Southeast Oklahoma Pump Storage Project *("The Project")*

PREPARED BY:

FINAL DRAFT

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Introduction

The Southeast Oklahoma Pump Storage Project ("Project") is proposing to design, engineer, and construct a closed loop with 1,200 MW and 1400 MW generating and pumping facility on an upper reservoir, a lower reservoir, and a regulating reservoir in Southeast Oklahoma using the Kiamichi River as the water source. The project includes high voltage transmission lines and a Substation of 40 Miles to SPP's Valliant 345kv substation and an additional 60 miles to ERCOT 's Paris TX, 345kv Substation north of Dallas, TX. The Project is approx. 100 Miles south of Tulsa, Oklahoma, and 140 miles southeast of Oklahoma City.

The goal of this report is to present the analysis conducted by ZGlobal Inc, which forecasts the Project revenue from 2030 to 2079. The analysis evaluates the Project economic by interconnecting to either ERCOT or SPP and both SPP/ERCOT regions.

In April 2023, The Federal Energy Regulatory Commission (FERC) granted a Preliminary Permit to develop a "closed loop" pumped storage hydroelectric (PSH) generating facility located entirely on private land in Pushmataha County, Oklahoma, with the proposed transmission line located entirely on private land in Pushmataha and Choctaw Counties, Oklahoma and Lamar County, Texas (FERC Project No. 14890). FERC has broad authority under the Federal Power Act which governs the construction and operation of nonfederal hydropower projects—preempts all state and local laws concerning hydroelectric licensing[1]. The FPA also includes broad condemnation authority to ensure that owners and operators of FERC-licensed hydropower projects can acquire the property and resources necessary for project development and functioning. Specifically, the FPA grants FERC licensees the ability, if necessary, to condemn "lands or property of others necessary to the construction, maintenance, or operation of any dam, reservoir, diversion structure, or the works appurtenant or accessory thereto. FERC's broad authority facilitates obtaining the Hydro license which would include environmental analysis, secure water rights, and transmission right of way all in the same permit.

The Project company and the development company are organized under these two Limited Liability Companies: Southeast Oklahoma Power Corporation ("SEOPC"), a corporation registered in the state of Nevada, and the PSH Oklahoma Development Company Inc. ("PSHDC"), a company registered in the state of Texas. The Project requested ZGlobal to perform a life cycle analysis to figure out the Project revenue in each and both ERCOT and SPP regional markets.

ZGlobal used public information along with proprietary modeling to perform the analysis presented and summarized in this report. The location of the Project is in the vicinity of SPP (south) and ERCOT (north) regions, which provide much optionality. After several feasibility analyses, and discussions with local utilities and regional ISO's, we concluded that it is workable to assume that the Project could connect to ERCOT only, SPP only; and both regions. The approach used in the analysis is to:

(a) We calculate the project revenues by performing a *backcast analysis* under each of three interconnection scenarios e.g., interconnection to ERCOT only, SPP only, and both ERCOT and SPP regions (Scenarios 1,2 and 3) from 2019 to 2022. This calculation is aimed at estimating the Project revenues if the project was operating from 2019 to 2022.

[1] See First Iowa Hydro-Electric Cooperative v. Federal Power Comm., 328 U.S. 152 (1946) (holding that a state cannot undermine the FPA and prevent a hydropower project from operating by denying the grant of a state permit to the operator).

(b) The second part of the analysis is to *forecast* the Project revenues and compute the unlevered return under three interconnection scenarios, e.g., interconnection to ERCOT only, SPP only, and both ERCOT and SPP regions (Scenarios 4, 5, and 6) while adhering to certain interconnection rules in Appendix A (Project Configuration Under Multiple Regional Markets) and Appendix D. Under each of the three interconnection forecast Scenarios, we analyzed three cases for each Scenario, for a total of 9 cases. Each case represents a set of fundamental assumptions of the main market fundamentals, such as natural gas price, demand growth, renewables penetration, retirement, and new generation among other future fundamental input assumptions for SPP & ERCOT region as shown in Section 14 and Appendix E. Therefore, each scenario was analyzed under three cases to quantify the Project economics for the study period from 20230 to 2079 (50 years).

(c) Several *sensitivity analyses* were conducted to help determine how changes in one input variable affect the output (i.e., Project NPV & IRR). This analysis is useful since it allows us to weigh the project benefits and risks under different conditions. We selected case 1 under Scenario 4,5 and 6 which represents the lowest project return reflecting conservative input assumptions. We increased project costs from $3.1 billion by 50%, reduced annual forecasted project revenues by 25%, and re-computed the change in NPV and IRR. The results are shown in Section 15,

(d) Selecting the lowest project return from the sensitivities in Section 15, we further conducted a *Value at Risk analysis* to better understand the distribution of the Project Net Present Value of profit, the NPV probability distribution, and the probability at which the NPV is zero or negative. The results are summarized in Section 16.

The forecast analysis for each of the three interconnection Scenarios are based on these three cases.

Case 1 (Low Case): Case 1 is characterized by adverse market fundamentals that lead to lower project economics due to low natural gas prices and electricity demand growth, renewable and conventional generation additions, and coal retirement. Specific examples of the conservative assumptions are demand growth of 0.5% (for each region) vs. the 2.6% ERCOT annual average last 10 years demand growth and the assumed average natural gas prices at 2.75 $/MMBTU which is 70% lower than the average natural gas prices from 1984 to 2022.

Case 2 (Medium Case): Case 2 is characterized by assumptions that have the greatest likelihood of occurring. We set natural gas prices at the historical average price of 4.62 $/MMBTU from 1984 to 2022, lower than *average demand growth* (1.5% annual peak demand growth for both regions), *expected* renewable and conventional generation additions, and coal retirements.

Case 3 (High Case): Case 3 is characterized by 30% higher than the historical average for natural gas prices, *about average demand growth* (2% annual peak demand growth for both regions), expected renewables and generation additions, and coal retirement.

Executive Summary

In all cases, the Project is profitable with Project economics and highly correlated with natural gas prices, demand, and renewables penetration. As natural gas prices increase more Project energy and ancillary services clear the market. Added intermittent resources lead to greater volatility of energy and ancillary services prices, thus creating greater profitability for the Project. Combined and individually, each creates added opportunities for the Project to capture market share and produce higher revenue given the Project's flexibility and quick response.

Furthermore, accelerated development and penetration of intermittent resources and the continued retirement of base demand resources in the SPP and ERCOT regions result in the dire need for more dispatchable resources. Both regions have also increased their resource adequacy (reserve capacity) or Planning Reserve Margin (PRM). For instance, and as discussed in this report, SPP reserve shortages are forecasted to dip below the required 15% to 9.7% margin by 2028 (Figure 1).

Under the ERCOT interconnection, the Project would reach the ERCOT market serving a peak demand of 85,000 MW. An SPP interconnection, the Project would reach the SPP market serving approximately 60,000 MW, as well as MISO and the Western Markets. Interconnecting the Project to both regions will enable the Project to reach at least SPP and ERCOT markets with over 165,000 MW of peak demand.

ERCOT's ancillary service market continues to go through fundamental changes as ancillary service requirements have nearly doubled since the Winter Ice Storm Uri. In July 2021, ERCOT changed the procurement and increased the ancillary services procurement such that a minimum of 6,000 MW of upward Ancillary Services (Regulation Up + Spin + Non-Spin) is kept for all hours on all days (increasing to 7,000 MW when forecast variability is high). On June 14, 2023, the ERCOT commission mandated a multi-step minimum Operating Reserve Demand Curve (ORDC) ancillary service requirement of 6,500 MW per hour and another floor at 7,000 MW. These increases in ancillary services requirements are extremely attractive to a fast ramping, dispatchable, long-duration storage such as this project.

In our analysis, we conducted a ***backcast*** analysis using historical hourly market clearing prices for energy and ancillary services from 2019 to 2022[2] and estimated resource adequacy revenue. The backcast uses market clearing prices and computes an optimized output of the project subject to project hydraulic and assumptions in Appendix A and D. The results of the backcast are shown in Appendix B and C.

Table 1 shows the annual project revenues of $604 million in 2022 under Scenario 3. The backcast shows robust and consistent project revenue with the highest under Scenario 3,1 and 2, respectively.

Energy, Resource Adequacy and Ancillary services annual revenue (minus Pumping Cost) Backcasting	ERCOT (Scenario 1)	SPP (Scenario 2)	ERCOT+SPP (Scenario 3)
2019	$424,821,142	$227,575,598	$471,835,844
2022	$430,232,640	$420,792,568	$604,290,696

Table 1– Summary of project revenue from Backcast Analysis under Scenarios 1, 2, and 3

The second phase of the analysis was to ***forecast*** the Project revenue and return on investment from 2030 to 2079 for the three interconnection Scenarios (4, 5, and 6) under each case. We used the Unlevered IRR (IRR) and the Benefit-To-Cost Ratio (BCR) to present Project economics.

Table 2 summarizes the Project’s Internal Rate of Return (IRR) and Benefit Cost Ratio (BCR) analysis in all cases and scenarios. The greatest Project value is Scenario 6 (interconnecting to both ERCOT and SPP) followed by Scenario 4 (ERCOT only) followed by Scenario 5 (SPP only).

[2] Section 11 shows each year from 2019 to 2022 energy and ancillary services revenues.

Forecast Unlevered IRR	Low Case	Medium Case	High Case
Scenario 4 (ERCOT only)	20.8%	27.0%	30.6%
Scenario 5 (SPP only)	15.4%	19.0%	24.4%
Scenario 6 (ERCOT and SPP)	25.3%	30.8%	36.8%
Benefit to cost Ratio	**Low Case**	**Medium Case**	**High Case**
Scenario 4 (ERCOT only)	2.6	3.8	4.0
Scenario 5 (SPP only)	2.5	3.6	3.8
Scenario 6 (ERCOT and SPP)	2.9	4.2	4.7

Table 2– Summary of Project Forecast Returns and BCR for Scenarios 4,5, and 6

These returns and benefit-to-cost ratios shown in Table 2, are solely from the sale of Energy, Resource adequacy, and Ancillary Services and do not include black start, voltage, or other payments and are based on the assumptions in this report. Also, these projections are based on selling theses services as a merchant to the regional ISOs. The return-on-investment projection can increase if tax incentives for US-made equipment could add 10% ITC which translates to a 4 to 5% IRR increase under any scenario.

Table 3 compares the ***annual forecasted revenue*** to the ***annual backcast revenue*** for comparison purposes.

a) The forecasted annual average revenue for ERCOT of $457 million under Scenario 4 - case 1, which is closer to the 2019 and 2022 backcast annual revenue (Scenario 1).
b) The forecasted annual average revenue for SPP of $345 million under Scenario 5 - case 1, which is below the 2022 backcast annual revenue of $420 million (Scenario 2).
c) The forecasted annual average revenue for ERCOT & SPP of $550 million under Scenario 6 - case 1, which is below the 2022 backcast annual revenue of $604 million (Scenario 3).

Energy, Resource Adequacy and Ancillary services annual revenue (minus Pumping Cost) Backcasting	ERCOT (Scenario 1)	SPP (Scenario 2)	ERCOT+SPP (Scenario 3)
2019	$424,821,142	$227,575,598	$471,835,844
2022	$430,232,640	$420,792,568	$604,290,696
Energy, Resource Adequacy and Ancillary services average annual revenue (minus Pumping Cost): Forecast	**ERCOT (Scenario 4)**	**SPP (Scenario 5)**	**ERCOT+SPP (Scenario 6)**
Low (Case1)	**$457,577,764**	$345,583,814	$550,418,035
Medium (Case 2)	**$820,343,866**	$553,519,176	$944,893,829
High (Case 3)	**$772,107,808**	$602,807,456	$958,212,957

Table 3– Comparison Between Backcast and Forecast Project Revenue

Sensitivity Analysis

We performed added sensitivity analysis to calculate the Project return if Project cost and/or Project net revenue decreased.

In choosing the sensitivity case, we selected sensitivity from the most conservative case 1 to capture stress events such as an increase in the Project cost and a decrease of project revenues from case 1 under all three interconnection scenarios 4,5, and 6. It's important to point out that our projected Project cost of $3.1 billion includes all development costs, engineering, procurement and construction, land, regulatory, legal, environmental, and an additional 15% contingency.

i. Case 1a; Increase Project cost from $3.1 Billion to $3.9 Billion or 25% increase. No change in project net revenue from case 1 except the adjustment made for tax equity investment and total operating cost.
ii. Case 1b; Increase Project cost from $3.1 Billion to $3.9 Billion or 25% increase. A decrease in the annual project net revenue of 25% from case 1.
iii. Case 1c; Increase Project cost from $3.1 Billion to $4.6 Billion or 50% increase. A decrease in the annual project net revenue of 25% from case 1.
iv. Case 1d; Decrease Project cost from $3.1 Billion to $2.5 Billion or 25% decrease. A decease in the annual project net revenue of 25% from case 1.

ERCOT	Project cost $ b	Average Annual Total Net Revenue ($M)	NPV ($b)	IRR %
Case 1	$3.1	$470	$5.1	20.80%
Case 2	$3.1	$833	$9.2	27.00%
Case 3	$3.1	$784	$9.8	30.60%
Case 1a	$3.9	$446	$4.2	16.00%
Case 1b	$3.9	$332	$2.4	11.80%
Case 1c	$4.6	$311	$1.6	9.40%
Case 1d	$2.3	$380	$4.2	22.10%

SPP	Project cost $ b	Average Annual Total Net Revenue ($M)	NPV ($b)	IRR %
Case 1	$3.1	$358	$3.2	15.40%
Case 2	$3.1	$566	$5.6	19.00%
Case 3	$3.1	$615	$7.0	24.40%
Case 1a	$3.9	$334	$2.3	11.60%
Case 1b	$3.9	$248	$1.0	8.50%
Case 1c	$4.6	$227	$0.3	6.60%
Case 1d	$2.3	$295	$2.8	16.80%

ERCOT + SPP	Project cost $ b	Average Annual Total Net Revenue ($M)	NPV ($b)	IRR %
Case 1	$3.1	$563	$6.5	25.3%
Case 2	$3.1	$957	$10.8	30.8%
Case 3	$3.1	$970	$12.7	36.8%
Case 1a	$3.9	$540	$5.7	19.4%
Case 1b	$3.9	$401	$3.5	14.4%
Case 1c	$4.6	$380	$2.8	11.7%
Case 1d	$2.3	$450	$5.3	26.6%

Table 4– Summary of Sensitivity Analysis of the Forecast Analysis

Table 4 shows that with a 50% increase in Project cost increase and a 25% decrease in the annual project net revenue (under Case 1c), the Project return ranges from 9.4%, 6.6%, and 11.7% respectively for scenarios 4,5, and 6. Section 15, provides more detail.

Section 16 provides risk analysis and computing the value at risk under the most stringent sensitivity (which Table 3 shows, case 1c). We used 1,000 Monte Carlo probability analyses for each project year applied to 50 years distribution of the Net Present Value of profit, the NPV probability distribution, and the probability at which the NPV is zero or negative.

1 Business Proposition

Currently, most new generation interconnections within the ERCOT and SPP regional grids are renewable resources, which produce power on an intermittent and variable basis. As renewable resources have increased, the grid operator has needed to obtain greater quantities of ancillary services in proportion to the level of renewable penetration to cope with the ever-larger variability in power production. This increase in the need for flexible dispatchable generators that can supply fast ramping energy and ancillary service has often required ERCOT and SPP to procure additional energy and Ancillary Services to meet the challenge of renewable variability. As a result, the dispatchable generation that remains to participate in our energy market is often the less flexible and inefficient older units.

For instance, this and the ice storm event have led ERCOT to increase the ancillary services requirements by 6,815MW per hour to a maximum of 9,162 MW per hour during peak hours of the Operating Reserve Demand Curve (ORDC). On June 14, 2023, the ERCOT commission approved a multi-step minimum ORDC ancillary service requirement of 6,500 MW per hour and another floor at 7,000 MW. On January 19, 2023, the ERCOT Commission recommended the creation of a new reliability service to ensure enough dispatchable generation is available during periods of low renewable output. This new service should be based on the Performance Credit Mechanism (PCM). On June 23, 2023, the Texas legislation passed a bill (SB7) that adopted the proposed PCM with an annual cap of $1 billion. The ORDC works in tandem with the PCM. The adjustment to the ORDC bolsters reliability in the real-time energy market. Changes to ancillary service products help the day-ahead market and create more operational certainty, while the PCM shores up long-term planning and reliability as an availability market.

The impact of intermittent on energy and ancillary services pricing has already been noticed in the energy and ancillary service pricing, as shown in Tables 5 and 6 and further discussed in section 13. Both ERCOT and SPP clearly show an increase in the number of hours when energy prices exceed 50$/MWh. For instance, Table 5 shows that there were 694 Hrs in 2018 where ERCOT energy prices with at or above 50$/MWh, in 2022, the number of hours when energy prices exceeded 50$/mwh increased to 4,113 hours. Similar patterns were seen in the Ancillary Services, Table 5, shows that the number of hours where ancillary services were above 20$/MWh increased from 22% in 2018 to 34% in 2022. The increase is due to natural gas prices and increased intermittent generation.

ERCOT	2018	2019	2020	2021	2022
# of hrs Energy Prices >50 $/MWh	694	529	262	1,382	4,113
% of hrs Ancilary Services >20 $/MWh	22%	20%	13%	26%	34%
NG averages $/MMBTU	$4.94	$2.90	$2.70	$4.90	$7.50

Table 5– ERCOT Energy and Ancillary Services Trends from 2018 to 2022

A similar partner is observed for SPP, Table 6 shows that there were 273 Hrs in 2018 where SPP energy prices with at or below 50$/MWh, in 2022, the number of hours when energy prices exceeded 50$/MWh increased to 3,912 hours.

SPP	2018	2019	2020	2021	2022
# of hrs Energy Prices >50 $/MWh	273	243	81	1,589	3,912
% of hrs Ancilary Services >20 $/MWh	14.64%	13.26%	10.34%	22.71%	27.50%
NG averages $/MMBTU	4.94	2.90	2.70	4.90	7.50

Table 6– SPP Energy and Ancillary Services Trends from 2018 to 2022

Table 6, also shows the number of hours where ancillary service prices exceeded 20$/MWh, increasing from 14.65 in 2018 to 27.5% in 2022.

As Section 11, shows that the number of hours, when the energy prices fall in the lower ranges ($10 - $20 and $20 - $50), declined significantly by 20.87% and 18.52% respectively in 2022 compared to 2018, whereas the number of hours when the energy price falls in the higher ranges ($50-$100 and >$100) spiked by 29.51% and 9.53% respectively. This shows that there are more hours with higher energy prices to sell energy which will yield more revenue as the years go by.

This also shows that there are more hours with higher energy and ancillary service prices to sell energy which will yield more revenue as the years go by. The forecast shows this pattern will continue despite Li-ion Storage penetration.

In SPP, the historical energy prices are trending negatively from 254 hrs. in 2018 to 619 and 450 hrs. in 2021 and 2022. This means the project buys wholesale energy from SPP to pump the water to the upper reservoir for free and the Project gets paid the negative energy price.

The SPP BA Area Planning Reserve Margin is 20.1% for the 2023 summer season and will decrease to 9.7% by the planning year 2028. The SPP BA Area Planning Reserve Margin determined from the 2023 summer season submissions has decreased by 1.9% from the 2022 summer season where the Planning Reserve Margin was 22.0%. For the 2023 summer season, the reliance on deliverable capacity has increased by 1,283 MW compared to the 2022 summer season[3].

[3] https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf

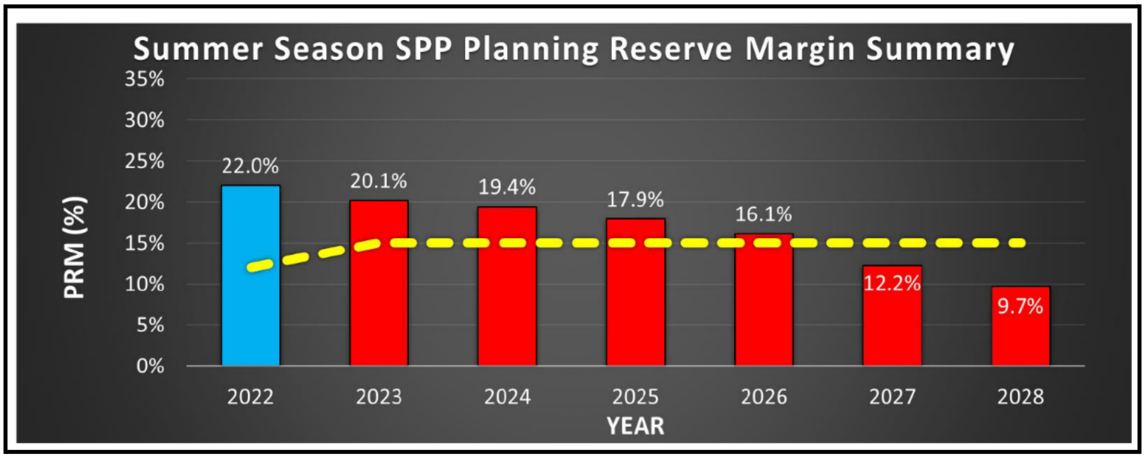

Figure 1– SPP Reserve Margin Forecast

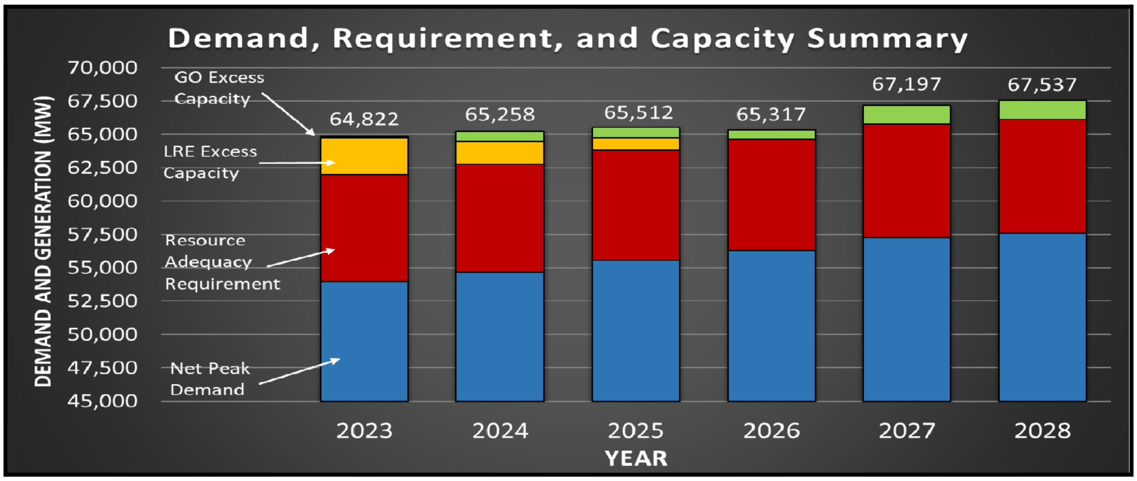

Figure 2– Demand and Generation Forecast in SPP

Based on 2023 Load Serving Entities (LSEs) data[4] , by the 2026 summer season, no excess capacity from LREs will be available. By the summer of 2027, the SPP system will not be able to meet the 15% reserve margin or PRM as the reserve dips 9.7% below the required 15% margin.

2 Recent Brief History of the Pump Storage Hydro (PSH)

Electrical energy storage is a critical area for optimal utilization of renewable sources of energy generation through existing electrical transmission and distribution infrastructure. The energy from the sun is intermittent in nature and available only during the daytime. Hence, to make its best and continuous use, an energy storage system which can store the energy when excess energy is available and then use the stored energy when it is not available. Renewable power and PHS-integrated power systems are the most economically and technically competitive technologies in different geographical areas. The combined use of intermittent resources with PHS

[4] https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf

is considered a means to exploit the abundant wind and solar potential, increase the wind installed capacity, and substitute the conventional peak supply.

The pumped-hydro storage technology has been proven for decades. It involves using excess power from the Grid to pump water to a higher elevation, where it's stored in a reservoir. When the power is needed, water flows back down, generating electricity along the way.

Pumped storage hydropower stands for the bulk of the United States' current long-duration energy storage capacity of 23 gigawatts (GW) of the 24-GW national total. This capacity was built between 1960 and 1990. PSH is a mature and proven method of energy storage with competitive round-trip efficiency and long-life spans. These qualities make PSH an extremely attractive potential solution to energy storage needs, particularly for longer-duration storage (8 hours or more); such storage will be crucial to bridge gaps in electricity production as variable wind and solar production continue to make up an ever-larger portion of the United States' energy.

The U.S. existing PSH fleet stands for 14% of global PSH Capacity while Asia accounts for 75% of installed PSH worldwide.

A few other pumped-hydro projects have final approvals in hand and could get built before then, including Rye Development's Swan Lake project and Absaroka Energy's Gordon Butte. The White Pine site will use two yet-to-be-made reservoirs with a 2,200-foot elevation gap between them, which generates more power with the same amount of water compared to locations with a lower height differential. Another advantage of this design is that it doesn't interfere with existing waterways.

The Goldendale Energy Storage Project in the state of Washington is a 1,200 MW PSH. The $2 billion+ project located about eight miles southeast of Goldendale, Washington is a closed-loop pumped storage hydropower facility[5].

[5] https://goldendaleenergystorage.com/project.html#:~:text=The%20Goldendale%20Energy%20Storage%20Project,loop%20pumped%20storage%20hydropower%20facility

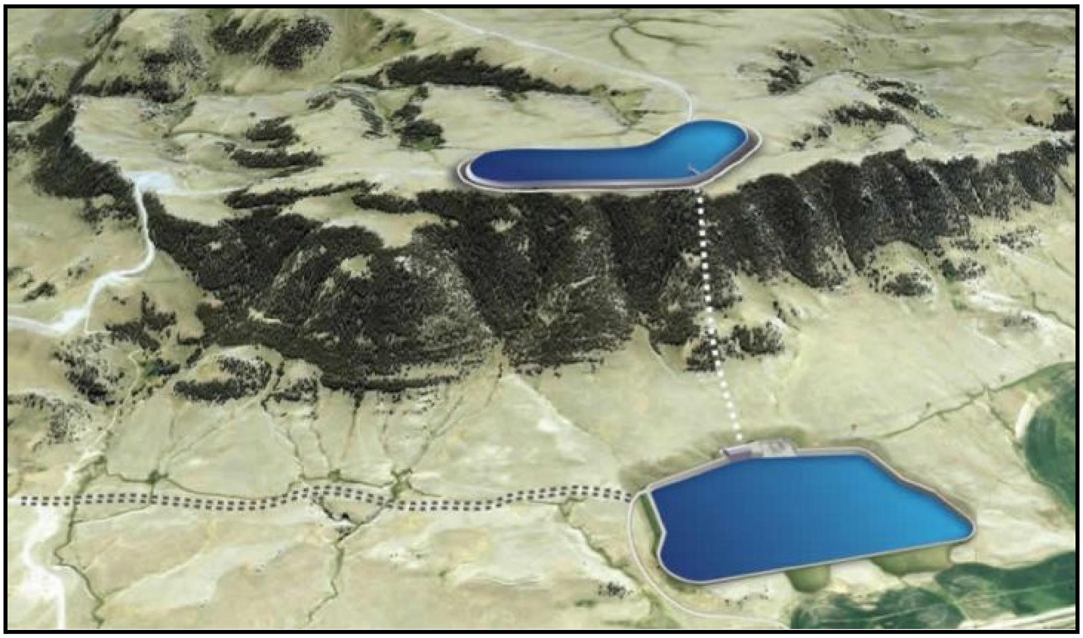

Figure 3– Absaroka 'Gorden Butte 400 MW PSH in Montana

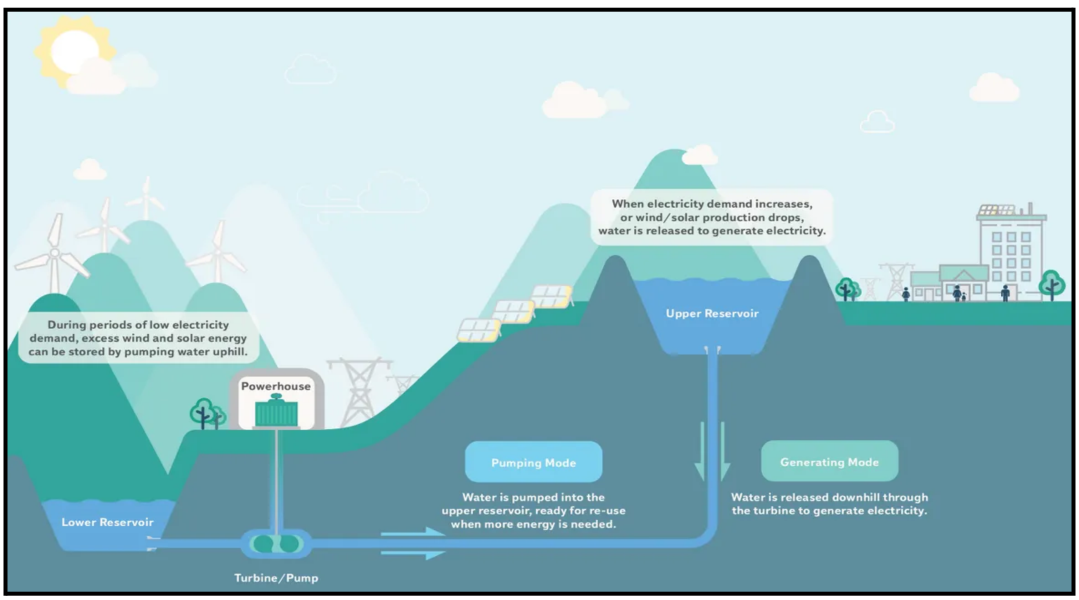

Figure 4– Topical's PSH Layout, Courtesy of Rye Development[6]

Rye Development has developed one of the three pumped storage projects in the U.S. that could now be considered shovel-ready, in that they have completed all necessary federal permitting and environmental reviews.

Venture capitalists are investing in novel ways to store clean energy, even though we already have a technology that does this, and does it well. That would be pumped-storage hydropower, which simply lifts

[6] https://www.canarymedia.com/articles/long-duration-energy-storage/pumped-hydro-grid-storage-could-be-poised-for-a-comeback

water to an elevated reservoir for storage, and then releases it to spin turbines and generate electricity when needed. This mechanism has been in use for more than a century and constitutes some 95 percent of grid-scale storage in the U.S. today, according to the Department of Energy.

Today's market for storing electricity is dominated by lithium-ion batteries. But they're better at sprints than at marathons, because their costs scale unfavorably when delivering power over many hours. Batteries today work as power plants for four hours straight, as in California, where they help meet evening demand after solar power production plummets. But those batteries aren't competitive if the power is needed for durations of eight hours or beyond.

The process requires arduous, years-long permitting, and then years of construction. In the past, regulated utilities would foot the hefty upfront bill for this kind of project, but eventually, they switched to preferring gas plants for on-demand power.

Recently PSH Development has the wind in their back on three main fronts:

(1) Intermittent Resource Penetration: The increase penetration of intermittent generation and reduction of base load generation is creating the need for dispatchable, clean, and long-duration storage like never before. The development of significant amounts of energy storage will be essential to the United States achieving greater deployment of renewable energy generation. Solar and wind electricity production, predicted to be by far the most common forms of renewable energy electricity production, have strong diurnal patterns. Solar only produces energy during the day; wind is less strictly patterned but does have diurnal patterns in most locations, usually with the night showing stronger wind than the day. This variation can be absorbed by the grid by adjusting the production from other sources of energy (e.g., ramping up or down gas or coal generator stations), but this strategy becomes less workable as the proportion of dispatchable conventional sources of energy decreases. Deploying long-duration energy storage is a key approach to bridging the gap in the diurnal patterns of these variable generation technologies.

(2) Tax Incentive: Recently PSH gained a critical victory in the Inflation Reduction Act, which included pumped-hydro storage in the new 30 percent investment tax credit for standalone grid storage. Projects can gain an additional 10 percent credit by meeting requirements for domestic materials. Pumped storage is well positioned to access that bonus since it relies on civil engineering and equipment that is already produced in the U.S., as opposed to batteries, which are manufactured overseas.

(3) Regulatory Policy: In October 2017, FERC announced a revised policy on license terms (for both original licenses and relicenses) in which the default term became 40 years. Nevertheless, FERC can still issue longer or shorter licenses if needed to coordinate license terms for projects within the same river basin or supported by a settlement agreement. Moreover, a longer license term can be granted if the relicense requires extensive new measures or the licensee already voluntarily implemented significant measures during the prior license term.

The American Water Infrastructure Act of 2018 (AWIA) directed FERC to introduce an expedited licensing process of 2 years from license application to final decision for qualifying closed-loop PSH projects. AWIA also introduced amendments to the qualifying conduit authorization pathway and allows FERC to extend preliminary permits and construction start timelines for longer periods.

States are committing to increasingly ambitious renewable or clean energy mandates and energy storage targets that could help increase investment in new hydropower and PSH.

- Since 2018, at least nine states have increased their renewable energy targets, and eight states (i.e., California, Hawaii, Maine, New Mexico, New York, Rhode Island, Virginia, and Washington), as well as Washington D.C. and Puerto Rico, have set a 100% renewable or clean energy mandate. Hydropower is limited in its eligibility to meet RPS targets in most states, but it typically counts toward clean energy mandates.
- Seven states (California, Oregon, New Jersey, New York, Massachusetts, Nevada, and Virginia) have adopted energy storage targets, and other States are considering introducing them.

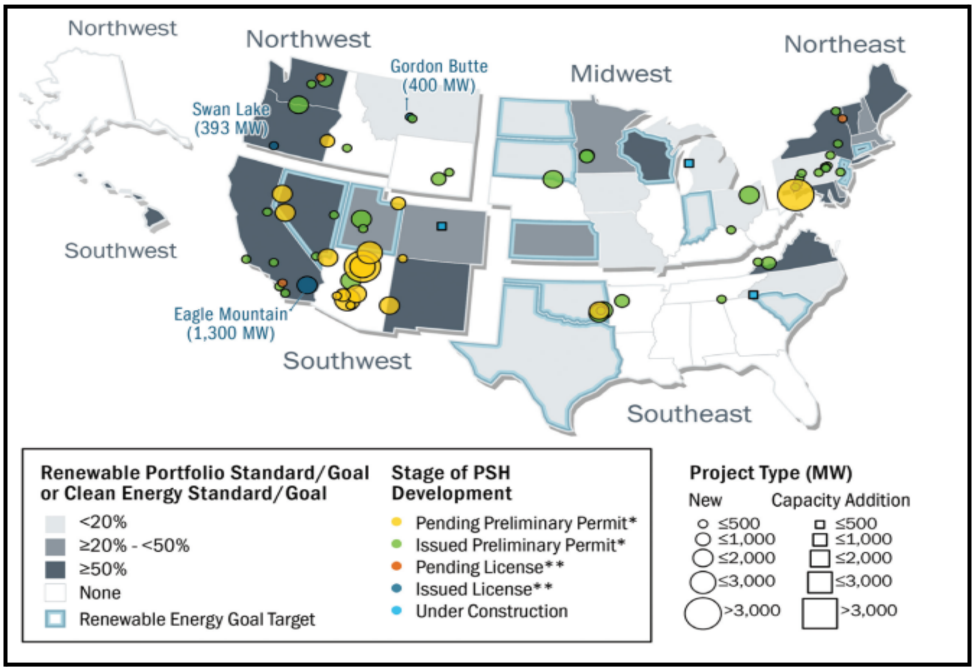

Figure 5– Hydropower Project Development Pipeline by Project Type, Region, Size, and Development Stage (as of December 31, 2019)[74]

3 Project Physical Size and Hydrology

The Project consists of 4 x 300 MW = 1,200 MW generating units that could be used to pump the water 4 x 320 MW = 1,400 MW.

HDR was retained by the Project and provided a "Determination of Water Source and Fill Rates – Preliminary Results: The results indicate enough water availability for the initial fill of the lower reservoir from the Kiamichi River initial. In addition, water availability from the river could sustain the project operation and supply annual

74 https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf

water to replace evaporation and leakage during the November to May period. Section 9 of this report explains the water availability and hydrology calculation used in this analysis.

4 Study Approach

The most important use for pumped storage has traditionally been to balance baseload power plants and demand fluctuation. However, we stipulate that The Project is highly effective in abating the fluctuating output of intermittent energy sources. The Project's stored energy, in addition to capacity at times of high electricity output and low electricity demand, enables added system peak capacity. In certain jurisdictions, electricity prices may be close to zero or occasionally negative when there is more electrical generation available than there is demand available to absorb it. For example, as wind or solar penetration increases, this will increase the likelihood of such occurrences.

The Project's economic analysis is based on forecasting project revenues from the sale of energy and ancillary services into the ERCOT, SPP, and both ERCOT & SPP Markets. We used the stochastic method to forecast the expected project revenues and the un-levered IRRs under each of the three forecasted scenarios. We also used the historical hourly energy and ancillary services clearing prices from each regional market to back-cast the project revenue.

The market revenue of any generating assets in a regional market is paid the locational Marginal Price (LMP) at the delivery node for energy and the delivery zone for ancillary services. The LMP is a way for wholesale electric energy prices to reflect the value of electric energy at various locations, accounting for the patterns of demand, generation, and the physical limits of the transmission system. In other words, LMP is the cost of optimally supplying an increment (or decrement) of demand at a particular location while satisfying all operational constraints. Many variables affect the LMP calculation, the single most variable that has the most impact is the natural gas price for any given day or hour because the marginal dispatchable resource available to move up or down is typically the gas-generating resource that sets the marginal cost of energy or the LMP. Therefore, our approach to forecasting the project returns is to calculate the expected Project revenue at ERCOT & SPP generation and demand assumptions over the Project life as shown in Section 14.

We performed several sensitivities to capture the impact of Project costs and annual revenue changes will have on the expected return and calculate a range of expected Project returns summarized in Section 15.

Finally, we performed a risk analysis to better understand the value at risk under the most conservative conditions (Case1) summarized in Section 16.

Although this analysis relies on market revenues and not an estimation of long-term Power Purchase Agreement, as a proxy to figure out the project return if all project revenues come from the correspondent market. Typically, we expect a high correlation between market revenue and long-term PPA and we would expect that market revenue is a good indicator of the potential revenue from any assets and this Project is no exception.

5 Study Objective, Definition, and Assumptions

The objective of this analysis is to back-cast the Project net revenue and estimate the future project revenue, costs, and Project return under each of the three interconnection scenarios.

Project assumptions and Definitions:

1. **Hydrology:** Water availability is sufficient to generate 1,200 MWh per hour for up to 23 hours and pump 1,400 MWh per hour for 27 hours.
2. **Interconnection:** The ability to inject and withdraw 1,200/1,400 MW from either the ERCOT and/or the SPP transmission grid by rules in Appendix A & C.
3. **The Project is a price taker** and has no impact on the ERCOT or SPP hub market clearing prices for both energy and ancillary services.
4. **Backcasting project revenue**: This report quantifies the energy, resources adequacy, and ancillary services back-cast gross and net revenues from connecting exclusively to ERCOT, exclusively to SPP, or both. Utilize publicly available day-ahead regional ERCOT North hub and SPP South hub for energy and ancillary service hub prices from 2019 and 2022 while connecting to ERCOT, SPP, and both ERCOT and SPP in accordance with Appendix A. we used hourly public information on the energy and ancillary services clearing prices in SPP and ERCOT and $5/kw-mo. for resource adequacy.
5. **Project economic life cycle** of 50 years, from 2030.
6. **Ancillary service sales are limited** to 15% of each region's ancillary service requirements**.**
7. **Project round-trip efficiency** is set at 80%.
8. **Generation and demand forecast:** We used the generation mix and estimated GWh for ERCOT and SPP as shown in Table 25 for ERCOT and Table 26 for SPP. Demand growth as shown in Figures 20 and 21. Also, refer to Appendix E for year-by-year forecast demand and generation.
9. **Natural gas prices**: we used the followings:

	Mean ($/MMBTU)	**Std Dev ($/MMBTU)**
Historical (1985-2022)	$4.62	$1.95
Low Case Forecast (2030 – 2079)	$2.75	$1.50
Medium Case Forecast (2030 – 2079)	$4.62	$1.95
High Case Forecast (2030 – 2079)	$6.0	$2.1

   Further explanation in Section 14.1.

10. **Energy and Ancillary services revenue:** these revenues were calculated for the years 2030 to 2079 based on the generation and demand forecast, natural gas prices, generation addition, and retirements as reported in Appendix E.
11. **Ancillary Services Selection Criteria:** Ancillary services are reliability services. Appendix D shows the rules used in the optimization to optimally select between the sale of energy and ancillary services per NERC and regional reliability criteria.

12. **Resource Adequacy Revenue forecast:** was estimated to equal $5/KW-mo. escalated at 1.5% annually.
13. **Project Revenue Forecasting:** we performed a forecast analysis to calculate the projected revenue from the sale of energy, resource adequacy, and ancillary services from 2030 to 2079 and (2) apply the stochastic method to the deterministic forecast of the Project revenues for 50 years starting 2030 under ERCOT and SPP/ ERCOT scenarios with the intent to capture uncertainty in project cost and revenues.
14. **Value at risk:** we calculated the normal distribution variation of the net revenue (project revenue minus pumping cost minus operating cost) by varying project capital cost and the annual net revenue from the mean in the table above at 25% standard deviation. We used a 1,000-iteration Monte Carlo probability analysis each year for 50 years.
15. **Project Cost:** All in cost, including Transmission interconnection cost. We assumed the Project cost is the same whether the Project interconnects to ERCOT only, SPP only; or both $ 3.1 billion includes a 15% contingency.
16. **Operation, Maintenance, and capital improvement:** we assumed 2% of the Project cost escalated to 1.5% annually.
17. **Tax Equity Investment and Payment:** we assume the tax investment is 30% of the 98% of the Project cost. Thirty percent included ITC. The Tax investment payment is assumed to equal 1% of the tax equity investment amount for each year from years 1 to 5. At year 6, we assumed a 4% payment to the tax equity investor at year 6. These annual payments from years 1 to 6 are included in the annual operating costs.
18. **Total annual Operating Cost** is equal to Operation, Maintenance and capital improvement, and Tax Equity payments.
19. **Investment Amount** is equal to Project Cost minus Tax Equity Investment amount).
20. **Annual Average Revenue (Energy, Resource Adequacy (RA), and Ancillary Service (AS) revenues minus Pump Cost).** Energy and Ancillary Services were forecasted, the Resource Adequacy payments are estimated to be 5$/kw-mo., escalated at 1.5% annually.
21. **Average of Total Annual Operating Cost (O&M + Land + Tax Equity Payment + Capital Improvement minus Pump Cost):** we assumed the O&M and capital improvement amount is equal to 2% of the project cost escalation at 1.5% annually.
22. **Average Annual Total Net Revenue (including Pump Cost):** straight average over 50 Years.
23. **Present Value Revenue $** including revenue from energy, ancillary services, and resource adequacy net pumping costs using a 6% discount rate.
24. **Present Value Total Operating Cost** using a 6% discount rate.
25. **NPV of Total Project Revenue or Net Cash Flow to Investor (Net Profit)**: This is net of Present Value Revenue and Present Value of Total Operating Cost. This is the net profit to the Investors prior to recovering their capital investment.
26. **Net Present Value Project Cost (PV of Total Operating Cost + Investment Amount):** This is the net profit to the Investors after recovering their capital cost invested.
27. **BCR Ratio = NPV Total Revenue / NPV Total Cost:** The benefit-cost ratio (BCR) is a ratio used in a cost-benefit analysis to summarize the overall relationship between the relative costs and benefits of a

proposed project in present value. If a project has a BCR greater than 1.0, the project is expected to deliver a positive net present value to a firm and its investors.

6 Summary of Back-Casting

This section summarizes the analysis performed using hourly clearing prices from 2019 to 2022 to calculate the potential *energy and ancillary service revenue (which includes pump cost and does not include resource adequacy potential revenues). The backcasting is solely based on market clearing prices optimized for this project and does not include resource adequacy revenue.*

(A) Scenario 1 – ERCOT Interconnection Only:

Based on ERCOT's hourly clearing prices for energy and ancillary services for the period from 2019 to 2021, we performed back-casting optimization and calculated the hourly Project revenues based on actual hourly clearing prices for energy and ancillary services and an estimated annual revenue from resource adequacy. As you can see in the detailed section of this report, the ice storm resulted in a possible Project revenue of $3.13 billion of which $2.8 billion was captured during the ice events from 2/12/2021 to 2/20/2021.

Annual Project Revenue from 2019 to 2022, except 2021 ranged from $358 million to $197 million. During this period, natural gas ranged from $3.91 to $2.29 per MBTU. Note that 2020 (COVID) and 2021 (ice storm) are assumed to be outliers.

(B) Scenario 2 – SPP Interconnection Only:

Based on SPP hourly clearing prices for *energy and ancillary services* for the period from 2019 to 2022, we performed back-casting optimization and calculated the hourly Project revenues based on actual hourly clearing prices for energy and ancillary services and an estimate annual revenue from resource adequacy. As you can see in the detailed section of this report, The **Annual Project Revenue** from 2019 to 2022, except 2021, ranged from $511 million to $158 million. During this period, natural gas ranged from $3.91 to $2.29 per MBTU. Note that 2020 (COVID) is assumed to be an outlier.

(C) Scenario 3 – ERCOT & SPP Interconnection:

a) Based on ERCOT & SPP's hourly clearing prices for energy and ancillary services for 2019 to 2022, we performed back-casting optimization and calculated the Project revenues based on these hourly clearing prices for energy and ancillary services only.
b) The **Annual Project Revenue** from 2019 to 2022, except 2021, ranged from $532 million to $224 million. During this period, natural gas ranged from $3.91 to 2.29 $/MMBTU. Note that 2020 (COVID) and 2021 (Ice storm) are assumed to be outliers.
c) The Annual Project Revenue when connected to both ERCOT and SPP under Scenario 3 is the highest in every year from 2019 to 2022, except 2021.
d) This option allows greater optionality in reaching two of the three regional markets (ERCOT, SPP, and possibly MISO). It also allows the project to leverage lower energy prices in SPP during the pumping period and periods when the energy and ancillary service prices are more lucrative than ERCOT, and vice versa.
e) The energy markets in ERCOT are larger and more lucrative than SPP.

f) The energy demand in ERCOT is increasing at a higher rate than that in SPP.
g) Ancillary service requirements in ERCOT have doubled.
h) The regulation market in SPP is just as lucrative as that in ERCOT due to the high variability of wind resources and the retirement of coal.

	Total Annual Project Revenue from Energy and Ancillary Services in $mm		
YEAR	**ERCOT only (Scenario 1)**	**SPP only (Scenario 2)**	**ERCOT & SPP (Scenario 3)**
2019	$352	$155	$400
2020	$169	$158	$224
2021	$3,417	$511	$3,494
2022	$358	$348	$532

Table 7– Summary of the Project Revenue FROM Energy and Ancillary Services Back-casting 2019 to 2022 (excluding resource adequacy revenue) Detailed Project Operations Under the Three Scenarios are Summarized in Appendix B & C

7 Observations

a) Ancillary services represent a critical market for this project as it will earn capacity payments without moving water. Ancillary service revenues are estimated to be 55% of the total net Project revenue. However, the maximum ancillary services from the Project to any given regional market did not exceed a reasonable part of the applicable regional ancillary service requirements.
b) The Project economics are highly correlated with natural gas prices and renewables penetration, the higher the natural gas and/or renewable penetration, the higher the Project revenue. The increase in penetration of intermittent resources causes higher volatility of energy and ancillary services prices, which ultimately leads to more opportunities for the Project to capture market share due to the Project's flexibility and quick response, resulting in higher revenue.
c) Events such as 2020 COVID and 2021 ice storms have a significant impact on the Project revenue but since it is difficult to predict, these events were noted but ignored for the purpose of projecting the Project revenues.

8 Summary of Project Forecast Revenues and Returns

This section summarizes the results of the forecast of project revenues for 2030 to 2079 and investment return under the following three cases under scenarios 4,5 and 6:

- **Case one** represents 70% lower-than-historic natural gas prices and lower-than-historic demand growth of 0.5% annually.
- **Case two** represents the same natural gas prices from 1985 to 2022 and a modest demand growth of 1.5% annually.
- **Case three** represents a 30% higher than the historical natural gas prices and above-average demand growth of 2% annually.

The tables below summarize the results of forecast project economics under Scenarios 4, 5, and 6 representing the three interconnections' scenarios:

ERCOT Scenario 4: Project Cost, investment amount, average annual revenues, and annual operating Cost	Case 1	Case 2	Case 3
Tax Equity Investment $	$3,100,000,000	$3,100,000,000	3,100,000,000
Investment amount (Project Cost minus Tax Equity Investment amount) $	$2,170,000,000	$2,170,000,000	$2,170,000,000
Annual Average Revenue (Energy, RA and AS revenue minus Pump Cost) $	$563,681,037	$926,447,138	$878,211,081
Average of Total Annual Operating Cost (O&M + Land + Tax Equity Payment + Capital Improvement minus Pump Cost) $	$93,257,930	$93,257,930	$93,257,930
Average Annual Total Net Revenue (including Pump Cost) $	$470,423,107	$833,189,208	$784,953,151
Present value and Net Present value, IRR and BCR	**Case 1**	**Case 2**	**Case 3**
Present Value Revenue $	$8,545,471,721	$12,638,918,395	$13,211,042,398
Present Value Total Operating Cost $	$1,293,367,537	$1,293,367,537	$1,293,367,537
PV Total Project cost (Operating Cost +Investment Amount $)	$3,463,367,537	$3,463,367,537	$3,463,367,537
BCR Ratio = PV Revenue / PV Total cost	2.47	3.65	3.81
Net Present Value (Net project profit to Invertor $)	$5,082,104,185	$9,175,550,859	$9,747,674,861
Unlevered IRR %	20.76%	26.9%	30.56%

Table 8– Scenario 4 - Summary of ERCOT Only Interconnection - Forecast Revenues and Returns

SPP Scenario 5: Project Cost, investment amount, average annual revenues, and annual operating Cost	Case 1	Case 2	Case 3
Project Cost $	3,100,000,000.00	3,100,000,000.00	3,100,000,000.00
Tax Equity Investment $	930,000,000.00	930,000,000.00	930,000,000.00
Investment amount (Project Cost minus Tax Equity Investment amount) $	2,170,000,000.00	2,170,000,000.00	2,170,000,000.00
Annual Average Revenue (Energy, RA and AS revenue minus Pump Cost) $	451,687,086.63	659,622,448.16	708,910,728.23
Average of Total Annual Operating Cost (O&M + Land + Tax Equity Payment + Capital Improvement minus Pump Cost) $	93,257,929.97	93,257,929.97	93,257,929.97
Average Annual Total Net Revenue (including Pump Cost) $	358,429,156.66	566,364,518.19	615,652,798.26
Present value and Net Present value, IRR and BCR	**Case 1**	**Case 2**	**Case 3**
Present Value Revenue $	6,704,380,808.63	9,047,898,920.76	10,531,260,500.02
Present Value Total Operating Cost $	1,293,367,536.56	1,293,367,536.56	1,293,367,536.56
PV Total Project cost (Operating Cost +Investment Amount $)	3,463,367,536.56	3,463,367,536.56	3,463,367,536.56
BCR Ratio = PV Revenue / PV Totalcost	1.94	2.61	3.04
Net Present Value (Net project profit to Invertor $)	3,241,013,272.07	5,584,531,384.20	7,067,892,963.47
Unlevered IRR %	0.15	0.19	0.24

Table 9– Scenario 5 - Summary of SPP Forecast Revenues and Returns

ERCOT & SPP Scenario 6: Project Cost, investment amount, average annual revenues, and annual operating Cost	Case 1	Case 2	Case 3
Tax Equity Investment $	$3,100,000,000	$3,100,000,000	$3,100,000,000
Investment amount (Project Cost minus Tax Equity Investment amount) $	$2,170,000,000	$2,170,000,000	$2,170,000,000
Annual Average Revenue (Energy, RA and AS revenue minus Pump Cost) $	$656,521,307	$1,063,667,164	$1,064,316,229
Average of Total Annual Operating Cost (O&M + Land + Tax Equity Payment + Capital Improvement minus Pump Cost) $	$93,257,930	$93,257,930	$93,257,930
Average Annual Total Net Revenue (including Pump Cost) $	$563,263,377	$970,409,234	$971,058,299
Present value and Net Present value, IRR and BCR	Case 1	Case 2	Case 3
Present Value Revenue $	$10,044,626,505	$14,382,873,960	$16,156,820,127
Present Value Total Operating Cost $	$1,293,367,537	$1,293,367,537	$1,293,367,537
PV Total Project cost (Operating Cost +Investment Amount $)	$3,463,367,537	$3,463,367,537	$3,463,367,537
BCR Ratio = PV Revenue / PV Total cost	2.90	4.15	4.67
Net Present Value (Net project profit to Invertor $)	$6,581,258,968	$10,919,506,424	$12,693,452,590
Unlevered IRR %	25.25%	30.82%	36.87%

Table 10– Scenario 6 - Summary of Both ERCOT and SPP Interconnection - Forecast Revenues and Returns

9 Detailed Report

9.1 Project Characteristics

The Southeast Oklahoma Pump Storage Project ("Project") is proposing to construct a closed-loop pumped storage project consisting of four 300 MW turbine generation and four 350 MW pumps with an upper reservoir, a lower reservoir, and a regulating reservoir. A channel will be constructed from the Kiamichi River to the regulating reservoir. During high-flow events on the Kiamichi River, water will be conveyed from the river to the regulating reservoir through the channel. There will not be a diversion structure located in the Kiamichi River. Pumps will convey water from the regulating reservoir to the lower reservoir. water in the regulating reservoir will be used as initial fill water for the lower reservoir and as a source of water to replace evaporative losses.

9.1.1 Physical Assumptions:

A pumped hydro system builds potential energy by storing water in a reservoir at a certain height when there is excess energy. It converts the potential energy to electricity by releasing the potential energy to turn the turbine generator when there is a demand. The reservoir is located at a specific height above the turbine generator (the head height) to generate potential energy. The flow rate is the amount of water (meters cubed per second) that flows in or out.

9.1.1.1 **Variable-Speed (Adjustable-Speed) Pump/Turbine:**

- Rotational speed of the motor/generator is adjustable. This enables adjustments of power consumed during pumping mode and power output during generation mode by adjusting the speed of the turbines and generators.
- Pump and turbine speeds can be independently varied to optimize efficiency over the range of flow rate and head.
- Pumping power can be varied in addition to generating power.
- Variable speed using a synchronous motor/generator (singly fed).
- Doubly fed asynchronous machine (DFAM) variable-speed operation with synchronous motor/generator.

9.1.1.2 Closed Loop

- Neither reservoir has a natural source of inflow.
- Initial filling of the lower reservoir will come from the Kiamichi River.
- Compensation for leakage and evaporation provided by groundwater wells and the Kiamichi River.

9.2 Project Benefit Assumptions

Pumped hydro plants can supply large amounts of power and energy and can quickly respond to large demand and renewables variations.

The response time of sudden changes:

- Classic Hydropower Plants = 3 to 5 minutes
- Pumped Storage Hydropower Plants = 3 to 5 minutes
- Natural Gas Plants = 1 to 3 hours
- Fuel Oil Plants = 3 hours
- Coal Fired Plants = 4 hours
- Nuclear Plants = 5 days

PSH Physical characteristics	Pumped Storage Hydropower Plants	Natural Gas Plants	Fuel Oil Plants	Coal Fired Plants	Nuclear Powerplants
Normal Duty Cycle	Peak-Intermediate	Peak	Peak-Intermediate	Baseload	Baseload
Unit Start-Up Daily	Yes	Yes	Yes	No	No
Quick Start (<10 minutes)	Yes	Yes	No	No	No
Black Start (ability to start without an external power source)	Yes	Yes	No	No	No

Table 11– Summary of Pump Storage Physical Characteristics from Grid Reliability Perspective

Table 11 illustrates the tremendous ability of Pumped Storage Projects to cycle daily, fast start and shut down, quick start in less than 10 minutes, and black start capabilities.

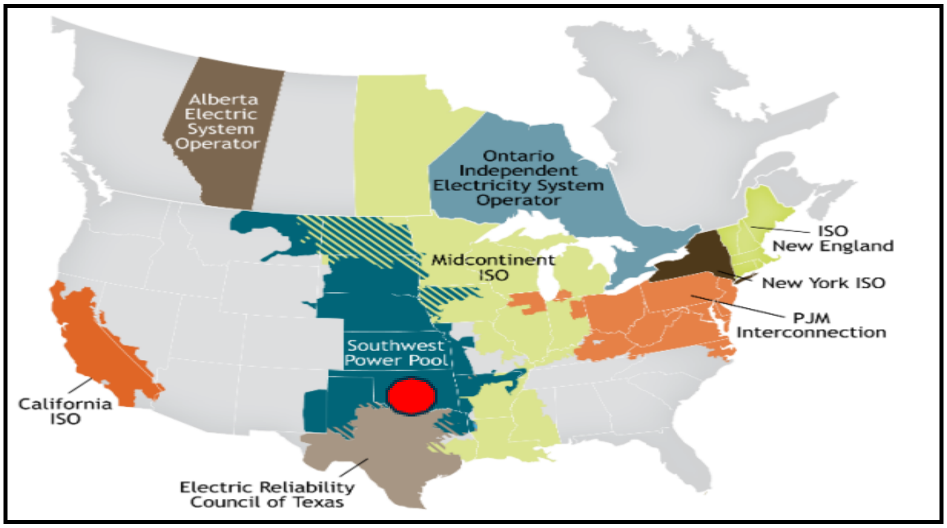

Figure 6– ERCOT, MISO & SPP Geographic Service Area and Project Location

a) Energy and Ancillary Services:

i. Arbitrage opportunity by purchasing energy from the grid during low-priced hours and selling energy to the grid during high-priced hours.

ii. Sell ancillary services (regulation up, regulation down, non-spinning and spinning reserves, or responsive reserves).

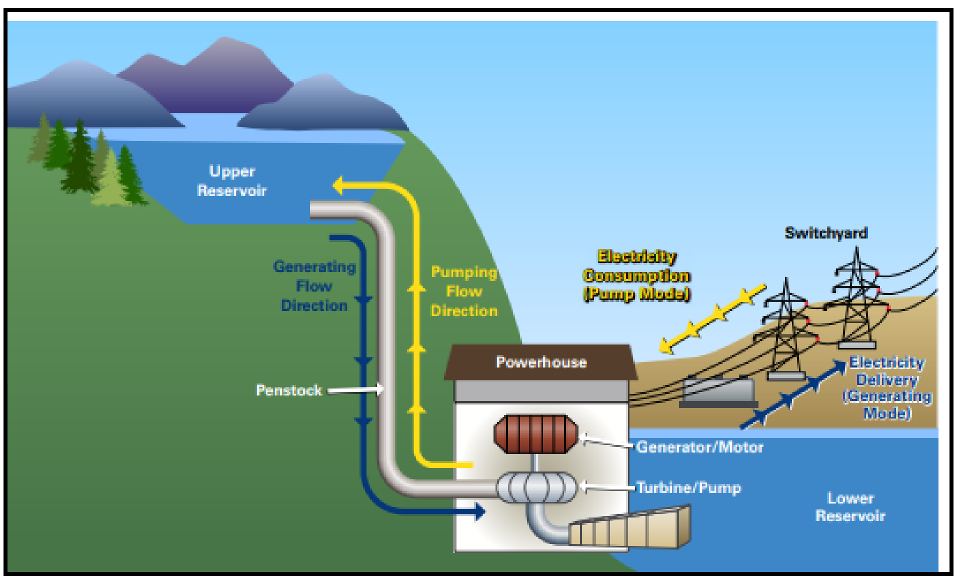

Figure 7– Schematic of Electricity Flow under Pump Hydro Operation

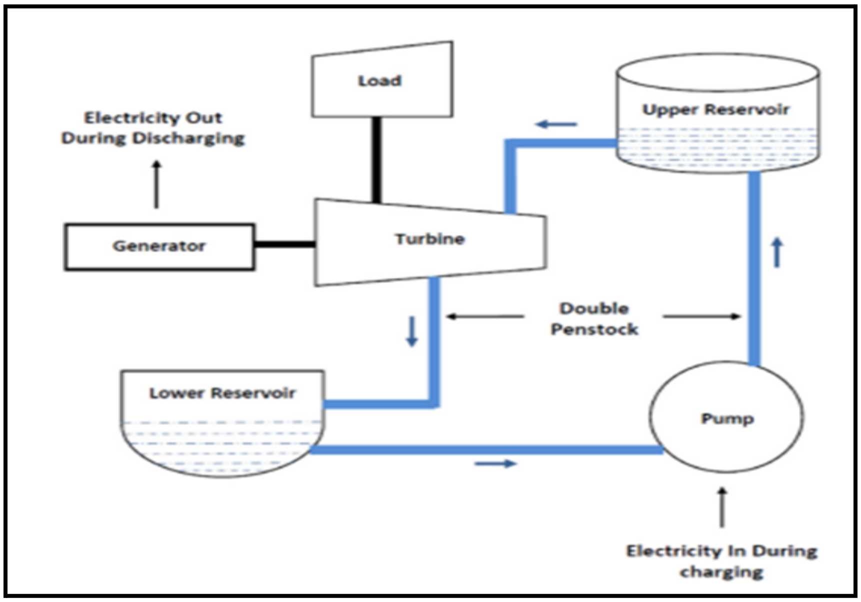

Figure 8– Schematic of Water Flow under Pump Hydro Operation

b) Frequency Regulation:

iii. Power variation to track short-term demand variations.

iv. Helps maintain grid frequency at 60 Hz (50 Hz).

v. Varying the field excitation voltage of the generator/motor.

vi. Even at zero real power – not pumping or generating.

c) Voltage Support:

i. Maintains voltage within bandwidth targets.

ii. Reactive power flow control to help maintain desired grid voltage.

iii. Varying the field excitation voltage of the generator/motor.

iv. Even at zero real power – not pumping or generating – an unloaded motor/generator can serve as a synchronous condenser.

v. Pump/turbine spinning.

d) Black Start Capability:

i. Ability to start generating without an external power supply.

ii. Bring the grid back online after a blackout.

iii. Non-spinning reserve and spare online generating capacity.

iv. Capable of responding quickly – within seconds to minutes – to the need for additional generation.

e) **Firming for 24-7 PPAs—**The decision for demand-firming solutions will be highly cost-based, and thus PSH with a lower LCOE will be necessary. As customer targets are set to require higher time-matching granularity within 24-7 PPAs, short-duration technologies will lose the LCOE advantage in being able to meet customer demand through all hours of the year (e.g., multiple systems would need to be stacked for extended periods of low resources / high demand).

f) **Technology Risk**

According to the DOE[8] March 2023 report of long-duration storage, the PSH was found to have fewer supply chain vulnerabilities compared to Li-ion alternative and ranked the lowest risks to no technological risks due to the maturity of PSH. Figure 9 shows that PSH has the lowest supply chain and technology risks. Table 12 shows the various Project benefits.

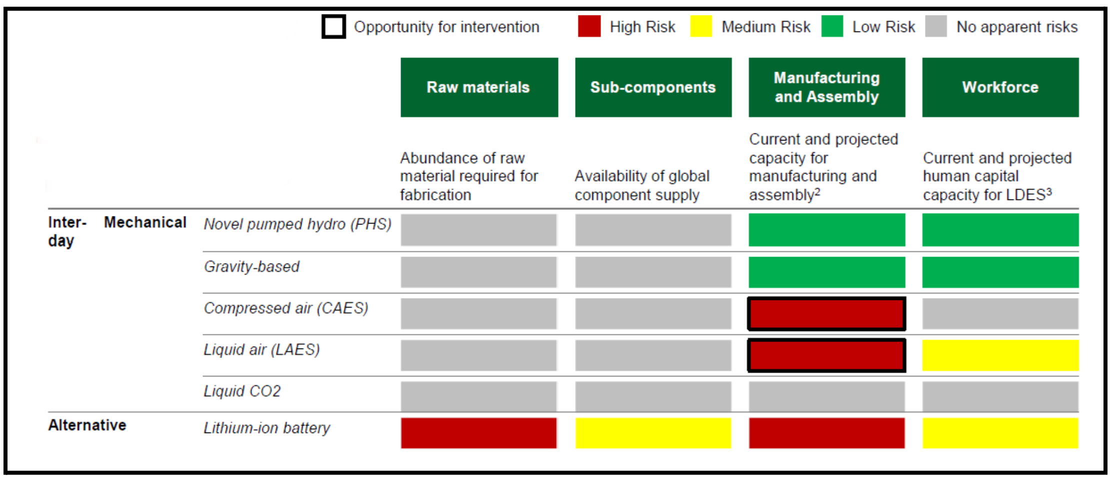

Figure 9– Supply Chain Risk for Storage Development[9]

[8] https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-LDES-vPUB.pdf

[9] https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-LDES-vPUB.pdf

Beneficiary	Cost/Benefit Category	Service or Impact	Types of Metrics Used to Describe Services/Impacts
PSH Owner or Operator	Bulk energy services	Electricity price arbitrage	Physical and monetary
		Bulk powder capacity	Physical and monetary
	Ancillary services	Frequency regulation	Physical and monetary
		spinning reserve	Physical and monetary
		Non-spinning reserve	Physical and monetary
		Supplemental reserve	Physical and monetary
		Voltage support and reactive power	Physical and monetary
		Black start service	Physical and monetary
Power System	Power system stability (dynamic performance)	Inertial response	Physical and qualitative
		Governor response	Physical and qualitative
		Flexibility (e.g., ramping and load following)	Physical, qualitative, and monetary
	Power system reliability and resilience	Reduced sustained power outages and restoration costs)	Physical and qualitative
	Power system indirect benefits	Reduced electricity generation cost	Monetary
		Reduced cycling and ramping (wear and tear costs) of thermal units	Physical and monetary
		Reduced curtailments of variable generation	Physical and monetary
	Transmission infrastructure benefits	Transmission upgrade deferral	Physical and monetary
		Transmission congestion relief	Monetary
Beneficiary	**Cost/Benefit Category**	**Service or Impact**	**Types of Metrics Used to Describe Services/Impacts**
Society	Non-energy services	Water management services	Physical, qualitative, and monetary
		Socioeconomic impacts (e.g., jobs, economic development, recreation)	Physical, qualitative, and monetary
		Environmental and health impacts	Physical, qualitative, and monetary
	Energy security benefits	Fuel availability, savings, and diversification	Physical, qualitative, and monetary
		Major blackouts avoided	Physical, qualitative, and monetary

Table 12– PSH Beneficiary Costs/Benefits

Table 12 summarizes the Project usage and benefits; however, only bulk energy services and ancillary services were analyzed in this study.

9.3 Water Assumptions

9.3.1 Water Availability

1) Annual estimated flows for the Kiamichi River at the proposed diversion location are less than five hundred cfs for approximately 50% of the year with a maximum average monthly flow of 838 cfs in May to 50 CFS in August (see Table 4-1 of the Project HDR report).
2) The period of December through May tends to be characterized as the higher flow season while the period of June through November tends to be characterized as the lower flow season. Annual and monthly flow duration curves are provided in Appendix B of the project HDR report.

3) The fill potentials for the lower reservoir were based on an assumed volume of 48,699 acre-feet. This volume and surface area where from the original preliminary permit, the volume and surface area where revised in the recently filed preliminary permit.
4) A significant potential to fill the lower reservoir within 6 months was determined not to be feasible based on the reviewed diversion rates and assumed pump capacities.
5) The fill potential for the lower reservoir for a 12-month period did not exceed 90% at the maximum assumed pump capacity and diversion rate. An 80% fill potential was calculated at a diversion rate of 40% and a pump capacity of 260 cfs. A pump capacity as low as two hundred cfs was determined to achieve a fill potential greater than 80% at a diversion rate of 50%.
6) For an 18-month period, an 80% potential to fill the lower reservoir was achieved with a 20% diversion rate and a pump capacity of two hundred cfs, or a diversion rate of 50% with a pump capacity of 100 cfs. The fill potential exceeded 95% at a diversion rate as low as 40% with a pump capacity of 260 cfs, or with a pump capacity greater than two hundred cfs with a 50% diversion rate.
7) For a 24-month period, the potential to fill the lower reservoir exceeded 80% with a 15% diversion rate and a pump capacity of 180 cfs, or a diversion rate of 35% with a pump capacity of eighty cfs. A 95% fill potential was calculated at a diversion rate as low as 20% with a pump capacity of two hundred cfs, or with a pump capacity as low as 100 cfs with a 50% diversion.
8) During a 30-month period, the potential to fill the lower reservoir exceeded 95% at a diversion rate as low as 15% with a pump capacity of 140 cfs, or a diversion rate of 35% with a pump capacity greater than eighty cfs.
9) HDR recommends a 260 cfs pump structure be assumed with an off-take no greater than 10 to 15 percent of the actual stream flow and an initial reservoir fill time of between 24 and 30 months minimum.
10) It should be noted that HDR used average flow rates, but during rainy periods stream flow increases dramatically, allowing for larger off-take and shorter reservoir fill times.

Month	Average Flow (cfs)	Maximum Flow (CFS)
January	564	15,067
February	569	13,233
March	820	22,480
April	816	25,509
May	838	19,995
June	382	9,214
July	192	9,167
August	50	1,323
September	133	5,891
October	259	9,730
November	468	19,451
December	738	31,412
Total Flow	5829	182,472
Average Monthly	486	15,206

***Table 13– Estimated Flows for the Kiamichi River*[10]**

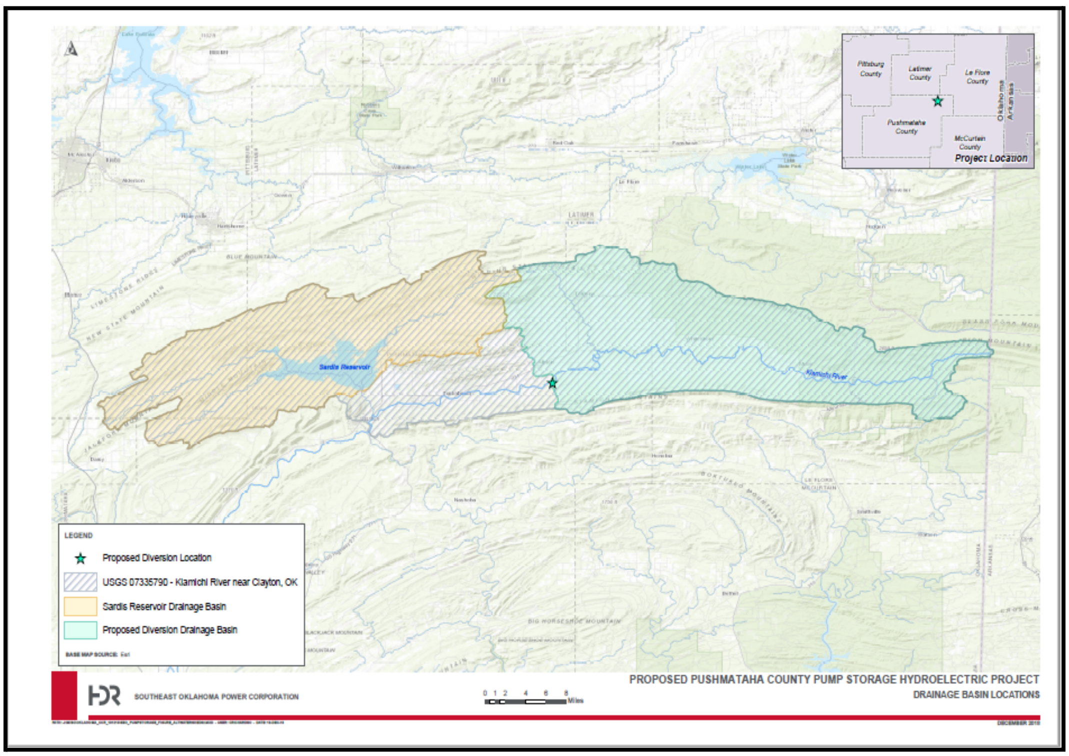

Figure 10– Water Basin Map

[10] daily mean flow data from the United States Geological Survey (USGS) for the gage on the Kiamichi River near Clayton, Oklahoma (07335790) and the United States Army Corps of Engineers (USACE) for discharges from the Sardis Reservoir to Jack fork Creek, a tributary to the Kiamichi River. The USGS gage on the Kiamichi River near Clayton, OK, is located approximately 20 river miles downstream of the proposed diversions. See Project HDR report dated 12/19/2018 for more details.

9.3.2 Project Setting

The project is located along the western edge of the Ouachita Mountain Range in the Choctaw Nation in southeast Oklahoma. The Ouachitas are part of the Interior Highlands geomorphic (physiographic) province. Near the project, the Ouachitas form a series of east-west trending ridges and valleys known as the Ouachita Fold and Thrust Belt. The bedrock in the project area is composed of the Mississippian Period Stanley Shale Formation, Pennsylvanian Period Jackfork Sandstone, Johns Valley Shale, and the Atoka Formation. Locally, the ridges are known as the Kiamichi Mountains. The topography of the project includes an east-west trending ridgeline with peak elevations of approximately 1900 feet and a flat-lying valley of the Kiamichi River flood plain situated north of the ridge at an approximate elevation of 590 feet. The Kiamichi River flows to the west-north of the project site.

The project is more specifically located on the southern side of the Kiamichi River south of the municipality of Albion, Oklahoma. US Highway 271 is located immediately north of the Kiamichi River and parallels the river in the vicinity of the project. The project includes an upper reservoir, a series of tunnels, large, excavated caverns or rooms, and a lower reservoir. The Lower Reservoir is planned between the Kiamichi River and the base of the Kiamichi Mountains. The series of tunnels and large, excavated caverns are planned within the Kiamichi Mountain range while the Upper Reservoir would impound Long Creek near the crest of the Kiamichi Mountains. Development in the vicinity of the project is sparse with infrastructure limited to two-lane paved roads and associated utilities. The land in the vicinity of the project is privately owned, and undeveloped with a wide variety of vegetation, while some land in the proposed location of the Lower Reservoir is currently being utilized for rangeland and agricultural activities.

9.3.3 Hydro Pump Storage Assumptions

Below is a summary of the water availability, hydraulic assumptions, energy, and power calculations of the Project per the Project FERC filing:

Lower Reservoir

1. Surface area: 887.37 acres
2. Watershed area: 6.10 sq. mi
3. Storage capacity: 48,699 acre-feet
4. Normal max surface elevation: 682 feet
5. Dead water level: 633 feet
6. Operation volume: 43,481 acre-feet
7. Longitude/latitude: 34°37’47’ N, 95°05”36” W

Upper Reservoir

1. Surface area: 599.55 acre
2. Watershed area: 2.25 sq. mi
3. Storage capacity: 68,269 acre-feet
4. Normal max surface elevation: 1,670 feet
5. Dead water level: 1,365 feet
6. Operation volume: 60,954 acre-feet

7. Longitude/latitude: 34°35’42” N, 95°08’05” W

Regulating Reservoir

1. Surface area: 40 acres
2. Storage capacity: 1,216 acre-feet
3. Normal max surface elevation: 672.57 feet
4. Longitude/latitude: 34°38’07” N, 95°05’11” W

Estimated Installed Capacity: 1,200 MW.

Midpoint of the Hydraulic Head for Estimating Capacity and Energy Output: 861 feet or 262 meters.

Number of Turbines/Generators: four (4) at 300 MW each.

Number of Turbines/Pumping: four (4) at 350 MW each.

9.3.4 Evaporation and Leakage

The upper reservoir is oversized by 19,570 acre-feet to consider evaporation, leakage, and seasonal flow on the river. Based on an evaporation rate of 10 feet per year, multiplied by the surface area of both reservoirs, plus a leak rate of 7%:

- Upper Reservoir surface area 599.55 acres plus Lower Reservoir surface area 887.37 acres (599.55 acres + 887.37 acres) x 10 feet per year of evaporation = 14,869.2 acre-feet.
- Upper reservoir leakage of 68,269 acre-feet x 7% leakage rate = 4,778 acre-feet.
- Total evaporation and leakage: 14,869.2 acre-feet + 4,778 acre-feet = 19,647.2 acre-feet.

Keep in mind that the Kiamichi River is not dammed and goes dry in the summer months, and we can only take water from the river during high flows (several months in the winter), therefore we need to have enough water in storage to operate year-round. Remember that most of the evaporation occurs during the spring, summer, and fall when we cannot get make-up water**.**

9.3.5 Hydro Pump Storage Calculation

9.3.5.1 Two Days Cycle

Generation Mode:

Upper reservoir Operating Volume = 60,270 Acre ft or 2.63 billion cubic ft of operating water availability. The maximum amount of continuous generation at full 1200 MW per hr. will use the 43,269-acre ft of water or 71 % of the upper reservoir operating water storage capacity on the upper reservoir will be used for 24 hours continuously. The total volume of water that will be discharged is 71% x 2.63 billion cubic ft = 1.88 billion cubic ft or 21,815 cfs.

At 1200 MW/hour for 24 hours, the flow rate = 1.88 billion cubic ft / (24hrs x 60 x 60) = 21,815 cubic ft/s. or 618 m^3/s. So, the flow rate Q is the amount of water that is discharged from the Upper reservoir through the turbines and to the lower reservoir.

The power output of a project is calculated using the potential energy of the water and can be found using the following hydropower formula:

$P = \eta \times P \times g \times h \times Q$

Where:

P is the power output, measured in Watts.

η is the efficiency of the turbine.

P is the density of water, taken as 998 kg/m^3 or 62,3 lb./cu ft.

g is the acceleration of gravity, equal to 9.81 m/s^2 or 32.2 ft/s^2.

h is the head, or the usable fall height, expressed in units of length (meters or feet). We assumed that the head is the difference between the elevation of the midpoint of the Upper Reservoir minus the midpoint of the elevation of the Lower Reservoir = 1,518 ft – 657 ft = 861 ft or 262 meters.

Q is the discharge (also called the flow rate). Assumed 24 hrs. flow rate is 21,815 cubic ft/s. or 618 m^3/s. so.

P = 80 % x 998 x 9.81 x 262 x 618 =1,268 MW

Gen Mode	Gen Mode
Max Storage capability (Acre ft)	68,269
Max Storage capability (Cubic Feet)	2,973,797,640
Operating storage (Acre ft)	60,954
Operating storage(Cubic Feet)	2,655,156,240
Hr. of Generation at full output	24
Amount of water release from UR %	71%
Amount of water release from UR (Acre ft)	43,269
Amount of water release from UR ((cubic feet)	1,884,797,640
Discharge Rate (m^3/s)	618
Discharge Rate (cubic ft/s)	21,815
Turbine Efficiency %	80%
Gravitational Acceleration m/s^2	9.81
Water Density kg/m^3	998
Head in meter	262
Head in ft	861
Power Output in Watt	1,267,852,397
Power Output in MW	1,268
Power Output (Kw Per Af)	29.30

Table 14– Maximum Continuous Operation (Hydrology Calculation)

Pumping Mode:

Lower reservoir Operating water availability = 43,269 aft or 1.9 billion Cubic ft of operating water. The total volume of water that will be pumped back to the upper reservoirs is 1.9 billion cubic ft or 43,481 Acre feet of water.

At 1400 MW per hour for 27 hrs., the flow rate = 1.9 billion cubic ft / (27hrs x 60 x 60) = 19,391 cubic ft/s. or 550 m^3/s. so, the flow rate Q is the amount of water that is discharged from the Upper reservoir through the turbines and to the lower reservoir.

The power output of a project is calculated using the potential energy of the water and can be found using the following hydropower formula:

P (shaft in watt) = (Q x h x P x g) / η

P (hydraulic in Watt) = Q x h x P x g

P is the Hydraulic power output, measured in Watts

η is the efficiency of the Pump.

P is the density of water, taken as 1000 kg/m^3

g is the acceleration of gravity, equal to 9.81 m/s^2

h is the head, or the usable fall height, expressed in units of length (meters or feet). We assumed that the head is the difference between the elevation of the midpoint of the Upper Reservoir minus the midpoint of the elevation of the Lower Reservoir = 1,518 ft – 657 ft = 861 ft or 262 meters.

Q is the discharge (also called the flow rate). Assuming 27 hrs. at 1,400 MW, the flow rate is 550 m^3/s.

P Shaft = (1,000 x 9.81 x 262 x 550) / 80% = 1,765 MW

P Hydraulic = 1,000 x 9.81 x 262 x 596 = 1,412 MW

The table below summarizes the operation of 10 Hours of generation at full capacity and followed by 14 of pumping at full capacity.

9.3.5.2 One Day's Cycle

This one-day cycle would be the normal course of operation.

The plant could be cycled daily by generating for 10 hours at a full output of 1200 MW/hour. and pumping the water back from lower to upper reservoir for 14 hours at 1,412 MW/hour. The table below summarizes such an operation; note that the project will use only 30% of the available water in the upper reservoir or 18,286 Acre

Gen Mode	Gen Mode
Max Storage capability (Acre ft)	68,269
Max Storage capability (Cubic Feet)	2,973,797,640
Operating storage (Acre ft)	60,954
Operating storage(Cubic Feet)	2,655,156,240
Hr. of Generation at full output Hrs.	10
Amount of water release from UR %	30%
Amount of water release from UR (Acre ft)	18,286
Amount of water release from UR (cubic feet)	796,546,872
Discharge Rate (m^3/s)	627
Discharge Rate (cfs)	22,126
Turbine Efficiency %	80%
Gravitational Acceleration m/s^2	9.81
Water Density kg/m^3	998
Head in meter	262
Head in ft	861
Power Output in Watt	1,285,957,290
Power Output in MW	1,286
Power Output (Kw Per Af)	70.32
Pump Mode	**Pump Mode**
Max Storage capability (Acre ft)	48,700
Operating storage (Cubic Feet)	43,481
Hr. of pumping at full output	14
Amount of water release from LR %	52%
Amount of water pump back from LR (Acre ft)	22,610
Amount of water pump back from LR (cubic feet)	984,896,827
Amount of water pump back from LR (m^3/s)	553.59
Amount of water pump back from LR (cfs)	19,542
Gravitational Acceleration m/s^2	9.81
Pump Efficiency %	80%
Water Density kg/m^3	1000
Head in meter	262
Head in ft	861
Shaft Power (MW)	1,779
Hydraulic Power (MW)	1,423
Power Consumption (Kw Per Af)	62.929

ft to generate 1,286 MW/hour for 10 hours. Conversely, the energy needed to pump the 22,610 ac ft of water from the lower to the upper reservoir.

10 Method and Approach for Valuation of PSH Services

10.1 Optimization Methods

ZGlobal's (ZG's) eGrid Analytics shown in Figure 11, is used to back-cast and forecast the Project under all three interconnection scenarios for case 1. The optimization calculates (backcast) energy and ancillary services revenue from all three scenarios for 2019 to 2022. The optimization also forecasts project revenues from 2030 to 2079 under all three interconnection Scenarios (4,5, and 6). These forecast calculations were performed based on input assumptions using resource cost modeling techniques, which can be described as optimization procedures whose objective is to maximize Project revenues. The Project revenues are subject to satisfying operational, physical, and Hydrology, round-trip efficiency constraints. This model is also referred to as the assumptions as shown in Table 25 and Table 26 and Appendix E are subject to capacity requirements to meet reliability standards and deterministic methods because they rely on a specific and well-designed set of assumptions.

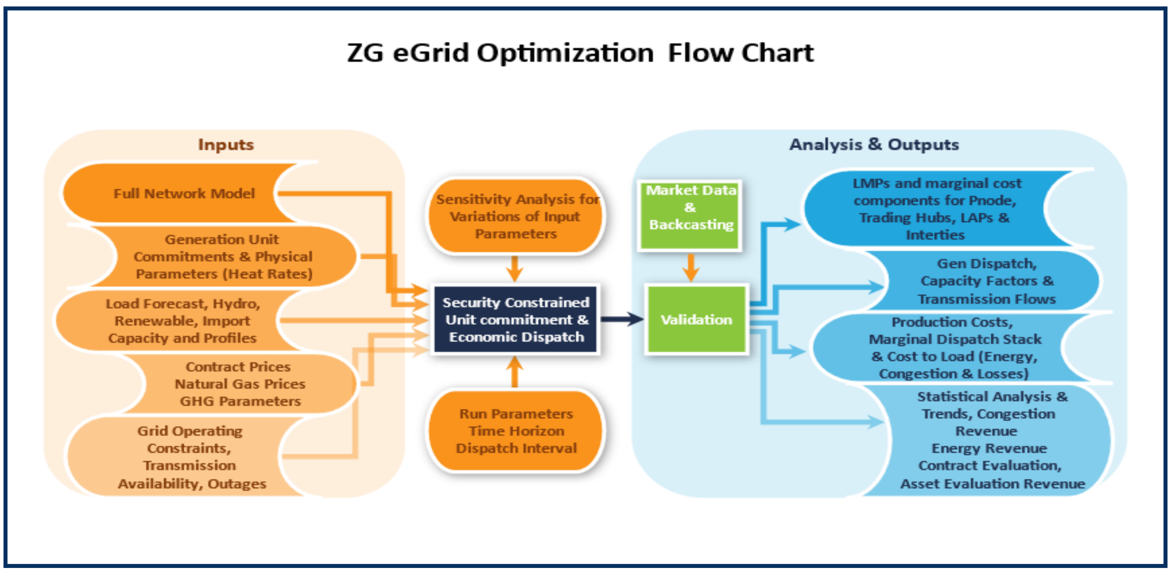

Figure 11– ZG eGrid Optimization Flow Chart

10.1.1 *Price Taker Model Estimation*

The price-taker approach and tools are used to estimate the historical or future revenue of the Project using historical market prices. These models offer a more flexible and simplified approach: measuring the Project revenues under the assumption that the unit does not significantly affect market prices. This type of model can be used to benchmark the historical and future value of the Project. We later discussed that the Project is more likely to operate for a few hours during the day at the peak when the energy and ancillary services price is the most attractive. Conversely, the Project will use the grid to pump the water back to the upper reservoir during hours when the prices are the lowest. The daily cycle explains the mode of the optimum way to operate the Project and is shown in Figure 12 below.

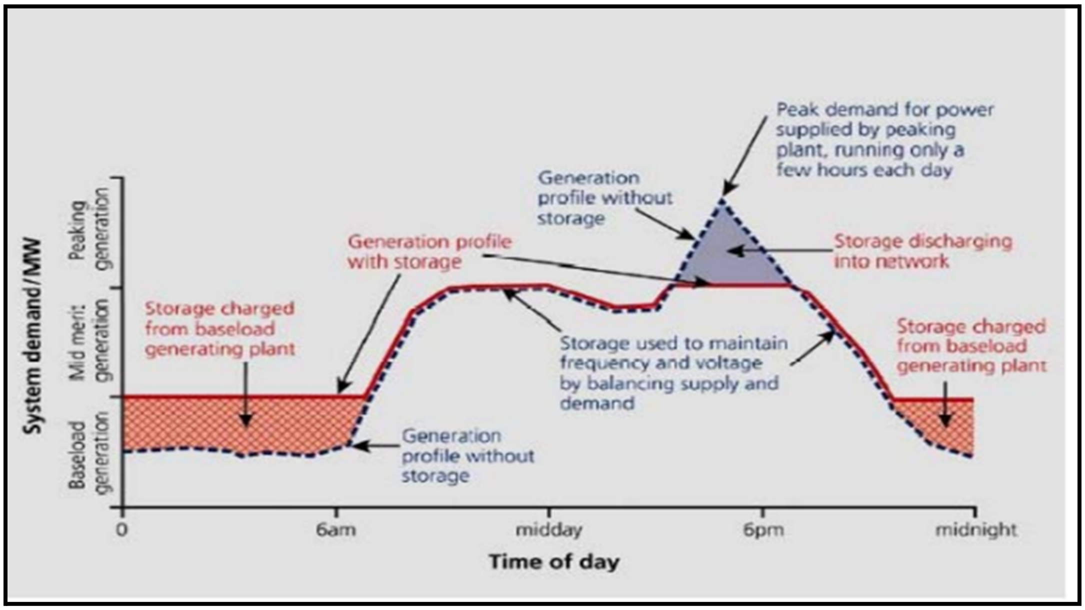

Figure 12– Project Typical Daily Cycle

10.1.2 Deterministic Method for Forecast of Project Revenue

- This method is used to derive the Project revenue from Energy and ancillary serviced for the 50-year analysis and is applied to all three interconnection scenarios for case 1.
- ZG uses its expertise and optimization software to calculate the optimum hourly dispatches of the Project. This process also includes the optimum time of the day and the amount of energy to store to not continually deliver to the grid but rather calculate when to release such stored energy to the grid in an optimum manner and over 24 24-hour optimization horizon. The results show the Project revenue at the hub. The results also show the amount of energy and ancillary services the Project is clearing in each of both regional markets.
- Deterministic optimization calculates the implied heat rate at the hub to detail the operations of the Project. To account for the uncertainty around the future of the driving factors, we consider the effect that changing annual baseline assumptions for natural case, demand growth, and generation capacity/ retirement and addition under the Stochastic method shown below.
- The deterministic method calculates the estimate of the “baseline” values of Project revenue because it provides how generation is “stacking up” to serve the demand. The energy stack it produces is critical to estimate the implied heat rate, spark spread, and the marginal cost of electricity, and therefore the Project revenue. To account for the uncertainty in Project revenues and Project cost, we performed a stochastic analysis on top of the deterministic analysis.

10.1.3 Stochastic Method

To determine certain impacts of key variables such as annual demand growth and natural gas prices on the project's future revenues, we used the deterministic “Low Case” to calculate the Project revenue and returns over the life of the project. We modified the Low case or case 1 annual demand growth, renewables, and new and retirement of generation and natural gas prices as shown in Appendix E to forecast both the "Medium Case" and "High Case" under Scenarios 4,5, and 6. We then used the Stochastic method to determine the Value at Risk by varying the project capital cost and project revenues.

The Stochastic method can be characterized as a combination of deterministic and stochastic models and is well-suited for investment in an uncertain environment. One of the advantages of this method is to capture future uncertainty and provide decision-makers with flexibility in their investment decisions. Furthermore, the Stochastic Model (also referred to as the Real Options model) is suitable for energy projects since many variables (the cost of equipment, the forecast of market price for wholesale ancillary services, energy market prices, the growth of renewable generation, and the changes in natural gas price) are uncertain and can vary significantly. The deterministic model is used to represent the supply and demand relations for a given set of supply and demand assumptions as well as generation retirement, additions, and capacity requirements as well as reliability requirements such as RA and ancillary services). The stochastic techniques are used to represent the evolution of the underlying drivers with the goal of answering the question: "What causes the project revenue to move up and down and what are the primary variables that describe the movements robustly and stably" This enables ZG to model the evolution of these variables. The stochastic approach uses the Box and Cox paper as a nonlinear transformation of a certain number of random variables with each variable or driver described with a standard deviation distribution. The distinct advantage of the Stochastic Model also captures the ability to exploit major sources of information that capture the uncertainty of events or risks, such as an increase in project cost, annual revenue, and natural gas prices but we did not capture the impact of heat waves, supply disruptions, heavy rains, or excessive unplanned outages that could affect electricity prices and therefore project revenues. The acknowledgment of uncertainty and risk implies that there is not only one anticipated outcome, but multiple possible outcomes, and the decision must be made with a range of values in mind. These quantifiable risks are incorporated to enhance the forecast of electricity prices used to forecast the Project revenue.

- **Stochastic method:** The distribution about the mean is assumed to be a normal distribution for each of the time of the day periods described below:

$$p(\chi) = \frac{1}{Sqrt\ (2\pi)^{*}\ \sigma} exp\ \left(-\ \frac{(\chi-\mu)^{2}}{2\sigma^{2}}\right)\ (1)$$

Net Annual Project Revenue:

μ = 25% variation of the forecasted net annual Project revenue mean.

σ = 25% variation of the forecasted net annual project revenue standard deviation.

P(χ) = Uniform probability density.

For P(χ) = we use a random variable.

The results along with Value at Risk are summarized in section 16.

The stochastic case uses the annual deterministic value as an input with the aid of Monte Carlo simulation. We applied this method to determine the impact of changes in project revenue and project capital cost for all three-interconnection scenarios (4,5, and 6), see section 16.

11 Backcasting Study Results under Scenario 1 - ERCOT Only Interconnection

ERCOT does not operate in a capacity market and relies on energy prices to maintain an adequate supply of electric generation to meet demand and capacity reserves to help support grid reliability if shortfalls occur. In 2014, ERCOT implemented the operating reserve demand curve, which creates a real-time price adder to reflect the value of available reserves in the system. It is based on the LOLP calculation and reflects the value of lost load (VoLL). The maximum VoLL at ERCOT is administratively set at $9,000/MWh and recently changed to 5,000 $/MWh, which is reached if the available reserve capacity drops below 2,000 MW.

Black Start: In ERCOT, black start units are paid an hourly standby fee which is determined through a competitive bi-annual bidding process.

11.1 Summary Project Back-cast Revenue and Return

We used public hourly clearing prices in ERCOT from 2019 to 2022 to calculate the Project revenue for each year[11].

Before we dive into the analysis it is important to note:

a) Understand the transition that ERCOT is undergoing as described above. Energy supplied from coal has decreased from 40% in 2010 to 18% in 2020, while wind increased from 8% to 23%. Natural gas generation has a net increase of 8% from 2010 to 2020. As wind and solar penetration increases, more volatility is expected. The Project is an excellent source to smooth the volatility and allow a flexible and fast-moving generation and provide ancillary services to the market.

b) The Project is not intended to be used as a baseload and therefore average prices can be misleading. The Project is designed to capture the time when the grid needs fast-moving generation and ancillary services. To this extent, as with most pumped storage hydro projects, the capacity factor is not a good indication of the value of the Project; rather, the ability to arbitrage between low and high price hours and receive capacity payments from the ancillary service market is fundamental to the valuation of this Project.

11.1.1 Key Observations in 2019

- Warm summer temperatures increased both the peak and average demands by 2% from 2018 and set a record peak hour demand of 74,820 MW on August 12, 2019.
- Average real-time energy prices rose by 32% in 2019, despite a 23% reduction in natural gas prices. This increase is attributable to the shortage of pricing in August and September, with prices close to the offer cap of $9,000 per MWh for a total of more than two hours. On January 17, 2019, the Commission modified ERCOT's shortage pricing by altering the operating reserve demand curve (ORDC). The first stage of these changes was implemented on March 1, 2019, and the effects were significant. The changes accounted for a $6 to $7 per MWh increase in average energy prices and an increase in energy

[11] Energy: https://www.ercot.com/mp/data-products/markets/day-ahead-market?id=NP4-180-ER
AS: https://www.ercot.com/mp/data-products/markets/day-ahead-market?id=NP4-181-ER

revenue of $1.9 to $2.1 billion in 2019. Prices greater than $1,000 per MWh occurred in more than 28 hours in 2019 and were between $7,000 and $8,999 for more than 3 hours.

11.1.2 Key Observations in 2020

The highest electricity demand in 2020 was 74,328 MW, occurring on August 13, 2020, between 4 p.m. and 5 p.m. This was about 500 MW lower than the all-time peak demand on August 12, 2019.

- Although the summer was warmer in 2020, which predictably increases electricity consumption, average consumption was slightly lower than in 2019 partly because of the impacts of the COVID-19 pandemic.
- Approximately 1,000 MW of natural gas resources were retired in 2020.
- ERCOT continued to set new records for peak wind output. A new wind output record was set on December 22, 2020 (21,972 MW). The amount of power produced by wind resources (23%) outpaced coal (18%) in 2020.
- Approximately 7,700 MW of new generation came online in 2020, including 7,250 MW of wind and solar resources and 400 MW of natural gas. The amount of utility-scale solar capacity added in 2020 was the largest amount added to the ERCOT system in any one year, bringing the total installed capacity to over 5,600 MW. 70 MW of battery energy storage resources began commercial operations in 2020. In addition, three flexible resources retired permanently, representing a decrease of 1,030 MW.
- February 8-20, 2021, during which the extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies, The total Event firm demand shed was the largest controlled firm demand shed event in U.S. history and was the third largest in quantity of outage megawatts (MW) of demand after the August 2003 northeast blackout and the August 1996 west coast blackout.

11.1.3 Key Observations in 2021

The February 2021 Event is the fourth in the past 10 years that jeopardized bulk-power system reliability due to unplanned cold weather-related generation outages[12]:

- 2011 –29,700 MW
- 2014 –19,500 MW
- 2018 –15,800 MW

[12] https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-full

Total demand for electricity in 2021 increased by 3% from 2020[13] – an increase of approximately 1,300 MW per hour on average as the effects of the pandemic dissipated. Approximately 1,045 individual generating units experienced 4,124 outages, derates, or failures to start, of which 604 were natural gas-fired generators. During the week of February 14, 2021, for over two consecutive days, ERCOT averaged 34,000 MW of generation outages, 49%, or half of ERCOT's 2021 actual all-time winter peak demand of 69,871 MW.

These resource changes along with changes in fuel prices led to the following changes in electricity production in 2021:

1. The percentage of total generation supplied by wind resources continued to increase to more than 24% of all annual generation.
2. Natural gas generation decreased in 2021 from 46% in 2020 to less than 42% in 2021 as natural gas prices rose sharply.
3. Approximately 8,800 MW of new generation resources came online in 2021. Energy storage amounts to 820 MW and 890 MW of natural gas. The remaining 7,090 MW are from intermittent resources with an effective peak serving capacity totaling 2,400 MW.
4. Increased non-spinning reserve requirements with a minimum ancillary reserve requirement set at 3,000 MW per hour.
5. The most substantial change was in December 2021, when the PUCT changed a market demand curve that lowered the energy price cap from $9,000 per megawatt hour to $5,000 per megawatt hour, but also made it easier to reach the lucrative price cap.
6. Potomac estimates that those changes added $1.7 billion in revenue to Texas' real-time electricity market in 2022 through Nov. 30. Most of the revenue went to dispatchable resources such as natural gas power producers.

Based on ERCOT's hourly clearing prices for energy and ancillary services for 2021, we performed a back-casting optimization and calculated the Project revenues for 2021 based on these hourly clearing prices. As you can see from Figure 13 below, the ice storm resulted in possible Project revenue of $3.13 billion of which $2.8 billion was captured during the ice events from 2/12/2021 to 2/20/2021.

In conclusion, if we consider 2020 (COVID) and 2021 (Ice storm) as outliers, the total revenue from 2018 to modified 2021 ranged from $333 million to $197 million. During this period, natural gas averaged 3.91 $/MBTU for 2021 and Modified 2021 to $2.04, $2.57, and $3.17 $/MBTU for 2020, 2019, and 2018, respectively.

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13 https://www.ercot.com/files/docs/2022/06/13/8%20Independent%20Market%20Monitor_IMM_2021%20State%20of%20the%20Market%20Report%20for%20the%20ERCOT%20Electricity%20Markets.pdf

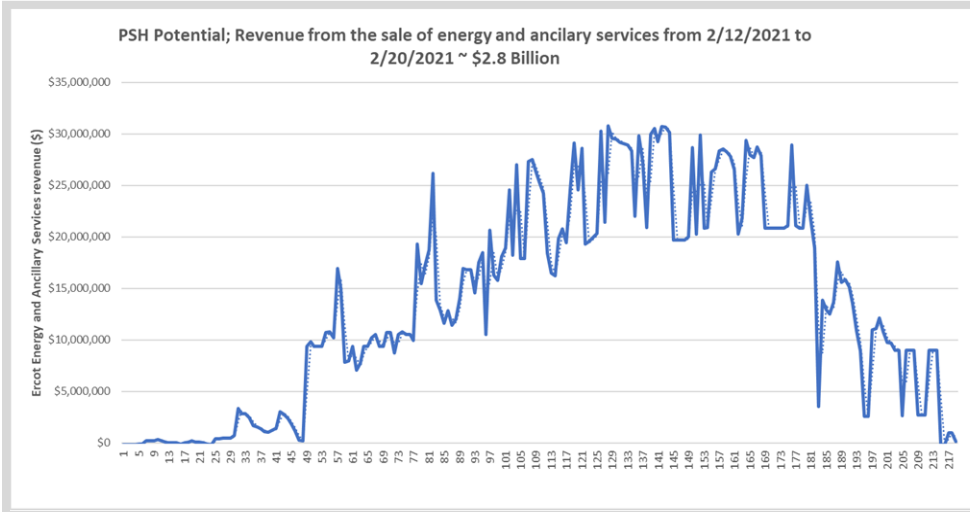


Figure 13– Project Potential Energy and Ancillary Services Revenue ($) During the Ice Storm

In 2021, ERCOT increased the Spinning Response Reserve Service (RRS) to a floor of 1,420 MW.

11.1.4 Key Observations in 2022

- ERCOT again increased the RRS to a floor of 2,800 MW during peak hours which are 14:00 through 22:00 (HE15 - HE22). "This additional RRS will help maintain a larger operating margin to operate more conservatively". Additional spinning reserve varies by hour and month ranging between 1,769 MW and 2,812 MW.
- Operating Reserve Demand Curve (ORDC) increased to 9,300 MW under the new reserve policy implemented in early 2022. The previous ORDC ranged from 5,770 MW and 6,7210 according to the 2022 Biennial ERCOT Report on the Operating Reserve Demand Curve issued on 10/31/2022[14]. The minimum contingency level was shifted from 2,000 MW to 3,000 MW as part of post-Uri conservative operations.

14 https://www.ercot.com/files/docs/2022/10/31/2022%20Biennial%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf

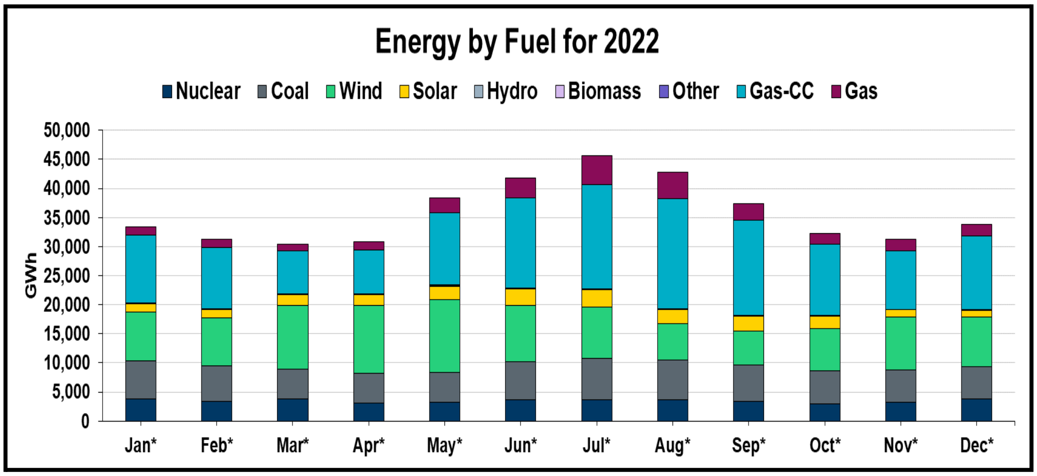


Figure 14– Energy by Fuel for 2022

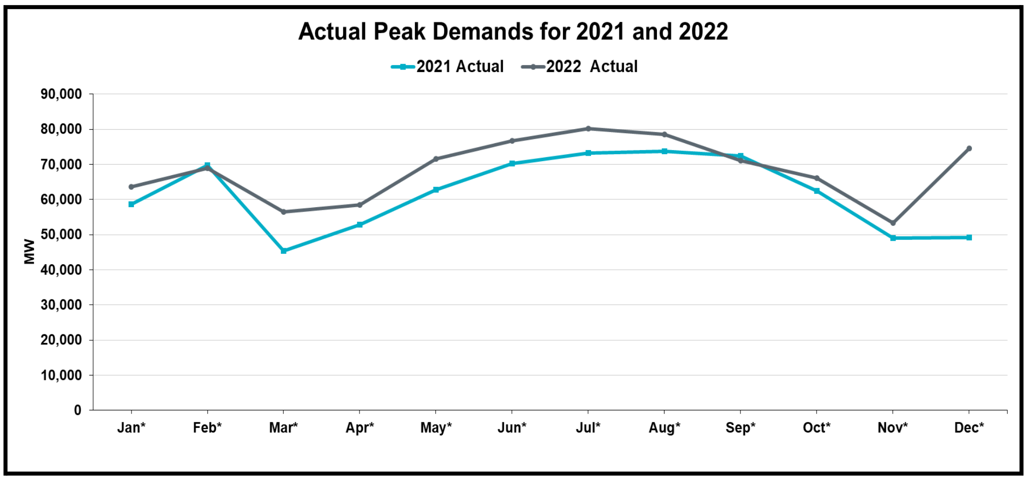


Figure 15– Actual Peak Demands for 2021 & 2022

- ERCOT set a new all-time winter peak record of 74,427 MW in the month of December on 12/23/2022; this is 4,615 MW more than the previous winter record of 69,812 MW set on 2/14/2021. This is 25,235 MW more than the December 2021 demand of 49,192 MW. Ancillary Service costs during the month of December 2022 reached $179.78 million [15] whereas the May 2022 and July 2022 ancillary service costs were $225 million and $250 million, respectively. ERCOT's Ancillary services market size was over $1.3 billion in 2022.

[15] https://www.ercot.com/files/docs/2023/01/18/ERCOT-Monthly-Operational-Overview-December-2022.pdf, Page 18

11.1.5 Key Observations in 2023

- In June 2023. ERCOT has launched the ERCOT Contingency Reserve Service (ECRS), a new daily procured Ancillary Service. As energy demand continues to grow in Texas, adding ECRS will support grid reliability and mitigate real-time operational issues to keep supply and demand balanced. This is an addition to the four Ancillary Services ERCOT currently uses: Regulation Up, Regulation Down, Responsive Reserve Service (spinning reserve), and Non-Spin Reserve Service. Figure 16 is ERCOT's July 1st, 2023, hourly ancillary service requirement which ranged from a minimum of 6,815MW to a maximum of 9,162 MW[16].

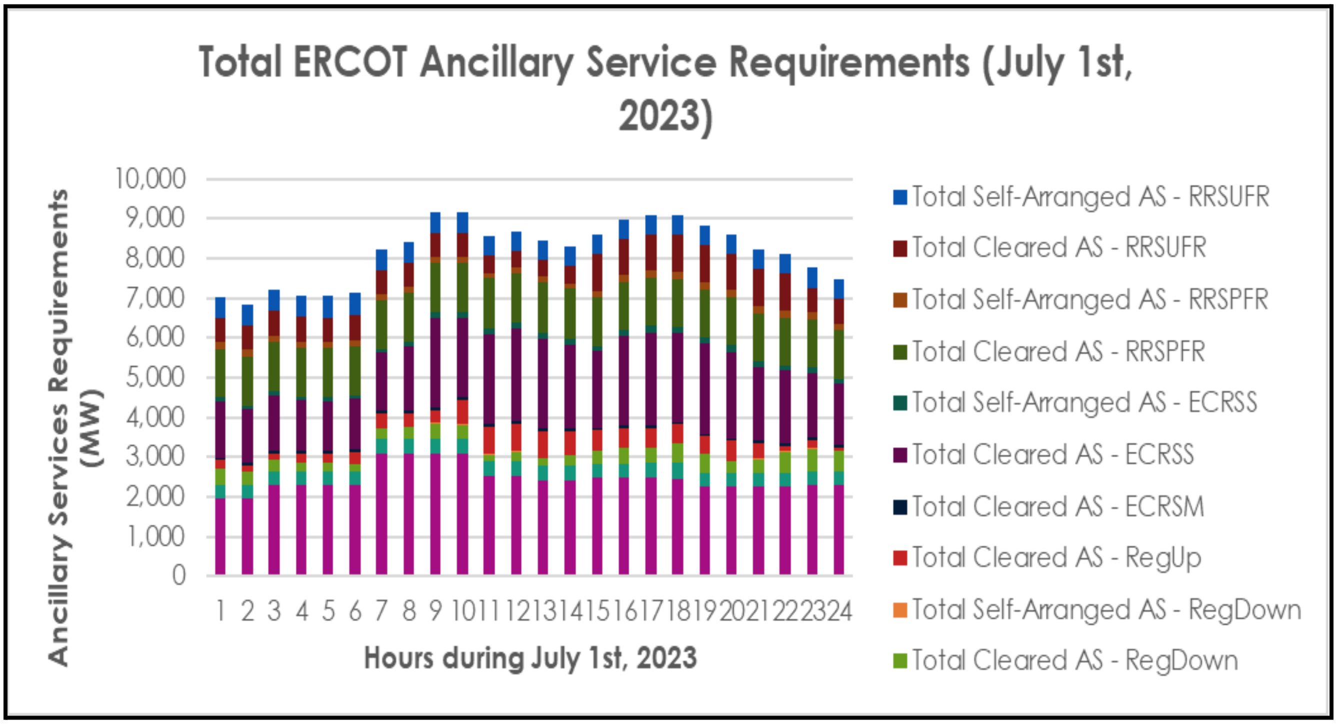


Figure 16– Ancillary Service Requirements (July 1st, 2023)

[16] https://www.ercot.com/mp/data-products/data-product-details?id=NP3-911-ER

11.2 ERCOT Energy and Ancillary Services Price Trend Analysis

	Frequency of 2018 Prices				
	Energy Prices	**Spin Prices**	**Nspin Prices**	**RegUP Prices**	**RegDown Prices**
< $0	0	0	0	0	0
>= $0 and < $10	60	4,271	7,880	6,297	7,994
>= $10 and < $20	2,202	2,685	527	1,587	510
>= $20 and < $50	5,804	1,521	264	691	234
>= $50 and < $100	567	194	38	110	16
>= $100	127	88	50	74	5
	Frequency of 2019 Prices				
	Energy Prices	**Spin Prices**	**Nspin Prices**	**RegUP Prices**	**RegDown Prices**
< $0	0	0	0	0	0
>= $0 and < $10	175	4,579	7,752	6,177	6,888
>= $10 and < $20	3,905	2,543	430	1,455	1,320
>= $20 and < $50	4,151	1,218	284	764	447
>= $50 and < $100	304	197	110	169	85
>= $100	225	223	184	195	20
	Frequency of 2020 Prices				
	Energy Prices	**Spin Prices**	**Nspin Prices**	**RegUP Prices**	**RegDown Prices**
< $0	0	0	0	0	0
>= $0 and < $10	457	5,747	8,113	6,452	6,608
>= $10 and < $20	5,118	2,070	422	1,519	1,919
>= $20 and < $50	2,947	807	179	664	222
>= $50 and < $100	197	105	42	100	35
>= $100	65	55	28	49	0
	Frequency of 2021 Prices				
	Energy Prices	**Spin Prices**	**Nspin Prices**	**RegUP Prices**	**RegDown Prices**
< $0	0	0	0	0	0
>= $0 and < $10	210	2,969	6,227	3,771	4,721
>= $10 and < $20	1,698	2,624	1,078	2,375	2,086
>= $20 and < $50	5,470	2,272	944	1,905	1,520
>= $50 and < $100	1,017	508	211	357	230
>= $100	365	387	300	351	202
	Frequency of 2022 Prices				
	Energy Prices	**Spin Prices**	**Nspin Prices**	**RegUP Prices**	**RegDown Prices**
< $0	0	0	0	0	0
>= $0 and < $10	91	5,669	5,759	5,082	6,462
>= $10 and < $20	374	1,337	1,052	1,676	1,496
>= $20 and < $50	4,182	1,207	1,273	1,404	722
>= $50 and < $100	3,151	322	358	366	68
>= $100	962	224	317	231	11

ERCOT Energy Price Trend	2019	2022	Increase/Decrease in 2022 From 2019
< $0	0	0	0.00%
>= $0 and < $10	175	91	-92.31%
>= $10 and < $20	3,905	374	-944.12%
>= $20 and < $50	4,151	4,182	0.74%
>= $50 and < $100	304	3,151	90.35%
>= $100	225	962	76.61%
Total	8,760	8,760	
ERCOT Spin Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	4,579	5,669	19.23%
>= $10 and < $20	2,543	1,337	-90.20%
>= $20 and < $50	1,218	1,207	-0.91%
>= $50 and < $100	197	322	38.82%
>= $100	223	224	0.45%
Total	8,760	8,759	
ERCOT Nspin Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	7,880	5,759	-36.83%
>= $10 and < $20	527	1,052	49.90%
>= $20 and < $50	264	1,273	79.26%
>= $50 and < $100	38	358	89.39%
>= $100	50	317	84.23%
Total	8,759	8,759	
ERCOT RegUP Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	6,177	5,082	-21.55%
>= $10 and < $20	1,455	1,676	13.19%
>= $20 and < $50	764	1,404	45.58%
>= $50 and < $100	169	366	53.83%
>= $100	195	231	15.58%
Total	8,760	8,759	
ERCOT RegDn Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	6,888	6,462	-6.59%
>= $10 and < $20	1,320	1,496	11.76%
>= $20 and < $50	447	722	38.09%
>= $50 and < $100	85	68	-25.00%
>= $100	20	11	-81.82%
Total	8,760	8,759	

Tables 16 and 17 compare the frequency of energy and ancillary services prices in ERCOT within the specified ranges between 2018 and 2022. We will use this data to analyze the historical trend of prices to understand expectations for the future.

- ERCOT energy prices above 50$/MWh were 529 hrs. in 2019 and jumped to 4,113 hrs. in 2022.
- The number of hours when the energy prices fall in the lower ranges of $0-$20, declined significantly from 4,080 hrs. in 2,029 to 465 hrs. in 2022.
- The revenue from the Spinning Reserve market in 2022 was lower than in 2019 while all other ancillary services revenues were higher in 2022.
- A similar trend can be noticed in the Non-Spinning Reserve, RegUp, and RegDown markets where the number of hours with prices in the lowest range (<$10) decrease by 24.21%, 13.87%, and 17.49% respectively. On the other side, there are varying increases in the number of hours where these prices

fall in the higher ranges. This indicates that there are fewer hours with low prices in these markets in favor of more hours with higher prices in 2022 compared to 2019, which will generate more revenue as the years go by.

- Non-Spinning reserve prices above 20$/MWh were 352 hrs. in 2019 and jumped to 1,948 hrs. in 2022 capturing $48 million in revenue in 2022.
- RegDown reserve prices above 20$/MWh were 1,128 hrs. in 2019 and jumped to 2,001 Hrs in 2022 capturing $55 million in revenue in 2022.
- RegUP reserve prices above 20$/MWh were 552 hrs. in 2019 and jumped to 801 Hrs in 2022 capturing $36million in revenue in 2022.
- This indicates a clear uptrend of energy and ancillary prices which presents a lucrative opportunity to sell energy and ancillary services in ERCOT.

11.3 Scenario 1 - ERCOT Historical or Backcasting of Annual Revenue

Ercot	2022	2021	2020	2019
Pump Load (MWh)	3,047,286	1,735,074	1,869,295	1,623,109
Energy Generation (MWh)	2,405,369	1,369,578	1,475,524	1,281,198
Spin Provision (MWh)	1,689,467	3,870,295	3,327,434	4,901,701
NonSpin Provision (MWh)	1,198,375	1,027,866	388,090	490,361
RegUP Provision (MWh)	3,734,645	1,798,556	2,130,207	1,450,335
RegDOWN Provision (MWh)	5,353,815	5,452,437	5,904,830	4,807,756
Cost to Pump ($)	-$108,393,057	-$42,148,090	-$22,039,010	-$22,521,248
Energy Revenue ($)	$262,570,978	$132,231,605	$58,347,681	$130,425,601
Spin Revenue ($)	$62,629,682	$2,781,146,820	$44,236,102	$158,337,035
NonSpin Revenue ($)	$48,617,986	$135,076,451	$1,995,581	$8,167,306
RegUP Revenue ($)	$36,883,463	$152,589,520	$27,007,255	$19,299,169
RegDOWN Revenue ($)	$55,923,589	$258,929,395	$60,223,428	$59,113,278
Total Gross Revenue ($)	$466,625,698	$3,459,973,791	$191,810,046	$375,342,390
Total Net Revenue ($)	$358,232,640	$3,417,825,701	$169,771,036	$352,821,142
Cost to Pump ($/MWh)	-$35.57	-$24.29	-$11.79	-$13.88
Energy Revenue ($/MWh)	$109.16	$96.55	$39.54	$101.80
Spin Revenue ($/MWh)	$37.07	$718.59	$13.29	$32.30
NonSpin Revenue ($/MWh)	$40.57	$131.41	$5.14	$16.66
RegUP Revenue ($/MWh)	$9.88	$84.84	$12.68	$13.31
RegDOWN Revenue ($/MWh)	$10.45	$47.49	$10.20	$12.30
Net Energy Revenue ($) (Sales Revenue - Pump Cost)	$154,177,920	$90,083,516	$36,308,671	$107,904,353
Total Ancillary Services Revenue ($)	$204,054,720	$3,327,742,186	$133,462,365	$244,916,789
Total Net Revenue ($)	$358,232,640	$3,417,825,701	$169,771,036	$352,821,142

Table 18– Scenario 1 - Summary of the Backcast Project Revenue from ERCOT Market

Table 18 above summarizes the results of the historical annual project revenues from energy and ancillary services and does *not* include resource adequacy. We recognize that 2021 may be an outlier due to the ice storm but it is possible that the same situation could occur 1 time in 20 years, which would be an "Extreme Event". The net Project revenue for 2021 was $3,417 million compared to $169 million in 2020, which represents a 1921% increase. We calculated the Project's net revenue using historical energy and ancillary services from 2019 to 2022. Appendix D is used to determine ancillary services and energy dispatch and results are summarized in Appendix C while Appendix B shows a sample of the project dispatch,

12 Backcasting Study Results under Scenario 2 - SPP Only Interconnection

12.1 Summary Project Back-cast Revenue in SPP

Like the ERCOT market, the generation mix is going through a transition. Generation from coal declined from 60% in 2014 to about 30%, while wind increased from 12% to 40%. SPP is different from ERCOT in at least two ways: (1) SPP is interconnected to other regional markets such as WECC and the Midwest and (2) SPP is generation-rich and does not serve as much demand as ERCOT but expands from Oklahoma to North Dakota.

SPP's nameplate capacity represents the total potential output of every generating unit registered in SPP's market: 98,608 MW. As of summer 2022, SPP's accredited capacity - a measure of the amount of generation SPP can expect to be available at a given time - was 64,486 MW. Both values exceed the region's record peak demand of 53,243 MW (set July 19, 2022). In 2022, Natural Gas generating capacity accounts for 37% while wind and coal are at 33% and 23%. Energy production was 287 TWh,

In 2022, the SPP region set a record for instantaneous demand: 53,243 MW on July 19, beating the previous record of 51,037 MW set on July 28, 2021. During Winter Storm Elliott in December 2022, SPP also set a new winter-season peak demand of 47,157 MW, far surpassing its previous winter peak of 43,661 set during the historic Winter Storm Uri on February 15, 2021.

SPP reached new record-high levels of wind penetration in 2022, serving as much as 88.5% of its demand with wind energy and 90.2% of its demand with all renewable energy sources for a period on March 29. There were also periods during which wind served as little as 1.5% of SPP’s total generation. During these intervals, other generation types like coal, natural gas, and nuclear units play a critical role in maintaining reliability.

Wind curtailment occurs when the energy generated into the grid exceeds the demand. Since there is no mechanism to store the excess energy, SPP curtailed wind energy generation by switching off wind turbines. SPP wind curtailment was 700 MWh in 2021 with 501 hours of negative prices. Note that, as shown in Table 6, there were 110 hours in the first five months of 2022 during which prices fell between $100/MWh to $200/MWh, which is more than similar hours in the entire year of 2021[17].

[17] Energy: https://marketplace.spp.org/pages/da-lmp-by-location
AS: https://marketplace.spp.org/pages/da-mcp#

12.2 Scenario 2 - SPP Energy and Ancillary Services Price Trend Analysis

	Frequency of 2018 Prices				
	Energy Prices	Spin Prices	NonSpin Prices	RegUP Prices	RegDown Prices
< $0	56	0	0	0	0
>= $0 and < $10	390	7,553	8,667	5,917	7,896
>= $10 and < $20	2,516	1,104	59	2,469	756
>= $20 and < $50	5,525	102	33	364	107
>= $50 and < $100	272	0	0	9	0
>= $100	1	0	0	0	0
	Frequency of 2019 Prices				
	Energy Prices	Spin Prices	NonSpin Prices	RegUP Prices	RegDown Prices
< $0	254	0	0	0	0
>= $0 and < $10	738	7,326	8,577	5,408	7,846
>= $10 and < $20	2,962	1,227	111	2,789	750
>= $20 and < $50	4,563	199	67	547	163
>= $50 and < $100	225	7	4	15	0
>= $100	18	0	0	0	0
	Frequency of 2020 Prices				
	Energy Prices	Spin Prices	NonSpin Prices	RegUP Prices	RegDown Prices
< $0	498	0	0	0	0
>= $0 and < $10	1,032	7,717	8,736	5,677	7,387
>= $10 and < $20	3,928	903	26	2,519	953
>= $20 and < $50	3,245	160	21	561	442
>= $50 and < $100	80	3	0	23	1
>= $100	1	0	0	3	0
	Frequency of 2021 Prices				
	Energy Prices	Spin Prices	NonSpin Prices	RegUP Prices	RegDown Prices
< $0	619	0	0	0	0
>= $0 and < $10	628	5,310	8,499	2,509	7,730
>= $10 and < $20	1,319	2,553	56	3,838	790
>= $20 and < $50	4,605	741	59	2,130	172
>= $50 and < $100	1,386	18	8	112	5
>= $100	203	137	137	170	62
	Frequency of 2022 Prices				
	Energy Prices	Spin Prices	NonSpin Prices	RegUP Prices	RegDown Prices
< $0	450	0	0	0	0
>= $0 and < $10	401	4,452	8,614	2,259	7,975
>= $10 and < $20	643	2,641	19	3,574	723
>= $20 and < $50	3,354	1,578	91	2,790	61
>= $50 and < $100	2,775	84	31	130	0
>= $100	1,137	4	4	6	0

SPP Energy Price Trend	2019	2022	Increase/Decrease in 2022 From 2019
< $0	254	450	43.56%
>= $0 and < $10	738	401	-84.04%
>= $10 and < $20	2,962	643	-360.65%
>= $20 and < $50	4,563	3,354	-36.05%
>= $50 and < $100	225	2,775	91.89%
>= $100	18	1,137	98.42%
Total	8,760	8,760	
SPP Spin Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	7,326	4,452	-64.56%
>= $10 and < $20	1,227	2,641	53.54%
>= $20 and < $50	199	1,578	87.39%
>= $50 and < $100	7	84	91.67%
>= $100	0	4	100.00%
Total	8,759	8,759	
SPP Nspin Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	8,577	8,614	0.43%
>= $10 and < $20	111	19	-484.21%
>= $20 and < $50	67	91	26.37%
>= $50 and < $100	4	31	87.10%
>= $100	0	4	100.00%
Total	8,759	8,759	
SPP RegUP Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	5,408	2,259	-139.40%
>= $10 and < $20	2,789	3,574	21.96%
>= $20 and < $50	547	2,790	80.39%
>= $50 and < $100	15	130	88.46%
>= $100	0	6	100.00%
Total	8,759	8,759	
SPP RegDn Price Trend	**2019**	**2022**	**Increase/Decrease in 2022 From 2019**
>= $0 and < $10	7,846	7,975	1.62%
>= $10 and < $20	750	723	-3.73%
>= $20 and < $50	163	61	-167.21%
>= $50 and < $100	0	0	0.00%
>= $100	0	0	0.00%
Total	8,759	8,759	

*Table SEQ Table * ARABIC 19– Summary of Scenario 2 -SPP 2018 to 2022 Energy and Ancillary Service Prices*

Tables 19 and 20 compare the frequency of energy Ancillary services prices in SPP within the specified ranges between 2018 and 2022. We will use this data to analyze the historical trend of prices to understand expectations for the future.

- The number of negatively priced energy hours increased from 254 hrs. in 2019 to 450 hrs. in 2022. This indicates that there are approximately 200 more hours to pump at negative prices. Negatively priced energy hours are crucial as they provide opportunities to pump while getting paid and generating revenue.
- SPP energy prices above 50$/MWh were 243 hrs. in 2019 and jumped to 3,912 hrs. in 2022.

- The number of hours when the energy prices fall in the $0-$20, declined sharply from 3700 to 1044 hrs.
- Spinning reserve prices above 20$/MWh were 206 hrs. in 3029 and jumped to 2,666 hrs. in 2022.
- RegDown reserve prices above 20$/MWh were 1,128 hrs. in 2019 and jumped to 2,001 Hrs in 2022 capturing $55 million in revenue in 2022.
- RegUP reserve prices above 20 $/MWh were 562 hrs. in 2019 and jumped to 2,926 hrs. in 2022.
- There is not a lot of movement in the RegDown market; however, the project will still yield revenue from selling RegDown regardless of prices due to the ability to turn on the pumps easily whenever the grid requires us to.
- There is not a lot of movement in the Non-Spinning Reserve market, which historically had low prices. That is further supported by the fact that our analysis concluded that the SPP non-spin sales are extremely low.

12.3 Scenario 2, Historical Annual Revenue in SPP

SPP	2022	2021	2020	2019
Pump Load (MWh)	4,041,188	3,684,440	3,274,112	3,292,615
Energy Generation (MWh)	3,189,903	2,908,305	2,584,414	2,599,019
Spin Provision (MWh)	400	2,999	2,400	3,595
NonSpin Provision (MWh)	400	1,799	1,200	1,200
RegUP Provision (MWh)	6,645,083	6,970,183	6,387,306	6,375,469
RegDOWN Provision (MWh)	4,166,783	3,877,781	4,702,168	4,639,938
Cost to Pump ($)	-$95,393,291	-$61,447,739	-$22,794,026	-$36,567,639
Energy Revenue ($)	$284,818,278	$180,352,056	$73,000,207	$91,402,548
Spin Revenue ($)	$3,648	$168,612	$18,032	$8,401
NonSpin Revenue ($)	$268	$153,026	$9,628	$804
RegUP Revenue ($)	$130,282,282	$364,075,752	$72,160,480	$72,807,147
Reg DOWN Revenue ($)	$29,081,384	$28,690,308	$36,357,954	$27,924,338
Total Gross Revenue ($)	$444,185,859	$573,439,754	$181,546,301	$192,143,238
Total Net Revenue ($)	$348,792,568	$511,992,015	$158,752,275	$155,575,598
Cost to Pump ($/MWh)	-$23.61	-$16.68	-$6.96	-$11.11
Energy Revenue ($/MWh)	$89.29	$62.01	$28.25	$35.17
Spin Revenue ($/MWh)	$9.12	$56.22	$7.51	$2.34
NonSpin Revenue ($/MWh)	$0.67	$85.04	$8.02	$0.67
RegUP Revenue ($/MWh)	$19.61	$52.23	$11.30	$11.42
RegDOWN Revenue ($/MWh)	$6.98	$7.40	$7.73	$6.02
Net Energy Revenue ($) (Sales Revenue - Pump Cost)	$189,424,987	$118,904,317	$50,206,181	$54,834,908
Total Ancillary Services Revenue ($)	$159,367,581	$393,087,699	$108,546,094	$100,740,690
Total Net Revenue ($)	$348,792,568	$511,992,015	$158,752,275	$155,575,598

Table 21– Scenario 2 - Summary of the Backcast Project Revenue from SPP Market

Table 21 above summarizes the results of the historical annual project revenues from energy and ancillary services and does **not** include resource adequacy. We recognize that 2021 may be an outlier due to the ice storm but it is possible that the same situation could occur time 1 in 20 years, which would be an “Extreme Event”.

The Project revenue for 2021 was $511 million compared to $158 million in 2020, which represents a 341% increase. Appendix D is used to determine ancillary services and energy dispatch and results are summarized in Appendix C while Appendix B shows a sample of the project dispatch.

13 SPP & ERCOT Simultaneous Interconnection

13.1 SPP & ERCOT Back-casting of Net Project Revenue

We analyzed the possibility of interconnecting the Project to both SPP and ERCOT. The interconnection procedure follows Appendix A &C. Appendix A describes how we modeled the switching of each of the four generators and pumps from one region to the other based on economic conditions. The back-casting results are summarized in Table 21 below. The results show an incremental revenue gain in net revenue due to the process of pumping from SPP at lower prices and generating into ERCOT at higher prices.

Ercot & SPP	2022	2021	2020	2019
Pump Load (MWh)	4,712,510	3,592,236	3,201,941	3,053,485
Energy Generation (MWh)	3,719,811	2,835,524	2,527,446	2,410,263
Spin Provision (MWh)	505,969	1,951,600	1,591,701	2,920,864
NonSpin Provision (MWh)	251,916	136,392	8,600	67,200
RegUP Provision (MWh)	5,567,442	4,161,353	4,041,418	3,339,477
RegDOWN Provision (MWh)	4,394,500	4,720,288	5,544,505	4,704,777
Cost to Pump ($)	-$117,480,515	-$81,091,379	-$21,151,356	-$32,867,263
Energy Revenue ($)	$415,708,900	$250,564,128	$94,134,246	$176,436,442
Spin Revenue ($)	$46,977,391	$2,896,208,617	$27,815,337	$144,966,928
NonSpin Revenue ($)	$35,504,019	$7,948,564	$158,004	$5,281,512
RegUP Revenue ($)	$104,609,704	$172,561,831	$60,337,201	$45,762,544
RegDOWN Revenue ($)	$46,971,197	$247,585,874	$62,977,324	$60,255,682
Total Gross Revenue ($)	$649,771,211	$3,574,869,014	$245,422,111	$432,703,108
Total Net Revenue ($)	$532,290,696	$3,493,777,635	$224,270,755	$399,835,844
Total $/MWh	$143	$1,232	$89	$166
Cost to Pump ($/MWh)	-$24.93	-$22.57	-$6.61	-$10.76
Energy Revenue ($/MWh)	$111.76	$88.37	$37.24	$73.20
Spin Revenue ($/MWh)	$92.85	$1,484.02	$17.48	$49.63
NonSpin Revenue ($/MWh)	$140.94	$58.28	$18.37	$78.59
RegUP Revenue ($/MWh)	$18.79	$41.47	$14.93	$13.70
RegDOWN Revenue ($/MWh)	$10.69	$52.45	$11.36	$12.81
Net Energy Revenue ($) (Sales Revenue - Pump Cost)	$298,228,385	$169,472,749	$72,982,890	$143,569,179
Total Ancillary Services Revenue ($)	$234,062,311	$3,324,304,886	$151,287,866	$256,266,666
Total Net Revenue ($)	$532,290,696	$3,493,777,635	$224,270,755	$399,835,844

Table 22– Scenario 3 - Summary of 2019 to 2022 Revenue from Connecting the Project to Both Regional Markets

- Table 22 above summarizes the results of the historical annual project revenues from energy and ancillary services and does ***not*** include resource adequacy from energy and ancillary services and does not include resource adequacy. Appendix D is used to determine ancillary services and energy dispatch and results are summarized in Appendix C while Appendix B shows a sample of the project dispatch,
- The energy and ancillary services market in ERCOT is a bit more lucrative than SPP. This is further proven by the following Table 24, which represents the number of hours in 2022 where the prices of the ancillary services exceed $20 in ERCOT and SPP:

ERCOT	2018	2019	2020	2021	2022
# of hrs Energy Prices >50 $/MWh	694	529	262	1,382	4,113
% of hrs Ancilary Services >20 $/MWh	22%	20%	13%	26%	34%
NG averages $/MMBTU	$4.94	$2.90	$2.70	$4.90	$7.50

*Table SEQ Table * ARABIC 23 – Evolution of ERCOT Energy and Ancillary Service Price Range*

	ERCOT 2022	SPP 2022
# of hrs Energy Prices >50 $/MWh	4,113	3,912
% of hrs Ancilary Services >20 $/MWh	34%	28%
NG averages $/MMBTU	$7.50	$7.50

Table 25 below compares the number of hours that fall within various average energy price ranges between ERCOT and SPP from 2018 to 2022. This table further indicates that ERCOT has higher profitability than SPP in energy and ancillary service prices.

- There are 375 hours in 2022 where energy prices are negative in SPP, as opposed to none in ERCOT, which presents an attractive opportunity to pump from SPP and get paid to take energy.

Energy	ERCOT	SPP
< $0	0	375
>= $0 and < $10	199	638
>= $10 and < $20	2,659	2,274
>= $20 and < $50	4,511	4,258
>= $50 and < $100	1,047	948
>= $100	349	272
Reg Up	**ERCOT**	**SPP**
< $0	0	0
>= $0 and < $10	5,556	4,354
>= $10 and < $20	1,722	3,038
>= $20 and < $50	1,086	1,278
>= $50 and < $100	220	58
>= $100	180	36
Reg Down	**ERCOT**	**SPP**
< $0	0	0
>= $0 and < $10	6,535	7,767
>= $10 and < $20	1,466	794
>= $20 and < $50	629	189
>= $50 and < $100	87	1
>= $100	48	12
Spin	**ERCOT**	**SPP**
< $0	0	0
>= $0 and < $10	4,647	6,472
>= $10 and < $20	2,252	1,686
>= $20 and < $50	1,405	556
>= $50 and < $100	265	22
>= $100	195	28

Table 25– Summary of Market pricing in SPP and ERCOT (2019 AND 2022)

- The increase in demand and renewable energy in ERCOT has led to a continued increase in the number of hours when energy prices are higher than $50/MWh. On average from 2018 to 2022, ERCOT shows that energy and ancillary services prices are consistently higher than SPP. Refer to the charts in Appendix C that compare the average hourly energy and ancillary services prices in 2022 of ERCOT to those of SPP. These charts present the economic strength of the ERCOT market over that of SPPs and highlight the ability of the project to pump from SPP at cheaper prices and sell energy to ERCOT at more lucrative prices. Moreover, these charts show the lucrative ancillary services markets in ERCOT vs those in SPP.

14 Project Forecast and Returns

The ZG forecast models for all three interconnection Scenarios are based on market fundamentals of supply and demand. This includes demand growth, new generating facilities, retirements, and new unit entry. Appendix E, Table 25, and Table 26 summarize the forecast of SPP and ERCOT supply and demand stack for Low Case, Medium Case, and High Case.

14.1 ERCOT & SPP Natural Gas Assumptions

Figure 17 below represents the historical natural gas prices[18] for Texas from 1984 to 2022.

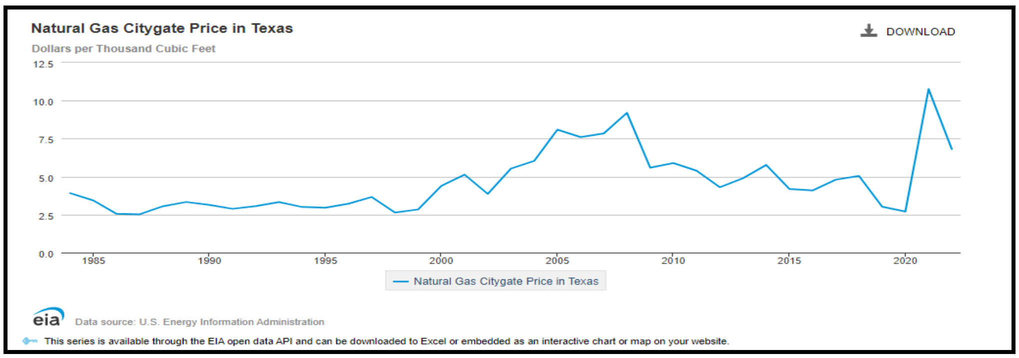


Figure 17 - Historical and Forecast Henry Hub Natural Gas Prices[19]

Below is the project life average forecast of Natural Gas prices in the ERCOT and SPP regions in $/ MMBTU.

	Mean	**Std dev**
Historical (1985 - 2022)	$4.62	$1.95
Low Case Forecast (2030 – 2079)	$2.75	$1.50
Medium Case Forecast (2030 – 2079)	$4.62	$1.95
High Case Forecast (2030 – 2079)	$6.0	$2.1

Note that the monthly Natural Gas prices were distributed based on the above average and standard deviation using the Stochastic method whereas the distribution about the mean is assumed to be a normal distribution. Also, the Medium Case uses the same Natural Gas mean and standard deviation from 1984 to 2022 shown in Figures 17 and 18.

[18] https://www.eia.gov/dnav/ng/hist/rngwhhdm.ht
[19] https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

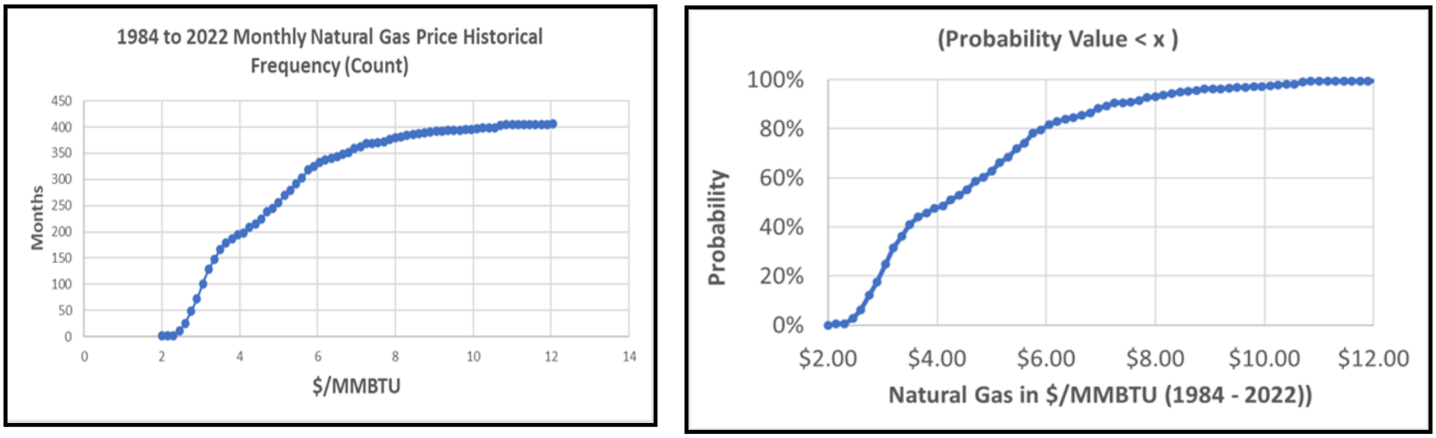


Figure 18– Historical and Forecast Henry Hub Natural Gas Prices 1984 to 2022

14.2 ERCOT & SPP Demand Forecast Assumptions

In 2022, the ERCOT forecasted energy and peak demand of 423,333 GWh and 77,733 MW, respectively. The actual energy and peak demand turned out to be 419,000 GWh and 80,038 MW. ERCOT Electricity demand has grown at 2.6% annually for the last ten years. ERCOT is forecasting a 2.1% annual demand increase until 2032 with 538,742 GWh.[20] We used 0.5%, 1.5%, and 2% annual demand increase in forecasting Project revenues applied to each of Scenarios 4,5, and 6.

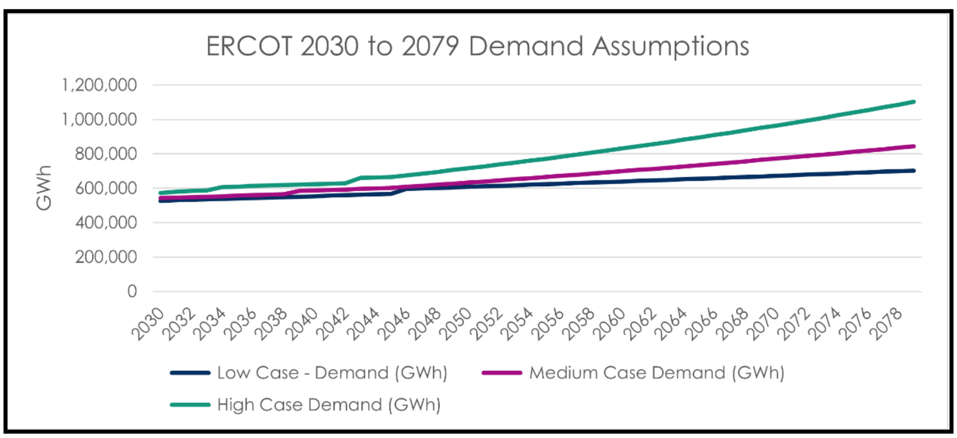
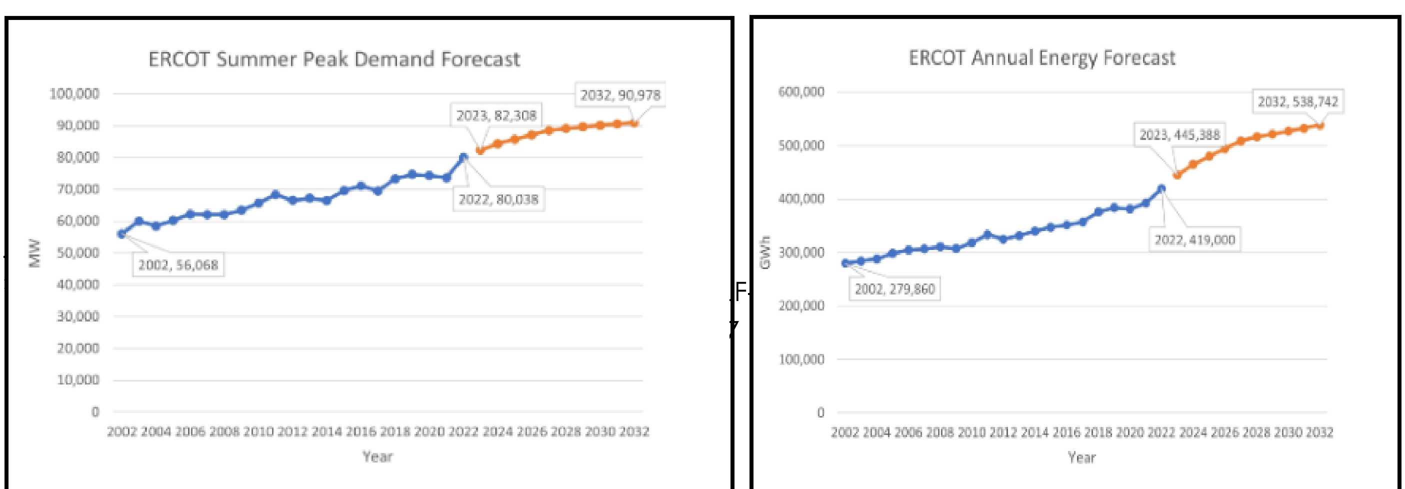


Figure 19– ERCOT 2030 to 2079 Demand Assumptions



Figures 21 and 22 above show ERCOT's own demand forecast. ERCOT forecasts an annual energy demand of 538.7 TWh. Comparably, our forecast assumptions for the low, medium, and high cases under Appendix E, for 2032 were 532 TWh, 548 TWh, and 583 TWh. August 10, 2023, the new demand peak record in ERCOT was set at 85,435 MW vs. ERCOT's demand forecast in Figure 20 of 82,308 MW for summer 2023. August 10, 2023, peak demand in ERCOT exceeded ERCOT's own forecast by 3,127 MW.

Figure 23 below shows these forecast demand assumptions presented in the SPP region (see Appendix E).

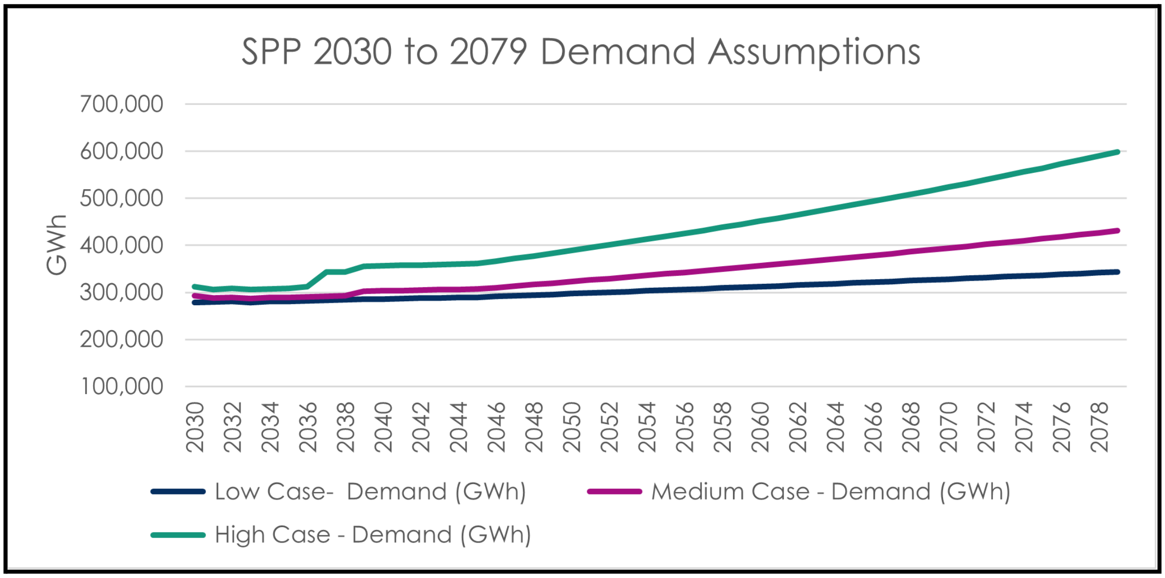


*Figure SEQ Figure * ARABIC 22– SPP 2030 to 2079 Demand Assumptions*

14.3 ERCOT & SPP Generation, Renewable and Supply Assumptions

As renewable or non-dispatchable generation increases, the number of hours when the price of energy is near or below $0/MWh increases. Additionally, as renewable penetration increases, the peak prices will increase. To demonstrate this reality, in March 2020, renewable penetration was 28% and increased to 43 percent in 2021. This resulted in an increase in Spinning Reserve prices from 15 to 30 $/MWh, which is a 104% increase. During the same period (March 2020 vs March 2021) Regulation Up prices increased from 12 to 20 $/MWh and Regulation Down prices increased from 6 $/MWh to 26 $/MWh. During March, ERCOT renewable production averaged 15.5 GW and represented 43% of all supply, far higher than any level previously seen in ERCOT.

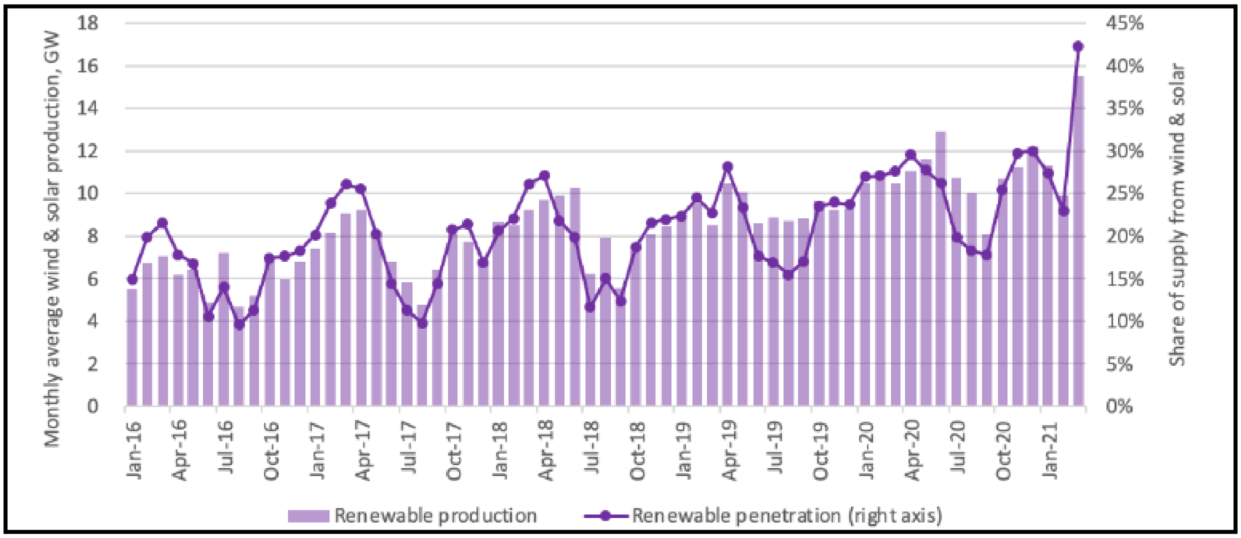


Figure 23– Renewable Production and Penetration

Another crucial factor is the wind capacity. Wind capacity varies across the year where the annual average is approximately 43 %; however, during February to June, the capacity factor is much higher than that in the summer months. We applied the actual monthly capacity factor for wind based on the average from 2016 to 2022 and used that capacity factor for the forecast analysis. The rapid deployment of battery storage will assist in damping the impact of higher renewables penetration; however, four hours of deployment of these batteries will not be sufficient. We assume that starting in 2030, demand growth in each region will increase by 0.5% annually under the Low Case, 1.5% annual increase under the Medium Case, and 2% annual increase under the High Case as shown in Tables 26 and 27 for ERCOT and SPP:

Total GWh Generation Dispatch (ERCOT Region 2030 to 2045)	Case 1 - Low	Case 2 - Medium	Case 3 -High
2030 peak Demand (MW)	91,093	92,459	92,915
2030 Demand (GWH)	526,900	542,707	572,560
2030 - 2045 Average annual Demand (GWh)	547,127	570,884	617,298
2030 -2045 Total Demand GWh	8,754,038	9,134,138	9,876,775
Hydro	12,800	12,800	12,800
Nuclear	641,696	641,696	641,696
Biomass	2,400	2,400	2,400
Solar	2,473,613	2,484,386	2,698,955
Onshore Wind	3,655,340	3,531,279	3,354,715
Offshore wind	283,087	302,400	408,240
Short duration storage	295,012	321,360	385,632
Long duration Storage	36,630	41,080	82,160
Net Import	1,528	1,431	1,528
Coal	193,396	263,320	263,320
BTM	128,991	160,268	240,402
Natural Gas	1,029,544	1,371,718	1,784,926
Annual Average Generation Dispatch (ERCOT Region 2030 to 2045)	**Case 1 - Low**	**Case 2 - Medium**	**Case 3 -High**
Demand GWh	547,127	570,884	617,298
Hydro	800	800	800
Nuclear	40,106	40,106	40,106
Biomass	150	150	150
Solar	154,601	155,274	168,685
Onshore Wind	228,459	220,705	209,670
Offshore wind	17,693	18,900	25,515
Short duration storage	18,438	20,085	24,102
Long duration Storage	2,289	2,568	5,135
Net Import	96	89	96
Coal	12,087	16,458	16,458
BTM	8,062	10,017	15,025
Natural Gas	64,346	85,732	111,558
% of Generation Dispatch (ERCOT Region 2030 to 2045)	**Case 1 - Low**	**Case 2 - Medium**	**Case 3 -High**
Hydro	0.15%	0.14%	0.13%
Nuclear	7.33%	7.03%	6.50%
Biomass	0.03%	0.03%	0.02%
Solar	28.26%	27.20%	27.33%
Onshore Wind	41.76%	38.66%	33.97%
Offshore wind	3.23%	3.31%	4.13%
Short duration storage	3.37%	3.52%	3.90%
Long duration Storage	0.42%	0.45%	0.83%
Net Import	0.02%	0.02%	0.02%
Coal	2.21%	2.88%	2.67%
BTM	1.47%	1.75%	2.43%
Natural Gas	11.76%	15.02%	18.07%

Total SPP Generation Dispatch (2030 to 2045)	Case 1 - Low	Case 2 - Medium	Case 3 -High
2030 Peak Demand (MW)	54,780	55,602	57,793
2030 Demand (GWH)	277,953	293,195	312,253
2030 - 2045 Average annual Demand (GWh)	283,790	296,509	334,649
2030 to 2079 Total Demand GWh	4,540,635	4,744,139	5,354,389
Hydro	216,044	216,044	216,044
Nuclear	220,464	220,464	220,464
Biomass	2,202	2,202	2,202
Solar	718,217	856,813	932,678
Onshore Wind	2,410,901	2,527,446	2,759,276
Short duration storage	165,075	182,079	219,880
Long duration Storage	101,890	120,230	122,268
Coal	32,233	32,233	28,000
Natural Gas	673,611	586,629	853,577
Annual Average Generation Dispatch (SPP Region 2030 to 2045)	**Case 1 - Low**	**Case 2 - Medium**	**Case 3 -High**
Total Demand GWh	4,540,635	4,744,139	5,354,389
Hydro	13,503	13,503	13,503
Nuclear	13,779	13,779	13,779
Biomass	138	138	138
Solar	44,889	53,551	58,292
Onshore Wind	150,681	157,965	172,455
Short duration storage	10,317	11,380	13,742
Long duration Storage	6,368	7,514	7,642
Coal	2,015	2,015	1,750
Natural Gas	42,101	36,664	53,349
% of Generation Dispatch (SPP Region 2030 to 2045)	**Case 1 - Low**	**Case 2 - Medium**	**Case 3 -High**
Hydro	4.76%	4.55%	4.03%
Nuclear	4.86%	4.65%	4.12%
Biomass	0.05%	0.05%	0.04%
Solar	15.82%	18.06%	17.42%
Onshore Wind	53.10%	53.28%	51.53%
Short duration storage	3.64%	3.84%	4.11%
Long duration Storage	2.24%	2.53%	2.28%
Coal	0.71%	0.68%	0.52%
Natural Gas	14.84%	12.37%	15.94%

Table 27– Total GWh Generation Dispatch (SPP Region 2030 - 2045)

14.4 Project Forecast of Revenue and Return

14.4.1 Scenario 4: ERCOT Only Interconnection

The results of the forecasted project revenue from the sale of Energy, Resource Adequacy, and Ancillary Services net pumping cost under the three Cases from 2030 to 2079 (50 years) are shown in Table 28 below. Recall that the 2019 and 2022 historical revenue from Energy and Ancillary Services sales resulted in $352 million and $358 million, respectively. After adding $5/kw-mo. to account for the resource adequacy portion (or $72 million), the backcast historical annual revenue for 2019 and 2022 could have been $424 million in 2019 and $430 million in 2022. Table 28 below compares the Project revenue results of cases 1,2, and 3.

Energy, Resource Adequacy and Ancillary services annual revenue (minus Pumping Cost) Backcasting	**ERCOT (Scenario 1)**
2019	$424,821,142
2022	$430,232,640
Energy, Resource Adequacy and Ancillary services average annual revenue (minus Pumping Cost): Forecast	**ERCOT (Scenario 4)**
Low (Case1)	**$457,577,764**
Medium (Case 2)	**$820,343,866**
High (Case 3)	**$772,107,808**

Scenario 4 - ERCOT	NPV ($b)	IRR	BCR
Case 1	$5.1	20.8%	2.5
Case 2	$9.2	27.0%	3.6
Case 3	$9.8	30.6%	3.8

Table 28 – Summary of Scenario 4 - ERCOT Project Forecast Revenue Results for Cases 1,2, and 3

The unlevered IRR ranged from 20.8% under case 1 to 30.6% under case 3.

14.4.2 Scenario 5: SPP Only Interconnection

The results of the forecasted project revenue from the sale of Energy, Resource Adequacy, and Ancillary Services net pumping cost under the three cases from 2030 to 2079 (50 years) are shown in Table 28 below. Recall that the 2019 and 2022 historical revenue from Energy and Ancillary Services sales resulted in $155 million and $348 million, respectively. After adding 5$/kw-mo. to account for the Resource Adequacy portion (or $72 million), the historical annual revenue for 2019 and 2022 could have been $228 million in 2019 and $421 million in 2022. Table 28 below compares the project forecast project revenue results shown in Cases 1,2 and 3 below. The forecasted average annual revenue under case 1 of $345 million *is below* the 2022 backcast. The forecasted average annual revenue under case 2 of $553 million is below the 2022 backcast. The forecasted average annual revenue under case 3 of $602 million is above the 2022 backcast.

Energy, Resource Adequacy and Ancillary services annual revenue (minus Pumping Cost) Backcasting	SPP (Scenario 2)
2019	$227,575,598
2022	$420,792,568

Energy, Resource Adequacy and Ancillary services average annual revenue (minus Pumping Cost): Forecast	SPP (Scenario 5)
Low (Case1)	$345,583,814
Medium (Case 2)	$553,519,176
High (Case 3)	$602,807,456

Scenario 5 - SPP	NPV($b)	IRR	BCR
Case 1	$3.2	15.4%	1.9
Case 2	$5.6	19.0%	2.6
Case 3	$7.0	24.4%	3.0

Table 29 – Summary of Scenario 5 - SPP Project Forecast Revenue Results for Cases 1,2, and 3

Under Scenario 5, the unlevered IRR ranged from 15.4% under Case 1 to 24.4% under Case 3.

14.4.3 Scenario 6: ERCOT & SPP Only Interconnection

The results of the forecasted project revenue from the sale of Energy, Resource Adequacy, and Ancillary Services net pumping cost under the three cases from 2030 to 2079 (50 years) are shown in Table 29 below. Recall that the 2019 and 2022 historical revenue from Energy and Ancillary Services sales resulted in $399 million and $532 million, respectively. After adding 5$/kw-mo. to account for the Resource Adequacy portion (or $72 million), the historical annual revenue for 2019 and 2022 could have been $ 471 million in 2019 and $604 million in 2022. Table 30 below compares the backcast versus the forecast average annual revenue under Cases 1,2 and 3.

The forecasted average annual revenue under case 1 of $550 million is below the 2022 backcast. The forecasted average annual revenue under case 2 and 3 are above the 2022 backcast. This Scenario is where we see a jump in annual average revenues when demand grows at 1.5% and 2% and natural gas prices are at the historic average or higher.

Energy, Resource Adequacy and Ancillary services annual revenue (minus Pumping Cost) Backcasting	ERCOT+SPP (Scenario 3)
2019	$471,835,844
2022	$604,290,696

Energy, Resource Adequacy and Ancillary services average annual revenue (minus Pumping Cost): Forecast	ERCOT+SPP (Scenario 6)
Low (Case1)	$550,418,035
Medium (Case 2)	$944,893,829
High (Case 3)	$958,212,957

Scenario 6 (ERCOT and SPP)	NPV $b	IRR	BCR
Case 1	$6.5	25.3%	2.9
Case 2	$10.8	30.8%	4.2
Case 3	$12.7	36.8%	4.7

Table 30 - Summary of Scenario 6: ERCOT/SPP Project Forecast Revenue Results for Cases 1,2, and 3

Under Scenario 6, the unlevered IRR ranged from 25.3% under Case 1 to 36.8% under Case 3. This scenario represents the highest project returns.

15 Sensitivity Analysis

Sensitivity analysis helps determine how changes in one input affect the output. This analysis is useful since it allows us to weigh the benefits and risks under different conditions. Quantify which input variable most influences the output. We focus on input variables such as project costs, Operating costs, and project revenue**.**

15.1 Scenario 4 ERCOT Sensitivity

This section aimed at quantifying the project return from interconnecting to ERCOT only. We previously concluded that the project returns ranged from 20.8% to 30.6% based on project cost of $3.1 billion and the annual average project revenues Table 27. The Project return of 20.8% under case 1 is the focus of this section. We attempt to answer two questions:

Under case 1, what would happen to the 20.8% project return if the project cost increased? What would happen to the project return of 20.8% if the project cost increased and the annual net revenues decreased simultaneously? This section shows the results of such sensitivity.

Recall that the Project cost was estimated to equal $3.1 billion which includes 15% contingencies.

Net Project cost = Project revenue cost (this is the Project revenue from the sale of energy, ancillary services, and resource adequacy net pumping cost – total Operating cost). Any change in Project capital cost will impact the total operating cost and therefore the Net Project Revenue. Changes in project capital cost will impact the tax equity investment amount and the remaining investor amount.

Any changes in the project revenue will also impact the net Project revenue.

We varied ERCOT scenario 4, case 1 in Table 28, as follows:

Case 1a: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly.

Case 1b: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

Case 1c: We increased the Project cost by 50% to $4.6 billion. We adjusted the tax equity investments, investment amount, and total Project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

Case 1d: We decreased the Project cost by 25% to $2.3 billion. We adjusted the tax equity investments, investment amount, and total Project operating cost accordingly. We also reduced the Project forecasted annual revenues by 25% annually from case 1.

The results are summarized in the Table below.

Scenario 4 - ERCOT	Project cost ($b)	Average Annual Total Net Revenue ($M)	NPV ($b)	NPV changes %	IRR %	IRR changes %
Case 1	$3.1	$470	$5.1	0.0%	20.8%	0.0%
Case 1a	$3.9	$446	$4.2	-17.6%	16.0%	-23.1%
Case 1b	$3.9	$332	$2.4	-52.9%	11.8%	-43.3%
Case 1c	$4.6	$311	$1.6	-68.6%	9.4%	-54.8%
Case 1d	$2.3	$380	$4.2	-17.6%	22.1%	6.3%

Table 31 - Summary of Sensitivity Analysis under Scenario 4, Case 1

Case 1c shows the lowest IRR from Increasing project costs by 50% to $4.6 billion and simultaneously decreasing net annual project revenue by 25%, each year, which will reduce the project return from 20.8% to 9.4%.

15.2 Scenario 5 SPP Sensitivity

This section aimed at quantifying the project return from interconnecting to SPP only. We previously concluded that the project returns ranged from 15.4% to 24.4% based on project cost of $3.1 billion and the annual average project revenues in Table 28. The Project return of 15.4% under case 1 is the focus of this section. We attempt to answer two questions:

Under case 1, what would happen to the 15.4% project return if the project cost increased? What would happen to the project return of 15.4% if the project cost increased and the annual net revenues decreased simultaneously? This section shows the results of such sensitivity.

Recall, the Project cost was estimated to equal $ 3.1 billion which includes 15% contingencies.

Net Project cost = Project revenue cost (this is the Project revenue from the sale of energy, ancillary services, and resource adequacy net pumping cost – total Operating cost). Any change in Project capital cost will impact the total operating cost and therefore the Net Project Revenue. Changes in project capital Cost will impact the tax equity investment amount and the remaining investor amount.

Any changes in the Project revenue will also impact the Net project revenue.

We varied SPP Scenario 5, Case 1 in Table 29, as follows:

Case 1a: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly.

Case 1b: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

Case 1c: We increased the Project cost by 50% to $4.6 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

Case 1d: We decreased the Project cost by 25% to $2.3 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

The results are summarized in the Table below.

Scenario 5 - SPP	Project cost ($b)	Average Annual Total Net Revenue ($M)	NPV ($b)	NPV changes %	IRR %	IRR changes %
Case 1	$3.1	$3.1	$358	0.0%	15.4%	0.0%
Case 1a	$3.9	$3.9	$334	-6.7%	11.60%	-24.7%
Case 1b	$3.9	$3.9	$248	-30.7%	8.50%	-44.8%
Case 1c	$4.6	$4.6	$227	-36.6%	6.60%	-57.1%
Case 1d	$2.3	$2.3	$295	-17.6%	16.80%	9.1%

Table 32– Summary of Sensitivity Analysis under Scenario 5, Case 1

Case 1c shows the lowest IRR from Increasing project cost by 50% to $4.6 billion and simultaneously decreasing net annual project revenue, each year, by 25% resulting in a decrease of project return from 15.4% to 6.6%.

15.3 Scenario 6 ERCOT/SPP Sensitivity

This section aimed at quantifying the project return from interconnecting to ERCOT/SPP. We previously concluded that the project returns ranged from 25.3% to 36.8% based on a project cost of $3.1 billion and the annual average project revenues Table 29. The Project return of 25.3% under case 1 is the focus of this section. We attempt to answer two questions:

Under case 1, what would happen to the 25.3% project return if the project cost increased? What would happen to the project return of 25.3% if the project cost increased and the annual net revenues decreased simultaneously? This section shows the results of such sensitivity.

Recall the Project cost was estimated to equal $ 3.1 billion which includes 15% contingencies.

Net Project cost = Project revenue cost (this is the Project revenue from the sale of energy, ancillary services, and resource adequacy net pumping cost – total Operating cost). Any change in Project capital cost will impact the total operating cost and therefore the Net Project Revenue. Changes in project capital cost will impact the tax equity investment amount and the remaining investor amount.

Any changes in the Project revenue will also impact the Net project revenue.

We varied ERCOT/SPP scenario 6, case 1 in Table 30, as follows:

Case 1a: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly.

Case 1b: We increased the Project cost by 25% to $3.9 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

Case 1c: We increased the Project cost by 50% to $4.6 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the Project forecasted annual revenues by 25% annually from case 1.

Case 1d: We decreased the Project cost by 25% to $2.3 billion. We adjusted the tax equity investments, investment amount, and total project operating cost accordingly. We also reduced the project forecasted annual revenues by 25% annually from case 1.

The results are summarized in the Table below.

Scenario 6 (ERCOT and SPP)	Project cost ($b)	Average Annual Total Net Revenue ($M)	NPV ($b)	NPV changes %	IRR %	IRR changes %
Case 1	$3.1	$563	$6.5	0.0%	25.3%	0.0%
Case 1a	$3.9	$540	$5.7	-12.3%	19.4%	-23.3%
Case 1b	$3.9	$401	$3.5	-46.2%	14.4%	-43.1%
Case 1c	$4.6	$380	$2.8	-56.9%	11.7%	-53.8%
Case 1d	$2.3	$450	$5.3	-18.5%	26.6%	5.0%

Table 33– Summary of Sensitivity Analysis under Scenario 6, Case 1

Case 1c shows the lowest IRR from Increasing project cost by 50% to $4.6 billion and simultaneously decreasing the net annual project revenue by 25% each year will reduce the Project return from 25.3% to 11.7%.

16 Scenarios 4,5 and 6 Value at Risk Analysis (VaR.)

Value at risk (VaR.) is a well-known, commonly used risk assessment technique. The VaR. calculation is a probability-based estimate of the minimum loss in NPV is expected over a period. The data produced is used by investors to strategically make investment decisions. This metric can be computed in three ways: the historical, variance-covariance, and Monte Carlo methods. We used the Monta Carlo method to assess the value at risk under the most conservative case where project cost increased by 50% and the project net annual revenue decreased by 25% annually (Case 1c). This section drills down using case 1c. The Monte Carlo method can be used with a wide range of risk measurement problems and relies upon the assumption that the probability distribution for risk factors is known.

This technique uses computational models to simulate projected returns over hundreds or thousands of iterations. Then, it takes the chance that a loss will occur—say, 1% of the time—and reveals the impact.

We calculated the normal distribution variation of the net revenue (project revenue minus pumping cost minus operating cost) by varying the annual net revenue from the mean under Case 1c for all three forecasted revenue scenarios 4,5, and 6.

16.1 Value at Risk Results

This section summarizes the project Value at Risk, Figures 24, 25, and Table 33 below show the VaR. for the NPV to be less than "X" probability. This means that 1000 random variations of the Project net annual revenues under the various sensitivity scenarios discussed in Section 15 above, specifically case 1c.

For instance, in section 15.1, under case 1c, we concluded that if the project cost increases by 50% and simultaneously the net project annual revenue decreases by 25%, the project return drops from 20.8% to 9.4%. This section attempts to drill down further to compute the probability distribution of the NPV when the net annual revenues are randomly varied from the annual net project revenue (mean)

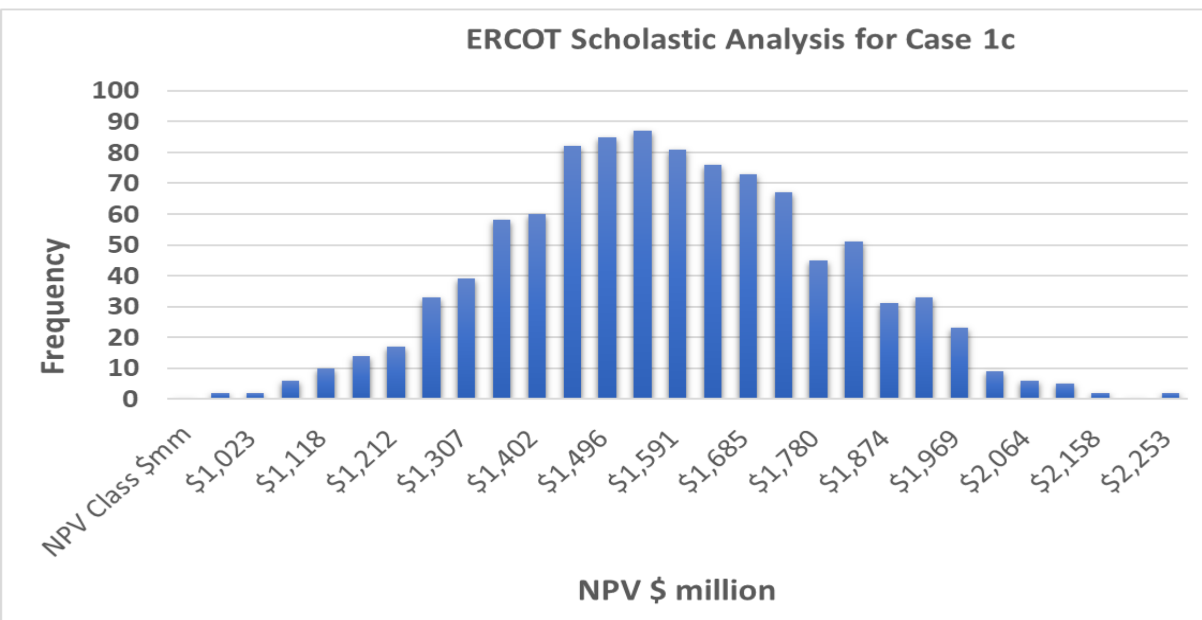


Figure 24– Scenario 4 - ERCOT Case 1c – Probability Distribution of the Project NPV

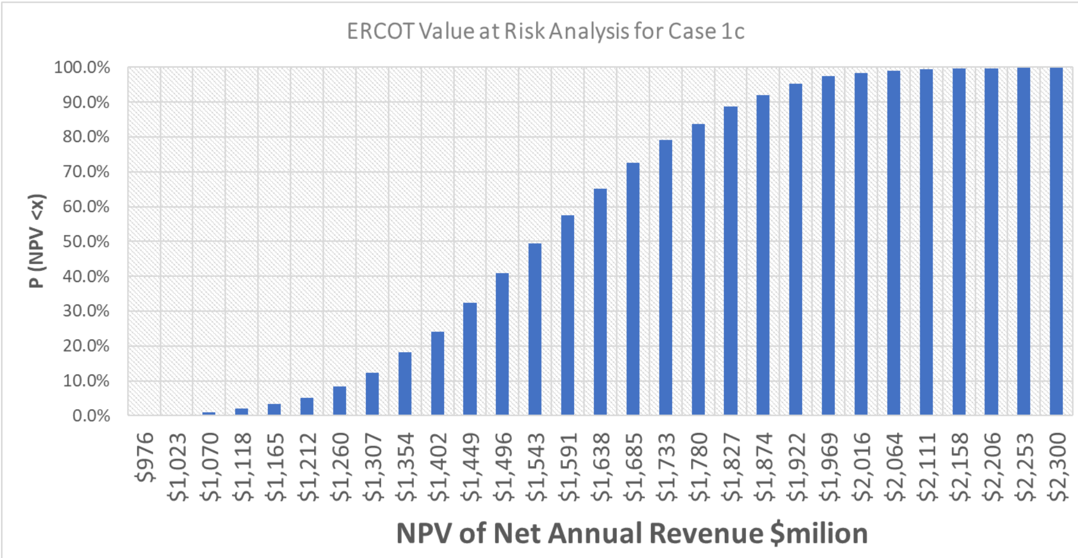


Figure 25– Scenario 4 - ERCOT Case 1c – Value at Risk Probability Assessment

NPV Class $mm	Count	Frequency	Probability NPV<X
$810	1	1	0.1%
$859	3	4	0.4%
$908	2	6	0.6%
$958	1	7	0.7%
$1,007	0	7	0.7%
$1,057	6	13	1.3%
$1,106	8	21	2.1%
$1,155	10	31	3.1%
$1,205	18	49	4.9%
$1,254	35	84	8.4%
$1,303	42	126	12.6%
$1,353	63	189	18.9%
$1,402	63	252	25.2%
$1,452	65	317	31.7%
$1,501	84	401	40.1%
$1,550	87	488	48.8%
$1,600	87	575	57.5%
$1,649	90	665	66.5%
$1,698	79	744	74.4%
$1,748	58	802	80.2%
$1,797	60	862	86.2%
$1,847	47	909	90.9%
$1,896	34	943	94.3%
$1,945	27	970	97.0%
$1,995	9	979	97.9%
$2,044	10	989	98.9%
$2,093	5	994	99%
$2,143	5	999	100%

Table 34– Summary of Probability Analysis under ERCOT, Case 1c

Table 34 above, reveals that under all 1000 Monta Carlo, the NPV was also positive, meaning even under extreme case 1c where the Project cost is increased by 50% and the project annual net revenues are decreased by 25% from case 1, the NPV remains positive, the VaR. at or below 0.7% has an impressive NPV of $1 billion. This means that there is a 0.7% probability that the NPV, under case 1c, will be at or below 1 billion and 99.3% that the NPV would be above $1 billion.

Similar analyses were conducted for the SPP scenario 5 and ERCOT / SPP scenario 6, Case 1c.

NPV Class $mm	Count	Frequency	Probability NPV<X
(187.8)	5	5	0.5%
(157.4)	3	8	0.8%
(125.9)	2	10	1.0%
(94.5)	7	17	1.7%
(63.0)	13	30	3.0%
(31.5)	18	48	4.8%
(0.0)	27	75	7.5%
31.4	47	122	12.2%
62.9	50	172	17.2%
94.4	59	231	23.1%
125.9	63	294	29.4%
157.3	76	370	37.0%
188.8	86	456	45.6%
220.3	79	535	53.5%
251.8	86	621	62.1%
283.2	71	692	69.2%
314.7	88	780	78.0%
346.2	43	823	82.3%
377.7	49	872	87.2%
409.2	28	900	90.0%
440.6	29	929	92.9%
472.1	23	952	95.2%
503.6	15	967	96.7%
535.1	13	980	98.0%
566.5	10	990	99.0%
598.0	6	996	99.6%
629.5	4	1000	100.0%

Table 35– Summary of Probability Analysis under SPP, Case 1c

Table 35 above shows that under SPP Scnerio, using case 1c, the probability of the NPV being equal to zero is 7.5%. This means that this scenario shows a 92.5% probability that the NPV is higher than zero. Table 35 also shows a 0.5% probability that the NPV is negative (-$187million).

NPV Class $mm	Count	Frequency	Probability NPV<X
$1,948	1	1	0.1%
$2,011	2	3	0.3%
$2,075	10	13	1.3%
$2,139	7	20	2.0%
$2,203	11	31	3.1%
$2,267	22	53	5.3%
$2,331	36	89	8.9%
$2,394	47	136	13.6%
$2,458	72	208	20.8%
$2,522	68	276	27.6%
$2,586	94	370	37.0%
$2,650	104	474	47.4%
$2,713	87	561	56.1%
$2,777	95	656	65.6%
$2,841	84	740	74.0%
$2,905	71	811	81.1%
$2,969	44	855	85.5%
$3,032	55	910	91.0%
$3,096	38	948	94.8%
$3,160	16	964	96.4%
$3,224	9	973	97.3%
$3,288	13	986	98.6%
$3,351	5	991	99.1%
$3,415	4	995	99.5%
$3,479	1	996	99.6%
$3,543	2	998	99.8%
$3,607	0	998	100%
$3,671	1	999	100%

Table 36 – Summary of Probability Analysis under ERCOT/SPP, Case 1c

Table 36 shows that under the ERCOT/SPP Scenario, using case 1c, the probability of the NPV being equal to zero is zero. This means that this scenario shows a 100% probability that the NPV is positive. Table 36 also shows that there is a 0.1% probability that the NPV is $1.9 billion or less. This scenario shows very robust results.

17 Dispatch Comparison

Figure 26 below compares the annual dispatch of one of the four units from the three interconnection scenarios presented in this report. Note that when any given curve is under the zero level, it means the project is pumping during this specific hour, while the curve being above the zero level represents an hour when the project is generating. The following points summarize our analysis of this chart:

- When the project is free to generate or pump from either market (red curve), it pumps higher amounts of energy for a longer period and then generates higher amounts for a longer period.

- This indicates that the project can capture a higher number of low prices to pump energy (most likely from SPP), and a higher number of high prices to generate energy (most likely coming from ERCOT).

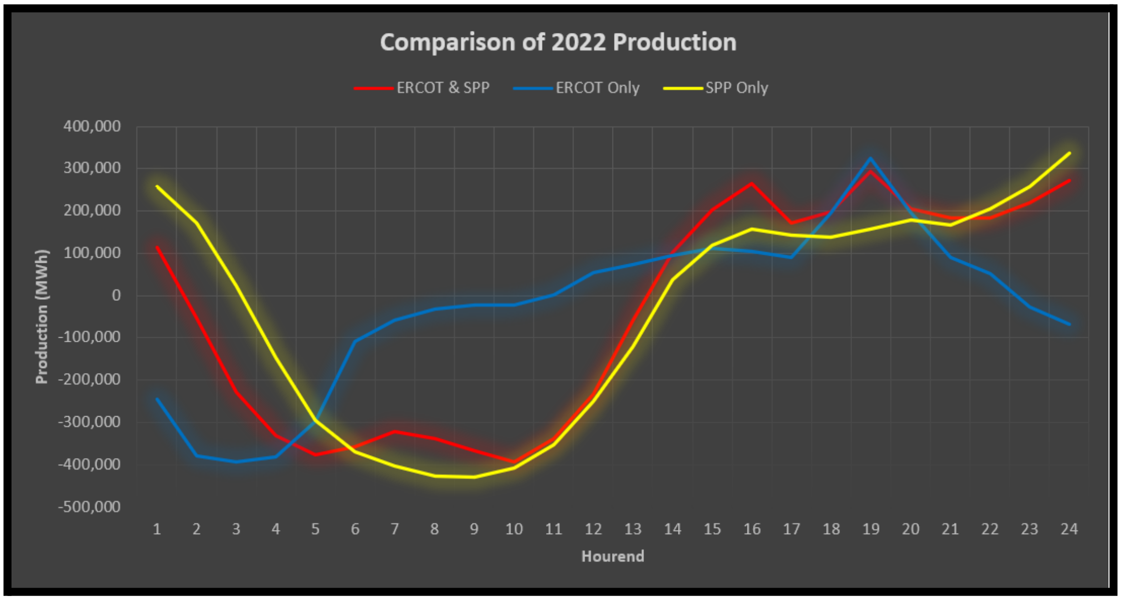
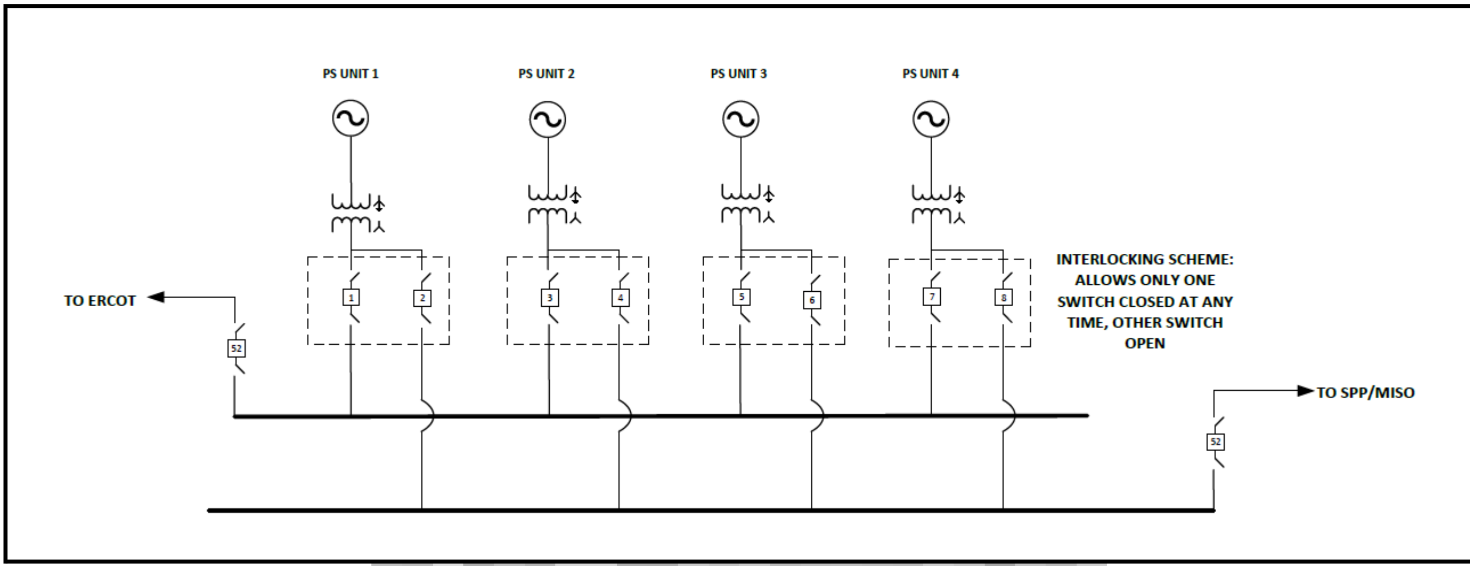


Figure 26– Comparison of the Productions of the Three Scenarios (1,2 and 3) Using One PSH Plant.

Appendix A: Project Configuration Under Multiple Regional Markets

Switching Station Configuration

The project switching station will be configured in a manner to allow for flexibility in the connections for each of the four (4) pump/storage units. The single-line diagram below shows how this may be accomplished. For energy metering purposes, it is anticipated that dedicated and redundant metering will be required associated with each of the eight (8) switches shown. Circuit Breakers 1, 3, 5, and 7, when closed, connect the units to the ERCOT system, while switches 2, 4, 6, and 8 connect the units to the SPP/MISO System. As noted, the switches will include interlocks that prevent an inadvertent connection of any one unit to both systems.



Following are examples of switching configurations:

Example 1: Unit 1 connected to ERCOT, Units 2, 3, 4 connected to SPP/MISO

- CB 1 Closed, CB 3, 5, 7 Open
- CB 2 Open, CB 4, 6, 8 Closed

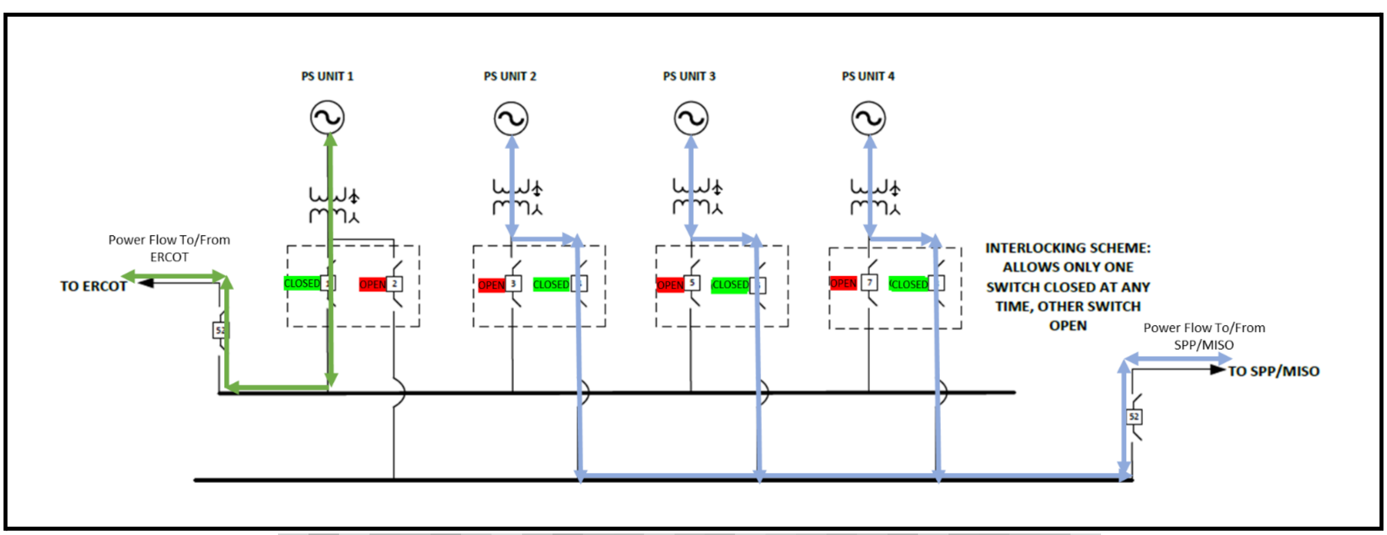


Figure 29– Example 1 of Switching Configurations

Example 2: Units 1 and 2 connected to ERCOT, Units 3 and 4 connected to SPP/MISO

- CB 1 and 3 Closed, CB 5 and 7 Open
- CB 2 and 4 Open, CB 6 and 8 Closed

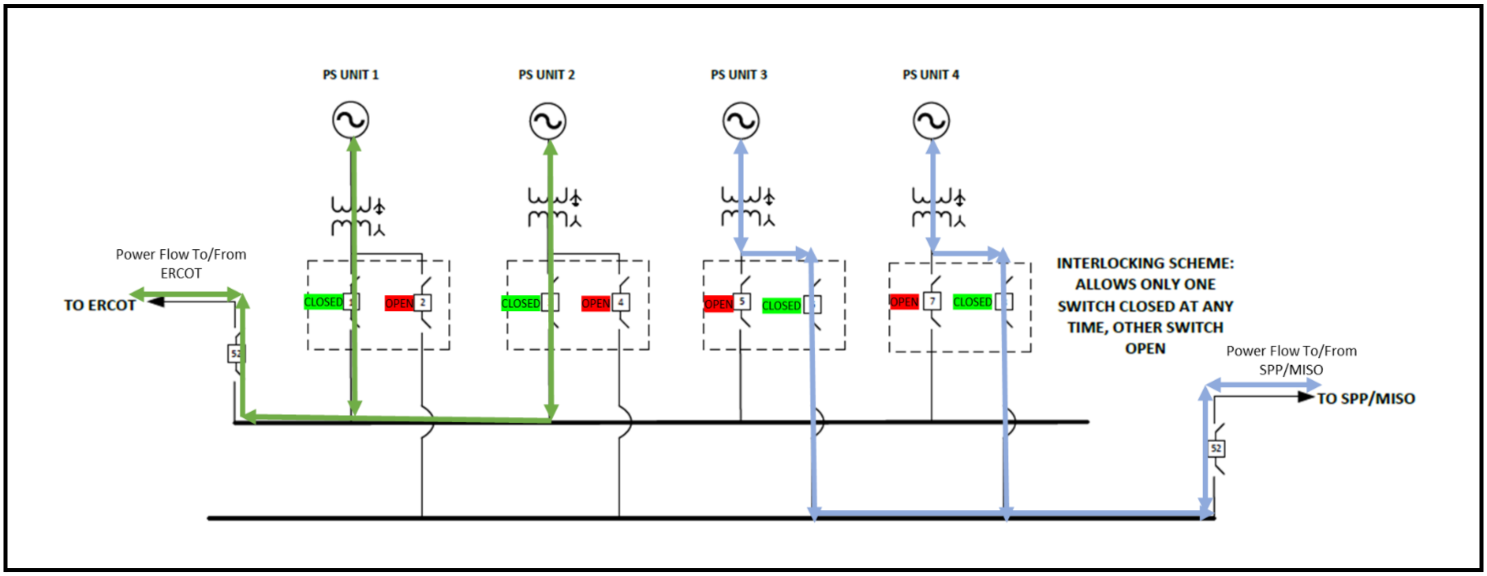


*Figure SEQ Figure * ARABIC 29– Example 2 of Switching Configurations*

Example 3: All Units connected to ERCOT

- CB 1, 3, 5, 7 Closed
- CB 2, 4, 6, 8 Open

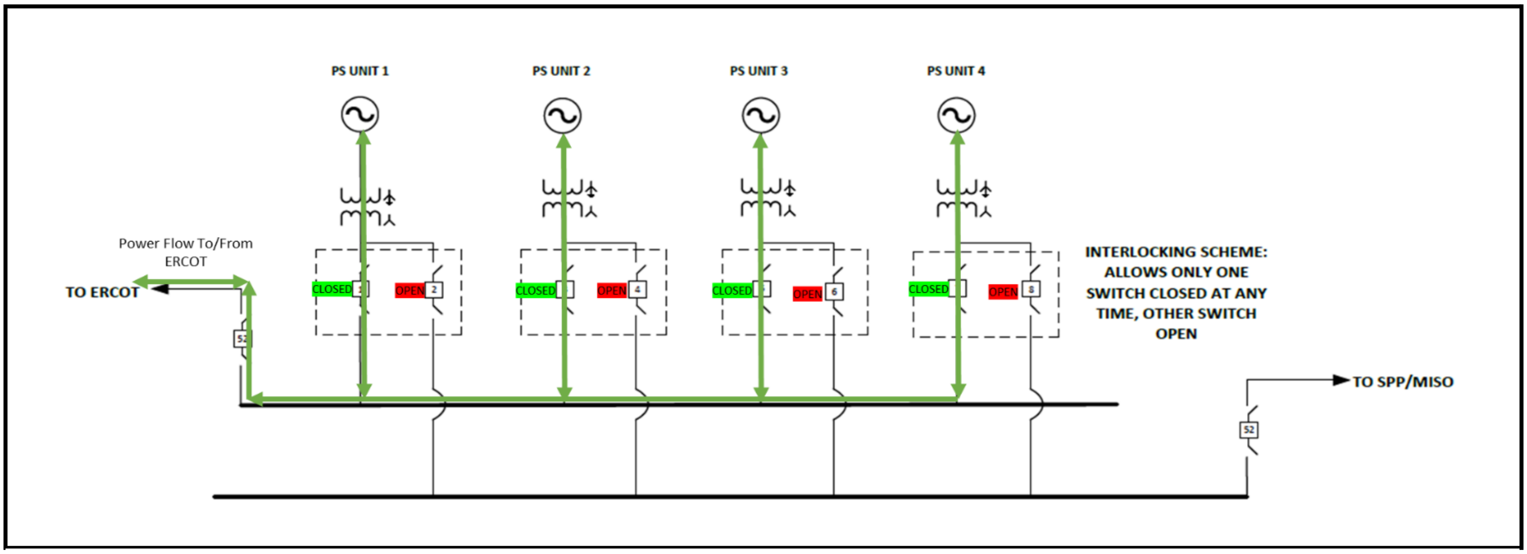


*Figure SEQ Figure * ARABIC 30– Example 3 of Switching Configurations*

Example 4: All Units connected to SPP/MISO

- CB 1, 3, 5, 7 Open
- CB 2, 4, 6, 8 Closed.

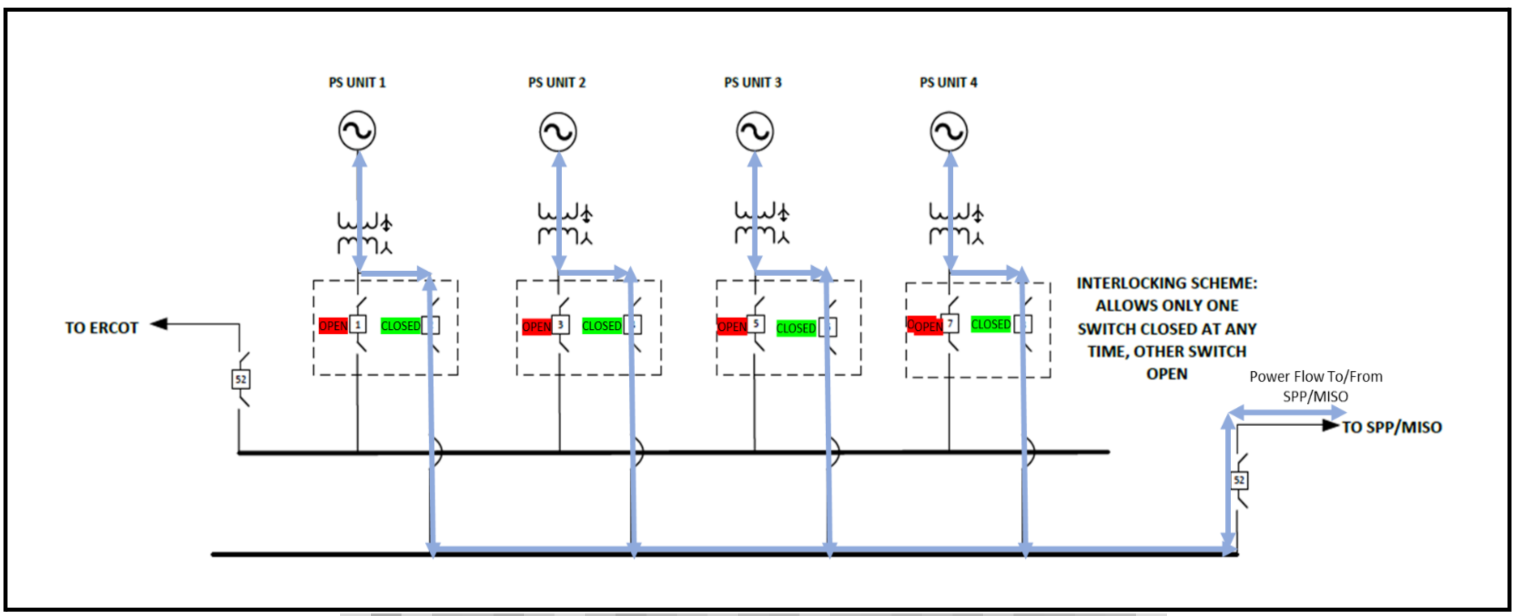
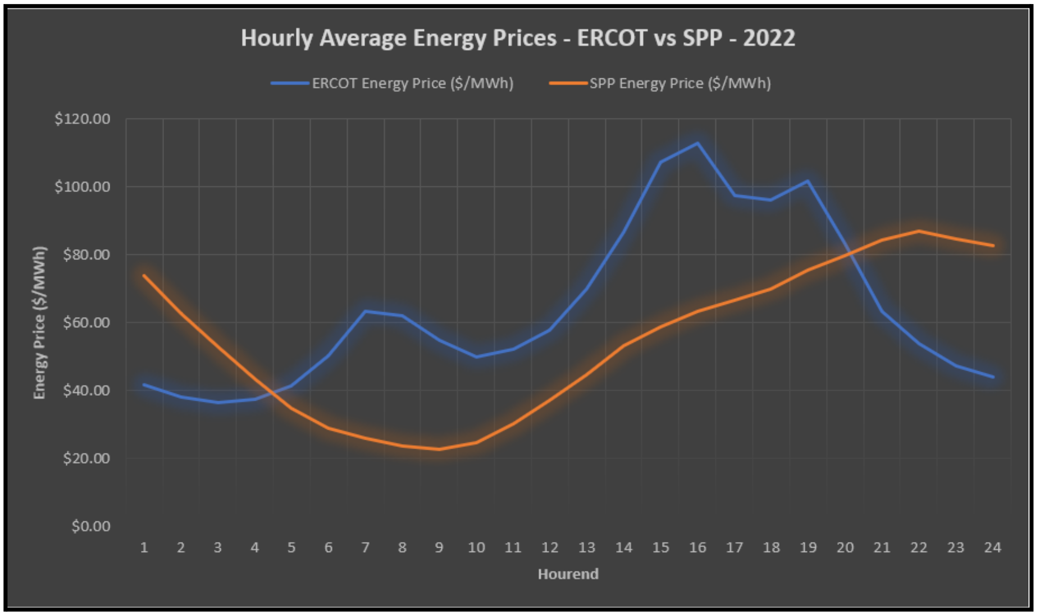
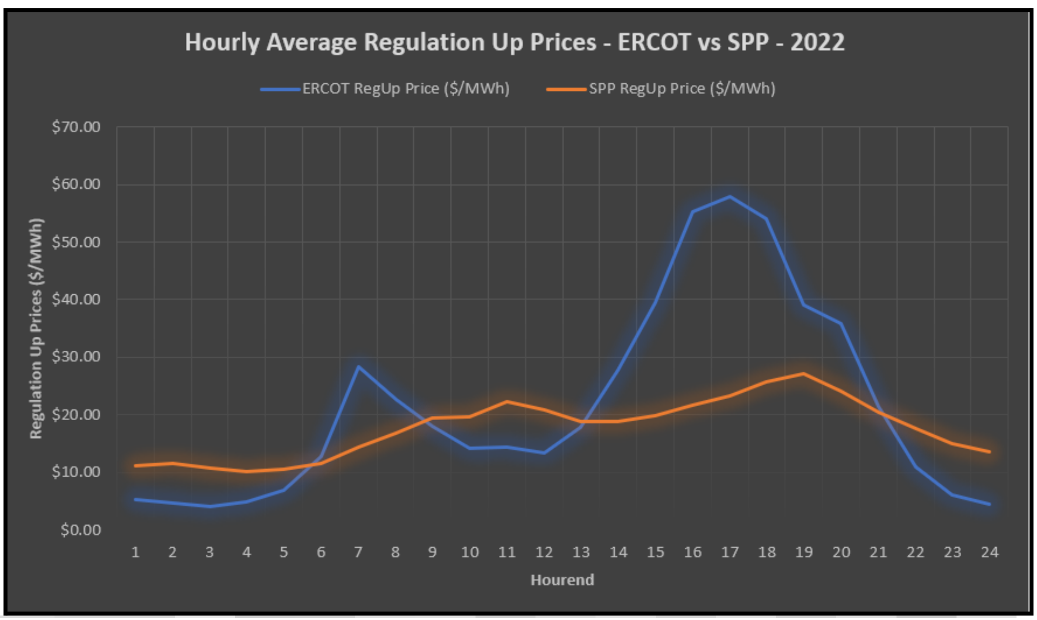


Figure 32– Example 4 of Switching Configurations

Appendix B: Backcast Project Optimization Results

Comparing the Average Hourly Energy & AS Prices of 2022 for ERCOT and SPP:





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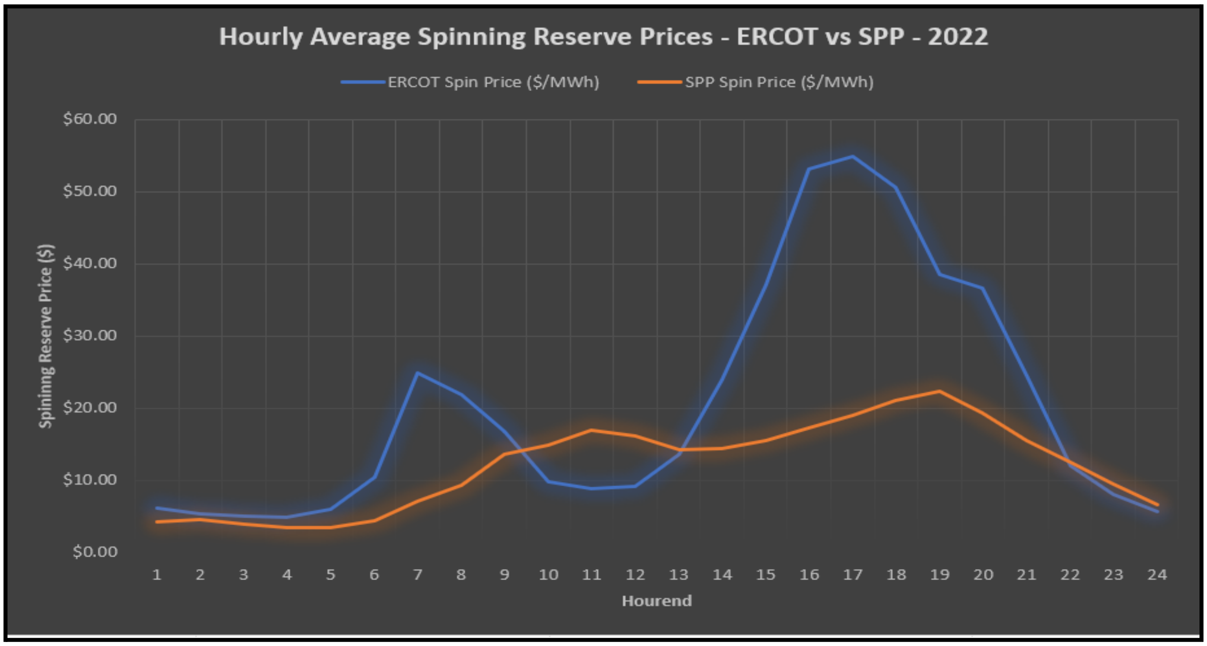


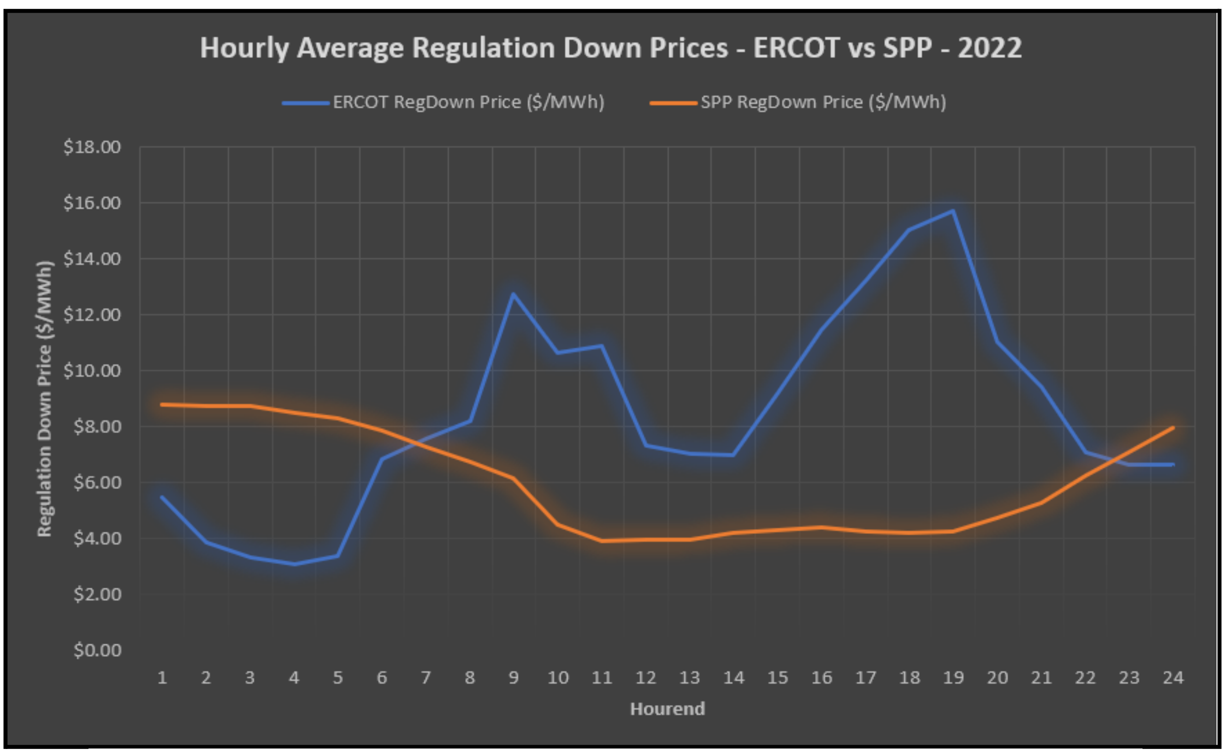
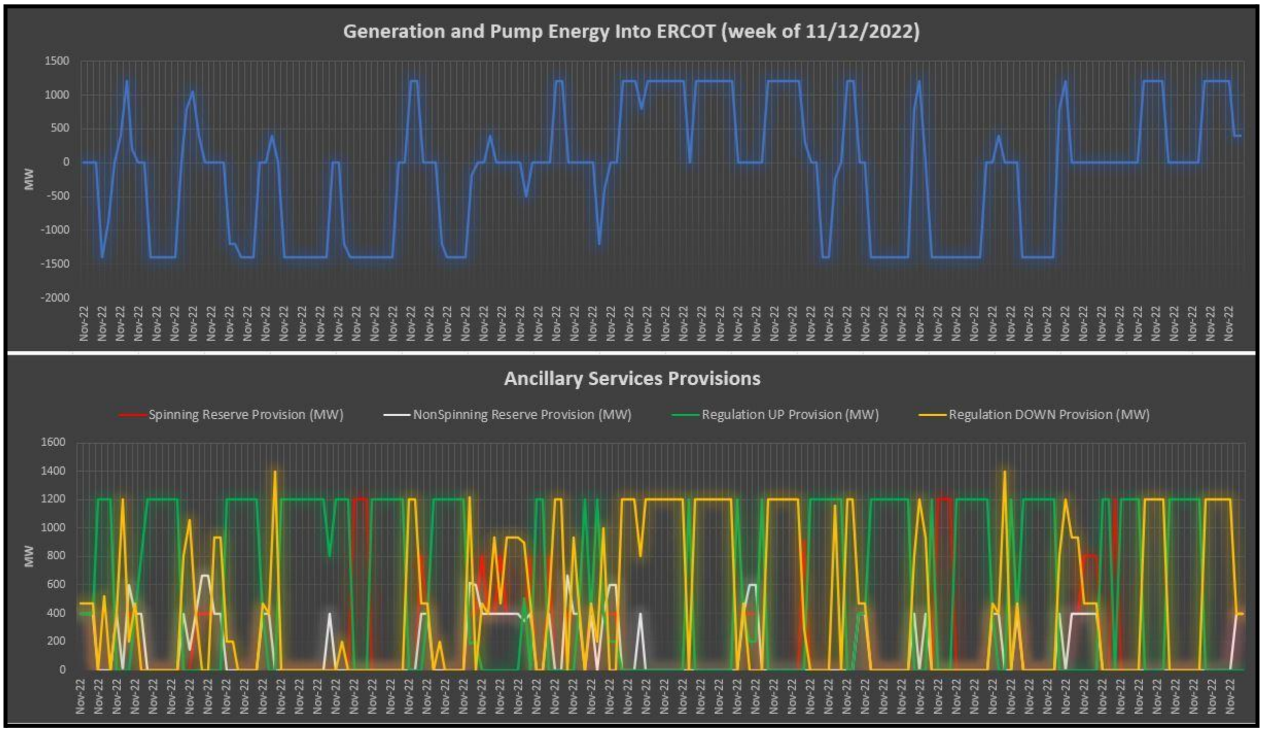


*Figure SEQ Figure * ARABIC 33– Average Hourly Spinning and Reg Down Prices of 2022 for ERCOT and SPP*

	Month	January	February	March	April	May	June	July	August	September	October	November	December	Total
Hours	Energy Only	0	0	0	0	0	0	0	0	0	0	0	0	0
	Energy + AS	145	190	226	196	205	199	226	222	205	179	219	147	2,359
	Pump Only	0	0	0	0	0	0	0	0	0	0	0	0	0
	Pump + AS	193	197	236	209	180	188	248	240	222	180	221	162	2,476
	Total Hours	338	387	462	405	385	387	474	462	427	359	440	309	4,835


Generation and Pump Energy Into ERCOT (week of 11/12/2022)
MW
1500
1000
500
0
-500
-1000
-1500
-2000
Nov-22
Ancillary Services Provisions
Spinning Reserve Provision (MW)
NonSpinning Reserve Provision (MW)
Regulation UP Provision (MW)
Regulation DOWN Provision (MW)
1600
1400
1200
1000
800
600
400
200
0

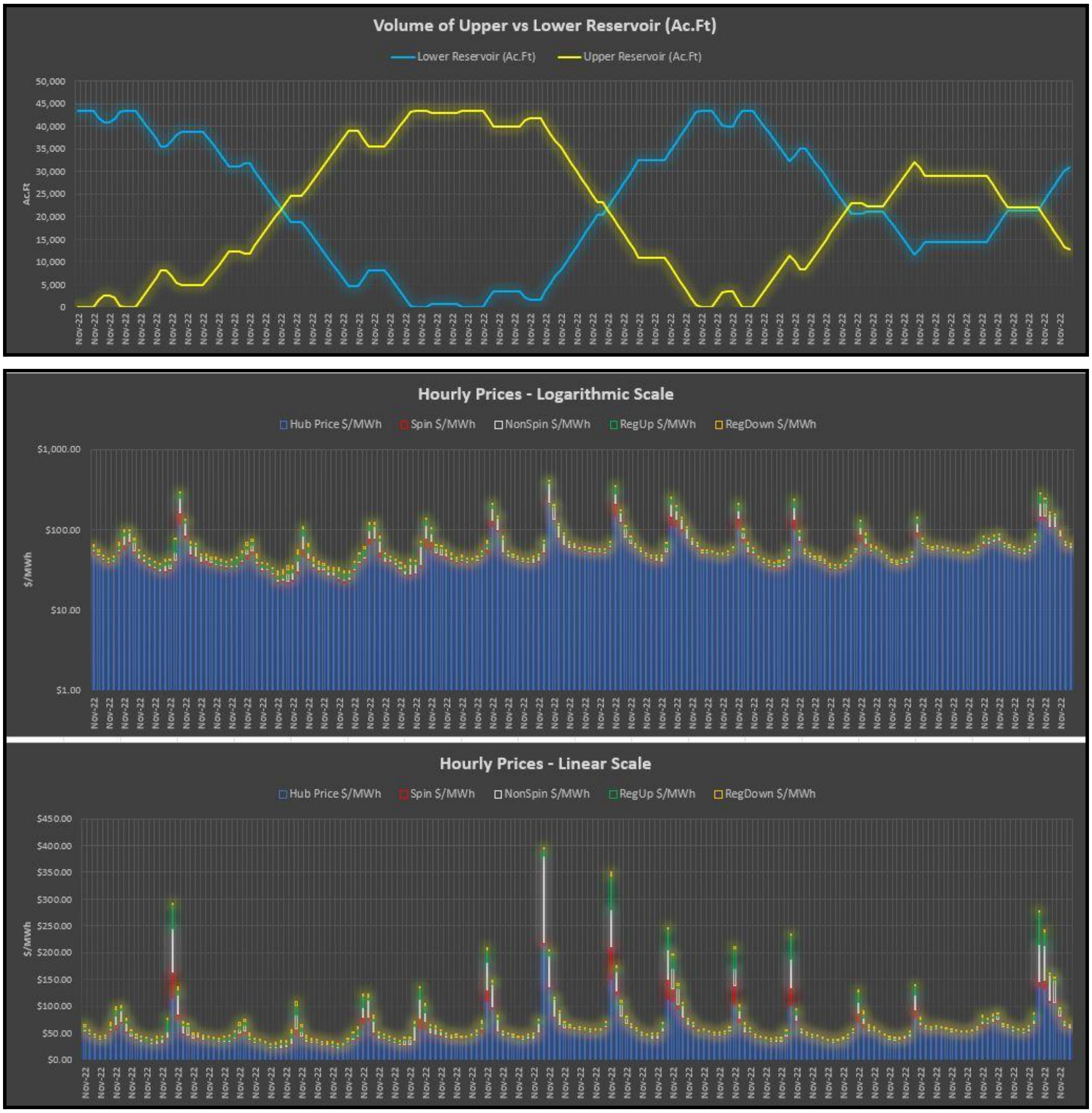
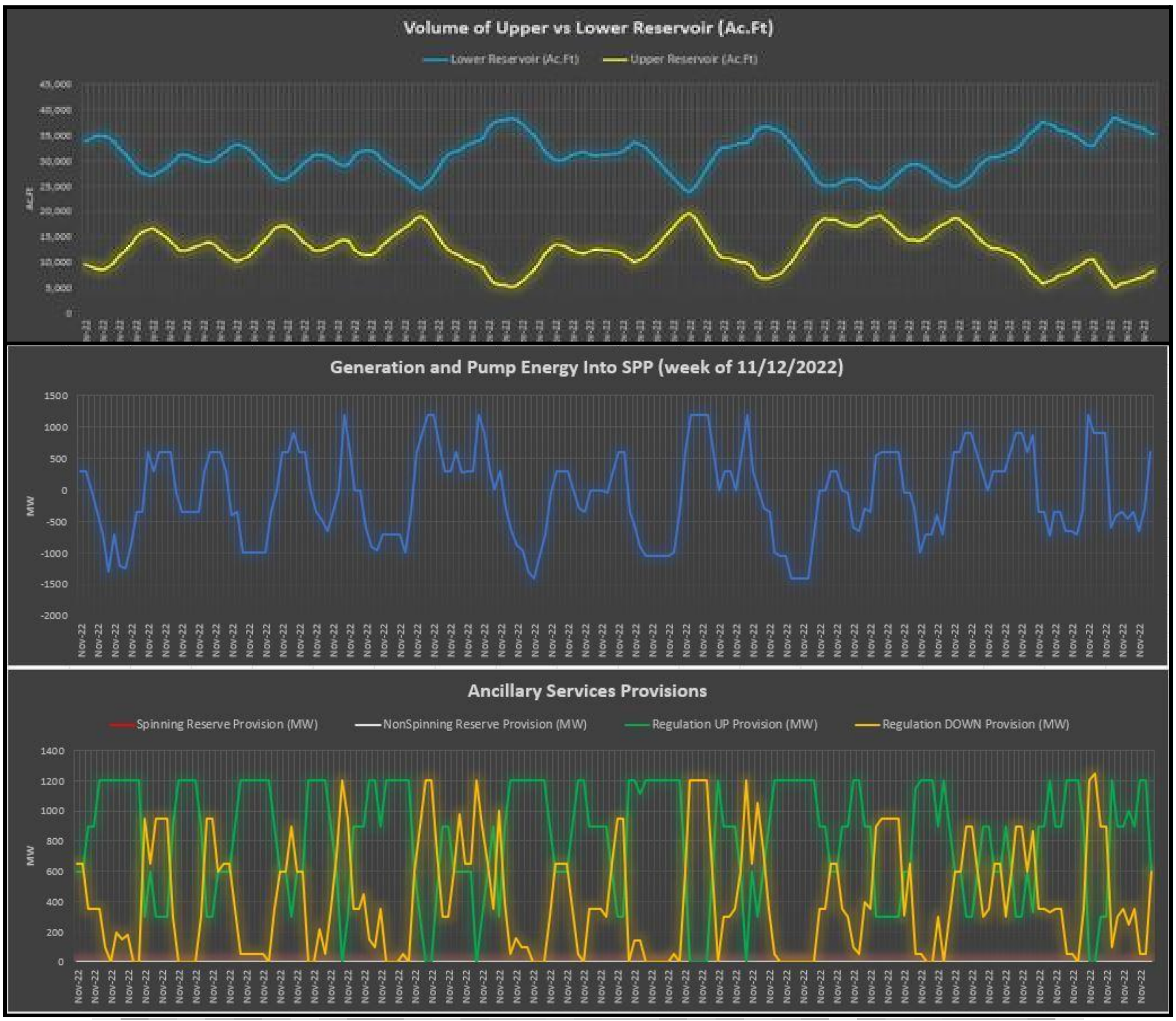


Figure 34– Samples of Weekly Operation in ERCOT - Week of 11/12/2022

	Month	January	February	March	April	May	June	July	August	September	October	November	December	Total
Hours	Energy Only	0	0	0	0	0	0	0	0	0	0	0	0	0
	Energy + AS	193	202	247	236	235	250	261	243	236	222	204	181	2,710
	Pump Only	0	0	0	0	0	0	0	0	0	0	0	0	0
	Pump + AS	234	224	278	268	267	278	290	268	258	241	234	207	3,047
	Total Hours	427	426	525	504	502	528	551	511	494	463	438	388	5,757
	Capacity Factor	58%	58%	72%	69%	69%	72%	75%	70%	68%	63%	60%	53%	
	Month	January	February	March	April	May	June	July	August	September	October	November	December	Total
Energy + AS	Energy	226,784	233,859	288,452	276,538	277,084	299,423	310,224	287,230	276,199	260,402	238,560	215,148	3,189,903
	RegUp	2,376	6,397	5,425	6,662	4,470	577	2,752	2,439	5,766	3,810	4,690	859	46,223
	RegDown	226,784	233,859	288,452	276,538	277,084	299,423	310,224	287,230	276,199	260,402	238,560	215,148	3,189,903
	Spinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
	NonSpinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	455,943	474,116	582,329	559,738	558,639	599,423	623,199	576,899	558,164	524,615	481,810	431,155	6,426,030
Pump + AS	Energy	297,184	289,431	362,390	350,337	357,428	377,491	393,251	362,125	350,343	326,419	308,305	266,483	4,041,188
	RegUp	279,805	266,668	332,545	320,442	318,728	332,817	344,654	321,600	309,367	288,526	280,524	245,985	3,641,660
	RegDown	30,416	24,169	26,810	24,863	16,372	11,709	12,749	13,075	10,857	10,981	19,295	23,317	224,612
	Spinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
	NonSpinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	607,405	580,268	721,745	695,642	692,528	722,017	750,654	696,800	670,567	625,926	608,124	535,785	7,907,460

Table 38– Monthly Operation in 2022 in SPP Only Interconnection



Appendix C: Backcast Hourly Dispatch Summary

This appendix summarizes the monthly production figures (in MWh) and revenues in ($), as well as the resulting $/MWh, for the three scenarios (SPP alone, ERCOT alone, SPP & ERCOT simultaneously) for the following conditions:

1. Under Energy Generation Mode: the data represents the amount of energy produced and revenue generated by these sales.
2. Under Ancillary Services in Generation Mode: the data represents the amount of Ancillary Services (RegUP + RegDOWN + Spin + NonSpin) sold and the revenue generated by these sales during hours when the unit is only generating.
3. Under Energy Pump Mode: the data represents the amount of energy pumped (bought from the grid) and the cost of these purchases.
4. Under Ancillary Services Pump Mode: the data represents the amount of Ancillary Servies (RegUP + RegDOWN + Spin + NonSpin) sold and the revenue generated by these sales during hours when the units are only pumping.

Monthly Tables for three options.xlsx

Appendix D: Energy, Ancillary Service Sales Assumptions during Generation and Pumping

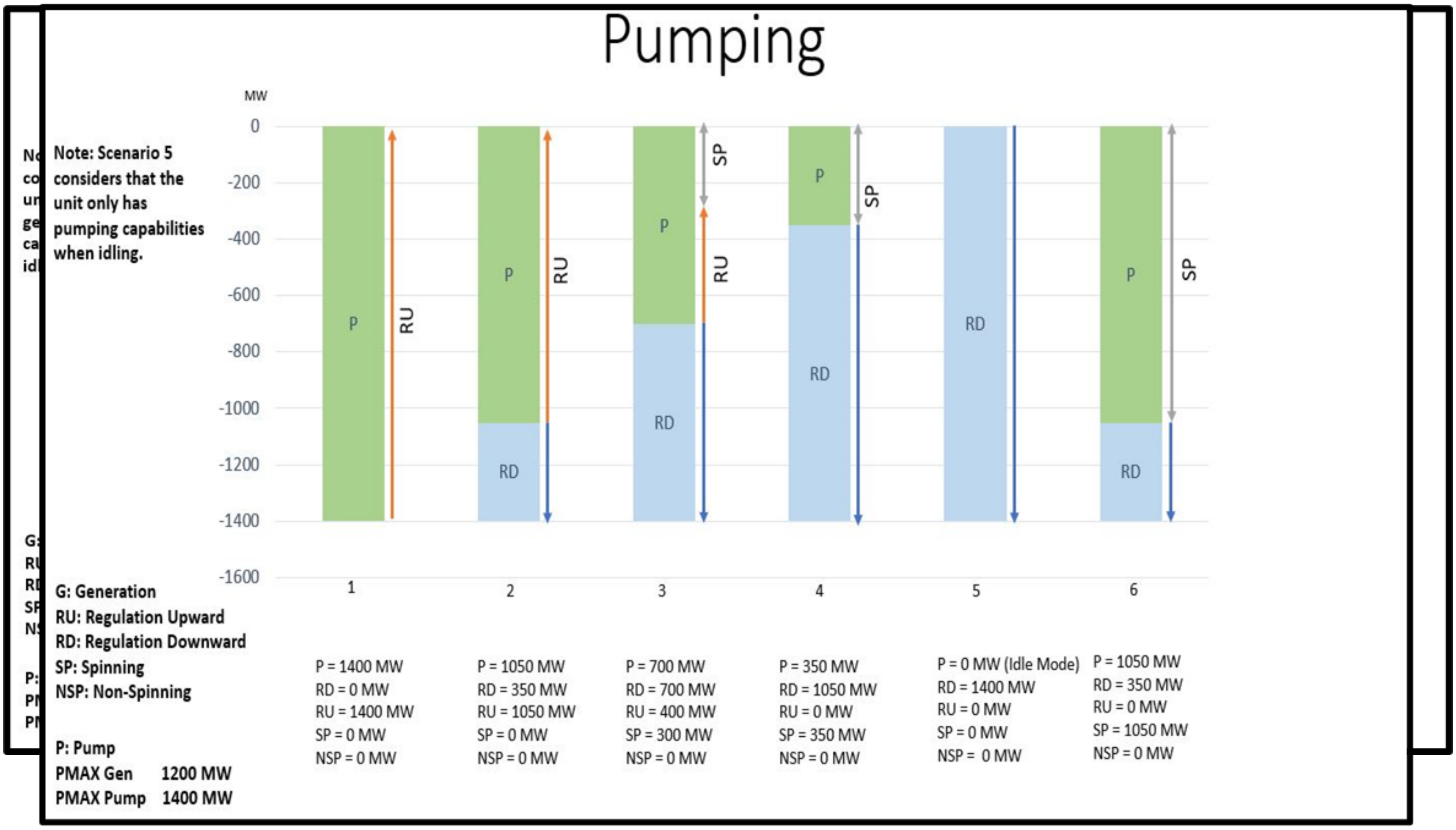


*Figure SEQ Figure * ARABIC 37– Energy and Ancillary Services Availability During Pumping*

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Appendix E: Forecast SPP and ERCOT Supply and Demand Stack for Low, Medium, and High Case

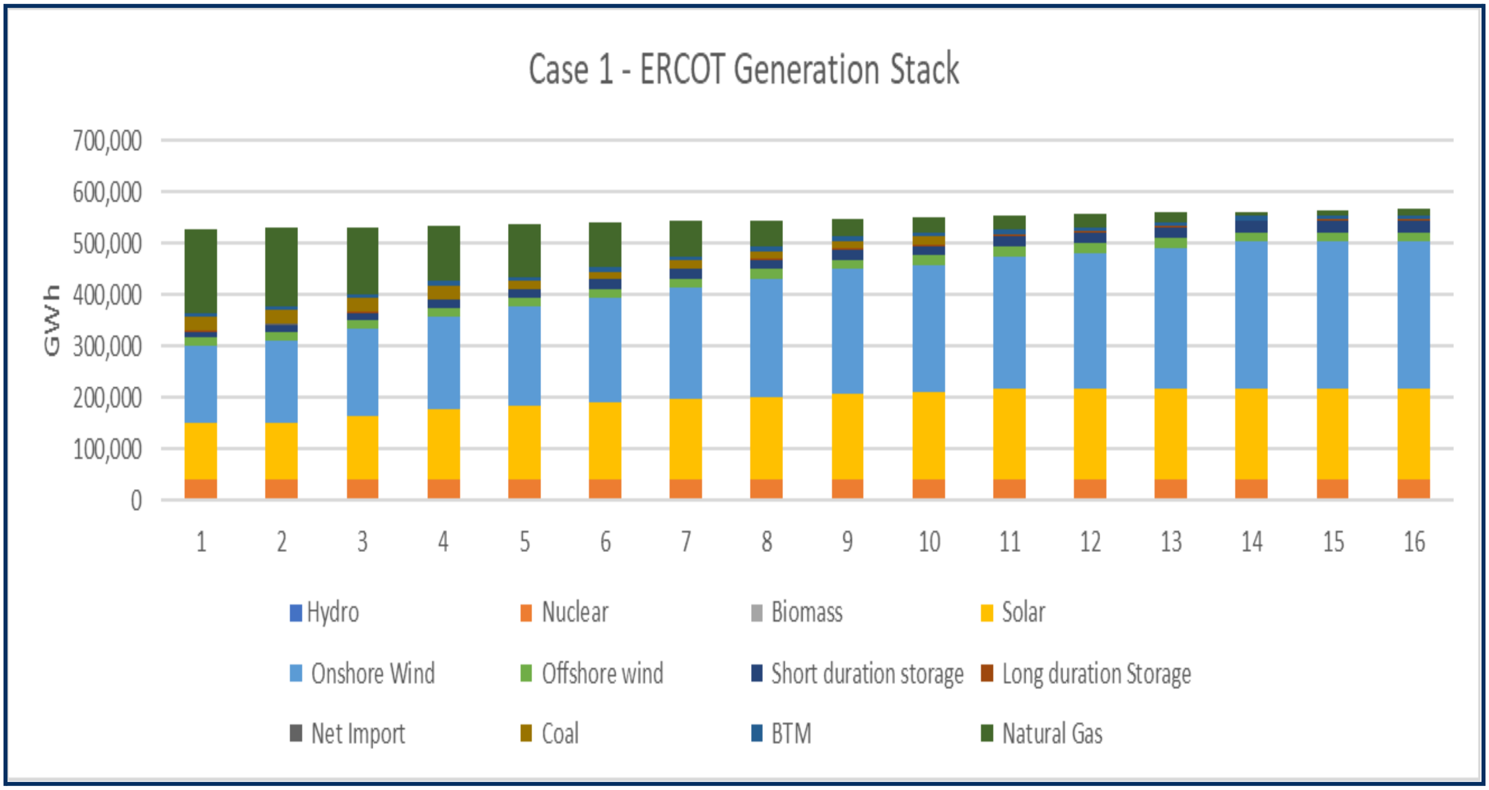
ERCOT	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Low Case - Peak Demand (MW)	91,093	91,453	92,915	93,380	93,847	94,316	94,787	95,261	95,738	96,216	96,697	97,181	97,667	98,155	98,646	99,139	
Low Case - Demand (GWh)	526,900	529,535	532,182	534,843	537,517	540,205	542,906	545,620	548,349	551,090	553,846	556,615	559,398	562,195	565,006	567,831	8,754,038
Net Total Generation (GWh)	526,900	529,535	532,182	534,843	537,517	540,205	542,906	545,620	548,349	551,090	553,846	556,615	559,398	562,195	565,006	567,831	8,754,038
Hydro	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	12,800
Nuclear	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	641,696
Biomass	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	2,400
Solar	107,560	109,141	122,050	134,608	143,463	149,356	154,767	160,133	165,464	170,768	176,051	176,051	176,051	176,051	176,051	176,051	2,473,613
Onshore Wind	152,442	160,876	171,461	182,609	192,998	203,925	217,739	230,955	244,188	245,972	258,656	263,611	273,274	285,547	285,547	285,547	3,655,340
Offshore wind	15,500	15,810	16,126	16,449	16,778	17,113	17,456	17,805	18,161	18,524	18,894	18,894	18,894	18,894	18,894	18,894	283,087
Short duration storage	12,310	13,553	14,407	15,255	16,109	17,720	18,613	18,606	19,548	19,537	20,521	20,513	21,547	21,539	22,624	22,616	295,012
Long duration Storage	1,750	1,750	1,980	1,750	1,750	2,100	2,100	2,100	2,100	2,750	2,750	2,750	2,750	2,750	2,750	2,750	36,630
Net Import	92	92	93	93	94	94	95	95	96	96	97	97	98	98	99	99	1,528
Coal	26,899	26,899	26,899	26,899	14,300	14,300	14,300	14,300	14,300	14,300	0	0	0	0	0	0	193,396
BTM	7,474	7,549	7,625	7,701	7,778	7,856	7,934	8,013	8,094	8,175	8,256	8,339	8,422	8,506	8,592	8,677	128,991
Natural Gas	161,816	152,809	130,486	108,424	103,197	86,684	68,847	52,557	35,347	29,913	27,565	25,304	17,306	7,754	9,394	12,141	1,029,544
Reserve Margin	20%	17.7%	18.8%	19.9%	16.6%	15.6%	19.9%	21.3%	22.1%	22.9%	23.7%	18.4%	21.0%	22.5%	23.7%	22.0%	
Available Capacity to Meet Peak Demand (MW)	109,408	107,640	110,398	111,974	109,425	109,029	113,662	115,551	116,898	118,247	119,613	115,062	118,177	120,240	122,024	120,950	
Annual Peak Demand Growth		0.39%	1.57%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	
ERCOT	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Medium Case peak Demand	92,459	92,825	94,309	94,780	95,254	95,731	96,209	96,690	97,174	97,660	98,148	98,639	99,132	99,627	100,126	100,626	
Medium Case Demand (GWh)	542,707	545,421	548,148	550,888	553,643	556,411	559,193	561,989	564,799	584,156	587,076	590,012	592,962	595,927	598,906	601,901	9,134,138
Net Total Generation (GWh)	542,707	545,421	548,148	550,888	553,643	556,411	559,193	561,989	564,799	584,156	587,076	590,012	592,962	595,927	598,906	601,901	9,134,138
Hydro	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	12,800
Nuclear	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	641,696
Biomass	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	2,400
Solar	97,782	103,944	116,233	128,198	140,650	146,428	151,732	156,993	162,220	167,420	172,599	177,760	182,908	188,045	193,174	198,296	2,484,386
Onshore Wind	145,188	153,215	163,295	173,913	183,808	194,214	207,370	219,957	232,560	234,259	246,399	258,442	270,569	282,720	282,720	282,720	3,531,279
Offshore wind	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	302,400
Short duration storage	14,157	15,585	16,563	17,543	18,526	18,895	19,274	19,660	20,053	20,454	20,863	21,280	21,706	24,770	26,018	26,008	321,360
Long duration Storage	1,750	1,750	1,960	1,750	1,750	2,100	2,100	3,100	3,100	3,100	3,100	3100	3,100	3,100	3100	3,100	41,060
Net Import	92	92	93	93	94	94	95	95	96	96	97	-	98	98	99	99	1,431
Coal	43,000	43,000	43,000	43,000	43,000	15,490	15,490	8,670	8,670	-	-	-	-	-	-	-	263,320
BTM	7,474	7,919	8,363	8,807	9,251	9,568	9,859	10,128	10,379	10,613	10,833	11,041	11,238	11,424	11,601	11,770	160,268
Natural Gas	173,313	159,959	138,654	117,628	96,613	109,665	93,317	83,430	67,767	88,257	73,289	58,432	43,388	25,814	22,239	19,952	1,371,718
Reserve Margin	15.84%	15.23%	17.50%	15.38%	16.50%	18.70%	15.30%	15.30%	17.50%	16.90%	18.50%	16.75%	14.60%	20.00%	20.20%	19.65%	
Available Capacity to Meet PeakD	107,102	106,962	110,813	109,360	110,971	113,632	110,929	111,484	114,179	114,164	116,305	115,161	113,605	119,553	120,351	120,399	
Annual Peak Demand Growth	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	
			1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	1.500%	
ERCOT	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
High Case peak Demand (MW)	92,915	93,282	94,773	95,247	95,723	96,202	96,683	97,167	97,652	98,141	98,631	99,124	99,620	100,118	100,619	101,122	
High Case Demand (GWh)	572,560	579,356	583,936	588,118	605,732	609,376	612,769	615,943	618,924	621,735	624,394	626,917	629,316	660,313	662,598	664,787	9,876,775
Net Total Generation (GWh)	572,560	579,356	583,936	588,118	605,732	609,376	612,769	615,943	618,924	621,735	624,394	626,917	629,316	660,313	662,598	664,787	9,876,775
Hydro	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	12,800
Nuclear	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	40,106	641,696
Biomass	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	2,400
Solar	107,560	114,338	127,861	141,018	154,715	161,071	166,905	172,692	178,442	184,162	189,858	195,536	201,199	201,199	201,199	201,199	2,698,955
Onshore Wind	137,924	145,554	155,131	165,218	174,613	184,504	197,002	208,959	220,932	222,546	234,022	245,520	257,040	268,584	268,584	268,584	3,354,715
Offshore wind	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	25,515	408,240
Short duration storage	16,988	18,702	19,882	21,052	22,231	22,675	23,129	23,592	24,063	24,545	25,036	25,536	26,047	29,724	31,221	31,210	385,632
Long duration Storage	3,500	3,500	3,960	3,500	3,500	4,200	4,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	82,160
Net Import	92	92	93	93	94	94	95	95	96	96	97	97	98	98	99	99	1,528
Coal	43,000	43,000	43,000	43,000	43,000	15,490	15,490	8,670	8,670	-	-	-	-	-	-	-	263,320
BTM	11,211	11,878	12,544	13,211	13,877	14,351	14,788	15,192	15,568	15,920	16,250	16,562	16,856	17,136	17,402	17,656	240,402
Natural Gas	185,714	175,720	154,894	134,456	127,131	140,420	124,590	113,972	98,388	101,696	85,360	70,894	55,305	70,801	71,323	73,268	1,784,926
Reserve Margin	15.20%	17.40%	18.40%	18.50%	14.75%	19.22%	16.40%	21.10%	18.44%	15.75%	23.88%	17.32%	15.90%	21.22%	16.70%	18.88%	
Available Capacity to Meet Peak Demand (MW)	107,038	109,513	112,212	112,868	109,843	114,692	112,539	117,669	115,659	113,598	122,184	116,298	115,460	121,363	117,422	120,214	
Annual Peak Demand Growth	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

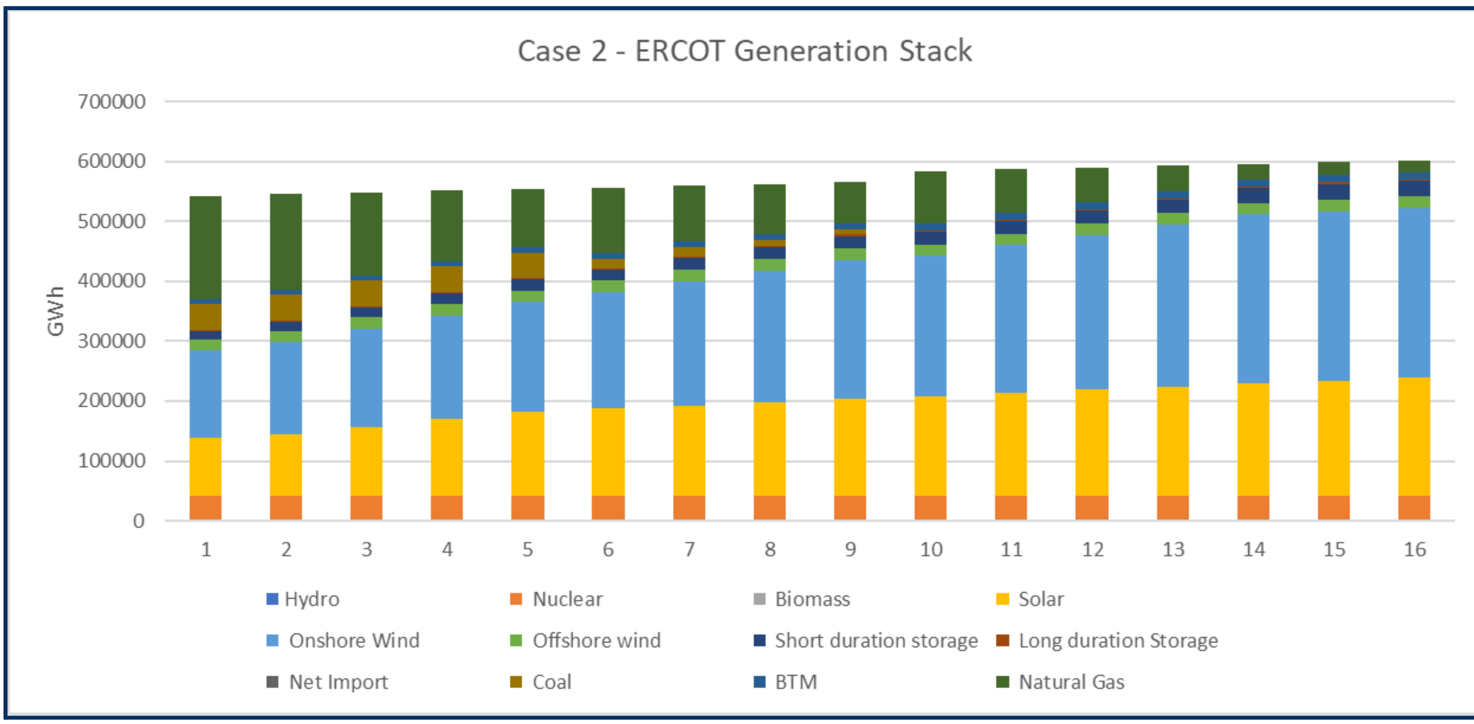
Confidential

August 23, 2023

SPP	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
LowCase - peak Demand (MW)	54,780	55,328	54,775	55,322	55,046	55,596	56,152	55,871	56,430	56,994	57,564	57,276	57,849	58,428	59,012	59,602	
LowCase- Demand (GWh)	277,953	279,372	280,698	278,535	280,401	281,208	282,317	283,321	284,137	285,088	285,993	286,859	287,599	288,348	289,061	289,745	4,540,635
Net Generation GWh)	277,953	279,372	280,698	278,535	280,401	281,208	282,317	283,321	284,137	285,088	285,993	286,859	287,599	288,348	289,061	289,745	4,540,635
Hydro	13,540	13,576	13,588	13,568	13,578	13,560	13,542	13,524	13,506	13,488	13,471	13,453	13,435	13,417	13,399	13,399	216,044
Nuclear	17,121	17,079	17,075	17,119	17,115	17,102	17,098	17,102	10,459	10,457	10,456	10,456	10,457	10,457	10,456	10,456	220,464
Biomass	78	78	78	78	160	160	160	160	160	160	155	155	155	155	155	155	2,202
Solar	26,373	30,099	33,745	36,701	39,665	42,621	45,614	48,619	51,061	53,493	55,940	58,390	60,846	62,731	64,617	7,701	718,217
Onshore Wind	132,074	134,154	136,202	136,554	138,879	140,693	143,869	147,011	150,072	153,221	156,363	160,387	164,361	168,359	172,353	176,348	2,410,901
Short duration storage	2,798	4,179	5,559	6,940	8,320	8,944	9,568	10,192	10,816	11,440	12,272	13,104	13,936	14,768	15,600	16,640	165,075
Long duration Storage	720	960	2,876	4,607	5,087	5,567	6,047	6,527	7,007	7,487	7,967	8,447	8,927	9,407	9,887	10,367	101,890
Coal	11,035	9,394	6,280	3,877	1,648	0	0	0	0	0	0	0	0	0	0	0	32,233
Natural Gas	74,214	69,854	65,294	59,092	55,950	52,562	46,419	40,186	41,056	35,341	29,370	22,466	15,482	9,054	2,592	54,679	673,611
Reserve Margin	20%	17.7%	18.8%	19.9%	16.6%	15.6%	19.9%	21.3%	22.1%	22.9%	23.7%	18.4%	21.0%	22.5%	23.7%	21.5%	
Available Capacity to Meet Peak Demand (MW)	65,791	65,121	65,081	66,338	64,183	64,269	67,333	67,771	68,900	70,045	71,206	67,815	69,998	71,574	72,997	72,417	
SPP	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MediumCase - peak Demand (MW)	55,602	56,158	55,596	56,152	55,871	56,430	56,994	56,709	57,276	57,849	58,428	58,136	58,717	59,304	59,897	60,496	
MediumCase - Demand (GWh)	293,195	287,753	289,119	286,891	288,813	289,644	290,786	291,821	292,661	302,193	303,153	304,070	304,855	305,649	306,405	307,130	4,744,139
Net Generation GWh)	293,195	287,753	289,119	286,891	288,813	289,644	290,786	291,821	292,661	302,193	303,153	304,070	304,855	305,649	306,405	307,130	4,744,139
Hydro	13,540	13,576	13,588	13,568	13,578	13,560	13,542	13,524	13,506	13,488	13,471	13,453	13,435	13,417	13,399	13,399	216,044
Nuclear	17,121	17,079	17,075	17,119	17,115	17,102	17,098	17,102	10,459	10,457	10,456	10,456	10,457	10,457	10,456	10,456	220,464
Biomass	78	78	78	78	160	160	160	160	160	160	155	155	155	155	155	155	2,202
Solar	29,149	33,267	37,297	40,564	43,840	47,107	50,416	53,737	56,436	59,124	61,828	64,537	67,251	69,334	71,419	71,505	856,813
Onshore Wind	138,678	140,861	143,012	143,381	145,823	147,727	151,062	154,362	157,576	160,882	164,181	168,407	172,579	176,777	180,971	181,165	2,527,446
Short duration storage	3,106	4,638	6,170	7,703	9,235	9,928	10,620	11,313	12,006	12,698	13,622	14,545	15,469	16,392	17,316	17,316	182,079
Long duration Storage	850	1,133	3,394	5,437	6,003	6,569	7,136	7,702	8,269	8,835	9,401	9,968	10,534	11,101	11,667	12,233	120,230
Coal	11,035	9,394	6,280	3,877	1,648	-	-	-	-	-	-	-	-	-	-	-	32,233
Natural Gas	79,639	67,727	62,224	55,164	51,412	47,491	40,753	33,922	34,251	36,548	30,039	22,550	14,975	8,016	1,021	899	586,629
Reserve Margin	15.84%	15.23%	17.50%	15.38%	16.50%	18.70%	15.30%	15.30%	17.50%	16.90%	18.50%	16.75%	14.60%	20.00%	20.20%	19.65%	
Available Capacity to Meet Peak Demand (MW)	64,407	64,711	65,325	64,790	65,090	66,982	65,714	65,386	67,300	67,626	69,237	67,873	67,290	71,165	71,996	72,384	
SPP	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
HighCase - peak Demand (MW)	57,793	58,371	57,787	58,365	58,073	58,654	59,240	58,944	59,534	60,129	60,730	60,427	61,031	61,641	62,258	62,880	
HighCase - Demand (GWh)	312,253	306,457	307,912	305,539	307,586	308,471	312,595	342,890	343,877	355,077	356,204	357,282	358,205	359,138	360,026	360,877	5,354,389
Net Generation GWh)	312,253	306,457	307,912	305,539	307,586	308,471	312,595	342,890	343,877	355,077	356,204	357,282	358,205	359,138	360,026	360,877	5,354,389
Hydro	13,540	13,576	13,588	13,568	13,578	13,560	13,542	13,524	13,506	13,488	13,471	13,453	13,435	13,417	13,399	13,399	216,044
Nuclear	17,121	17,079	17,075	17,119	17,115	17,102	17,098	17,102	10,459	10,457	10,456	10,456	10,457	10,457	10,456	10,456	220,464
Biomass	78	78	78	78	160	160	160	160	160	160	155	155	155	155	155	155	2,202
Solar	33,743	37,830	41,144	44,467	47,780	51,136	54,504	57,242	59,969	62,711	65,459	68,212	75,688	76,566	77,556	78,673	932,678
Onshore Wind	151,159	153,539	155,883	156,286	158,947	161,023	164,658	168,254	171,758	175,362	178,957	183,563	188,112	192,687	197,259	201,830	2,759,276
Short duration storage	3,727	5,566	7,405	9,243	11,082	11,913	12,745	13,576	14,407	15,238	16,346	17,455	18,563	19,671	20,779	22,164	219,880
Long duration Storage	864	1,152	3,451	5,529	6,105	6,681	7,257	7,833	8,409	8,985	9,561	10,137	10,713	11,289	11,865	12,441	122,268
Coal	5,600	5,600	5,600	5,600	5,600	-	-	-	-	-	-	-	-	-	-	-	28,000
Natural Gas	86,421	72,038	63,687	53,649	47,220	46,897	42,632	65,199	65,210	68,676	61,800	53,852	41,083	34,897	28,557	21,759	853,577
Reserve Margin	15.64%	15.04%	17.28%	15.19%	16.29%	18.47%	15.11%	15.11%	17.28%	16.69%	18.27%	16.54%	14.42%	19.75%	19.95%	19.40%	
Available Capacity to Meet Peak Demand (MW)	66,831	67,150	67,773	67,231	67,535	69,485	68,191	67,850	69,822	70,164	71,825	70,422	69,830	73,815	74,676	75,082	

Table 39– Forecast SPP and ERCOT Supply and Demand Stack for Low, Medium, and High Case


Case 1 - ERCOT Generation Stack
GWh
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16
Hydro
Nuclear
Biomass
Solar
Onshore Wind
Offshore wind
Short duration storage
Long duration Storage
Net Import
Coal
BTM
Natural Gas


Case 2 - ERCOT Generation Stack
GWh
700000
600000
500000
400000
300000
200000
100000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16
Hydro
Nuclear
Biomass
Solar
Onshore Wind
Offshore wind
Short duration storage
Long duration Storage
Net Import
Coal
BTM
Natural Gas

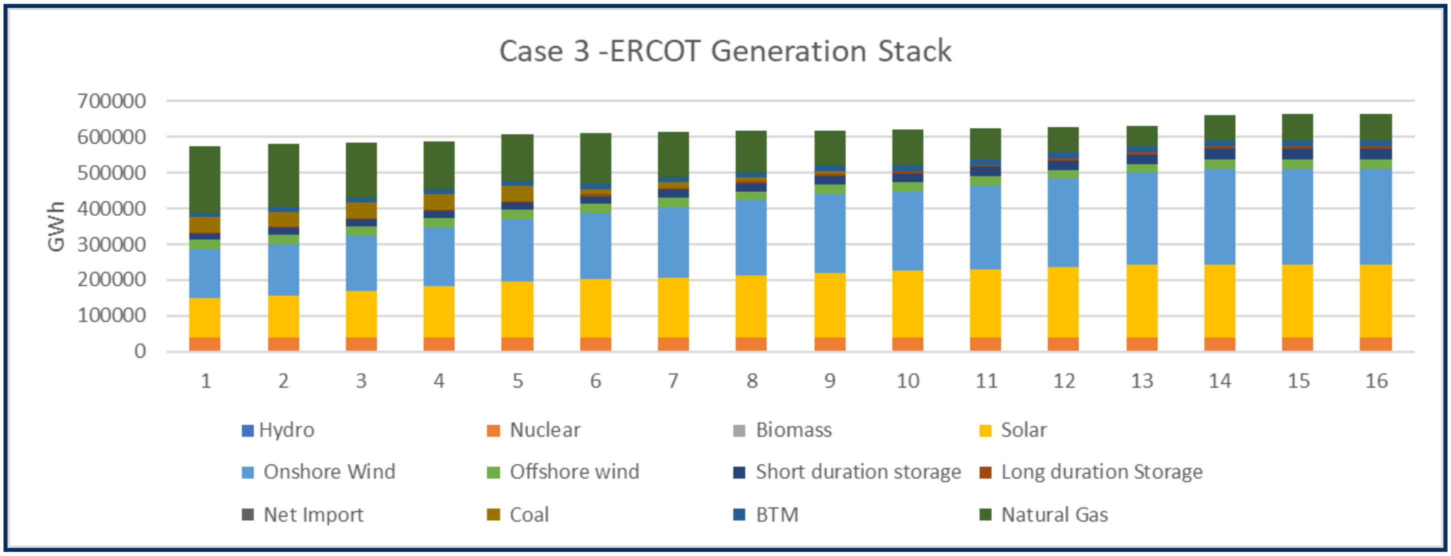
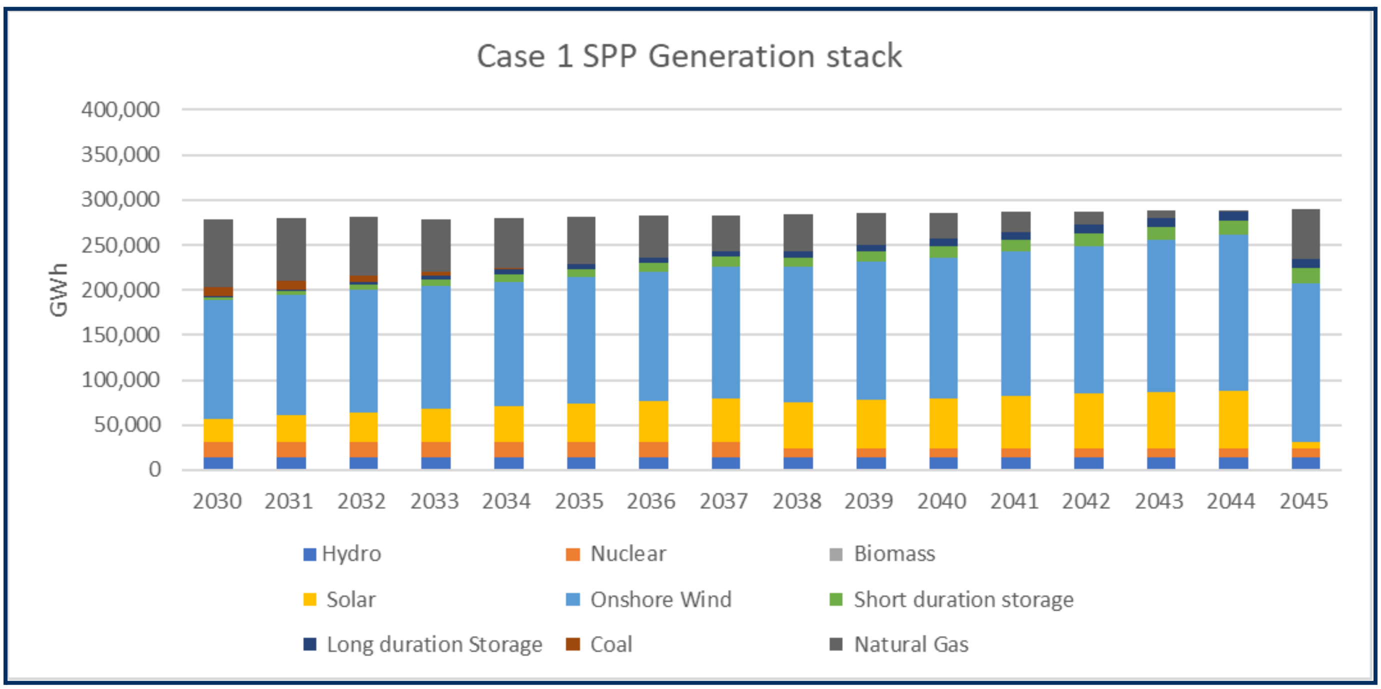
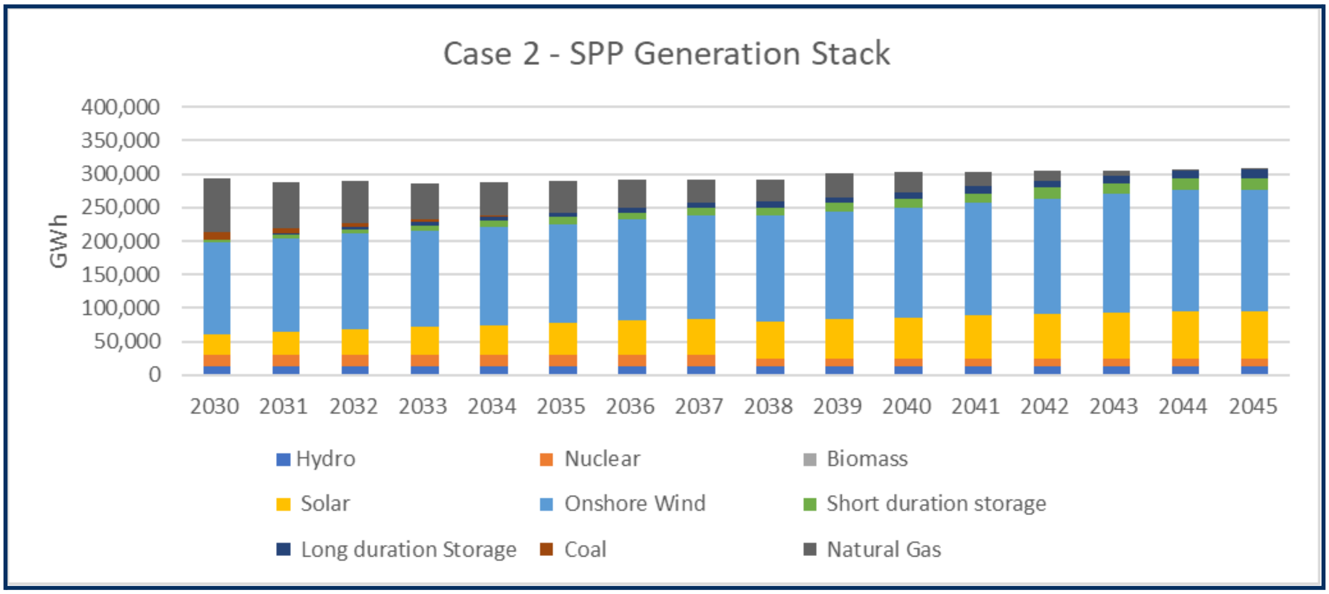


Figure 38– Summary of the ERCOT Forecast Generation Stack.





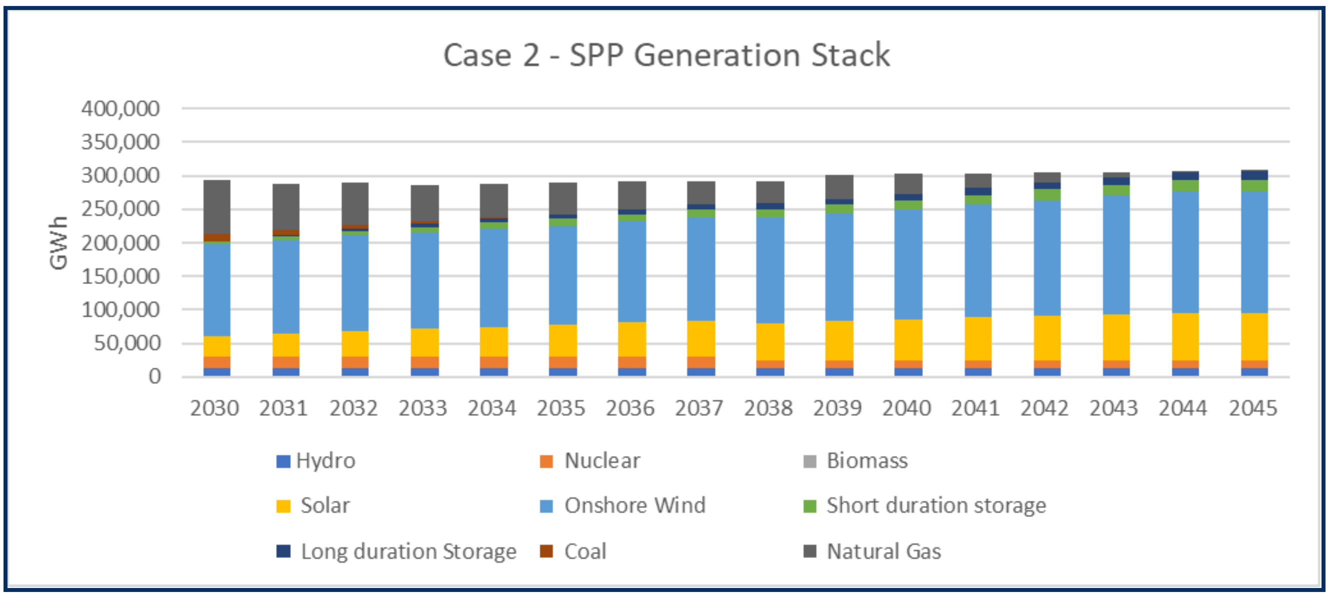


Figure 39– Summary of the SPP Forecast Generation Stack