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Quantifying the Operational Benefits of Conventional and Advanced Pumped Storage Hydro on Reliability and Efficiency

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Abstract—**Pumped storage hydro (PSH) plants have significant potential in providing reliability and efficiency benefits in future electric power systems. New PSH technologies, like adjustable-speed PSH, have also been introduced and can present further benefits. An understanding of these benefits on systems with high penetrations of variable generation (VG) is a primary focus. This paper will demonstrate and quantify some of the reliability and efficiency benefits afforded by pumped storage hydro plants utilizing the Flexible Energy Scheduling Tool for Integrating Variable generation (FESTIV), an integrated power system operations tool which evaluates both reliability and production costs. A description about the FESTIV tool and how it simulates PSH operations at multiple timescales will be given. Impacts of PSH on area control error, production costs, and system operation are quantified on a high VG scenario in the Balancing Area of Northern California. We also perform a study on how advanced PSH can provide a fast form of regulation to improve reliability and potentially reduce costs.**

Index Terms—**area control error (ACE), automatic generation control (AGC), electricity markets, pumped storage hydro (PSH), variable generation (VG)**

I. Introduction

The benefits of energy storage systems are desirable and well documented. They can help reduce production costs by providing power during expensive peak periods, while purchasing the power and storing it during cheap off-peak periods. They can provide numerous types of active power control support including contingency reserve, primary frequency control, automatic generation control, and load following. It can also provide benefits for reducing capacity needs, congestion management, and voltage and reactive power support. The response time, synchronization time, and ability to provide energy as both a generator and a load give energy storage unique qualities for both improving reliability and reducing production costs. Currently, the most common form of utility-scale energy storage is pumped storage hydro (PSH).

PSH first began gaining popularity in the 1970s in response to a sharp rise in natural gas and oil prices. In the USA, the Power Plant and Industrial Fuel Use Act was enacted which would limit the amount of oil and natural gas that can be consumed via new power plants [1]. The construction of new PSH plants was justified by comparing the net cost of a PSH plant and an equivalently sized fossil fuel plant [1-3]. This method disregarded the operational benefits that PSH can provide and failed to provide a level comparison. The financial justification of PSH was based on the potential for energy arbitrage. As a result, the allure of PSH has slowly diminished over the years due to falling oil and gas prices and improved thermal generator operating characteristics. However, by incentivizing and recognizing the other benefits afforded by PSH, namely their ability to aid in system reliability, there is potential for PSH to again return to the forefront of emerging grid technologies.

There has been some research performed in an attempt to better model PSH plants. The authors of [4] developed a mixed integer linear programming (MIP) model of PSH that considers the operating characteristics of PSH such as ramp transition constraints and pumped-storage operating mode constraints. They also introduce a method to model the head effect through approximations to capture the relationship between power, volume of the water, and the flow of the water. The authors of [5] developed an aggregate hydro plant, mixed-integer model that considers minimum on and off times, unit availability constraints, start-up constraints, change of water flow limit constraints, water flow constraints, reservoir balance constraints, reservoir volume limits, and reservoir spill constraints.

Conventional PSH units typically utilized synchronous machines to generate electricity. As a result, the generators' speed is fixed at the corresponding synchronous frequency. Adjustable-speed PSH can utilize a doubly-fed induction machine (DFIM) rather than the synchronous generator. As a result, the speed of the generator can be varied and a power

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electronics converter can be used to control the output power [6].

There has been considerable research performed in an attempt to demonstrate the value of PSH in facilitating the penetration of variable generation such as wind and solar. The authors of [7] indicate that new PSH plants could significantly improve grid reliability while reducing the need for new thermal generation in areas with high levels of wind and solar generators. The authors of [8] devise a co-optimized coordination of wind power and PSH. They develop a stochastic MIP-based solution method that minimizes expected operating costs and corrective action costs. Wind forecast uncertainties and component outages are treated as stochastic variables. The authors of [9] investigated the use of PSH in small, islanded systems with high wind penetration. Their study showed that PSH is particularly valuable in such scenarios due to their ability to provide primary frequency control. The authors of [10] develop an operating strategy of a hybrid wind-hydro system with the goal of ensuring wind generation output for 24 hours. The operational strategy is determined via a 24-hour stochastic, operational profit maximization optimization problem incorporating the operational constraints of the wind-hydro system. The authors conclude that by co-optimizing wind and PSH, operational profits can be increased anywhere from 12% to 22% depending on the deviation penalty level.

Today's electricity markets may not be designed in a way that would allow market regions to obtain all the benefits that energy storage owners can provide. Potential ways that ISOs and RTOs could extract more of the benefits and avoid limitations are described in [11]. For example, some entities argued in the past that in some wholesale electricity markets, some market participants may have faced undue discrimination in the way that frequency regulation was procured. The Federal Energy Regulatory Commission (FERC) acknowledged that previous compensation methods for frequency regulation did not recognize the performance benefit of faster-ramping and more accurate resources. In order to correct this, FERC Order 755 requires all system and transmission operators to pay resources based on their actual performance, including a capacity payment that covers opportunity costs and a performance payment that reflects the generator's ability to follow the control signal [12]. Traditionally, resources were sent a smoothed, low frequency control signal for frequency control, but now it may be beneficial to allow certain generators that have the ability to follow the unfiltered or high-frequency control signal.

Power systems will become more susceptible to variability and uncertainty as the amount of VG installed increases. Variability can be seen as the expected changes in system variables while uncertainty is the unexpected changes in system variables [13]. Variability and uncertainty occurs at multiple timescales and it is important to understand these characteristics vary at different timescales. As more and more VG is installed, net load forecasting can become less accurate and system ramping events can become more prevalent. As a result, systems must adapt and become more flexible in order to maintain reliability at least cost. Due to their fast ramping and response time, PSH can be a useful tool in mitigating these problems.

The rest of this paper is organized as follows: section II introduces the model used, section III describes the test system and assumptions used, section IV describes the results of the simulations, and section V concludes the paper.

II. FESTIV

This study utilizes the Flexible Energy Scheduling Tool for Integration of Variable generation (FESTIV) developed by the National Renewable Energy Laboratory [14]. This model mimics the behavior of system operations at multiple timescales including the day-ahead security-constrained unit commitment (DASCUC), real-time security-constrained unit commitment (RTSCUC) and economic dispatch (RTSCED), and automatic generation control (AGC).

The main feature of this model is its ability to simulate the system at multiple time scales by interconnecting the different forms of operational scheduling. This feature allows for the investigation of the variability and uncertainty of variable generation at fine time scales. It provides both cost and reliability information about the system. First, the day-ahead security constrained unit commitment is solved and the day-ahead market is cleared. When the real time operations begin, the system periodically solves the real time security constrained unit commitment and the real time security constrained economic dispatch and clears the real time market accordingly. Upon completing the economic dispatch, the model employs a rule based automatic generation control algorithm that corrects the system area control error (ACE).

The security constrained unit commitment problems are solved using mixed integer programming while the economic dispatch problem is formulated as a linear programming problem. The optimizations include typical operational constraints such as generator start-up times, minimum run times, minimum down times, generator ramp rates, minimum and maximum generation levels, as well as transmission line loading constraints. The model also schedules different types of reserves, and deploys them at the appropriate time including contingency spin reserves, regulation reserves, and flex reserves. The timing parameters of all the different models are configurable. The model is built in MATLAB and leverages the General Algebraic Modeling System (GAMS) using the CPLEX mixed integer optimization solver [15-16].

The outputs of each model are fed as inputs to the subsequent models while maintaining a consistent time reference. The end result is a harmonized, operational simulation of the power system across multiple temporal resolutions that accounts for both system costs as well as system reliability. The model produces the total system production costs as well as several reliability performance metrics including CPS2 violations, the standard deviation of ACE as well as the Absolute ACE in Energy (AACEE) which is the accumulated area control error over time provided in megawatt-hours. A more detailed discussion of the model can be found in [17].

In this study, a number of enhancements were made to the FESTIV model to incorporate conventional and advanced

PSH at multiple operational timescales. These enhancements included variable efficiency levels, energy limits, pumping limitations in the security constrained unit commitment (SCUC) model, the security constrained economic dispatch (SCED) model, and the AGC model, ancillary service provision while pumping, and efficient exchange of energy levels between day-ahead and real-time. These enhancements can be seen in more detail in [18].

III. Simulation

Utilizing the National Renewable Energy Laboratory's Western Wind and Solar Integration Study data set, a test system based on the Balancing Area of Northern California (BANC) was developed. This system was deemed large enough to produce meaningful results and included significant variable generation penetration so as to adequately capture the benefits PSH can provide. The test system was then simulated for two individual weeks. One week was chosen due to its being the system peak period in July. The second week was chosen as a high variable generation output period in April. A brief system overview is provided in Table I.

TABLE I – OVERVIEW OF SYSTEM DETAILS

Peak Load	4207 MW
Total Installed Capacity	6975 MW
Total Installed Wind Capacity	1738 MW
Total Installed Solar Capacity	325 MW
Total Conventional Hydro Capacity	2509 MW
Total Combined Cycle Capacity	1482 MW
Total Combustion Turbine Capacity	372 MW

The day-ahead unit commitment problem was solved every 24 hours for the next 24 hours with hourly time steps. The real time unit commitment was solved every 15 minutes for the next three hours with 15 minute time steps. The real-time economic dispatch was solved every five minutes for the next 60 minutes with five minute time steps. The automatic generation control was solved every four second interval.

In order to simulate the advanced, adjustable-speed pumped storage hydro plants, the operating characteristics shown in table II were used. The main difference of adjustable-speed and conventional PSH is that the minimum pumping output of conventional PSH is equal to its maximum pumping output of 133 MW. As a result, the adjustable-speed PSH is able to regulate its active power output while pumping while the conventional PSH cannot.

Table II – SUMMARY OF PSH OPERATING CHARACTERISTICS

Maximum Pumping Output [MW]	133
Maximum Generating Output [MW]	133
Minimum Pumping Output [MW]	79.8
Minimum Generating Output [MW]	39.9
Minimum Pumping Time [hours]	0
Minimum Generating Time [hours]	0
Time to Start Pumping [minutes]	15
Time to Start Generating [minutes]	15
Pumping Ramp Rate [MW/s]	7
Generating Ramp Rate [MW/s]	7
Pumping Efficiency	0.80472
Total Maximum Storage Capacity [MWh]	5000

The reserve schedules were determined based on the methodology employed in phase 2 of the Western Wind and Solar Integration Study. The requirements take into account the needs that wind and solar forecast uncertainty have on reserve requirements. Wind generators are assumed to have short term persistence forecasts and solar generators are assumed to use a cloudy, persistence forecast (i.e., assumes the current cloudiness will remain but the daily ramp up and down are factored in). These requirements are then added to the base requirements to obtain the total system reserve requirements. The types of reserves considered are spinning, non-spinning, regulation up, regulation down, and flexibility reserves. An in depth discussion on these reserves can be found in [13].

The spin and non-spin reserves were taken as 3% of the system load. The regulation reserves were taken as the geometric sum of 1% of load and the additional requirements due to the additional wind and solar generators. The flexibility reserves were taken as the geometric sum of the solar and wind hour-ahead forecast errors covering 70% of the distribution. More details on the methodology used to determine these reserves can be found in [19]. The flexibility reserves were held in the unit commitment problems and dispatched in the economic dispatch problem. This is because the flexibility reserves were viewed as products deployed across dispatch intervals to assist the system operator.

Three different scenarios were simulated. Scenario one is the base case scenario that does not include any pumped storage hydro plants. Scenario two includes a conventional, single-speed pumped storage hydro plant consisting of three units. Scenario three includes an advanced, adjustable-speed pumped storage hydro plant consisting of three units.

IV. Results

The costs of each scenario are shown in figure III. In order to ensure an even comparison, any inadvertent interchange or deviation from the scheduled final storage level is either purchased or sold. As a result, fair comparisons between the scenarios can be made. Notice that by adding PSH (scenarios 2 and 3) the total production cost is reduced.

TABLE III – COST RESULTS

	April	July
Scenario 1	$3.449M	$5.394M
Scenario 2	$3.169M	$5.101M
Scenario 3	$3.032M	$5.021M

A summary of the reliability results is shown table IV.

TABLE IV – SUMMARY OF RELIABILITY RESULTS

	April		
	Scenario 1	Scenario 2	Scenario 3
CPS2 Violations	49	47	45
CPS2 Score	0.951	0.953	0.955
AACEE [MWh]	2582.78	2619.72	2644.19
sigma ACE [MW]	23.80	25.10	23.00
	July		
	Scenario 1	Scenario 2	Scenario 3
CPS2 Violations	40	16	15
CPS2 Score	0.960	0.984	0.985
AACEE [MWh]	3201.00	2736.00	2593.00
sigma ACE [MW]	29.30	21.30	20.20

As is evident from tables III and IV, there are benefits to total production cost and reliability when either a conventional or adjustable-speed pumped storage hydro plant is added to the system. In April, total production costs were reduced by 8% and 12% by adding single-speed PSH and adjustable-speed PSH respectively. In July, the total production costs were reduced by approximately 5% and 7% by adding single-speed PSH and adjustable-speed PSH respectively.

In April, while the number of CPS2 violations decreased, the AACEE and the standard deviation of the ACE remained relatively unchanged. This could be due to the fact that the introduction of the PSH units could allow for more inflexible units that are cheaper to be committed. In July, there were substantial improvements in all reliability metrics. Since the system load is much higher, other flexible units were likely still needed. These reliability improvements may also be the result of the PSH being asked to regulate approximately 22% of the time while in April, they were only asked to regulate approximately 13% of the time. This could be due to the fact there are significant amounts of installed conventional hydro units in the system that are quite flexible themselves. So the PSH benefit is not as noticeable during times of low loading.

Fig. 1 shows a portion of the realized generation schedule of an advanced, adjustable-speed PSH unit. Notice that the PSH is able to regulate while in pumping mode. This is important since the single-speed PSH cannot regulate while pumping (Fig 2a, Fig 2c).

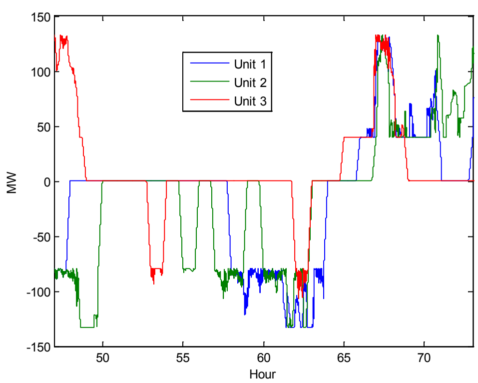

Figure 1 – Realized schedule for 3 adjustable-speed PSH units

Table V shows that amount of energy consumed and produced by the PSH plant for both the single-speed plant (scenario 2) and the adjustable-speed plant (scenario 3).

Table V – AMOUNT OF ENERGY CONSUMED AND PRODUCED BY PSH IN MWH

	April			July		
	Gen	Pump	% Gen	Gen	Pump	% Gen
Scenario 2	11,951	15,328	78.0%	17,543	21,823	80.4%
Scenario 3	11,736	16,029	73.2%	16,606	20,897	79.5%

If the final reservoir level exactly matched the initial reservoir level, the ratio of energy generating to pumping would exactly match the round-trip efficiency of the PSH, in this case 80.4%. Only the July simulation of scenario 2 reflected this. The PSH generated more in July than in April. This is most likely due to the increased load in July resulting with a higher energy cost. In general, the adjustable-speed PSH plant would pump more than it generated (i.e. the percent that it pumped as a percentage of its generation is less than its round trip efficiency). This is interesting because intuition would suggest that since the adjustable-speed PSH can change its pumping production, it would not need to pump more than it generates. However, since the adjustable-speed PSH can regulate in pumping mode, the optimization utilizes their pumping ability more often. This is evident in the fact that the adjustable-speed PSH were selected to regulate more, 48% more in April and 36% more in July.

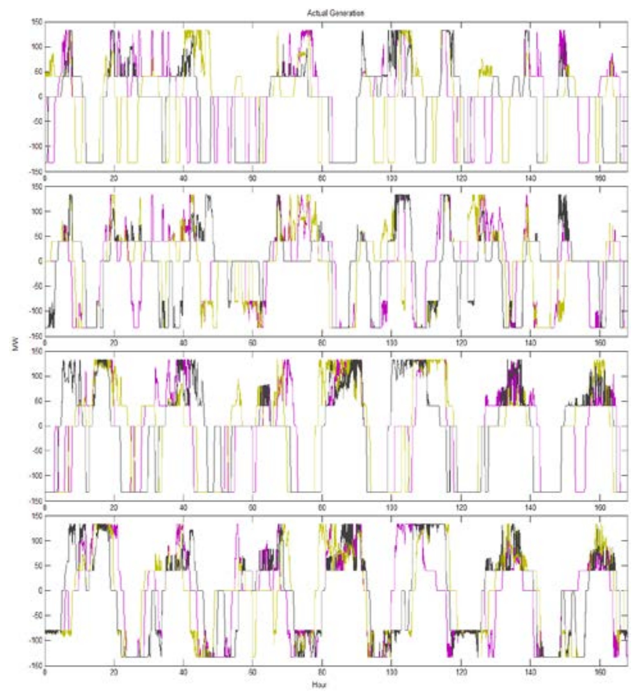

Figure 2 – Realized output of three PSH generators in (a) April scenario 2 (b) April scenario 3 (c) July scenario 2 and (d) July scenario 3

The use of PSH was also able to curb the use of expensive thermal units. For the week in April, the conventional, single-speed PSH plants were able to reduce the energy production of the thermal units by approximately 14%. The advanced, adjustable-speed PSH were able to reduce it by approximately 15%. In July, both the single-speed PSH and the adjustable-speed PSH reduced the energy production of thermal units by approximately 4%.

Similar results can be seen in a system without any variable generation (VG) as summarized in Table VI.

Table VI – APRIL SIMULATION RESULTS OF A SYSTEM WITHOUT VG

	Scenario 1	Scenario 2	Scenario 3
Total Cost	$6.226M	$5.582M	$5.616M
CPS2 Violations	3	1	0
CPS2 Score	99.7	0.999	1
AACEE [MWh]	2112	2268	2176
Sigma ACE [MW]	16.7	17.5	16.8

It is evident from Table VI that even in a system without any VG, PSH plants can still provide benefits to the system. In this case, the adjustable-speed PSH was able to reduce the total system production costs by approximately 10%. Both scenarios successfully reduced the number of CPS2 violations while the absolute ACE and the standard deviation of the ACE where slightly increased. Since there isn't any VG, the only variability and uncertainty comes from the load.

Table VII shows the reliability improvements affordable by adjustable-speed PSH tracking the raw ACE signal.

Table VII – SUMMARY OF SCENARIO 4 BENEFITS

	April		July	
	Scenario 3	Scenario 4	Scenario 3	Scenario 4
Cost	\$3.032M	\$2.941M	\$5.021M	\$4.924M
CPS2 Violations	45	44	15	14
AACEE [MWh]	2644.19	1992.00	2593.00	1233.00
sigma ACE [MW]	23.00	20.00	20.20	12.17

In terms of CPS2 violations, there is not any significant improvement by allowing the PSH to follow the raw ACE signal. However, in terms of AACEE and σ_{ACE}, there is a significant improvement. In April, the AACEE is reduced by approximately 25%, and by 48% in July. This means that in general, the magnitude of the ACE is reduced significantly throughout the study period. The standard deviation of the ACE is also reduced considerably meaning that the ACE becomes less volatile if the PSH plants are allowed to track the unfiltered ACE signal. These operational improvements could yield financial benefits to PSH owners through market rules that have been implemented to meet FERC Order 755.

Allowing the PSH plants to track the unfiltered ACE signal resulted in further reducing the total production costs. Note that these costs only reflect the production costs and do not include wear-and-tear costs or other cycling costs. By allowing the PSH to track the unfiltered ACE signal, it reduces the ACE to zero much more quickly than in scenario 3. As a result, other thermal units are not regulating as much and can be operated closer to their optimal loading point. As a result, the overall system operates more efficiently and the total production cost is reduced.

V. CONCLUSION

This paper explored these benefits of PSH and quantified the total production cost savings and reliability impacts on CPS2 violations, AACEE, and the standard deviation of the ACE. PSH plants can provide both production cost savings and reliability improvements for systems with significant VG. They provide much more than just energy arbitrage, including numerous ancillary services and, especially adjustable-speed PSH, system reliablitiy improvements. PSH was able to reduce total production costs in all scenarios when compared to the system without PSH. The adjustable-speed PSH was able to improve reliability, especially during high load periods. Both types of PSH were able to reduce the number of CPS2 violations. In a system without VG, the PSH were able to provide more production cost savings rather than reliablity improvements. Adjustable-speed PSH was able to signficantly improve reliablity metrics by following the unfiltered ACE control signal. Further research should be pursued to better model conventional and advanced PSH, and how best to extract and quantify their potential benefits.

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