WECC

Long-Duration Energy Storage Assessment

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Executive Summary

The purpose of this Long-Duration Energy Storage (LDES) assessment is to determine whether long-duration (greater than 12 hours) energy storage systems mitigate challenges in reaching higher clean energy percentages, as identified in the 2040 Clean Energy Scenarios (CES) assessment such as -capacity of renewables to be added to meet clean energy targets. WECC (Western Electricity Coordinating Council) completed the CES assessment as part of the 2020-2021 Study Program. That assessment examined increasing clean energy and energy needs percentages provided by non-carbon-emitting resources in 2040 to 80, 90, and 100 percent. The LDES assessment initially sought to examine the impacts on the clean energy percentage of increasing energy storage duration—to 24, 48, 168, and 336 hours. In WECC's initial simulations, Energy Storage charging and discharging cycles for longer than 24 hours were not used due to modeling options requiring use of static annual user defined energy prices, thus resulting in lower than anticipated use of storage devices. Therefore, the study, focused on if an 80-90% clean energy scenario, with load and generation balanced, can be achieved with 12-hour duration energy storage. The study explored following reliability impact on the Western Interconnection of these high clean energy scenarios:

1. What would be the composition of the resulting renewable and storage mix to achieve 80-90% clean energy dispatch with load and generation balanced for an entire year?
2. Can additional storage reduce "spillage[1]" due to over generation conditions of renewable resources?
3. Could transmission flows in the high energy storage and high renewable energy cases lead to reliability risks?

The 2022 LDES assessment produced the following takeaways:

1. Energy storage systems with a 12-hour storage duration modeled over a 24-hour charging and discharging cycle can mitigate daily fluctuations in loads and resource availability.
2. Different modeling tools are needed to model charging and discharging cycles longer than 24 hours.
3. To achieve a 90% clean energy scenario, significant capacity addition was needed for both renewable and energy storage resources. Careful balance between renewables and storage is needed to achieve the desired clean energy targets.
4. Increasing storage and renewable energy capacity also increases the "spillage" of renewable resources.

[1] In many of the modeling runs, the software was not able to dispatch all of the available renewable resource generation. As a result, the software "spilled" excess renewable capacity, meaning even though the energy was generated, it could not be used to serve load, so it was wasted.

5. Expanding storage and renewable energy capacity—to reach higher clean energy percentages—increases exports from the Northwest[2], Basin, and Desert Southwest regions due to increased solar and wind resource production.
6. Increasing energy storage and renewable resources—to increase the clean energy percentage—shifts BES (Bulk Electric System) peak load from approximately 4:00 p.m. to 1:00 p.m. This shift is due to the increased storage charging load during mid-day—when there is a high availability of solar energy.
7. Significant transmission system enhancements will likely be needed to accommodate the increasing proliferation of renewable energy and energy storage systems.

Building on the current 2022 LDES assessment, the following opportunities will increase the understanding of potential energy storage system benefits in 2023:

1. Exploring tools for modeling energy storage systems with charging and discharging cycles longer than 24 hours.
2. Seeking ways to model designated long-duration storage systems to store renewable energy otherwise spilled during light-load periods—without the current limitations of the battery energy storage system (BESS) modeling approach.
3. Assessing ways LDES systems mitigate reliability risks associated with extreme natural events including scenarios with prolonged low availability of variable energy resources or hydro generation.

WECC relies on input from industry, policymakers, regulators, and technical partners in the West to develop the Study Program Assessments and is committed to continuously improving its stakeholder engagement in the production and dissemination of its work. WECC would like to thank the stakeholders who provided input and recommendations that helped shape this assessment.

[2] The Northwest region includes Washington, Oregon, part of Idaho, Montana. and Wyoming.

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Purpose

The Scenarios Work Group (SWG) conducted a series of assessments for horizon year 2040 as part of the 2020–2021 WECC Study Program. The study identified generation mix challenges in attaining a clean energy contribution exceeding 80% in the Western Interconnection. Specifically, the study found that, at renewable penetration levels above 80%, there is a saturation point at which adding more renewable generation or storage capacity did not significantly increase the overall clean energy percentage. The 2040 Clean Energy Sensitivities (CES) Study also found a critical need for emerging clean energy technologies (resources that are non-carbon emitting and are dispatchable) to increase the clean energy percentage above 80% on the path to a 100% clean energy future.

The original intent of this study was to determine whether long-duration energy storage (LDES) (storage duration greater than 12 hours) technologies mitigate challenges in the resource mix, focusing on one or two emerging storage technologies with extensive development support and funding. Due to software limitations, it was not possible to model LDES's impact on the system for storage durations over 12 hours. Therefore, this assessment focused on achieving an 80% and 90% clean energy dispatch with a mix of 12-hour storage, increasing the storage capacity and the renewable energy penetration in a 20-year scenario, including a high electrification load.

This assessment evolved to explore these reliability questions:

1. By adding more renewable generation and storage, can we reach 80% and 90% clean energy dispatch for an entire year? What would be the composition of the resulting renewable and storage mix?
2. Does adding more energy storage in a high renewable energy study case eliminate unserved energy on the Bulk Power System (BPS)?
3. Can additional storage reduce "spillage" due to over-generation conditions of renewable resources?
4. Can increasing the duration of energy storage achieve a higher clean energy dispatch?
5. Could transmission flows in the high energy storage and high renewable energy cases lead to reliability risks?

Key Assumptions

For this assessment, a high renewable and heavy load electrification scenario was assumed for a 20-year future; i.e., the year 2040. The following assumptions were made regarding this scenario:

1. **Load Electrification**—It was assumed that the BPS would experience a higher load due to the proliferation of commercial and residential electric vehicles. Additionally, replacing natural gas space and water heating appliances with electric appliances—such as heat pumps and electric

water heaters—will also contribute to this higher load. The increased load growth projection is based on the National Renewable Energy Laboratory's (NREL) Electrification Futures Study (EFS), as shown in Figure 1.

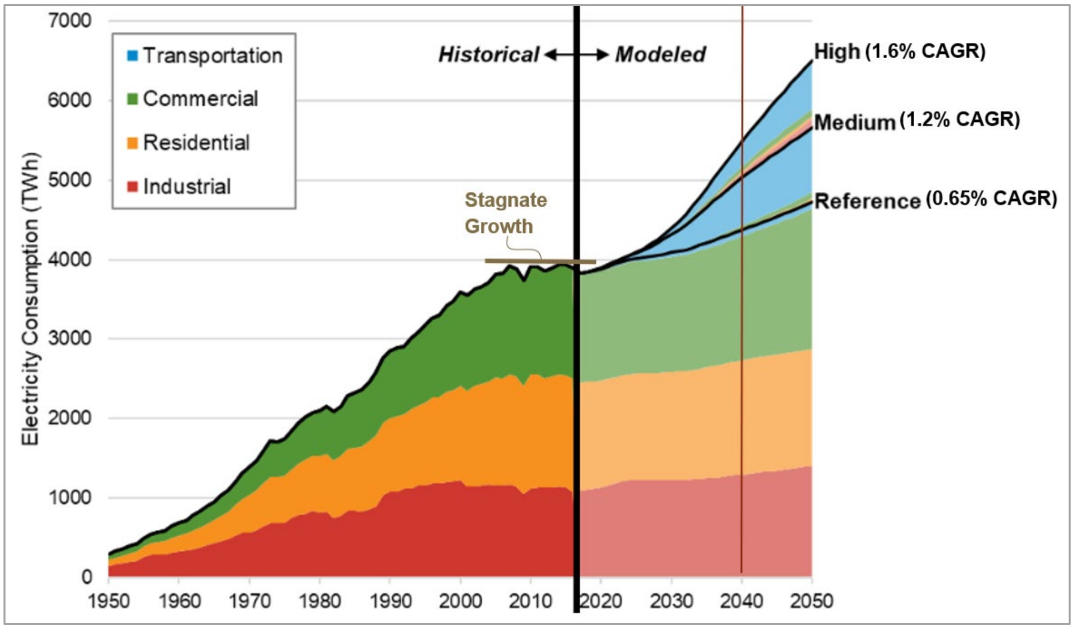
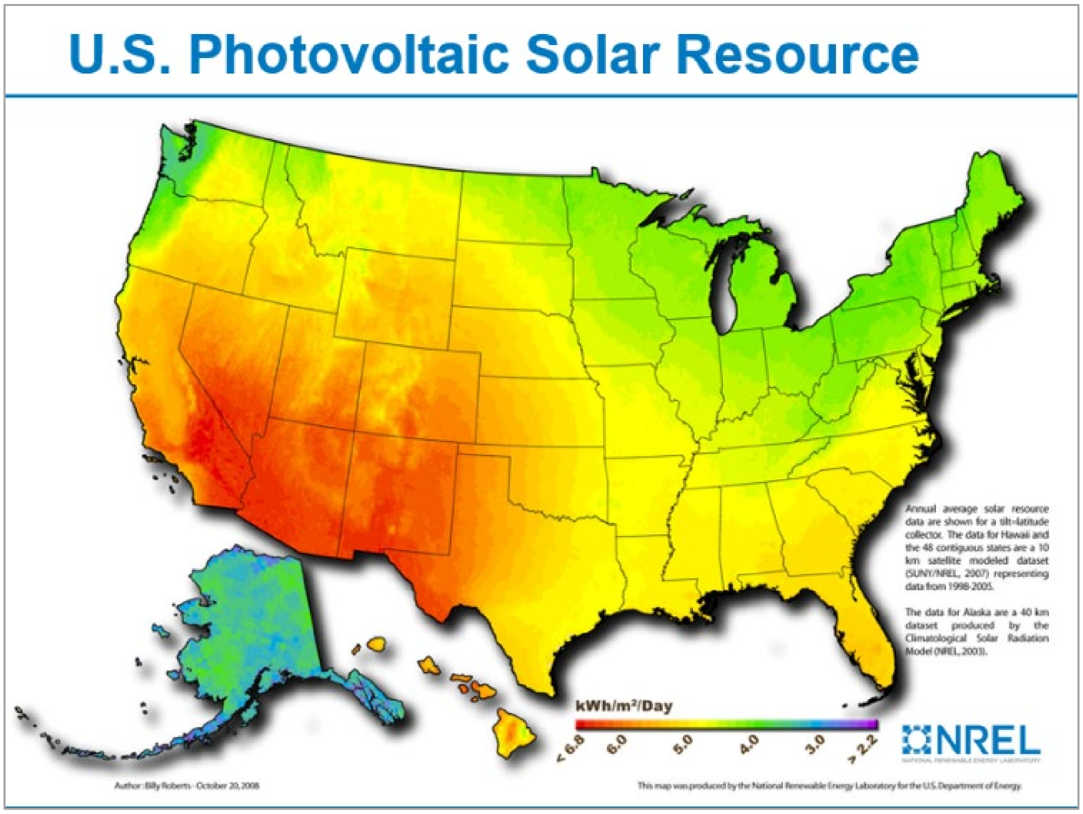


Figure 1: NREL EFS study—electrification load growth up to 2050

2. **High Renewable penetration**—NREL's renewable energy maps were used to site the potential additional solar and wind resources throughout the interconnection, as shown in Figure 2.



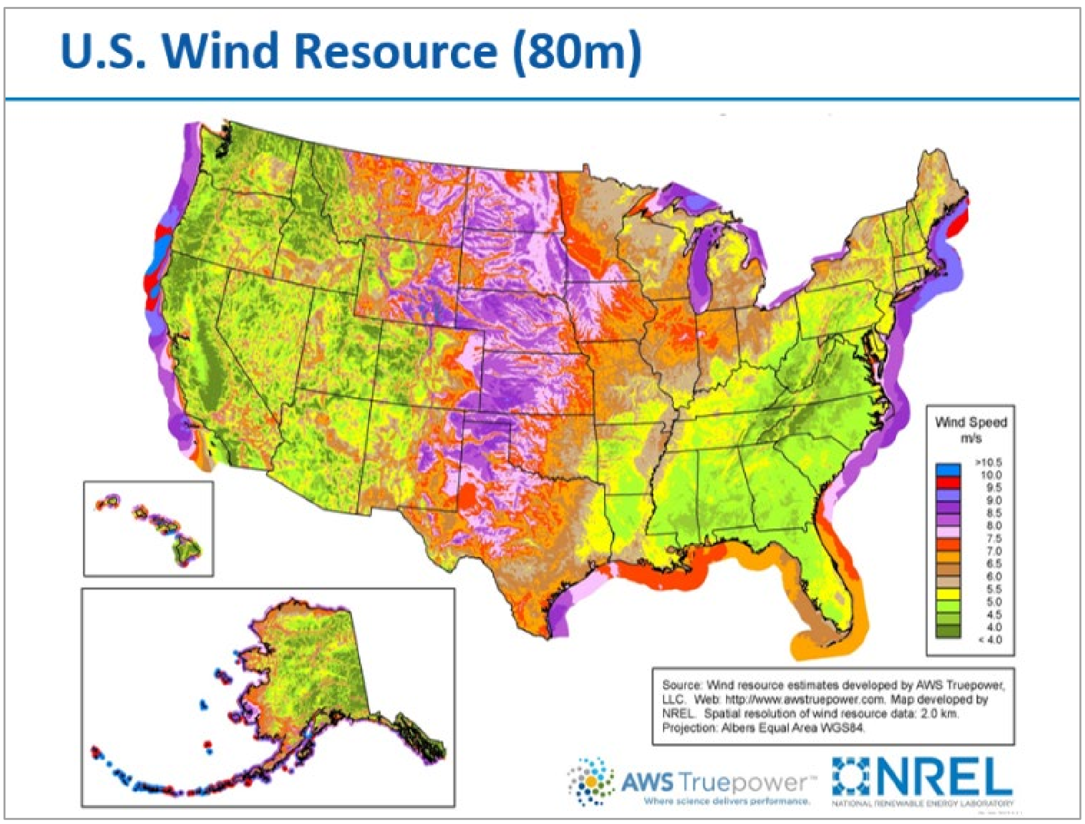


Figure 2: Renewable Energy Potential across USA

3. **A production cost model (PCM) tool** was used to perform an hourly dispatch of resources for the entire year to match the load across the Western Interconnection. Hitachi Energy's PCM tool, GridView, was used to model scenarios for this assessment.
4. This scenario would be resource adequate with no unserved energy during the year.
5. **Energy storage would be the predominant clean energy technology** added—instead of another emerging clean and flexible resource.
6. A system-wide carbon penalty of $100/ton for CO_2 emissions was assumed consistent with the 2040 CES study.
7. All necessary transmission **path upgrades and reinforcements for transmission lines below 230 kV** would be in place.

Note: Transmission constraints were not considered in this assessment. See ***Modeling Approach*** *for a discussion on addressing transmission constraints.*

Input Data

This assessment was built on the 2040 CES case (80% clean energy)[3] with several adjustments. The 2040 CES case used the 2030 Anchor Data Set (ADS) as a starting point for existing transmission and generation. In this case, loads were derived using models from the NREL EFS. New candidate generation resources were derived from NREL's Annual Technology Baseline (ATB) for 2040 and resources with proxy representation of an emerging clean technology were added.

The following adjustments were made to the case to identify the effects of additional storage:

- All emerging clean technology resources (resources that are non-carbon emitting and are dispatchable) included in the 2040 CES Study were replaced with storage units.
- The solar generation profiles for hourly solar resources augmented for year 2040 in the 2040 CES study were too low compared to expected solar profiles in year 2030 ADS case, as shown in Figure 3. Thus, the solar profiles for these hourly solar resources were updated to 2030 ADS case profiles.

[3]https://internal.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/2040%20Clean%20Energy%20Sensitivities%20Report.pdf&action=default&DefaultItemOpen=1

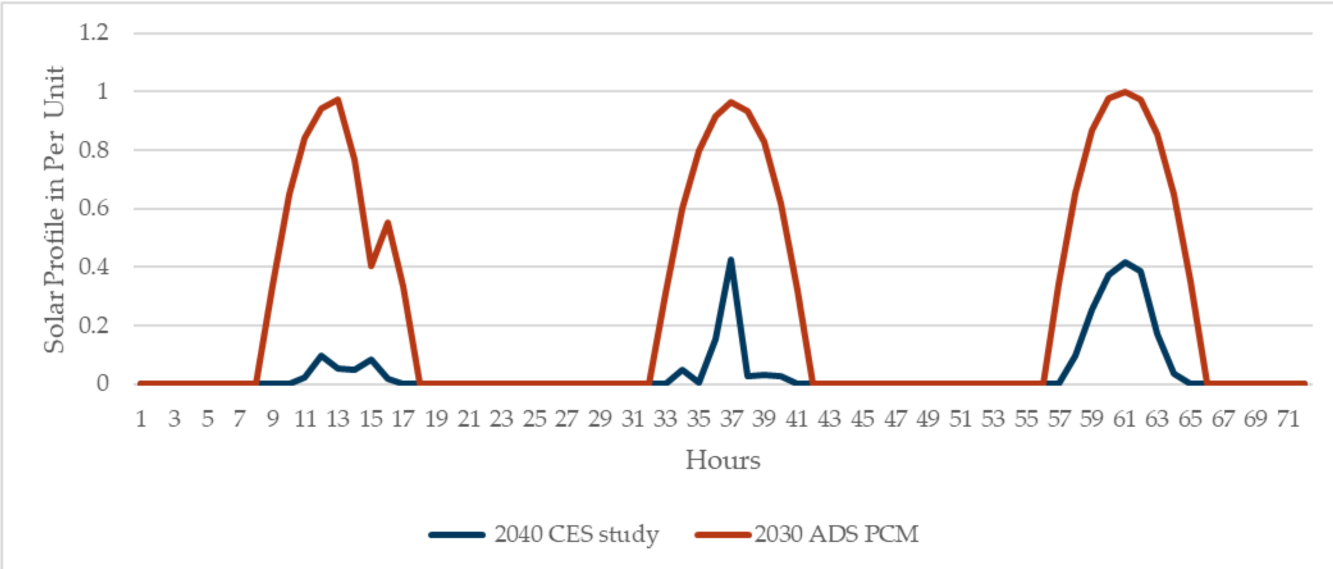


Figure 3: Example of 72-hour solar profile in ADS 2030 vs. 2040 CES Study

- Load and generation resources in the 2040 CES study were modeled by area, representing regional Balancing Authority (BA) boundaries in the Western Interconnection. Table 3 in the appendix includes the names and abbreviations of the BAs in the Western Interconnection. The appendix's Figure 25 details a map of BA boundaries along with its subregions. Load profiles remain unchanged from the 2040 CES study.
- In the 2040 CES study, thermal resources were augmented for 2040 by about 7,800 MW, with each heat rate block being 1,500 MW. This assumption in the 2040 CES study prevented the resources from being appropriately dispatched due to modeling constraints. As an improvement in this study, incremental thermal resources added to meet the increased load demand for year 2040 were kept below 300 MW—while keeping the total thermal capacity the same as the 2040 CES—by increasing the number of these resources. These resources were then distributed to load areas in the same proportion as in the 2040 CES study.
- The heat rates for the 2040 thermal units were updated with the generic Input-Output (IO) curves from the 2032 ADS case, and the heat rates were calculated by GridView, using the designated IO curves.
- In the 2040 CES study, maintenance for all thermal resources for the year 2040 was scheduled during the first two weeks of January. For the LDES case, the maintenance schedules for these resources were spread during the year, excluding peak summer and winter months.
- The augmented storage units for year 2040 in the 2040 CES study were of the order of 1 GW capacity, resulting in them being insufficiently dispatched. For this assessment, the storage resource capacity of an individual plant was capped at 350 MW, while keeping the total storage capacity for the entire system the same as in the 2040 CES by increasing the number of these

resources. These added resources had the same distribution by area as in the 2040 CES study case.

Modeling Approach

Unserved Energy

The 2040 CES case had unserved energy due to transmission constraints because of the assumed sizes of the resources. The 2040 CES case had the same set of transmission lines and paths—with flow limits enforced according to the 2030 ADS case. For this assessment, following changes were to made to the 2040 CES study case regarding transmission flow constraints to address unserved energy:

- Flow limits on major transmission paths were removed to address unserved energy in the cases. Path ratings were changed to 9,999 MW and -9,999 MW to achieve this. This adjustment also allowed the modeling run to record the maximum flow on these paths, while allowing the flow to exceed the path limits.
- Flow limits on transmission lines up to 230 kV were removed to address unserved energy.

Four test cases were run with various configurations of transmission flow limits enforced to determine the best configuration for storage dispatch:

1. Case 1: All transmission flow constraints were removed.
2. Case 2: Only 345 kV and above were enforced.
3. Case 3: Only 230 kV and below were enforced.
4. Case 4: Only a defined set of 534 transmission lines 345 kV and above flow limits were enforced—which were the same lines as in the 2030 ADS case.

The best set of transmission constraints for resource and storage dispatches with no unserved energy was Case 4, listed above. These transmission constraints allowed for optimized thermal resource dispatch, mitigating all unserved energy.

Increasing the Clean Energy Percentage

In the 2030 ADS case, the total installed storage capacity was 57.4 GW, and the hourly renewable resource (solar and wind) capacity was 104.4 GW. For year 2040, total installed storage capacity and hourly renewables were increased by 51.7 GW (619.8 GWh) in storage and 161.1 GW in hourly renewables, as shown in Figure 4(a). Once a feasible reference case with 80% clean energy and no unserved energy was achieved (referred to as 2040 Reference case for this assessment), the goal was to adjust the resource portfolio to increase the clean energy percentage to 90%. Two approaches were used to achieve this: a) increasing the total storage capacity and b) increasing the renewable resource capacity available for dispatch. Capacity of storage resources added beyond year 2030 (referred as 2040 storage) in the amount of 51.7 GW were increased by 4, 6, 8 and 12-fold from the reference case—

keeping a 12-hour storage duration in each scenario. This incident provided five storage capacity levels for sensitivity cases, with total storge capacities of 109.1 GW, 264.2 GW, 367.6 GW, 471 GW, and 677.8 GW, respectively. Similarly, the capacity of hourly renewable resources added beyond year 2030 (referred as 2040 hourly renewables) in the amount of 161.1 GW were increased by 30%, 50%, and 100% from the reference case. These increases resulted in four levels of hourly renewable capacity for sensitivity cases, with 265.5 GW, 313.83 GW, 346.1 GW, and 426.6 GW, respectively. These approaches resulted in 20 sensitivity cases in understanding the impacts of changing storage capacity and available renewable capacity, as shown in Table 5 in the appendix. This report focuses on four cases at the ends of the sensitivity case spectrums:

1. The 2040 Reference;
2. The case with the highest renewable increases without a storage increase (High Renewables);
3. The case with the highest storage increases without a renewable increase (High Storage); and
4. The case with both highest storage and highest renewable increase (High Storage–High Renewables)

The installed capacity for the four sensitivity cases is shown in **Figure 4**.

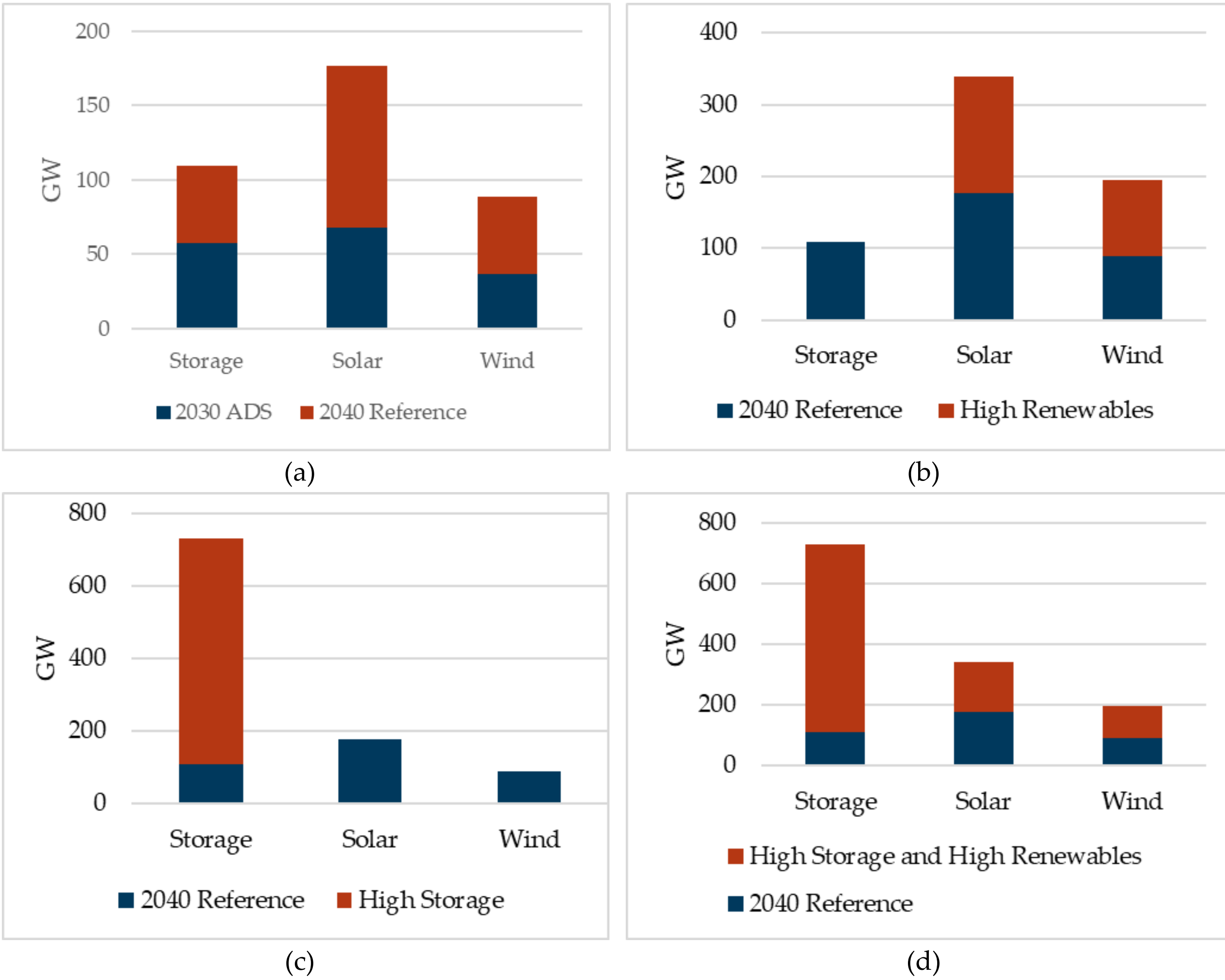


Figure 4: Installed capacity of storage and hourly renewables in sensitivity cases

Tool and Modeling Limitations and Observations

Storage Model: GridView Battery Model vs. Pumped Storage Model

Two approaches for modeling storage capacity are available through the GridView PCM software: one based on battery energy storage systems (BESS) and one based on pumped storage (PS) hydro. Several test cases were run to compare the performance of the storage model as BESS and PS. The BESS model has a limitation of a fixed, user-defined charging and discharging price, which is a constant for each battery storage unit throughout the year. In the PS model, simulation options available are Daily Peak Shaving, Daily Schedule on Price, and User-defined Prices. Daily Schedule on Price was selected to allow GridView to optimize each unit’s daily charging and discharging price throughout the year and across the Western Interconnection. Upon testing, both BESS and PS models operated on daily charge and discharge cycle of 24 hour. In the PS model, the charge and discharge prices were optimized over 24 hours, and storage dispatch was found to be higher than in the BESS model, therefore the PS model was selected to simulate energy storage in this assessment. The price curve was selected for the PS schedule mode rather than the load curve to minimize run-time and avoid unserved energy in the sensitivity cases.

Simulation Run Times: Multi Interval Optimization vs. Look-Ahead Simulation

GridView has two simulation options: Multi-Interval Optimization (MIO) and Look-Ahead (LA) logic. The MIO option is for multi-interval economic dispatch, which:

- More effectively operates thermal units with ramping rate limits;
- Allows more hydro energy dispatch during higher location marginal price (LMP) hours;
- Allows more effective pumped storage operation by price-driven logic.

The LA logic program optimizes thermal unit commitments and looks ahead for up to eight days—to improve unit commitments for each hour. In the cases tested, the look-ahead period was set to seven days. Running cases with the MIO option required system hardware upgrades with a minimum configuration of 64 GB of RAM, 25 MB of cache memory, and a 12-core processor, as shown in Figure 5.

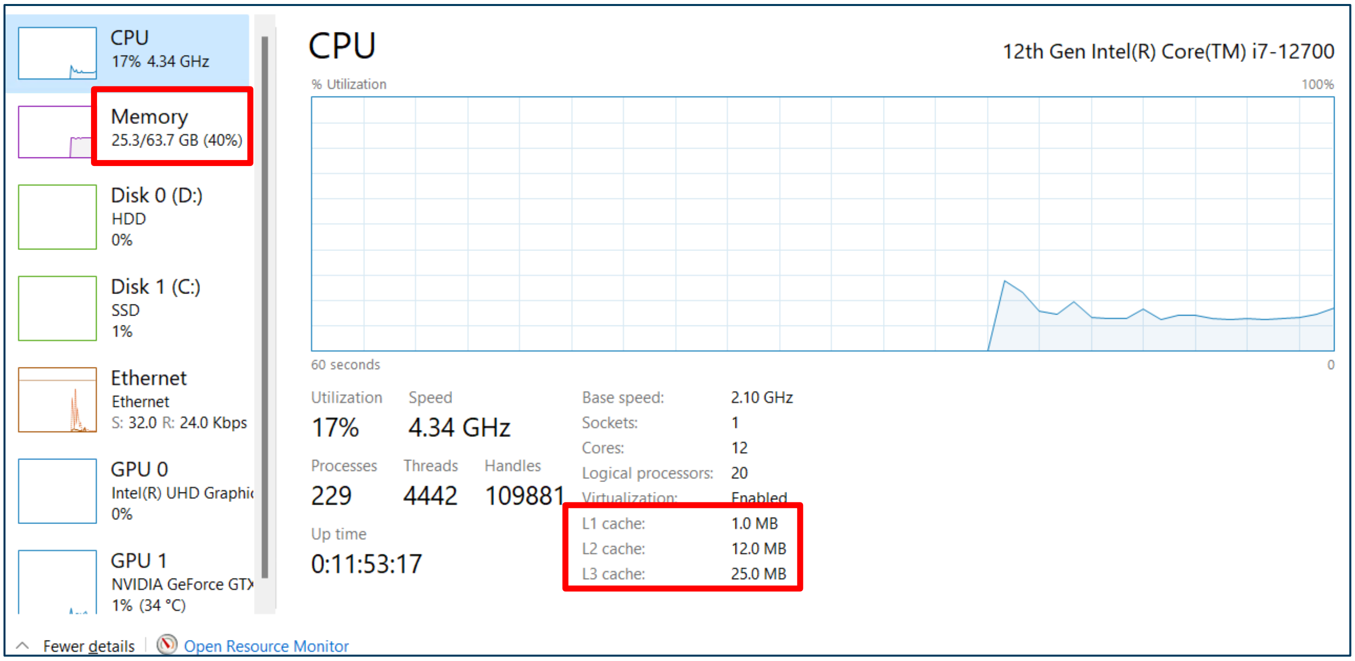


Figure 5: System requirements for using MIO option

A typical simulation run-time for a test case with MIO was 50 hours, whereas it was about seven hours with look-ahead logic. Further, the test cases with the MIO option did not produce a significantly better performance of the storage dispatch than the look-ahead dispatch option. For the 2040 Reference scenario, simulations showed:

- The total system spillage was about 3,600 GWh lower with the LA logic than with MIO dispatch logic, as shown in Figure 6.

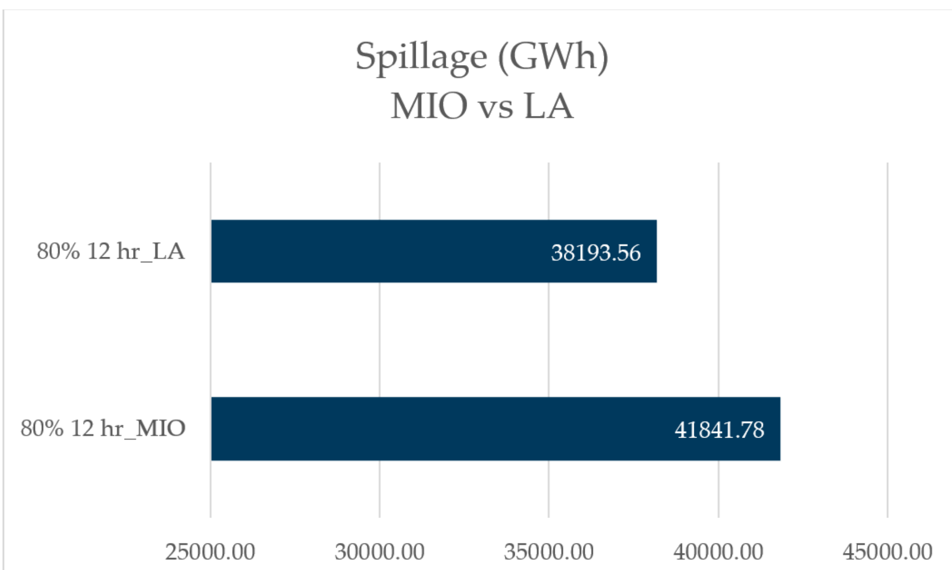


Figure 6: System spillage (GWh) for 2040 Reference scenario—MIO vs. LA

- The total system production cost was about 10% lower with the LA logic than with MIO dispatch logic, as shown in Figure 7.

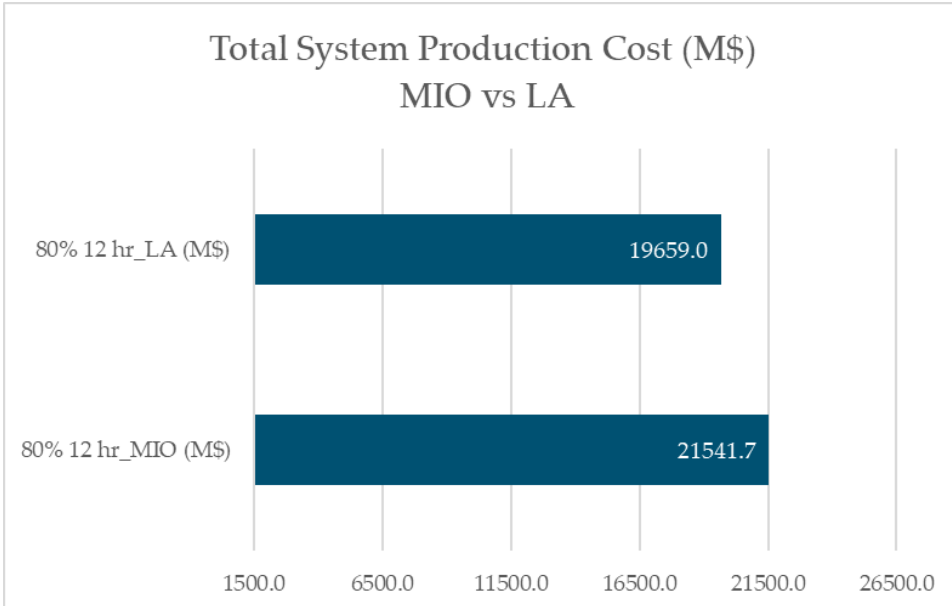


Figure 7: Total system production cost (M$) for 2040 Reference scenario—MIO vs. LA

- Energy storage dispatch was slightly better with LA logic (7.7% contribution to total dispatch) than with an MIO dispatch option (7.3% contribution to total dispatch), as shown in Figure 8.

Therefore, LA logic was selected to run the sensitivity cases for this assessment.

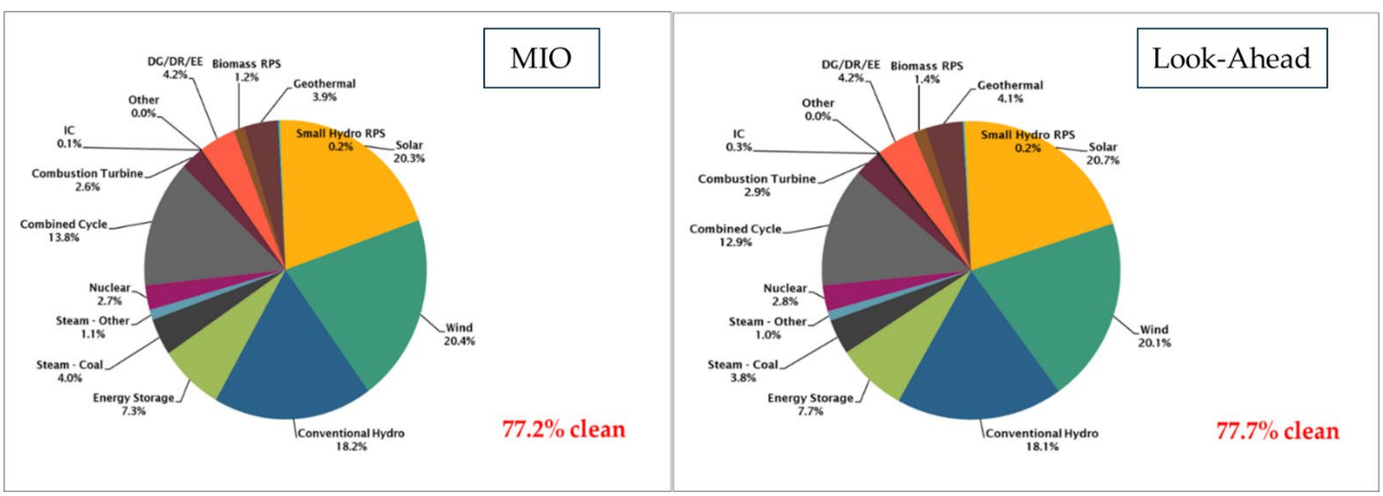


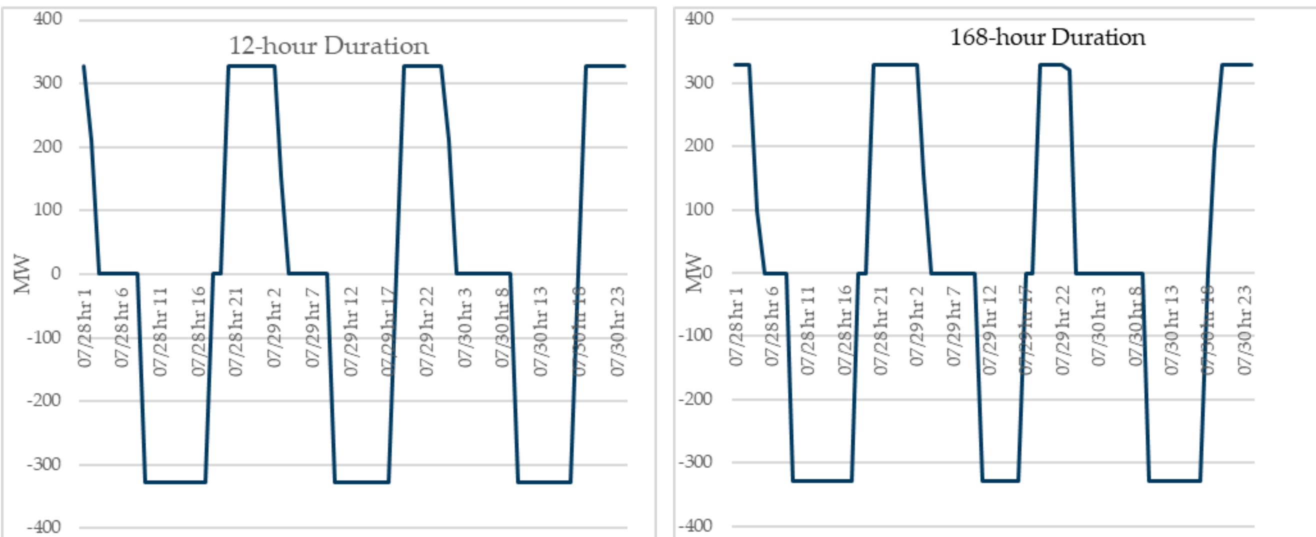
Figure 8: Annual generation mix for 2040 Reference scenario–MIO vs. LA

Findings and Conclusions

Impact of Storage Duration on Availability of Charging Resources

The model was tested for 12-, 24-, 48-, 168-, and 336-hour storage durations to identify the impact of longer-duration storage on the reliability of the Western Interconnection.

For all storage duration test scenarios, storage units are typically charged and discharged for seven to 10 hours—between 8:00 a.m. and 5:00 p.m. and between 7:00 p.m. and 1:00 a.m.—with few periods reaching 12 hours for all tested durations. Figure 9 illustrates this result, comparing the same storage resource of 328 MW modeled with 12-hour storage vs. 168-hour storage for the same three-day period in July.



(a) 12-hour-duration storage (b) 168-hour-duration storage

Figure 9: Battery storage performance 12-hour vs. 168-hour duration storage

Further, there were no significant differences in the system LMP, served load, or spillage when increasing storage duration from 12 hours to 336 hours, as shown in Figure 10, Figure 11, and Figure 12, respectively. These results were due to a a) software limitation—as the software cannot dispatch storage beyond 24 hours, and b) storage is being operated daily with a typical seven- to 10-hour charge and discharge operation. Thus, 12-hour duration storage was selected as a standard for the sensitivity cases for further analysis in this assessment.

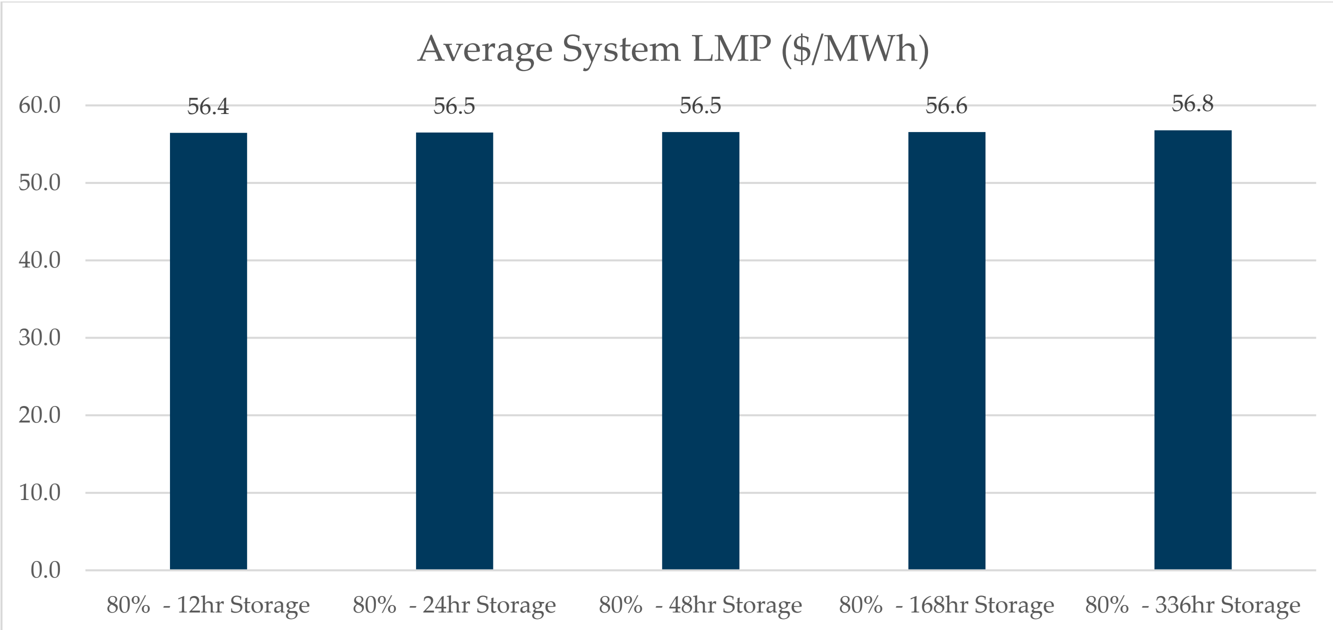


Figure 10: Average system LMP($/MWh)

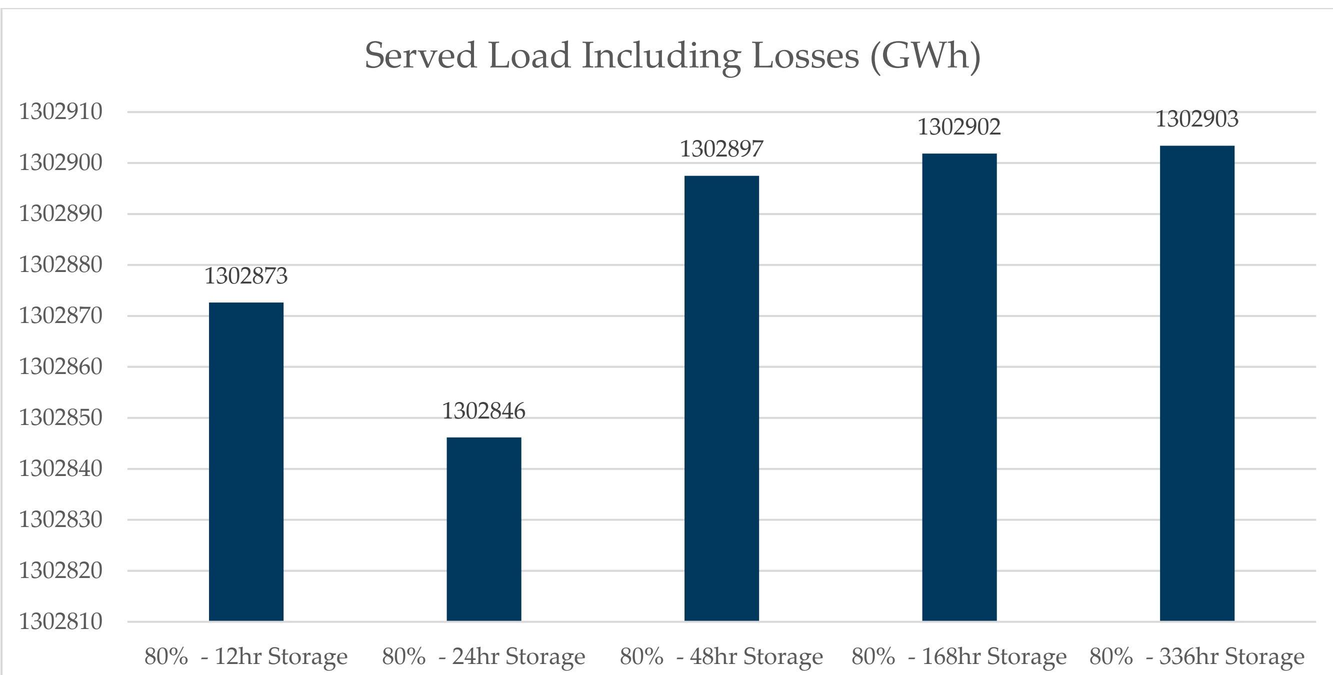


Figure 11: Total served load (GWh)

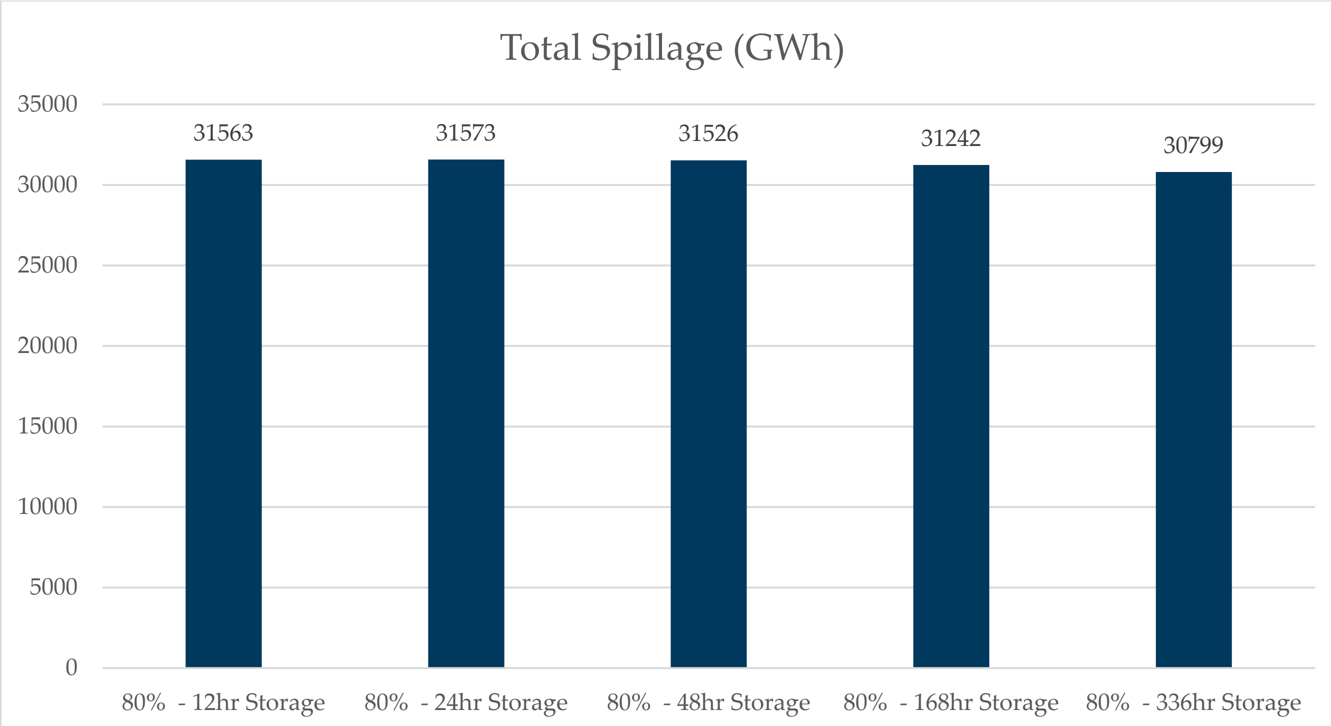


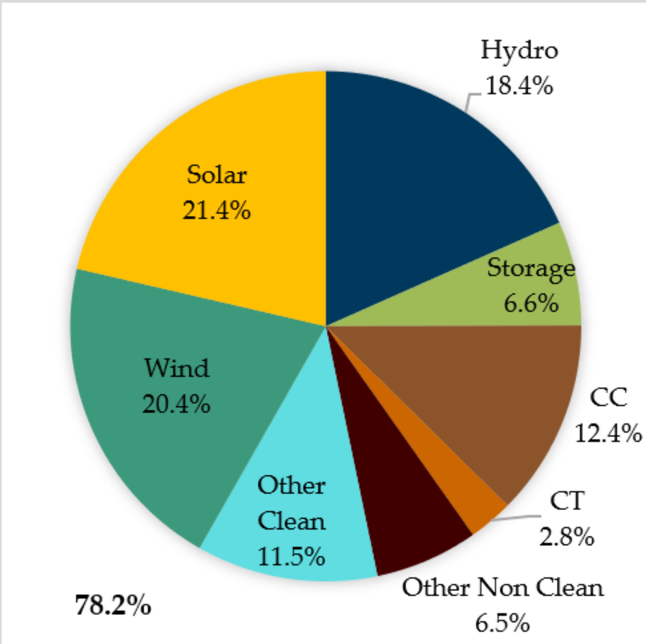
Figure 12: Total spillage (GWh)

Increasing the Clean Energy Percentage

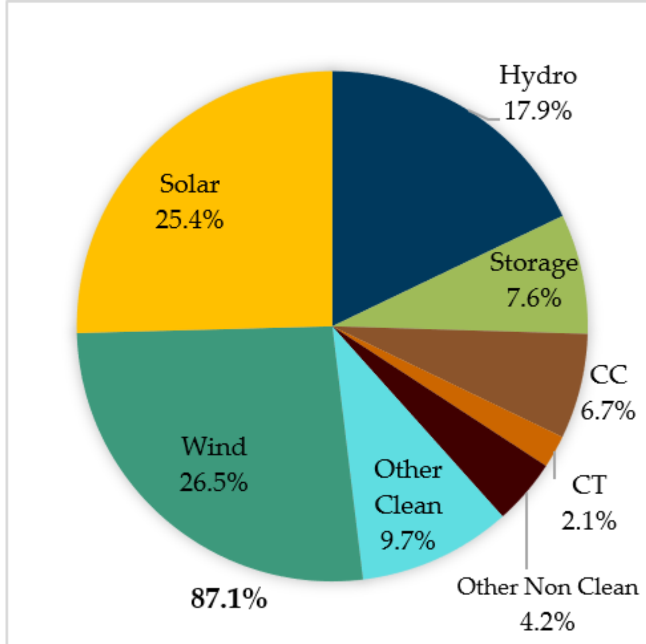
Figure 13 shows each resource type's percentage contribution to total energy for the four sensitivity cases considered. Table 1 summarizes the clean energy percentage and contribution from storage for each of the four sensitivity cases. Though storage's contribution was higher in the High Storage case, an increase in renewables was required to achieve a clean energy dispatch higher than 80%. The incremental increase in percentage clean, the contribution from storage, and system spillage as storage and renewables were increased in 20 sensitivity cases, are shown in Table 5 in the appendix.

Table 1: Percentage clean energy and storage contribution to dispatch

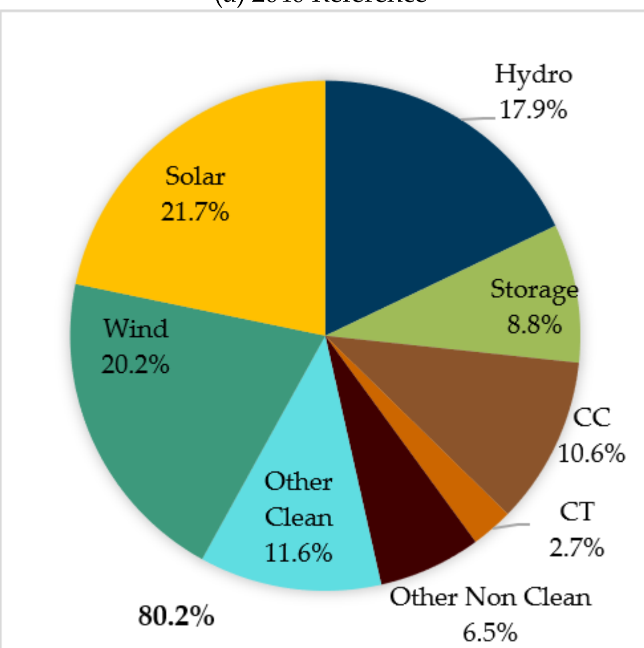
Case	Storage %	Clean Energy %
2040 Reference Case	6.6%	78.2%
High Storage	8.8%	80.2%
High Renewables	7.6%	87.1%
High Storage–High Renewables	11.4%	91.1%



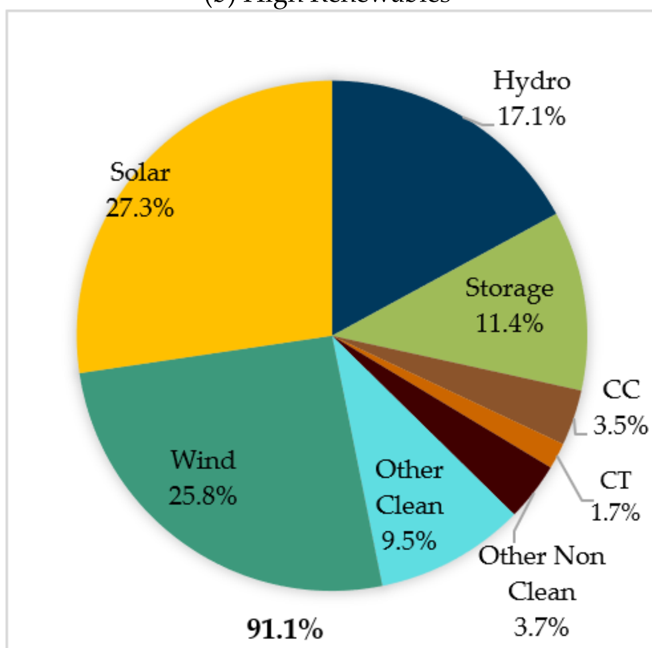
(a) 2040 Reference



(b) High Renewables



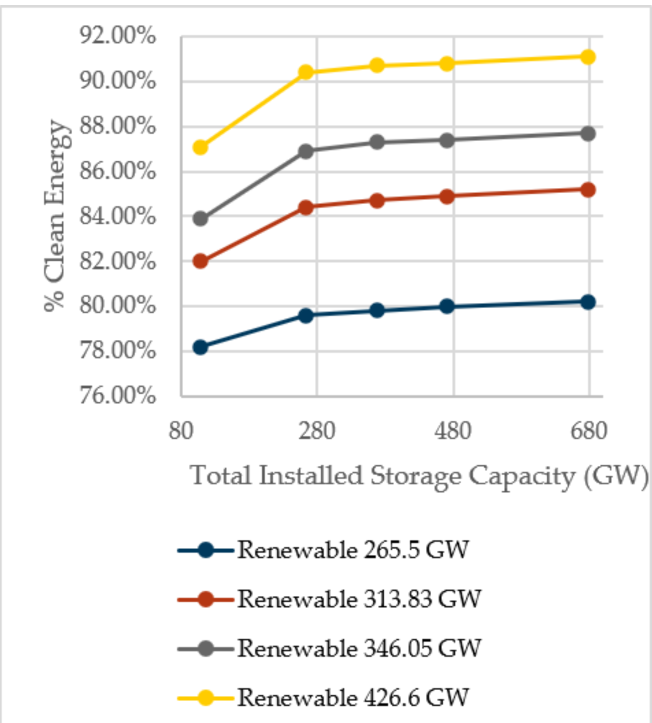
(c) High Storage



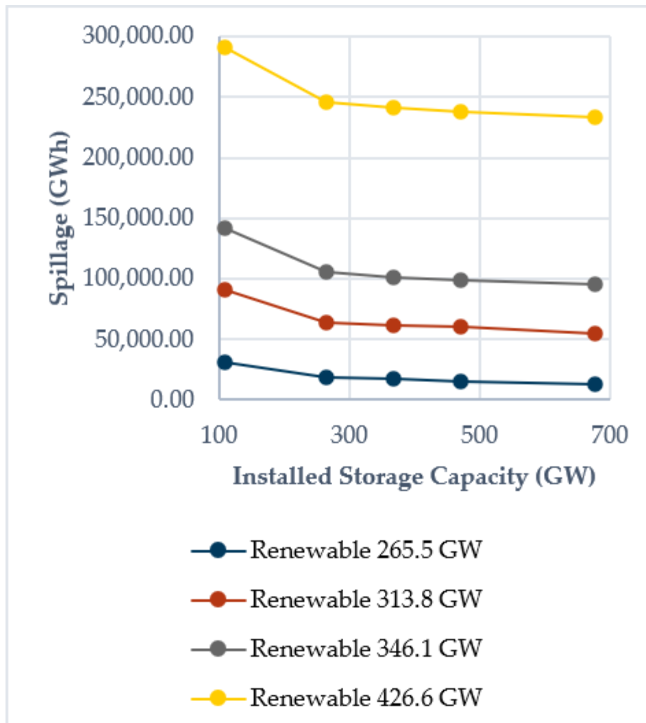
(d) High Storage–High Renewables

Figure 13: Percentage contribution to energy by resource type

Increasing storage from the 2040 Reference to the High Storage case (an increase of 568.2 GW) increased the percentage of clean energy by only 2–4% at each level of renewable energy, as shown in Figure 14(a). The rate of increase of clean energy starts to settle after adding 264.2 GW of storage capacity at all renewable levels. Increasing the level of storage reduces spillage by storing and using renewable energy more for all levels of renewables, as shown in Figure 14(b), but settles down to a low rate of increase after reaching a storage level of 264.2 GW. In the 2040 Reference case, about 5% of renewable energy spilled. By increasing the storage in the High Storage case, spillage was reduced to 2% of the renewable energy generated, as shown in Figure 15. Increasing storage capacity over 264.2 GW did not significantly increase in contribution to clean energy and resulted in about 3% more use of excess renewable generation in the cases studied. This was due to not enough renewable energy available to charge all storage at higher storage capacity levels during high load periods and non-renewable resources were used to charge storage. To achieve higher clean dispatch, the addition of more renewables was required.



(a) % Clean Energy vs. Storage Capacity (GW)



(b) Spillage (MWh) vs. Storage Capacity (GW)

Figure 14: Percentage clean energy and spillage vs. total installed storage capacity (GW) at increasing level of renewable capacity

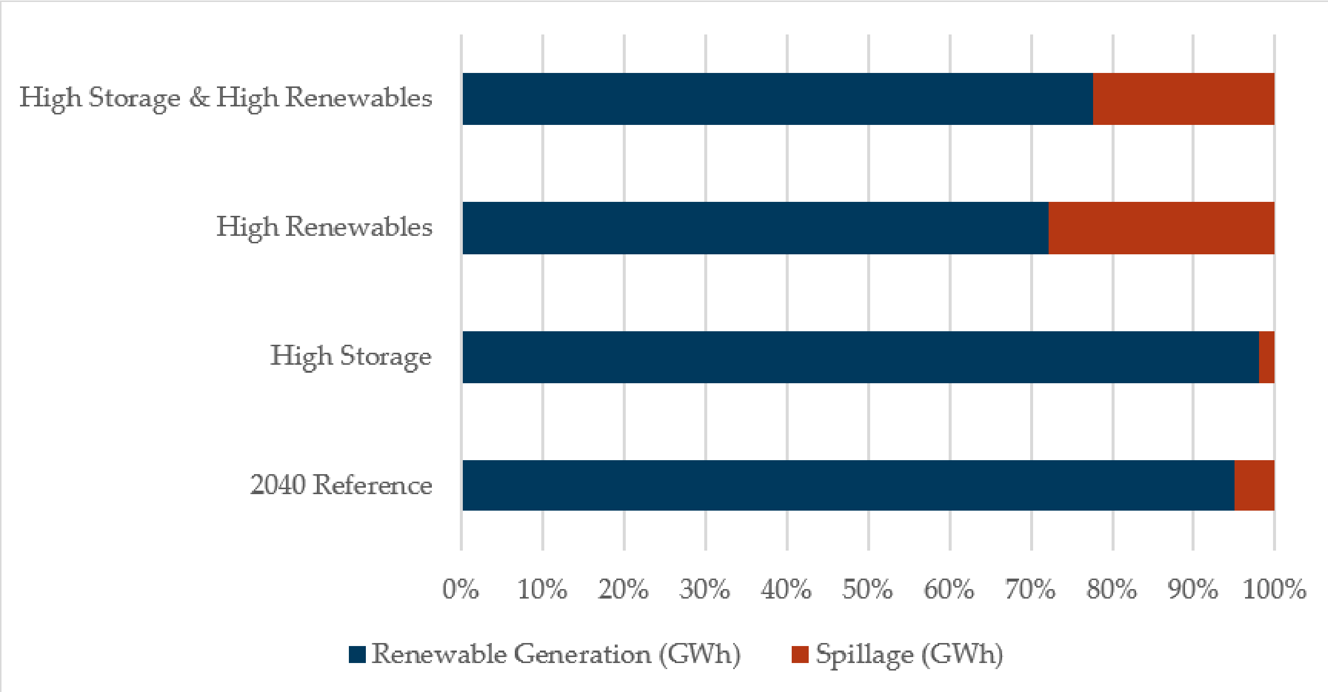
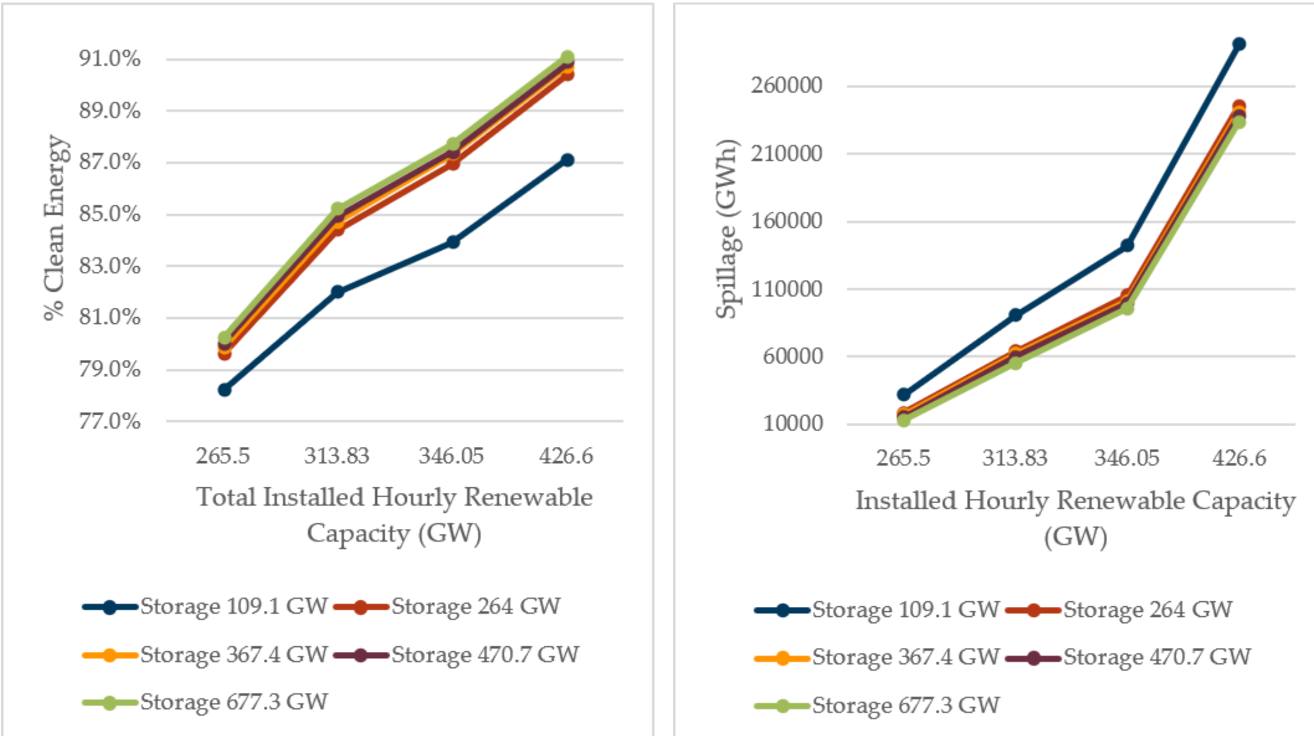


Figure 15: Percentage of renewable generation dispatched (GWh) vs. spilled (GWh)

Increasing hourly renewable capacity from the 2040 Reference case to the High Renewable case (an increase of 161 GW), while keeping storage capacity constant, increased the clean energy percentage by 9–11% at each storage level, as shown in Figure 16(a). The rate of clean percentage increase was much higher with increasing renewables capacity than storage capacity in the cases studied. The increasing rate of clean energy percentages did not saturate out in the studied cases and continued to grow with increasing renewables. The spillage also grew exponentially with increasing renewables, as shown in Figure 16(b). In the High Renewables case, 28% of the renewable energy generated was spilled (Figure 15), an increase of 23% from the 2040 Reference case. By increasing storage in the High Storage–High Renewable case, spillage was reduced to 22% of the renewable energy generated (Figure 15). This shows the added renewables infrastructure, though contributing to higher clean energy is not being used effectively with the 12-hour duration storage modeled in this assessment, especially over 264 GW of storage. Further, it was observed that considerable amounts of storage and renewable capacity were needed to achieve higher clean energy dispatch. To achieve a 90% clean energy dispatch, and to serve 224 GW of peak load, 264 GW of storage capacity and 426.5 GW of renewables were needed. To reduce spillage at high renewable penetrations, it may be necessary to explore flexible load options (e.g., seasonal storage or hydrogen) that increase demand during periods of excessive renewable generation.



(a) % Clean Energy vs. Renewable Capacity (GW)

(b) Spillage (GWh) vs. Renewable Capacity (GW)

Figure 16: Percentage clean energy and spillage vs. total installed hourly renewable capacity (GW) at increasing level of storage capacity

Impact on Regional Energy Interchange of Increasing Storage and Renewables

Added Capacity by Region and Peak Demand

Figure 17 shows the distribution of resource capacity by type for each region in the Western Interconnection for the four sensitivity cases. The largest siting of solar resources was in the California–Mexico region, due to its high solar potential, followed by the Desert Southwest region. The highest potential for wind distribution was in the Desert Southwest and Northwest regions. Storage was sited in high renewable regions with the highest siting being in California–Mexico followed by the Desert Southwest, then the Northwest.

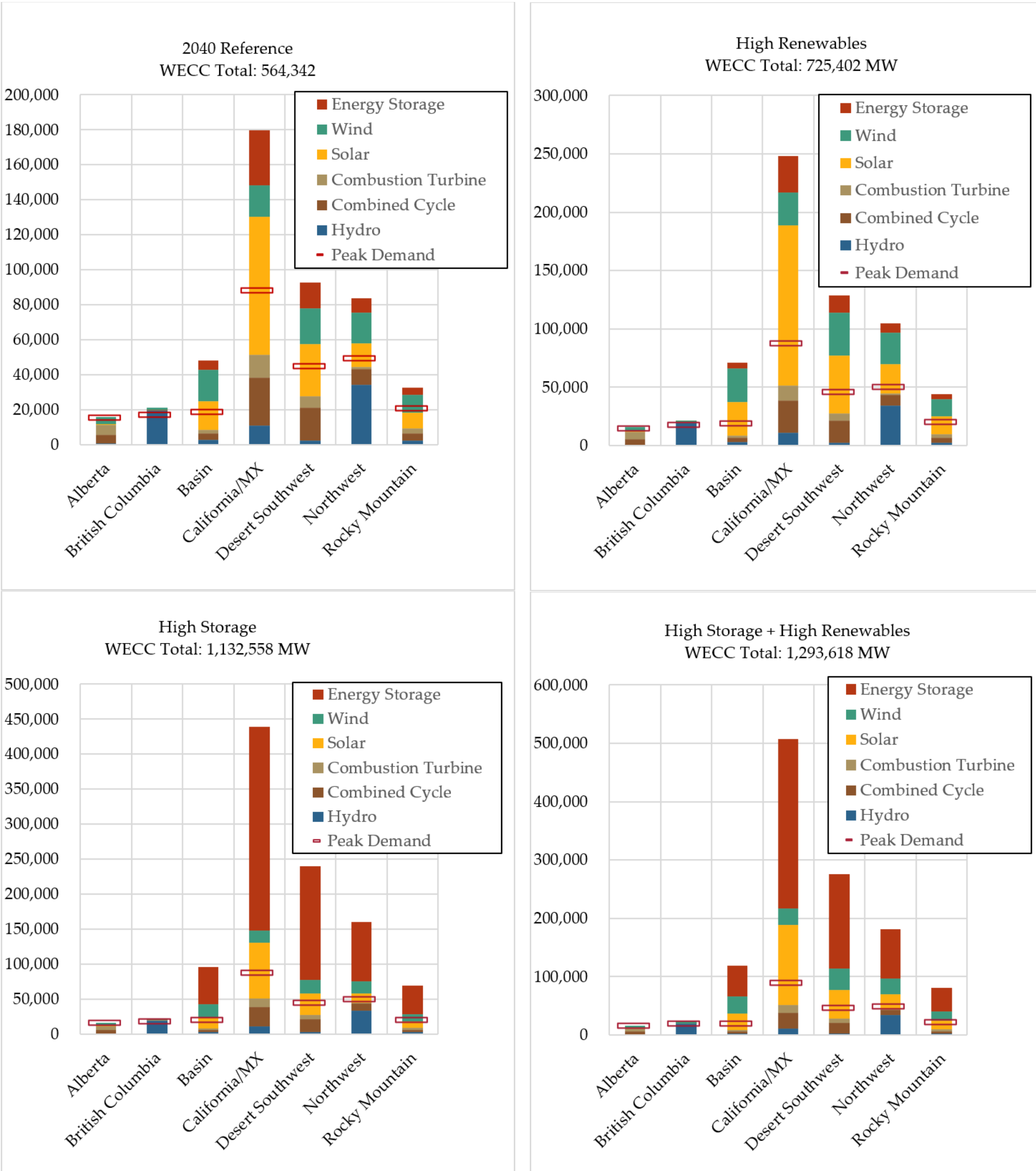


Figure 17: Generation subtype distribution by regional area

Regional Energy Interchange

The regional energy interchanges for the four sensitivity cases are shown in Figure 18. The net import or export in the regions is shown in Table 2, along with the percentage change in import or export compared to the 2040 Reference case. As storage is increased without increasing renewables, there is a significant increase in imports into the California–Mexico region from the Desert Southwest and Northwest regions. There is also a reduction in imports from the Basin because the additional batteries in California were charging with cheaper wind and solar available in the Northwest and Desert Southwest, respectively—while reducing the reliance on conventional resources in the Basin. Even though the California–Mexico region has a high concentration of solar resources, the region requires additional imports from renewable-rich regions to charge the additional storage, as the cost of renewable imports is lower, compared to available non-renewable generating resources within this region. Alberta and British Columbia also see higher imports to use clean energy.

As renewable resources increase without increasing storage, the Northwest region becomes a significant exporter to its neighboring regions due to high wind resources. Imports into California–Mexico, Alberta, and British Columbia increase as more low-cost renewable energy (especially wind from the Northwest) is used to generate power, while using less non-renewable resources, thus increasing system-wide clean energy percentages. Imports into California from the Basin also increase to support the evening ramp, relying more on energy from non-renewable resources. The Rocky Mountain region imports less and uses added wind and solar resources within the region.

For the High Storage–High Renewable case, imports into California–Mexico, and the Rocky Mountain regions decrease compared to the High Renewable case due to higher use of storage dispatched within the region.

Table 2: Net import or export in a region

Net Imports/Exports	2040 Reference (GWh)	% Difference from 2040 Ref to High Storage	% Difference from 2040 Ref to High Renewables	% Difference from 2040 Ref to High Storage + High Renewables
Alberta Import	1825	63%	477%	587%
British Columbia Import	4511	2%	38%	47%
Northwest Export	835	20%	2190%	2187%
Basin Export	22108	16%	-9%	7%
Rocky Mtn Import	11158	13%	-27%	-23%
CA/MX Import	24480	16%	53%	47%
Desert Southwest Export	19031	16%	21%	10%

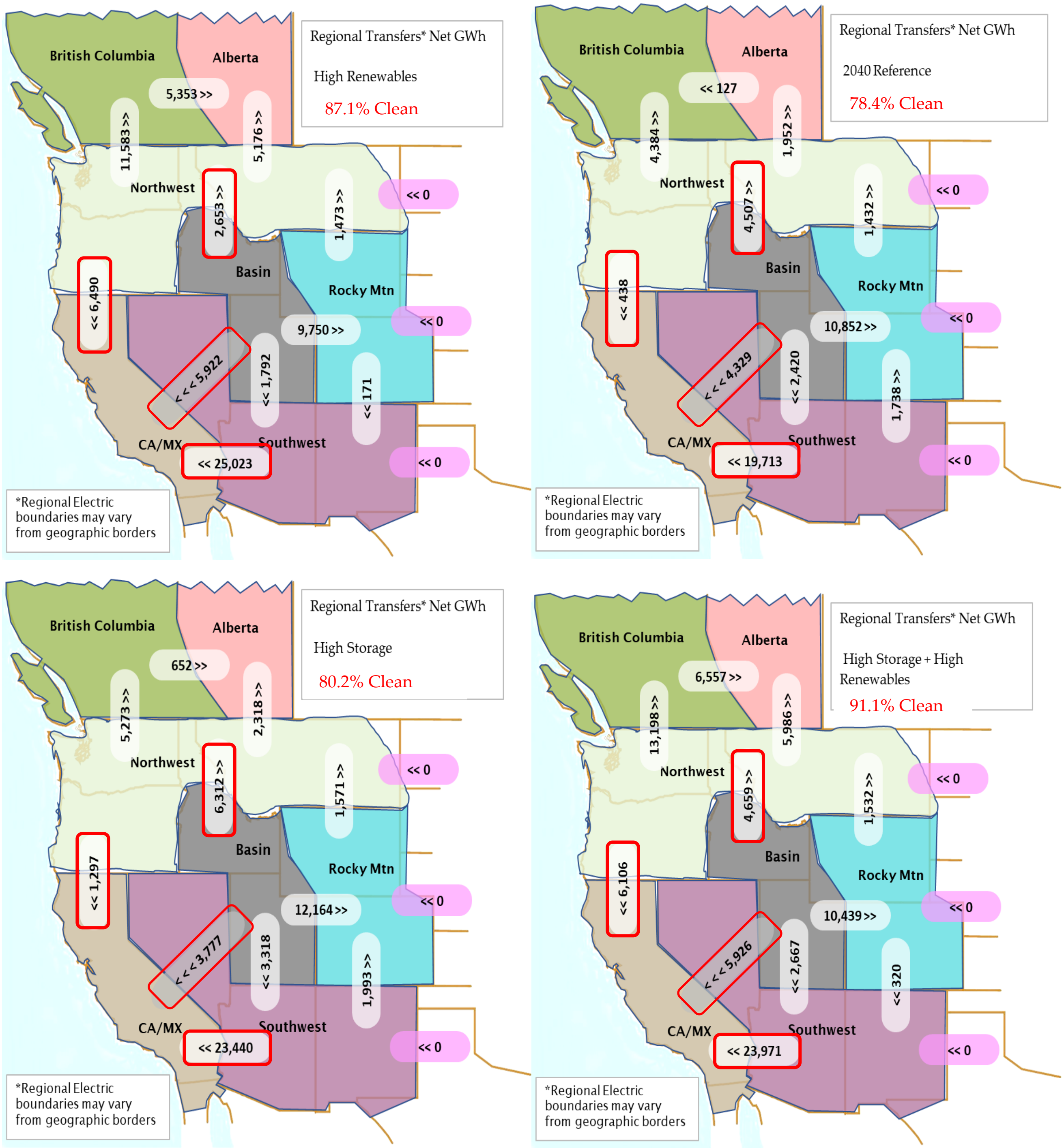


Figure 18: Regional Energy Interchange

Impact on Major Transmission Paths

Increasing either storage or renewable resources may require transmission system enhancements. This section's results are based on the assumptions used in this assessment—including the load and resource placement specific to the cases. Figure 19 shows the top five transmission paths exceeding their flow limits for each sensitivity case, which reveals the impact on the transmission system. In the 2040 Reference case, 38 transmission paths exceeded their path flow limits. This number increased to 40 for both the High Storage and High Renewable cases. For the High Storage–High Renewable case, 43 transmission paths exceeded their path ratings. The highest loaded paths exceeded their path ratings more than 40% of the hours in the year and a few came close to exceeding their path ratings 100% of the hours in the year. More storage and renewables increased transmission flows on some of the paths. The effects were especially extreme on paths transporting large amounts of clean renewable energy from a high renewable region to areas of high demand, such as P45 SDG&E–CFE and the P83 Montana–Alberta tie line.

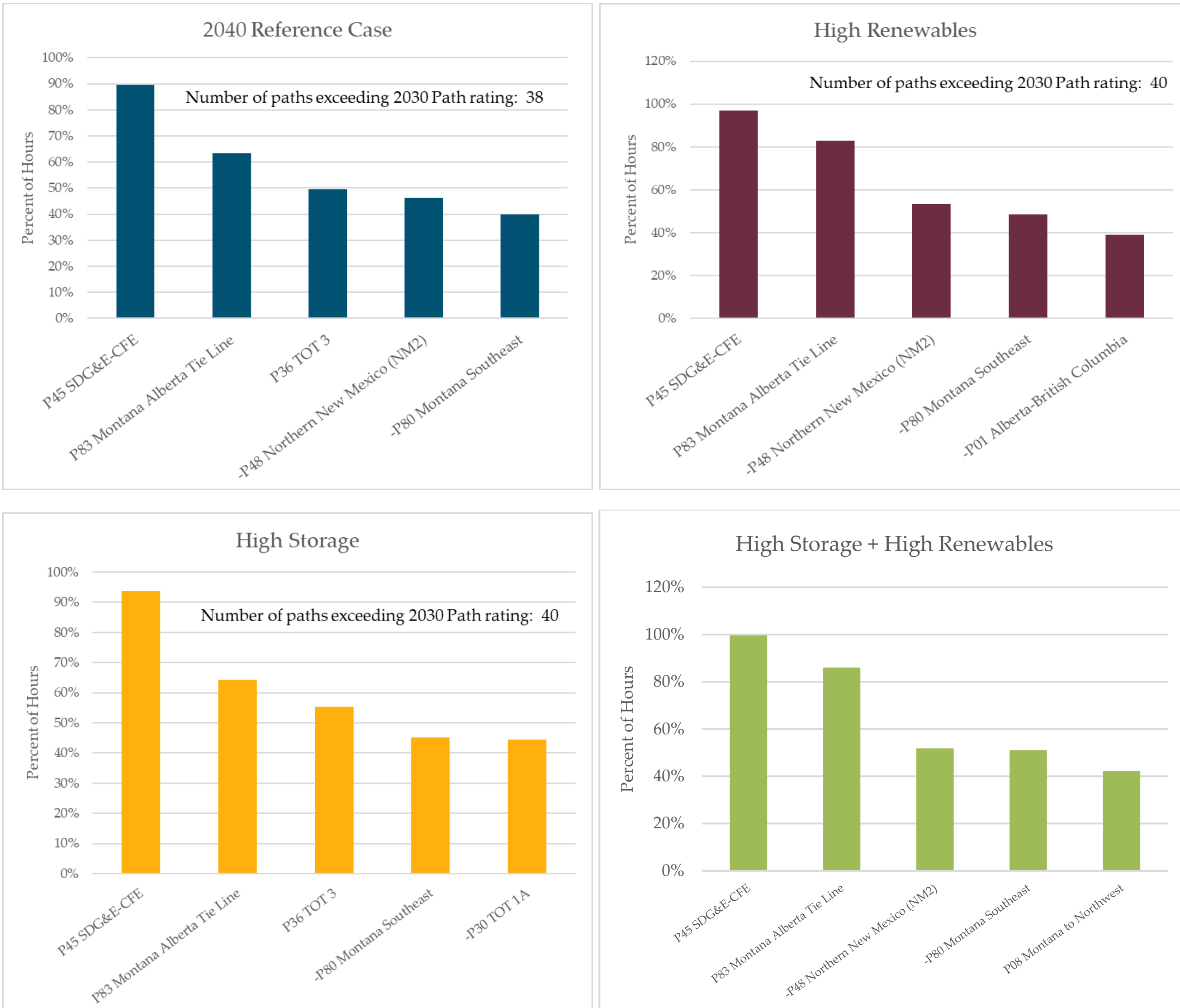


Figure 19: Top paths exceeding 2030 path limits

To estimate how much the paths may exceed their flow limits, the peak flow on the most heavily utilized paths was compared to their path flow limits in Figure 20 for all four sensitivity studies. Table 3 shows the defined path flow direction and path limits in the defined flow direction. Negative flow in Figure 20, indicates that the flow is in the opposite direction to the flow defined in Table 3. The list of lines which constitute each WECC paths can be found in the public version of the Path Rating Catalogue. The peak flow plotted below is the maximum flow on each path in either direction. This figure also shows the impact of increasing storge and renewables on peak path flow. The peak flow on all paths was significantly higher than their 2030 limits for all sensitivity cases, indicating that achieving an 80–90% clean energy future may require significant enhancements to the transmission system.

Table 3: Defined flow direction and path flow

WECC Paths	Defined flow Direction	Path Rating
P01 Alberta–British Columbia	Alberta to British Columbia	1,000 MW
P08 Montana to Northwest	NWMT to BPA	2,200 MW
P18 Montana–Idaho	Montana to Idaho	383 MW
P30 TOT 1A	Colorado to Utah	650 MW
P36 TOT 3	Wyoming to Colorado	1,680 MW
P48 Northern New Mexico (NM2)	north to south	2,150 MW
P80 Montana Southeast	north to south	600 MW
P83 Montana Alberta Tie Line	Montana to Alberta	300 MW

Figure 20: Max transmission path flow (MW) as comparted to 2030 path limits observed in sensitivity cases

Load-Generation Balance

Two days were analyzed for the High Storage–High Renewable case to see how the hourly load is met by different resource types on a light load day and a heavy load day. Figure 21 shows the light load day in April, and Figure 22 shows a heavy load day in July. Native load in these charts is the load without storage charging, which has an evening peak when solar is ramping down and load is peaking. Due to storage charging during the daytime, the system peak shifts to mid-morning when solar is abundant and storage is charging. This shift occurs due to the storage dispatch option, following the system price curve. The storage units would charge when the LMPs are at their lowest and when there is an abundance of solar generation to drive the LMP to a minimum. A second but smaller peak occurs during evening hours when solar is ramping down and the native load is high. Storage effectively follows the evening ramp-ups and discharges to provide energy. During light load days, the spillage is excessive—the storage mostly stays full and cycles less. The reliance on gas-fired units is minimal. The spillage is significantly less during heavy load days, though not eliminated. The storage adds significantly to the clean energy contribution and reduces spillage, but does not eliminate it, and can be an effective tool in the resource mix at high renewable penetrations. This further indicates that seasonal storage or flexible loads in the generation mix can be particularly useful in minimizing renewable energy spillage, especially during light load conditions. Storage could also offset the reliance on gas resources during heavy load days and help achieve a higher clean energy percentage future.

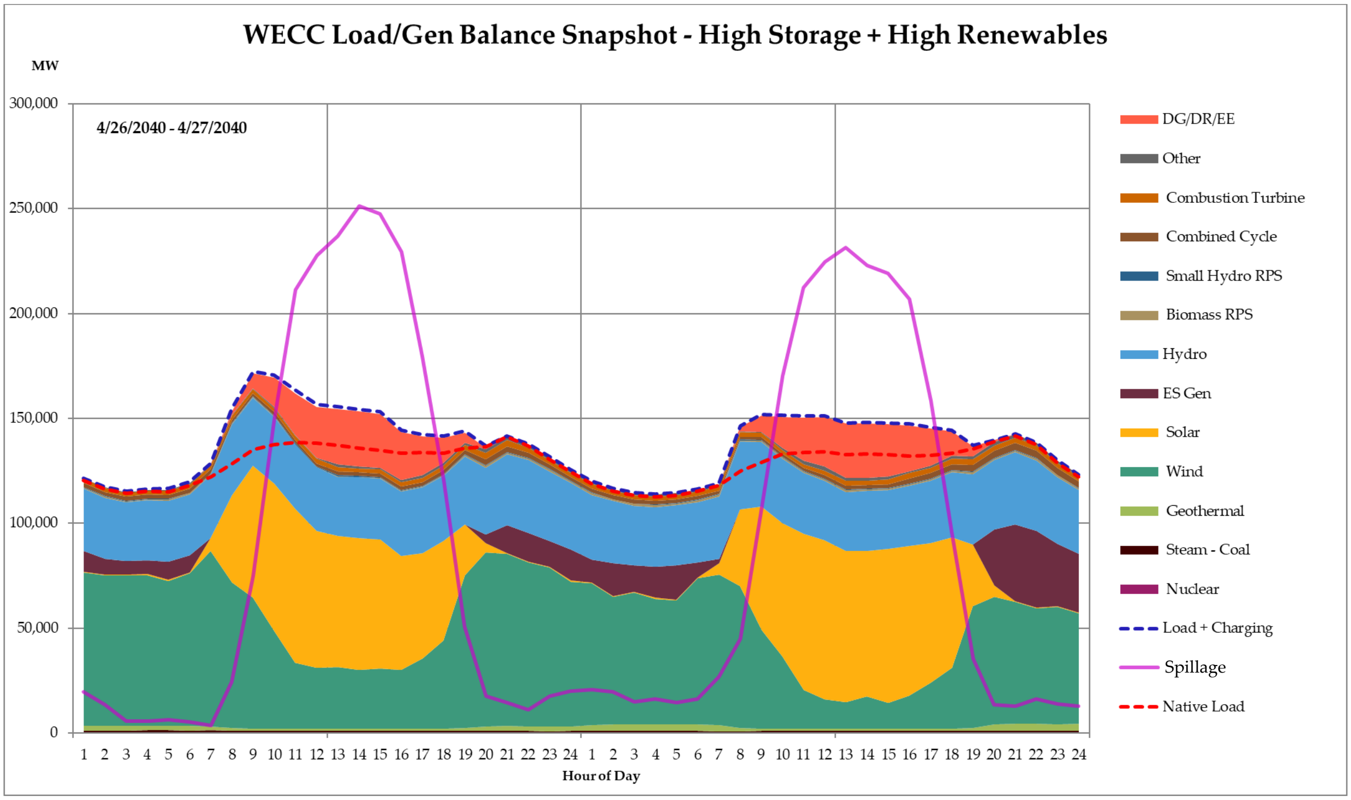


Figure 21: Load-generation balance on a light load spring day, with high renewables and high storage

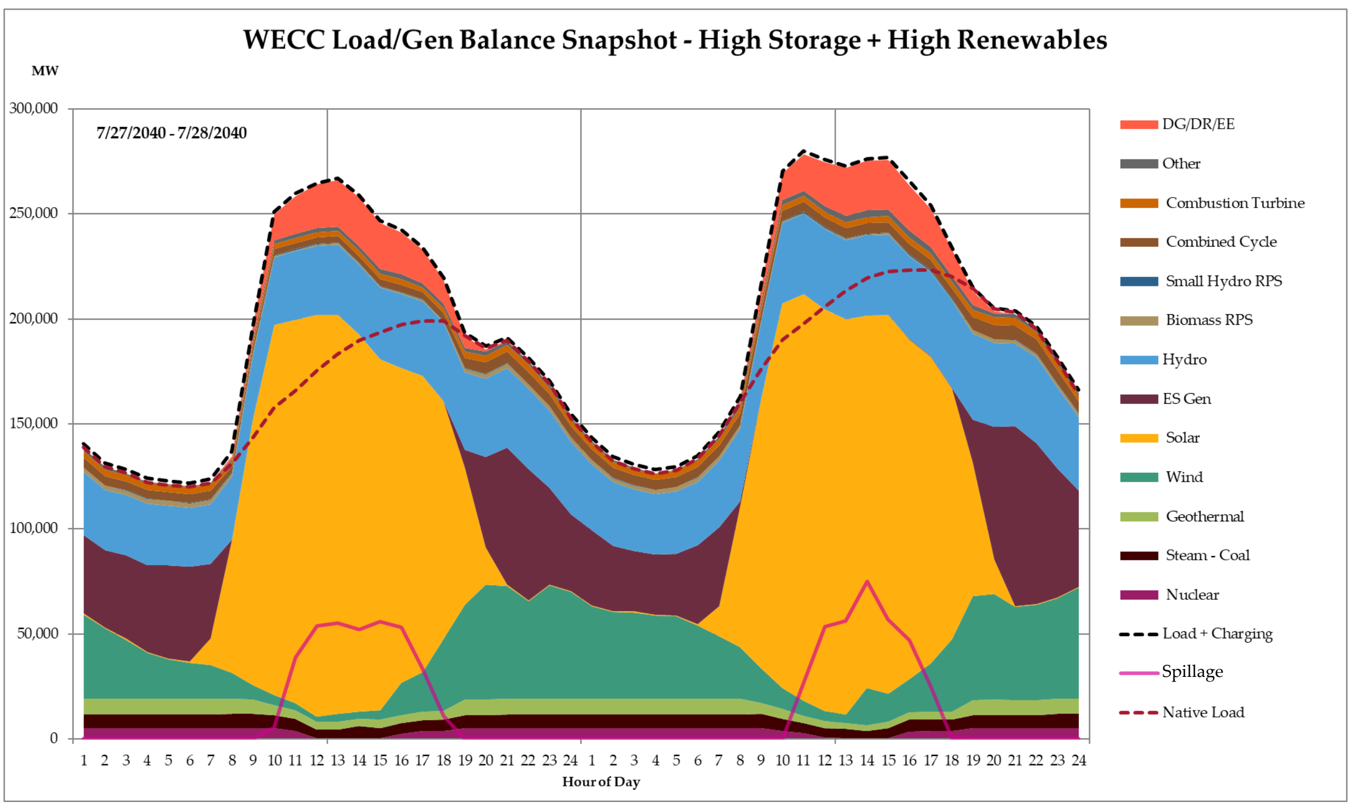


Figure 22: Load-generation balance on a heavy load summer day with high renewables and high storage

Impact of Storage and High Renewables on System LMP

Light and heavy load days were analyzed to see the impact of high storage and renewable resource penetration on system LMP. Figure 23 and Figure 24 show system LMP compared to system storage charging and discharging for light load days April 26-27, and heavy load days July 27–28, respectively. On a light load day, the average system LMP drops below zero (not going below -15 $/MWh) between 10:00 a.m. and 6:00 p.m., when excess solar generation results in high spillage (as shown in Figure 21). During a heavy load day in July, the average system LMP dips low between 10:00 a.m. and 6:00 p.m. and reaches zero $/MWh at around 1:00 p.m. due to excess solar generation resulting in spillage during those hours. Renewable energy spillage is much higher on light load days than on heavy load days. For both light load days and heavy load days, energy storage in the system responds to the LMP by charging when the LMP is lowest in the day and discharging when the LMP is highest, and it provides support to the evening ramping requirements. Market models can be further adjusted to allow more opportunity for storage to charge during low LMP while discouraging non-clean resources from bidding in the market. This would further reduce spillage of excess renewable generation and allow higher use of available renewable capacity.

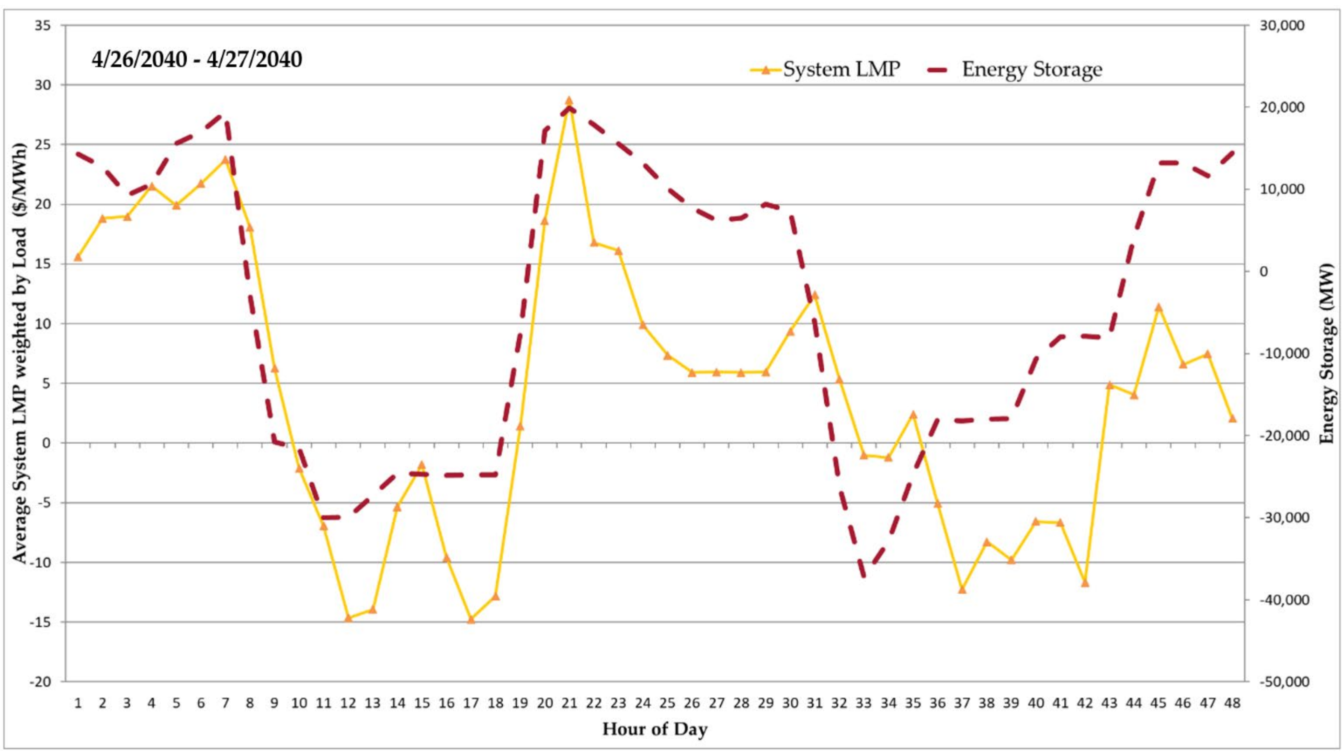


Figure 23: Average system LMP and storage operation on a light load spring day with high renewables and high storage

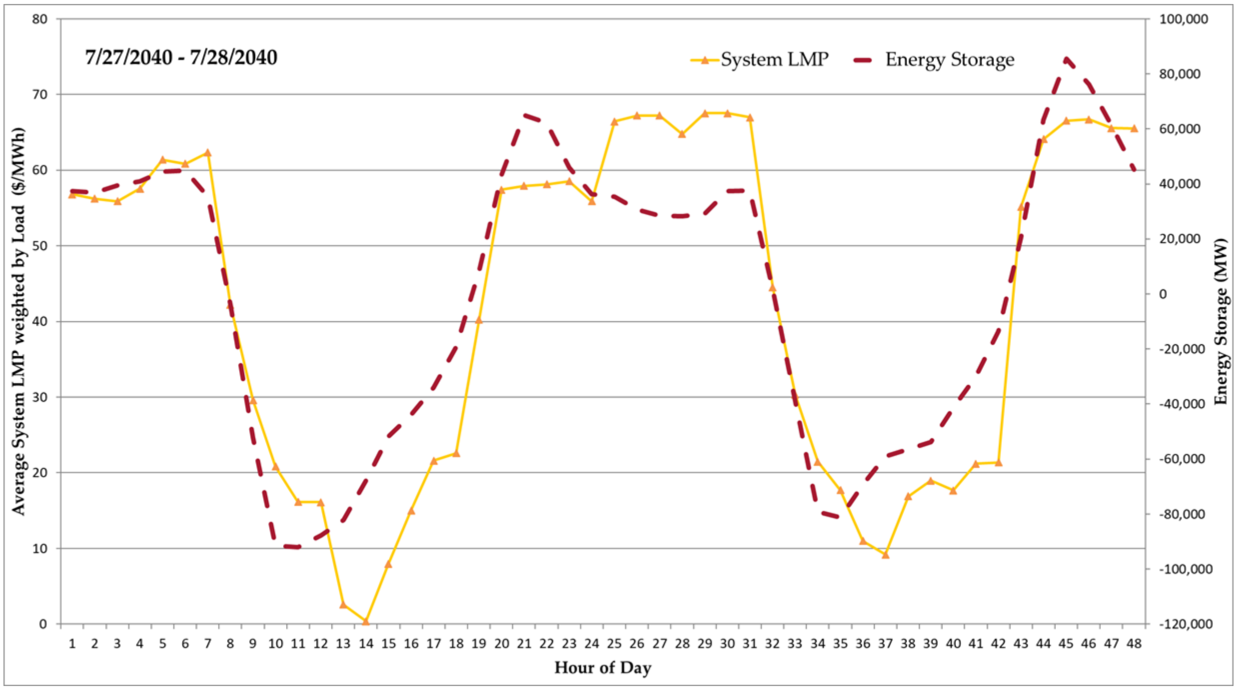


Figure 24: Average system LMP and storage operation on a heavy load summer day with high renewables and high storage

Conclusions

1. Current tool limitations and modeling challenges limit the ability to effectively model long-duration storage in a production cost model.
2. Energy storage systems with a 12-hour storage duration modeled over a 24-hour charging and discharging cycle can mitigate daily fluctuations in loads and resource availability.
3. With 12-hour storage modeled in this assessment, a saturation point was seen at 264 GW of storage capacity. Adding storage capacity above this level could not achieve over 80% clean energy due to not enough renewable energy available to charge all storage during high load periods. Additional renewable resources were needed to increase the clean energy percentage to 90%. In the cases as modeled, 427 GW of hourly renewable energy was required to achieve 90% clean energy.
4. The 12-hour duration storage modeled in this assessment was found to reduce but not eliminate spillage at higher renewable penetration. A saturation point was reached at about 264 GW of storage capacity. Increasing storage capacity above this level did not further mitigate the spillage of renewable energy.
5. Inter-regional transfers would play an essential role in transporting clean energy from renewable-rich regions to other regions to not only offset non-clean resources but also to meet the higher storage charging load in a region.

6. Most major transmission paths were found to exceed their flow limits, indicating that significant enhancement of the transmission system may be required to take advantage of increased renewable energy and storage capacity interconnection wide.
7. With a high storage penetration, the system may have two peaks: mid-morning and evening. Peak load shifts to mid-morning when the solar generation is at peak and storage is charging. A second peak was observed when the solar ramps down and the evening load picks up. Storage discharge was found to ramp up with the evening peak and would be an essential tool in the resource mix to achieve a higher clean energy percentage future.
8. Market models may need to be revisited to encourage seasonal storage to charge during excess renewable generation periods in spring and dispatch only during the heavy summer months. This will result in lower curtailment of hourly renewable resources during the light load months while reducing the dependency on peaking non-clean resources during the heavy summer months.

Recommendations

Following recommendations were identified based on the observations of the results of this assessment. WECC will perform an LDES study in the 20-year horizon as part of its 2023 study program and will try to address some of the issues described below. Other entities may also pursue assessments to address these issues.

1. Further studies are needed using a modeling tool capable of storage look-ahead logic to see the impact of LDES on the challenges identified in the [2040 Clean Energy Scenarios Study] in achieving clean energy contribution to the generation mix exceeding 80 percent in the Western Interconnection.
2. A 100% clean energy dispatch was not achieved due to time limitations and should be planned in future assessments.
3. Transmission planners undertake transmission expansion studies while trying to achieve a high renewable and high storage future.
4. Further studies are needed to understand the effects of seasonal storage, flexible load, and emerging clean technologies (e.g., hydrogen) on the resource mix and curtailments at higher renewable penetration levels modeled to achieve higher clean energy percentages.
5. Further studies are needed to analyze ways in which LDES might mitigate reliability risks associated with extreme natural events such as extended periods of no solar and wind availability, wildfires, and low hydro availability.

Appendix

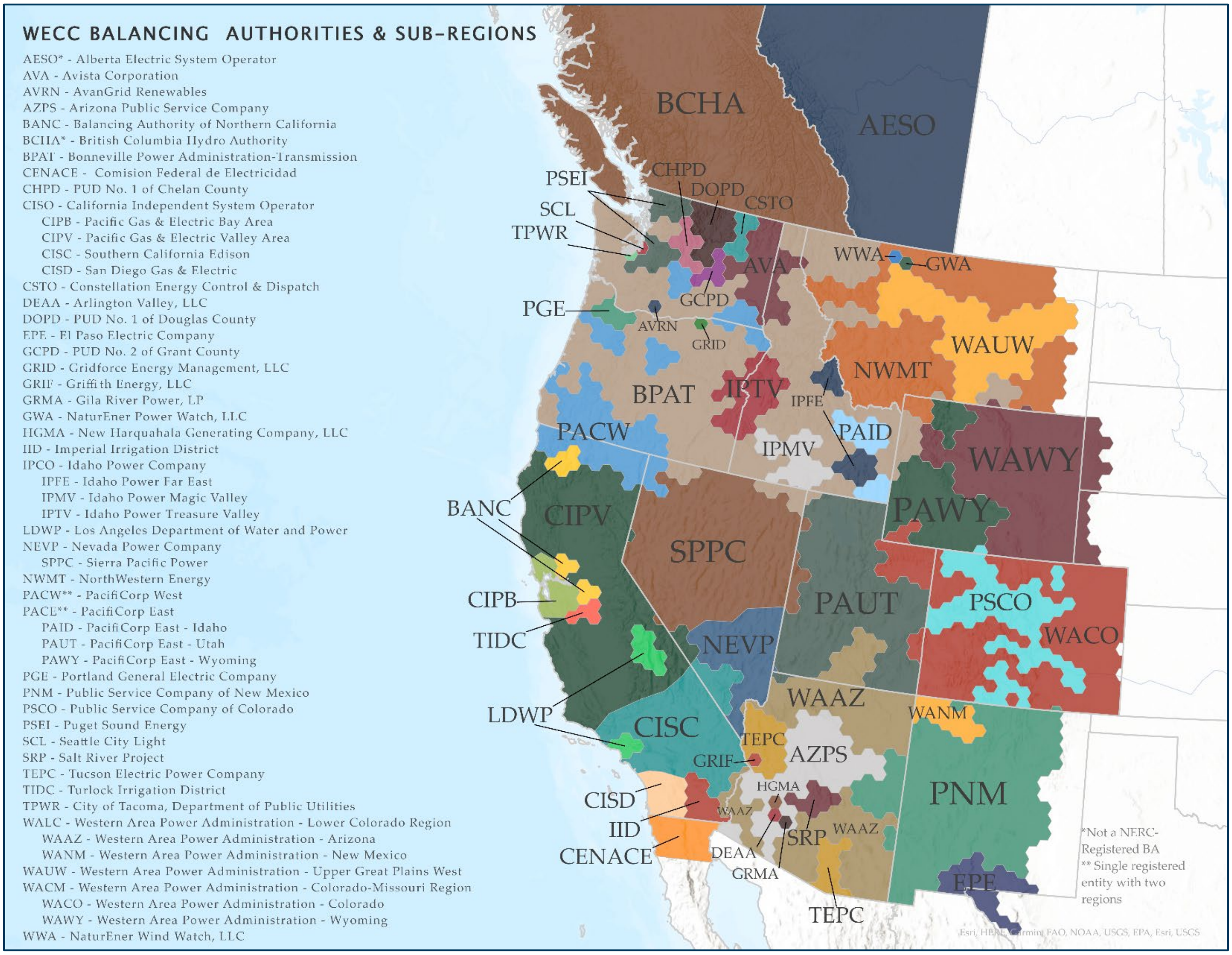


Figure 25: Boundaries of Balancing Authority Areas

Table 4: Balancing Authority abbreviations and names

Abbreviation	Balancing Authority Name
AB_AESO	Alberta—Alberta Electric System Operator
BC_BCHA	British Columbia—British Columbia Hydro
BS_IPCO	Basin—Idaho Power Company
BS_PACE	Basin—PacifiCorp East
CA_BANC	California—Balancing Authority of Northern California

Abbreviation	Balancing Authority Name
CA_CFE/CENACE	California—Comisión Federal de Electricidad
CA_CISO	California—California Independent System Operator
CA_IID	California—Imperial Irrigation District
CA_LDWP	California—Los Angeles Department of Water and Power
CA_TIDC	California—Turlock Irrigation District
NW_AVA	Northwest—Avista Corporation
NW_BPAT	Northwest—Bonneville Power Administration-Transmission
NW_CHPD	Northwest—PUD No. 1 of Chelan County
NW_DOPD	Northwest—PUD No. 1 of Douglas County
NW_GCPD	Northwest—PUD No. 2 of Grant County
NW_NWMT	Northwest—Northwestern Energy
NW_PACW	Northwest—PacifiCorp West
NW_PGE	Northwest—Portland General Electric Company
NW_PSEI	Northwest—Puget Sound Energy
NW_SCL	Northwest—Seattle City Light
NW_TPWR	Northwest—City of Tacoma, Department of Public Utilities
NW_WAUW	Northwest—Western Area Power Administration, Upper Great Plains West
RM_PSCO	Rocky Mountain—Public Service Company of Colorado
RM_WACM	Southwest—Western Area Power Administration, Colorado-Missouri Region
SW_AZPS	Southwest—Arizona Public Service Company
SW_EPE	Southwest—El Paso Electric Company
SW_NVE	Southwest—Nevada Energy
SW_PNM	Southwest—Public Service Company of New Mexico
SW_SRP	Southwest—Salt River Project
SW_TEPC	Southwest—Tucson Electric Power Company
SW_WALC	Southwest—Western Area Power Administration, Lower Colorado Region

Table 5: Percentage clean energy, system spillage, and storage use in sensitivity cases

Storage Capacity	% increase in Renewable Capacity			
	2040 Renewables** 2040 Solar – 108.3 GW 2040 Wind – 52.7 GW	30% increase in 2040 Renewables 2040 Solar – 140.9 GW 2040 Wind – 68.4 GW	50% increase in 2040 Renewables 2040 Solar – 162.6 GW 2040 Wind – 79.0 GW	100% increase in 2040 Renewables 2040 Solar – 216.7 GW 2040 Wind – 105.4 GW
2040 Storage* 2040 Storage – 51.6 GW (619.8 GWh)	**2040 Reference** 78.4% Clean Storage Utilization 6.6% System Spillage= 31,470.3 GWh	82% Clean Storage Utilization 7.2% System Spillage 90,756.7 GWh	83.9% Clean Storage Utilization 7.4% System Spillage 141,870.4 GWh	**High Renewables** 87.1% Clean Storage Utilization 7.6% System Spillage 290,942.7 GWh
4 times 2040 Storage Capacity 2040 Storage – 206.6 GW (2,479.5 GWh)	79.6% Clean Storage Utilization 8% System Spillage 18,881.0GWh	84.4% Clean Storage Utilization 9.4% System Spillage 52,323 GWh	86.9% Clean Storage Utilization 10% System Spillage 105457.8 GWh	90.4% Clean Storage Utilization 10.4% System Spillage 245,787.5 GWh
6 times 2040 Storage Capacity 2040 Storage – 309.9 GW (3,719.2 GWh)	79.8% Clean Storage Utilization 8.2% System Spillage 16903.7 GWh	84.7%Clean Storage Utilization 9.6% System Spillage 62057.7 GWh	87.3% Clean Storage Utilization 10.3% System Spillage 101608.7 GWh	90.7% Clean Storage Utilization 10.7% System Spillage 241359.8 GWh
8 times 2040 Storage Capacity 2040 Storage – 413.2 GW (4,958.9 GWh)	80% Clean Storage Utilization 8.4% System Spillage 15,289.6 GWh	84.9% Clean Storage Utilization 9.8% System Spillage 60,121.7 GWh	87.4 % Clean Storage Utilization 10.4% System Spillage 99391.1 GWh	90.8% Clean Storage Utilization 11% System Spillage 238116.7 GWh
12 times 2040 Storage Capacity 2040 Storage – 619.8 GW (7,438.4 GWh)	**High Storage** 80.2% Clean Storage Utilization 8.8% System Spillage 12714.2GWh	85.2% Clean Storage Utilization 10.2% System Spillage 55,211.7 GWh	87.7% Clean Storage Utilization 10.9% System Spillage 95,541.6 GWh	**High Storage + High Renewables** 91.1% Clean Storage Utilization 11.4% System Spillage 233678.9 GWh

*2040 Storage: Storage for year 2040 in addition of 2030 ADS PCM storage capacity.

**2040 Renewables: Renewable capacity for year 2040 in addition of 2030 ADS PCM solar and wind capacity.