# A Computational Framework for Energy Storage Participation in Transmission Planning with Electricity Market Participation

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***HydroWIRES***

In April 2019, WPTO launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas: understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

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[1] Hydropower and Water Innovation for a Resilient Electricity System ("HydroWIRES")

HydroWIRES is distinguished in its close engagement with the DOE National Laboratories. Five National Laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and National Laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at https://energy.gov/hydrowires.

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# Executive Summary

Energy storage technologies—including pumped storage hydropower (PSH), batteries, and other technologies—have been technically proven to be capable of providing transmission services[2] by regulating power flows and providing voltage support[3]. These technologies will potentially increase the flexibility of transmission infrastructure and may defer (or eliminate) the need for transmission upgrades or new investments. On the regulatory side, Congress and the Federal Energy Regulatory Commission (FERC) have issued several orders over decades that have established energy storage's (ES) eligibility as a transmission asset[4,5]. The orders have required transmission planning entities to provide a level playing field where ES can participate in the transmission planning process (TPP) without undue discrimination and preference of technology. These developments pave the way for ES to participate in transmission planning as a transmission asset. On the other hand, as a flexible resource, ES can play an important role in the electricity market to enable more renewable energy integration by providing energy and grid reliability services. This could bring more revenue in return.

However, studies have shown that ES resources are not widely selected as a cost-effective transmission solution in the TPP due to a complex set of technical and regulatory issues[6]. For example, a PSH-based transmission solution generally has a large capacity, which corresponds to a more expensive investment cost compared to a traditional line solution. Market participation may allow the PSH asset to offset part of its high investment cost. A critical question is whether it is economically and technically viable to allow a PSH-based transmission project for "dual-use" (transmission services and market participation) without jeopardizing transmission system reliability. On the institutional side, there is a procedural gap regarding the integration of an ES project into the existing TPP. Supporting the ES dual-use application will make this process more complex since transmission planning and generation resource planning are managed by different authorities in many U.S. electricity markets. Additionally, there is often no coordination between the planning authorities. On the technical side, there is a lack of computational tools to support ES project developers and system operators in their decision-making processes.

In this project, we develop a computational framework that can assist PSH project operators in proposing an optimal transmission solution for participation in a TPP. The framework addresses a pre-defined transmission upgrade need and offsets part of its investment cost with potential revenue from market participation outside of the transmission services obligation period. The framework has two major components. The first one, called the ES for Transmission Planning (ES4TP) model, finds the optimal PSH-based ES solution with the least cost (in terms of capacity, duration, and location) as a transmission asset to address a known transmission upgrade

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2 Luburić, Zora, Hrvoje Pandžić, Tomislav Plavšić, Ljupko Teklić, and Vladimir Valentić. "Role of energy storage in ensuring transmission system adequacy and security." *Energy* 156 (2018): 229-239.

3 Twitchell J.B., D. Bhatnagar, S.E. Barrows, and K. Mongird. 2022. *Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset*. PNNL-32196. Richland, WA: Pacific Northwest National Laboratory.

4 Federal Energy Regulatory Commission, "FERC Order 890," 2007.

5 Federal Energy Regulatory Commission, " FERC Order No. 1000," 2011.

6 Z. Zhou, J. Kwon, Y. Tian and D. Zhao, "Role of Large-Scale Energy Storage in Transmission Planning," Argonne National Laboratory, to be published, , Lemont, IL, 2019.

need. Then, based on the PSH solution identified in the ES4TP model, Argonne National Laboratory's in-house tool, Pumped Storage Hydropower Market Analysis Tool[7] (PMAT), models the market participation strategies during the period when the PSH project is allowed to participate in an electricity market outside of the transmission service period (TSP) and analyzes its market revenue.

ES4TP and PMAT will support project investors/developers and system operators assessing cost recovery mechanisms based on the capital expenditure and market revenue information. The overall computational framework and use cases also provide technical guidance and evidence to state and federal energy regulatory organizations when considering the storage technologies as alternative transmission solutions.

As a case study, the framework and workflow were tested on the WECC 240-bus test system with California Independent System Operator (CAISO) market structure and data. We also considered information about potential PSH site locations and capacities in California, leveraged from another ongoing project funded by the WPTO HydroWIRES program[8]. The case study shows that revenue from market participation is comparable to the annualized investment cost. The market revenue ranges from 29.2% to 87.7% of the annualized investment cost. The percentage depends on many factors, including the investment cost, capacity, location of the PSH project, price dynamics of the electricity market, and more importantly, the restrictions applied to the PSH project on its market participation (e.g., duration and starting time of market participation, state of charge (SOC) requirement at the end of this duration, etc.).

In summary, the main takeaways of this project are as follows:

- Depending on locational physical constraints, the investment cost of a PSH-based transmission upgrade solution can be higher than a traditional line solution but can be offset partially with revenue from energy market participation if allowed.

- Besides its own physical settings and market dynamics, the market performance of a dual-use PSH project is highly dependent on advanced information regarding when and how long it can participate in the market, and what the SOC requirements are at the end of market participation. The decision may be a conflict with the market participation objective of profit maximization.

- In the context of dual-use, a PSH project may fully recover its cost or even have positive annual revenue at some point during its lifetime. Cost recovery depends on the settings of the cost recovery mechanism, which determines the percentage of the cost that is recovered by the system operator and the percentage of market revenue that can be kept by the PSH owner.

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7 Kwon, Jonghwan, Todd Levin, and Vladimir Koritarov. "Optimal Market Participation of Pumped Storage Hydropower Plants Considering Hydraulic Short-Circuit Operation." In 2020 52nd North American Power Symposium (NAPS), pp. 1-6. IEEE, 2021

8 E. Rosenlieb and D. Heimiller, "Closed Loop Pumped Storage Hydropower Resource Assessment for the United States," National Renewable Energy Laboratory, Golden, CO, 2022.

# Acronyms and Abbreviations

| | |
|---|---|
| AC | Alternating Current |
| AF | acre-feet |
| ANL | Argonne National Laboratory |
| AS | Ancillary service |
| ATT | Advanced Transmission Technologies |
| A-LEAF | Argonne Low-carbon Electricity Analysis Framework |
| cfs | Cubic feet per second |
| CAISO | California Independent System Operator |
| DA | Day-ahead |
| DC | Direct current |
| DOE | Department of Energy |
| ES | Energy storage |
| ES4TP | ES for Transmission Planning |
| FERC | Federal Energy Regulatory Commission |
| GW | Gigawatt |
| IEEE | Institute of Electrical and Electronics Engineers |
| ISO | Independent system operator |
| LMP | Locational-based marginal price |
| ML | Million liter |
| MPP | Market Participation Period |
| MW | Megawatt |
| NREL | National Renewable Energy Laboratory |
| NPV | Net present value |
| PHES | Pumped hydropower energy storage |
| PMAT | Pumped Storage Hydropower Market Analysis Tool |
| PSH | Pumped storage hydropower |
| RT | Real-time |
| RTO | Regional transmission operator |
| RTS | Reliability test system |
| SOC | State of charge |
| TEP | Transmission Expansion Planning |
| TPA | Transmission Planning Authority |
| TPP | Transmission Planning Process |
| TSP | Transmission Service Period |
| USGS | United States Geological Survey |
| WECC | Western Electricity Coordinating Council |
| WPTO | Water Power Technologies Office |

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# 1.0 Introduction

The electricity industry has been facing rapid integration of energy storage (ES) in recent years due to technology advancements, cost reductions, and policy directions. In the U.S., there are 43 Pumped storage hydropower (PSH) plants with a total installed capacity of 21.6 GW [1]. The total installed capacity of other ES technologies reached 1,238 MW and 1,967 MWh in 2018[9]. Also, the annual increase rate of ES interconnection in 2018 was about 45% [2]. ES can make a significant contribution to the electric power grid because it provides various grid services, such as energy arbitrage, ancillary services (AS), as well as transmission and distribution services. The common transmission services provided by ES include transmission congestion relief, transmission investment deferral, and voltage support. Technically, transmission services could be achieved through proper charging and discharging scheduling. Therefore, ES can be an alternative transmission solution compared to conventional line solutions, which may be subject to restrictions such as land use, cross states coordination, etc. ES resources need to be included in the Transmission Planning Process (TPP) to receive cost recovery associated with the provision of transmission services. TPP is a process of determining the time, location, type, and size of new transmission assets that should be invested in the transmission system to ensure reliable and efficient operation of the system. TPP is, oftentimes, also called transmission expansion planning (TEP).

Congress and Federal Energy Regulatory Commission (FERC) have issued several orders over decades that have established ES's eligibility as a transmission asset. They have required transmission planning entities to provide a level playing field where ES can participate in a TPP without undue discrimination and preference of technology. Specifically, in 2005, Congress established a definition of advanced transmission technologies (ATT) that include selected ES technologies [3][10]. In 2007, FERC issued Order 890 that mandates that transmission planning entities to offer a comparable treatment to all ATT in the regional TPP [4]. In 2011, FERC issued Order 1000 that enhanced Order 890 to encourage further competition in the regional TPP by increasing the opportunity for non-incumbent ES developers to be included in the regional TPP [5].

As a transmission service provider, a PSH project may mitigate transmission line congestion or thermal overloading and provide voltage support without the need for expensive transmission upgrades, while improving the reliability of the grid. If selected in the TPP, the PSH project will get its investment cost fully recovered by a transmission planning authority (TPA). Although a PSH resource can improve grid reliability, it may have low utilization if it stands by all the time as a transmission asset. Besides transmission services, ES can provide many additional services to the grid, including energy, AS, etc. It is expected that market participation brings additional revenue to offset its investment cost. However, although the use of PSH as a market participant provides efficient utilization of resources while earning high revenue for the operator, market

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[9] ES technology includes batteries, flow batteries, and kinetic energy storages.

[10] The selected ES technologies in ATT include PSH, compressed air energy storage, flywheel energy storage, battery energy storage, and superconducting magnetic energy storage.

participation may jeopardize PSH's role as a transmission asset to ensure transmission system reliability if it's not operated with appropriate restrictions in the market.

Therefore, it is critical to evaluate how technically and economically viable an ES project is when it provides transmission services as a transmission asset and participates in an energy market when transmission services are not needed. In this project, we are particularly interested in the dual-use case of an ES. In the current U.S context, as a dual-use asset, an ES project must be selected through a TPP to serve a transmission need in the first place, which is managed by a regional transmission operator (RTO). However, studies, including a recent study conducted by the investigator [6], have shown that ES resources are still not readily selected as a cost-effective transmission solution in TPP due to a complex set of technical and regulatory issues [7]. As a logical continuation of previous work conducted by the investigator [6], this project explores how ES, with a particular focus on PSH, could provide cost-effective transmission services to address transmission needs. More importantly, the project explores the technical and economic viability of PSH as a dual-use asset: transmission service and market participation. That is, the PSH is allowed to participate in an electricity market when it is outside of its TSP. This study describes a computational framework to help ES developers determine the economic viability of dual-use ES, where the ES both addresses a transmission update need and participates in the electricity market.

The framework includes two major modules. The first module determines the optimal ES solution in terms of capacity, duration, and location to address a transmission upgrade need. The second module estimates the economic benefit if the project is allowed to participate in an electricity market outside of its TSP, under various cost recovery schemes. A case study is conducted to illustrate how the framework works in the WECC 240-bus test system and CAISO market context. The framework and models are implemented in Julia, and the optimization model is solved by CPLEX.

In addition to ES project investors/developers as target users of this dual-use application, the conceptual tool is also valuable for transmission system planners/operators, state energy commissions (generation expansion planner), and electricity market operators (ISO) to understand the economic and technical roles of ES as a dual-use asset from a system perspective to facilitate better resource utilization while ensuring system reliability. Moreover, since the dual-use application has not been successfully captured by any projects, the overall computational framework and use cases also provides technical guidance and evidence to extended stakeholders when considering the storage technologies as alternative transmission solutions and dual-use applications in operations.

The report is organized as follows. Chapter 2.0 reviews the academic literature on how ES is integrated into transmission planning problems. Chapter 3.0 introduces the computational framework, workflow, and details of the two major models. Chapter 4.0 is a case study illustrating how the framework performs based on the WECC 240-bus test system and CAISO market data. Lastly, Chapter 5.0 concludes the project with major findings and future work discussion.

# 2.0 Literature review

In this section, we review prior academic literature that considers ES in optimization models for the long-term TPP. We start with a general formulation of the TPP problem, which is presented as follows:

$$\underset{\Xi}{Minimize}\, f(\boldsymbol{x})$$

Subject to:

$$P(\boldsymbol{x}) \geq 0$$

$$F(\boldsymbol{x}) \geq 0$$

$$R(\boldsymbol{x}) \geq 0$$

Here, a TPP problem typically minimizes the objective function, $f(\boldsymbol{x})$, which includes the costs for investment, operation, and reliability. The set of decision variables, $\boldsymbol{x}$, typically includes the investment of expansion candidates and scheduling of generation and transmission assets. The physical constraints, $P(\boldsymbol{x})$, capture the physics in the operation of power systems, including power balance, power flow, and operating limits. The financial constraints, $F(\boldsymbol{x})$, reflect the maximum budget for investments. The reliability constraints, $R(\boldsymbol{x})$, enforce the reliable operation of the system in pre- and post-contingency conditions. The consideration of ES as an expansion candidate can be reflected in the constraints mentioned above in different ways depending on the desired level of detail.

The survey papers [8] and [9] provide a comprehensive review of conventional design and technical approaches to TEP problems based on recent practices and a literature review that covers traditional transmission assets, such as transmission lines, substations, and transformers, but has limited information on the consideration of ES in TEP.

The installation and operation of ES in transmission systems have started to gain traction in the literature. The way to construct the problem can be categorized into three major groups: (1) centralized planning of transmission expansion, (2) ES market participation with centralized planning, and (3) ES to improve system and market operation efficiency.

Centralized planning with transmission expansion means that ES is treated as a candidate technology, along with others, in a transmission expansion model from a transmission system planner. References [10] - [11] investigate how ES can provide demand shifting and transmission upgrade deferral when considering ES and transmission lines as investment options and conduct validation based on a small test system. Reference [12] studies an economic ES solution that provides a positive contribution based on a conventional TEP model. This study finds that ES can provide the net social welfare increment and traditional transmission upgrade deferral, which also depend on the specific application context (e.g., ES cost, grid system settings).

In the second group, the models integrate ES market participation with centralized planning [13] [14], and usually have a bi-level structure, with the upper-level ES market participation component representing investment decisions by ES developers and the lower-level centralized planning process representing a system operator's decision. Reference [13] investigates the contribution of ES to the growth of social welfare in TEP and the impact of a capacity remuneration mechanism of the transmission network (referred to as incentive regulation in this paper) on the need and value of ES. The authors propose a bi-level optimization problem for TEP that considers the transmission sector as a natural monopoly operated by an ISO, and where the ES sector is operated under a competitive market environment. The study shows that ES investments contribute to higher social welfare[11], where the benefit is higher with incentive regulations. Reference [14] proposes a bi-level formulation for a coordinated generation and TEP problem that considers ES resources. The upper level represents a centralized transmission system operator, and the lower level represents decentralized generating companies. In addition, this study presents an enhanced period representation technique to capture both long-term and short-term ES resources. The case study using a small system shows that the consideration of 250 MWh of ES provides a more efficient transmission and generation expansion plan.

The third group of models determines the investment of ES in the context of grid operations to improve system efficiency. Often, these long-term investment decisions are based on production cost simulation models with a range of existing and future operational scenarios, which are then extended to consider ES installation and operations. Reference [15] proposes an optimization model that finds an optimal capacity and scheduling of ES for congestion management considering the uncertainties related to wind and solar units. The study shows a reduction in the congestion cost with the installation and operation of ES. Reference [16] investigates how PSH can maximize wind power utilization in power systems. The authors propose a PSH investment model that is integrated into a TEP model. This study shows how the optimal allocation of PSH can help the system achieve the minimum level of wind energy curtailment and transmission reinforcement costs. Reference [17] investigates optimal ES operation and portfolio (i.e., the size, technology, and location) using an enhanced DC optimal power flow model. The proposed model can assess how potential regulatory measures might affect the optimal allocation of ES in the system. The case study compares the optimal ES allocation solutions under different scenarios that consider transmission networks, congestion, and regulatory payments. The results show that the network properties and the type of ES have a high impact on storage allocation. Similarly, [18] presents a modeling framework for determining the optimal allocation of ES in a co-optimized electricity market. This paper presents system-level market opportunity indicators for candidate ES installation locations. The case study with a small test system compares the outcome of solutions with the installation of ES and the transmission expansion plans. The results show that bulk ES can provide most of the benefits that a transmission asset could provide, in addition to the other benefits such as AS provision and market efficiency. Reference [19] proposes an analytical framework, which is tested in a real case study, to investigate the dynamic interactions between wind energy output and ES in transmission congestion management considering the ramping rates of power plants. This study measures congestion mitigation in terms of congestion probability, line load factor, and total energy curtailed. The case study results show a reduction in production costs when using ES along with the re-dispatch of power plants and wind curtailment for congestion management.

[11] It is the economic surplus of the electricity market from a regulator or market operator's perspective in this paper.

The planning models can be formulated into various types of mathematical programming problems, which can be categorized as either deterministic or stochastic. The deterministic models are mainly formulated as mixed linear integer programming problems, where the ES investment decision variable is modeled as an integer variable [10]- [20], [21]. There are also a few models that are formulated as mixed-integer nonlinear optimization problems. For example, Reference [22] formulates the problem as a mixed-integer, second-order-conic problem. Stochastic models usually deal with significant system uncertainty (e.g., load, renewable generation) by representing them explicitly in various forms, such as a scenario set or robust set, which can be further categorized as stochastic programming based if a set of scenarios is used [15], [23], [24] or robust optimization-based if a robust set is used [25], [26].

Most of the models are validated based on some forms of grid test systems, including the IEEE RTS 24-bus system [11]- [12], [25]- [24], or its variation [10]; Garver's 6-bus system [10]- [13], [23]; and IEEE 118-bus system [13], [26]. Some test systems are stylized to loosely represent a simplified real-world system. Reference [20] represents the main Chilean network with a 27-bus system. Reference [15] represents the New England grid system by a modified IEEE-39 bus system.

Additionally, various metrics have been proposed in TEP problem modeling. Reference [27] proposes economic criteria for assessing the merits of a transmission investment along with an assessment methodology. One common criterion used is social welfare maximization; however, the authors show that the dominance of the substitution effect caused by local market power may result in a transmission expansion plan that differs from the expansion plan that maximizes social welfare. Likewise, the authors state that the consideration of total producer or consumer surplus maximization may provide different transmission expansion plans. Reference [12] introduces two efficiency metrics that can be used to assess the effects of incorporating expansion options (i.e., new transmission lines and ES) in TEP. First, the saturation index is used to indicate the system-wide utilization rate of the transmission network, which ranges from 0 to 1. Second, the congestion index is used to measure the level of congestion in a system.

Several prior studies consider PSH, particularly in transmission operations and planning. Reference [28] investigates the impact of PSH on transmission congestion management using an optimization model for congestion management. This study shows that the integration of PSH can provide deductions in the congestion cost and increase system security. Reference [29] presents a robust optimization approach to schedule thermal generators in a day-ahead market while considering the randomness of wind power production. This study shows a significant reduction in total production costs when considering PSH units. Reference [30] examines the benefit of operating PSH in power systems with high wind penetration. This study compares power system scheduling (i.e., unit commitment) with and without PSH to capture the economic benefit of PSH. This study shows that the uncertainty of wind makes PSH more attractive depending on the size of PSH and the level of wind penetration. Lastly, Table 2-1 summarizes the reviewed papers by their problem structure, formulation, and test systems.

Most of the publications propose conceptual models for long-term TEP considering ES as an expansion option, and solution methods to solve such complex optimization problems. The concepts are usually validated on small test systems. It is a challenge to apply them to realistic transmission systems with tractable solutions, especially when considering various practical conditions, such as the interactions between separate decision-makers in the TPP, and various evaluation criteria.

In addition, the consideration of alternative technologies, such as ES, mainly happens in and begins at the solution identification stage of the TPP of ISO/RTOs. Decisions regarding the selection of ES as a transmission solution depend on the cost-effectiveness of the project proposal submitted by stakeholders or ES project developers. There is no consideration of the potential revenue from market participation and corresponding cost recovery mechanism. Therefore, there is a need for a structured framework that will help ES developers identify the optimal sizing and sitting of an ES project while addressing pre-determined transmission needs. The framework will also help ES developers meet other evaluation criteria, like dual-use of transmission services, market participation in operations, and corresponding cost recovery analysis. The concept of this modeling framework has been widely investigated in academic literature. Thus, this research will bring academia and industry closer together to enable a TEP practice that is specifically able to consider ES as an alternative technology solution.

**Table 2-1 Literature review summary**

| Model Features | | Papers |
|---|---|---|
| Problem Structure | Centralized Planning | [10]- [20], [21]- [24] |
| | Market Participation with Centralized Planning | [13] [14] |
| | Operation | [15]- [19] |
| Formulation | Deterministic - Mixed Integer Linear Program | [10]- [14], [21] |
| | Deterministic - Mixed Integer Nonlinear Program | [22] |
| | Stochastic - Stochastic Programming | [15] [23] [24] |
| | Stochastic - Robust Programming | [25] [26] |
| Test Case | Standard - Garver's 6-bus System | [10]- [12], [13], [23] |
| | Standard - IEEE RTS 24-bus System | [11] [12] [16] [21] [25] [26] [24] |
| | Standard - IEEE 118-bus System | [13] [26] |
| | Customized Test Systems | [20] [15] |

# 3.0 Model descriptions and formulations

In this project, we investigate the technical and economic viability of the dual-use of a PSH project in transmission services and market participation. It is achieved by the following two-step computational framework. In the first step, using the ES4TP model developed in the fiscal year 2020 [31], the proposed framework finds the optimal ES (e.g., PSH) solution with the least cost (in terms of capacity, duration, and location) as a transmission asset to address a known transmission upgrade need. Then, based on the identified PSH solution in the first step, the framework uses Argonne's customized in-house market analysis tool, PMAT, to model PSH's market participation strategies when it is allowed to participate in an electricity market outside of the TSP. Finally, we analyze PSH market revenue, profit, and other financial implications when considering different cost recovery mechanisms.

## 3.1 Assumptions

Generally, transmission upgrades are triggered by the following issues: (1) reliability, (2) economics, and (3) policy. This project focuses on the upgrade needs triggered by reliability issues, that is, addressing a transmission line violation caused by contingencies, such as transmission line losses. The target user group of this framework is PSH project developers, who determine the optimal ES solution to address a known transmission upgrade requested by a system operator and submit the solution to participate in the TPP. In the meantime, the PSH project can participate in an electricity market, where the revenue is assumed to be split with the system operator based on some agreement that is part of a proposal for a TPP, as shown in Figure 3-1. The left part of the figure is a complete general TPP. A project operator takes information on the transmission upgrade need, and then identifies and proposes a transmission solution based on PSH technology with dual-use, as illustrated in the right part of Figure 3-1.

In this dual-use context, a PSH project is planned with two steps. First planned as a transmission asset (participant in a TPP; red box in Figure 3-1), then for market participation on an as-available basis (green box in Figure 3-1). This process adheres to FERC's guideline that the reliability function performed by a dual-use storage resource in its transmission role takes priority at all times and that market services may only be provided in a manner that does not compromise the asset's ability to meet its transmission obligations. Therefore, the ES solution model and market participation model are not co-optimized. Instead, the ES solution model identifies an optimal ES solution first, then passes the solution to the market participation model to estimate economic performance in the electricity market.

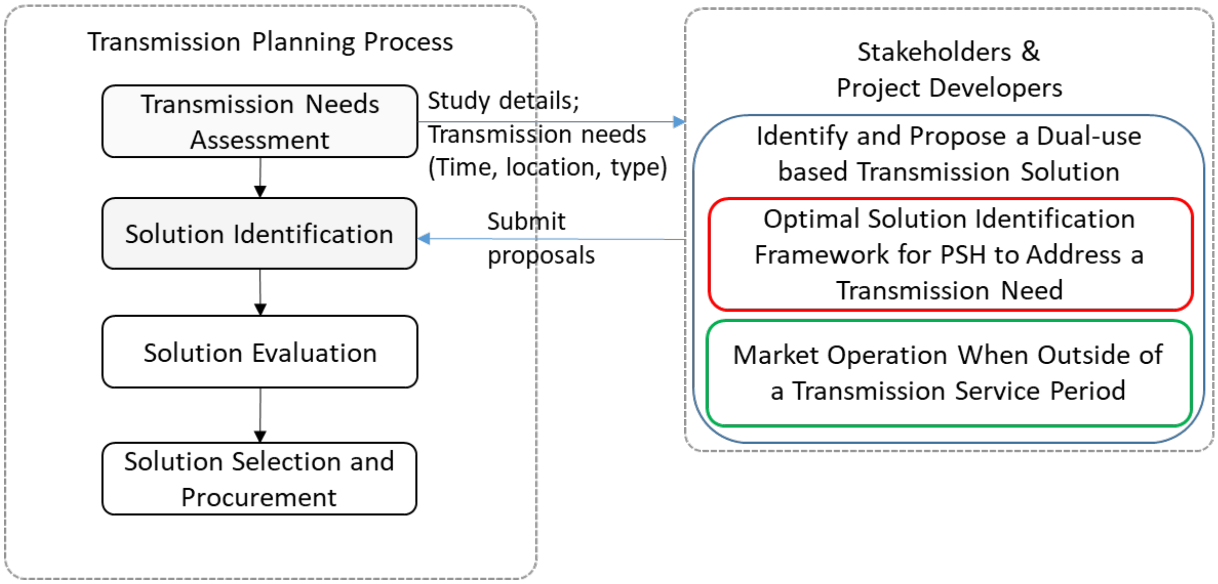


**Figure 3-1  Overview of a TPP and the framework for project developers**

To follow FERC's guidelines (i.e., (1) ISO/RTO independence must be maintained, and (2) adverse market impacts of dual-use assets must be minimized), the dual-use is modeled in the following way: the operation period of a selected ES will be split into the TSP and otherwise. The TSP and requirements are determined by a transmission system operator in advance. During this period, the ES is a transmission asset that is controlled by signals from a transmission system operator. Outside of this period, the ES can participate in an electricity market based on its own decision. An ES operator needs to know the TSP and requirements (e.g., SOC) ahead of time so that an ES can participate in an electricity market (e.g., day-ahead market) with sufficient lead time and meet other requirements when it exits market participation and enters transmission services. In addition, it is assumed that PSH can provide AS and energy in an electricity market. Energy arbitrage strategies can be driven by price differences between in day-ahead and real-time markets, or at different times within the same market.

The authors note that the current model doesn't model specific transmission services during the TSP in transmission system operation, which may have an impact on determining the duration, beginning of the period, and SOC requirement at the beginning of the period. Without loss of generality, settings on those parameters are pre-determined. The sensitivity of those parameters on market performance is analyzed in a case study.

Using the assumptions discussed above, the workflow is developed in the following way. We specifically focus on the development of market participation with restrictions from transmission service obligation, which is the main task in fiscal year 2021.

## 3.2 Workflow

The workflow is illustrated in Figure 3-2. Based on information about thermal overloading on a line, a project operator identifies an optimal PSH-based solution to address this transmission upgrade need. With the setup of this PSH project, the project operator is allowed to participate in

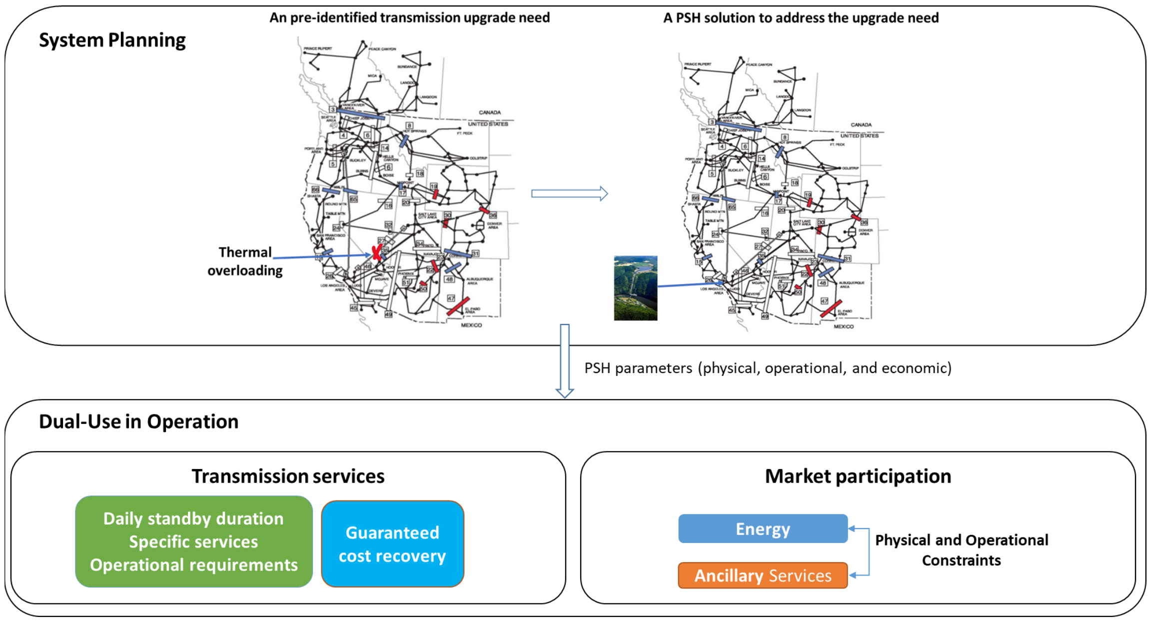


**Figure 3-2 PSH project dual-use workflow illustration (An optimal PSH solution is identified in the planning stage; Dual-use market participation in the operation stage)**

markets when it is outside of a predefined TSP. During the market participation period (MPP), the PSH project operator determines market strategies to maximize revenue and is subject to restrictions from its transmission service obligation.

Figure 3-3 shows the operational timeline of a dual-use PSH operation engaged in transmission service and market participation. It is assumed that the TSP is a fixed period during each day, and that the PSH project can engage in market participation, during the rest of the day (or non-TSP), as shown in Figure 3-3. When a PSH project participates in a market, it is required to meet SOC requirements at the end of the MPP (i.e., start of the coming TSP). During market participation, the PSH project can bid into a day-ahead and/or real-time market with energy and AS provided simultaneously in a co-optimization framework, based on its forecasting of corresponding prices with the assumption that it is a price taker.

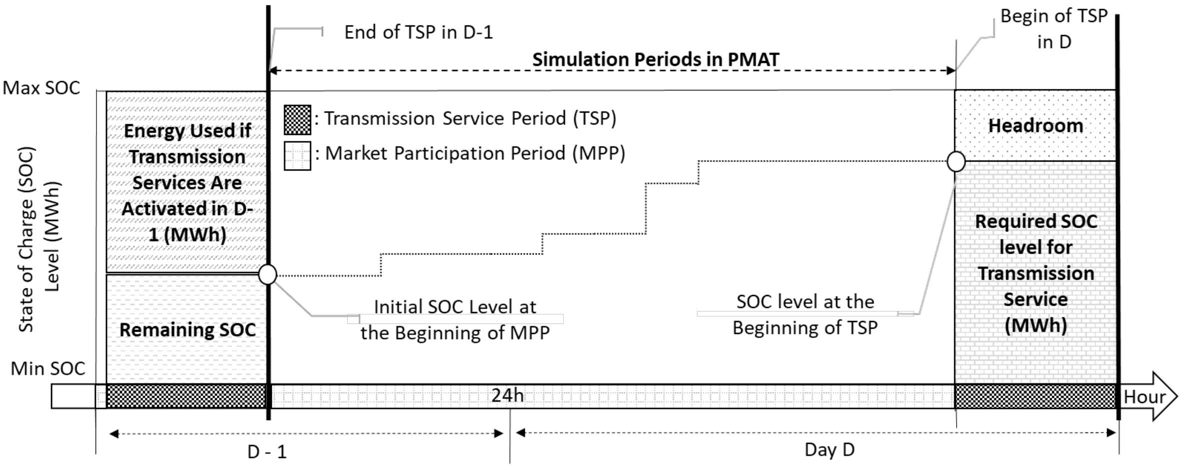


**Figure 3-3..Timeline of a dual-use PSH project engaged in transmission service and market participation (Day D/D-1:** An arbitrary day and the day before; Headroom: reserved capacity for ancillary services; PMAT: PSH Market Analysis Tool for market participation simulation)

## 3.3 Models and formulations

This section details the two major steps in this framework.

### 3.3.1 Energy Storage for Transmission Planning (ES4TP)

To determine an optimal PSH solution that addresses a known upgrade need, the framework was developed in three processes as shown in Figure 3-4: (1) planning case development, (2) solution identification, and (3) feasibility test. The planning case development stage is a transmission reliability study that identifies transmission needs and mimics the ISO/RTO's transmission needs assessment process. This stage is not necessary in practice if a project developer can get this information from an RTO. This process generates power flow base and contingency cases based on AC power flow analysis. The planning case development process is based on the assumption that a PSH project developer has limited information on the system configuration settings and operating status (e.g., power flow cases). The generated power flow cases are then utilized in the following two processes. The solution identification process determines the location, capacity, and duration of a PSH-based transmission solution for a given transmission need (i.e., branch flow violation) developed in the planning case development process. It is an iterative process.

In each iteration, the process starts at Module 1, which finds a PSH solution from a candidate location with optimal capacity (MW) to address a given transmission need. Module 1 is based on a single period (one snapshot) DC optimal power flow. Module 2 determines the minimum duration of the PSH solution from Module 1, while considering the possible SOC and power flow profiles for a multi-period that covers the single period in Module 1 (e.g., ±1 day). Module 2 is based on DC optimal power flow as well. The model updates the capital cost of the PSH solution once a better value of duration is found, and then iterates back to Module 1 to check whether there is a better solution. Iterations in the solution identification process end when there are no changes in the solution.

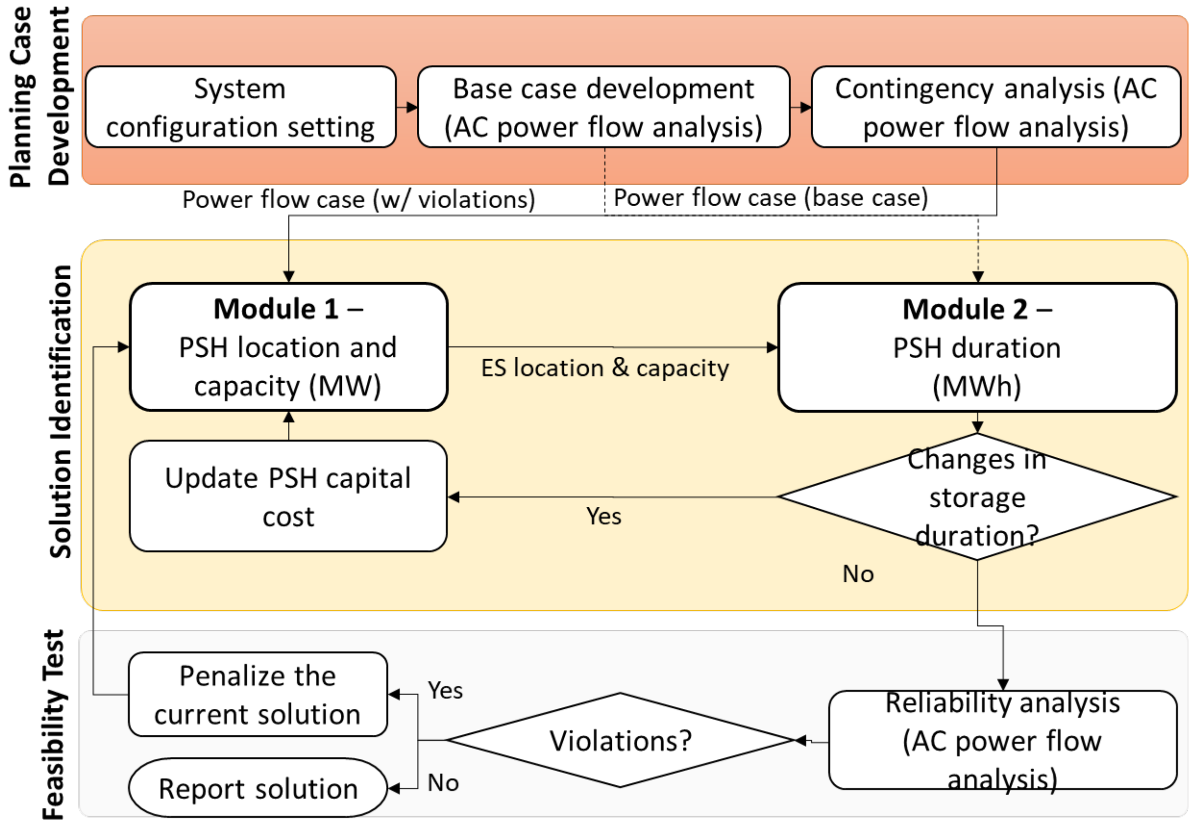


**Figure 3-4 ES4TP three-process workflow for PSH solution identification and validation**

Then the optimal PSH solution identified is passed to the third process: a feasibility test. The feasibility test process evaluates whether the PSH solution would cause any violation in the AC power flow analysis since the PSH solution is based on DC optimal power flow in the solution identification process. If the PSH solution causes a violation, the process loops back to the solution identification process where the failed solution is penalized to identify another optimal PSH solution. The model reports the final solution once it identifies and validates an optimal solution that addresses the original transmission need and does not cause other violations. For more information about ES4TP, please refer to [31].

### 3.3.2 Dual-use market participation

We explored the role of a PSH plant as a market participant [32] and transmission asset [31]. As a transmission service provider, a PSH project may mitigate transmission line congestion or thermal overloading and provide voltage support without the need for expensive transmission upgrades, while improving the reliability of the grid. If selected in the TPP, the PSH project will get its investment cost fully recovered by a transmission planning authority (TPA). Although a PSH resource can improve grid reliability, it may have low utilization if it stands by all the time as a transmission asset. As a flexible resource, PSH can participate in an electricity market, and PSH operators can make a profit in the market by providing capacity, energy arbitrage, regulation, and spinning services. Although the use of PSH as a market participant provides efficient utilization of resources while earning high revenue for the operator, market participation may jeopardize PSH's role as a transmission asset to ensure transmission system reliability if it's not operated with appropriate restrictions in the market.

As summarized in [33], a dual-use market participation model should be bound by three principals: (1) ensure the energy storage's ability to serve the transmission function as the first priority; (2) base market participation on established market practices; and (3) balance cost recovery mechanisms to incent market participation. Following these principals, a dual-use market participation model is designed and implemented in this project, where the TPA can reserve PSH for transmission services during a certain period of the day and the PSH operator can participate in the energy and AS market for the rest of the day, with some restrictions. Accordingly, the TPA recovers part of the investment cost, and any revenue earned from market participation is shared between the PSH owner and the TPA. The PSH participates in an electricity market subject to the following restrictions: 1) duration of the TSP, 2) time of the TSP, and 3) minimum required SOC at the beginning of the TSP. The first two restrictions determine the period that the PSH can participate in the market and the third restriction determines the SOC at the end of its market participation. In this work, we use the modified PMAT [32] to simulate PSH market strategies and analyze the impact of these factors on total market revenue.

As a part of the Argonne Low-carbon Electricity Analysis Framework (A-LEAF), PMAT is an optimization model that improves the market participation strategy for a PSH plant to maximize its potential revenue by providing various grid services [32]. Using PMAT, we can optimize the participation of PSH in the capacity market, energy market, and AS, including regulation-up, regulation-down, spinning, and non-spinning reserves. PMAT also models a detailed representation of the physical and operational constraints of a PSH plant when applicable (e.g., close-loop PSH configuration, hydraulic short circuit, etc.). As a price-taker model, PMAT assumes perfect foresight on market prices while performing time-coupled co-optimization of capacity, energy, and AS to determine the optimal market participation strategy. It must be noted that PMAT, originally developed in [32], is a market participation model that does not consider a dual-use application.

Specifically, the original PMAT model was modified with additional constraints related to the dual-use operation of the PSH plant. To ensure that there is sufficient generation capacity during the TSP, the water level at the end of the MPP must be greater than a threshold. We impose the following additional constraint:

$$V_T^{min} \leq v_{h=H,t=T}^{RT},$$

where $v_{h=H,t=T}^{RT}$ is real-time upper reservoir water level at the end of market participation period which must be greater than $V_T^{min}$. Additionally, to maintain the system's reliability, we must ensure that there is enough generation and storage capacity maintained at all times of the MPP for emergencies and other contingencies. This is implemented by modifying equations (7) and (8) of the PMAT model (developed in [32]) as follows:

$$v_{ht}^{RT} \leq V^{+} - V_{ht}^{RES+} - \sum_{i} wh_{iht}^{P,RT} \;\; \forall t, h,$$

$$v_{ht}^{RT} \geq V^{-} + V_{ht}^{RES-} + \sum_{i} wh_{iht}^{G,RT} \;\; \forall t, h.$$

Here $v_{ht}^{RT}$ is upper reservoir water level at hour $h$ and time $t$. Furthermore, we impose the constraint that the PSH plant cannot participate in the electricity market during the TSP, which is represented by its duration and start time. Because the PSH plant cannot participate in the market during certain hours of the day (most likely during peak hours), it is not allowed to participate in a capacity market. Therefore, in this work, we explore revenues from energy and AS market participation only.

### 3.3.3 Economic analysis - cost recovery and market revenue payback mechanism

In this work, we investigate the financial benefits of the dual-use participation model. The total investment cost of building a PSH plant consists of the cost of building upper and lower reservoirs, tunnels between these reservoirs, and powerhouses. The estimated cost is based on a simplified pumped hydropower energy storage cost calculator [34]. The cost of building the reservoir increases with the storage capacity of the PSH plant, as PSH with higher storage capacity needs a larger reservoir. The cost of building the tunnel increases with the power rating of the PSH, the separation between the two reservoirs, and decreases in the height difference between the reservoirs. Finally, the cost of building a powerhouse depends on the power rating of the PSH plant and the height difference between the upper and lower reservoir.

$$\text{Cost of Building the PSH} = \text{Reservoir Cost} + \text{Tunnel Cost} + \text{Powerhouse Cost}$$

where

$$\text{Reservoir Cost (\$)} = \text{Cost of building a dam} * \text{Rock volume required to construct the walls}$$

$$\text{Tunnel Cost (\$)} = (66{,}000\,P + 17{,}000{,}000) + S(1{,}280P + 210{,}000)H^{-0.54}$$

$$\text{Powerhouse Cost (\$)} = 63{,}500{,}000 H^{-0.5} P^{0.75}$$

In this work, we assume the cost of building a dam is $\$168/m^3$ [34] . Here $P$ is the power rating of the PSH, $S$ is the separation between upper and lower reservoirs, and $H$ is the height difference between the reservoirs. When a PSH plant is operated only as a transmission asset, the PSH operator is guaranteed full investment cost recovery from the TPA. In the dual-use model, any profits from market participation are shared between PSH operators and the TPA, as shown in the equations below. In this model, PSH operators have an incentive to make additional revenue from the energy market and the TPA recovers some costs from market earnings of the PSH plant, ultimately leading to higher use of the PSH plant. Different market revenue splitting mechanisms might have substantial impacts on the decision-making processes of the TPA and PSH operators. In the dual-use model, assuming that the PSH operator recovers a fraction $(\alpha)$ of the PSH investment cost from the TPA and keeps a fraction ($\beta$) of market profits, total revenue for the PSH operator can be:

$$\text{Total revenue for PSH} = \text{Guaranteed Cost Recovery} + \text{Kept Market Revenue}$$

where

Guaranteed Cost Recovery = $\alpha \times$ Full Investment Cost

$$\text{Kept Market Revenue} = (\beta \times |\text{Total Market Revenue}|^{+})$$

Similarly, the TPA may only recover a fraction $(\alpha)$ of the total investment cost and earn a fraction $(1 - \beta)$ of market revenue. The total cost for the TPA can be:

$$\text{Cost for the TPA} = (\alpha \times \text{Full Investment Cost}) - (1 - \beta) \times |\text{Total Market Revenue}|^{+})$$

Values of $\alpha$ and $\beta$ can be agreed upon by the PSH operator and the TPA.

# 4.0 Case Study

In this section, we illustrate how the whole computational framework evaluates the technical and economic viability of a PSH-based transmission service and market participation dual-use case using a case study based on the WECC 240-bus test system [35] and CAISO market structure and data. More specifically, the case study was conducted using the following steps: 1) identify transmission upgrade need based on a contingency analysis of the WECC 240-bus test system using synthetic data; 2) identify a PSH-based solution (location, capacity, and duration) that solves the identified transmission need with ES4TP; 3) simulate the dual-use operation of the PSH project by running the modified PMAT with CAISO market data, and 4) perform a cost-benefit analysis of dual-use PSH with a transmission upgrade from both PSH operator's and system operator's perspectives.

For PSH market participation, we first identified possible PSH siting locations in California and identified nearby transmission nodes on the WECC 240-bus system. Then, we identified optimal PSH locations and sizes that can resolve identified transmission issues in California. Finally, based on the PSH project, we ran a one-year market participation simulation with PMAT using CAISO market price data for the identified node. We assumed that the PSH operator uses a price taker approach where the PSH operator has perfect foresight of the market prices. The price taker model assumes that the operation of the PSH plant will not affect market prices significantly, which is a reasonable assumption for a PSH plant with limited market participation. The PSH project was subject to restrictions from transmission service requirements when participating in the CAISO market. The annual earnings based on 2020 prices from different levels of PSH market participation were estimated. The whole workflow is shown in 4-1.

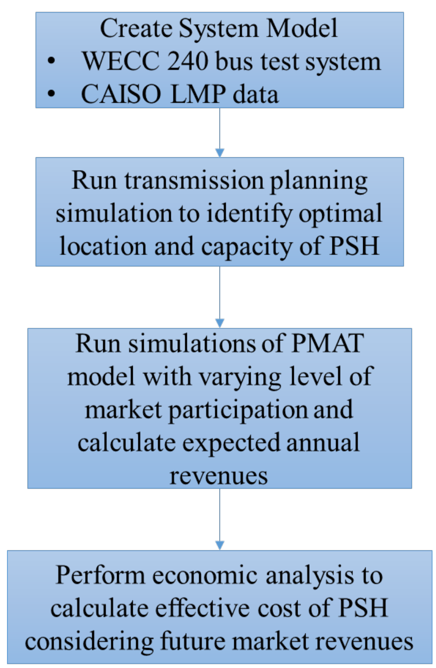


**Figure 4-1 Case study workflow**

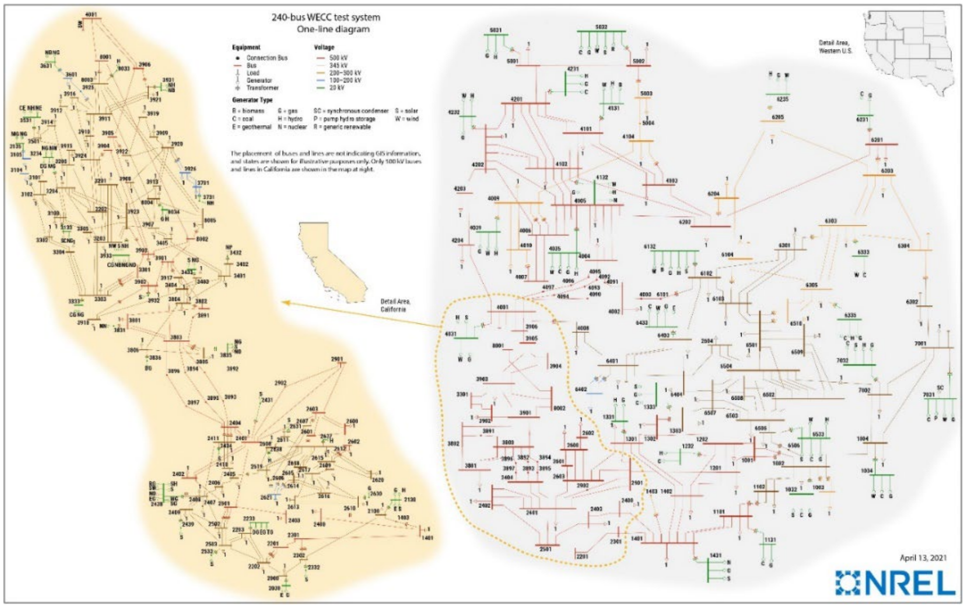


**Figure 4-2 One line diagram of the WECC 240-bus test system [35] [36]**

## 4.1 Case study setting

### 4.1.1 Test system

In this work, we use the WECC 240-bus test system as the testbed, shown in 4-2. The WECC 240-bus test system has a total of 243 transmission buses (including 20kV, 115 kV, 138kV, 230kV, 287kV, 345kV, and 500KV buses), 140 different generators (that includes biomass, coal, gas, geothermal, hydro, nuclear, solar, and wind generation) with a total generation capacity of 277.47 GW, and 451 transmission lines. The test system loosely represents the WECC system that covers the entire western interconnection, which covers states shown in 4-2. For simulation purposes, we use 2020 historical market price data from CAISO to optimize operation of the PSH plant as our target PSH plant is located in California.

### 4.1.2 Candidate PSH sites

We use the National Renewable Energy Laboratory's (NREL) PSH potential capacity assessment project [37] data to identify the nearest PSH capacity for each node. Table 4-1 shows 31 potential transmission network nodes located in California that are within 100 miles of any potential PSH site, their nearest potential PSH capacity, and distance based on local geographical considerations. It must be noted that only the capacity of the nearest PSH location is listed for each node in Table 4-1. There might be multiple potential PSH locations within 100 miles of a given node. The ES4TP model identifies an optimal PSH solution from the candidate PSH sites.

**Table 4-1 List of nodes in the WECC test system within California and nearest PSH capacity to each node**

| Node | Nearest Capacity (MW) | PSH site_id | Distance (Mile) |
|---|---|---|---|
| 2130 | 213 | 95402 | 63 |
| 2233 | 170 | 113068 | 39 |
| 2400 | 156 | 91664 | 9 |
| 2431 | 140 | 125430 | 33 |
| 2434 | 105 | 215568 | 26 |
| 2439 | 154 | 218051 | 20 |
| 2533 | 183 | 90671 | 23 |
| 2600 | 153 | 126584 | 26 |
| 2607 | 121 | 157681 | 42 |
| 2631 | 177 | 78254 | 18 |
| 2638 | 200 | 152832 | 61 |
| 3135 | 257 | 22188 | 35 |
| 3234 | 211 | 107057 | 47 |
| 3401 | 179 | 63260 | 52 |
| 3405 | 495 | 7155 | 34 |
| 3432 | 280 | 26489 | 31 |
| 3433 | 124 | 140395 | 23 |
| 3531 | 244 | 108117 | 16 |
| 3631 | 103 | 196479 | 81 |
| 3831 | 282 | 16503 | 25 |
| 3891 | 106 | 197116 | 31 |
| 3897 | 138 | 201666 | 43 |
| 3909 | 187 | 51253 | 11 |
| 3915 | 132 | 205560 | 45 |
| 3916 | 113 | 165380 | 92 |
| 3917 | 122 | 189006 | 48 |
| 3922 | 167 | 76274 | 47 |
| 3926 | 166 | 112892 | 4 |
| 3931 | 207 | 112204 | 77 |
| 3933 | 203 | 42828 | 22 |
| 8033 | 112 | 168425 | 9 |

## 4.2 Optimal PSH solution identification

### 4.2.1 Selection of an optimal PSH site based on transmission upgrade need

To identify the optimal location and size of the PSH plant that can resolve a transmission reliability need, we conducted full $T-1$ transmission line contingency screening to identify the transmission upgrade need. Table 4-2shows the results of identified five reliability-driven transmission upgrade needs (TN1, TN2, TN3, TN4, and TN5). For example, from Table 4-2, we can see that the TN1 transmission contingency is triggered by a contingency at line number 9, which causes a thermal overloading violation at line number 59 with an amount of 42.56 MW. When there is a contingency at line number 3, we observed three violations. During the TN2, TN3, and TN4 contingency, we observed thermal overloading violations of 173.18MW, 89.95 MW, and 17.16 MW at line numbers 59, 317, and 182 respectively. Finally, during TN5 contingency, when there is contingency at line number 10, we observed thermal overloading violations of 42.56 MW at line number 59. After conducting a full transmission line contingency screening, we identified PSH solutions to resolve these reliability needs individually.

From Table 4-3, we can see that the TN1 contingency can be resolved by building a PSH plant of 50 MW at node 2533. Similarly, the TN2 contingency requires higher PSH capacity to resolve the reliability need. For the TN2 contingency, the PSH solution identified was the 570MW PSH plant at node 2533. It must be noted that although the nearest PSH location to bus 2533 is only 183MW, there are multiple potential PSH sites near node 2533, whose combined capacity is greater than 570 MW. In the rest of this project, we take this optimal PSH solution at node 2533 to address the TN2 contingency as an example to continue the dual-use application study.

**Table 4-2 Identified reliability violation**

| Transmission contingency | Transmission needs ID | Reliability violation location and type | Reliability violation amount (MW) |
|---|---|---|---|
| Line # 9 | TN1 | Thermal overloading on line # 59 | 42.56 |
| Line # 3 | TN2 | Thermal overloading on line # 59 | 173.18 |
| | TN3 | Thermal overloading on line # 317 | 89.95 |
| | TN4 | Thermal overloading on line # 182 | 17.16 |
| Line #10 | TN5 | Thermal overloading on line # 59 | 42.56 |

**Table 2-3 Minimum capacity and duration of the PSH transmission solution for TN1 and TN2**

| Transmission Needs | TN1 | TN2 |
|---|---|---|
| PSH location (node) | 2533 | 2533 |
| Required transmission service capacity (MW) at line 59 | 43.25 | 177.55 |
| PSH transmission service capacity (MW) | 48.75 | 568.86 |
| PSH capacity (MW) | 50 | 570 |
| PSH duration for transmission service (MWh) | 292.54 | 3413.19 |

### 4.2.2 PSH specifications and investment cost estimation

The geographic location of node 2533 is close to San Diego and near the coastline. We use geographical information about the region from USGS [38] to estimate the possible height and size of the PSH reservoirs. Based on the heights of nearby hills, we selected the height difference between the upper and lower reservoir as 148.5 meters. To build a PSH plant with 570 MW output for at least 10 hours of operation that result in 5,700 MWh ES capacity, we estimate the area of the upper reservoir as 10 Ha considering a 20 m average depth, which gives a usable reservoir volume of 16,800 ML. Assuming 84% round trip efficiency, we estimate turbine and pump penstock flow equals 12,000 and 10,080 cfs, respectively [34]. All PSH parameters are shown in Table 4-4.

**Table 4-4 PSH parameter settings**

| Parameter | Value |
|---|---|
| Number of Generators and Pump | 1 |
| Nameplate Capacity (Pump and Generator) | 570 MW (10 hours) |
| Height | 148.5 m |
| Maximum Water Level (AF) | 156,520 |
| Roundtrip Efficiency | 84% |
| Turbine Penstock Flow (cfs) | 12,000 |
| Pump Penstock Flow (cfs) | 10,080 |
| Emergency Water Headroom | 10% |
| Emergency Water Reserve | 10% |

**Table 4-5 Additional PSH parameter setting and assumptions**

| Pumped hydro energy storage | E=m*g*h*efficiency |
|---|---|
| Round trip efficiency (%) | 84% |
| Useable fraction (%) | 84% |
| Reservoir average depth (m) | 20 |
| Upper reservoir area (Ha) | 100 |
| Useable reservoir volume (ML) | 16800 |
| Stored energy (Joules) | 2.1E+13 |
| Water-rock volume ratio | 10 |

We then estimated the cost of building a PSH plant based on the assumptions and parameter settings specified in Table 4-4 and Table 4-5. We assume the separation between reservoirs is 2,500 meters. Assuming a $\$168/m^3$ cost of building a dam, the total cost of building this PSH plant was estimated to be $1.1 billion[12], as shown in Table 4-6, based on the online cost calculator [34].

**Table 4-6 Approximate cost of building the PSH plant**

| Components | Capital Costs | Fraction |
|---|---|---|
| Cost - reservoirs (energy storage) | $306.76 million | 27% |
| Cost – tunnel | $212 million | 19% |
| Cost – Powerhouse | $605 million | 54% |
| **Total** | **$1,123.0 million** | |

### 4.2.3 CAISO market and prices at the PSH market access point

Using node 2533 on the WECC test system as a PSH project connection node, we gathered the corresponding real-time and day-ahead market price data (electricity locational-based marginal price and AS prices) from CAISO for the equivalent node. We used these as inputs for the market participation simulation. In the proposed dual-use model, the PSH plant participates in energy arbitrage and provides AS, like spinning reserve, regulation-up, and regulation-down services during the MPP. The PSH plant cannot participate in the capacity market due to dual-use constraints. Table 4-7 summarizes relevant CAISO market parameters on AS, including the required amount of each service, the historical provision percentage from overall hydropower resources, and maximum provision from individual hydropower resources, which are used to set a constraint on the maximum number of AS that the PSH project can bid into the market. Table 4-8shows major statistics (e.g., mean, median, variance, minimum, and maximum values) of

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[12] The total cost could be higher if it includes other costs such as interconnection, substations, etc.

various market prices at node 2533 for the year 2020. In general, the day-ahead prices are higher and more stable compared to real-time prices, which indicates that the PSH project may participate more in the day-ahead market than in the real-time market. In this study, for simulation purposes, we use historical prices as inputs to analyze the PSH project's market performance for a full year and extrapolate this performance to its full lifetime. The authors note that this setting may overestimate its market performance since it assumes that the PSH operator has a perfect insight of market prices and the use of historical prices to forecast prices in future years may introduce inaccuracies.

**Table 4-7 CAISO market parameters**

| Unit (MW) | Requirement (Market Size) | Provision from Hydro | Capped to Individual Provider |
|---|---|---|---|
| **Regulation-Up** | 310 | 30% | 10% |
| **Regulation-Down** | 400 | 30% | 10% |
| **Spin** | 980 | 50% | 10% |
| **Non-Spin** | 980 | 8% | 10% |

**Table 4-8 CAISO energy price statistics for Node 2533 in Year 2020**

| Statistic | Market Price | Real Time | Day Ahead | Market Price | Real Time | Day Ahead |
|---|---|---|---|---|---|---|
| Mean | **Energy** | $32.75 | $37.71 | **Regulation-Up** | $7.53 | $9.82 |
| Median | | $25.82 | $33.89 | | $3.00 | $5.94 |
| Variance | | 4309.5 | 224.66 | | 1,284.18 | 970.50 |
| Minimum Value | | -$37.57 | $7.81 | | $0.00 | $0.10 |
| Maximum Value | | $1,567.50 | $103.84 | | $1,066.78 | $962.54 |
| Mean | **Spin** | $3.72 | $5.71 | **Regulation-Down** | $6.50 | $9.43 |
| Median | | $0.10 | $2.74 | | $0.55 | $6.80 |
| Variance | | 948.60 | 920.62 | | 497.00 | 110.08 |
| Minimum Value | | $0.00 | $0.10 | | $0.00 | $0.00 |
| Maximum Value | | $1,019.56 | $950.61 | | $722.70 | $207.26 |

## 4.3 Market simulation results and sensitivity analysis

After configuring the PSH plant accessing node 2533 and downloading CAISO market prices for this node, we ran a dual-use simulation with PMAT based on 2020 data for various scenarios and calculated the corresponding revenues. The total market revenue for PSH in the proposed dual-use model is sensitive to the duration of the MPP, the time of the TSP, and the minimum SOC at the beginning of the TSP requirement. To analyze the impact of these parameters, we simulated 15 different scenarios summarized in Table 4-9. We varied the TSP between 4 hours, 6 hours, 8 hours, and 12 hours to investigate the impact of transmission service duration. Similarly, we changed the minimum SOC requirement at the beginning of the TSP from 70% to 90%. It must be noted that, in addition to the duration of the TSP, the time of the TSP can impact total market revenue because the price of electricity might differ during different hours of the day. Scenario groups 10-12 and 13-15 differ in the time of the TSP.

**Table 4-9 Dual-use participation sensitivity scenarios**

| Case ID | TSP | Minimum SOC requirement |
|---|---|---|
| 1-3 | 10 AM – 10 PM (12 hours) | 70%, 80%, 90% |
| 4-6 | 2 PM – 10 PM (8 hours) | 70%, 80%, 90% |
| 7-9 | 4 PM – 10 PM (6 hours) | 70%, 80%, 90% |
| 10-12 | 4 PM – 8 PM (4 hours) | 70%, 80%, 90% |
| 13-15 | 6 PM – 10 PM (4 hours) | 70%, 80%, 90% |

Table 4-10 and Figure 4-3 show the total profit from energy and AS market participation for all scenarios. The annual revenue from market participation is highest ($54 million) when the duration of the TSP is between 6 and10 pm with a 70% minimum SOC requirement. The annual revenue from market participation is lowest ($18 million) when the duration of the TSP is between 10 am and 10 pm with a 90% minimum SOC requirement. From Table 4-10 and Figure 4-3, we can see that the total revenue decreases as the minimum SOC requirement at the beginning of the TSP increases from 70% to 90% for each scenario. This is because a higher SOC requirement at the beginning of the TSP means that the PSH operator has more restrictions in market operation so that the PSH plant can meet the SOC requirement at the end of the MPP. Similarly, revenue increases as the duration of market participation increases, as expected. In addition to the duration of the MPP, the starting hour of the TSP has an impact on the total market revenue. From Table 4-10, we can see that total market revenue is higher when the TSP starts at 6 pm compared to when the TSP starts at 4 pm, because the prices of electricity are different during different times of the day. Additionally, the PSH plant makes most of its revenue from energy arbitrage (around 95%) compared to participation in the AS market due to higher energy price variability on that specific node.

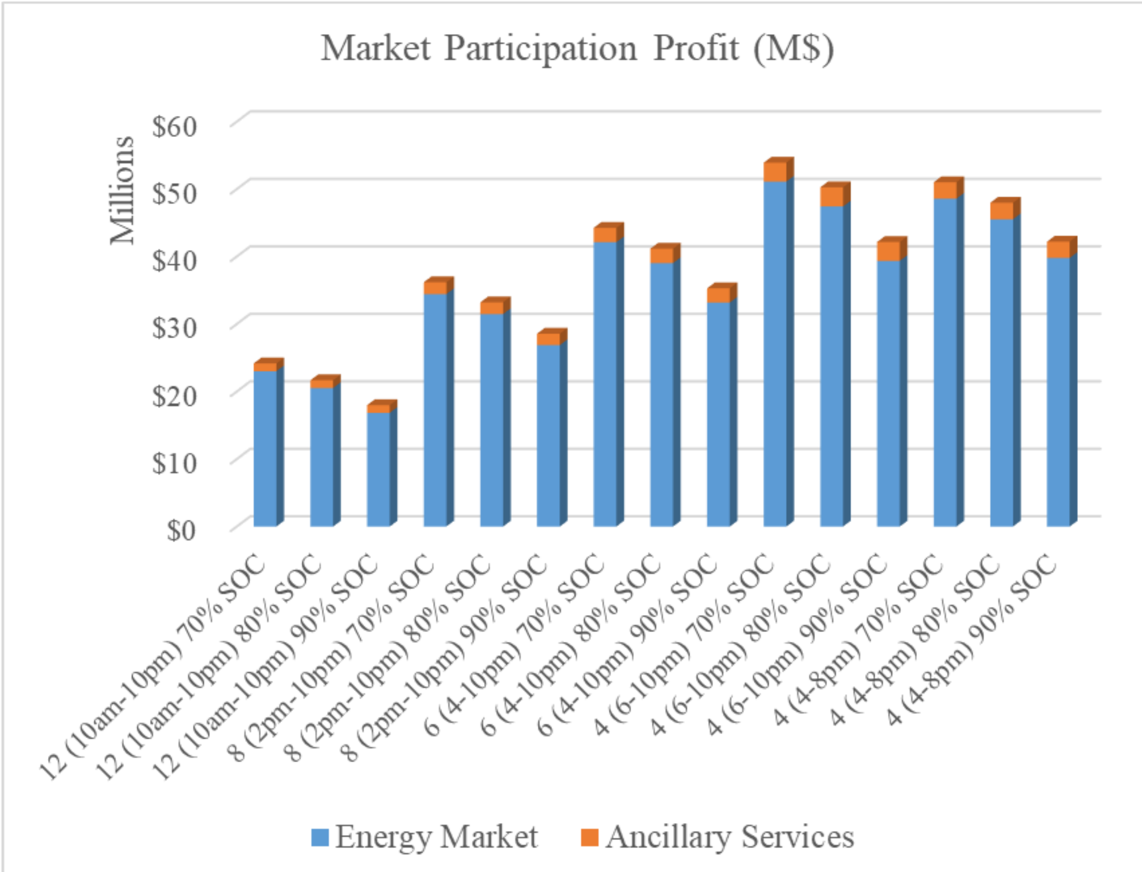


**Figure 4-3 Breakdown of revenue from energy market and ancillary service participation for various TSPs and SOC requirements: Groups of cases with shorter TSP (e.g. 4-hour (6-10pm) and 4-hour (4-8)) have higher profits. Within each group, cases with higher SOC (e.g. 90%) have less profits.**

Figure 4-4 shows the total weekly profit from market participation for each scenario for all 52 weeks. We can see that market revenue varies from week to week as the electricity prices vary. Similar to the annual market revenue trend, weekly market revenue increased with the hours of market participation and decreased as the minimum SOC requirement increased.

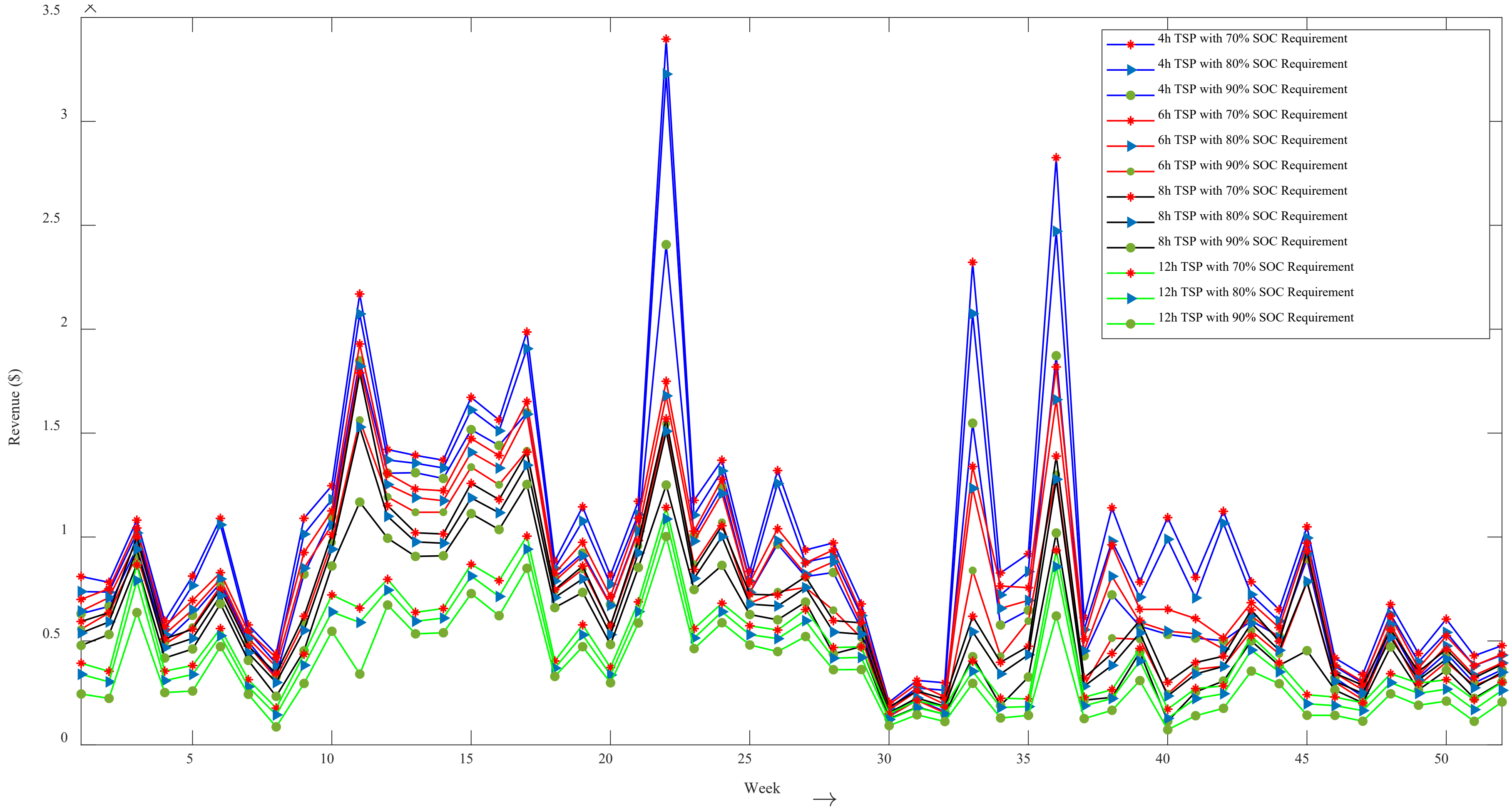


**Figure 4-4 Weekly breakdown of revenue from market participation**

**Table 4-10 Revenue from energy market and ancillary service participation**

| Scenario | Hours of the TSP | Minimum SOC at end of the MPP | Total Profit | Energy Market | Ancillary Service |
|---|---|---|---|---|---|
| 1 | 12 (10am-10pm) | 70% | $24,171,697 | $23,011,740 | $1,159,956 |
| 2 | 12(10am-10pm) | 80% | $21,678,218 | $20,532,436 | $1,145,781 |
| 3 | 12 (10am-10pm) | 90% | $17,986,621 | $16,853,749 | $1,132,872 |
| 4 | 8 (2pm to 10 pm) | 70% | $36,191,928 | $34,447,664 | $1,744,264 |
| 5 | 8 (2pm to 10 pm) | 80% | $33,232,872 | $31,481,361 | $1,751,510 |
| 6 | 8 (2pm to 10 pm) | 90% | $28,578,030 | $26,873,555 | $1,704,475 |
| 7 | 6 (4pm to 10 pm) | 70% | $44,266,802 | $42,130,297 | $2,136,504 |
| 8 | 6 (4pm to 10 pm) | 80% | $41,176,323 | $39,039,529 | $2,136,793 |
| 9 | 6 (4pm to 10 pm) | 90% | $35,304,815 | $33,204,213 | $2,100,602 |
| 10 | 4 (6pm to 10 pm) | 70% | $53,931,265 | $51,113,634 | $2,817,630 |
| 11 | 4 (6pm to 10 pm) | 80% | $50,261,203 | $47,428,359 | $2,832,844 |
| 12 | 4 (6pm to 10 pm) | 90% | $42,161,089 | $39,351,702 | $2,809,386 |
| 13 | 4 (4pm to 8 pm) | 70% | $51,016,017 | $48,575,113 | $2,440,904 |
| 14 | 4 (4pm to 8 pm) | 80% | $47,979,775 | $45,531,449 | $2,448,326 |
| 15 | 4 (4pm to 8 pm) | 90% | $42,228,964 | $39,812,619 | $2,416,345 |

Figure 4-5 and Table 4-11 show the total annual revenue from AS and the itemized breakdown from various AS. The PSH operator makes revenue by providing spinning, regulation-up, and regulation-down services from generating and pumping. We can see that the PSH operator makes a significant part of AS revenue by providing spinning reserve even though the mean price of spinning services is lower than regulation services. This is due to the greater demand for spinning services in this market setting. From Figure 4-5, we can see that total annual revenue from market participation increased with the increased duration of the MPP, as expected. A longer MPP allows the PSH operator more opportunities to provide various AS and earn profit. Unlike revenue from energy arbitrage, which is sensitive to the minimum SOC requirement, revenue from the AS market does not change significantly with the minimum SOC requirement. This is expected since the AS provision only requires that capacity is reserved, without a need for an actual generation. Additionally, restricting TSP to 6-10 pm would generate more market revenue than the period of 4-8 pm, even though they have the same length (4 hours). The period of 4-8 pm is more profitable for the market participation compared to the 6-10 pm period as 4-8 pm is a high demand period. If the PSH is restricted to transmission service during the peak demand period of 4-8 pm, it will miss the opportunity to generate as much AS revenue as it participates to the market instead. However, this period overlaps more with grid peak hours when transmission services are more likely to be required.

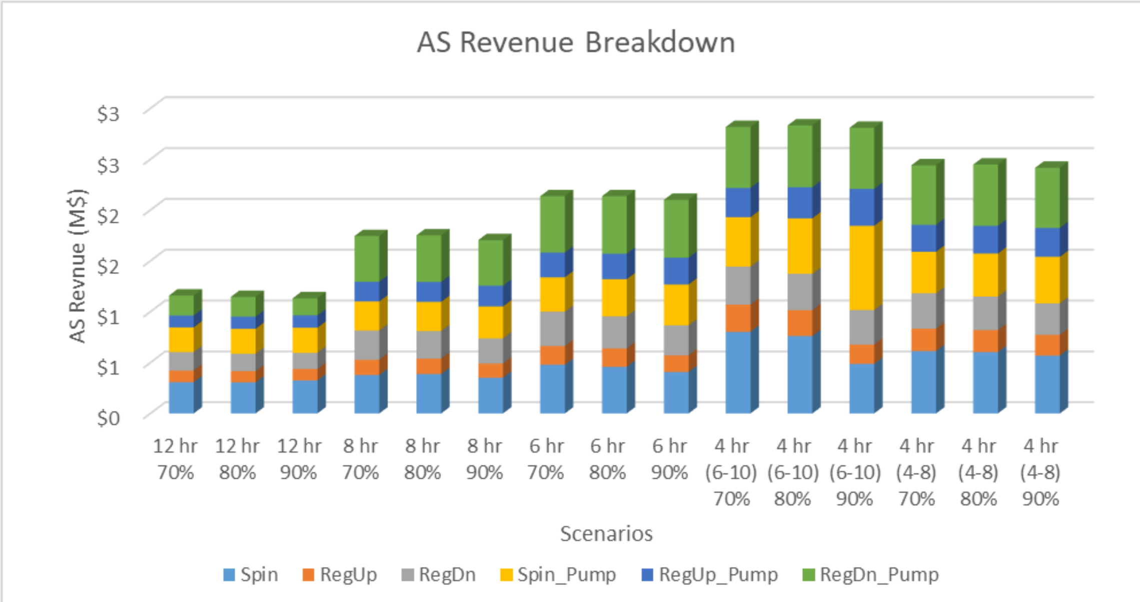


**Figure 4-5 Breakdown of revenue from various ancillary services**

**Table4-11 Revenue from various ancillary services for different market participation restrictions**

| Case | Ancillary Service | Spin | RegUp | RegDn | Spin Pump | RegUp Pump | RegDn Pump |
|---|---|---|---|---|---|---|---|
| 12 hr 70% | $1,159,956 | $308,025 | $113,045 | $183,025 | $242,351 | $116,934 | $196,574 |
| 12 hr 80% | $1,145,781 | $305,379 | $110,067 | $171,754 | $245,675 | $119,150 | $193,754 |
| 12 hr 90% | $1,132,872 | $324,503 | $112,825 | $158,125 | $247,595 | $121,276 | $168,546 |
| 8 hr 70% | $1,744,264 | $378,436 | $149,565 | $286,969 | $286,465 | $193,321 | $449,506 |
| 8 hr 80% | $1,751,510 | $387,703 | $151,731 | $270,617 | $287,384 | $195,802 | $458,270 |
| 8 hr 90% | $1,704,475 | $351,663 | $138,893 | $247,665 | $313,648 | $204,725 | $447,877 |
| 6 hr 70% | $2,136,504 | $479,251 | $184,168 | $337,678 | $337,447 | $244,030 | $553,928 |
| 6 hr 80% | $2,136,793 | $458,904 | $180,405 | $315,597 | $365,698 | $251,394 | $564,792 |
| 6 hr 90% | $2,100,602 | $407,389 | $163,401 | $295,716 | $402,180 | $263,506 | $568,407 |
| 4 hr(6-10) 70% | $2,817,630 | $802,791 | $267,585 | $374,525 | $485,037 | $287,818 | $599,871 |
| 4 hr(6-10) 80% | $2,832,844 | $761,687 | $254,226 | $357,669 | $545,384 | $304,903 | $608,973 |
| 4 hr(6-10) 90% | $2,809,386 | $487,372 | $189,747 | $340,130 | $827,519 | $363,677 | $600,939 |
| 4 hr (4-8) 70% | $2,440,904 | $613,063 | $220,437 | $348,238 | $407,896 | $265,830 | $585,438 |
| 4 hr (4-8) 80% | $2,448,326 | $603,293 | $216,063 | $329,858 | $423,911 | $271,669 | $603,531 |
| 4 hr (4-8) 90% | $2,416,345 | $568,686 | $203,949 | $309,855 | $457,199 | $284,377 | $592,275 |

In addition, we analyzed the daily operation of the PSH plant under different scenarios. We present a one-day operation of the PSH plant for May 24, 2020, when market prices were high and dynamic. We looked at the: 1) water level in the upper reservoir, 2) day-ahead and real-time market prices for energy and various AS, and 3) day-ahead and real-time generation and pumping activities. Figures A-1 to A-5, show the daily operation of the PSH plant on May 24, 2020 for a 12-hour TSP, 8-hour TSP, 6-hour TSP, 4-hour TSP starting at 6 pm, and 4-hour TSP starting at 4 pm, respectively. In each figure, the plot on the left corresponds to a 70% minimum SOC requirement scenario, the center plot corresponds to an 80% minimum SOC requirement scenario, and the right plot corresponds to a 90% minimum SOC requirement scenario.

The top subplot in each figure shows the water level in the upper reservoir. It must be noted that the water level at hour 0 (midnight) is not the same for all scenarios. Since PMAT optimizes weekly PSH operation and May 24, 2020 was not the first day of the week, the initial water level was impacted by the price of electricity on the previous day as well as the hours of the TSP and the minimum SOC requirements. Therefore, water levels at the beginning (e.g., hour 0) are lower for 70% minimum SOC requirement scenarios compared to 90% minimum SOC requirement scenarios. During the market participation period (e.g., hour 0 to 14 in Figure 4-6), the PSH scenarios with 70% and 80% minimum SOC requirements had more active charging and discharging activity than the scenario with a 90% minimum SOC requirement. This is because the PSH plant has more operational flexibility when the SOC requirements at the end of the MPP are lower. We can also see that the water level in the upper reservoir is always greater than the minimum SOC requirement during the TSP, and it does not change during the TSP because the PSH operator is not buying or selling energy (e.g., hour 14-22 in Figure 4-6). Additionally, the PSH plant maintains a 10% emergency headroom at all times for emergencies.

Day-ahead and real-time prices for energy market and ancillary services (spinning, regulation-up, and regulation-down) for node 2533 on May 24, 2020 are shown by dashed (day-ahead) and solid (real-time) lines in Figure 4-7. It must be noted that because PMAT uses a price-taker approach, operation of the PSH plant has no impact on electricity prices. Therefore, market prices are the same for every scenario across all figures. Although average day-ahead market prices are higher than real-time prices according to Table 4-8, there are specific situations where real-time prices are significantly higher than day-ahead prices, which can be seen in Figure 4-7. Moreover, we can see that market prices are significantly high around 7 pm, but due to TSP restrictions, the PSH operator cannot buy or sell electricity during this period.

Please refer to the Appendix section for more detailed daily operation results of the PSH in various sensitivity settings.

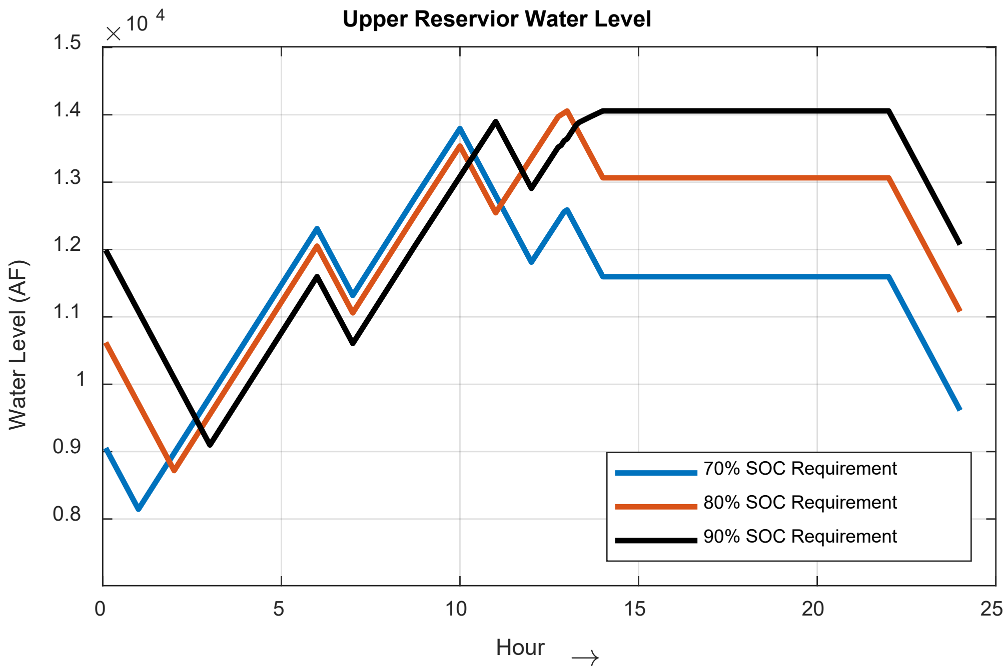


**Figure 4-6 Upper Reservoir Water level for different SOC Requirement for an 8-hour (2 pm to 10 pm) TSP on May 24, 2020**

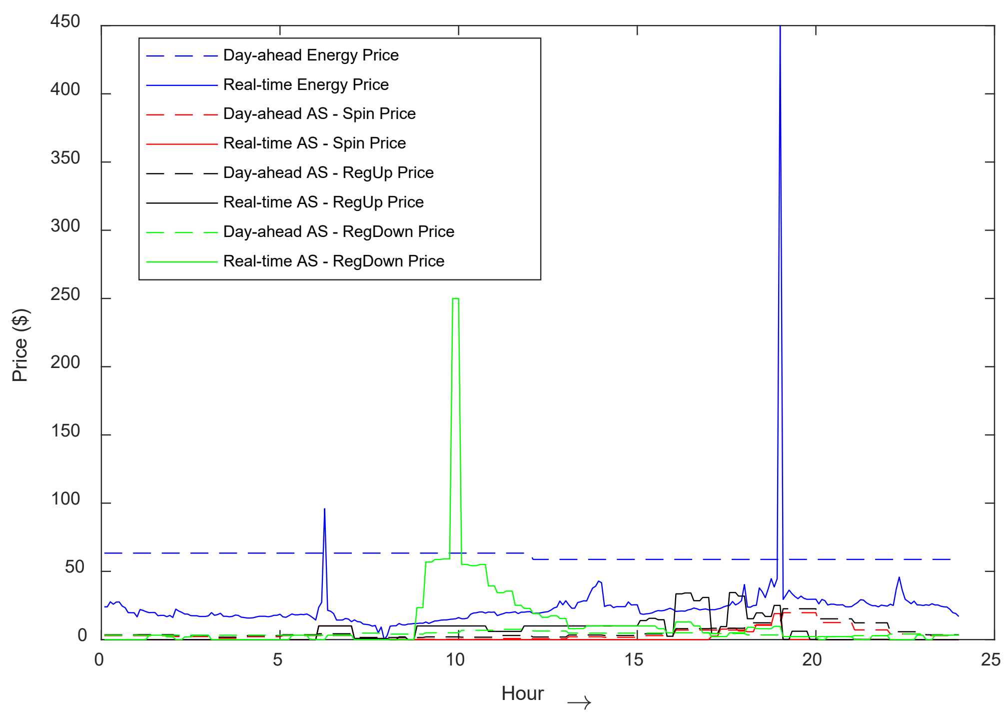


**Figure 4-7 Day-ahead and real-time price of energy and ancillary services for May 24, 2020**

### 4.3.1 PSH revenue and cost recovery

Once the PSH plant is operational, the PSH operator receives $\beta\%$ shares of the total annual market revenue and $\alpha\%$ shares of the annualized full investment cost from the TPA. Therefore, we calculated the net present value (NPV) of these future earnings. In this work, we assumed that the PSH plant will be operational for 50 years with market revenues increasing by 2% each year. We took 2020 as the base year, and the prices from the previous simulation were used as input for the market performance analysis. Based on a discount rate value, NPV can be calculated as:

$$NPV = \sum_{t=0}^{T} \frac{R_t}{(1+i)^t}$$
$$= \sum_{t=0}^{T} \frac{(\alpha \times \text{ Guaranteed Cost Recovery})_t + (\beta \times |\text{Total Market Revenue}|^+)_t - (\text{Mortgage})_t}{(1+i)^t}$$

Here, $R_t$ is the cash flow for year $t$, $i$ is the discount rate, and $T$ is the number of years of operation. The PSH operator was assumed to take a loan for the amount of the investment cost for 50 years. The value of the annual mortgage depends on the investment cost and interest rate. Here, the value of $R_t$ depends on the value of $\alpha$ and $\beta$. It must be noted that annualized cost recovery from the TPA remains constant, whereas revenue from market shares increase incrementally year after year due to inflation and other factors. In this case study, we assumed that the PSH operator took a 50-year loan for the \$1,123 million cost of building the PSH plant. Assuming an interest rate of 5%, the annual loan payment would be \$61,514,273.95. Given that these payments are spread across 50 years, we calculated the NPV of the investment cost, assuming a discount rate of 3%, to be \$1,582,747,752.

### 4.3.2 Transmission planning authority's cost

When a PSH plant is solely a transmission asset, the TPA is responsible for full investment cost recovery; however, in the dual-use participation model, the TPA could be responsible for only part of the investment cost recovery. Additionally, the TPA may receive a share of revenue from the PSH plant's market participation. As a result, the TPA may save a significant amount of ratepayer's money in the dual-use participation model.

In this case study, we use the case of an "8-hour TSP with an 80% minimum SOC requirement at the beginning of the TSP" as a representative example to describe how to estimate the cost and revenue for the TPA and PSH operators. It must be noted that such calculations can be performed for any scenario. From Table 4-10, we can see that the total annual revenue of the PSH plant from market participation in 2020 was \$33,232,872. We assumed that annual revenue from market participation increased at a rate of 2% annually. When the PSH plant is only used as a transmission asset (i.e., $\alpha = 1$, and $\beta = 0$), the TPA is responsible for the entire investment cost and therefore pays \$61,514,274 each year as a guaranteed cost recovery mechanism, as shown by the blue horizontal line in Figure 4-8. When $\alpha = 0.5$ and $\beta = 0.5$, the PSH operator receives only half of the full annualized investment cost and keeps half of the market revenue. Figure 4-8 shows annualized revenue for the PSH operator for all 50 years under different cost recovery mechanism scenarios. It must be noted that the guaranteed cost recovery remains the

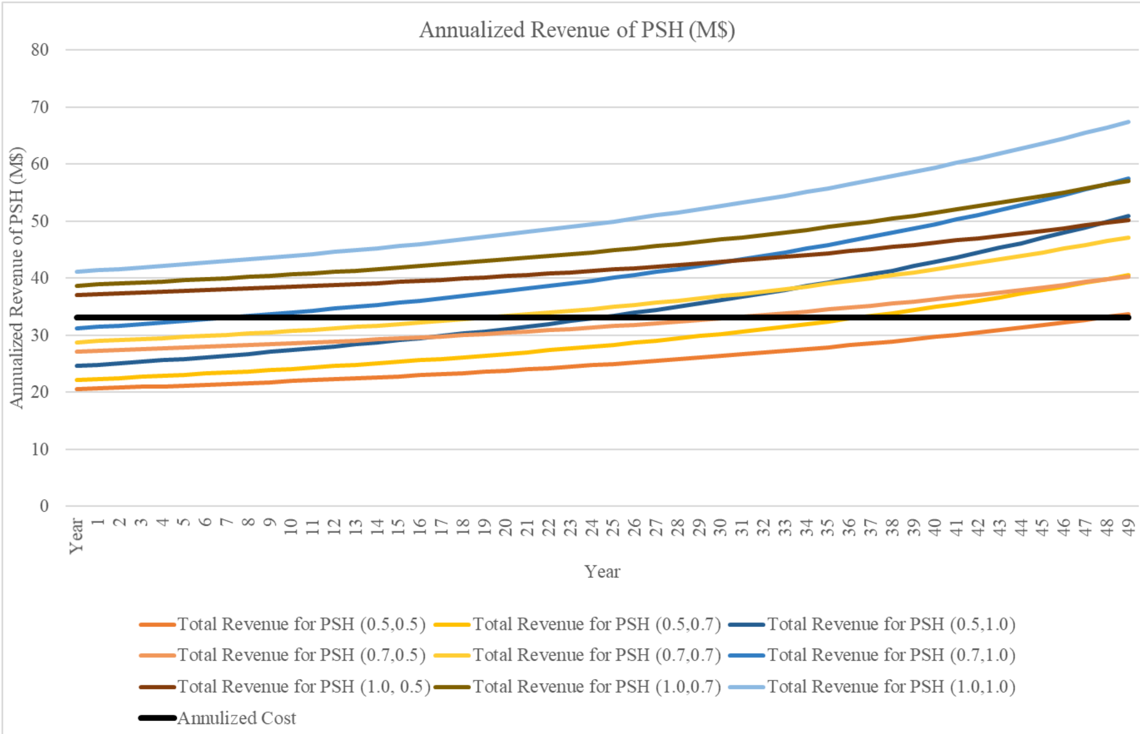


**Figure 4-8 Annualized revenue of PSH under various cost recovery mechanisms for 8-hour TSP and 80% minimum SOC requirement scenario under various settings of ($\alpha$, $\beta$) on cost recovery fraction ($\alpha$) and market revenue kept fraction ($\beta$) (Assuming 3% discount rate, 5% loan rate, 2% annual market revenue increase, and 50 years project life)**

same for each year; however, the PSH operator's share of market revenue increases 2% annually. From the results, we can see that when the PSH operator receives full investment cost recovery, they make a profit each year, as annualized revenue is higher than the mortgage amount. When $\alpha < 1.0$, it may take a few years before the PSH operator's revenue to be greater than the mortgage amount depending upon the value of $\beta$ and total market revenue. We can see that for $\alpha = 0.7$ and $\beta = 1.0$, revenue of the PSH operator increases more than the mortgage after year 6. Similarly, for $\alpha = 0.5$ and $\beta = 0.5$, it take 48 years for the revenue of the PSH operator to increase more than the mortgage amount. On the other side, for $\alpha = 1$, the PSH operator makes more revenue than the mortgage amount irrespective of $\beta$, as all mortgage cost is covered by guaranteed cost recovery.

We can calculate the NPV of future earnings for the PSH operator based on the PSH operator's total annual revenue from market participation and the share of annualized investment cost recovered from the TPA. First, the total annual revenue for the PSH operator for all 50 years is estimated. Second, the total NPV of all future earnings is calculated. Figure 4-9 shows the NPV of lifetime revenues from the PSH plant, considering a 3% discount rate under various cost-share mechanisms. The brown horizontal line in Figure 4-9 shows the NPV of lifetime annual loan payments. From Figure 4-9, we can see that when guaranteed cost recovery is higher than 60% of the investment cost ($\alpha \geq 0.6$), the PSH operator will make a net profit over the lifetime of the project, considering an 8-hour TSP with an 80% minimum SOC requirement at the beginning of the TSP. The NPV of all future earnings increases as the PSH operator receives more for guaranteed cost recovery and a greater share of market revenue. The PSH operator observes net profit on their investment only if the NPV of future revenue is higher than this threshold (brown horizontal line).

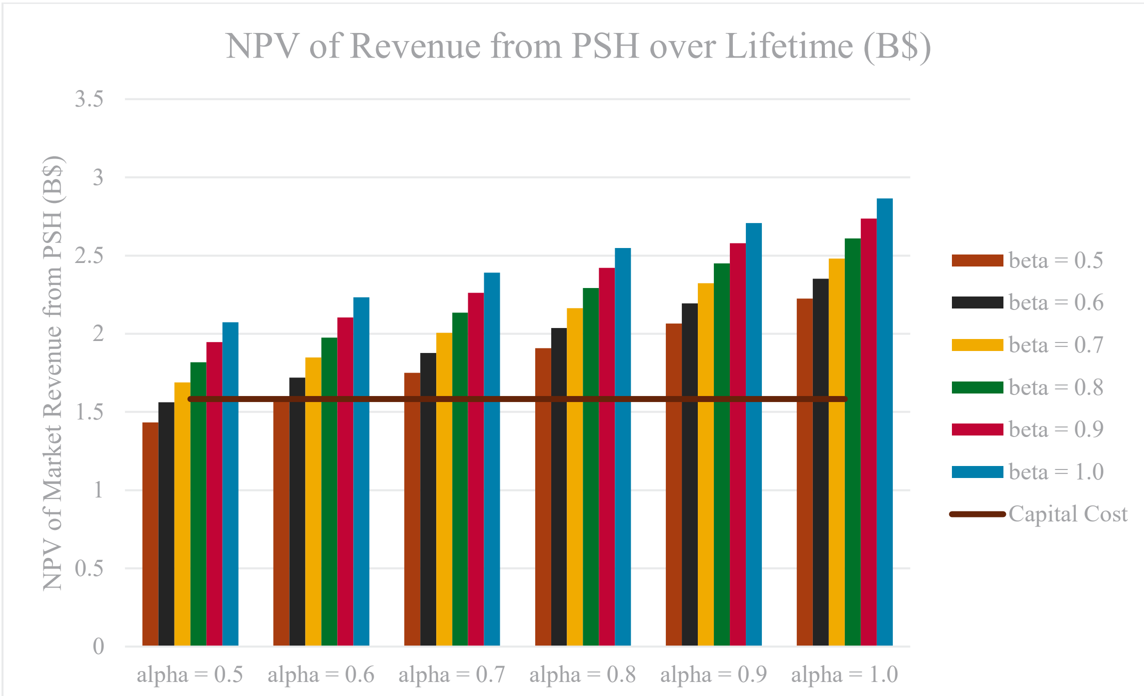


**Figure 4-9 NPV of lifetime revenue from the PSH plant under various cost recovery mechanisms for an 8-hour transmission service period and an 80% minimum SOC requirement under various settings on cost recovery fraction ($\alpha$) and market revenue kept fraction ($\beta$) (Assuming 3% discount rate, 5% loan rate, 2% annual market revenue increase, and 50 years project life)**

In the dual-use model, the TPA pays part ($\alpha$) of the full annualized investment cost recovery and receives a share $(1 - \beta)$ of total market revenue. When $\alpha = 1$ and $\beta = 1$, the TPA pays the full annualized investment cost recovery and receives no revenue from market participation, which is shown by the light blue horizontal line at the top of Figure 4-10. The annual cost for the TPA under various cost-share mechanisms, considering an 8-hour TSP and an 80% minimum SOC requirement, is shown in Figure 4-10. Based on these annual costs, we can calculate the NPV of future costs for the TPA. The brown dashed line and blue vertical bar on the right side of Figure 4-11 show the NPV of future costs for the TPA considering full annualized investment cost recovery and no market revenue ($\alpha = 1, \beta = 1$). The NPV of the lifetime cost of the PSH plant for the TPA under various cost-share mechanisms is shown in Figure 4-11. The NPV of future cost is lower than the brown line for all cost-share mechanisms. Therefore, under all scenarios, the TPA can save a significant amount of money by allowing dual-use participation of the PSH plant compared to when the PSH plant is only a transmission asset and the TPA is responsible for the entire building cost. In this report, we demonstrated costs and revenues for the TPA and the PSH operator for an 8-hour TSP with an 80% minimum SOC requirement. We did similar calculations for other dual-use parameters.

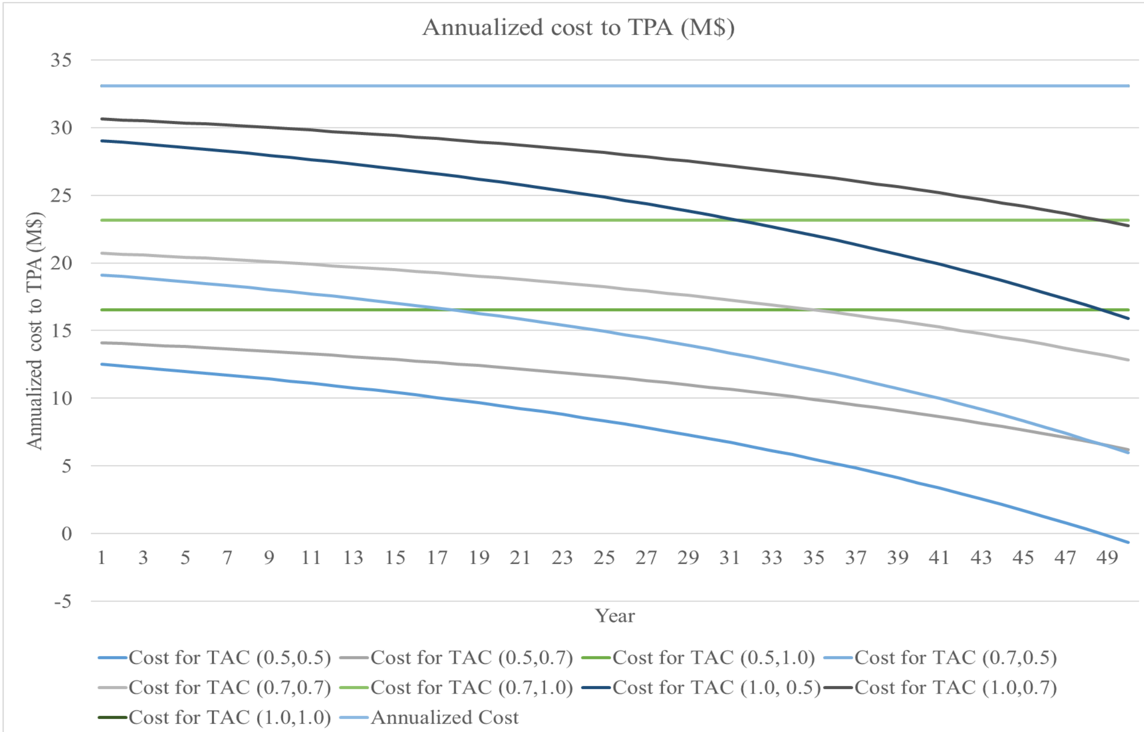


**Figure 4-10 Annualized cost to the TPA under various cost recovery mechanisms $(\alpha, \beta)$ for an 8-hour TSP and an 80% minimum SOC requirement: When $\alpha = 1$ and $\beta = 1$, the TPA pays the full annualized investment cost recovery and receives no revenue from market participation, which is shown by the light blue horizontal line at the top; Any recovery mechanism would save cost to the TPA, depending on the setting of $(\alpha, \beta)$.**

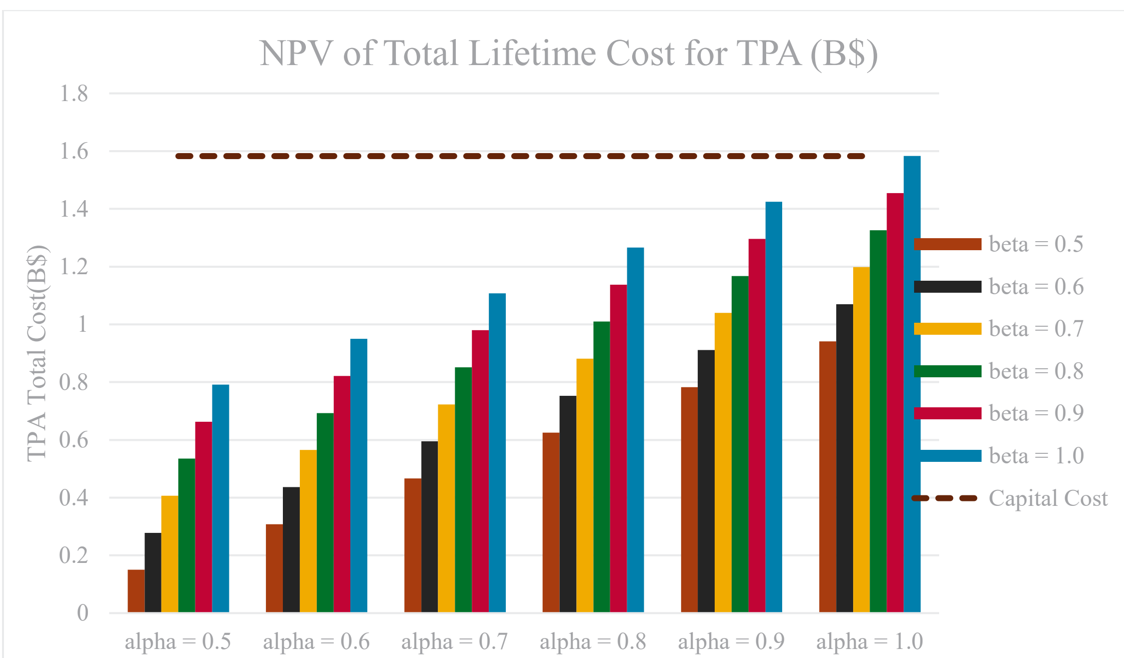


**Figure 4-11 NPV of total lifetime cost for the TPA under various cost recovery mechanisms for 8-hour transmission service period and 80% minimum SOC requirement**

## 4.4 Case study summary

From the case study results, we can see that allowing dual-use participation of the PSH plant can provide significant financial benefits for the PSH operator as well as the TPA. In the proposed dual-use model, total market revenue is subject to the minimum SOC requirement at the beginning of the TSP, the duration of the MPP, and the time of the TSP. We observed that a PSH operator can earn significant revenue from market participation, even when the PSH plant is reserved for transmission services during peak load hours where the price of electricity is usually high. This revenue can be further increased by increasing the duration of the MPP, which gives the PSH operator more opportunities to provide market services. In addition, reducing the minimum SOC requirement at the beginning of the TSP could also increase revenue by allowing the PSH operator a higher degree of freedom during market participation hours. It must be noted that increased revenue might come at the cost of reliability, as reducing the duration of the TSP might result in the unavailability of PSH resources for transmission service during a time of need. However, this issue can be alleviated to a certain extent by carefully and dynamically planning the TSP and SOC requirements of a PSH plant to find the right tradeoff between efficient utilization of resources and grid reliability.

In a dual-use market participation scenario, market revenue is shared between the PSH operator and the TPA. Providing a share of market revenue to the TPA incentivizes the TPA to allow market participation. A higher share of market revenue also provides an incentive for the PSH operator to efficiently participate in the electricity market during market participation hours. From the NPV calculations in the case study, we can see that the PSH operator makes a 50% return on their investment and the TPA saves 37.5% on the investment cost for our representative test case presented in this section ($\alpha = 0.8$ and $\beta = 0.8$). This shows that efficient utilization of the PSH plant can provide financial benefits. However, the impact of a dual-use scenario on the PSH plant's ability to ensure transmission system reliability as a transmission asset needs to be further investigated.

# 5.0 Conclusions

The report presents a computational framework that can assist PSH project operators in proposing an optimal transmission solution for participation in a TPP and market participation in operations subject to transmission service obligation. The report also documents a case study to inform the applications of the computational framework to address a pre-defined transmission upgrade need and offsets part of its investment cost with potential revenue from market participation outside of the transmission services obligation period. Some key findings that emerged from the review and case study based on the WECC 240-bus test system and CAISO market data are summarized as follows.:

- The revenues from market participation can significantly offset the annualized investment cost of a PSH project, ranging from 29.2% to 87.7%. The percentage depends on many factors, including the capital cost, capacity, location of the PSH project, and price dynamics of the electricity market at the node where the PSH project accesses the market.

- The restrictions applied to the PSH project on market participation (e.g., duration and starting time of market participation, SOC requirement at the end of this duration, etc.) have a substantial impact on its market revenue. The sensitivity study (as shown in cases 10-12 and cases 13-15) shows that higher market profits may come from longer duration of market participation or a lower SOC requirement. The profitability can be further improved if the allowed market participation period overlaps with a daily peak demand period.

- A PSH project may have its cost fully recovered or even positive annual total revenue at some point during its lifetime depending on its cost recovery mechanism, which determines the percentage of the cost that is recovered by a system operator and the percentage of market revenue that is kept by a PSH owner. Therefore, even if the investment cost of a PSH-based solution is greater than a traditional line solution, it can be partially offset with revenue from market participation if market participation is allowed.

- Market performance highly depends on how a PSH project's participation in an electricity market is restricted. Specifically, a PSH operator needs information in advance on when the PSH plant needs to standby as a transmission asset, when and how long it can participate in a market, and the SOC requirement when it starts its TSP.

While the project developed a technical pathway to implement energy storage as a transmission asset in planning and market participation in operations subject to transmission services obligation. There are still some limitations in the concept and gaps in implementation. Here are a couple of suggestions on future extensions.

Firstly, PSH plants with capacity larger than transmission upgrade needs require further investigation. Oftentimes, a location that is identified to have PSH capability has a relatively large potential capacity. It would be a waste of resources to build the PSH plant at a smaller capacity to solve just the transmission upgrade need. However, if the PSH plant is built according to its full potential capacity, then it is overcapacity from a transmission upgrade perspective and the associated operation and cost recovery, especially under the dual-use context, could be complicated.

Secondly, it is critical to estimate market participation restriction requirements for a PSH plant for its dual-use operation accurately based on transmission system reliability conditions (e.g., line flow conditions). The case study showed that a PSH project's market performance depends on restrictions from its transmission services obligation (e.g., duration and starting point of the TSP, SOC at the starting point). These restrictions should be adapted based on transmission system reliability conditions in operation. If the transmission system is under more stress, the transmission system operator is more likely to request transmission services from the PSH project. In this event, the system operator should apply more restrictions on the PSH project's market participation so that the PSH plant is ready for any potential transmission system reliability issues. In contrast, the PSH plant may have greater flexibility regarding market participation when the transmission system is less stressed. Therefore, with market participation restriction requirements information in advance (e.g., before a day-ahead market is closed) from the system operator, the PSH plant can first ensure its responsibility on transmission system reliability, and then efficiently utilize its market participation under adaptive restrictions.

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# Appendix A:

Figures A-1 through A-5 show and compare the daily operation of the PSH for various transmission service period and the minimum SOC requirement at beginning of the transmission service period (TSP) for May 24, 2020. From Figures A-1 through A-5 it can be seen the PSH plant participates in the energy market as well as provide various ancillary services like spinning reserve, regulation up, and regulation down outside of the TSP. Duration of the TSP, the PSH plant does not buy or sell electricity and does not provide any market ancillary service as it stands by to satisfy any upcoming transmission service requirements. This can be seen by the unchanging water level in the upper reservoir during the TSP as seen by the top plots in all Figures A-1 through A-5. Additionally, the duration of the TSP and minimum SOC requirement at the beginning of the TSP have an impact on the PSH operation outside the TSP. The PSH plant optimizing its charging and generation schedules to meet its SOC requirements at the beginning of the TSP. Therefore, the TSP with shorter TSP and lower SOC requirements at the beginning of the TSP have more degrees of freedom while participating in market services and therefore opportunity to make more money from market participation.

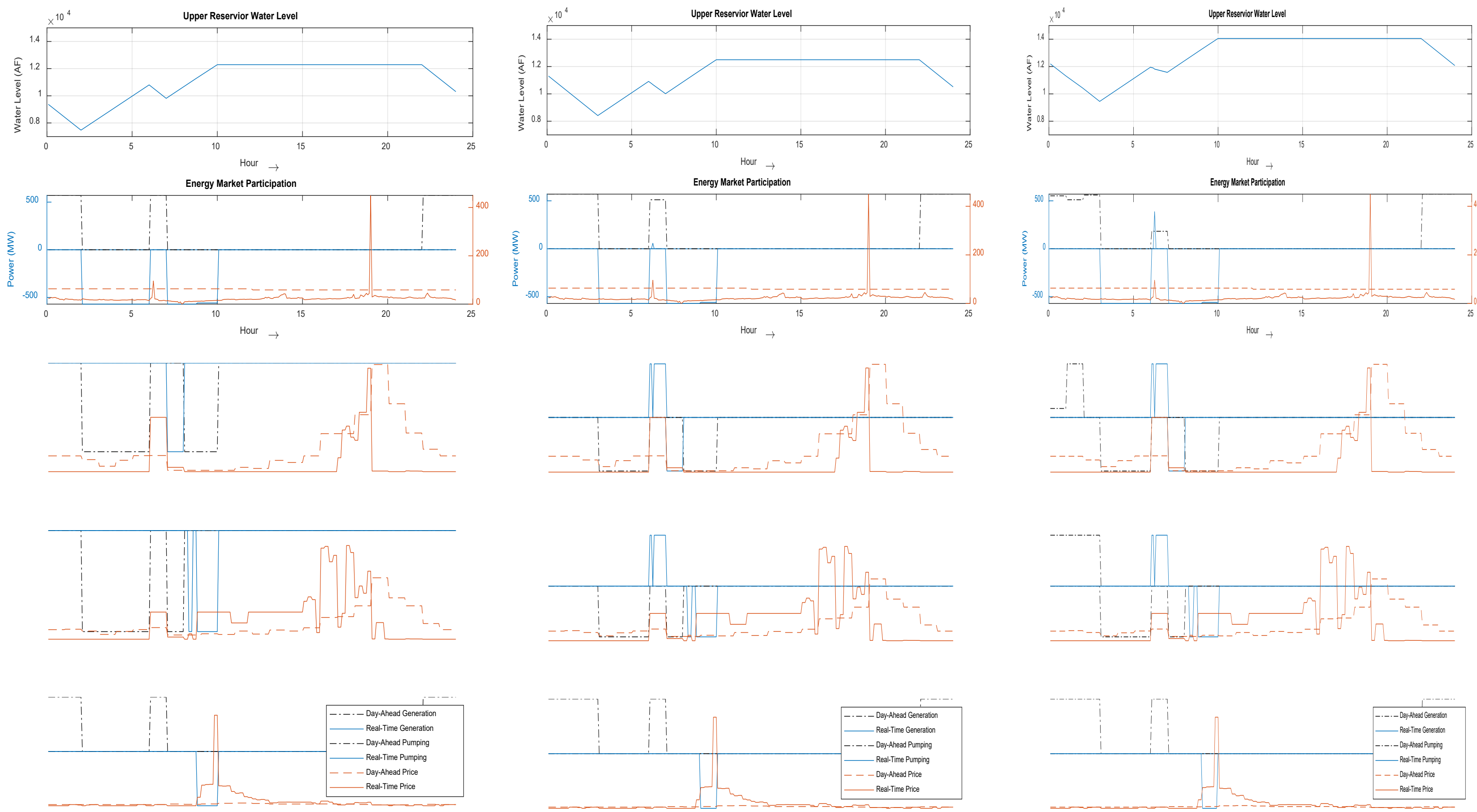


**Figure A-1 Daily operation for a 12-hour (10 am to 10 pm) TSP on May 24, 2020 with SOC requirements of 70% (left), 80% (center), and 90% (right)**

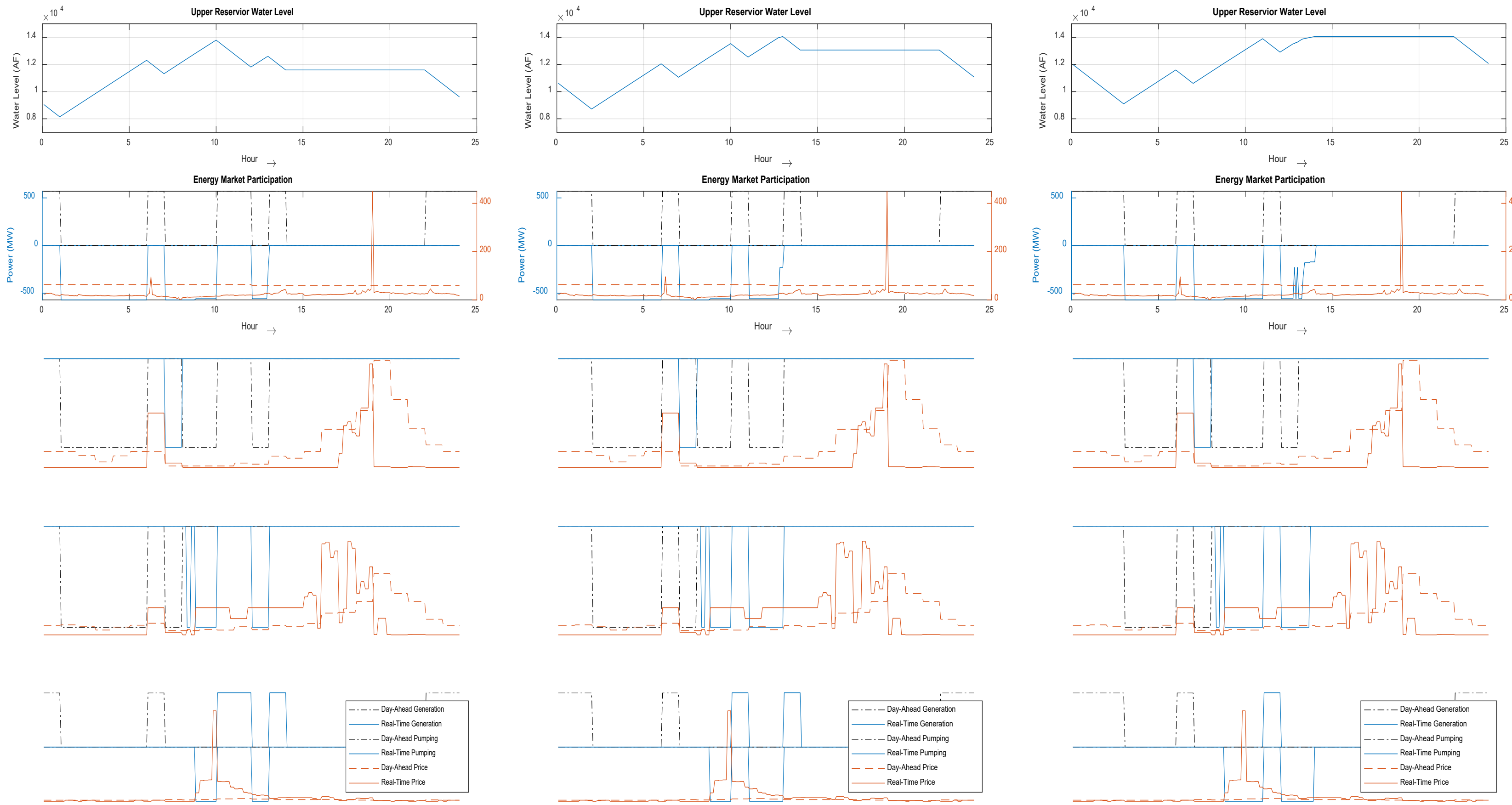


**Figure A-2 Daily operation for an 8-hour (2 pm to 10 pm) TSP on May 24, 2020 with SOC requirements of 70% (left), 80% (center), and 90% (right)**

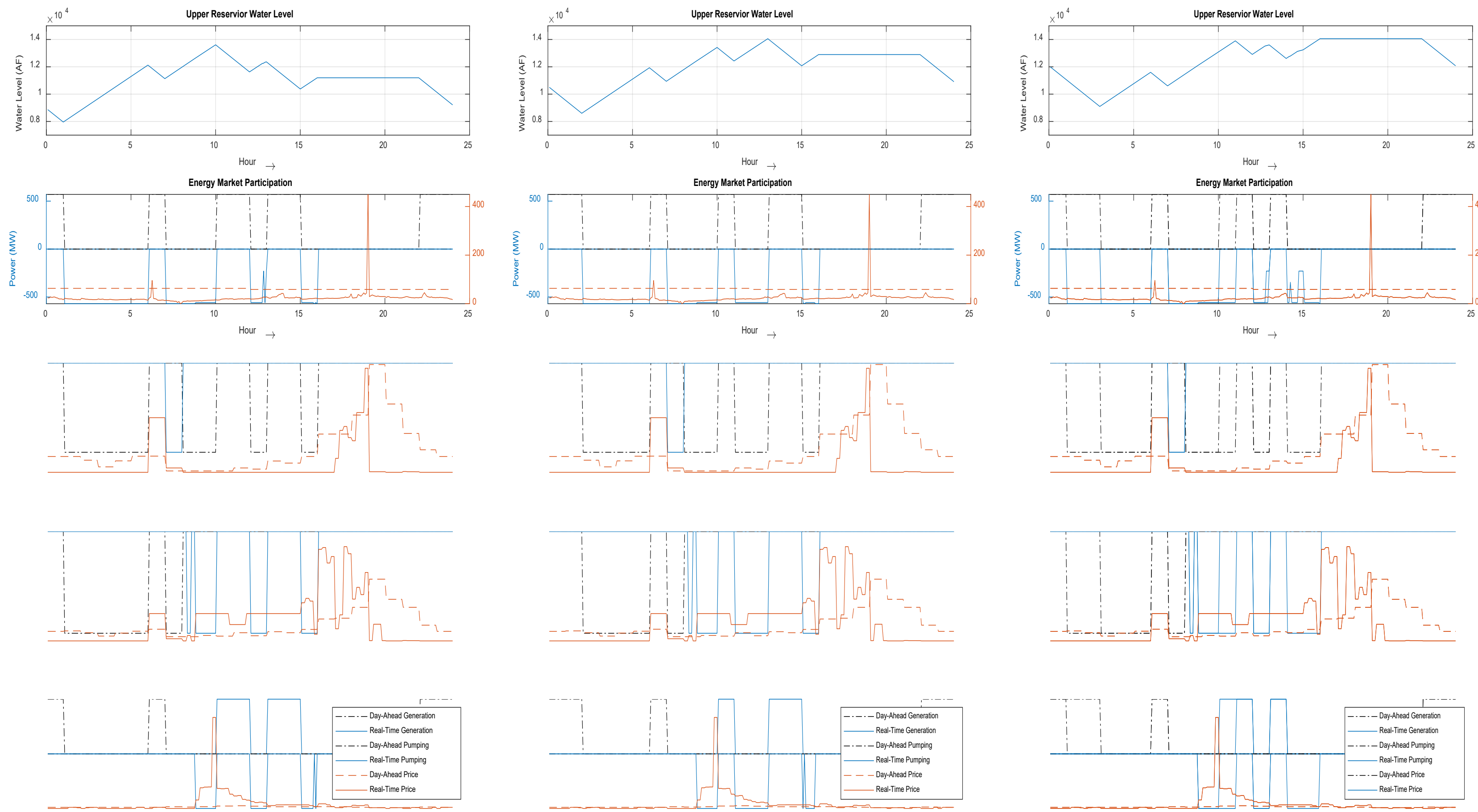


**Figure A-3 Daily operation for a 6-hour (4 pm to 10 pm) TSP on May 24, 2020 with SOC requirements of 70% (left), 80% (center), and 90% (right)**

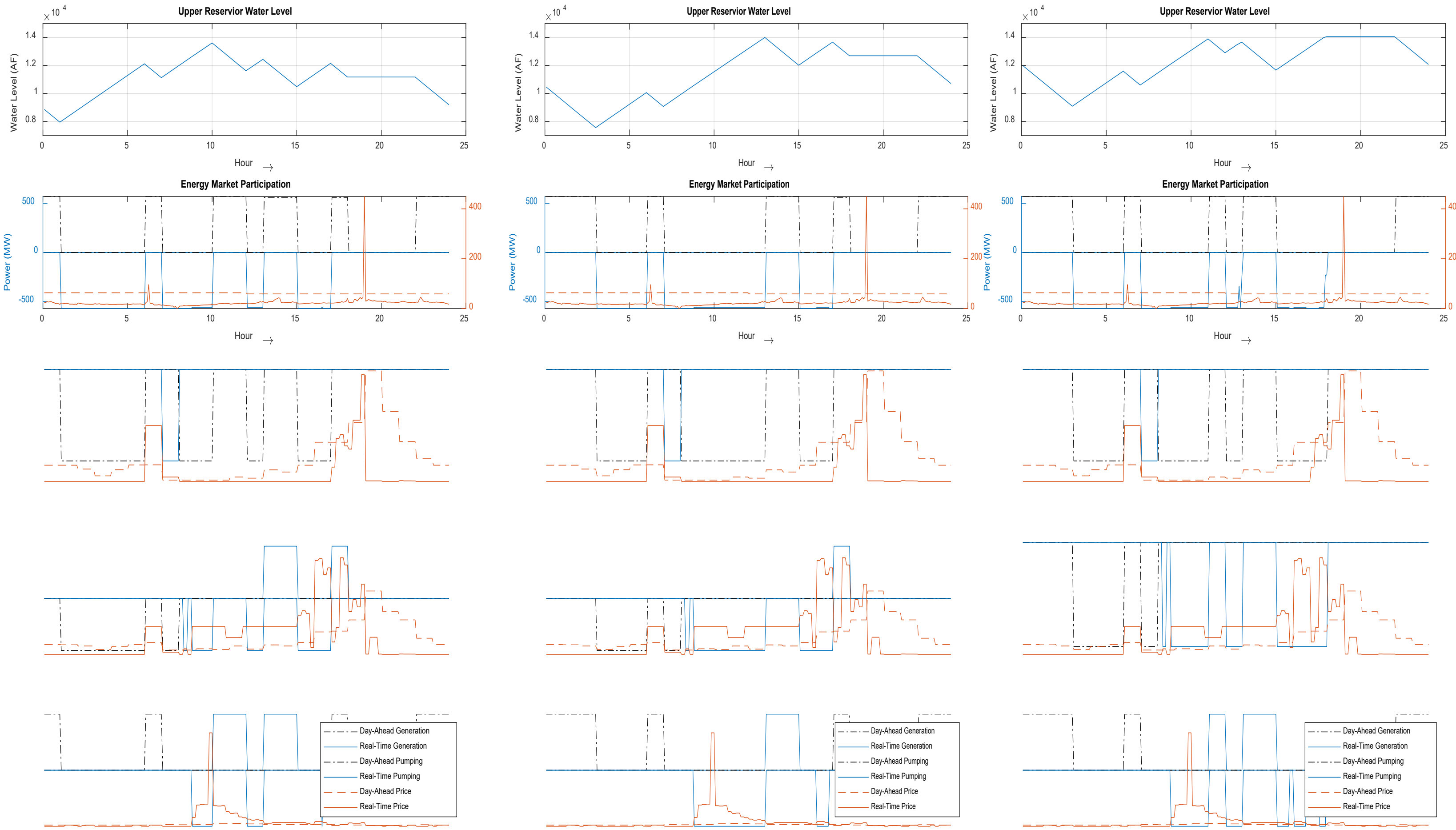


**Figure A-4 Daily operation for a 4-hour (6 pm to 10 pm) TSP on May 24, 2020 with SOC requirements of 70% (left), 80% (center), and 90% (right)**

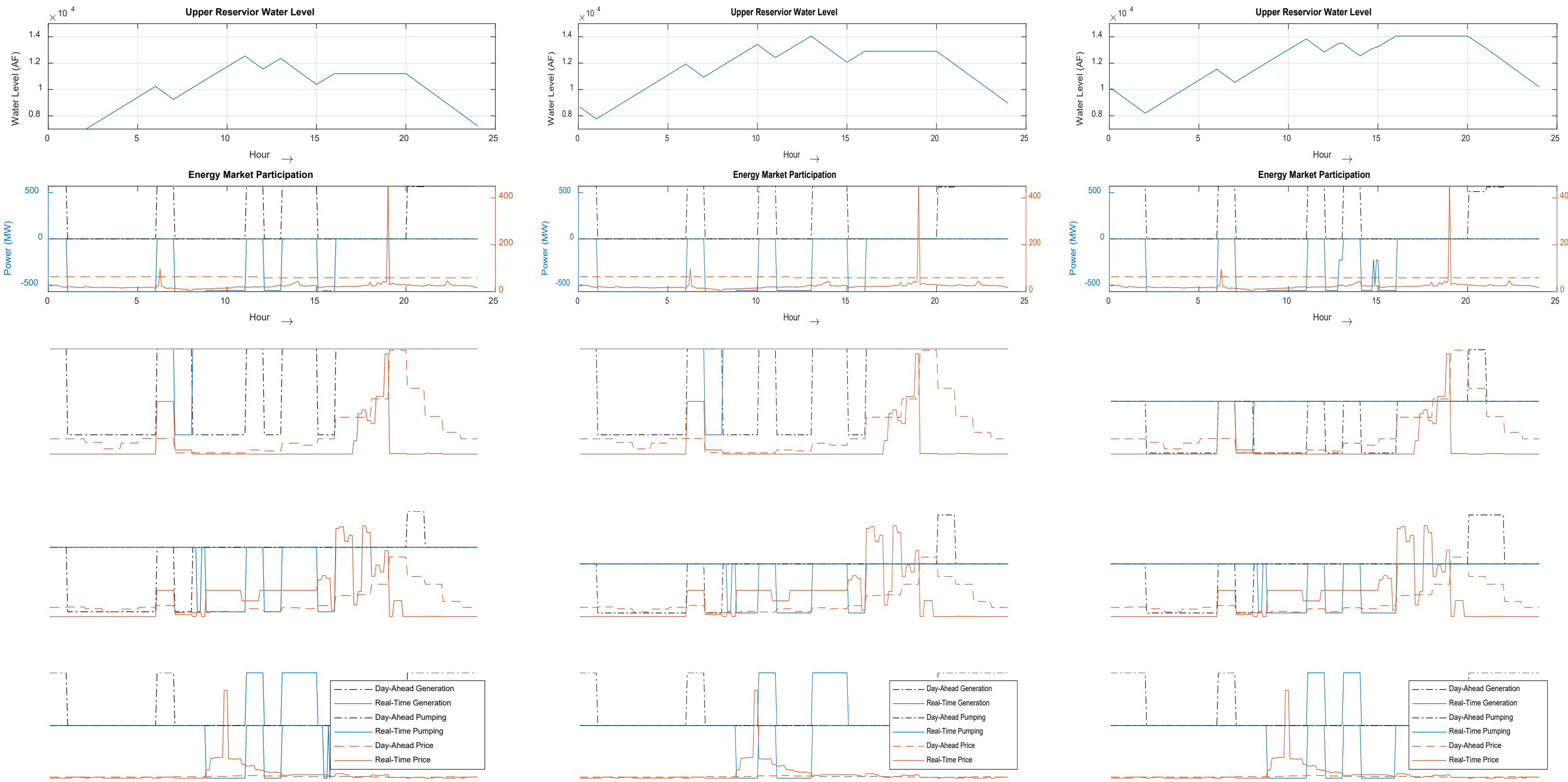


**Figure A-5 Daily operation for a 4-hour (4 pm to 8 pm) TSP on May 24, 2020 with SOC requirements of 70% (left), 80% (center), and 90% (right)**

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