Battery energy Storage System (BESS) Report

R.L. Harris Hydroelectric Project

FERC No. 2628

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 INTRODUCTION

Alabama Power Company (Alabama Power) owns and operates the R.L. Harris Project (FERC Project No. 2628) (Harris Project), licensed by the Federal Energy Regulatory Commission (FERC or Commission). Alabama Power is relicensing the 135-megawatt (MW) Harris Project, and the existing license expires in 2023. The Harris Project consists of a dam, spillway, powerhouse, and those lands and waters necessary for the operation of the hydroelectric project and enhancement and protection of environmental resources.

Harris Reservoir is maintained at or below the elevations specified by the Harris operating curve, except when storing floodwater. From May 1 through October 1, Harris Reservoir is maintained at or below elevation 793 feet mean sea level (msl), depending on inflow conditions. Between October 1 and December 1, the operating curve elevation drops to elevation 785 feet msl. The pool level remains at or below elevation 785 feet msl until April 1. From April 1 to May 1, the operating curve elevation rises to full pool at elevation 793 feet msl. During high flow conditions, U.S. Army Corps of Engineers (USACE)-approved flood control procedures in the Harris Water Control Manual (WCM) are implemented. During low flow conditions, the drought contingency curve is intended to be used as one of several factors in evaluating reservoir operations consistent with approved drought plans.

Alabama Power began operating the Harris Project in 1983. Initially, the Harris Project operated in peaking mode with no intermittent flows between peaks. Agencies and nongovernmental organizations requested that Alabama Power modify operations to potentially enhance downstream aquatic habitat. In 2005, based on recommendations developed in cooperation with stakeholders, Alabama Power implemented a pulsing scheme for releases from Harris Dam known as the Green Plan (Alabama Power and Kleinschmidt 2018). The purpose of the Green Plan was to reduce the effects of peaking operations on the aquatic community downstream. Although Green Plan operations are not required by the existing license, Alabama Power has operated Harris Dam according to its guidelines since 2005.

1.1 Study Background

Alabama Power filed its Initial Study Report (ISR) with FERC on April 10, 2020 and held an ISR Meeting on April 27, 2020.

As part of the Integrated Licensing Process (ILP), stakeholders can request study modifications or propose new studies following the issuance of the ISR. On June 11, 2020, Alabama Rivers Alliance (ARA) filed comments[1] on the ISR, requesting a new study titled

[1] Accession No. 20200611-5114

"Battery Storage Feasibility Study to Retain Full Peaking Capabilities While Mitigating Hydropeaking Impacts". The goal of the requested study was to determine whether a Battery Energy Storage System (BESS) could be economically integrated at Harris to mitigate the impacts of peaking, while retaining full system peaking capabilities. ARA stated that a feasibility study is needed to assess how much operational flexibility a BESS could provide and how it might allow for more fine-tuned control of ramping rates and discharges while also benefitting the larger grid and Alabama Power.

On July 10, 2020, Alabama Power responded to the ISR comments and additional study requests, respectfully declining to conduct the proposed BESS study[2]. As outlined in Alabama Power's response, the Harris Project units are not capable of ramping and, thus, the cost of a BESS system with restricted hydraulic ramping must include not only the battery but also the cost of replacing turbine runners as well as determining the extent of the effect on the balance of plant.

On August 10, 2020, FERC issued a *Determination on Requests for Study Modifications for the R.L. Harris Hydroelectric Project* [3].Within its determination, FERC recommended that Alabama Power conduct a BESS Study along with the Downstream Release Alternative Study[4], stating that it currently had insufficient information to evaluate the potential environmental benefits of a BESS. FERC stated that the feasibility of a BESS would require evaluating not only the cost of installing the battery units, as requested by ARA, but also the potential benefits to both developmental and non-developmental resources. FERC recommended that two new release alternatives should be evaluated: (a) a 50 percent reduction in peak releases associated with installing one 60 MW battery unit and (b) a proportionately smaller reduction in peak releases associated with installing a smaller MW battery unit (i.e., 5, 10 or 20 MW battery). FERC stated further that Alabama Power should include in its cost estimates for installing a BESS any specific structural changes, any changes in turbine-generator units, and costs needed to implement each battery storage type, as well as evaluate how each of these release alternatives would affect recreation and aquatic resources in the project reservoir and downstream.

While Alabama Power does not consider installation of a BESS at the Harris Project as a reasonable alternative, this feasibility study was conducted to provide FERC with the information needed to support its analysis. Commonly used acronyms used in this report are included in Appendix A. The information in this report was developed using both internal Southern Company expertise as well as externally published information from the National Renewable Energy Laboratory (NREL) (Appendix B).

[2] Accession No. 20200710-5122

[3] Accession No. 20200810-3007

[4] For reasons stated in Section 5.0, Alabama Power did not conduct the BESS study as part of the Downstream Release Alternative study.

2.0 BESS STUDY SCOPE

Harris Dam has two hydroelectric units, each rated at 67.5 MW, and each unit produces approximately 60 megawatts (MW) at best gate (i.e., efficient gate). The average flow at best gate for each unit is approximately 6,500 cubic feet per second (cfs)[5].

Both units were designed as peaking units to quickly react to electrical grid needs, and as such, the turbines were not designed to operate over a wide operating range – or restricted ramping rate – over an extended period. In fact, restricted ramping is avoided to prevent damage to hydro turbine and generator equipment. When transitioning from spinning mode[6] to generating mode, the wicket gates are opened over a period of approximately 45 seconds. One reason for this method of operating is so the turbine spends a minimal amount of time in the rough zone. The rough zone is an area in the turbine operating range where flows that are less than efficient gate cause increased vibrations in the turbine as well as cavitation along the low-pressure surfaces of the turbine runner. Prolonged ramping of the units can cause severe damage to the hydro turbine and generator equipment machinery by exposing it to excessive vibrations from vortex cores, pressure oscillations, and cavitation. Because the existing turbines are not designed to operate in a gradually loaded state or at flows lower than best gate, this study also evaluates replacing one existing unit with an upgraded unit.

Hydropower operations (i.e., project peaking operations) within this report are defined as one unit operating for 4 hours during peak energy demand, which is consistent with hydropower operations included in the Hydrologic Engineering Center's Reservoir System Simulation (HEC-ResSim) Daily Model as described in Section 4.2.1.6 of the *Downstream Release Alternatives (DRA) Phase 1 Report*[7] (Alabama Power and Kleinschmidt 2020). As outlined in the DRA Phase 1 report, a power guide factor was used to simulate the existing generation at Harris. With full power storage available, the HEC-ResSim Daily Model is programmed to generate 3.84 hours per day. Note, however, that actual historic data illustrates that Harris operates, as needed, one or both units for *more than 4 hours* to meet higher peak demands (when water is available) or when inflows are high (i.e., flood conditions). For example, two-unit generation occurs for approximately 9 percent of the total historical period. Therefore, although this study evaluated a battery that is sized to meet the hydropower operations as defined in the HEC-ResSim Daily Model (i.e., a 60 MW battery with 240 MWh capacity that can provide the equivalent generation of

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[5] In its August 10, 2020 Study Determination letter, FERC incorrectly states the best gate hydraulic capacity at 8,000 cfs. The best gate (i.e., efficient gate) hydraulic capacity of the units at Harris is approximately 6,500 cfs each, and the full gate (i.e., maximum gate; maximum turbine discharge) is approximately 8,000 cfs each.

[6] "Spinning mode is also known as motoring or synchronous condensing (condensing) mode, where, upon shutdown from a generating condition, the unit essentially becomes a motor with an exciter system that then allows the generating unit to receive or supply reactive power as necessary to maintain transmission system voltage.

[7] Accession No. 20200727-5088

one unit at best gate for 4 hours per day/every day), this size battery is not adequate to retain full system peaking capabilities.

Based on FERC's recommendations and ARA's study objectives, two BESS alternatives were evaluated in this study: Option A and Option B.

Option A is a 60 MW battery with 240 MWh capacity that can provide the equivalent generation of one unit at best gate for 4 hours per day/every day.

Option B is a 20 MW battery with 80 MWh capacity that can provide the equivalent generation of one-third of one unit at best gate for 4 hours per day/every day. The remaining 40 MW needed for 1-unit peaking generation would be produced by a new, upgraded unit.

As recommended by FERC, the scope for both Option A and Option B includes developing information and analyses to address the following questions.

1. What are the cost estimates for installing a BESS, any specific structural changes, any changes in turbine-generator units, and costs needed to implement each battery storage type? (Section 3.0)
2. What are the impacts to recreation and aquatic resources in the Tallapoosa River downstream of Harris Dam as a result of installing and operating a BESS at the Harris Project? (Section 4.0)

To provide a cost estimate for installing and maintaining a BESS, the scope for both Option A and Option B also includes developing information and analyses to address the following questions:

3. What are the costs associated with augmentation programs to maintain the nameplate capacity of a BESS? (Section 3.1.2)
4. How often does a BESS need to be replaced, and what is the replacement cost? (Section 3.1.3)
5. What are the efficiency considerations when sizing the BESS for each option? (Section 3.1.5)
6. How would the battery be charged? (Section 3.1.5)
7. Where would a battery of this size be located? How much space would be needed? (Section 3.1.6)
8. To what extent does installing and operating a BESS affect transmission? (Section 3.1.7)

2.1 Assumptions

Assumptions used in gathering and analyzing data for the BESS study are included below.

1. All BESS related cost projections were based on the National Renewable Energy Laboratory (NREL) "Cost Projections for Utility-Scale Battery Storage: 2020 Update". This paper was based on 19 publications that focus on lithium-ion, utility scale battery systems. The report developed an advanced, moderate, and conservative projection for capital cost as well as operating and maintenance cost. Moderate projections were used for all costs in this study. Due to only four publications including data for 2050, NREL assumed a 25 percent reduction in cost for the high and median cases and a 39 percent reduction for the low case between 2030 and 2050. Therefore, *all cost estimates are screening level only*. Additionally, because the evaluation is conducted at screening level, potential incentives to offset battery costs are not included.
2. This evaluation focused solely on the Lithium Ion (Li-ion) battery chemistry as it is the most established battery technology for this application. Power quality and stability were not considered in evaluating the batteries.
3. Preliminary transmission impacts are presented at a screening level effort.
4. For siting and environmental permitting, a high potential for variability exists, and site-specific details regarding battery installation were not vetted at this time.
5. All analyses assume an initial in-service date of 2025, which presumes that the new Harris license is issued in 2023 upon the expiration of the current license as well as a two-year installation period.
6. Power supplied to the grid is unchanged.
7. Turbine/unit modifications, including replacing one unit with an upgraded unit, would be required to meet the goal of the study.
8. NREL data used in this report also incorporates oversizing to accommodate energy losses.
9. For Option A, the same daily volume of flow is released, but the amount of flow that would have been released from one unit at best gate is now dispersed throughout the day.
10. For Option B, a peak release would still be required, because 40 MW is still required by the hydropower unit during peak (20 MW battery + 40 MW hydropower unit = 60 MW peaking capacity).

3.0 ECONOMICS

3.1 BESS

A BESS is an electrochemical device that charges (or collects and stores energy) from the grid or a power plant and then discharges that energy at a later time to provide electricity or other grid services when needed. Several battery chemistries are available or under investigation, but the current market is dominated by lithium-ion chemistries (NREL 2021). Historically, BESS integrates variable renewable energy sources such as solar and wind. Recently, a smaller scale BESS (i.e. approximately 4 MW) has been coupled with a *run-of-river* hydropower plant at the request of the licensee[8]. However, integration with storage hydroelectric projects is just now being developed on small scale projects, and at the licensee's request. This is likely because the value streams that can be realized by the integration of a BESS and a hydro facility (energy arbitrage, ancillary benefits) already exist at storage projects. In other words, hydro storage projects by nature are already similar to large batteries.

3.1.1 BESS Estimated Installation Costs

Option A

Using the NREL 2020 Annual Technology Book (ATB) (Appendix B), the Moderate In-Service Cost (2018$) is 1,004/kilowatt (kW). Incorporating an inflation assumption of 2.5 percent, the 2025 In-Service cost would be $1,194/kW and a total in-service cost of $71.64 Million (M), which does not include interconnection costs, internal overhead costs, contingency, and financing. These costs add an additional $25M to the total cost of the project as outlined below.

- BESS System - $71.64M[9]
- Interconnection - $9M [10]
- Internal Overheads - $3M [11]
- Contingency - $8.4M[12]
- Financing - $4.6M[13]
- ***Total Installed Cost (2025$) - $96.6M ($1,610 / kW)***

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[8] See FERC Project No. P-1904

[9] BESS System estimates provided in this report are based on NREL moderate projection for 2025 In-Service.

[10] Interconnection estimates provided in this report are based on preliminary transmission planning review provided in Section 3.1.7.

[11] Internal Overhead estimates provided in this report are based on a 36-month development and implementation schedule.

[12] Contingency estimates provided in this report are estimated at 10% of total cost.

[13] Financing estimates provided in this report are estimated at 5 percent of total cost based on 36-month schedule.

Option B

Using the NREL 2020 ATB (Appendix B), the Moderate In-Service Cost (2018$) is 1,004/kilowatt (kW). Incorporating an inflation assumption of 2.5 percent, the 2025 In-Service cost would be $1,194/kW and a total in-service cost of $23.9M, which does not include interconnection costs, internal overhead costs, contingency, and financing. These costs add an additional $17.1M to the total cost of the project as outlined below.

- BESS System - $23.9M
- Interconnection - $9M
- Internal Overheads - $2.5M
- Contingency - $3.6M
- Financing - $2.0M
- ***Total Installed Cost (2025$) - $41.0M ($2,050 / kW)***

3.1.2 Fixed Operation & Maintenance with Augmentation

All Li-ion systems degrade over time, losing capacity, and these systems' Li-ion cells have both a calendar life (years) and cycle life (MWhs). The literature on calendar and cycle life continues to evolve as the technology advances. The rate of degradation is based on the rate of charging and discharging, use cycles, operating temperature, and chemistry of the battery. A cycle is defined as one full charge and discharge cycle.

Due to degradation, suppliers offer augmentation programs to maintain the nameplate capacity of a system. These augmentation programs can involve adjusting the system over time by replacing modules, adding additional modules, or simply over building the system and adjusting the operations. Due to the complex nature of augmentation, this process is not typically performed annually. Rather, it is typically performed every 2 to 3 years based on projected use, lead times on equipment, and market prices.

Utilizing NREL's guidance for a 2025 in-service date, the annual fixed Operation & Maintenance (O&M) cost (including the cost for augmentation) adjusted for inflation is $29.84/kW-yr. For Option A, this would result in an annual estimated cost of $1.79M for the first twenty years. For Option B, this would result in an annual estimated cost of $0.597M. Following battery replacement (see below), the annual estimated cost for Option A would be $1.94M, and Option B would be $0.647M. Approximately two-thirds of this cost is associated with the augmentation of the system to maintain the rated capacity.

3.1.3 Battery Replacement - Estimated Replacement Costs

Recognizing that a Li-ion battery storage asset life is typically no more than 20 years, it is assumed the asset would need be totally replaced in 2045. Utilizing the NREL 2020 ATB (Appendix B), the moderate replacement cost (2045$) is $1,293/kW.

Option A

Utilizing an inflation assumption of 2.5 percent, this results in the 2025$ replacement cost of $789/kW and a total 2025$ replacement cost of $47.4M, which does not include, internal overhead costs, contingency, and financing. These costs add an additional $9.1M (2025$) to the total cost of the project as outlined below.

- BESS System - $47.4M[14] (NREL)
- Internal Overhead costs - $1.5M[15]
- Contingency - $4.9M[16]
- Financing - $2.7M[17]
- ***Total 2045 Replacement Cost (2025$) - $56.5M ($941 / kW)***

Option B

Utilizing an inflation assumption of 2.5 percent, this results in the 2025$ replacement cost of $789/kW and a total 2025$ replacement cost of $15.8M, which does not include internal overhead costs, contingency, and financing. These costs add an additional $3.89M (2025$) to the total cost of the project as outlined below:

- BESS System - $15.8M
- Internal Overheads - $1.25M
- Contingency - $1.7M
- Financing - $0.94M
- ***Total Replacement Cost (2025$) - $19.7M ($984 / kW)***

[14] Based on NREL moderate projection for 2045 replacement (2025$)

[15] Based on an 18-month development and implementation schedule (2025$)

[16] Estimated at 10 percent of total cost (2025$)

[17] Estimated at 5 percent of total cost based on 18-month schedule (2025$)

3.1.4 Asset Value

When adding an asset to the Southern Company system, the potential value of the asset relative to the alternative must be considered, in addition to its costs.

When comparing the hydro peaking unit and the BESS peaking unit, Harris Dam hydro is given full deferred generation credit due to its ability to provide full-rated capacity for at least 8 hours. Whereas, based on current internal company guidance, a 4-hour energy storage asset would only receive approximately 76 percent annual deferred generation capacity credit. Deferred generation capacity credit is typically valued at the Cost of New Entry (CONE).

As discussed in Section 3.1.5, the hydro asset would create greater energy production cost savings due to its zero-cost fuel source. The BESS would only transfer energy from one time to another while overcoming its efficiency losses. While a BESS could be directly charged by a hydro facility if electrically configured correctly, it would only be attributed with the incremental energy production savings (Peak Discharge Cost vs. Off-Peak Charge Cost)[18].

The majority of the energy production cost savings would be attributed to the zero-cost fuel hydro facility. For this reason, it is not reasonable or necessary to locate a BESS near the Harris hydro asset. Any BESS would be located at the most cost-effective location in the Southern Company system.

While the combination of an upgraded unit and BESS could be considered equivalent to the peaking capabilities of the existing unit, it comes at a significant capital and long-term operations and maintenance cost. While the energy production savings could be deemed equivalent it would require a greater production of energy to overcome the efficiency losses through the BESS.

3.1.5 Battery Efficiency, Dispatch, and Charging

Efficiency

A BESS is a net energy consumer, as it requires more energy to charge than is discharged. For every 1 kW that enters the BESS, only 0.85 kW is exited, exhibiting a round-trip efficiency loss of 15 percent (Cole 2020; NREL 2020). Therefore, 15 percent of every kWh is lost due to charging and discharging processes. This efficiency is typically inclusive of the auxiliary loads to operate the battery's cooling systems. Current information puts the auxiliary load requirement at 1 to 2 percent of annual usage depending on the cooling technology and usage duty cycle.

[18] As discussed in Section 3.1.5, the inflow would not sufficiently charge the BESS at the Harris Project.

To accommodate these losses, a BESS is typically oversized (7 to 10 percent) so that the required useable energy can be delivered at the point of interconnection (POI). For a BESS to supply 60 MW for 4 hours or 240 MWh of useable energy the system would have an installed direct current capacity of approximately 260 MWh. Similarly, for a BESS to supply 20 MW for 4 hours or 80 MWh of useable energy, the system would have an installed direct current capacity of approximately 88MWh.

A BESS is made up of both a power conversion block and the energy block. The power conversion block is typically comprised of an inverter and transformer, and the energy block is comprised of the batteries and battery management system. The power block is typically oversized to accommodate the reactive power requirements to maintain power stability.

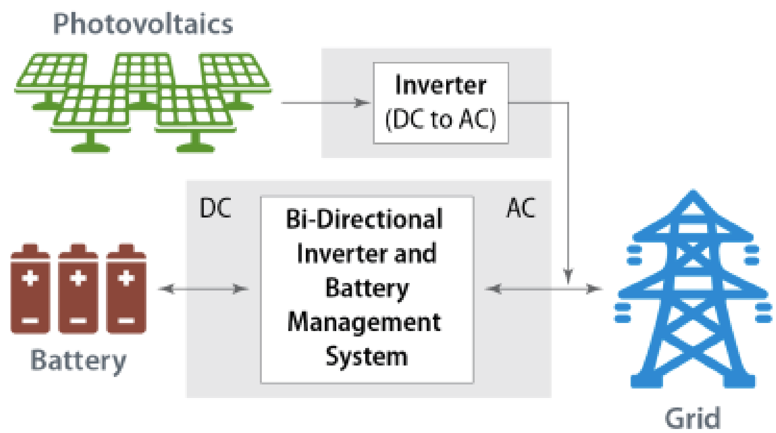
Dispatch and Charging

Southern Company dispatches generating assets to serve customers at the lowest cost while maintaining required reserve margins for reliability purposes. In the case of renewables such as solar, wind, or hydro, these assets can create significant energy production cost savings due to the zero-cost fuel. Solar and wind are variable energy resources where the output is dependent on the variable nature of the fuel resource. Solar and wind resources are typically allowed to dispatch as energy is generated to recognize those energy production cost savings for customers. Hydroelectric power is also dependent on nature and the amount of rain that has occurred throughout a time period. Peaking projects, like the Harris Project, operate to store energy in the reservoir and use it at the most valuable times of the day to create the greatest energy production costs-savings for customers.

A BESS can be charged using several different electrical configurations. An independently sited BESS would be directly connected and charged from the electrical grid. A BESS can also be charged by a co-located generator such as a solar or hydro facility, if electrically configured appropriately. In both configurations, the cost of charging the BESS would be at Southern Company's avoided energy cost while accounting for the efficiency losses of the BESS. Avoided energy cost is defined as the cost of the next increment of energy ($/MWh) to meet the next increment of load.

A BESS is a direct current (DC) system, so it requires a bi-directional inverter to connect to the alternating current (AC) power grid. Figure 3-1 below provides an example of a solar photovoltaic (PV) PV that is AC-coupled to a battery system through a common/shared switchgear. Whether the BESS is charged from the grid or the solar PV, its charging cost would be at the system's avoided energy cost if there is not a transmission related issue that limits the output of the solar PV. Due to efficiency losses, the amount of energy used to charge the BESS would be greater than is discharged.

Therefore, there would be an efficiency adjustment to the charging cost when determining the most economical times to dispatch power from the BESS.



Source: NREL 2017

Figure 3-1 AC-Coupled, Grid Connected BESS

In an example where the solar PV is directed to the BESS, the solar output that could have been directed to the grid to serve customers and create the associated energy production cost savings at those time periods is now directed to the BESS. Prior to directing the solar energy to the BESS, an economic optimization would be performed to recognize that the solar PV output by itself would have created a certain amount of energy production cost savings for customers and that there was an incremental amount of savings that could be realized for customers by using the BESS to shift solar production to more valuable (higher avoided energy cost) hours of the day while also recognizing the efficiency loss costs. While the BESS is creating an incremental amount of value for customers, it is really the hydro, solar, or wind assets that are creating the most energy production savings to customers. The BESS is merely trying to trans fer energy from one time to another to create an incremental amount of value, while requiring 15 percent more energy production.

When considering solar, the goal is to save the energy produced by the PV in the battery to use at a more optimal (peak) time. For hydro, the same concept would apply if the project is run-of-river, i.e., inflows are being instantaneously passed through the turbines and that energy is captured in a battery to use during the peak. The Harris Project, however, is not a run-of-river project; it is a storage project.

Charging a BESS with a hydropower unit is dependent on a reliable reservoir inflow. Otherwise, charging inconsistencies can affect the life of the battery and the guarantee that it can supply a certain amount of energy each day. The amount of inflow into Harris Reservoir is insufficient to fully charge both the Option A and the Option B BESS on a daily basis. The amount of flow into Harris Reservoir that can be consistently relied upon to charge the BESS is 247 cfs, which is the 95-percentile flow from the 1939-2011 unimpaired flow data in the HEC-ResSim model.

In order for the BESS to supply energy equally over a 4-hour peaking period, the battery would charge for 20 hours and discharge for 4 hours. Using the power equation and assuming a turbine efficiency of 90 percent[19], as well as considering the BESS efficiency losses described above, the energy produced by the hydropower unit with a flow of 247 cfs over 20 hours would be approximately 41 MWh. This means the BESS would have enough energy stored from the hydropower unit to produce approximately 10 MW per hour for 4 hours. The shortfall of the remaining 50 MW needed for peaking would be produced by the hydropower unit.

3.1.6 Battery Siting

A BESS has high energy density, meaning a substantial amount of energy can be placed in a small footprint; this correlates to a smaller acreage of land needed to site the BESS. A 60 MW / 240 MWh BESS would typically require approximately two acres of contiguous flat land to be cost effective. This land would house the battery containers, power conversion system, balance of plant equipment, and project level substation. Additional land would be required for the transmission system and construction staging operations.

Based on a cursory review of the proposed area around Harris Dam, adequate property for the BESS exists. Additional due diligence would be needed to determine siting availability and development feasibility and these studies would be performed in conjunction with any transmission interconnection studies. No environmental review was undertaken for this siting screening.

3.1.7 Interconnection

Alabama Power performed a screening level transmission study of the 60 MW (240 MWh)[20] BESS near Harris Dam. The BESS was evaluated as both a generator and a load to determine the impact on the transmission lines and associated system feeding the Crooked Creek Transformer Substation (TS) (Crooked Creek TS). This screening did not consider any stability or power quality analysis and represents a preliminary assessment of the BESS based on current assumptions within the transmission planning model.

The screening analysis determined that there is not currently adequate space and/or a spare terminal at the Harris Dam or Crooked Creek TS that could be used to interconnect the BESS. This screening analysis assumed that potential interconnection locations would be located at a new substation approximately one mile along the routes following the existing transmission lines from Crooked Creek TS. This would include either the East

[19] A turbine efficiency of 90 percent is high for a turbine being operated at the lower end of its operating range.
[20] Results are also applicable to Option B.

Roanoke – Crooked Creek 115 kV Transmission Line (TL) or the Martin Dam – Crooked Creek #1 115 kV TL. Site acquisition, design, and survey would be required to determine the optimal interconnection location and configuration. The estimated screening level capital cost for interconnections is approximately $9M, which includes costs associated with a new substation. The estimated screening level long-term, annual O&M costs for interconnections is an additional $173,000 per year[21].

3.2 Changes in Turbine-Generator Units

As described above, the existing turbines are not designed to operate at flows lower than best gate. Therefore, both alternatives evaluated within this study require replacing one of the existing turbines.

The existing turbines at Harris are Francis turbines with a maximum discharge of 8,000 cfs each. When evaluating an upgraded unit, it is imperative that the new unit retain the maximum discharge capacity of 8,000 cfs in order to operate during flood conditions. Additionally, an upgraded unit at Harris would need to operate at a much lower flow for both Options A and B. Option A would require a variable flow turbine capable of low flows to the current full gate flow, which is an unrealistic range given the mass of the rotating components. Option B would require a newly designed Francis turbine with a wider operating range capable of flows from ~4300 cfs up to the current full gate flow.

Replacing an existing Francis turbine with a new Francis turbine that has a wider operating range will require not only replacing the runner but replacing or refurbishing additional components that are normally addressed during a major turbine upgrade. Based on recent turbine upgrades at other Alabama Power projects, it is estimated that the cost to upgrade one of the Harris turbines with a new Francis turbine would exceed $20M. Francis turbines cannot operate at the lower flows required by Option A at Harris; therefore, a Francis turbine with a wider operating range would only be a possibility for Option B. A Kaplan variable flow turbine could provide lower flows in comparison to a Francis turbine; however, it is unlikely a Kaplan turbine could provide the full operating range required by Option A. If it could, replacing a Francis turbine with a Kaplan would require much more than the replacement of the runner and related components. It would require extensive structural modifications as well as complete replacement of major components such as wicket gates, discharge ring, hydraulic system, etc. In other words, installing a Kaplan variable flow unit would require a complete redesign of the Harris Project, because the powerhouse was constructed for a Francis style unit. A detailed engineering design would be required to determine if a Kaplan turbine is even possible in a powerhouse designed for a Francis unit. If it could be done, the range of flows would then be determined in addition to the costs of replacing a Francis unit with a Kaplan unit. This level of design detail is beyond the scope of this study. Therefore, Alabama Power is not providing a cost

[21] Based on current Open Access Transmission Tariff (OATT) rates and subject to periodic adjustments

estimate for replacing one of the existing turbines with a Kaplan variable flow turbine for Option A.

3.3 Summary of Estimated Costs

Option A is a 60 MW battery with 240 MWh capacity that can provide the equivalent generation of one unit at best gate for 4 hours per day/every day.

Option B is a 20 MW battery with 80 MWh capacity that can provide the equivalent generation of one-third of one unit at best gate for 4 hours per day/every day. The remaining 40 MW needed for 1-unit peaking generation would be produced by an upgraded hydro unit. Option "B" has a significantly higher cost per kW for total cost installed, because the fixed costs such as interconnection are not reduced significantly as the size of the project is reduced. Table 3-1 below summarizes the estimated costs of BESS over the license term.

Table 3-1 Summary of BESS Cost Estimates Over 40-Year License Term at the Harris Project

	Option A	Option B
Total Installed Cost (2025$)	$96.6M ($1,610 / kW)	$41.0M ($2,050 / kW)
Fixed O&M (including augmentation) (2025-2044)	$1.77M * 20 years	$0.597 * 20 years
Total Replacement Cost (2025$)	$56.5M ($941 / kW)	$19.7M ($984 / kW)
Fixed O&M (including augmentation) (2045-2064)	$1.94M * 20 years	$0.647M * 20 years
Turbine Replacement Cost	Undetermined	$20M
Interconnection O&M (based on current OATT rate and subject to periodic adjustments)	$173,000 * 40 years	$173,000 * 40 years

4.0 RESOURCE EFFECTS

Alabama Power is providing a scoping-level semi-quantitative assessment of the BESS effects on recreation and aquatic resources. The models utilized in the Final *Downstream Release Alternatives Phase 1 Study Report* (Alabama Power and Kleinschmidt 2020) include operational parameters such as peaking operations and continuous minimum flows. To model Project operations with peaking removed, the HEC-ResSim and Hydrological Engineering Center's River Analysis System (HEC-RAS) models would need to be redesigned to incorporate new operating rules. Defining new operating rules and redesigning the models is outside the scope of the study proposed by ARA and recommended by FERC.

In order to provide a semi-quantitative assessment, the 2001 operations hydrograph that was used to model the alternatives in the Downstream Release Alternatives Study was modified to create theoretical hydrographs for BESS Options A and B. For days with more than 4 unit hours of generation, the discharge was reduced by the equivalent of 4 unit hours of generation to represent replacement by BESS Option A. For Option B, the discharge was reduced by the equivalent of one-third of 4 unit hours of generation. The discharge replaced by BESS was then distributed evenly over each hour for that day for both Options A and B.

For days with 4 or less unit hours of generation for Option A and 1.33 or less unit hours of generation for Option B, the discharge for that day was averaged and distributed across each hour for that day. Figure 4-1 and Figure 4-2 provide 24-hour theoretical hydrographs for BESS Options A and B during winter, spring, summer, and fall.

Metrics for the theoretical BESS hydrographs were calculated to provide a comparison to Green Plan (baseline) operations. Results indicate BESS Option A and B would provide a daily average minimum flow of approximately 701 cfs and 316 cfs, respectively[22], though it would range substantially higher and lower on a daily basis, compared to a daily average minimum flow of 120 cfs under baseline (Green Plan) operations (Table 4-1). For BESS Option A, the daily minimum release ranged from 0 to 6,900 cfs, with 25th and 75th percentile values of 210 and 1,027 cfs. For BESS Option B, the daily minimum release ranged from 0 to 10,421 cfs, with 25th and 75th percentile values of 178 and 278 cfs.

Compared to baseline, the average magnitude of daily flow fluctuations would decrease by approximately 71% under BESS Option A and 27% under BESS Option B. Average hourly flow fluctuations would decrease by approximately 48% under BESS Option A and 39% under BESS Option B.

[22] Note that this is a daily average based on the 2001 calendar year flow conditions, not a continuous day-to-day minimum flow release; therefore, there would be no effects on lake levels compared to baseline.

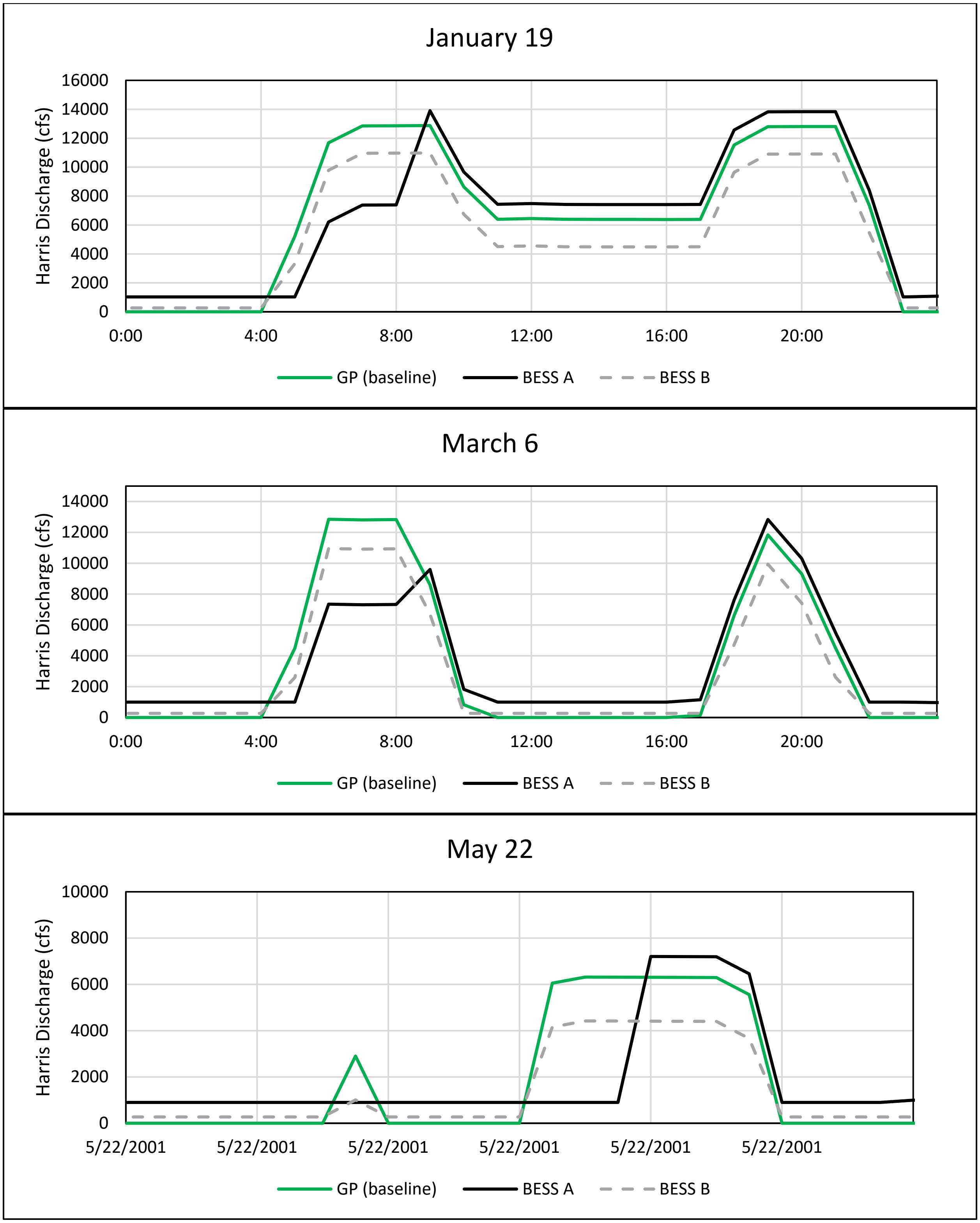


Figure 4-1 Theoretical 24-hour Hydrographs for BESS Options A & B for Example Dates in Winter and Spring

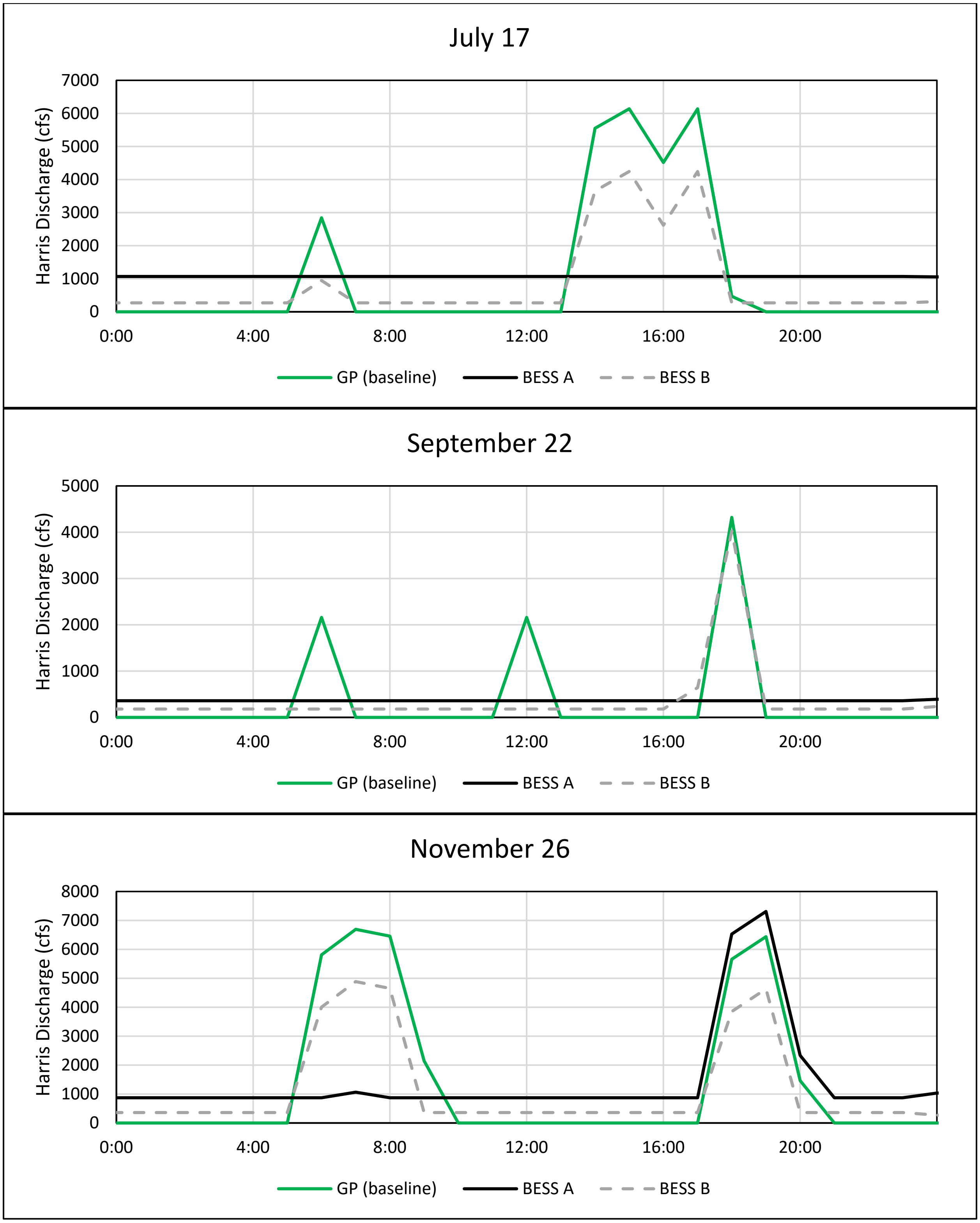


Figure 4-2 Theoretical 24-hour Hydrographs for BESS Options A & B for Example Dates in Summer and Fall

Table 4-1 Comparison of Metrics from Theoretical Hydrographs for BESS Options A and B

Operating Alternative	Average Daily Minimum Discharge (cfs)	Average Daily Flow Delta (cfs)	% Reduction in Average Daily Flow Delta	Average Hourly Flow Delta (cfs)	% Reduction in Average Hourly Flow Delta
Baseline (Green Plan)	120 (0 – 0)[1]	6,728	NA	875	NA
BESS Option A	701 (210 – 1027)	1,955	71%	452	48%
BESS Option B	316 (178 – 278)	4,880	27%	532	39%

[1] Numbers in parentheses depict 25th and 75th percentile values for the daily minimum discharge

Alabama Power would like to make one clarification to previous comments by FERC on the potential benefits of a BESS application on lake levels at the Harris Project. In the Determination on Study Modifications, FERC stated that during a 24-hour period the elevation level in Lake Harris can fluctuate 0.5 to 1.5 feet. Using the assumption that the volume of daily releases remains constant, but one unit is replaced by a 60 MW battery, FERC stated that the daily fluctuations could be cut in half. FERC's description of reservoir fluctuations is incorrect. As described in the Pre-Application Document and other relicensing documents, under normal conditions, Alabama Power operates the Harris Project during daily peak-load requirements to maintain reservoir levels according to the operating curve. Harris Reservoir is maintained at or below the elevations specified by the operating curve, except when storing floodwater. Table 4-2 below provides maximum, minimum, and average daily lake level fluctuations for the Harris Reservoir, as measured at Harris Dam. The average daily lake level fluctuation is well below 0.5 foot. Table 4-3 provides the number of days between 2015 and 2020 that the daily lake level fluctuation exceeded 1 foot. Special operations, such as flood control procedures, were in place each time the elevation fluctuation exceeded 1 foot within a day.

Table 4-2 Maximum, Average and Minimum Lake Harris Fluctuations (Daily)

Lake Harris Elevation Fluctuation in a Day (feet)							
	2015-2020	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Max	3.26	3.26	2.57	1.23	1.31	1.43	3.22
Average	0.23	0.23	0.20	0.19	0.23	0.19	0.32
Min	0.01	0.05	0.01	0.05	0.04	0.04	0.04

Table 4-3 Days Exceeding 1 Foot Fluctuation in Lake Harris from 2015-2020

	2015-2020	2015	2016	2017	2018	2019	2020
# of Days	34	6	5	2	3	1	17

4.1 Recreation Effects

4.1.1 Harris Reservoir

Assuming that utilizing a BESS would result in releasing the same daily volume of water as released under current operations, there would be no effect to reservoir levels, and, therefore, no effect on Lake Harris recreation.

However, if integrating a BESS (and concurrently, an upgraded unit) resulted in releasing a higher volume of water, the reservoir levels could be impacted. In the event that the daily volume of water released increased to the point that it affects Alabama Power's ability to maintain its operating curve, a negative impact on recreation would result[23].

4.1.2 Downstream of Harris Dam

Downstream recreation use can be affected by peaking flows. Flow effects on recreation-based activities can range widely in magnitude, frequency, and duration, depending on the project and its operational constraints (Reiser, Nightengale, Hendrix and Beck 2008). Although results from the Recreation Evaluation Report showed that the majority of recreation users below Harris Dam found all water levels acceptable (with river flows ranging from 499 to 6,110 cfs) and the recreation effort did not appear to be affected by flow (Kleinschmidt 2020), intermittent flows may decrease opportunities for recreation, particularly in the Project tailrace, where depth of water is very shallow when the turbines are not releasing water. Further downstream from the Project, the effect of a peaking flow is less as operating flows attenuate (Kleinschmidt 2020). For Option A, it is assumed the amount of flow that would normally be placed on peak would be released throughout the day resulting in more stable stage differences (i.e., less fluctuation), compared to one-unit peak releases. A more stable flow would benefit recreationists launching in the tailrace and for the first few miles below Harris Dam. Once a boater reaches the area around Malone, effects from changing the downstream peak release would be less apparent.

[23] See Section 3.7 of the Downstream Release Alternatives Phase 2 Report (Alabama Power and Kleinschmidt 2021) for further discussion regarding effects on Harris Reservoir recreation and the potential to reduce the usability of shoreline structures in the summer months in the event that the operating curve is not followed.

For Option B, the effects of peaking flows, and therefore intermittent flows, on recreation-based activities in the Project tailrace and first few miles downstream would still occur as they do under baseline operations, although the peak release would be smaller.

4.2 Aquatic Resource Effects

When flow varies, a number of stream variables may be affected, including velocity, depth, width, and wetted perimeter (the distance along the stream bottom from one shoreline to the other (Cushman 1985). Option A could potentially result in a reduced magnitude of water level fluctuations downstream because it is assumed that the one-unit release would be dispersed throughout the day. This would likely benefit the aquatic resources in the first seven miles downstream of Harris Dam, because a flow released over a longer time, compared to a one-unit peak release could benefit wetted perimeter by gradually increasing wetted area, allowing those species to move to other areas for refugia or other habitat, and increasing habitat stability. Based on analysis of the theoretical hydrograph for Option A, over the course of the 2001 calendar year, the daily average minimum flow would be approximately 701 cfs, though it would range substantially higher and lower on a daily basis. This would yield average increases in wetted perimeter within the range of results for the 600 and 800 cfs minimum flow scenarios modeled in the *Downstream Release Alternatives Draft Phase 2 Study Report* (Alabama Power and Kleinschmidt Associates 2021)(Table 4-6).

Option B would not have the same benefits as Option A because a peak release would still be required. With a 20 MW BESS, 40 MW is still required by the hydropower unit during peak. Therefore, the peak release would still occur, but would be proportionately smaller (i.e., approximately 4,300 cfs). In Option B, effects on the amount and stability of wetted habitat would be similar to the 300 cfs continuous minimum flow scenario described in the *Downstream Release Alternatives Draft Phase 2 Study Report* (Alabama Power and Kleinschmidt Associates 2021).

Note that for both Options A and B, a daily or periodic peak release would still occur, as shown in Figures 4-1 and 4-2 above.

Table 4-4 Percent Increase (compared to GP (baseline)) in Wetted Perimeter for 300, 600, and 800 cfs Continuous Minimum Flow Scenarios

Miles Below Harris	Mesohabitat Type	300 cfs	600 cfs	800 cfs
0.4	Riffle	6%	11%	14%
1	Riffle	2%	3%	4%
2	Riffle	7%	8%	9%
4	Pool	0%	1%	1%
7	Pool	6%	11%	12%
10	Riffle	1%	2%	2%
14	Run-Pool	1%	1%	1%
19	Riffle-Run	2%	7%	11%
23	Riffle	3%	7%	11%
38	Riffle	1%	2%	3%
43	Pool	1%	1%	2%

5.0 SUMMARY

The goal of this study is to evaluate whether a BESS could be economically integrated at the Harris Project in order to mitigate the impacts of peaking, while retaining full system peaking capabilities.

Based on FERC's recommendations and ARA's study objectives, Alabama Power evaluated two BESS release alternatives:

- 60 MW battery with 240 MWh capacity that can provide the equivalent generation of one unit at best gate for 4 hours per day/every day.
- 20 MW battery with 80 MWh capacity that can provide the equivalent generation of one-third of one unit at best gate for 4 hours per day/every day. The remaining 40 MW needed for 1-unit peaking generation would be produced by the new, upgraded unit.

Although FERC recommended that these analyses be conducted as part of the Downstream Release Alternatives Study, Alabama Power determined that a separate analysis is more appropriate. This evaluation differs from those included in the Downstream Release Alternatives Study in that it is a screening level effort, requires a more detailed economic analysis, and considers the replacement and addition of generation equipment such as the replacement cost of a turbine and installation/replacement cost of batteries. Additionally, in order to model Project operations with peaking removed, the HEC-ResSim and HEC-RAS models would need to be redesigned to incorporate new operating rules. Defining new operating rules and redesigning the models is outside the scope of the study proposed by ARA and recommended by FERC. Therefore, the impacts analysis is primarily qualitative only, whereas the Downstream Release Alternatives Study includes both quantitative and qualitative impacts analysis.

As discussed in this report, the cost of integrating a BESS at Harris is substantial, and, therefore, not economical in comparison to the potential limited environmental benefits. In addition to installation costs, costs associated with augmentation are required to maintain the nameplate capacity of a system. Furthermore, recognizing that a Li-ion battery storage asset life is typically no more than 20 years, it is assumed the asset would need be totally replaced in 2045. In terms of asset value, hydro generation provides more value when compared to BESS. Key considerations include the need to charge the BESS from the grid due to insufficient inflows as well the need for greater production of energy to overcome the efficiency losses through the BESS. Moreover, additional costs will be incurred for interconnection, as well as costs associated with replacing an existing unit.

Neither of the two alternatives retain full system peaking capabilities. Both alternatives evaluate hydropower operations (i.e. project peaking operations) defined as one unit operating for 4 hours during peak generation, which is consistent with the HEC-ResSim Daily Model in the DRA Phase 1 Report. As described in Section 2.0, actual historic data illustrates that Harris operates, as needed, one or both units for *more than 4 hours* to meet higher peak demands (when water is available) or when inflows are high (i.e., flood conditions). Therefore, for both Option A and Option B, there would be times throughout the year when higher, peaking flows would continue to be released, thereby reducing the potential environmental and recreational benefits of a BESS at the Harris Project.

Lastly, the extent to which the integration of a BESS at the Harris Project would mitigate the impact of peaking on recreation and aquatic resources was estimated by creating theoretical hydrographs using the same 2001 calendar year data employed in the Downstream Release Alternatives Study. Option A would potentially result in benefits to aquatic resources by increasing the amount and stability of wetted habitat to levels between the previously modeled 600 and 800 cfs minimum flow scenarios. Option B would result in benefits similar to the previously modeled 300 cfs minimum flow scenario. Under both options, benefits to aquatic resources would vary as the average daily minimum flow would vary higher and lower, depending on inflows.

BESS technology is very new, and methodology for integrating BESS at hydropower facilities is limited. In the handful of examples where a BESS has been integrated at a FERC-regulated hydropower project, it has been at the request of the licensee as it makes economic sense for those specific projects within those energy markets. For all of the reasons described above, integrating a BESS at the Harris Project is not a viable option for Alabama Power, and Alabama Power does not consider it a reasonable alternative.

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APPENDIX A

ACRONYMS AND ABBREVIATIONS

ACRONYMS AND ABBREVIATIONS

A

A&I	Agricultural and Industrial
ACFWRU	Alabama Cooperative Fish and Wildlife Research Unit
ACF	Apalachicola-Chattahoochee-Flint (River Basin)
ACT	Alabama-Coosa-Tallapoosa (River Basin)
ADCNR	Alabama Department of Conservation and Natural Resources
ADECA	Alabama Department of Economic and Community Affairs
ADEM	Alabama Department of Environmental Management
ADROP	Alabama-ACT Drought Response Operations Plan
AHC	Alabama Historical Commission
Alabama Power	Alabama Power Company
AMP	Adaptive Management Plan
ALNHP	Alabama Natural Heritage Program
APE	Area of Potential Effects
ARA	Alabama Rivers Alliance
ASSF	Alabama State Site File
ATV	All-Terrain Vehicle
AWIC	Alabama Water Improvement Commission
AWW	Alabama Water Watch

B

BA	Biological Assessment
B.A.S.S.	Bass Anglers Sportsmen Society
BCC	Birds of Conservation Concern
BLM	U.S. Bureau of Land Management
BOD	Biological Oxygen Demand

C

°C	Degrees Celsius or Centrigrade
CEII	Critical Energy Infrastructure Information
CFR	Code of Federal Regulation
cfs	Cubic Feet per Second
cfu	Colony Forming Unit
CLEAR	Community Livability for the East Alabama Region
CPUE	Catch-per-unit-effort
CWA	Clean Water Act

D

DEM	Digital Elevation Model
DIL	Drought Intensity Level
DO	Dissolved Oxygen
dsf	day-second-feet

E

EAP	Emergency Action Plan
ECOS	Environmental Conservation Online System
EFDC	Environmental Fluid Dynamics Code
EFH	Essential Fish Habitat
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act

F

°F	Degrees Fahrenheit
ft	Feet
F&W	Fish and Wildlife
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FNU	Formazin Nephelometric Unit
FOIA	Freedom of Information Act
FPA	Federal Power Act

G

GCN	Greatest Conservation Need
GIS	Geographic Information System
GNSS	Global Navigation Satellite System
GPS	Global Positioning Systems
GSA	Geological Survey of Alabama

H

Harris Project	R.L. Harris Hydroelectric Project
HAT	Harris Action Team
HEC	Hydrologic Engineering Center
HEC-DSSVue	HEC-Data Storage System and Viewer
HEC-FFA	HEC-Flood Frequency Analysis
HEC-RAS	HEC-River Analysis System
HEC-ResSim	HEC-Reservoir System Simulation Model
HEC-SSP	HEC-Statistical Software Package

HDSS	High Definition Stream Survey
hp	Horsepower
HPMP	Historic Properties Management Plan
HPUE	Harvest-per-unit-effort
HSB	Horseshoe Bend National Military Park

I

IBI	Index of Biological Integrity
IDP	Inadvertent Discovery Plan
IIC	Intercompany Interchange Contract
IVM	Integrated Vegetation Management
ILP	Integrated Licensing Process
IPaC	Information Planning and Conservation
ISR	Initial Study Report

J

JTU	Jackson Turbidity Units

K

kV	Kilovolt
kva	Kilovolt-amp
kHz	Kilohertz

L

LIDAR	Light Detection and Ranging
LWF	Limited Warm-water Fishery
LWPOA	Lake Wedowee Property Owners' Association

M

m	Meter
m^3	Cubic Meter
M&I	Municipal and Industrial
mg/L	Milligrams per liter
ml	Milliliter
mgd	Million Gallons per Day
µg/L	Microgram per liter
µs/cm	Microsiemens per centimeter
mi^2	Square Miles
MOU	Memorandum of Understanding

MPN	Most Probable Number
MRLC	Multi-Resolution Land Characteristics
msl	Mean Sea Level
MW	Megawatt
MWh	Megawatt Hour

N

n	Number of Samples
NEPA	National Environmental Policy Act
NGO	Non-governmental Organization
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NOAA	National Oceanographic and Atmospheric Administration
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NTU	Nephelometric Turbidity Unit
NWI	National Wetlands Inventory

O

OAR	Office of Archaeological Resources
OAW	Outstanding Alabama Water
ORV	Off-road Vehicle
OWR	Office of Water Resources

P

PA	Programmatic Agreement
PAD	Pre-Application Document
PDF	Portable Document Format
pH	Potential of Hydrogen
PID	Preliminary Information Document
PLP	Preliminary Licensing Proposal
Project	R.L. Harris Hydroelectric Project
PUB	Palustrine Unconsolidated Bottom
PURPA	Public Utility Regulatory Policies Act
PWC	Personal Watercraft
PWS	Public Water Supply

Q

QA/QC	Quality Assurance/Quality Control

R

RM	River Mile
RTE	Rare, Threatened and Endangered
RV	Recreational Vehicle

S

S	Swimming
SCORP	State Comprehensive Outdoor Recreation Plan
SCP	Shoreline Compliance Program
SD1	Scoping Document 1
SH	Shellfish Harvesting
SHPO	State Historic Preservation Office
Skyline WMA	James D. Martin-Skyline Wildlife Management Area
SMP	Shoreline Management Plan
SU	Standard Units

T

T&E	Threatened and Endangered
TCP	Traditional Cultural Properties
TMDL	Total Maximum Daily Load
TNC	The Nature Conservancy
TRB	Tallapoosa River Basin
TSI	Trophic State Index
TSS	Total Suspended Soils
TVA	Tennessee Valley Authority

U

USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service

W

WCM	Water Control Manual
WMA	Wildlife Management Area
WMP	Wildlife Management Plan
WQC	Water Quality Certification

APPENDIX B

2020 ATB DATA FROM NREL

Cost Projections for Utility-Scale Battery Storage: 2020 Update

Wesley Cole and A. Will Frazier

National Renewable Energy Laboratory

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Office of Energy Efficiency & Renewable Energy
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Executive Summary

In this work we describe the development of cost and performance projections for utility-scale lithium-ion battery systems, with a focus on 4-hour duration systems. The projections are developed from an analysis of 19 publications that consider utility-scale storage costs. The suite of publications demonstrates varied cost reductions for battery storage over time. Figure ES-1 shows the low, mid, and high cost projections developed in this work (on a normalized basis) relative to the published values. Figure ES-2 shows the overall capital cost for a 4-hour battery system based on those projections, with storage costs of $144/kWh, $208/kWh, and $293/kWh in 2030 and $88/kWh, $156/kWh, and $219/kWh in 2050. Battery variable operations and maintenance costs, lifetimes, and efficiencies are also discussed, with recommended values selected based on the publications surveyed.

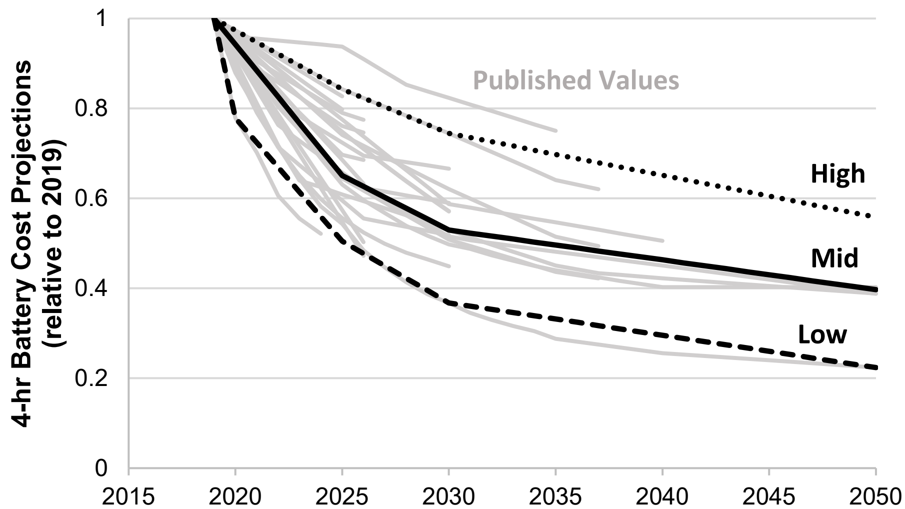

Figure ES-1. Battery cost projections for 4-hour lithium-ion systems, with values relative to 2019. The high, mid, and low cost projections developed in this work are shown as the bolded lines.

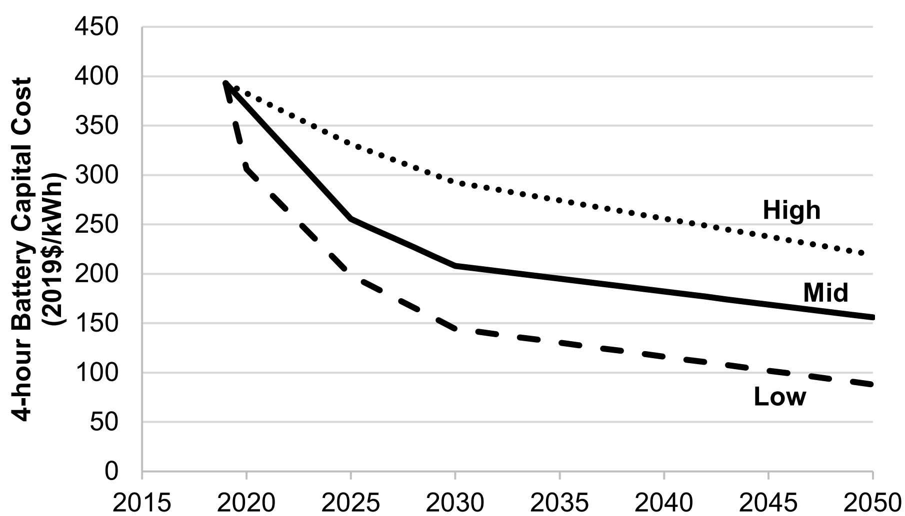

Figure ES-2. Battery cost projections for 4-hour lithium ion systems.

Table of Contents

List of Figures

List of Tables

1 Background

Battery storage costs have changed rapidly over the past decade. In 2016, the National Renewable Energy Laboratory (NREL) published a set of cost projections for utility-scale lithium-ion batteries (Cole et al. 2016). Those 2016 projections relied heavily on electric vehicle battery projections because utility-scale battery projections were largely unavailable for durations longer than 30 minutes. In 2019, battery cost projections were updated based on publications that focused on utility-scale battery systems (Cole and Frazier 2019). This report updates the cost projections published in 2019.

The projections in this work focus on utility-scale lithium-ion battery systems for use in capacity expansion models. NREL utilizes the Regional Energy Deployment System (ReEDS) (Cohen et al. 2019) and the Resource Planning Model (RPM) (Mai et al. 2013) for capacity expansion modeling, and the battery cost projections developed here are designed to be used in those models. Additionally, the projections are intended to inform the cost projections published in the Annual Technology Baseline (NREL 2019).

2 Methods

The cost and performance projections developed in this work use a literature-based approach in which projections are generally based on the low, median, and highest values from the literature. Table 1 lists 19 publications that are used in this work, though the projections rely primarily on those published in 2018 or 2019.

Table 1. List of publications used in this study to determine battery cost and performance projections.

Author or Organization	Citation
Avista	Avista (2017)
BNEF	BNEF (2019)
Brattle	Hledik et al. (2018)
CAISO	Energy and Environmental Economics, Inc. (2017)
DNV GL	DNV GL (2017)
EIA	EIA (2020)
EPRI	EPRI (2018)
IEA	IEA (2019)
IRENA	IRENA (2017)
Lazard	Lazard (2018) and Lazard (2019)
Navigant	Navigant (2017)
NIPSCO	NIPSCO (2018)
NYSERDA	NYSERDA (2018)
Platt River Power Authority	Aquino et al. (2017)
PNNL	Mongird et al. (2019)
PSE	PSE (2017)
Schmidt et al.	Schmidt et al. (2019)
Wood Mackenzie	Wood Mackenzie & Energy Storage Association (2019)

There are a number of challenges inherent in developing cost and performance projections based on published values. First among those is that the definition of the published values is not always clear. For example, dollar year, duration, depth-of-discharge, lifetime, and O&M are not always defined in the same way (or even defined at all) for a given set of values. As such, some of the values presented here required interpretation from the sources specified. Second, many of the published values compare their published projection against projections produced by others, and it is unclear how much the projections rely upon one-another. Thus, if one projection is used to inform another, that projection might artificially bias our results (toward that particular projection) more than others. Third, because of the relatively limited dataset for actual battery systems and the rapidly changing costs, it is not clear how different battery projections should be weighted. For example, should projections published in 2018 be given higher weight than those published in 2016? Or are some organizations better at making projections and therefore should be given higher weight?

In the interest of providing a neutral survey of the current literature, all cost projections included in this report are weighted equally. Only storage projections published in 2017 or later were considered. Many of the newest projections, however, are simply a compilation of older projections (just like this report). For example, Comello and Reichelstein (2019) relies on publications produced in 2017 or earlier, and Nian, Jindal, an Li (2019) use Cole et al. (2016) and IRENA (2017) for their cost projections. Thus, many of the latest papers with cost projections would create known redundancies (per the second challenge listed above) and were therefore excluded from this work. All cost values were converted to 2019$ using the consumer pricing index. In cases where the dollar year was not specified, the dollar year was assumed to be the same as the publication year.

We only used projections for 4-hour lithium-ion storage systems. We define the 4-hour duration as the output duration of the battery, such that a 4-hour device would be able to discharge at rated power capacity for 4-hours. In practice that would mean that the device would charge for more than 4 hours and would nominally hold more than its rated energy capacity in order to compensate for losses during charge and discharge.

We report our price projections as a total system overnight capital cost expressed in units of $/kWh. However, not all components of the battery system cost scale directly with the energy capacity (i.e., kWh) of the system (Feldman et al. Forthcoming). For example, the inverter costs scale according to the power capacity (i.e., kW) of the system, and some cost components such as the developer costs can scale with both power and energy. By expressing battery costs in $/kWh, we are deviating from other power generation technologies such as combustion turbines or solar photovoltaic plants where capital costs are usually expressed as $/kW. We use the units of $/kWh because that is the most common way that battery system costs have been expressed in published material to date. The $/kWh costs we report can be converted to $/kW costs simply by multiplying by the duration (e.g., a $300/kWh, 4-hour battery would have a power capacity cost of $1200/kW).

To develop cost projections, storage costs were normalized to their 2019 value such that each projection started with a value of 1 in 2019. We chose to use normalized costs rather than absolute costs because systems were not always clearly defined in the publications. For example, it is not clear if a system is more expensive because it is more efficient and has a longer lifetime, or if the authors simply anticipate higher system costs. With the normalized method, many of the difference matter to a lesser degree. Additionally, as will be shown in the results section, the 2019 benchmark cost that we have chosen for our current cost of storage is lower than nearly all the 2019 costs for projections published in 2017. By using normalized costs, we can more easily use these 2017 projections to inform cost reductions from our lower initial point.

If a publication began its projections after 2019, the 2019 value was estimated using linear extrapolation from the nearest value. For example, if the 2020 price was $500/kWh and the 2021 price was $480/kWh, then the 2019 price was assumed to be $520/kWh. Because projections tend to have more rapid declines in the early years, the linear approach will tend to underestimate the 2019 value, which in turn will overestimate the normalized values. If publications only provided values for specific years (e.g., 2018, 2020, and 2030), linear interpolation was used to fill in values for in-between years in order to create yearly projections.[1]

In order to define our low, mid, and high projections, we only considered cost projections published in 2018 and later. Projections published in 2017 are still shown in many figures in the results section, and we used the 2017-vintage data as a benchmark for the projections that we developed. We felt that the later vintage publications would provide a better assessment on anticipated storage cost reductions than those published in earlier years.

We defined our low, mid, and high projections as the minimum, median, and maximum point, respectively in 2020, 2025, and 2030. Defining the 2050 points was more challenging because only four datasets extended to 2050. Of the three datasets, they showed a 19%, 25%, 27%, and 39% cost reduction from 2030 to 2050. The 39% reduction was used from the low case, while 25% was used for the mid and high cases. In other words, the low case was assumed to decline by 39% from 2030 to 2050, while the mid and high cases were assumed to decline by 25% from 2030 to 2050.

Points in between 2018, 2020, 2025, 2030, and 2050 were set based on linear interpolation between years with values assigned. To convert these normalized low, mid, and high projections into cost values, the normalized values were multiplied by the 4-hour battery storage cost from Feldman et al. (Forthcoming) to produce 4-hour battery systems costs.

To estimate the costs for other storage durations (i.e., durations other than 4 hours), we assign separate energy costs and power costs such that

$$\text{Total Cost (\$/kWh)} = \text{Energy Cost (\$/kWh)} + \text{Power Cost (\$/kW)} / \text{Duration (hr)}$$

To break apart the total cost into energy and power components, we used the 4-hour and 2-hour cost estimates from Feldman et al. (Forthcoming). By using the total cost for two distinct durations, we could calculate the energy and power costs. We could also check these energy and power costs against the 1-hour and 0.5-hour cost estimates that were also included in Feldman et

[1] There was one exception to this linear interpolation. Because the projection from Schmidt et al. (2019) drove some of the low-cost projection in this work, we interpolated their values using a fourth-order polynomial in order to get a better estimates for their pre-2035 values.

al. (Forthcoming). We assume that the relative cost reductions developed for the total battery system cost apply equally to the energy and power components of the battery.

The method employed in this work relies solely on literature projections. It does not take into account other factors that might impact costs over time, such as materials availability, market size, and policy factors. Unless these and other factors are not captured in the work surveyed, then they will not be reflected in the projection produced here.

3 Results and Discussion

The normalized cost trajectories with the low, mid, and high projections are shown in Figure 1. The high projection follows the highest cost trajectory (of 2018 vintage or newer) through 2030. It then receives the 25% cost reduction from 2030 through 2050 as described in the methods section. The mid and low projections have initial slopes being steeper than later slopes, indicating that most publications see larger cost reductions in the near-term that then slow over time. By 2030, costs are reduced by 63%, 47%, and 26% in the low, mid, and high cases, respectively, and by 2050 are reduced by 78%, 60%, and 44%, respectively.

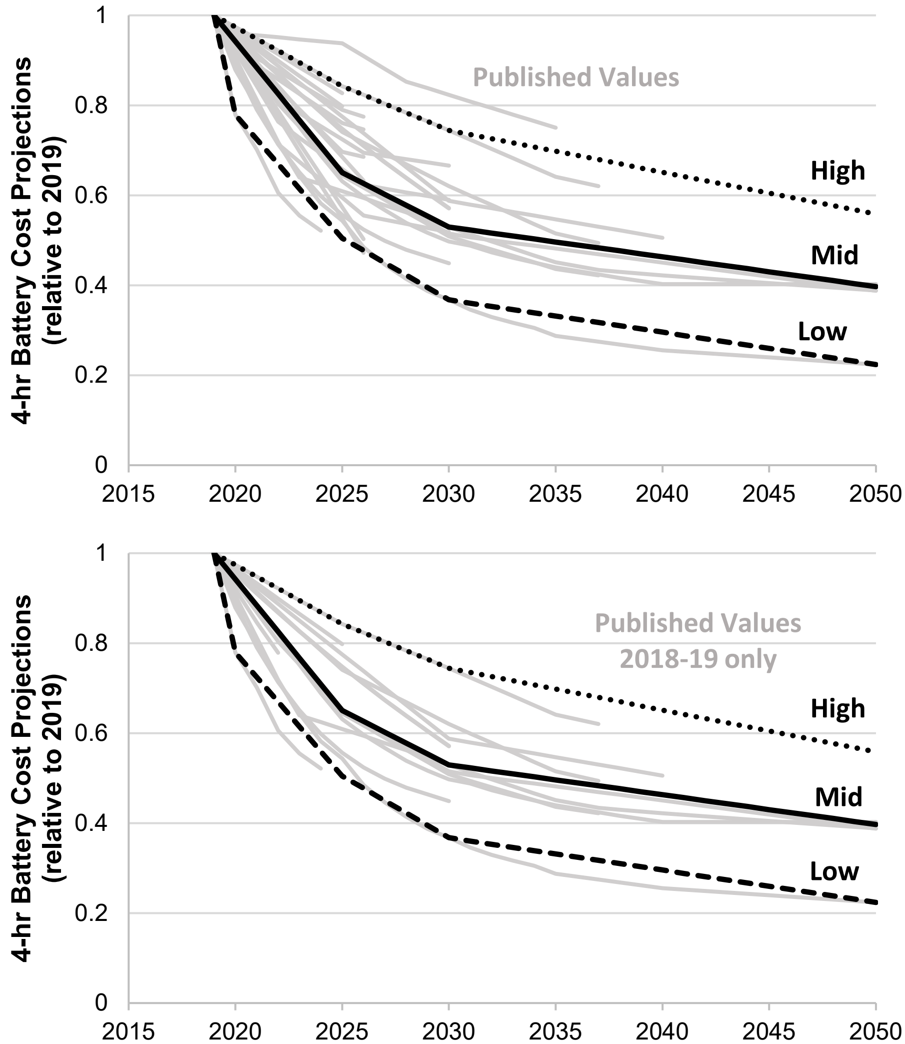

Figure 1. Battery cost projections for 4-hour lithium-ion systems, with values relative to 2019. The high, mid, and low cost projections developed in this work are shown as the bolded lines. The upper figure shows the full range of cost projections used in this work, while the lower figure shows only those cost projections published after 2017. Figure values are included in the Appendix.

The resulting total system cost for a 4-hour device is shown in Figure 2. The 2019 starting point of $380/kWh is taken from Feldman et al. (Forthcoming). Although there is uncertainty in the 2019 cost (which is discussed later), we use a single cost for 2019 for convenience as we apply these costs in our long-term planning models (applying the same costs in 2019 means that the 2019 solution will not change as we shift from a "high" to a "mid" to a "low" cost projection for storage). By definition, the projections follow the same trajectories as the normalized cost values. Storage costs are $124/kWh, $207/kWh, and $338/kWh in 2030 and $76/kWh, $156/kWh, and $258/kWh in 2050. Costs for each year and each trajectory are included in the Appendix.

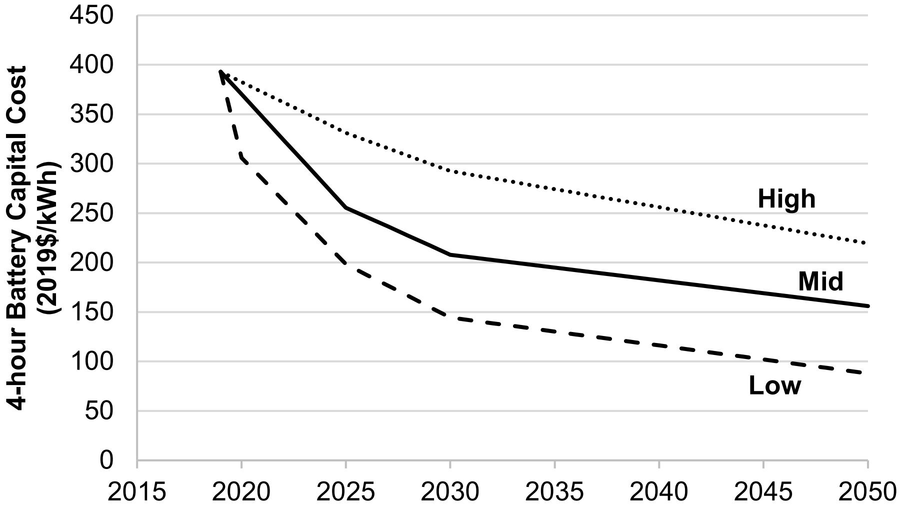

Figure 2. Battery cost projections for 4-hour lithium ion systems.

These values represent overnight capital costs for the complete battery system. Figure values are included in the Appendix.

Figure 3 shows how the absolute cost projections from Figure 2 compare to the published cost projection values. Because we chose to develop our projections based on the normalized cost values, they do not necessarily line up with the published cost projections. Many of the published cost projections never even reach the starting point that we have selected, while a few others are at some point lower than our low projection. Some of that discrepancy is due to the vintage of the projection. Cost projections published in 2017 tend to be higher than those published in 2018 or later. The lower plot in Figure 3 shows that the cost projections tend to be better aligned on an absolute basis when only the more recent cost projections are considered.

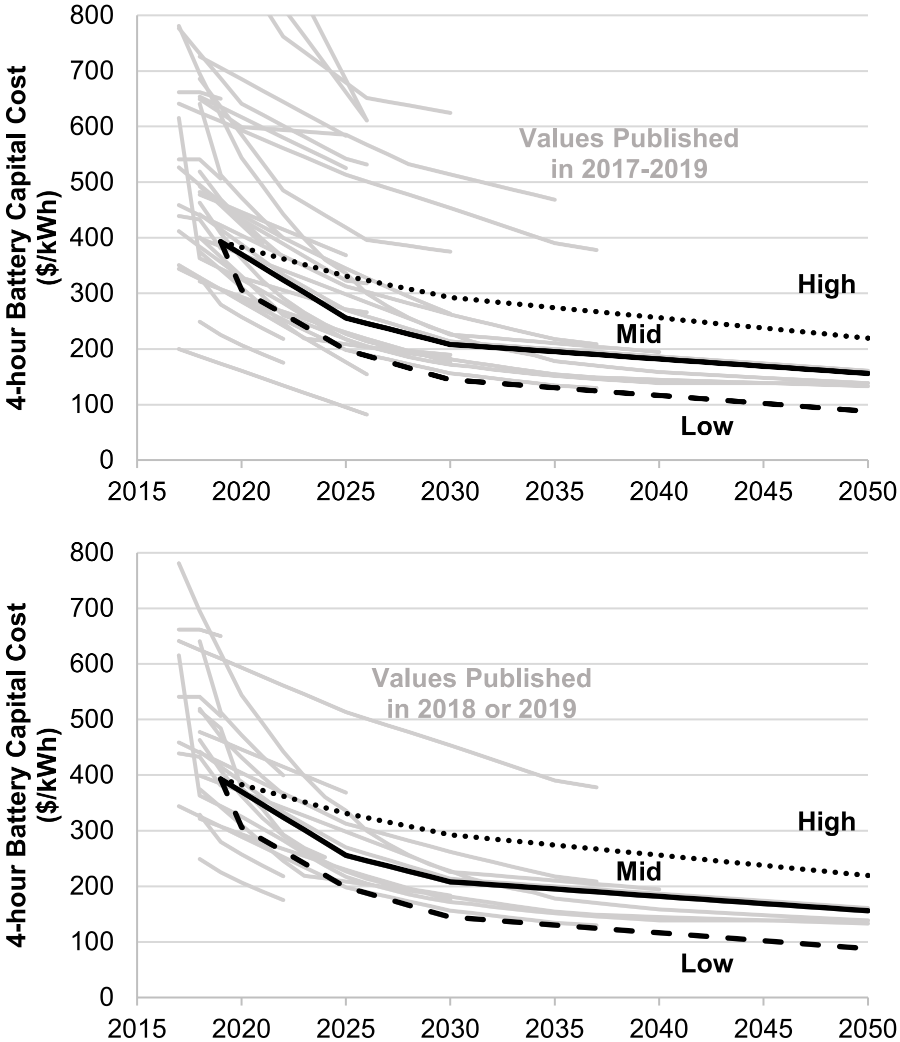

Figure 3. Battery cost projections developed in this work (bolded lines) relative to published cost projections. The upper figure shows the full range of cost projections used in this work, while the lower figure shows only those cost projections published after 2017. Cost values above $800/kWh are not shown.

One of the key assumptions in our projections is the choice of the starting point. A higher or lower starting point would shift the set of projections up or down relative to the change in magnitude of the starting point. To better assess the quality of our starting point, we compared the value from Feldman et al. (Forthcoming) with other values published in 2018 or later (shown in Figure 4). We did not consider older reported values because of the rapid changes in battery costs. This comparison increases our confidence that the starting value we have selected is reasonable, although it does demonstrate that there is considerable uncertainty (±$100/kWh) in the current price of battery storage systems.

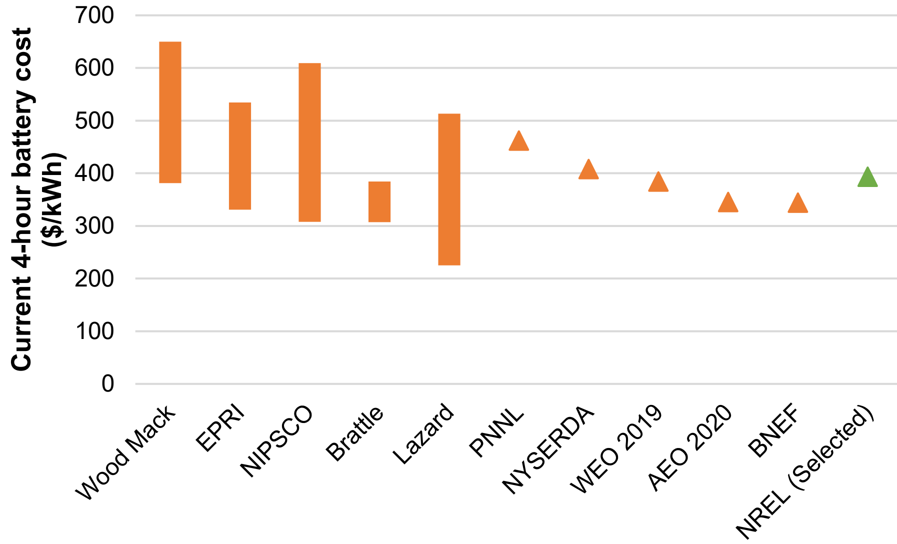

Figure 4. Current battery storage costs from studies published in 2018 or later. The NREL value (Feldman et al. Forthcoming) was selected as the 2019 starting cost for this work.

One of the other challenges with using the normalized cost reductions to develop our projections is that projections that start at a higher value than our starting point might see greater cost reduction potential, and thus have a high percent reduction but still never have a low $/kWh cost. Conversely, projections that start lower than our starting point might have smaller cost reduction potential on a percentage basis but achieve very low $/kWh costs. However, we still prefer to use the normalized cost reduction numbers because of the large discrepancy in starting costs across published projections, and because it helps to obviate the challenge of different cost and system definitions in the different publications.

Figure 5 shows the cost projections for the power and energy components of the battery. The breakdown of power and energy is derived from Feldman et al. (Forthcoming) as described in the methods section. These components are combined to give a total system cost, where the system cost (in $/kWh) is the power component divided by the duration plus the energy component.

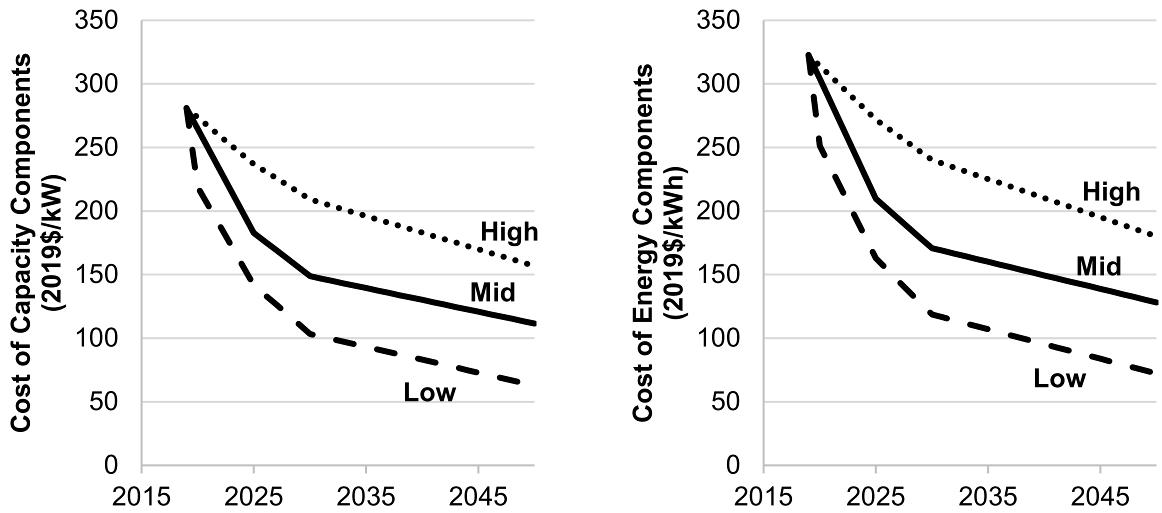

Figure 5. Cost projections for power (left) and energy (right) components of lithium-ion systems.
Note the different units in the two plots.

These power and energy costs can be used to specify the capital costs for other durations. Figure 6 shows the cost projections for 2-, 4-, and 6-hour duration batteries (using the mid projection only). On a $/kWh basis, longer duration batteries have a lower capital cost, and on a $/kW basis, shorter duration batteries have a lower capital cost. Figure 6 (left) also demonstrates why it is critical to cite the duration whenever providing a capital cost in $/kWh or $/kW.

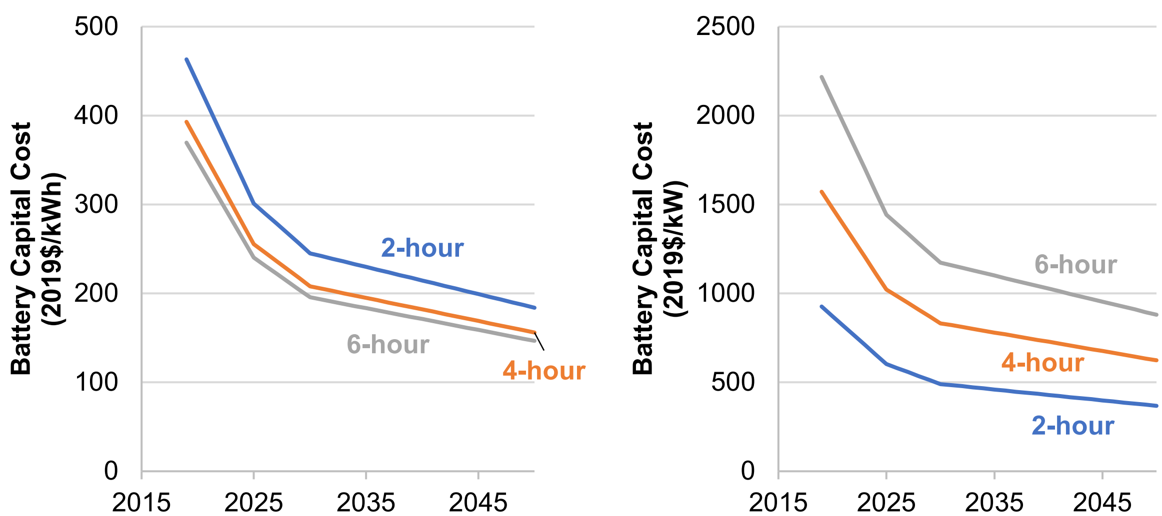

Figure 6. Cost projections for 2-, 4-, and 6-hour duration batteries using the mid cost projection.
Left shows the values in $/kWh, while right shows the costs in $/kW.

To fully specify the cost and performance of a battery storage system for capacity expansion modeling tools, additional parameters besides the capital costs are needed. Figure 6 shows the range of variable operations and maintenance (VOM), fixed operations and maintenance (FOM), lifetime, and round-trip efficiency[2] assumptions from the publications surveyed. The rightmost point in the figure shows the value that we have selected to represent our 4-hour battery system. The VOM is generally taken to be zero or near zero, and we have adopted zero for the VOM. This VOM is defined to coincide with an assumed one cycle per day and a given calendar lifetime. Cycling more than once per day might reduce that lifetime, so cycles beyond once per day should see a non-zero VOM.

We have allocated the all operating costs (at the one-cycle-per-day level) to the FOM. By putting the operations and maintenance costs in the FOM rather than the VOM we in essence assume that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator. The FOM has a much broader range of values. One of the primary differences in the level of FOM was whether augmentation or performance maintenance were included in the cost. For example, DNV GL (2017) reports a $6/kW-yr FOM and a $7.5/kWh-yr capacity maintenance cost to address degradation (values in 2017$). Lower FOM numbers typically include only simple maintenance while higher FOM numbers include some capacity additions or replacements to deal with degradation. We have adopted a FOM value from the high end and assume that the FOM cost will counteract degradation such that the system will be able to perform at rated capacity throughout its lifetime. The FOM value selected is 2.5% of the $/kW capacity cost for a 4-hour battery. We assume that this FOM is consistent with providing approximately one cycle per day. If the battery is operating at a much higher rate of cycling, then this FOM value might not be sufficient to counteract degradation.

[2] Round-trip efficiency is defined as the system efficiency through a charge/discharge cycle. For example, it would include losses associated with cooling systems or battery control equipment.

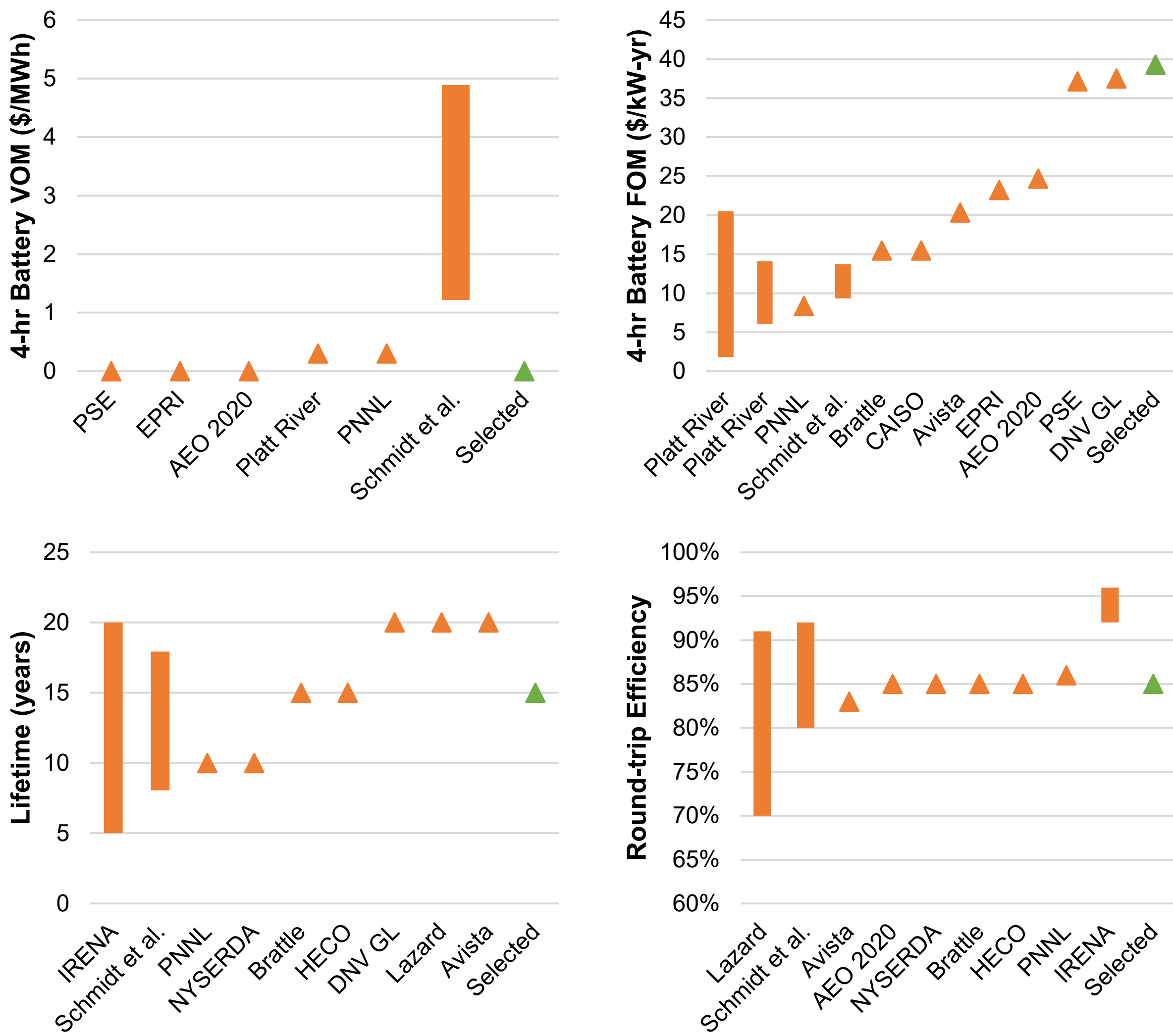

Figure 7. Variable O&M (top right), fixed O&M (top left), lifetime (bottom right), and round-trip efficiency (bottom left) from various published sources. The values selected for this study are the right-most values shown.

The lifetime we selected is 15 years, which is near the median of the published values. The round-trip efficiency is chosen to be 85%, which is well aligned with published values.

4 Summary

Battery storage costs have evolved rapidly over the past several years, necessitating an update to storage cost projections used in long-term planning models and other activities. This work documents the development of these projections, which are based on recent publications of storage costs. The projections show a wide range of storage costs, both in terms of current costs as well as future costs. Although the range in projections is considerable, all projections do show a decline in capital costs, with cost reductions by 2025 of 6-48%.

The cost projections developed in this work utilize the normalized cost reductions across the literature, and result in 26-63% capital cost reductions by 2030 and 44-78% cost reductions by

2050. The cost projections are also accompanied by assumed operations and maintenance costs, lifetimes, and round-trip efficiencies, and these performance metrics are benchmarked against other published values.

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Appendix

Table 2 includes the values that are plotted in Figure 1 and Figure 2. Figure 9 and Figure 10 show the comparison of the projections developed in this work relative to the projections that were produced in last year's report (Cole and Frazier 2019). Although 4-hour costs did not change much from last year's report, the relative distribution between the power and energy costs did change. Thus, 2-hour or 6-hour battery costs calculated using data from this year's report will show greater differences than the 4-hour batteries.

Table 2. Values from Figure 1 and Figure 2, which show the normalized and absolute storage costs over time. Storage costs are overnight capital costs for a complete 4-hour battery system.

	Normalized Cost Reduction			4-hour Storage Costs (2019$/kWh)		
Year	Low	Mid	High	Low	Mid	High
2019	1.00	1.00	1.00	393	393	393
2020	0.78	0.94	0.97	306	370	383
2021	0.73	0.89	0.95	286	351	372
2022	0.68	0.84	0.92	266	331	362
2023	0.62	0.79	0.90	245	312	352
2024	0.57	0.74	0.87	225	293	341
2025	0.52	0.70	0.84	205	273	331
2026	0.49	0.66	0.82	193	260	323
2027	0.46	0.63	0.80	181	247	316
2028	0.43	0.60	0.78	169	234	308
2029	0.40	0.56	0.76	156	221	300
2030	0.37	0.53	0.74	144	208	293
2031	0.36	0.52	0.74	142	205	289
2032	0.35	0.52	0.73	139	203	285
2033	0.35	0.51	0.72	136	200	282
2034	0.34	0.50	0.71	133	198	278
2035	0.33	0.50	0.70	130	195	274
2036	0.32	0.49	0.69	127	192	271
2037	0.32	0.48	0.68	125	190	267
2038	0.31	0.48	0.67	122	187	263
2039	0.30	0.47	0.66	119	185	260
2040	0.30	0.46	0.65	116	182	256
2041	0.29	0.46	0.64	113	179	252
2042	0.28	0.45	0.63	111	177	249
2043	0.27	0.44	0.62	108	174	245
2044	0.27	0.44	0.61	105	172	241
2045	0.26	0.43	0.60	102	169	238
2046	0.25	0.42	0.60	99	166	234
2047	0.25	0.42	0.59	96	164	230

	Normalized Cost Reduction			4-hour Storage Costs (2019$/kWh)		
2048	0.24	0.41	0.58	94	161	227
2049	0.23	0.40	0.57	91	159	223
2050	0.22	0.40	0.56	88	156	219

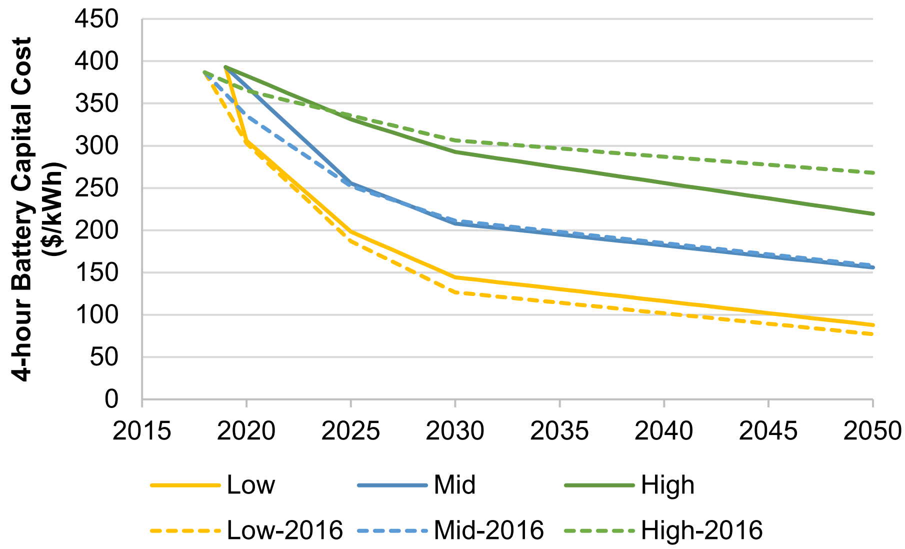

Figure 8. Comparison of cost projections developed in this report (solid lines) against the values from the 2019 cost projection report (Cole and Frazier 2019) (dashed lines).

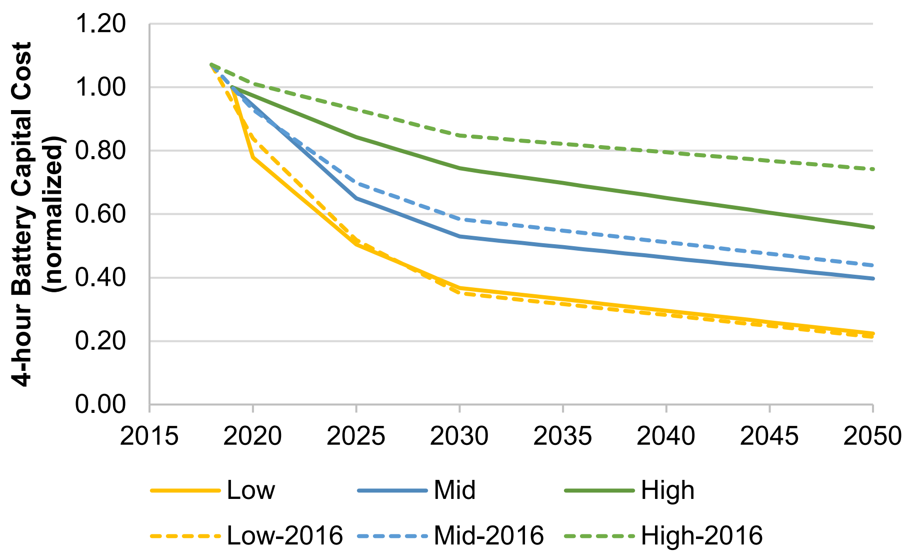

Figure 9. Comparison of cost projections developed in this report (solid lines) the values from the 2019 cost projection report (Cole and Frazier 2019) (dashed lines), with all values normalized to the "Mid" cost projection in the year 2019.

APPENDIX C

STAKEHOLDER COMMENT TABLE

Commenting Entity	**Date of Comment & FERC Accession Number**	**Comment – Battery Energy Storage System (BESS)**	**Alabama Power Response**
Alabama Department of Conservation and Natural Resources (ADCNR)	**5/27/2021** 20210527-5024	On page 17, Table 3-1 of the BESS Report, in addition to Option A and Option B, we recommend including a column which includes Cost Estimates Over 40-Year License Term at the Harris Project under current Green Plan operating procedures. It would be beneficial to include and discuss when the last turbine replacements were completed, the current life expectancy of the operating turbines, what routine turbine replacement would cost and what fixed O&M will be. Without this information it is difficult for stakeholders to identify and compare the full extent of cost estimates for BESS versus current operating conditions.	As required by 18 CFR § 5.18, Alabama Power will include within its Final License Application costs estimates under the No Action alternative (i.e. baseline, Green Plan). As previously stated, Alabama Power's Licensing Proposal does not include replacement of either unit at Harris.
Alabama Rivers Alliance (ARA)	**06/11/2021** 20210611-5070[1]	**A. Cost Analysis** … only explored one ownership option for procuring BESS, that being an outright purchase or company investment in the BESS. An evaluation of an independent power purchase agreement (PPA) for BESS services was not included as an alternative to financing the BESS internally, …Alabama Power's cost analysis does not factor in any potential incentives, including tax credits, that could be used to reduce the overall costs of a BESS…incorporating a survey of market PPA prices for BESS into the analysis will more accurately reflect these available incentives…Discussion of how incentives could reduce overall costs should be included in the final BESS Report. …the Draft BESS Report did not explore or mention the possibility of siting a BESS elsewhere on the transmission and distribution system…should consider the system benefits (and reduced interconnection costs) of siting the BESS elsewhere on the grid. … did not fully determine the costs of modifying or replacing one of the turbine-generators to enable installation of a BESS and accommodate a wider range of flows.	As stated in Alabama Power's Response to ARA's dispute on the BESS Study (Accession No. 20210712-5085), these topics go far beyond the limited scope of the study recommended by FERC and can more accurately be viewed as a request for additional studies. ARA failed to meet the requirements in 18 CFR § 5.15(e) for requesting new studies at this late stage of the Harris relicensing proceeding and failed to show good cause for why these additional studies are justified by one of the criteria in §5.15(e). As stated in the Final Report, the cost analysis was conducted at a screening level, and, therefore, potential incentives to offset battery costs were not included. Siting of a BESS elsewhere on the transmission and distribution system (i.e., on the grid) is outside of the scope of a hydroelectric relicensing process. As stated in the BESS Report, a detailed engineering design would be required to determine if a Kaplan turbine is even possible in a powerhouse designed for a Francis unit. If it could be done, the range of flows would then be determined in addition to the costs of replacing a Francis unit with a Kaplan unit. This level of design detail is beyond the scope of this study.

[1] In addition to comments filed with FERC as part of the Study Dispute concerning the Draft Battery Energy Storage System Report, ARA provided similar comments to Alabama Power via email dated 05/27/2021. The 05/27/2021 comments are included within the stakeholder consultation record for reference.

Commenting Entity	Date of Comment & FERC Accession Number	Comment – Battery Energy Storage System (BESS)	Alabama Power Response
Alabama Rivers Alliance (ARA)	**06/11/2021** 20210611-5070	**B. Benefits Analysis** The Draft BESS Report currently lacks sufficient benefits analysis, both regarding environmental benefits and system benefits that could make the installation more economic. *a. Grid and Economic Benefits* …did not analyze any potential benefits that adding a BESS could provide to its distribution system, its peak capacity, or any ancillary services such as voltage regulation and black start capabilities that would result…Acknowledgement and analysis of these overall system benefits that could make the installation of a BESS more economic should be included in the final report. *b. Environmental Benefits* Only a single paragraph of the Draft BESS Report is dedicated to assessing the beneficial effects on aquatic resources, and improved environmental outcomes generally are dismissed as "potential limited environmental benefits" without analysis. …new research by the Pacific Northwest National Laboratory (PNNL) explores just how many environmental benefits can accrue from optimizing BESS with hydropower operations, including releasing flows that are more similar to the historical hydrograph, improving water temperature regimes and dissolved oxygen levels, accommodating spawning windows, and fostering safer fish passage through hydropower structures…We encourage Licensee to incorporate the new research and instructive framework presented in the PNNL white paper.	If Alabama Power were to pursue the addition of a new generating asset such as a BESS to its energy portfolio, located at any of its hydropower projects or elsewhere, that decision would be made independent of the FERC relicensing process. It is important to note that as a storage project that was designed and licensed as such, the Harris Project is in effect, a large battery, providing not only energy during peak use times, but also ancillary services such as black start capability, system reliability, and voltage regulation. To meet the intent of providing an analysis of effects on aquatic and recreational resources, Alabama Power conducted the qualitative assessment using existing literature to provide information to FERC on the potential effects of the two BESS alternatives on downstream aquatic and recreational resources. This is consistent with a desktop level study, where using qualitative information in the absence of quantitative information is standard and accepted practice. It is an oversimplification to assume that the results of other relicensing studies, particularly the Downstream Release Alternatives study where potential effects on aquatic habitat and recreation were quantitatively analyzed, can be used to quantitively analyze the effects of integrating a BESS, because all of those operational alternatives included releases from the existing turbines as they are designed to operate, i.e., at a peaking, best gate flow. For these reasons, only a qualitative assessment was performed as part of this study. Alabama Power notes that the PNNL white paper was of little value in determining quantitative environmental analysis for the Harris Project resources other than to suggest the types of studies that would be needed to provide quantitative information; again, conducting these types of studies is outside the scope of the BESS analysis.

Commenting Entity	Date of Comment & FERC Accession Number	Comment – Battery Energy Storage System (BESS)	Alabama Power Response
Alabama Rivers Alliance (ARA)	**06/11/2021** 20210611-5070	**C. Lack of Modeling Data Available** Currently, the HEC-RAS and HEC-ResSim models and outputs are not available to stakeholders…ARA will continue its investigation of opportunities for increased operational flexibility and associated environmental benefits once those models and outputs are available.	As noted in Alabama Power's June 29, 2021 letter discussing the transmittal of modeling files (Accession No. 20210629-5073): Due to the file sizes associated with the HEC-RAS, HEC-ResSim, and EFDC models, Alabama Power is unable to file these models on FERC's elibrary. Stakeholders may request a copy of the three models by e-mailing harrisrelicensing@southernco.com and the models will be provided on a flash drive via U.S Postal Service.
Alabama Rivers Alliance (ARA)	**06/11/2021** 20210611-5070	**D. Potential Use of BESS with a Continuous Minimum Flow Turbine** …ARA suggests that Alabama Power consider matching a smaller-sized BESS with any minimum flow turbine to store energy to use on peak while passing a continuous minimum flow.	The evaluation of matching a smaller-sized BESS with any minimum flow turbine is beyond the limited scope of the FERC recommended study.
Synapse Energy Economics, Inc. via comments of Alabama Rivers Alliance (ARA)	**06/11/2021** 20210611-5070	**Recommendations** Based on our observations regarding the draft report, Synapse makes the following recommendations: • Alabama Power should provide cost and benefit information beyond the cost of the batteries. This would include economic and operational benefits in addition to more detailed environmental benefits. • Alabama Power should provide details on the operational assumptions used for hydro generation and BESS operations. • Alabama Power should provide information that evaluates possible BESS operations based on of hourly data for generation, water flow, energy prices, and modeled battery charging and discharging. • Alabama Power should analyze sizing the BESS to match the full capacity of an existing turbine. • Alabama Power should consider a power purchase agreement (PPA) for the battery system rather than a company investment. This would also include information on solar and BESS PPAs considered in Docket 32953 or other comparable PPAs. • Alabama Power should consider the benefits of locating the BESS elsewhere on the grid. • Alabama Power should consider the benefits of combining a BESS system with solar and obtaining investment tax credits. • Alabama Power should consider a minimum flow turbine and a smaller matching battery system. • Alabama Power should evaluate the impacts of reduced peaking operation without a BESS to the extent that has not been analyzed in the Green Plan. • Alabama Power should evaluate the benefits, including environmental ones, as well as the costs in all the analyses.	Comment noted

<u>Commenting Entity</u>	**<u>Date of Comment & FERC Accession Number</u>**	**<u>Comment – Battery Energy Storage System (BESS)</u>**	**<u>Alabama Power Response</u>**
<u>Federal Energy Regulatory Commission</u>	**<u>08/10/2021</u>** 20210810-3043	…consistent with the Downstream Release Alternative Study, the Draft BESS Report must be revised to include a detailed, quantitative assessment of the effects of integrating a BESS at the Harris Project on aquatic and recreational resources in Lake Harris and the Tallapoosa river downstream from Harris Dam.	Alabama Power has updated the report to include additional resources effects analyses.
<u>Federal Energy Regulatory Commission</u>	**<u>08/10/2021</u>** 20210810-3043	Information from other Harris relicensing studies, as well as the Pacific Northwest National Laboratory's white paper, "Deployment of Energy Storage to Improve Environmental Outcomes of Hydropower," should be used, as appropriate, to inform the environmental benefits analysis in the Final BESS Report.	Alabama Power notes that the PNNL white paper was of little value in determining quantitative environmental analysis for the Harris Project resources other than to suggest the types of studies that would be needed to provide quantitative information; again, conducting these types of studies is outside the scope of the BESS analysis.