Battery Storage Feasibility Study for Hydroelectric Plants at Wilder, Bellows Falls, and Vernon

ENGS 174: Energy Conversion Term Project Report

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1. Driving questions

This study aims to evaluate the feasibility of integrating a battery storage system (BSS) with the hydropower plants at Wilder, Bellows Falls, and Vernon as an alternative to the current stored hydropower system. The driving questions guiding this study are:

- Should the hydropower plants integrate a battery storage system?
- What type, size and configuration of battery storage must they employ?
- How much would the battery system cost?
- What are the technical and economic barriers?
- What are the policy and tax benefits associated with this transition?

2. Background

2.1. Basics of hydropower

Hydropower plants are located in areas that have large rivers with a natural drop in elevation. In the case of peaking plants, river water is stored in a reservoir behind the dam and is allowed to flow out of the reservoir into the penstock when required to meet peak energy demand. This is in contrast to hydroelectric plants that operate as run-of-river where electricity is generated during the natural flow regimes.

When the dams reach capacity, the gates open and water flows down a penstock. The potential energy in the stored water is therefore converted to kinetic energy. At the bottom of the penstock is a turbine where the high velocity water rotates the rotor of the turbine generating mechanical energy. The turbine turns a shaft in an electric generator converting mechanical energy to electromagnetic energy. Electricity produced is then fed into the grid system for transmission to industrial, homes, offices etc.

Peaking Hydropower Plants

Energy demand varies greatly throughout the day and seasons. The conventional power sources such as fossil fuel plants and nuclear plants are not efficient for meeting short spikes in electricity demands during peak hours. This is because they require long startup times. Peaking hydropower plants, on the other hand, have the ability to generate electricity almost instantly to meet peak energy demands. They collect water behind the damn throughout the day and when energy demand is high, water is allowed to flow through the penstock to the turbine-generator, thereby generating electricity to meet peak demands. For this reason, hydropower plants are mostly operated as peaking plants.

One of the main challenges with peaking hydropower plants is that the daily pool elevation changes of the river put an enormous strain on the river, land, and ecosystem [1]. Riverine species are not adapted to the constant disturbances of the river or to the sudden flow and high velocity flow that is associated with hydro. The constant elevation and drop of the river may result in reduced abundance, diversity and productivity of riverine species over a long period of time. Studies have shown a reduction of biomass of between 40 - 60% in disturbed areas compared to undisturbed areas [1]. In addition, elevation and dropping of the river level may lead to a change in the morphology of the river which can result in further damage to the ecosystem.

2.2. Battery storage for hydropower plants

Peak electricity demands can only be met by energy sources that can inject into the grid instantly. This can only be achieved by the use of storage systems such as peaking hydro power or battery storage. Although peaking hydropower is the most popular form of energy storage, accounting for 95% of utility-scale energy storage, its impacts to the ecosystem cannot be ignored. Alternative forms of storage, such as battery storage have the potential to mitigate the long term effects of daily pool level elevations that are required with peaking hydropower plants. [2]

This can be made possible by coupling a run-of-river hydropower plants with a battery storage system. The combined system can provide both base load and peak load services. The run-of-river system would generate electricity that would feed directly into the grid providing base load services without causing damage to the ecosystem. When the energy demand is low, the electricity generated from the run-of-river plant would be used to charge the battery system instead of feeding directly into the grid system. When electricity demand peaks, the battery system would respond instantly and discharge into the grid thereby meeting peak energy demands.

2.3. Examples of deployment of BSS for hydroelectric power plants

Cordova, a small town located 150 miles southeast of Anchorage, Alaska, is pioneering the integration of a lithium-ion energy storage system (ESS) into a hydropower microgrid. The microgrid run by Cordova Energy Cooperative Inc. (CEC) covers the base load demand with a 6 MW run-of-river, and a 1.25 MW run-of-river hydro generators. CEC’s hydropower costs around $0.06/kWh, while diesel generation can cost as high as $0.60/kWh. CEC meets about 78% of its annual demand with hydropower alone. A grid-scale ESS enables CEC to reduce its reliance on imported diesel and makes its energy system more holistic and resilient. [3]

This case might be different from that of the Connecticut River Conservancy (CRC), because CEC tries to incorporate battery storage as an energy storage system for the run-of-river hydropower plants. The CRC on the other hand is comparing the feasibility of peaking hydro storage with battery storage.

3. Connecticut River Conservancy

The Connecticut River Conservancy (CRC) is an agency that advocates for the Connecticut River watershed while collaborating with partners across Connecticut, Massachusetts, New Hampshire, and Vermont. One of CRC’s main roles is to advocate in the Federal Energy Regulatory Commission (FERC) process that regulates hydropower facilities in the Connecticut River basin.

The five major hydro plants on the Connecticut River account for more than 30% of hydropower generation in New England. The way that most hydro plants work is through 30-50 year licenses that determine minimum flow requirements, impoundment levels, fish passages and operating regimes. Therefore, advocating for the rivers during the re-licensing period is really important to find the best balance between power, environmental, and recreational needs. [4]

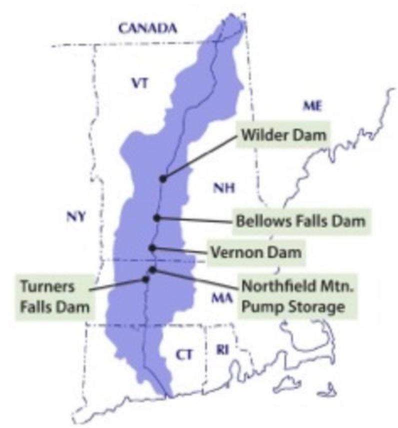

Figure 1: The five major hydro plants in the Connecticut River basin

CRC is concerned with the effects of the peaking hydro plants on the river, land, and ecosystem and this study will examine the feasibility of using battery storage systems in the three main hydro plants in Vermont: Wilder, Bellows Falls, and Vernon. The hydro plants are owned by Great River Hydro, formerly known as TransCanada, and have a total installed capacity of 108.8 kW. Information about their power generation is included in Table 1. [5]

Table 1: Information for hydro plants in study

	Wilder	Bellows Falls	Vernon
Installed capacity	35,600 kW	40,800 kW	32,400 kW
Power generating units	2x 16,200 kW 1x 3,200 kW	3x 13,600 kW	4x 2,000 kW 4x 4,000 kW 2x 4,200 kW

4. ISO energy markets

Wholesale Energy Markets are energy markets where electricity is bought and resold before reaching the end customer. This is carried out by utilities, Independent Power Producers (IPP) and electricity marketers. Wholesale electricity markets are based on competition, supply and demand. In the power grid, supply must meet demand exactly and this balance is regulated by Independent System Operators (ISO) and Regional Transmission Organizations (RTO) through organized markets. The ISO also regulates competition by electricity generators. The ISO manages the energy markets, forward capacity markets, and ancillary markets. [6]

The hydroelectric plants bid into the day ahead market, forward capacity market, reserve markets and. The revenue from the day-ahead and forward capacity markets are their primary sources of revenue. The day ahead market consists of on-peak and off-peak prices. The ISO dispatches the power source that has the lowest cost first and increases supply by dispatching resources of higher prices until demand is met . All power producers that are called upon are paid a uniform price referred to as the clearing price. This price is set by the last power producer that met electricity demand. Forward capacity markets (FCM) exist to ensure that the grid can meet future demand. Power producers bid into the FCM three years in advance to the commitment period and are paid based on the capacity they bid basis regardless of whether they are called upon or not. These markets are integral to understanding the financial impact of converting a peaking hydroelectric plant to a run-of-river plant.

5. Battery system options

5.1 Battery basics

A battery contains one or more electrochemical cells, connected in series or parallel to achieve a desired voltage and power. The anode is the electronegative electrode from which electrons are generated to do external work. The cathode is the electropositive electrode to which positive ions migrate inside the cell and electrons migrate through the external electrical circuit. The electrolyte allows the flow of ions, for example, lithium ions in Li-ion batteries allow flow from one electrode to another. The electrolyte is commonly a liquid solution containing a salt dissolved in a solvent. The electrolyte must be stable in the presence of both electrodes.

Electricity in an AC system cannot be stored as such, and needs to be converted to electrochemical, electromagnetic, potential or kinetic energy. Any energy storage technology is characterized by the amount of energy that can be stored in the device, and the rate at which energy can be transferred into or out of the system.

5.2 Battery selection

Key factors to consider when selecting the battery type for a given scenario include but are not limited to: power rating, energy rating, lifetime, power density, energy density, response time, round trip efficiency, capital and operating costs, and technological maturity. The following table compares various energy storage systems and lists their applications and advantages/disadvantages:

Table 2: Comparison of energy storage technologies [7], [8]

Energy Storage Technologies	Power rating (MW)	Capacity (MWh)	Lifetime (years)	Cycle Efficiency (%)	Advantages	Disadvantages	Power Applications	Energy Applications
Lead-acid batteries	-	-	5-15	75-90	Low power density, low capital cost	Limited lifetime when deeply discharged	Fully suitable and capable	Feasible but not economical or practical
Lithium-ion batteries	0.001-0.1	-	5-15	80-95	High power & energy densities, high efficiency	High production cost, requires a special charging circuit	Fully suitable and capable	**Feasible but expensive**
Sodium-sulfur batteries	0.05	0.4	10-15	80-85	High power energy	**Safety concerns**	Fully suitable and capable	Fully suitable and capable

					density, efficiency			
Flow batteries	0.05-15	120	10-20	75-85	**Independent power & energy ratings**	Low capacity	Suitable	Fully suitable and capable
Pumped hydro	<3000	Depends on size	**40-60**	65-85	High capacity	Special site requirement	Not feasible or economical	Fully suitable and capable

We note from the table that: pumped hydro storage has the longest lifetime compared to any of the electrochemical battery options. Li-ion batteries currently achieve the highest efficiencies, while flow batteries offer the flexibility to vary the power and energy ratings independently. Although Sodium Sulfur batteries currently make up the highest percentage of electrochemical batteries deployed at utility scale, it brings with it safety concerns that still need work. [8]

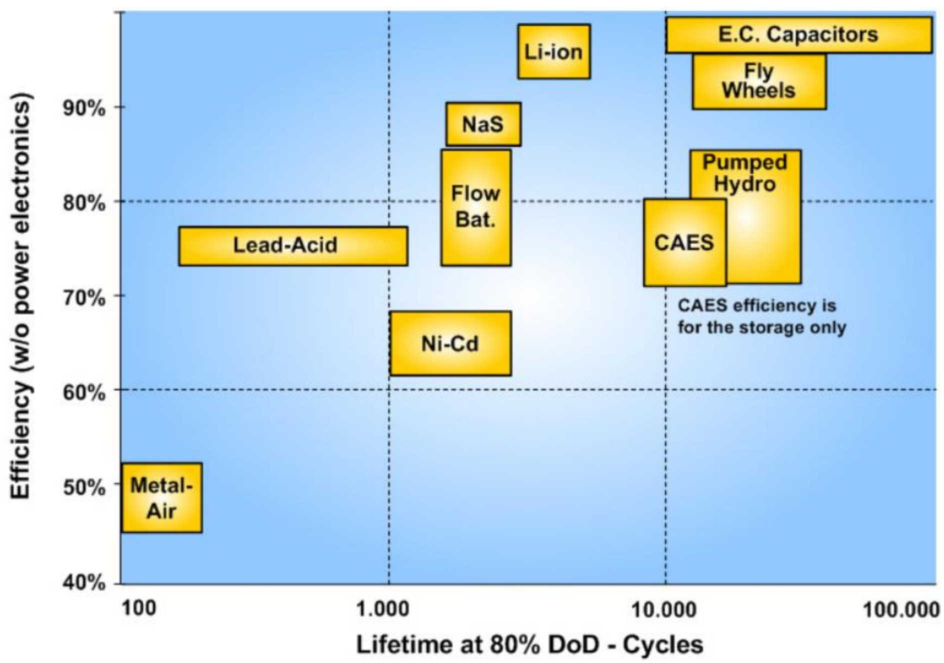

Figure 2: Graph comparing energy storage systems on their efficiency and lifetime [9]

Based on trends in recent deployment, declining prices, high efficiency and decent lifetime, we decided to select **Li-ion batteries** for our further analysis. [10] The image below showcases the battery components of utility scale storage system [11], [12].

Figure 3: Battery system components [13]

6. Methodology

For this study, we analyzed generation data from the hydropower plants, made assumptions applicable to the context, and used results from the flexibility study conducted by UMass to guide our scenarios for integration of battery storage. The following subsections detail our approach and analyses.

6.1. Generation data analysis

Monthly generation data for the years 2000-2011 of the three hydro plants was provided to us by CRC. The average of generation from this data was used as an estimate for future generation output for each hydro plant, as shown in Figures 4-6.

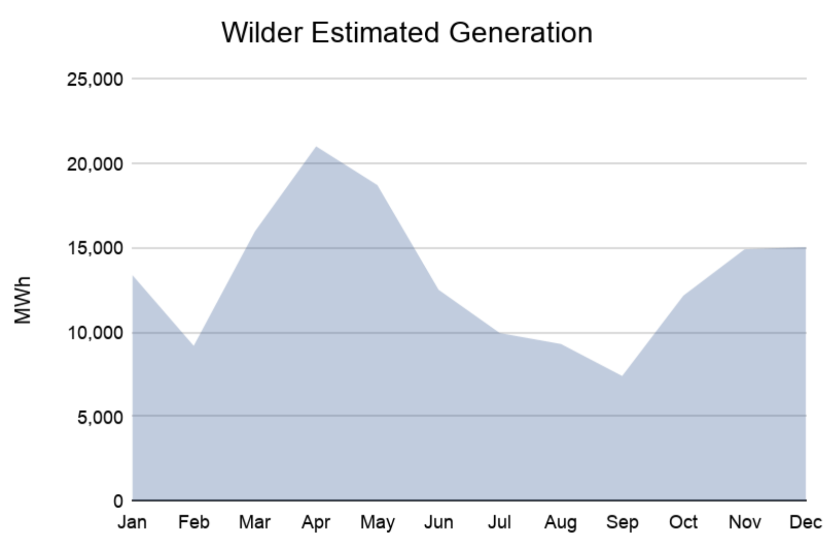

Figure 4: Monthly average generation for Wilder Dam (2000-2011)

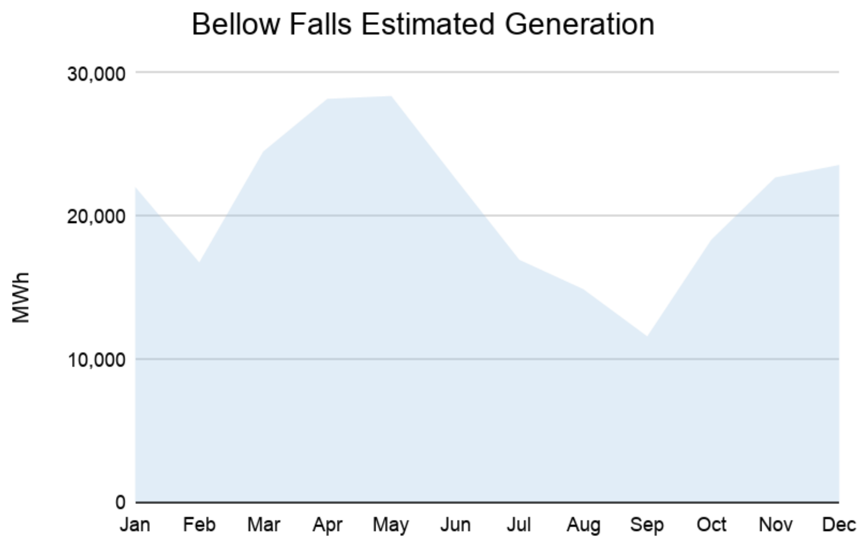

Figure 5 : Monthly average generation for Bellow Falls Dam (2000-2011)

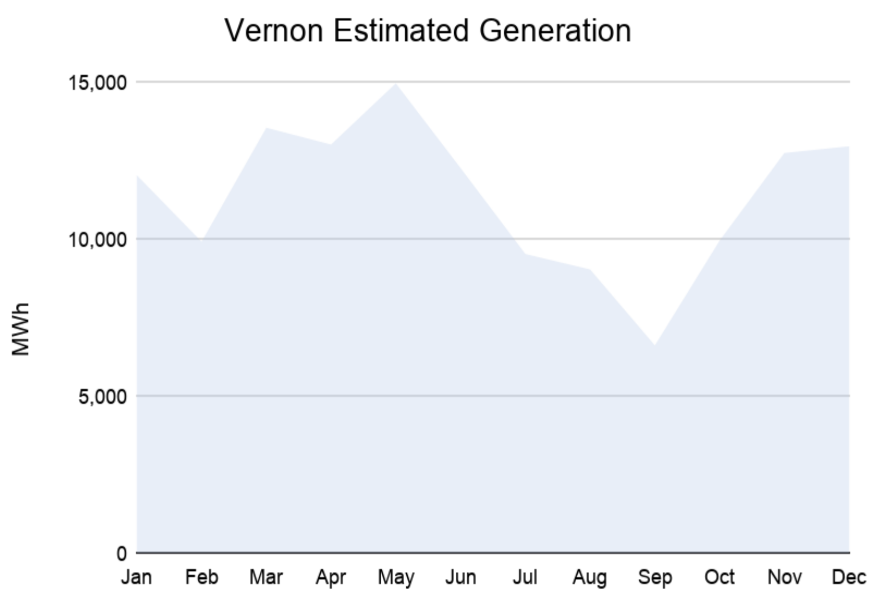

Figure 6: Monthly average generation for Vernon Dam (2000-2011)

The standard deviation for generation output of the plants for across the years was found to be relatively low, confirming that the average would be an appropriate estimate for future power generation. Figure 7 shows that the generation trends remain similar across years.

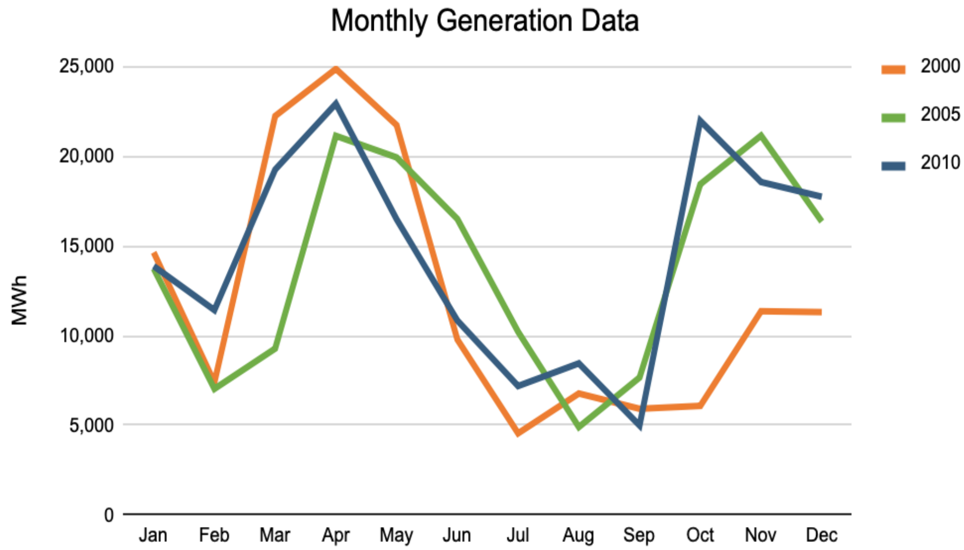

Figure 7: Generation trends for the years 2000, 2005 and 2010

6.2. Revenue and pricing considerations

For our estimation of revenue for various scenarios studied, we used public information on loads, pricing and market information provided by Great River Hydro and ISO New England.

We started with the Federal Energy Regulatory Commission (FERC) revenue reportings for the three hydro-plants. Figure 8 showcases the revenue generated from on-peak and off-peak energy, forward capacity markets, real-time reserves, volt-ampere-reactive support, and renewable credits.

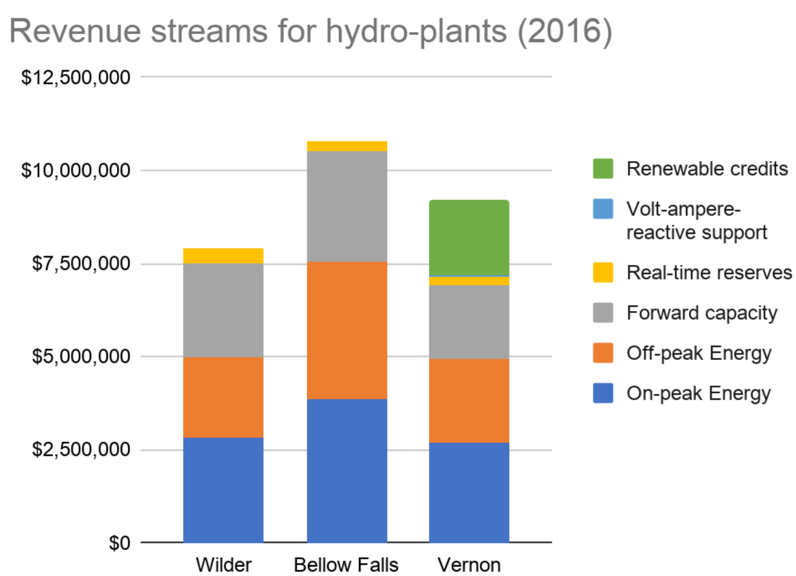

Figure 8: Revenue streams for the three hydropower plants

Energy prices for each dam (in $/MWh) shown in Table 3 were calculated by dividing the total revenue by the total generation. We found this value to be within margin of error of the average price documented in publicly available data. The capacity and ancillary revenue were calculated by dividing the corresponding revenues by the total capacity (MW) and generation (MWh) respectively. The % on-peak energy and % off-peak energy were determined to be proportional to the revenues associated with on and off peak energies documented.

Table 3: Energy and revenue calculations

	Wilder	**Bellow Falls**	**Vernon**
Energy Price ($/MWh)	30.67	30.5	29.95
Reference Year Average Price	29.62	29.62	29.62
Capacity Revenue ($/MW)	51,313	67,936	34,546
Ancillary Revenue ($/MWh)	2.47	1.14	1.66
% on-peak energy	**57%**	**51%**	**54%**
% off-peak energy	**43%**	**49%**	**46%**

We then used the monthly generation data to estimate the average generation per day, under the assumption that the plants operate every single day of the month. The percentage on-peak and off-peak energy estimated from revenue was used to calculate the average share of on-peak and off-peak generation per day. The following graph summarizes the maximum and minimum on-peak and off-peak generation on average per day.

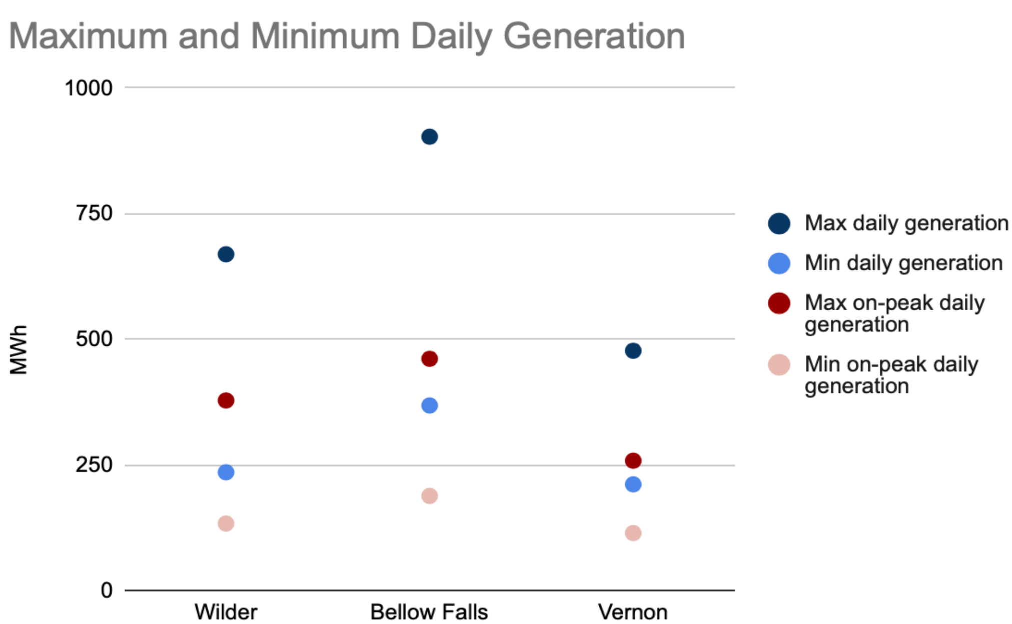

Figure 9: Maximum and minimum daily generation averages for each dam

6.3. UMass flexibility study scenario

The scenario considered in this study is based on a flexibility study conducted by a research group at the University of Massachusetts Amherst. Their research was titled “Investigating the Integration of Flexibility into Dam Operation Planning”. In their analysis, they considered change in revenue when the river’s inflow equals outflow (IEO) versus when there is a percentage deviation from the IEO condition. The IEO constraint equates the inflow to the outflow on any given day.

We work with the revenues corresponding to the seasonal minimum flows obtained from this analysis, as an estimate of the percentage losses of revenue and flow encountered when the dam transitions to operate as run-of-river. The table below shows the percent loss in revenue across nine years for each dam.

Table 4: Revenue and percentage losses associated with seasonal minimum flows

Dam	9 Year Revenue Baseline ($)	Seasonal Min Flows ($)	Percent loss
Wilder	92,496,909	90,210,371	-2.47%
Bellows Falls	136,793,775	134,278,255	-1.84%
Vernon	82,509,892	80,939,211	-1.90%
TOTAL	311,800,576	305,427,838	-2.04%

6.4. Integration of the Battery Storage System

The assumptions and calculations of revenue and percent losses associated with transitioning to run-of-river in comparison with the business-as-usual, led us to identifying and sizing a battery storage system (BSS) best suitable for the scenario. The BSS would charge when energy prices are low and generate when the prices are high, making a revenue from arbitrage. This would supplement the revenue made from letting the dam generate electricity by run-of river thereby making up for losses associated with the transition from stored hydro.

The following subsections discuss the assumptions made and calculations performed to identify the right size and configuration of the battery storage system to meet the revenue requirements.

6.4.1 Battery Operations

Our battery system will be charged between 12:00 am and 5:00 am where energy demand and prices are low. Each battery requires 5 hours to charge to full capacity. With a depth of discharge (DoD) of 80%, they can discharge for 4 hours [14]. Batteries will discharge during peak hours between 7:00 am and 10:00 pm.

6.4.2 Revenue calculations

The battery systems will charge during off-peak hours when the day-ahead energy prices are low and will discharge during on-peak hours when electricity prices are high. In 2017, the average on-peak prices were $37.63 /MWh while the average off-peak prices were $28.95/MWh in Vermont. These average prices were necessary to determine the revenue lost from operating as a run-of-river hydropower plant as opposed to a peaking hydroelectric plant. The following figure displays the variation in on-peak and off-peak prices throughout the year for 2017. [15]

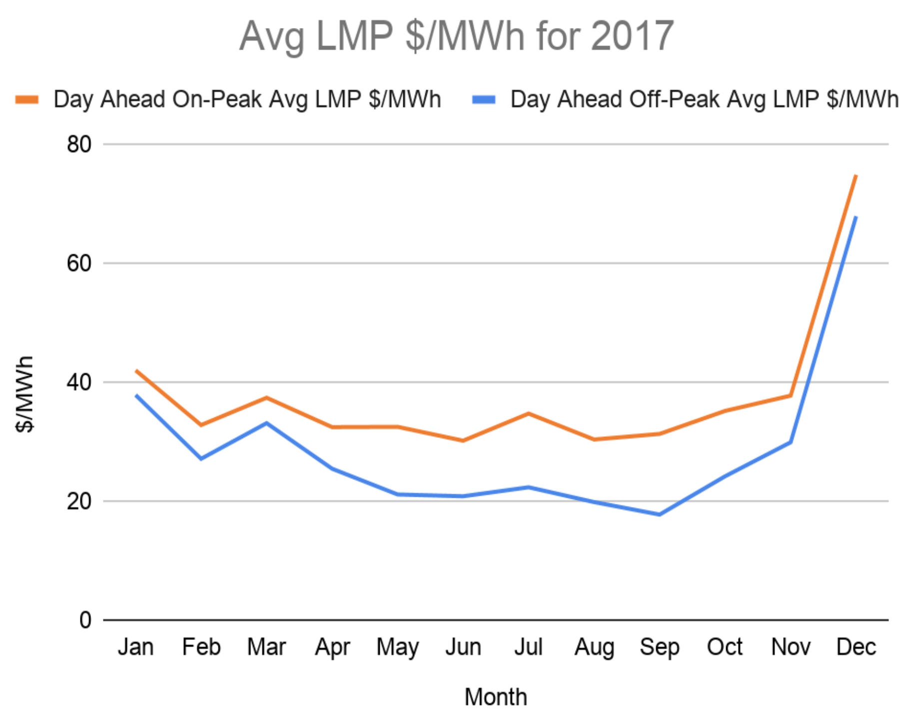

Figure 10: Day-ahead on-peak and off-peak pricing per month [6]

Using the average on-peak and off-peak energy prices in 2017, we determined the revenue streams from load shifting are as follows:

- Revenue lost from charging the battery system for 5 hours between 12:00 - 5:00 am totals to **$144.75/MWh**
- Discharging the battery during 4 peak hours during the day would result in a revenue of **$150.52/MWh**
- This results in a net increase in revenue of **$5.77/MWh**. We make a simplifying assumption that this net increase in revenue is uniform throughout the year.

The battery size will be determined in accordance with the net revenue in order to meet the revenue lost when transitioning to run-of-river. Table 5 below shows the generation (MWh) losses in a year and the resulting revenue losses per day. The battery capacities required to recover these losses through load shifting are shown in the table below. [16]

Table 5: Battery sizing

Dam	Generation (MWh)	Energy Revenue	Percent loss	Generation lost	Revenue Lost/Day	MWh battery to recover lost revenue
Wilder	163,145 MWh	$5,004,205	-2.47%	-4,029 MWh	$388.64	**58.69 MWh**
Bellows Falls	247,388 MWh	$7,544,867	-1.84%	-4,551 MWh	$380.34	**65.92 MWh**
Vernon	165,104 MWh	$4,944,984	-1.90%	-3,136 MWh	$257.41	**44.61 MWh**

6.4.3 Battery Sizing

By selecting a duration of 4h for the battery system and in order to meet the capacity required to recover the lost revenue, the battery systems for the hydropower plants would need to have the following specifications.

Table 6: Estimated battery specifications to meet revenue requirements

Dam	Power	Capacity	Duration	Revenue from FCM Battery
Wilder	15 MW	60 MWh	4h	$840,351.33
Bellows Falls	16.25 MW	65 MWh	4h	$943,839.74
Vernon	11.25 MW	45 MWh	4h	$638,774.16

How does changing from peaking to RoR change the amount of capacity that the plant can bid into the Forward Capacity Markets? Incorporating a battery storage system has the potential to increase the overall capacity of the hydropower plant. If a 60 MWh battery system with a 4-hour duration is incorporated, this will result in an increased capacity of 15 MW. The hydropower plant can bid this additional capacity into the forward capacity market resulting in increased revenue as shown in Table X above based on the average FCM price of $57,274/MW. [16]

6.4. Battery size, manufacturers and configuration

The table below lists existing battery storage system options in the market by prominent companies for utility scale applications. The exact costs were not always available as the manufacturers only respond to business quotes. Therefore, we employed the capital costs estimated by Lazard for our financial analysis detailed in the subsequent section.

Table 7: Table with major lithium-ion manufacturers and battery specifications [17], [18], [19], [20],

Manufacturers		**Unit options**	**Power rating**	**Capacity rating**
	BYD	1	250 kW	1 MWh
		2	500 kW	1 MWh
		3	1 MW	1 MWh
		4	1.8 MW	800 kWh
	Fluence	Advancion	2-100+ MW	
	GE	Energy RSU-4000	1.2 MW	4.18 MWh
		Mid-Power	0.96 MW	3.7 MWh
		High Power	0.72 MW	2.5 MWh
	SAFT Intensium	Max + 20M	2.5 MW	1.09 MWh
		Max + 20P	2.8 MW	0.7 MWh
	Samsung SDI	E3-M090	-	122 kWh
	TESLA	Powerpack	50 kW	210 kWh
		Megapack	-	3 MWh

7. Financial Analysis

Battery systems are purchased in units with preset energy, and power ratings. Our calculations are therefore based on battery specifications of Energy RSU-4000 battery system from General Electric. This is a 4.18 MWh battery storage system, with a maximum power of 1.2 MW.

The number of units, energy, and power outputs from these battery systems is shown in Table 8 below. GE does not disclose the costs of these units, therefore, we used the capital cost projections for lithium-ion battery technology provided by Lazard, as seen in Figure 11 below. This cost for 2019 is approximately $500/kWh.

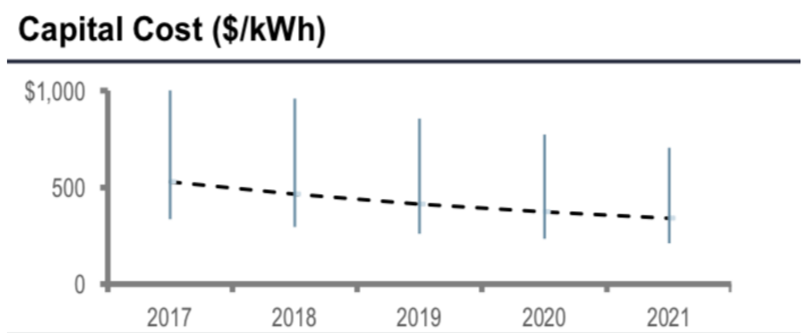

Figure 11: Levelized cost of battery storage options [21]

Table 8: Estimated capital cost of deploying the battery storage system

Dam	# of RSU-4000 batteries	Capacity	Cost ($500/kWh)
Wilder	14	58.52 MWh	**$29.26 M**
Bellows Falls	16	66.88 MWh	**$33.44 M**
Vernon	11	45.98 MWh	**$22.99 M**

8. Tax incentives and policy

8.1. Energy storage tax incentive and deployment act

A new legislation introduced in the House of Representatives by Congressman Mike Doyle, seeks to modify the federal tax code to include energy storage as an eligible technology for Investment Tax Credit (ITC). Currently the ITC under Section 48 and 25D of the Internal Revenue Code allows project owners to receive federal tax credits for designated renewable energy generation equipment. This code has covered Solar PV projects since its inception in 2006. In March 2018, the IRS clarified that battery storage may also receive credits if it receives a majority of its energy from solar panels. Standalone storage has not been eligible for ITC [22].

This bill has been taken forward when Senators Dianne Feinstein, Martin Heinrich, and Cory Gardner introduced the bi-partisan Energy Storage Tax Incentive and Deployment Act of 2019 in the Senate. A past bill introduced by Sen. Heinrich in 2016 for standalone energy storage never passed the committee.

Highlights of the energy storage tax incentive and deployment act:

- Business energy investment credit for energy storage: For commercial applications, the bill provides the same tax incentive as currently available for solar energy in section 48 of the IRS code. All energy storage technologies would qualify, including batteries, flywheels, pumped hydro, thermal energy, compressed air, etc. To qualify for the ITC, the system must have a storage capacity of at least 5 kilowatt-hours. The credit allowed is the same as currently available for solar energy, including the phase down. The IRS currently allows a limited ITC for energy storage when it is installed in conjunction with a solar or wind energy system. The bill would extend the ITC for any energy storage project in all applications, including consumer-owned, grid-connected, or off-grid.
- Residential energy property tax credit for energy storage: For residential applications, the bill provides homeowners the same credit as currently available for solar energy in section 25D. However, only battery storage is eligible for the residential ITC, and the system must have a storage capacity of at least 3 kilowatt-hours.

8.2. Structure of existing federal tax incentives for energy storage

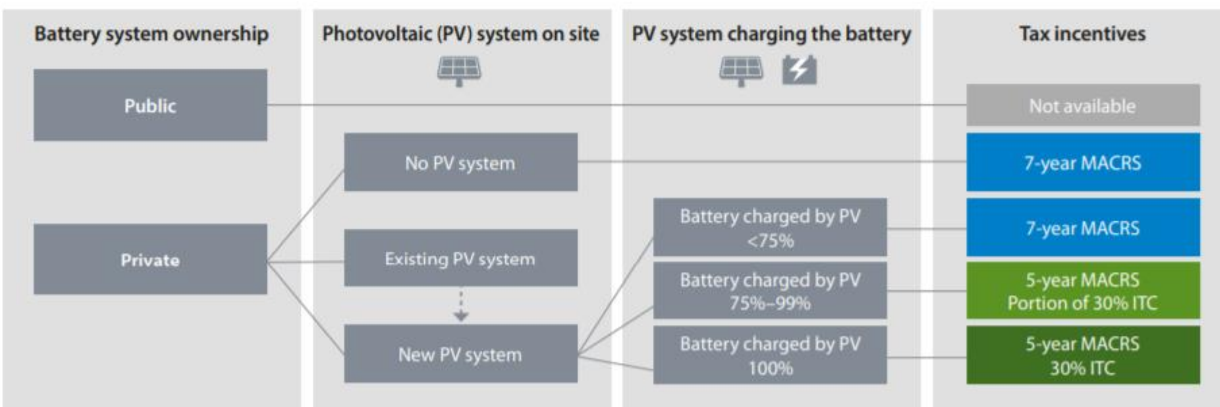

Figure 12: Incentives for battery systems

In the current system, Investment Tax Credit (ITC) and the Modified Accelerated Cost Recovery System (MACRS) depreciation deduction may apply to energy storage systems such as batteries depending on who owns the battery and how it is used. If the battery is owned by a public entity such as a public university or federal agency, they are not eligible for tax-based incentives. If owned by a private party, battery systems may be eligible for some benefits [23].

Modified Accelerated Cost Recovery System:

- Without a renewable energy system installed, battery systems may be eligible for a 7-year MACRS depreciation schedule: an equivalent reduction in capital cost of about 20%.
- If the battery system is charged by a renewable energy system by more than 75% of the time on an annual basis, the battery should qualify for the 5-year MACRS schedule, equal to about 21% reduction in capital costs.

Investment Tax Credits:

- Battery storage systems charged by a renewable energy system for more than 75% of the time are also eligible for Investment Tax Credits (ITC). This is currently 30% for systems charged by PV which will be declining to 10% from 2022 onwards.
- Battery systems charged by a renewable energy system for 75-99.9% of the time are eligible for that portion of the value of the ITC.
- For example, a system charged by renewable energy 80% of the time is eligible for the 30% ITC multiplied by 80%, which equals a 24% ITC instead of 30% (the tax credit is vested over 5 years, and recapture can apply in unvested years if the percentage of renewable energy charging declines).
- Battery systems that are charged by a renewable energy system 100% of the time on an annual basis can claim the full value of the ITC [23], [22].

9. Ownership options for the battery system

Except from tax incentives and policy, the hydropower plants can avoid the high capital costs of the battery system by having a different company own and operate the battery system. The third-party company would incur the initial high capital costs of the batteries and would operate the system. At the same time the hydro plants would have an agreement with that company and receive compensation for having the battery in their property.

One example where a battery system is owned and operated by a third-party is that of Arsenal's Emirates Stadium in London. Pivot Power was the company that installed the system and it will operate it for the next 15 years. Their 3MW battery will generate income by providing services to National Grid to help it balance supply and demand, which will be shared between Pivot Power, Downing LLP and Arsenal. [24]

10. Scope for future work

Further investigation ought to be carried out to accurately determine the financial impact of converting the peaking plants to run-of-river hydropower plants. We suggest:

- Evaluating the impact of run-of-river operations on the capacity that the hydropower plants can bid into the **forward capacity markets**. This will accurately determine the overall change in revenue from operating as run-of-river plant.
- Varying the **battery size** to lower the net present cost of the battery system. A larger battery system will result in increased on-peak and capacity revenue streams, however, the battery system will have higher initial capital costs.The battery system size can be optimized for the lowest net present costs.
- Performing a detailed **financial analysis** that will include the return on investment (ROI) and payback time for the battery system.
- Identifying the **optimal time** to install the battery system taking into account tax incentives that might become available in the future as well as declining cost of batteries.

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