perfect reliability is factored in.

The optimized Intermediate systems (to meet >95% survival probability) are listed in Table 8 for all three installations.

Table 8. Intermediate Diesel-Fuel-Free Systems

Installation	PV (MW_{DC})	BESS (MW)	BESS (hours)	CO_2 Reduction	20-Year NPV
Fort Bliss	59	16.0	45.6	28%	+$30.6 million
Patuxent River NAS	69	8.4	96.2	45%	+$24.3 million
Holloman AFB	26	6.3	62.9	48%	+$4.4 million

All the systems have positive 20-year NPVs, meaning they save money. A longer investment time period, say 25 years, would further increase these savings. The systems all require large utility-scale solar PV. The area required for such large solar PV is not expected to be an issue at a base like Fort Bliss or Holloman AFB, but a base like Patuxent River NAS might not be able to accommodate such a large solar PV, which requires 414 acres. To achieve similar resiliency performance at a base like Patuxent River NAS with land constraints is more difficult. If only 100 or 200 acres are available for solar PV, Antora Energy's BESS duration would need to be increased to thousands of hours. If only 300 acres are available a system can be designed with a positive NPV but roughly a third of the unconstrained result.

The required BESS are large, multimegawatt batteries with multiday durations. The affordability of such a large system requires a BESS that was designed to be an LDES. If one designed a similar system using a Li-ion BESS at costs expected in 2026 (26), the resulting system would be unaffordable. Achieving a greater than 95% survival probability at the end of a 14-day outage would cost >$30 million more than the baseline cost of the diesel systems.

Each system provides a large reduction in the carbon footprint of the electricity consumed by the base. They do this using local on-base resources and thus contribute to both DoD's goal of procuring 100% carbon-free energy (CFE) on an annual basis and at least 50% of demand matched to CFE regional supply on an hourly basis. Higher levels of CO_2 reduction can be achieved if desired with an increase in system costs.

The ability to meet the resiliency requirement and be cost-effective is tied to both Antora Energy BESS's low cost of energy and the ultra-fast charging rate. Due to the high charging capacity, no solar PV energy is curtailed while grid tied, and the excess solar energy during a grid outage is used. Table 9 illustrates the maximum charging capacity relative to the discharging capacity at all three sites.

Table 9. Ratio of Charging Capacity to Discharging Capacity

Installation	Maximum Charging Capacity to Discharging Capacity
Fort Bliss	3.3
Patuxent River NAS	4.9
Holloman AFB	2.3

An electrochemical LDES would be unable to meet these ratios.

The performance of the diesel-fuel-free Intermediate LDES-based systems is better than the diesel-based systems. Figures 9, 10, and 11 illustrate this for the systems defined in Table 8.

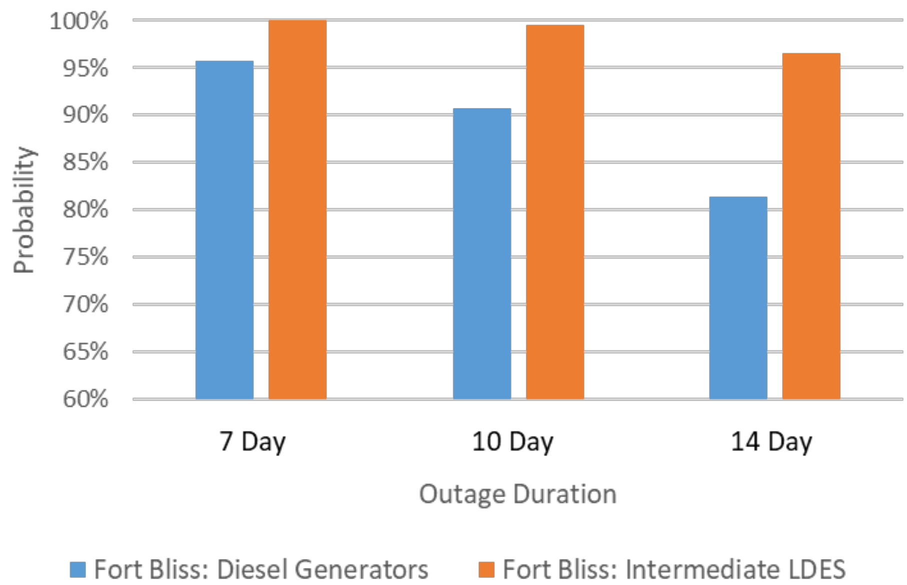

Figure 9. Fort Bliss resiliency comparison

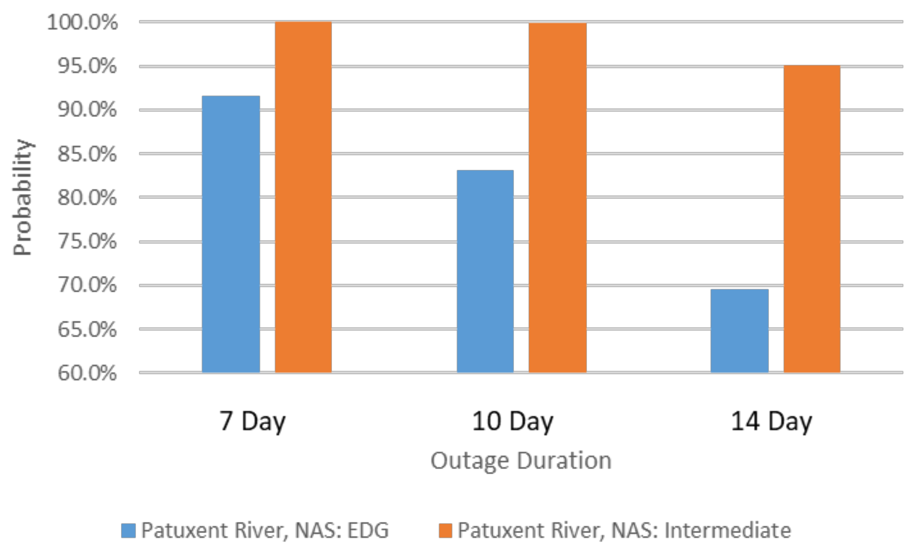

Figure 10. Patuxent River NAS resiliency comparison

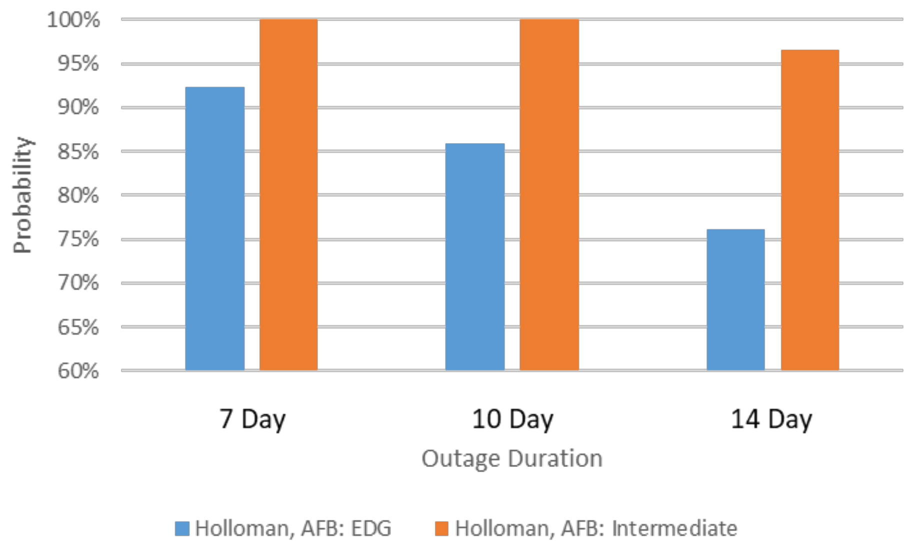

Figure 11. Holloman AFB resiliency comparison

The Intermediate LDES-based system is both a higher-performing system and has a higher NPV than a network of N+1 EDGs and yields a larger decrease in the CO_2 emissions from grid-purchased electricity. Table 10 summarizes the life cycle cost differences between the LDES systems defined in Table 8 and the EDG-based systems coupled with solar PV defined in Tables 6 and 7.

Table 10. Comparison of 20-Year NPV

Installation	EDG System and Solar PV	LDES and Solar PV System
Fort Bliss	−$11.1 million	+$30.6 million
Patuxent River NAS	+$20.5 million	+$24.3 million
Holloman AFB	−$3.1 million	+$4.3 million

The avoided costs at Fort Bliss and Holloman AFB further increase the value of the LDES-based system. The diesel-based system at Patuxent River, due to the value of the on-base utility-scale solar PV, has a positive NPV and thus does not represent an avoided cost.

Far-Term Opportunities (Goal)

Antora Energy's BESS Goal costs and performance are described in Section 2 and Appendix A. We find that a cost-effective energy resilience solution can easily be designed. The Goal system has a higher RTE and roughly half the cost. Not surprisingly, this makes it easier to find high-performing, cost-effective solutions. As in the Intermediate case we assume the grid-tied minimum SOC is 60%. Again, there is a direct trade-off between costs and survival probability. One can continually increase the performance of the system to achieve higher and higher survival probability, but the costs will increase. Given the lower costs and higher performance, we looked for solutions that surpassed a 98% survival probability at the end of a 14-day outage.

The optimized Goal systems (to meet >98% survival probability) are listed in Table 11 for all three installations.

Table 11. Goal Diesel-Fuel-Free Systems

Installation	PV (MW_{DC})	BESS (MW)	BESS (hours)	CO_2 Reduction	20-Year NPV
Fort Bliss	61	20.6	36.0	29%	+$48.5 million
Patuxent River NAS	70	8.5	94.8	47%	+$37.8 million
Holloman AFB	22	6.3	64.4	42%	+$13.2 million

All the systems have a higher positive 20-year NPV than the Intermediate systems, meaning they save even more money. The Fort Bliss system is the same as the optimal economic configuration. That configuration by itself fulfills the resiliency requirement without modification. A longer time, say 25 years, would further increase these savings. The systems still all require large utility-scale solar PV. As in the Intermediate case, the area required for such large solar PV is not expected to be an issue at a base like Fort Bliss or Holloman AFB, but a base like Patuxent River NAS might be unable to accommodate such a large solar PV, which requires about 400 acres.

The diesel-fuel-free Goal LDES-based systems significantly outperform the diesel-based systems. Figures 12, 13, and 14 illustrate this for the systems defined in Table 11.

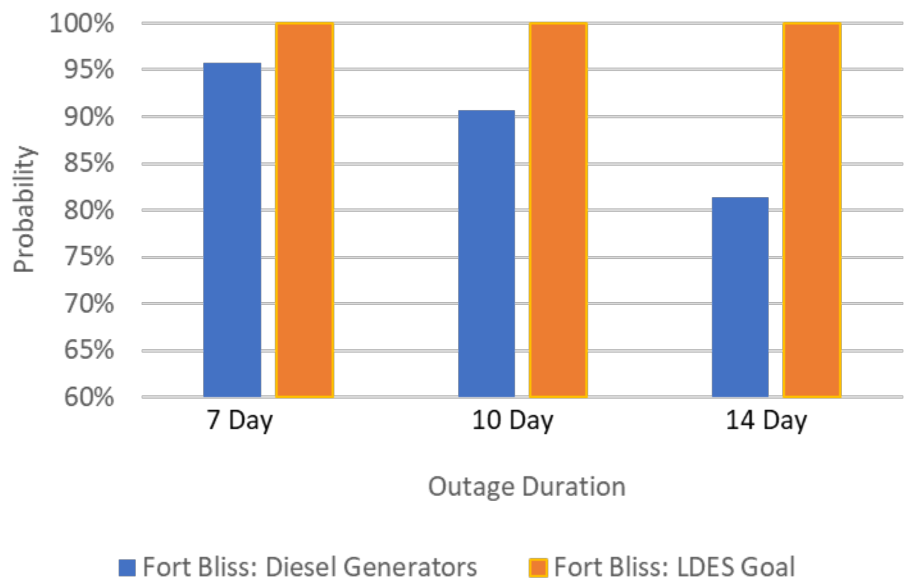

Figure 12. Fort Bliss resiliency comparison

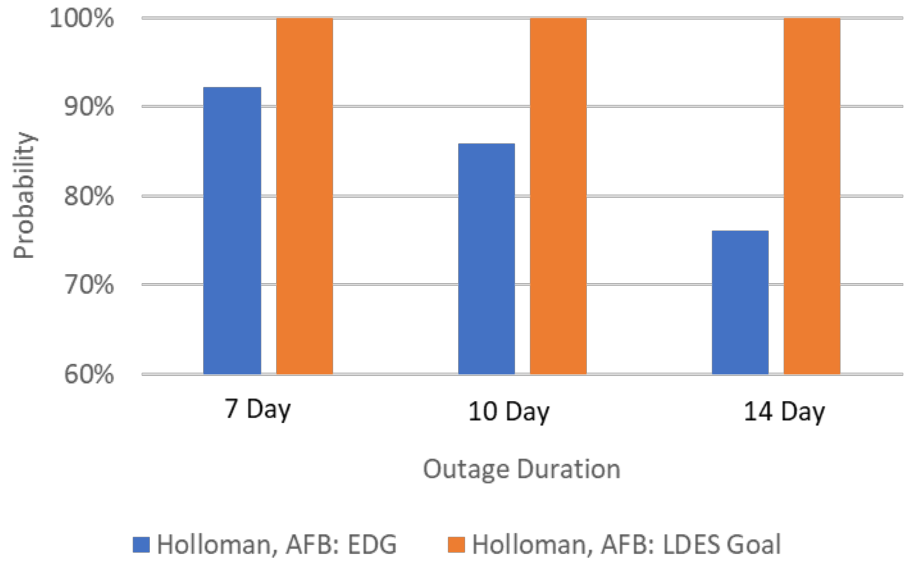

Figure 13. Holloman AFB resiliency comparison

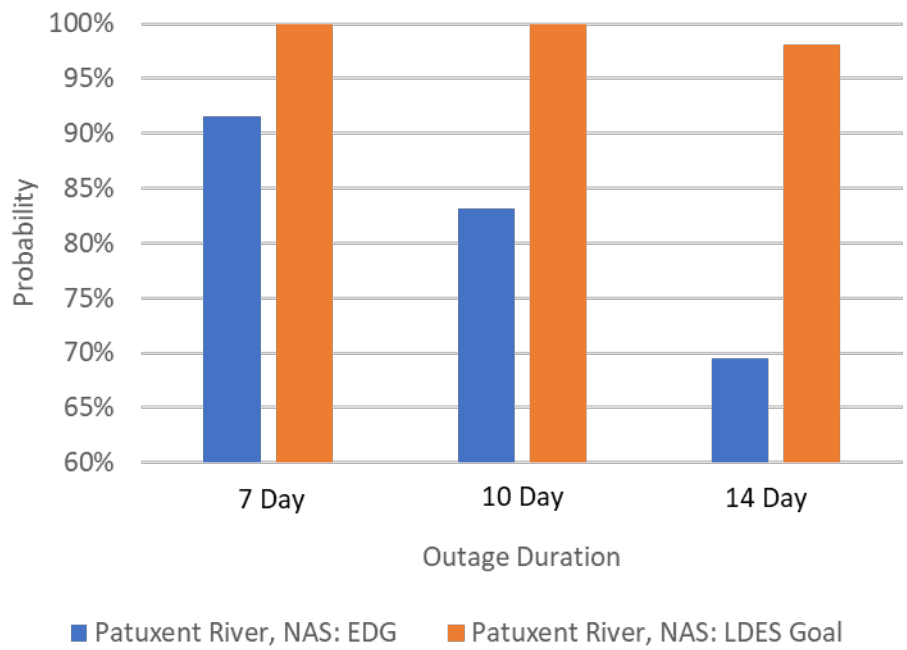

Figure 14. Patuxent River NAS resiliency comparison

The Goal LDES systems have 100% reliability for all outage durations at Fort Bliss and Holloman AFB.

The Goal LDES-based system is both higher performing and lower cost than a network of N+1 EDGs and yields a larger decrease in the CO_2 emissions from grid-purchased electricity. Table 12 summarizes the life cycle cost differences between the Goal LDES systems defined in Table 11 and the EDG-based systems coupled with solar PV defined in Tables 6 and 7.

Table 12. Comparison of EDG and Goal LDES Systems 20-Year NPV

Installation	EDG System and Solar PV	LDES and Solar PV System
Fort Bliss	−$11.1 million	+$48.5 million
Patuxent River NAS	+$20.5 million	+$37.8 million
Holloman AFB	−$3.1 million	+$13.2 million

The avoided costs at Fort Bliss and Holloman AFB further increase the value of the LDES-based system.

6.2 Hybrid System Energy Resiliency

Hybrid systems that combine EDGs, Li-ion BESS, and solar PV are known to often be less costly and better performing (6). We investigated the value of a hybrid system combining EDGs, solar PV, and Antora Energy BESS for the Intermediate cost case. We consider hybrid systems that have a certain number of EDGs that support the critical load (called active) combined with an additional EDG that is available if one of the active EDGs fails. Table 13 details the hybrid configurations of active EDGs that were considered.

Table 13. EDG Configuration in Hybrid Systems

Installation	Individual EDG Sizes	Number of Active EDGs	EDG Percent of Peak Critcal Load
Fort Bliss	2 MW	1 and 3	16% and 48%
Patuxent River NAS	1.5 MW	1 and 3	19% and 56%
Holloman AFB	2 MW	1 and 2	33% and 67%

These are the sizes of EDGs that are used to provide power for the critical loads in concert with the solar PV and Antora Energy's BESS. Because of the reliability issues of EDGs discussed in Section 5, we assume one additional EDG is on hot standby in case of an EDG failure. We include the life cycle cost of the additional EDG in the NPV estimates but assume it does not support loads unless one of the active EDGs fails.

The cost-optimal hybrid solutions that have at least a 95% survival probability at the end of a 2-week outage are shown in Table 14.

Table 14. Hybrid System Configurations

Installation	Number of Active EDGs	PV (MW_{DC})	BESS (MW)	BESS (hours)
Fort Bliss	1	53	15.0	33.5
	3	53	15.0	33.5
Patuxent River NAS	1	60	8.4	56.7
	3	52	8.4	21.3
Holloman AFB	1	16	6.3	19.3
	2	16	6.3	19.3

Fort Bliss and Holloman AFB have the same size solar PV and BESS for the two hybrid cases. Hybrid systems on all three installations require smaller solar PV and shorter BESS durations (see Table 8). Their resilience performances by design are similar. Table 15 compares the costs assuming a third-party ownership model of the single active EDG hybrid systems to a diesel-free system listed in Table 8.

Table 15. Single Active EDG Hybrid System 20-Year NPV Comparison

Installation	Fort Bliss	Patuxent River NAS	Holloman AFB
Hybrid NPV	+26.13 million	+$25.1 million	+2.97 million
Diesel-free NPV	+$30.6 million	+$24.3 million	+$4.7 million

These NPVs are for the Intermediate cost case and include the cost of one additional EDG for improved reliability. The 20-year NPV cost differences are modest and by design have similar performance to the diesel-free systems. There does not appear to be any advantage for a hybrid system if there is no constraint on the land available for the solar PV.

Of greater interest is the potential value of a hybrid system to address the land constraints at sites like Patuxent River NAS, where the size of the solar PV is likely to be constrained. Again, we focus only on the mid-term Intermediate case with a single active EDG. The unconstrained hybrid system requires 360 acres of land versus 414 acres for the diesel-free LDES system. Table 16 compares these two systems with increasing land constraints. All require an 8.4-MW BESS and exceed a 95% survival probability at the end of a 2-week outage.

Table 16. Land-Constrained Patuxent River NAS Systems

Land Constraint	BESS (hours) Hybrid	BESS (hours) Diesel-Free	20-Year NPV Hybrid	20-Year NPV Diesel-Free
Unconstrained	56.7	96.2	+$25.1 million	+$24.3 million
300 acres	85.8	182	+$19.8 million	+$9.9 million
200 acres	126	2,476	+$3.5 million	−$360 million
100 acres	163	5,418	−$12.6 million	−$839 million

The land-constrained cases all have the maximum allowed solar PV systems of 50 MW, 33 MW, and 17 MW for the 300-acre, 200-acre, and 100-acres sites, respectively.[5] As the land constraint of solar PV deployment increases, longer-duration BESS are required, which results in a lower NPV. For the 100- and 200-acre constrained cases, the diesel-free systems require an unrealistically long-duration BESS, which is unrealistic. Even the 300-acre constraint leads to a greatly lower NPV. The hybrid case with only one active EDG (and one in reserve) provides a solution at a site like Patuxent River NAS that has only 300 acres of land available for a solar PV deployment, with an NPV only 15% less than the unconstrained case. At sites with greater land constraints, the diesel-free solution is less attractive. Hybrid systems help in cases where land constraints limit the size of solar PV, but they do not eliminate the issue.

[5] We assume 6 acres is required per megawatt-DC of PV.

6.3 Supporting Thermal Loads

Antora Energy's BESS can dispatch both electrical and thermal energy. DoD installation energy is roughly 49% electricity, with next largest contribution being natural gas at 38% (27). Natural gas is predominantly used to supply thermal energy though boilers or CHP systems. Antora Energy's BESS can act like a CHP system. To assess its value to provide thermal energy, we examined one case where Antora Energy's BESS coupled to on-base solar PV could offset, for economic gain, the natural gas burned in an existing boiler while still maximizing its value to provide electricity while grid tied and during an islanding event when the electric grid is down.

We selected Patuxent River NAS to assess the value of using Antora Energy's BESS as a CHP system. The economics of replacing thermal energy produced by natural gas with thermal energy stored in Antora Energy's BESS that has been generated by either electric grid power or on-base solar power will be sensitive to the local prices of natural gas, the cost of grid electricity, and the local solar resources. The results for the Patuxent River NAS in Maryland may not be representative of other locations but supports that this is worth considering at many locations.

We assumed a thermal load typical of climate zones like Patuxent River NAS and scaled it to be representative of the thermal loads relative to electric loads commonly found on military installations. It may not be accurate for Patuxent River NAS hourly thermal loads, but we believe it is realistic for military installations. The thermal load and cost information is provided in Appendix A and Appendix D.

Using the modeling process discussed in Section 3, we used the Intermediate cost and performance metrics of Antora Energy's BESS and looked for an economically optimized solution whose survival probability at the end of a 2-week grid outage was more than 95%. The boiler was assumed to be existing equipment, so its only cost was operations and maintenance (O&M) and fuel.

The resulting system for an installation like Patuxent River NAS is described in Table 17.

Table 17. Intermediate Diesel-Fuel-Free CHP Systems

Installation	PV (MW_{DC})	BESS (MW)	BESS (hours)	20-Year NPV
Patuxent River NAS	100	8.4	83.9	+$45.0 million

This system replaces 50% of the energy from the boiler with energy from Antora Energy's BESS. It yields an NPV that is more than $20 million higher than the electric-energy-only case. This allows the optimized system to use a larger solar PV and does not compromise the electric energy resiliency.

7 Conclusion

This study assessed the potential value for military installations of a future commercial version of Antora Energy's LDES battery. Antora Energy's BESS is currently at a TRL of 7 and undergoing beta testing in the field. The study's motivation was to provide information to support near-term decisions on the value of conducting large-scale demonstrations on military installations to test its performance and support its maturation. Our analysis provides strong support for the future value of Antora Energy's BESS for military installations and moving forward with field demonstration(s) on military installations.

Although the primary motivation for the development of Antora Energy's BESS is to provide heat and power to industry and support the electric grid, it has significant potential value as a behind-the-meter asset to meet DoD's installation energy needs. DoD has two key installation energy requirements: (1) energy resilience and (2) CFE to reduce CO_2 emissions both on an annual basis and hour by hour.

DoD's energy resilience goals require it to have the ability to support its mission-critical loads during a grid outage for up to 14 days. It seeks to accomplish this in an affordable manner with high reliability. It plans to meet this requirement through the deployment of installation microgrids. Today those microgrids depend on diesel generators, often in combination with other DERs such as on-base solar PV, Li-ion BESS, and natural-gas-driven generation. These systems depend on a vulnerable diesel supply chain, have far-less-than-perfect reliability for a 14-day outage, and can be expensive. The largest cost component of microgrids is typically the on-base DERs (28).

This study analyzed the value to DoD of deploying a large Antora Energy BESS in combination with on-base solar PV on three installations: Fort Bliss, Patuxent River NAS, and Holloman AFB. These bases, located in Texas, Maryland, and New Mexico, respectively, represent loads typical of mid to large active military installations. They were modeled to provide an assessment of realistic installation conditions. The results are not intended to serve as a design or a site-specific recommendation.

Our study found that Antora Energy's BESS coupled to on-base, utility-scale solar PV can provide great value for DoD installations in meeting their energy resilience and CFE goals. Such a system can:

- Meet DoD's electric energy resilience requirements with a higher reliability than typically found in diesel-fueled systems.
- Provide resiliency without use of diesel fuel, thus eliminating the risk and vulnerability associated with the diesel fuel supply chain during a long-duration grid outage.
- Have a lower life cycle cost than traditional diesel-based microgrid systems.
- Be cost-effective in the mid-term by providing the required DERs at a positive NPV and thus be potentially funded through a third-party mechanism.
- Provide a large reduction in CO_2 as a side benefit of its resiliency design.
- Economically replace a portion of natural gas used for thermal loads and further reduce an installation's CO_2 footprint.

Accomplishing these benefits requires multimegawatt BESS with multiday durations coupled to utility-scale solar PV. An on-base utility-scale solar PV requires a large tract of available land. This study found that eliminating dependence on diesel fuel would require 100–400 acres of available land, a requirement easily met at some but not all military installations. The size of the required solar PV can be reduced by deploying a hybrid system with a small amount of diesel generation.

The ability to provide these cost and performance benefits is due to multiple factors:

- The continued rapid decline in PV costs allows for utility-scale PV to be economically attractive at many locations. These declines are expected to continue, which will further increase the positive NPV in the future.
- The emergence of low-cost storage per kilowatt-hour allows for affordable multiday energy storage durations.
- The ability to charge more rapidly than discharging allows the Antora battery to exploit available excess solar PV production during an outage.
- Critical loads being a fraction (20%–40%) of total loads provides opportunity to have large sources of cost savings while grid tied.
- Availability of large tracts of land on DoD installations allows DoD to site utility-scale solar PV on the installation.

All LDES technologies can take advantage of some of these factors, although many cannot exploit all of them.

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Appendix A. Modeling Assumptions

This section provides detailed cost and performance inputs and their rationale for the REopt-based analysis. The REopt modeling assumes a solar PV deployment cost expected in 2026. Cost estimates for 2026 are provided for technologies that are mature but are continuing to show significant price declines such as solar PV and Li-ion batteries. Technologies such as emergency generators that are mature and not changing are assumed to be at their current costs. All costs are in 2021 dollars.

A.1 Financial

The REopt calculation for PV and PV with LDES assumes a third-party ownership model, typical of large PV project developments on DoD installations. Due to the large tax incentives for both solar PV and storage in the Inflation Reduction Act (29) and advantages of third-party ownership in terms of sustainment costs, this is the most effective way to deploy these large-scale systems. The EDG system is assumed to be owned by the installation.

Table A-1. Financial Assumptions

Economic Input	Assumption	Source
Analysis period	20	N/A
Developer discount rate	6.1%	Annual Technology Baseline (ATB) (26)
Developer tax rate	26%	REopt default (16)
Installation discount rate	4.2%	Office of Management and Budget Circular No. A-94 (30)
Installation tax rate	0%	N/A
O&M cost escalation rate	1.9%	REopt default (16)
Diesel escalation rate	2.5%	REopt default (16)
Natural gas escalation rate	3.4%	REopt default (16)
Electricity escalation rate	1.9%	REopt default (16)

Most of the financial assumptions are default values provided in the REopt tool. The REopt user manual (31) provides a discussion on these assumptions. The developer discount is set at the nominal weighted area cost of capital from the 2023 ATB (26) for utility-scale solar. Utility-scale solar is the dominant driver of total capital costs.

A.2 Solar PV

The size of solar PV on the three installations modeled represents a utility-scale solar project. Costs and performance values were selected for a utility-scale solar project in 2026.

Table A-2. Utility-Scale Solar PV Assumptions

Solar PV Input	Assumption	Source
System type	Ground-mount, single-axis tracking	N/A
Resource profile	Generated by NREL's PVWatts® using typical meteorological year (TMY) weather data from the National Solar Radiation Database	(32) and (33)
Space requirements	6 acres/MW_{DC}	REopt default (16)
Tilt	N/A (panels are single-axis tracking)	N/A
Azimuth	180° (south-facing)	REopt default (16)
System losses	14%	REopt default (16)
Capital costs	\$902/kW_{DC}	ATB (26)
O&M costs	\$20/kW_{DC}/year	ATB (26)
Incentives	30% investment tax credit (ITC); 5-year modified accelerated cost recovery system (MACRS), 80% bonus, 0.5 MACRS ITC reduction	REopt default (16)
PV degradation	0.5%/year	REopt default (16)
DC:AC ratio	1.2	REopt default (16)

The solar PV capital costs are from the 2026 moderate scenario ATB estimate (26). The moderate scenario assumes R&D investment continuing at similar levels as today, with current industry technology road maps achieved, but no substantial innovations or new technologies introduced to the market. Capital costs include generation equipment and infrastructure, electric infrastructure, balance-of-system, installation and indirect, developer, and site costs. Utility-scale solar ATB costs are reported in dollars per kilowatt-AC. REopt requires cost estimates in dollars per kilowatt-DC. The AC cost was converted to DC costs based on DC:AC ratios (34).

A.3 Li-Ion Battery

The size of the Li-ion battery on the three installations modeled represents a utility-scale battery. Costs and performance values were selected for a utility-scale Li-ion battery in 2026.

Table A-3. Li-Ion Battery Assumptions

Li-Ion Battery Input	Assumption	Source
Rectifier and inverter efficiencies	96%	REopt default (16)
Internal efficiency fraction	97.5	REopt default (16)
Minimum state of charge	20% or 60% (as indicated in the scenario)	N/A
Initial state of charge	80%	N/A
Minimum kW	1.05 times the maximum critical load	N/A
Capital costs	\$275/kWh + \$289/kW	ATB (26)
Replacement costs (Year 10)	\$203/kWh + \$282/kW	ATB (26)
Incentives	30% ITC; 7-year MACRS, 80% bonus, 0.5 MACRS ITC reduction	REopt default (16)
Can the grid charge the battery?	Yes	N/A

The Li-ion battery capital costs are set to the 2026 moderate scenario ATB estimate (26). The moderate scenario assumes R&D investment continuing at similar levels as today, with current industry technology road maps achieved, but no substantial innovations or new technologies introduced to the market. Capital costs include generation equipment and infrastructure, electric infrastructure, balance-of-system, installation, indirect developer, and site costs.

A.4 Emergency Diesel Generator

Table A-4 provides a summary of the cost and performance of emergency generators for the size used on the REopt modeling.

Table A-4. Emergency Diesel Generator Assumptions

Emergency Diesel Generator Input	Assumption	Source
Installed cost	\$670/kW and \$820/kW (Tier IV)	Total cost of ownership (23)
Fuel cost	\$3.00/gallon	N/A
Fixed O&M	\$24/kW/year	Total cost of ownership (23)
Variable O&M	\$0	N/A
On-site fuel storage installed cost	\$4.80/gallon	Army Facilities Pricing Guide (22)
On-site fuel storage fixed O&M	\$3.07/gallon/year	Army Facilities Pricing Guide (22)
Fuel availability	Unlimited	N/A

The costs were calculated using Generac's Total Cost of Ownership calculator (23), which was validated by comparing its results to both Army Corps of Engineers guidance (22) and data from the Electric Power Research Institute (35). The installed costs include genset capital costs, enclosures, 12-hour fuel tanks, initial fuel fill, switch gear, cabling, installation, site prep, engineering, and program management. The diesel generators can run in parallel with each other, and two types were priced: a non-EPA-compliant generator and an EPA-compliant Tier IV, which can run in parallel to the grid. The fixed O&M costs include annual preventive maintenance, testing under load (including fuel used), and fuel polishing. On-site fuel storage installed costs include tank costs and initial fill. Annual O&M includes fuel tank maintenance and fuel polishing. Fuel polishing was assumed to cost \$2/gallon.

Unlimited fuel availability implies either large on-site storage beyond what would be required for a 14-day outage or guaranteed delivery from an off-site supplier. Relying on an off-site supplier to provide diesel fuel during an extended outage entails a very high risk.

A.5 Natural Gas Boiler Assumptions

A natural gas boiler at Patuxent River NAS was modeled to understand the value proposition of Antora Energy's BESS dispatching thermal energy in addition to electricity.

Table A-5. Natural Gas Boiler Assumptions

Emergency Diesel Generator Input	Assumption	Source
Installed cost	$0/MMBtu/h (assume the boiler is already installed)	N/A
Natural gas cost (Patuxent River NAS)	$14.459/MMBtu	Energy Information Administration average of May 2021–April 2023 monthly commercial natural gas costs in Maryland (36)
Fixed O&M	$2,930/MMBtu/h	REopt default (16)
Variable O&M	$0	N/A
Fuel availability	Unlimited	N/A
Efficiency	80%	REopt default (16)

A.6 Antora Energy's BESS

Antora Energy's BESS is not currently commercially available. It is estimated to be at a TRL of 7. Estimates for its cost and performance were established independently by NREL.

Table A-6. Antora LDES Assumptions

Antora Input	Assumption
Inverter efficiency	96%
TPV efficiency: Goal	50%
TPV efficiency: Intermediate	40%
Minimum kW	1.05 times maximum critical load
Thermal discharge efficiency	90%
Minimum state of charge	60%
Initial state of charge	80%
Installed cost: Goal	Includes inverter and balance of system[6]
Installed cost: Intermediate	Approximately twice the costs of goal system
Inverter replacement costs (Year 15)	$50/kW
Fixed O&M	Nominal value
Incentives	30% ITC; 7-yr MACRS, 80% bonus, 0.5 MACRS ITC reduction
Can the grid charge the battery?	Yes

Two future systems have been defined: Goal and Intermediate. The Goal represents Antora Energy's cost goals, while the Intermediate represents a mid-term target. The installed costs include an Antora Energy battery, inverter, transformer, and balance of system. The inverter cost is assumed to be $50/kW, and the transformer and balance of system is $150/kW. The

[6] The goal cost was selected by NREL to be consistent with values reported in "The design space for long-duration energy storage in decarbonized power systems", Nestor A. Sepulveda, Jesse D. Jenkins, Aurora Edington, Dharik S. Mallapragada and Richard K. Lester for multi junction thermal photovoltaic thermal storage systems. Expected costs of an inverter and balance of system were added.

developer's indirect costs are assumed to be covered by the utility-scale solar PV costs, which are larger than the battery costs. The only replacement cost over 20 years is assumed to be the inverter at Year 15.

Appendix B. EDG Cost Cases

The NPV of a system of EDGs is dependent on how the EDGs are used and the approach used for supplying the required diesel fuel. In the body of the report, we provided an estimate for the 20-year NPV for EDGs that run only during a grid outage without any costs for dedicated central diesel storage.

Patuxent River NAS and Holloman AFB have the potential to run on-base EDGs while grid tied. Running the EDGs while grid tied provides revenue from capacity-based demand response programs and reduces utility costs through peak shaving. These capabilities come at an increased cost of $150/kW for the EDGs. Patuxent River NAS is within the PJM ISO region, and PJM offers a capacity-based demand response program called Capacity Performance.[7] Holloman AFB's local utility, El Paso Electric Company, offers a capacity-based demand response program called the Load Management Program. This program offers a yearly capacity-based payment for curtailing load.[8] These capacity-based programs provide an annual payment per kilowatt per year. Installations need to work through a third party to participate. The power level that each installation could potentially commit, and the price paid if the base gets 80% of the revenue, are provided in Table B-1.

Table B-1. Demand Response Programs

Installation	Enrolled Power	Installation Revenue
Patuxent River NAS	10,500 kW	$50/kW/year
Holloman AFB	3,800 kW	$38.4/kW/year

Table B-2 provides the 20-year NPV for the N+1 EDG systems defined in Table 3 with and without grid-tied EDGs and with and without dedicated central diesel storage. The cost of obtaining the required air permits is not included.

Table B-2. Emergency Diesel Generators 20-Year NPV

Installation	Non-Grid-Tied, No Dedicated Diesel Storage	Non-Grid-Tied, Dedicated Diesel Storage	Grid-Tied, No Dedicated Diesel Storage	Grid-Tied, Dedicated Diesel Storage
Fort Bliss	−$17,210,867	−$29,628,596	N/A	N/A
Patuxent River NAS	−$12,871,362	−$19,829,840	−$630,618	−$9,164,096
Holloman AFB	−$8,605,434	−$14,225,091	−$2,954,980	−$7,237,546

The revenue from running EDGs grid tied can be significant and pays for the increased costs of the EDGs, but the ability to do this in the future remains uncertain. The costs of dedicated central diesel storage are significant and need be factored in if it does not already exist.

[7] CPower. Understanding PJM Capacity Demand Response Changes.
[8] El Paso Electric Company. El Paso Electric Company's 2020 Load Management Program.

Appendix C. Antora Entergy's BESS and Solar PV System Reliability

The LDES-based system modeled in this report is a complex power system. The system includes Antora Energy's BESS and a utility-scale solar PV. Antora Energy's BESS has a thermal storage unit, TPV modules that generate DC power, a set of inverters to transform the DC power to AC, and a transformer. In this appendix we review previously reported data and modeling of utility-scale solar PV reliability and make estimates for the reliability of Antora Energy's BESS. Diesel generators either operate or fail. They do not degrade to lower power capacity. In contrast, solar PV and BESS can have component failures that lead to a reduced power level as opposed to total failure.

Solar PV system reliability studies (37) (38) (39) show that inverter failures account for the vast majority of component failures. Data from fielded utility-scale solar PV systems show that inverters account for 94% of reported hardware faults (40). Detailed solar PV reliability modeling (19) demonstrates that the mean time to failure for utility-scale solar PV is very long and failures during an outage can be ignored. In other words, if the solar PV is operating when the grid outage occurs it is highly unlikely to experience a failure during the next 2 weeks. Although component failures are rare, it can take days to months to repair a utility-scale solar PV system, and the time to repair is highly variable (19). Because solar PV is intermittent, care must be taken in defining availability. Availability is defined as the actual measured hours of production divided by the expected or modeled hours of production. Most data collections have been motivated by a need to quantify the economic performance of a PV system and thus include external causes of loss of PV power such as curtailments or grid outages when PV systems not installed as part of a microgrid automatically shut off. We are concerned with the availability of a microgrid-integrated solar PV system that can support an islanded operation, so empirically based reported estimates are a lower bound. Based on empirical data, utility-scale solar PV availability to support islanding operations will be 99% (41).

Antora Energy's BESS configuration is like a utility-scale PV system. In Antora Energy's BESS, the thermal storage plays the role of the sun, while the TPV modules play the role of the solar PV modules. Antora Energy's BESS also includes multiple shutters, which expose the TPV to the thermal source. This subsystem is not included in our reliability assessment. Any future demonstration should seek to understand its impact on the reliability of Antora Energy's BESS. We exploit past work on the reliability of utility-scale PV systems (19) to estimate the expected reliability of Antora Energy's BESS.

In estimating the system's reliability, it is important to differentiate a fault that causes a reduction in power capacity versus a fault or set of faults that results in the total loss of power capacity. To understand the likelihood of faults that cause total loss of power versus partial loss and to quantify the magnitude of partial power losses requires us to look at the subsystem faults and their resulting impacts. Figure C-1 is a diagram of Antora Energy's BESS configuration.

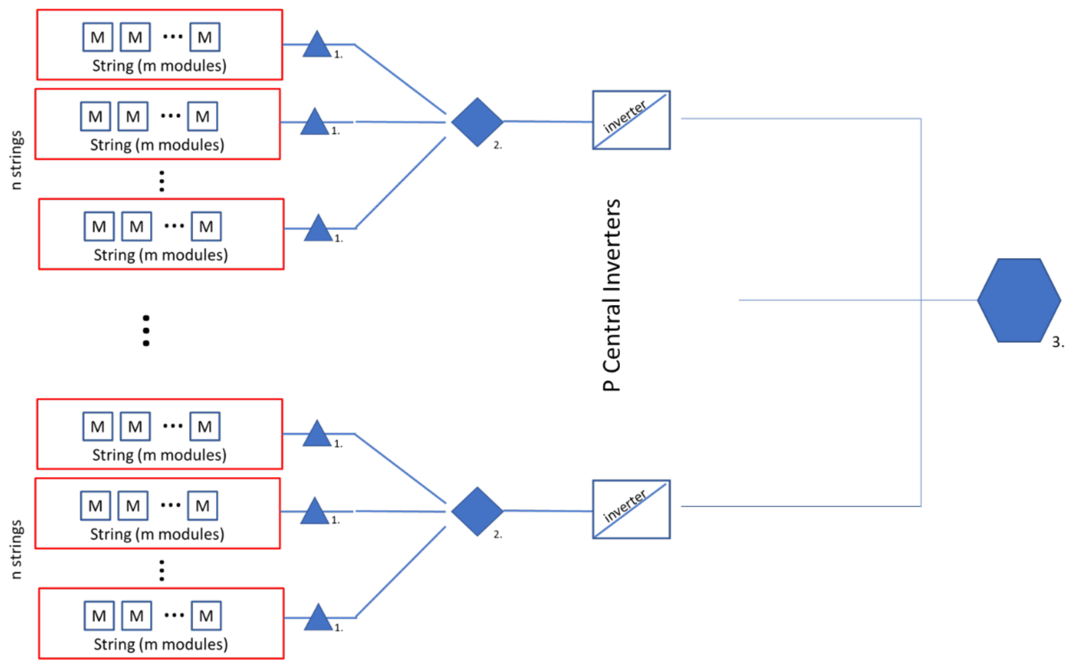


Figure C-1. Simplified diagram of Antora Energy's BESS

This system has *m* TPV modules in *n* strings linked to *p* central inverters. Component 1 is string connectors and protectors (fuses), Component 2 is the DC combiner boxes containing a DC disconnect, and Component 3 is a transformer. Antora Energy expects to have between 7 and 8 TPV modules in each string.[9]

Given the design illustrated here, a simple fault tree can be created for this system. Combining components that are in series, we find a three-tier tree Figure C-2.

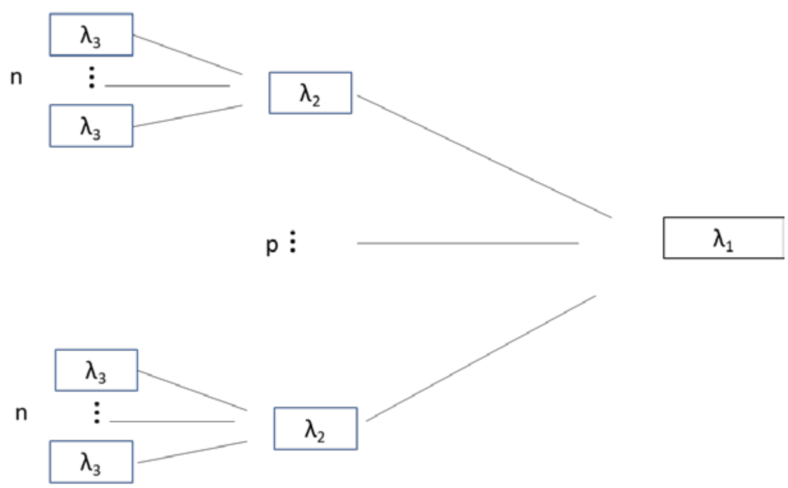


Figure C-2. Antora Energy's BESS fault tree

[9] Private communication with Antora Energy.

Where λ_i represents the failure rate for that block and $\lambda_1 = \lambda_{transformer}$, $\lambda_2 = \lambda_{DC\ combiner} + \lambda_{inverter}$, and $\lambda_3 = m \times \lambda_{module} + \lambda_{string\ connector} + \lambda_{string\ protector}$.

Failure rates for components in common with utility-scale solar PV (19) are listed in Table C-1.

Table C-1. PV System Component Failure Rates

Component	λ Failure Rate (10^{-6} per hour)
String connector	0.0056
String protector	0.063
DC combiner box [a]	3.14
Inverter [b]	74.0

[a] The DC combiner box is assumed to have a DC switch, terminal screws, fuses, and DC cables in series (see Reference 32).
[b] The inverter reliabilities include the DC and AC circuit breakers associated with the inverters.

The transformer represents the only single-point failure for the system. A summary of recent estimates for transformer reliability is shown in Table C-2.

Table C-2. Transformer Failure Rate Data

Data Source	Ref (42)	Ref (37)
λ failure rate (10^{-6} per hour)	0.30	0.24
Number of units	8982	574
Unit years of observation	144,205	2,870

Given the consistency between the failure rate from a very large reliability data set and the data from a large set of fielded PV systems, we conservatively assume a value of 0.30×10^{-6} failures per hour for the transformer.

TPV is a relatively new technology, and to our knowledge no data exist on the module reliabilities.[10] Claims are made in the literature (43) (44) that they should have high reliabilities, but no empirical data have been provided. TPV modules are made from III-V materials. Concentrating solar III-V cells are also made from similar III-V materials. Data on concentrating solar III-V cells indicate that they are reliable, but these data are also limited, and the conditions at which they operate are different than the TPVs in Antora Energy's BESS. To estimate the impact of the TPV module's reliability we have modeled its reliability as equal to a Si-based solar PV module (19), and 10 or 100 times worse.

Given these subsystem failure rate estimates, we can analyze the likelihood of a total loss of power and the expected magnitude of partial losses over a grid outage of 1 hour to 2 weeks. A total loss of power occurs if and only if all TPV modules fail, all inverters fail, or the transformer fails. The probability that a transformer fails over a 2-week outage is close to zero and not a consideration. The probability all TPV modules would fail is essentially zero even if the TPV modules are 100 times less reliable than a silicon solar PV module. The only design issue of

[10] This is contrary to the extensive data available on Si-based solar PV cells.

concern is the number of inverters. In Figure C-3, the probability of a total loss of power due to inverter failures is shown for Antora Energy's BESS with one, two, or four inverters.

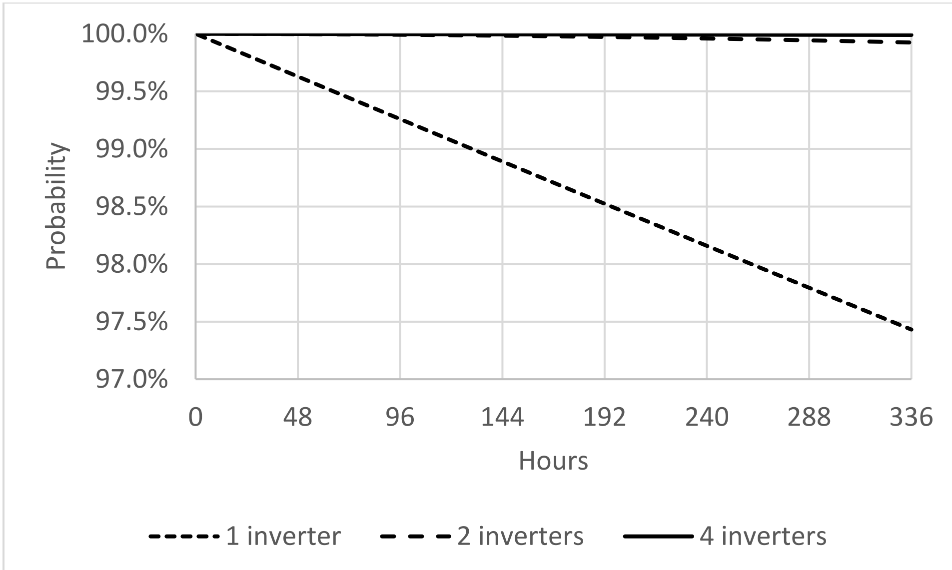


Figure C-3. Probability a PV system has the capability to produce power

An Antora Energy BESS with two or more inverters has a very high likelihood (>99.9%) of being able to produce power if operational at the start of a grid outage for 2 weeks. The impact of the mechanical shutters on the system's reliability is unknown at this time.

Even if an Antora Energy BESS can produce power, component faults can lead to a reduced level of power. Any failure in the fault tree shown in Figure C-2 will lead to a reduction in capacity. We define the cumulative probability of a component in tier *i* to be working at time *t* as:

$$R_i(t) = \mathrm{Exp}(-\lambda_i t)$$

And the cumulative probability that it fails as:

$$F_i(t) = 1 - R_i(t)$$

For a system of *N* components in parallel, the cumulative probability that *k* components are working is (45):

$$P_i(k,N) = (N!/[k!(N-k)!])\, R_i^k F_i^{N-k}$$

The fraction of power that flows through a given tier *i* if *k* component out of *N* operating is *k/N*. Thus, the expected fraction of capacity relative to capacity at the start of the outage, *C(t)*, is simply:

$$C(t) = R_1(t) \times R_2(t) \times R_3(t)$$

The fractional power capacity is independent of the number of inverters, but it does depend on the length of the string. Figure C-4 shows the mean fractional power capacity as a function of outage duration for a central inverter system, assuming a string length for the Antora Energy BESS of eight modules.

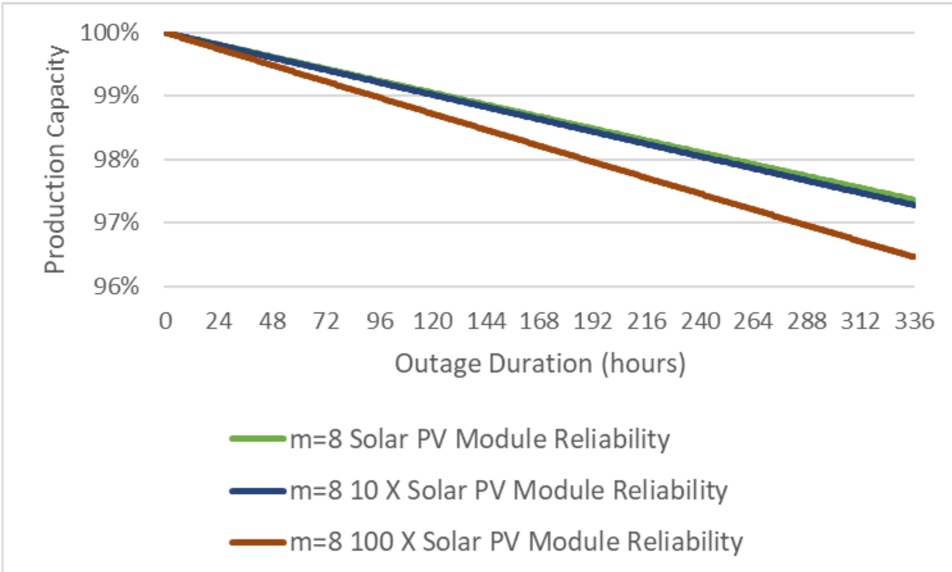


Figure C-4. Reduction in Antora Energy's BESS capacity due to component failures

A change of less than 4% over a 2-week outage is predicted. This change is minor compared to the uncertainty in the modeling of the system. Thus, in estimating the reliability of Antora Energy's BESS system, one can safely assume that if it is operational at the start of the outage, it will be operational with a very similar capacity for the next 2 weeks. Again, this result does not include the impact of the mechanical shutters.

Although component failures are rare, we do not know how long it will take to repair a system. The time to repair a utility-scale PV is driven by the time to repair or replace inverters and is highly variable, depending on business practices as much as technical issues. The repair business practices are correlated with the acquisition approach. We have assumed that the Antora Energy BESS will be procured through a third party like most large-scale solar PV systems on military installations. The expected availability of the Antora Energy BESS will be driven by inverter failures and should be like utility-scale solar PV availability of 99%.

Appendix D. Installation Data

Details on each installation are provided in this appendix.

D.1 Fort Bliss

Figure D-1 illustrates Fort Bliss's total and critical hourly load used in the modeling. It was based on the Fort Bliss 2018 actual hourly load that has been slightly modified for security reasons.

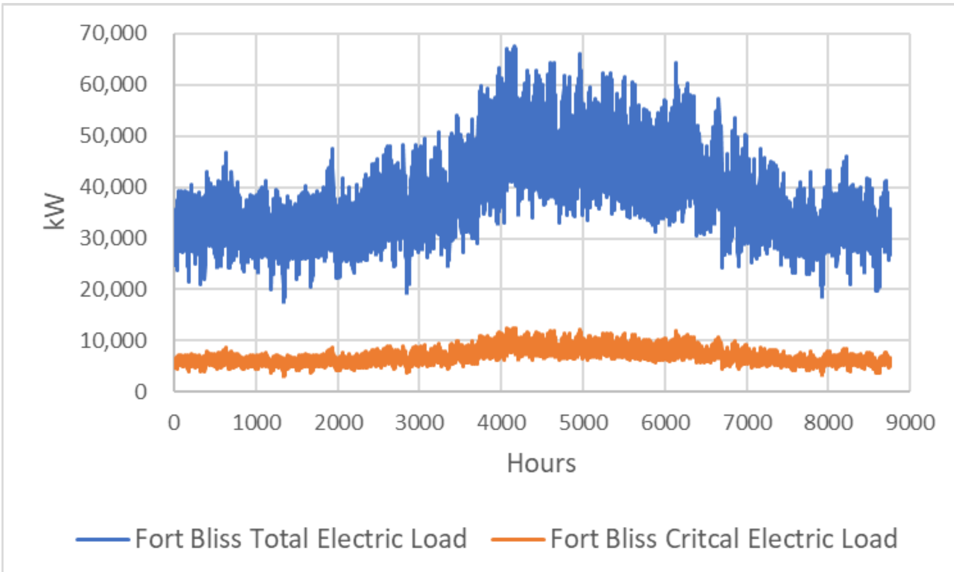


Figure D-1. Fort Bliss hourly load

Figures D-2 and D-3 provide information on the electricity tariff, El Paso Electric Military Reservation Service, used in modeling Fort Bliss. The tariff includes a fixed charge of \$139.896/day.

Energy Charges

Energy Charges - ***Rate** Periods*

Period	Tier in Period	Max. Energy Purchases (kWh/month)	Energy Charge ($/kWh)
1	1	unlimited	0.017173
2	1	unlimited	0.131643

Time of Use Energy Charges - ***Weekday** Schedule*

	12 am	1 am	2 am	3 am	4 am	5 am	6 am	7 am	8 am	9 am	10 am	11 am	12 pm	1 pm	2 pm	3 pm	4 pm	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Time of Use Energy Charges - ***Weekend** Schedule*

	12 am	1 am	2 am	3 am	4 am	5 am	6 am	7 am	8 am	9 am	10 am	11 am	12 pm	1 pm	2 pm	3 pm	4 pm	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Figure D-2. Fort Bliss energy charges

Facility Demand Charges

Facility Demand Charges - ***Monthly*** *Schedule*

Month	Monthly Demand Charge ($/kW)	Apply lookback percent?
January	17.29	no
February	17.29	no
March	17.29	no
April	17.29	no
May	17.29	no
June	21.42	no
July	21.42	no
August	21.42	no
September	21.42	no
October	17.29	no
November	17.29	no
December	17.29	no

Figure D-3. Fort Bliss demand charges

D.2 Patuxent River NAS

Figure D-4 illustrates Patuxent River NAS's total and critical hourly load used in the modeling. It was based on Patuxent River's 2018 actual hourly load that has been slightly modified for security reasons.

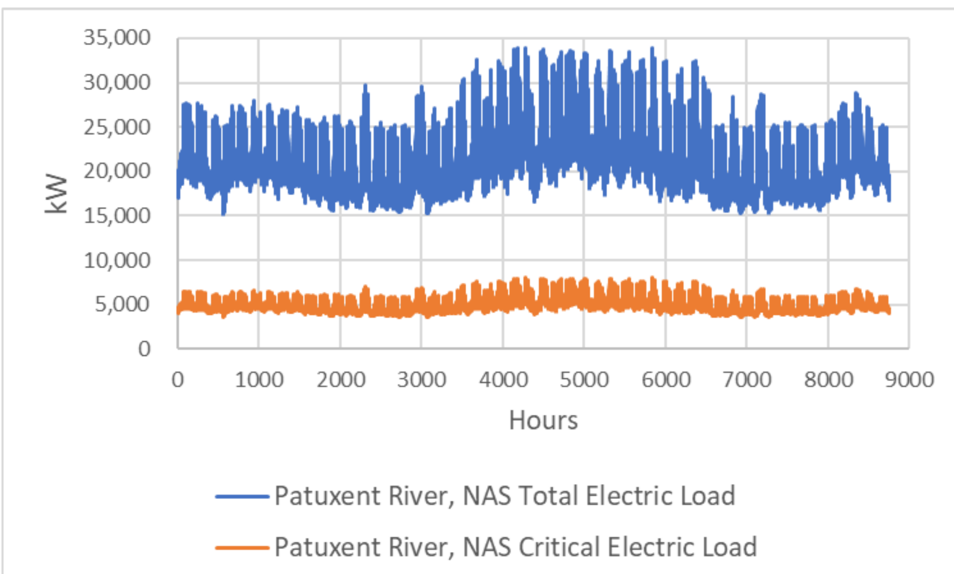


Figure D-4. Patuxent River NAS hourly load

Figure D-5 illustrates a notional Patuxent River NAS hourly thermal load used in the modeling.

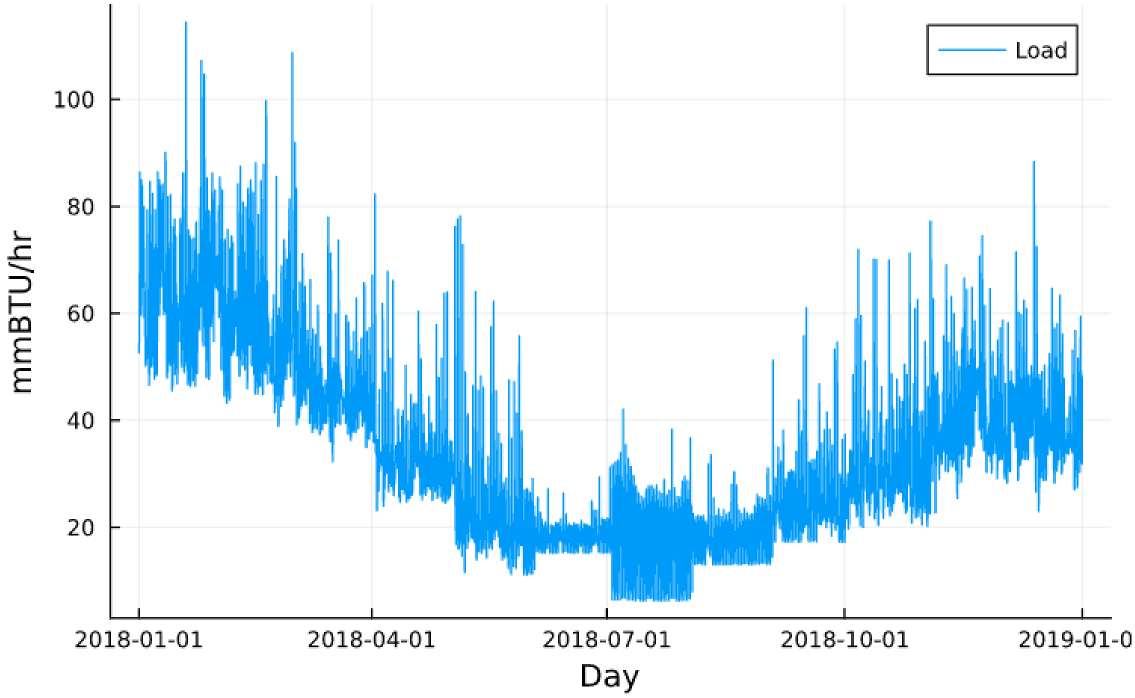


Figure D-5. Patuxent River NAS hourly thermal load

Figures D-6 and D-7 provide information on the electricity tariff used in modeling Patuxent River NAS.

Energy Charges

Energy Charges - ***Rate** Periods*

Period	Tier in Period	Max. Energy Purchases (kWh/month)	Energy Charge ($/kWh)
1	1	unlimited	0.088
2	1	unlimited	0.066

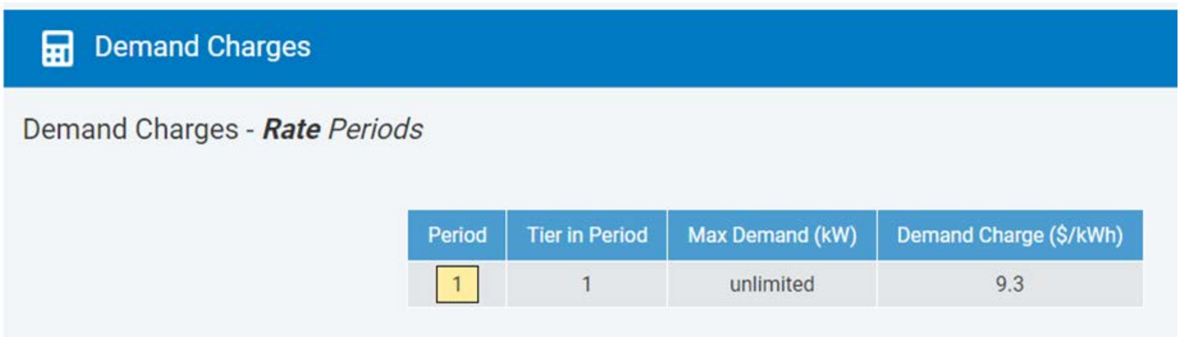
Time of Use Energy Charges - ***Weekday** Schedule*

	12 am	1 am	2 am	3 am	4 am	5 am	6 am	7 am	8 am	9 am	10 am	11 am	12 pm	1 pm	2 pm	3 pm	4 pm	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm
Jan	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Feb	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Mar	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Apr	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
May	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Nov	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Dec	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Time of Use Energy Charges - ***Weekend** Schedule*

	12 am	1 am	2 am	3 am	4 am	5 am	6 am	7 am	8 am	9 am	10 am	11 am	12 pm	1 pm	2 pm	3 pm	4 pm	5 pm	6 pm	7 pm	8 pm	9 pm	10 pm	11 pm
Jan	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Feb	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Mar	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Apr	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
May	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Nov	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Dec	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Figure D-6. Patuxent River NAS energy charges



Demand Charges

Demand Charges - ***Rate** Periods*

Period	Tier in Period	Max Demand (kW)	Demand Charge ($/kWh)
1	1	unlimited	9.3

Figure D-7. Patuxent River NAS demand charges

D.3 Holloman AFB

Figure D-8 illustrates Holloman AFB’s total and critical hourly load used in the modeling. It was based on Holloman’s 2018 actual hourly load that has been slightly modified for security reasons.

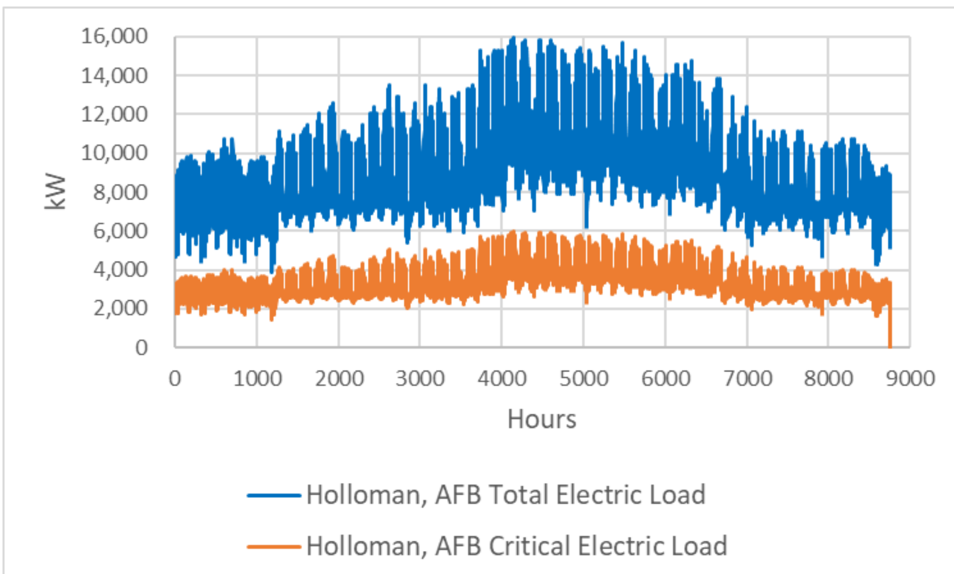


Figure D-8. Holloman AFB hourly load

The electricity tariff, El Paso Electric Military Reservation Service, shown in Figures D-2 and D-3 was used in modeling Holloman AFB.