2024 Integrated Resource Plan Annual Update Report

File No. EO-2024-0249

The Empire District Electric Company
d/b/a Liberty

March 2024

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2024 Integrated Resource Plan Annual Update Report

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Liberty – The Empire District Electric Company
("Liberty" or the "Company")
2024 Integrated Resource Plan ("IRP") Annual Update Report

1. Introduction

The purpose of the IRP Annual Update is to ensure that members of the Missouri stakeholder group have the opportunity to provide input and to stay informed regarding the changing conditions since the last triennial IRP ("2022 IRP") filed in April 2022 (File No. EO-2021-0331) and the last IRP Annual Update ("2023 IRP Update") filed in March 2023 (File No. EO-2023-0294). Consistent with 20 CSR 4240-22 (the "Rule"), this annual update filing includes updates regarding the:

1) Utility's current preferred resource plan;
2) Status of the identified critical uncertain factors;
3) Utility's progress in implementing the resource acquisition strategy;
4) Analyses and conclusions regarding any special contemporary issues that may have been identified pursuant to 20 CSR 4240-22.080(4);
5) Resolution of any deficiencies or concerns pursuant to 20 CSR 4240-22.080(16); and
6) Changing conditions generally.

In developing this report, Liberty reviewed, updated, and compared the critical uncertain factors identified in the 2022 IRP with the 2023 IRP Update and current budget conditions. Some of these 2024 updates were based on Liberty's 2024-2029 Budget Cycle forecast, which was developed and used for internal short-term budgeting purposes.

This report also provides updates regarding Liberty's progress on implementing various aspects of the 2022 IRP Short-Term Action Plan, including the replacement of Riverton Units 10 and 11 and the progress being made on this project with new dual fuel (natural gas and liquid fuel) units that will replace them in the 2026 timeframe, and a progress update on the plans for the Company's first utility scale solar project, projected to be operational in the 2026-2027 timeframe .

Additionally, since resource planning is a dynamic process, there have been some notable industry changes since the Company filed the IRP in April 2022, which were also discussed in the 2023 IRP Update. This includes changes to the Southwest Power Pool ("SPP") planning reserve margin (increasing from 12% to 15%); the future introduction of performance-based accreditation for traditional resources and Effective Load Carrying Capability ("ELCC") for wind and solar resources expected in 2026; and the passage of the Inflation Reduction Act ("IRA").

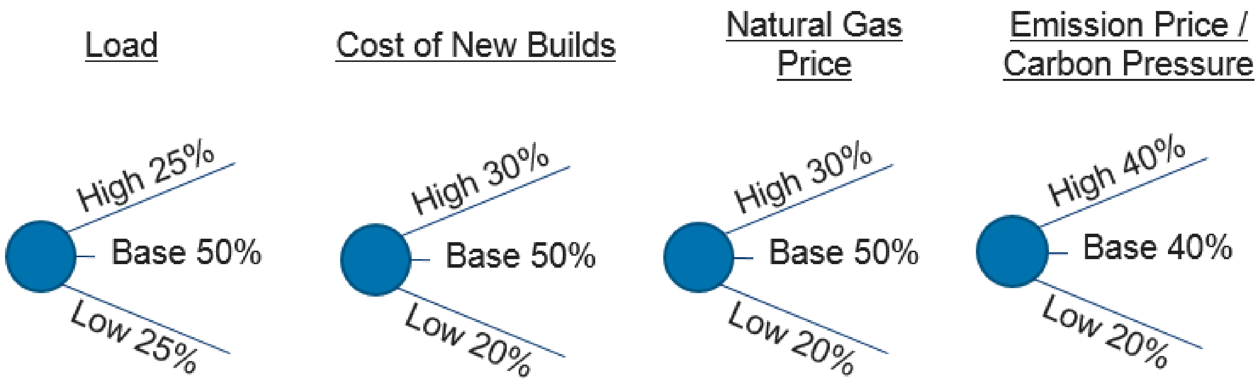
Finally, the 2024 IRP Annual Update report analyzes and responds to six special contemporary issues. As the Rule states, special contemporary issues involve a "written list of issues contained in a Commission order with input from staff, public counsel, and intervenors that are evolving new issues, which may not otherwise have been addressed by the utility or are continuations of unresolved issues from the preceding triennial compliance filing or annual update filing." 20 CSR 4240-22.020(55). The Order establishing the special contemporary issues to be addressed in this annual update was issued on October 25, 2023, in File No. EO-2024-0045, with an effective date of November 4, 2023. These issues are addressed in Section 7 of this report.

Following section (1) introduction, this report contains sections addressing (2) the status of the critical uncertain factors, (3) a resource acquisition strategy update, (4) a transmission and distribution analysis update, (5) other general updates, (6) a preferred plan update, and (7) responses to the special contemporary issues.

Liberty's next triennial IRP compliance filing is scheduled for 2025.

2. Status of the Identified Critical Uncertain Factors

In the 2022 IRP, Liberty identified the following critical uncertain factors: (1) load; (2) the cost of new builds; (3) natural gas prices; and (4) emission prices and the pressure to reduce carbon.



This section will address the changes to these planning factors since the filing of the 2022 IRP and the 2023 IRP Update. Most of the critical uncertain factor updates in this section are based on Liberty's most recent rolling six-year business plan, which is internally developed on an annual basis as a part of Liberty's ongoing internal planning and budgeting process. The 2024 internal budget covers the period 2024-2029.

Load Forecast Update

A summary of the 2022 IRP load forecast can be found in the 2022 IRP Executive Summary. Additional information can be found in the 2022 IRP Volume 3, which is dedicated to load analysis and load forecasting. Each of these volumes can be found in the filing made in EO-2021-0331. As a part of its ongoing internal planning process, Liberty developed a new six-year load forecast for the Company's six-year Budget Cycle covering the period 2024-2029.

Liberty used the 2024-2029 Budget Cycle load forecast for the purpose of updating this report ("2024 Update"). The following tables compare the demand and energy forecasts from the 2022 IRP, the 2023 IRP Update for the period 2023-2028 and the 2024 Update.

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As shown in the tables above, the Company's 2024-2029 Budget Cycle forecast (2024 Update) is similar to the load forecast presented in last year's Annual Update. The 2022 IRP was developed in late 2021, the 2023 Update was developed in mid-2022, while the most recent budget forecast was developed in mid-2023. Some minor differences in forecasts are common and expected, based on timing and methodology. Given that the

2022 IRP is a long-term 20 plus year forecast utilizing the statistically adjusted end-use ("SAE") methodology, and the budget forecasts are shorter-term six-year non-SAE forecast, all the forecasts presented are reasonably aligned. Each year in the presented data, the 2024 Update consistently shows a slight increase compared to the annual energy forecast from the 2022 IRP. The summer peaks are slightly higher in the 2022 IRP as compared to the 2024 Update, and the winter peaks are slightly lower in years 2024 and 2025 and then become higher in the outer years. If you consider the absolute value difference between the 2022 IRP forecast and the 2024 Update forecast, the six-year average differences between the two forecasts would be 0.86% for summer peaks, 1.45% for winter peaks and 2.06% for the native load energy requirement. Similarly, if you compare the absolute value difference between the 2023 IRP Update forecast and the 2024 Update forecast, the five-year average differences between the two forecasts would be 0.93% for summer peaks, 0.58% for winter peaks and 0.83% for the native load energy requirement. The following tables present the deltas between the two forecasts.

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The summer peaks are lower in the 2024 Update, as compared to both the 2022 IRP and the 2023 IRP Update. The primary driver was due to the re-estimation of the model with additional years of data. There was a downward shift in the cooling slope in actual data as compared to prior years. When including more recent data in the model estimation, the model reacts to these lower data points by reducing the peak forecast in the summer. The increase in the energy forecast can be primarily attributed to the higher customer count forecast for the 2024 Update as compared to the other forecasts. The customer data assumptions are presented below.

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Cost of New Builds Update

The cost of 2022 IRP supply-side resource candidates can be found in 2022 IRP Volume 4, Supply-Side Resource Analysis. This section will address updates to the cost of new resource options since the 2022 IRP was prepared.

Technology Capital Cost Update

The original planning-level capital cost assumptions for generic resources in the 2022 IRP were developed by Charles River Associates ("CRA") with review and input by experts from a third-party engineering firm, Black and Veatch. For this 2024 IRP update, CRA reviewed key publicly available resources to identify any material trends in cost evolution that have occurred since the original study.

The Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2023 released in Spring 2023 indicates that the capital costs for natural gas fueled combustion turbine ("CT"), combined cycle ("CC"), and reciprocating internal combustion engine ("RICE") generators, have increased by around 10% in real terms (20-25% nominal terms) relative to the EIA AEO 2021 which served as a key input for the 2022 IRP study. On the same basis, battery costs have declined by 4% in real terms, translating to an increase of 9% in nominal terms. Relative to the EIA AEO 2022 referenced in 2023 IRP Update, the AEO 2023 indicates a 3% cost increase in real terms (11% in nominal terms) for gas-fired technologies and an 11% decline for battery storage in real terms (3% decline in nominal terms). Although AEO 2023 will have an inherent lag relative to current cost levels, recent trends reflect the magnitude and direction of inflationary pressures observed across the industrial sector and broader economy since the 2022 IRP.

Renewable technologies have similarly experienced cost increases. In its Q4 2023 PPA Price Index, LevelTen Energy observes that PPA prices increased by 60-75% for both solar and wind since Q4 2021, the time of the 2022 IRP study. Since the 2023 IRP Update, the PPA price increase has been between 15 and 25% for both solar and wind.

Liberty will monitor and again reevaluate the capital costs and all other planning assumptions during the development of the 2025 triennial IRP.

Inflation Reduction Act and the Cost of Resource Options

The IRA of 2022 passed the Senate and House of Representatives and was signed by President Biden on August 16, 2022. The bill includes the following energy related features which have implications for power markets:

- Extension of the investment tax credit ("ITC") and production tax credit ("PTC") by 10 years, which become technology neutral starting in 2025. A new ITC for stand-alone storage was also included.

- Bonus tax credit levels available based on prevailing wage and apprenticeship requirements, domestic content conditions, and location of projects in newly defined "energy communities," in proximity to retired coal infrastructure or regions of the country with high unemployment and employment associated with the fossil fuel industry.
- New or expanded subsidies for emerging technologies such as carbon capture, hydrogen, and existing nuclear generators.
- Subsidies for energy efficiency and electric vehicles.

The IRA has a material impact on the economics of new low emissions resources. Prior to the IRA, previous policy provided federal tax incentives for wind via the PTC at a rate of $15/MWh (60% of $25/MWh real $2021 level) with eligibility through 2021 for start of service, and for solar via the ITC at a rate of 10% of upfront capital cost for start of service after 2025 (phasing down from 30%, 26%, and 22% ITC for projects commencing construction through 2019, 2022, and 2023, respectively, and in service through 2025). The IRA extends eligibility for the PTC and ITC for ten years (and potentially longer if nationwide power sector carbon emissions do not decline by 75%) at a rate of $27.5/MWh (real $2023, assuming prevailing wage and apprenticeship requirements are met), expands the PTC to include solar, makes storage eligible for the ITC at a rate of 30% of the upfront capital cost, and provides provisions for other low emissions technologies including nuclear, hydrogen, and carbon capture and storage ("CCS").

Liberty will continue to monitor technology costs and federal tax incentives for clean energy going forward.

Natural Gas Price Update

This section discusses updates to natural gas prices since the filing of the 2022 IRP. A summary of the natural gas price forecast used in the 2022 IRP can be found in more detail in 2022 IRP Volume 4, Supply-Side Resource Analysis. It should be noted that natural gas prices are impacted by a number of factors and can be volatile and difficult to predict with a degree of accuracy. The triennial IRP, for example, utilizes multiple natural gas price levels and considers these factors in the risk analysis phase of the study.

For the long-range 2022 IRP study, Liberty used the natural gas price forecasts from the CRA Natural Gas Fundamentals Model (“NGF”) (considered confidential). CRA developed three separate price forecasts for use in modeling base, low, and high gas price scenarios. For the 2023 IRP Annual Update, Liberty used natural gas price forecasts from the Horizons Energy Spring 2022 Advisory Service, which were also used in the development of Liberty’s six-year budget for the 2023-2028 Budget Cycle.

For the development of a six-year budget for the 2024-2029 Budget Cycle, Liberty used natural gas price forecasts from the Horizons Energy Spring 2023 Advisory Service. In the near-term, the natural gas price forecasts used for the 2024-2029 Budget Cycle were slightly higher than the natural gas price forecasts modeled in the 2022 IRP Base Case but still within the range of uncertainty analyzed in the 2022 IRP. In the latter years, the natural gas price forecasts used in the 2024 Budget Cycle fall slightly below the 2022 IRP Base Case. The natural gas price forecasts from the 2022 IRP, the 2023 IRP Update and Budget Cycle, the recent 2024 budget cycle, and EIA AEO 2023 are shown below for comparison.

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Emission Price / Carbon Pressure Update

Carbon prices from the 2022 IRP can be found in 2022 IRP Volume 4, Supply-Side Resource Analysis, Section 5.4.1. This section will provide an update on the emission price/carbon pressure critical uncertain factor.

Affordable Clean Energy Rule

In December 2017, the U.S. Environmental Protection Agency ("EPA") issued an advance notice of proposed rulemaking ("ANPRM") in which the EPA proposed emission guidelines to limit greenhouse gas ("GHG") emissions from existing Electrical Generating Units ("EGUs") and solicited information on the proper respective roles of the state and federal governments in that process, as well as information on systems of emission reduction that are applicable at or to an existing EGU, information on compliance measures, and information on state planning requirements under the Clean Air Act ("CAA"). This ANPRM did not propose any regulatory requirements.

In June 2019, the EPA issued the final Affordable Clean Energy ("ACE") rule and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. The ACE rule has several components: a determination of the best system of emission reduction for GHG emissions from coal-fired power plants, a list of "candidate technologies" states can use when developing their plans, a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a "major modification" triggering New Source Review, and new implementing regulations for emission guidelines under CAA 111(d). During 2020, Missouri utilities conducted regular meetings with the Missouri Department of Natural Resources to determine the standard of compliance for this rule. Plum Point Energy Associates has also been working through the standard of compliance with the Arkansas Division of Environmental Quality. However, on January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit struck down the ACE Rule.

On May 11, 2023, the EPA proposed new carbon pollution standards for coal and natural gas-fired power plants. The proposal includes a flexible approach administered by states with options for compliance accounting such as averaging or trading of emissions. Guidelines for emissions reduction are based on Best System Emissions Reduction ("BSER") standards where stringency increases with time horizon, unit capacity factor, unit size, and distinguishes between new and existing units, and by technology. Of the various permutations, the following is a selection of general guidance on BSER for key applications:

- New units - Either carbon capture and storage ("CCS") by 2035, or hydrogen blending at 30% by 2032 and at 96% by 2038.

- Existing coal units - CCS if planning to operate beyond 2039; 40% natural gas co-firing if planning to operate beyond 2032 and stop operations by 2039.

- Existing gas units – For larger baseload plants (i.e.- CCGT), either CCS by 2035, or hydrogen blending at 30% by 2032 and at 96% by 2038, although the EPA has recently indicated that a separate rule with different requirements for existing natural gas-fired plants will be issued; No BSER for smaller or peaking turbine plants.

The new draft power sector carbon emissions rule is likely to be finalized in the summer of 2024, although ultimate implementation remains uncertain, particularly given the June 30, 2022, Supreme Court decision in West Virginia v. EPA, which specifically limited the EPA's ability to regulate carbon dioxide emissions from power plants, on the basis that the original CPP had overstepped authority granted under the Clean Air Act.

Carbon Price Timing

In the 2022 IRP, Liberty evaluated the probable environmental costs of new supply side resource options associated with potential CO2 emissions. Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level.

Given a number of previous federal proposals to regulate carbon emissions, Liberty's Base Case for the 2022 IRP incorporated a modest price on carbon emissions of $9/short ton starting in 2026, which can be seen as a proxy for several different potential pathways for legislative action or executive regulation (not explicitly a carbon tax). However, with the passage of the Inflation Reduction Act and associated additional near to medium term renewable development, any Congressional action on power sector carbon emissions pricing is now unlikely until 2030 or later. To reflect these factors, for modeling of the 2023 Solar Study, Liberty has revised its carbon price view to $10.5/short ton starting in 2031, as shown in the "Updated Analysis of 2026-2027 Utility-Scale Solar Project" section.

Liberty will continue tracking federal action related to GHG emissions going forward.

3. Resource Acquisition Strategy Update

This section provides a status update on the supply-side and demand-side implementation plan and describes progress made since the filing of the 2022 IRP. For the 2024 IRP Annual

Update, the following will be discussed: the Riverton replacement project in the 2026 timeframe; the status of the Community Solar Phase 2; The Utility-Scale Solar project in the 2026-2027 timeframe; Distributed Solar in the 2027 timeframe; and the status of the demand-side management implementation plan.

Riverton Units 10 and 11 Replacement Project (2026 timeframe)

The Riverton 10 and 11 replacement project is currently in progress. This thermal unit replacement project has an open Certificate of Convenience and Necessity ("CCN") docket in Missouri (EA-2023-0131). The 2022 IRP preferred resource plan included the replacement of the aging Riverton Units 10 and 11 to enhance the resiliency of Liberty's electric supply. The original plan identified the addition of approximately 30 MW of reciprocating internal combustion engine ("RICE") generation using existing interconnection at the Riverton site with the retirements of Riverton Units 10 and 11. Following the 2022 IRP filing, Liberty worked with Black & Veatch ("B&V") on a technology review examining three models of RICE, six simple-cycle CT models, and batteries. These units were further evaluated in the 2023 IRP Annual Update process, where it was determined—with updated information—the Riverton Replacement project had a lower long run projected cost with the installation of two CT generators. This project has a projected commercial operation date in the second quarter of 2026. Each new CT unit will have a nominal net output of 13.3 MW. The turbines are fast-starting and are dual fuel capable, providing resiliency for periods of natural gas scarcity and the capability to start when no off-site power is available. The two new turbines will have no post-combustion pollution controls but will employ dry low NOx combustion to limit NOx formation. The new units will be more efficient than the existing units, meaning they will consume approximately 37% less fuel per kWh generated than the units they will replace. Additionally, the CTs may provide a benefit for the potential of utilizing H2 as a blend fuel in the future.

Community Solar Phase 2

The existing Prosperity Community Solar facility, located on approximately 15 acres of land near Prosperity, Missouri with a capacity of approximately 2.25 MWs (with more than 5,500 bifacial photovoltaic panels) went into service in 2021. Additional community solar capacity is expected to be installed during the next five years. The exact amount to be built will depend upon customer demand. Community solar is unique, in that it is sold as a voluntary option to interested customers as dedicated renewable supply to offset their individual consumption. These customers participate through a simple and convenient billing mechanism, so they gain the benefits of solar energy supply without needing to install a dedicated system on their own roof or facility. The tariff also requires a full subscription before additional CCNs may be effective. The Company has a substantial waitlist for customers expressing interest in community solar. Liberty's revised tariff sheets are effective, and a CCN application will likely be filed later this year.

Utility-Scale Solar Project (2026-2027 timeframe)

The 2022 IRP preferred resource plan included 105 MW of utility-scale 2:1 solar + storge in 2027. As modeled in the 2022 IRP, this resource could not be used for accredited capacity until Energy Units 1 and 2 retired due to its co-location at the Energy Center site given the site's interconnection status. Since that time, resource adequacy has become a major focus, with the previously mentioned increase in SPP's planning reserve margin and the future performance-based accreditation as examples. In addition, new tax credit opportunities via the IRA are now available, causing the Company to re-evaluate plans for this resource. Since the last IRP Annual Update, the Company issued a request for information ("RFI") and contracted with CRA to analyze the best step forward. Subsequently, the Company has recently issued a request for proposal ("RFP") for this project. Currently, the Company is considering a standalone utility-scale solar project at a greenfield site in the 2026-2027 timeframe. Depending on the results of the RFP, a future change to the preferred resource plan could be made if warranted. A description of the

CRA analysis can be found in section 6, Preferred Plan Update, in the subsection "Updated Analysis of 2026-2027 Utility-Scale Solar Project."

Distributed Solar (2027 timeframe)

The 2022 IRP preferred resource plan included 5 MW of distributed solar in 2027. Liberty still plans to strategically deploy its first distributed solar generation facility not associated with the Community Solar Program as envisioned in the IRP. This facility will have a capacity of about five megawatts. The installation of distributed solar generation across the Company will provide renewable power and supply and simultaneously mitigate delivery congestion, constraints, or power quality issues.

Demand-Side Management ("DSM") Implementation Plan Update

The 2022 IRP preferred plan included the low, mid, and high-cost bundle of the Realistically Achievable Potential ("RAP") DSM Plan. At this time, Liberty is offering energy efficiency programs under the Missouri Energy Efficiency Investment Act ("MEEIA") approved by the stipulation and agreement in File No. EO-2022-0078. The portfolio has a total budget of $4,067,313 and consists of Residential Program offerings that include Efficient Products; Low Income Multifamily; the Heating, Ventilation, and Air-Conditioning Program; and Whole Home Energy. Commercial Program offerings include Small Business Direct Install and a Commercial and Industrial ("C&I") program. These programs were developed with the results of the 2019 IRP analysis. Liberty is operating this portfolio of programs through 2024. In agreement with the Missouri Public Service Commission, 2024 will be a continuation of the 2023 programs and agreements. Liberty Utilities intends to file MEEIA Cycle 2 to cover 2025-2027 with results of the 2022 IRP analysis. For more information, see the section about "Energy Efficiency Projects at Missouri Schools" in the Other Update section.

4. Transmission and Distribution ("T&D") Analysis

This section of the report will update stakeholders about Liberty's T&D system reliability efforts, specifically the SPP interconnection studies conducted for the recent State Line CC upgrade.

State Line Combined Cycle Interconnection & Transmission Studies

The existing State Line Combined Cycle ("SLCC") generator was placed into service in 1997 and converted to a combined cycle in 2001. Liberty identified potential facility upgrades that would increase the capacity (about 64 MW of additional capacity being studied) and generator efficiency. These upgrades were included in the GI Queue (GEN-2020-064) and subsequently placed in the Definitive Interconnection System Impact Study (DISIS-2020-001) in June of 2020. Both phase one and phase two of the established three-phase Generator Interconnection process for SPP showed no required upgrade costs for the additional capacity to be interconnected at the State Line facility. According to SPP, the complete set of study results for DISIS-2020-001 should be expected by 2025.

5. Other Updates

This section of the report will provide updates to other IRP related issues, or what the IRP Rule refers to as "changing conditions generally."

Energy Efficiency Projects at Missouri Schools

Liberty had a great deal of success in 2023 helping Missouri schools implement energy efficiency projects through the Liberty Commercial and Industrial Rebate Program. The education market accounted for more than 20% of dollars paid and kilowatt-hours (kWh) claimed in Liberty's Missouri electric territory. One activity of note was with Joplin Public Schools.

Joplin Public Schools completed two qualifying projects in 2023 where they received incentives through the Liberty Commercial and Industrial Rebate Program. The combined energy savings from both projects totaled approximately 500,000 kWh, annually. These upgrades also improved the overall learning environment, benefiting all stakeholders. The Liberty Commercial and Industrial Rebate Program helps education facilities save on construction costs and helps make more dollars available for teaching students. In addition, districts can better allocate taxpayer dollars and enhance the overall scope of projects. Liberty looks forward to continuing to work with Joplin Public Schools and has already identified projects for 2024.

Demand-Side Management Update for Arkansas

As of December 31, 2023, Liberty serves about 5,558 customers in northwest Arkansas. Besides Missouri, Arkansas is the only other jurisdiction where Liberty offers electric demand-side programs. Liberty has been granted a variance from statewide energy efficiency savings targets for 2024-2026 due to the small customer count, the rural nature of Liberty's Arkansas service territory, and other factors. However, Liberty continues to make improvements and offers a portfolio of programs. In 2024, Liberty introduced a new portfolio, which offers a residential products program, Residential Weatherization, and a school-based energy education program for residential customers, and prescriptive and custom rebates for Commercial and Industrial customers. Liberty also contributes its share to the statewide energy education program, Energy Efficiency Arkansas. Liberty has offered customer programs in Arkansas since October 2007. Liberty was approved for a new energy efficiency program plan for Arkansas in 2023, for program years 2024-2026.

Transportation Electrification

Decarbonizing transportation through electrification contributes to safer and healthier communities. Liberty is supporting this objective through a diverse portfolio of projects and programs that enable transportation electrification equitably across its service territory through education, charging infrastructure, financial incentives, and hands-on support with customers as they transition their fleets and specific equipment to electric. In January 2022, a Liberty Transportation Electrification ("TE") pilot comprised of utility-administered electric vehicle ("EV") charging programs for different types of electric customers was approved by the Commission (File No. ET-2020-0390).

Aside from supporting the development of EV infrastructure in Liberty's service territory, the TE pilot program continues to enable the Company to gather insights in multiple areas that will enhance its long-term planning capabilities, including:

- the extent (if any) of accelerated strain to adjacent assets brought about by EV charging (and especially Direct Current chargers);
- technical and operating parameters of potential Vehicle-to-Grid and EV-specific Demand Response ("DR") schemes;
- the demand elasticity of EV charging in response to the Time of Use rate schedules approved by the program;
- the customer journey insights, including the real and perceived barriers of customer EV adoption in Liberty's service territory;
- the suitability of charger equipped consumption measurement devices for the purposes of utility customer billing.

In addition to these Transportation Electrification programs for customers, Liberty continues to decarbonize emissions from its own fleet.

Asbury Demolition

The Asbury Power Plant ("Asbury") was an approximately 200 MW mine-mouth coal-fired electric power plant located in Jasper County, Missouri, first operational in 1970. The unit was wholly owned and operated by the Company until being officially de-designated from

SPP as of March 1, 2020. The electric generating unit was felled on June 29, 2023. Removal of scrap and debris and restoration of the site was completed in March 2024.

Inflation Reduction Act

The IRA of 2022 was signed into law on August 16, 2022. This United States federal law invests in domestic energy production while promoting clean energy and energy justice. Utilities can leverage the climate law's clean energy tax credits to bolster investments in renewable energy and battery storage. Although the law supports an increase in investments, clean energy projects can be constrained by permitting delays, transmission constraints, operational curtailments, and lack of energy storage to satisfy demand during renewable generation's off-peak hours. Intended outcomes of the law include reducing greenhouse gas, impacting climate change, and providing energy justice to underserved communities. Additional information on the IRA can be found in Section 2 of this report.

Other Environmental Updates

Liberty is subject to various federal, state, and local laws and regulations with respect to air and water quality; hazardous and toxic materials; hazardous and other wastes including their identification, transportation, disposal, and record-keeping; reporting; and remediation of contaminated sites and other environmental matters. Liberty's jointly owned coal-fired generating facilities, jointly owned combined cycle facility, and all other wholly owned resources must be operated in compliance with environmental laws and regulations.

Environmental laws or regulations that may be imposed at some point within the planning period may impact air emissions, water discharges, or waste material disposal. A brief discussion of the probable compliance costs that could result from expected and existing environmental standards was provided in the 2022 IRP Volume 4 Section 2.5. An additional update to the standards since the filing of the 2022 IRP is described below.

National Ambient Air Quality Standards

The Clean Air Act ("CAA") requires the EPA to set National Ambient Air Quality Standards ("NAAQS") for four air pollutants associated with fossil-fuel generation, including particulate matter, ground-level ozone, sulfur dioxide ("SO_2"), and nitrogen dioxides ("NO_X"). These air pollutants are regulated by setting human health-based or environmental-based criteria for permissible levels.

Particulate Matter

In 2013, the EPA strengthened the PM standard. The Jasper County (Missouri) area is currently in attainment of the 2013 PM NAAQS. On January 6, 2023, EPA announced its proposed decision to revise the annual National Ambient Air Quality Standard (NAAQS) for fine particulate matter (PM 2.5). The PM 2.5 revision was finalized on February 7, 2024. It is not yet known how the revision to the PM 2.5 NAAQS will impact the generation fleet as Jasper County currently does not have an ambient air PM 2.5 monitor to measure attainment status. However, modeling Jasper County emission source's impacts to downwind monitors (i.e., Kansas City and St. Louis) could potentially have a future impact on Liberty's fleet. Future non-attainment could require additional reduction technologies, emission limits, or both on fossil-fueled units.

Ozone

In 2015, the EPA strengthened the NAAQS for ground-level ozone. The Jasper County area is currently in attainment of the 2015 Ozone NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional NO_X reduction technologies, emission limits, or both on fossil-fueled units.

Sulfur Dioxide

In 2010, the EPA strengthened the NAAQS for SO_2. The Jasper County area is currently in attainment of the 2010 SO_2 NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional SO_2 reduction technologies, emission limits or both on fossil-fueled units.

Nitrogen Dioxides

In 2010, the EPA strengthened the NAAQS for NO_X. The Jasper County area is currently in attainment of the 2010 NO_X NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional NO_X reduction technologies, emission limits or both on fossil-fueled units.

Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. The CSAPR Update Rule took effect in 2017 with more stringent ozone-season NO_X emission budgets for electric generating units ("EGUs") in many states to address significant contribution and maintenance issues with respect to the ozone NAAQS established in 2008. In 2021, the EPA issued new amended budgets for 12 states, although Missouri and Kansas were not impacted.

In 2022, the Missouri Department of Natural Resources ("MDNR") proposed revisions to the Missouri State Implementation Plan ("SIP"). This revision is a supplement to the SIP-Interstate Transport Provisions for the 2015 Ozone Standard. The EPA's response to the MDNR SIP revision was proposed denial. In addition, the EPA also proposed implementing the Good Neighbor Federal Implementation Plan ("FIP") to assure that the 26 states identified in the proposal (including Missouri) do not significantly contribute to problems attaining and maintaining the 2015 Ozone NAAQS in downwind states. The Good Neighbor FIP would impose more stringent NOx ozone season compliance requirements for Missouri EGUs. Should the Good Neighbor FIP become applicable, additional emission control equipment could be needed to comply with this rule. In lieu of adding control equipment to comply with the Good Neighbor FIP, the Company could also comply through a combination of trading allowances within or outside its system and changes in operations, as necessary. The proposed Good Neighbor FIP has the potential to move Missouri sources from the Group 2 NOx ozone season trading program to Group 3 NOx ozone season trading program. Pricing per ton emitted is much higher in the Group 3 trading program (fall of 2022 Group 3 NOx ozone season allowances have cost as much as $35,000 each). Future strengthened ozone, NO_X, or SO_2 standards could result in additional cross-state rule updates requiring additional trading of allowances, emission reduction technologies or reduced generation on fossil-fueled units. The Eighth U.S. Circuit Court of Appeals granted the Missouri Attorney General's request for a stay, preventing the EPA from imposing this regulation on Missouri sources until the appeals process plays out.

Regional Haze

In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls known as best available retrofit technology ("BART") for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze.

The pollutants that reduce visibility include $PM_{2.5}$ and compounds which contribute to $PM_{2.5}$ formation, such as NO_X, SO_2, and under certain conditions, volatile organic compounds, and ammonia. Under the 1999 Regional Haze Rule, states are required to set periodic goals for improving visibility in natural areas. As states work to reach these goals, they must develop regional haze implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution.

The Regional Haze Rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. It also directs these agencies to file Regional Haze plans with the EPA for approval.

Future visibility progress goals could result in additional SO_2, NO_X, and PM controls or reduction technologies on fossil-fired units.

Mercury and Air Toxics Standards ("MATS")

In 2011, the EPA finalized a rule to reduce emissions of toxic air pollutants from power plants. These MATS for power plants reduced emissions from new and existing coal and oil-fired electric EGUs. Control equipment was installed at Liberty facilities to comply with this rule. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the rule will be strengthened in the future. Future strengthening of the rule could require additional reduction technologies, emission limits, or both on coal and oil-fired units.

Water Related Impacts

Liberty operates under the Kansas and Missouri National Pollutant Discharge Elimination System ("NPDES") plans that were implemented in response to the Federal Clean Water Act ("CWA"). Liberty operates its generation facilities in compliance with applicable regulations, and all facilities have received necessary discharge permits.

Clean Water Act Section 316(b)

On September 17, 2018, the Kansas Department of Health and Environment ("KDHE") issued a Certificate of Determination stating that the Riverton Generating Station cooling water intake structure ("CWIS") is in compliance with Section 316(b) of the CWA. The location, design, construction, and capacity of the CWIS reflects the best technology available ("BTA") for minimizing adverse environmental impacts. Additionally, Iatan Unit 2 and Plum Point Unit 1 also meet the BTA standard. Future modifications at the Iatan Unit 1 facility could range from flow velocity reductions, traveling screen modifications, or the installation of a closed cycle cooling tower retrofit.

Surface Impoundments

Liberty owns and maintains a closed coal ash impoundment at the former and closed Asbury Power Plant site. Additionally, Liberty owns a 12 percent interest in a landfill at the Iatan Generating Station and a 7.52 percent interest in a landfill at Plum Point. Future closure of all surface impoundments is anticipated.

Effluent Limitation Guidelines ("ELGs") for Steam Electrical Power Generating Point Sources are currently incorporated into all facilities' wastewater discharge permits. The EPA rule defines bottom ash transport water, fly ash transport water, and scrubber wastes as wastewaters which cannot be discharged after December 31, 2023.

Coal Combustion Residuals ("CCR")

Final closure of the other existing ash impoundment at the Iatan Generating Station has been accounted for in Liberty's Asset Retirement Obligation ("ARO"). In December 2016, The Missouri Department of Natural Resources ("MDNR") granted Liberty a Utility Waste Disposal Area Construction Permit that could be used for CCR waste disposal. Construction of the landfill is not expected as Liberty closed the Asbury impoundment by leaving all accumulated CCR in place.

In 2014, the former Riverton Plant impoundment was closed as a monofil landfill in accordance with Kansas Department of Health and Environment regulations.

Elk River Windfarm PPA Contract Expiration in 2025

The 150 MW Elk River Windfarm PPA is a 20-year contract that began in mid-December 2005. This resource is located in Butler County, Kansas near the town of Beaumont. During the duration of this contract, the Company receives 100% of the output from this facility at a net energy price established by contract. This contract will expire in mid-December 2025.

Meridian Way Windfarm PPA Contract Expiration in 2028

The 105 MW Meridian Way Windfarm PPA is a 20-year contract signed in mid-June 2007, with the windfarm entering service in late December 2008. This resource is located in Cloud County, Kansas, near the town of Concordia. During the duration of this contract, the Company receives 100% of the output from this facility at a net energy price established by contract. This contract will expire in December 2028.

Missouri Renewable Energy Standard Requirement

The Missouri Renewable Energy Standard ("RES") requires Liberty and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources or purchase Renewable Energy Credits ("RECs") to meet a specified percentage of the Missouri retail energy requirement. The RES portfolio requirement is currently 15% of Missouri retail electric sales. The Company currently complies with the RES by utilizing the Elk River Windfarm PPA, the Meridian Way Windfarm PPA, the Neosho Ridge Wind Project, the North Fork Ridge Wind Farm, the Kings Point Wind Farm, the Ozark Beach hydroelectric facility, and a solar component supplied by the Customer Solar Rebate program.

Additionally, the Company has REC volumes available to Missouri retail non-residential customers based upon customer usage and a current market rate. In the future, if new renewable energy requirements are implemented, the Company is in a favorable position to meet additional requirements.

6. Preferred Plan Update

During the period covered by this IRP Annual Update (2024-2029), the preferred plan from the 2022 IRP consisted of supply-side and demand-side resource additions, the replacement of Riverton Units 10 and 11, and the expiration of existing wind farm PPA contracts. The supply-side resources from the 2022 IRP are included in the load and capability balance tables presented in the next section and can be summarized as follows:

- Replacement of Riverton Units 10 and 11 in 2026 with approximately 26 MW of combustion turbines at the Riverton, Kansas site in 2026
- 150 MW Elk River Windfarm PPA contract expiration in December 2025
- 105 MW utility scale solar + storage in 2027 (as discussed in the Resource Acquisition Strategy Update section, this project is currently being considered for revision. It is further discussed in the following section "Updated Analysis of 2026-2027 Utility-Scale Solar Project")
- 5 MW distributed solar in 2027
- 105 MW Meridian Way Windfarm PPA contract expiration in December 2028

Updated Analysis of 2026-2027 Utility-Scale Solar Project

The Company worked with CRA to conduct an updated analysis of the solar + storage project that was included in the 2022 IRP preferred plan. The 2022 IRP preferred plan originally found that a 105 MW co-located 2:1 solar + storage hybrid system located at the Energy Center site would be an economic addition to the portfolio in 2027. The solar + storage system would not receive capacity accreditation until retirement of Energy Center units 1 and 2 in 2035 due to limitation in the proposed use of the surplus interconnection provision in the SPP Open Access Transmission Tariff ("OATT") at the site. Liberty is now considering to instead build standalone solar at a greenfield site in the 2026-2027 timeframe. The greenfield solar would take advantage of earlier capacity accreditation, higher energy value, and possibly sited within an "energy community" to realize a 10% tax credit bonus. Details of the nature and timing of change are shown below in Table 6.1.

Table 6.1 - Energy Center Solar Project Proposed Update Overview

Year	Units Replaced and Contract Expiry	Additions	
		2022 IRP Plan	Proposed Update
2025	Riverton 10-11 (27 MW) Elk River (150 MW)	CT at Riverton Site (27 MW)	
2026			Standalone Greenfield Solar (145 MW)
2027		2:1 Solar + storage at EC Site (105 MW)	
2028	Meridian Way (105 MW)		
2029			

To assess the economic viability of the proposed changes to the preferred plan, CRA undertook a comparative analysis to determine the net present value of revenue requirements ("NPVRR") of the original plan against a revised portfolio with the standalone solar project. The analysis included updates to load, technology costs, and commodity prices.

Liberty recently conducted an RFI to gather cost information for new solar and storage additions in its territory. Based on the RFI offers, the capital cost for 2026-2027 solar is estimated to be around $1,900/kW (nominal $ in 2026), with storage costing around $1,800/kW (weighted average of projects). Interconnection and network upgrade costs are estimated at an additional $186/kW (nominal $ in 2026). The Inflation Reduction Act provides a 30% ITC for new projects and a 10% adder for "energy community" projects, including those located in proximity to retired coal units (the PTC is also now available for solar). Both solar and storage components are eligible under the IRA. These key assumptions details are shown below in Table 6.2.

Table 6.2 - Solar Project Parameters

Parameter	Units	2:1 Solar + storage at EC Site (2022 IRP)	Standalone Greenfield Solar (Proposed Replacement)	Source
Year of Commissioning		2027	2026	Empire
Initial Capex	Nom $/kW	1,840	1,916	Empire RFP (solar - $1,916/kW, storage - $1,777/kW in 2026)
Interconnection + Network Capex	Nom $/kW	-	186	Empire RFP
Tax Credit	%	30% ITC	30% ITC + 10% Energy Community	CRA (Empire guidance on location)
Capacity	MW	105	145	Empire (RFP for new project)
Capacity Factor	%	25% for solar component	25%	Empire RFP (aligns with B&V/CRA)
Fixed O&M	$/kW-yr*	13	14	B&V/CRA
Ongoing Capex	$/kW-yr*	13 (associated with storage)	-	B&V/CRA

** real $2023*

The analysis included Liberty's updated peak load and reserve margin outlook for its planning territory to reflect the latest future demand expectations. Winter peak load was revised upwards by 2.5% (30 MW) by 2029, while the summer peak is similar to the previous outlook. The planning reserve margin was revised from 15% to 18% for summer and to 25% for winter by 2030. Together, these revisions represent an increase in capacity obligation, predominantly in winter, as Liberty expects likely increases in planning requirements from SPP as a result of ongoing market reforms.[1] The revised peak load outlook, reserve margin expectations, and resulting capacity obligation relative to the assumptions from the 2022 IRP are shown in Exhibit 6.1.

[1] To adequately serve the increased capacity obligation, incremental standalone storage capacity was added to supplement both portfolios: 250 MW of incremental standalone storage were added by 2041 to the 2022 IRP-based preferred plan that also included 105 MW of 2:1 solar + storage at Energy Center, while 270 MW of incremental standalone storage were added for the proposed updated portfolio that also included the 145 MW standalone greenfield solar.

Exhibit 6.1.1 - Peak Load Outlook

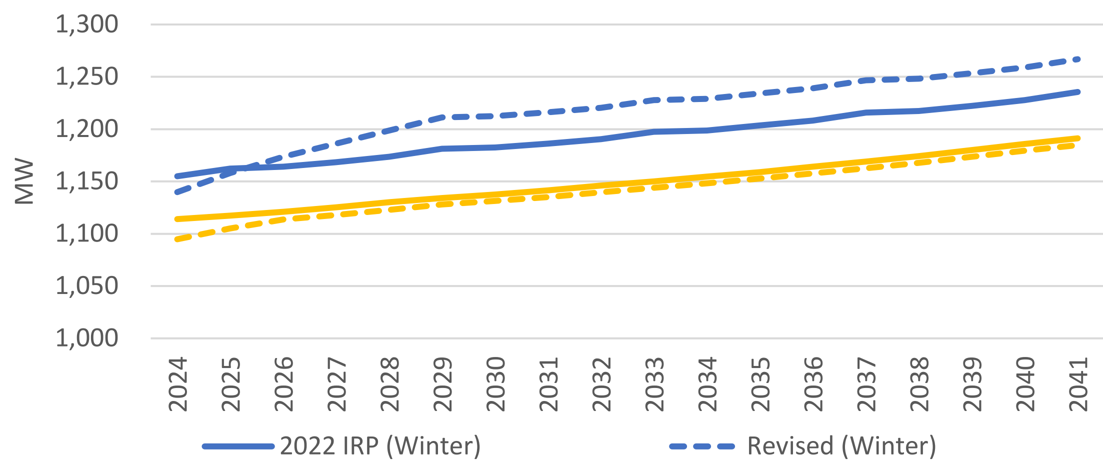


Exhibit 6.1.2 – Reserve Margin Outlook

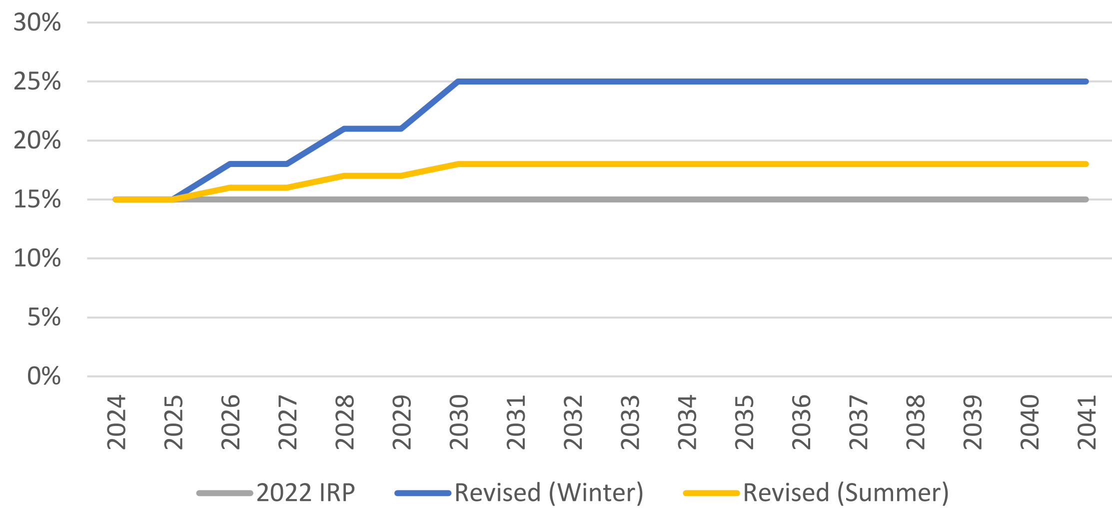
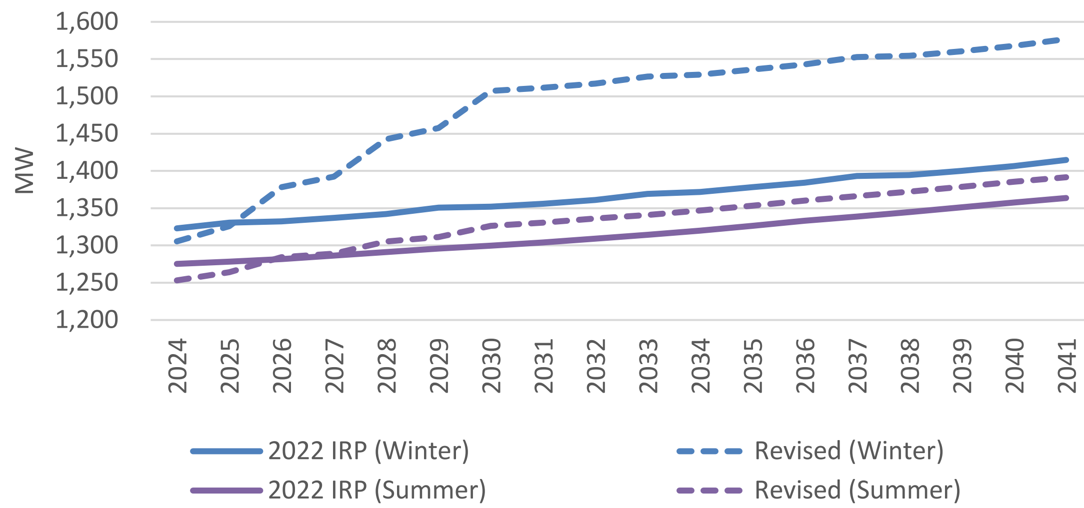


Exhibit 6.1.3 – Capacity Obligation Outlook



For the comparative NPVRR analysis, Liberty also updated the commodity price outlook. CRA derived an updated outlook for SPP pricing based on the revised commodity, load, and technology cost outlooks using the AURORA market model. The Liberty portfolio was then dispatched against the revised market price projections. Details of the revised outlooks are shown in the charts below.

Exhibit 6.2.1 - Natural Gas Price Outlook

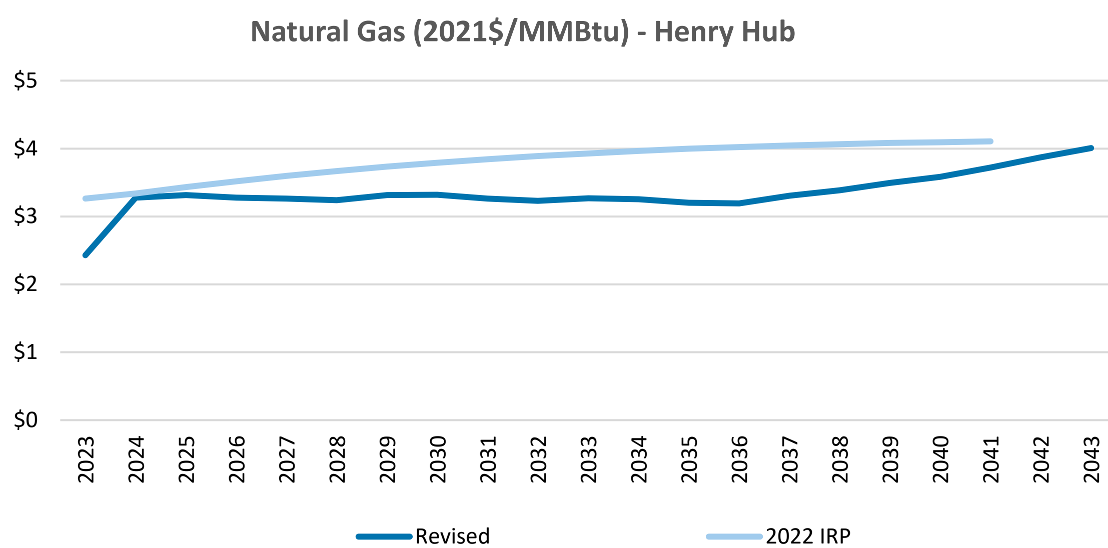


Exhibit 6.2.2 - Carbon Emissions Price Outlook

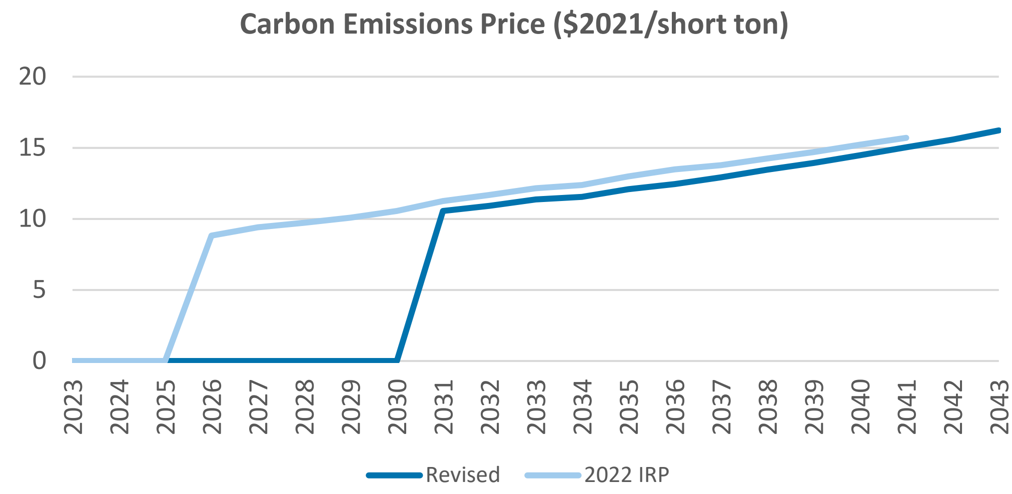
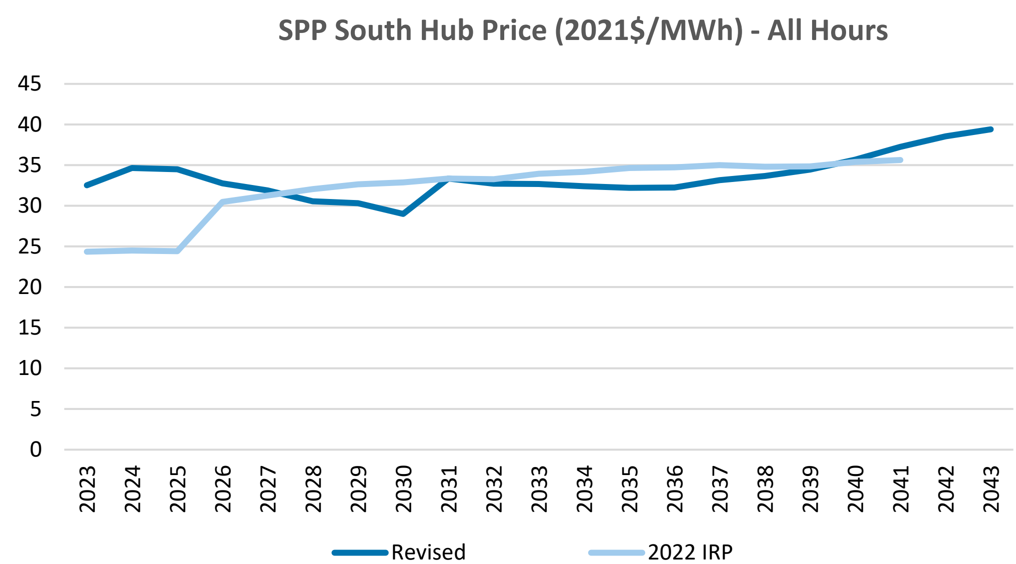


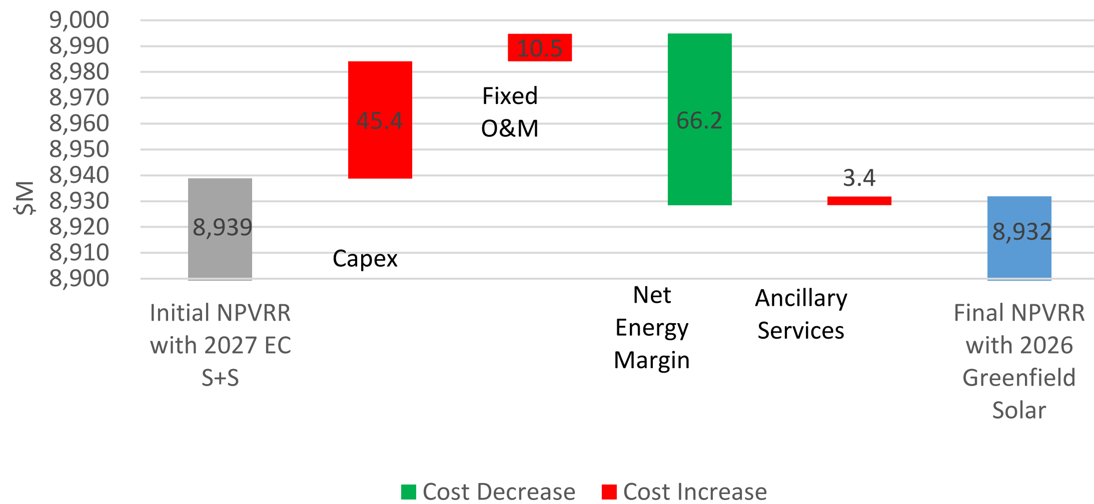
Exhibit 6.2.3 - SPP South Hub Price Outlook



After completing the dispatch analysis and developing portfolio cost projections, CRA performed financial model analysis to derive 20-year portfolio NPVRRs using the revised inputs described above. NPVRR comparisons were developed for the 2022 IRP preferred plan portfolio with 105 MW 2:1 solar + storage added at the Energy Center site in 2027 relative to the revised portfolio with standalone solar added at a greenfield site in 2026.

The revised portfolio with the standalone greenfield solar project is projected to cost $7 million less than the portfolio with 2:1 solar + storage project at Energy Center on an NPVRR basis. The revised portfolio results in $45 million higher capex even after accounting for the tax credit value due primarily to larger project size (145 MW vs 105 MW) and additional interconnection costs required for the greenfield site. Moreover, the higher quantity of standalone solar results in lower accredited capacity for winter, requiring that the portfolio carry more supplemental storage (270 MW vs 250 MW incremental storage) to meet winter adequacy requirements. However, this higher capital cost requirement is more than offset by an increase of $66 million in energy value.[2] The 145 MW standalone solar project would generate roughly double the energy of 105 MW 2:1 solar + storage system, adding energy value to the portfolio and ultimately resulting in a $7 million lower 20-year NPVRR than the original plan.

Table 6.3 – 20-year NPVRR Comparison:
2027 EC S+S (105MW) vs 2026 Standalone Greenfield Solar (145MW)



[2] Note that the original solar+storage project does not result in incremental capacity accreditation relative to the alternative until the EC retirement in 2035. This has been taken into account in the analysis.

SPP Accreditation Changes

Changes to the SPP Planning Reserve Margin

Based on the results of the 2021 Loss of Load Expectation ("LOLE") Study along with additional considerations, the SPP Board of Directors and Regional State Committee approved to increase the Planning Reserve Margin ("PRM") requirement from 12% to 15% beginning in the 2023 Summer Season. The 15% PRM requirement resulted in a LOLE of less than 1-day-in-10 years for both generation reduction scenarios studied and reflected a reduced level of risk compared to lower PRM levels studied. According to SPP, "The increased PRM requirement increases confidence that the SPP Balancing Authority ("BA") will have access to generating resources needed to continuously supply demand."

SPP Performance Based Accreditation

According to SPP, "Current accreditation methodologies for conventional resources consist of one hour performance testing of the resources on an annual basis (for the operational test) and a more stringent one-hour capability test (while maintaining a four-hour continuous availability requirement) every five (5) years. The current methodology does not consider past performance (i.e., outages) or availability and generally closely aligns with the nameplate of the conventional resource. The objective of [RR554] is to implement performance-based accreditation methodology, to better align capacity accreditation to the capacity value provided by conventional resources starting with the 2026 Summer Season."

The approved Performance Based Accreditation ("PBA") methodologies can be found in the proposed updates to attachment AA of the SPP OATT in RR554. In short, the PBA calculation is a "deterministic method that utilizes an equation and historical outages to calculate an individual resource's accredited capacity" known as the "Demand Equivalent Forced Outage Rate" ("EFORd"). According to SPP, this is "the most common equation used in the industry and takes into consideration forced outages and derates when the resource is needed most to serve load." The calculated EFORd value shall be applied to the resource's demonstrated net generating capability to determine each resource's Accredited Capacity as follows:

$$\begin{aligned}&\mathit{Accredited\ Capacity\ (ACAP)}\\&\quad = \mathit{demonstrated\ net\ generating\ capability} \times (1 - \mathit{EFORd})\end{aligned}$$

Additionally, resources with less than 100 Service Hours ("SH") per season and year will have their Service Hours adjusted in accordance with the formula below.

Where Service Hours < (Months of Operation/4 * 100) and attempted starts is greater than zero:

$$SH' = \left[\left(\frac{\mathit{Actual\ Starts}}{\mathit{Attempted\ Starts}}\right) * \left(\frac{\mathit{Months\ of\ Operation}}{4} * 100 - SH\right)\right] + SH$$

The newly approved EFORd methodology will be calculated independently for both the summer and winter seasons. The most recent seven (7) years of historical performance data will be used when determining a resource's EFORd for each season. For the first four (4) years of the performance-based accreditation policy, 2026 through 2029, seven years of historical data will not be available for the EFORd calculation on each resource. Therefore, the most recent three years of historical data from the individual resource and four years of class average EFORd for the specific resource will be utilized for year 2026 seasonal EFORd calculations. For year 2027 calculations, the EFORd for the most recent year will be factored into the calculation and one class average value will be excluded from the calculation while keeping the remaining class average values from the previous year's calculation. By year 2029, seven years of historical data from the individual resource will be used when determining the resource's seasonal EFORd. The data gathering period for this new policy began in 2022 and is expected to be implemented in the summer season of 2026.

Updated ELCC Estimates for Existing Resources

Beginning with the 2026 summer season, the accreditation for wind and solar resources in SPP will be determined using the ELCC methodology.

ELCC is defined as the amount of incremental load a resource, in this case wind and solar, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. According to SPP, ELCC is an industry-wide accepted methodology used for determining the capacity value of resources.

In February 2021, SPP completed its first ***informational-only*** study for both wind and solar resources using the approved ELCC methodology for future use. As of October 2022, SPP completed the first formal ELCC study which was intended to be effective for the summer 2023 and winter 2023-2024 seasons. However, On March 2, 2023 in Docket ER22-379, in response to Clean Energy Advocates seeking a rehearing of FERC's August 5th, 2022 order accepting, subject to condition, SPP's proposed revisions to Attachment AA of the SPP OATT, FERC set aside their August 2022 Order's acceptance of SPP's proposal and rejected SPP's proposed OATT revisions to include the ELCC methodology and encouraged SPP to "expeditiously submit any future filings it may choose to make" due to the relationship between ELCC and reliability. Since that time, SPP stakeholders have been working to address the FERC's concerns developing two Revision Requests (RR554 and RR568) which reflect guidance provided by FERC in Docket ER22-379. These Revision Requests have completed the SPP stakeholder process and have received SPP Board of Directors approval and are pending filing with FERC by SPP.

The comparison between the 2021 and 2022 ***informational-only*** study results for Liberty's existing renewable resources can be seen in the table below. However, SPP is currently in the process of developing the study scope and model for the 2024 ELCC Study so the current accreditation methodology is being reflected in the following Load and Capability tables as it is the best information currently available and consistent with the Company's 2024 SPP Resource Adequacy submission.

Table 6.4- ELCC 2021 vs 2022 Comparison

Resource	2021 ELCC Summer Accredited Value (MW)	2022 ELCC Summer Accredited Value (MW)	2021 ELCC Winter Accredited Value (MW)	2022 ELCC Winter Accredited Value (MW)
Elk River Wind Farm PPA (150 MW)	25.7	20.5	21.9	18.3
Meridian Way Windfarm PPA (105 MW)	13.1	11.2	14.6	13.7
Neosho Ridge Wind (301 MW)	66.9	51.3	57.8	94.2
North Fork Ridge Wind (149 MW)	37.3	28.2	38.1	57.6
King's Point Wind (149 MW)	37.6	27.5	38.4	58.8

Load and Capability Balance Report

The 2022 IRP preferred plan was described in the 2022 IRP Executive Summary. Additional information can be found in Volume 7 of the IRP.

The Load and Capability Balance Report for the 2024 IRP Annual Update is presented on the following pages and is consistent with the current requirements of SPP Resource Adequacy and consistent with the Company's recent 2024 SPP Resource Adequacy submission.

Due to the nature of the evolving requirements of SPP Resource Adequacy, there are notable differences in certain assumptions between the 2022 IRP Load and Capability Balance Report and the 2024 IRP Annual Update Load and Capability Balance Report. For example, the new DSM that is included in the 2022 IRP is not included below because it is still a "prospective" resource addition that is still lacking certain planning details that are required by SPP, such as a tariff rate.

Another assumption that differs between the 2022 IRP and 2024 IRP Annual Update Load and Capability Balance Reports is the capacity credit assumed for wind resources. With SPP's transition to ELCC methodology accreditation for wind and solar resources beginning in the summer season of 2026, SPP is currently in the process of developing the study scope and model for the 2024 ELCC Study. As a result, the current accreditation methodology is being reflected in the following Load and Capability tables as it is the best information currently available and consistent with the Company's 2024 SPP Resource Adequacy submission.

Additionally, PBA for conventional resources has been approved by the SPP stakeholder process and has begun its data gathering stage with implementation expected beginning in the summer season of 2026.

Moreover, Liberty included small community solar, distributed solar, and solar + storage resources as behind-the-meter resources, as a reduction to the load and peak forecasts rather than separate resources in the following table, as it is assumed that these resources will not be registered in the SPP Integrated Marketplace based upon SPP Business Practices Section 2.0.

Finally, the following Load and Capability tables are updated to reflect SPP's change in the planning reserve margin from 12% to 15%.

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7. Liberty Special Contemporary Issues

According to the Rule, special contemporary issues ("SCI") means "a written list of issues contained in a Commission order with input from staff, public counsel, and interveners that are evolving new issues, which may not otherwise have been addressed by the utility or are continuations of unresolved issues from the preceding triennial compliance filing or annual update filing."

In this section of the report, Liberty will address the six SCIs (issues A through F) that were established by Commission Order in File No. EO-2024-0045. It should be noted that some SCIs for this IRP Annual Update reference sections of the IRP Rule that are specific to the triennial compliance requirements. In those cases, the Company has attempted to address the SCI as completely as possible within the scope of the IRP Annual Update process. Further, the Commission Order establishing the SCIs stated that "[t]he Commission does not intend that a utility spend an unreasonable amount to address any special contemporary issue. If Liberty finds that the cost to address a special contemporary issue is excessive, it may explain its concerns in its next IRP filing, while addressing the issue to the extent reasonably possible."

(A). Model and explicitly present future resource adequacy scenarios based on the following assumptions.

For the purposes of this SCI, the Company used data from the modelling that was performed in accordance with its 2022 IRP so as not to spend an unreasonable amount to address this SCI in this annual update as directed by the Commission's Order establishing the Special Contemporary Resource Planning Issues. The following tables reflect the Company's forecasted peak load, supply-side resources, capacity purchases and sales, and Realistic Achievable Potential of demand-side programs that were evaluated in the Company's 2022 IRP. These tables reflect the current supply-side resource accredited capacity values that correspond with the Company's recent SPP Resource Adequacy submission, and the currently required 15% Planning Reserve Margin.

1. With demand-side rates and traditional demand-side management investments (e.g., MEEIA).

The table below reflects the estimated impact of demand-side rates and traditional demand-side management investments including Time of Use Opt-In programs, Critical Peak Pricing Rates, and Real Time Pricing programs, and DLC Smart Thermostats that were evaluated in the Company's 2022 IRP. The "Demand-side rates and DSM" row shows the Realistic Achievable peak savings in MWs realized from these programs in the modelling. Additionally, the "Capacity Balance" row shows the Company's capacity balance after accounting for the 15% required Planning Reserve Margin.

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2. Only demand-side rates without MEEIA investment.

The table below reflects the estimated impact of only the Time of Use Opt-In rates that were evaluated in the Company's 2022 IRP. The "Demand-side rates only" row shows the Realistic Achievable peak savings in MWs realized from this program in the modelling. Additionally, the "Capacity Balance" row shows the Company's capacity balance after accounting for the 15% required Planning Reserve Margin.

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3. Neither demand-side rates nor MEEIA (but maintain naturally occurring energy efficiency adoption).

The table below reflects the estimated impact of only naturally occurring energy efficiency adoption most naturally occurring is inherent to the load forecast and does not include any of the programs mentioned above. The “Capacity Balance” row shows the Company’s capacity balance after accounting for the 15% required Planning Reserve Margin.

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4. Indicate whether or not naturally occurring savings and/or federally-sponsored DSM savings are included in the modeling. If yes, these savings should be identified and separated as well.

In Volume 5 (Demand-Side Resource Analysis) of the Company's 2022 IRP, Applied Energy Group ("AEG") states, "Prior to developing estimates of energy efficiency potential, AEG developed a baseline end-use projection to quantify what the consumption is likely to be in the future in the absence of any energy efficiency programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future. Thus, the potential analysis captures all possible savings from future programs." This includes, "Naturally occurring energy efficiency, which reflects the manufacturing of more efficient options in response to new appliance standards and purchases of high-efficiency appliances and equipment by early adopters outside of utility programs." These savings are included in the peak forecast as they are part of the historical data used in the regression analysis. However, the level of data granularity required to show this as a separate line item in the tables above is not readily available without additional modelling that would be more in line with a triennial filing.

5. Include an explicit section within the demand-side management volume and the executive summary where low, medium, and high TOU differentials are modeled and presented with expected demand savings articulated separate and aside from other demand-side management practices.

In the Company's 2022 triennial IRP, AEG conducted a Demand-Side Management ("DSM") Market Potential Study ("Study") to provide estimates of the technical, economic, and achievable energy efficiency potential of various energy efficiency programs. Within the scope of this IRP Annual Update, the Company has opted to use data from that Study in responding to this Special Contemporary Issue. Using the Potential Results by Options in Volume 5 Appendix 5A (Tables 3-12 and 3-13) of the 2022 IRP, the Realistic Achievable Potential by season and program is shown in terms of peak reduction (MW). Southwest Power Pool's current Resource Adequacy rules require Load Serving Entities to maintain a 15% PRM. In the tables above, The Company's capacity balance, given the required 15% PRM, is shown in each of the scenarios outlined above.

As of March 2024, Liberty has 164,716 customers on time-of-use ("TOU") rate plans as seen in the table below. These plans currently consist of low differential Time Choice plans, high differential Time Choice Plus plans, and an Electric School Bus Pilot Program.

Table 7.4 - TOU Rate Plans and Customer Counts

Customer Class	Plan	Customer Count
Residential	Time Choice	140,705
Residential	Time Choice Plus	74
General Service	Time Choice	21,406
General Service	Time Choice Plus	4
General Service	Electric School Bus Pilot Program	1
Large General Service	Time Choice	2,494
Small Primary Service	Time Choice	32
Total		164,716

Given that this report is an Annual Update, there are no Technical Volumes or Executive Summary accompanying it. However, the modelling that was performed around TOU rates in association with the Company's 2022 triennial IRP filing and the assumed demand savings by program can be found in the DSM Volume and Appendices of that filing.

(B). Analyze and produce estimated costs for mothballing any dispatchable generation resource that is subject to a planned retirement in the 20-year planning period. Estimates should include all costs including the minimum continued O&M of the mothballed units.

Through the 2022 IRP process, Liberty planned for retirement of the Riverton 10 and 11 gas combustion turbine units in 2025, the Energy Center 1 and 2 gas combustion turbine units in 2035, and the Iatan coal steam unit in 2039.

Mothballing estimates for dispatchable thermal generation can vary widely and tend to be plant-specific, reflecting operational considerations, such as type, age, and condition of the facility in question. Public estimates for the cost mothball[3] generic unit types can be observed in PJM Default Avoidable Cost Rates ("ACR")[4] which were last published specific to mothball bids for the 2019/2020 delivery year capacity auction.[5] The ACR indicates the default estimated fixed cost that would be avoided when a unit is taken out of service, where a price level below this threshold would warrant shutdown. Although these estimates are for PJM region applications, they also serve as an indication more broadly. The ACR for retirement of industrial frame combustion turbine machines was shown to be \$42/MW-day, and for mothball was shown to be \$31/MW-day. This demonstrates that mothballing is not costless and has an implied \$11/MW-day (\$4/kW-yr) cost. For coal unit applications, this incremental cost for mothball is \$26/MW-day (\$10/kW-yr). Mothball shutdowns of actual facilities can also provide an indication of costs. First Energy's subsidiary Mon Power estimated for the Pleasants coal plant in West Virginia the

[3] Liberty understands the term 'mothball' to mean effectively stopping operations and market participation of the unit indefinitely, although retaining readiness to restart operations again if needed.
[4] ACR is a market power mitigation mechanism which represents the PJM capacity auction offer or revenue level below which a unit would be uneconomic and seeking deactivation.
[5] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2019-2020-default-avoidable-cost-rates.ashx

costs to keep the facility in a non-operating but ready state to be $36 million per year, or $28/kW-yr for 1,300 MW.[6]

(C). Model for low, medium, and high participation scenario of commercial and industrial customers electing to participate in demand response activities based on the introduction of a third-party(s) ARC within its footprint and provide an analysis on what the impact of said ARC would have on Liberty's IRP.

This SCI seems to be related to FERC Order No. 2222, with a proposed implementation date around 2026 and FERC Order No. 719 implemented in 2008. The main goal of Order No. 2222 is to better enable distributed energy resources ("DERs") to participate in the electricity markets run by regional grid operators, while the main goal of Order No. 719 is to improve the operation of organized wholesale electric markets in four distinct areas, including demand response. According to the FERC website, Order No. 2222 is seeking to facilitate participation and competition in any of the Regional Transmission Organization ("RTO") markets as long as qualifications are met. DER aggregations would have the opportunity to earn the same compensation as other types of resources that participate in RTO markets, such as power plants. In order to enable many small DERs to participate in electricity markets that have a lot of rules and requirements, FERC is reducing barriers to the participation of aggregations of DERs. Individually, small DERs might not be large enough to participate in regional electricity markets. Grid operators need aggregations to be of a sufficient size in order to efficiently manage the market and the electric grid and not overburden their systems. When combined into an aggregation, the output and activity of several or many DERs can satisfy minimum size and performance requirements for participation established by the RTO. According to the FERC website, Order No. 719 was intended to improve the operation of organized wholesale electric markets in areas of

- demand response and market pricing during periods of operating reserve shortage;

[6] https://wvpublic.org/psc-approves-proposal-to-keep-pleasants-power-station-from-closing/

- long-term power contracting;
- market-monitoring policies; and
- the responsiveness of RTOs and independent system operators (ISOs) to their customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services.

This was an SCI that the Company addressed last year in its 2023 IRP Annual Update. Like last year, the Company is preparing an annual update and not a triennial filing while addressing this SCI and will therefore respond similar to last year within the scope of an IRP annual update.

At the onset of Liberty's evaluation of various demand response technologies during the last triennial IRP, FERC order 2222 had not existed or materialized at various public engagements with FERC. However, Liberty pre-emptively considered the impacts of aggregation DERs on its transmission and distribution networks as supplemental to FERC order 2222.

In anticipation of FERC order 2222, Liberty considered establishing fiber-optic networks which could also be used in the real-time system awareness and aggregation efforts for DERs. In doing so, Liberty would be poised for implementation to comply with plans set forth by the RTO. Integration of DERs along with new innovative technologies should yield a more robust electrical network to serve Liberty's customers and a more fluid implementation of near-term regulatory requirements. These resources require time-variant pricing. Accordingly, they require the availability of detailed participant billing determinants at the hourly or sub-hourly level of granularity, which can be addressed with two-way Advanced Metering Infrastructure ("AMI"). Liberty implemented two-way AMI across its service territory.

As part of the 2022 IPR process, Liberty engaged AEG to conduct a DSM Potential Study in the Company's service territory and develop DSM program inputs, including for demand response. AEG evaluated demand response measures and included several as candidate demand-side resources for residential and commercial applications as a part of the Realistic Achievable Potential ("RAP") and Maximum Achievable Potential ("MAP") cases (described in the 2022 IRP technical Volume 5 – Demand-Side Resource Analysis). Within the RAP and MAP scenarios, AEG bundled

DSM programs together based on the cost of the programs (low, mid, and high-cost energy efficiency bundles, plus a DR and demand side rates bundle) for use in the integrated portfolio analysis. Although not explicitly representing aggregated resources, these bundles were evaluated against avoided cost levels aligned with those expected for the broader power market. The DSM bundles were also incorporated into the IRP as eligible resources in the portfolio optimization analysis along with supply-side resources in the alternative plan development stage. The demand response programs were not selected as a part of the Preferred Plan. A summary of the demand response programs used in the integrated analysis is presented below in Table 7.5.

Table 7.5 – Description of Demand Response Programs in 2022 IRP DSM Bundles

Program Bundle	Description
RAP	DR and DSR programs. Includes: - Time of Use Rate (Res & Non-Res) - Critical Peak Pricing (Res & Non-Res) - DLC Smart Thermostat - Real Time Pricing
MAP	DR and DSR programs. Includes: - Time of Use Rate (Res & Non-Res) - Critical Peak Pricing (Res & Non-Res) - DLC Smart Thermostat - Real Time Pricing

Liberty will continue to monitor regulatory developments and consider aggregation of demand response resource options for its planning activities.

(D). Describe the inclusion of Virtual Power Plants (“VPPs”) within the Company’s IRP update or triennial analysis. In doing so, identify which distributed energy resources (“DER”) or complement of DERs were included in the analysis, consider both the retail VPP and market-participant VPP perspectives, and explain the benefits and challenges related to scalability attributed of VPPs. Address VPP contributions to the utility’s resource adequacy requirements, grid stability, resiliency, transmission and distribution capacity deferrals, load management

strategies, and system optimization. Discuss limitations, if any, to incorporating VPPs in the Company's distribution or resource planning analysis due to challenges of aggregating and dispatching retail and market-participants' DERs.

Deployment of VPPs could help address increasing demand, potentially at lower cost than conventional resources, reducing energy costs for customers.

Although Liberty's analysis did not explicitly include formalized VPP systems as part of its 2022 IRP, it did include the key building blocks of VPP's such as distributed generation and storage resources and energy efficiency programs. Generation distributed energy resources ("DERs") like reciprocating engines ("RICE") and solar were evaluated in the IRP, and 4-hour lithium-ion battery storage was also evaluated as a DER option.

In order to evaluate energy efficiency in the 2022 IRP, Liberty engaged AEG to conduct a demand side management ("DSM") Potential Study in the Company's service territory and develop DSM program inputs for the IRP analysis. AEG utilized load management analysis, among other tools, to perform these studies, which resulted in two levels of achievable potential for energy savings associated with DSM programs: realistic achievable potential ("RAP") and maximum achievable potential ("MAP"). Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. MAP is defined as the maximum amount of savings that can be realized under ideal market, implementation, and customer preference conditions, and has higher incentives than RAP due to higher program participation. RAP reflects expected program participation given barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets.

Within the RAP and MAP scenarios, AEG bundled DSM programs together based on the $/kWh cost of the programs (low, mid, and high-cost energy efficiency bundles plus a demand side rate bundle) for use in the integrated portfolio analysis. These DSM bundles were incorporated into the IRP as eligible resources in the portfolio optimization analysis along with supply-side resources in the alternative plan development stage. A summary of the demand-side program bundles used in the integrated analysis is presented below in Table 7.6.

Table 7.6 – Description of DSM 2022 IRP Bundles

DSM	Program Bundle	Description
RAP	Low Cost	Programs with a three-year average $/kWh saved below $0.18 per kWh. Includes: - Retail Lighting - Residential Behavioral - Commercial Custom - SEM - Retrocommissioning
	Mid Cost	Programs with a three-year average $/kWh saved between $0.18 to $0.25 per kWh. Includes: - Residential Prescriptive - Appliance Recycling - Commercial Prescriptive - Midstream Food Service
	High Cost	Programs with a three-year average $/kWh saved above $0.25 per kWh. Includes: - Whole Home Efficiency - SBDI
	Demand Side Rates (“DSR”)	DR and DSR programs. Includes: - Time of Use Rate (Res & Non-Res) - Critical Peak Pricing (Res & Non-Res) - DLC Smart Thermostat - Real Time Pricing
MAP	Low Cost	Programs with a three-year average $/kWh saved below $0.18 per kWh. Includes: - Retail Lighting - Residential Behavioral - Commercial Custom - SEM - Retrocommissioning
	Mid Cost	Programs with a three-year average $/kWh saved between $0.18 to $0.25 per kWh. Includes: - Residential Prescriptive - Appliance Recycling - Commercial Prescriptive - Midstream Food Service
	High Cost	Programs with a three-year average $/kWh saved above $0.25 per kWh. Includes: - Whole Home Efficiency - SBDI
	Demand Side Rates (“DSR”)	DR and DSR programs. Includes: - Time of Use Rate (Res & Non-Res) - Critical Peak Pricing (Res & Non-Res) - DLC Smart Thermostat - Real Time Pricing

The preferred plan includes 110 MW of distributed solar, 12 MW of solar + storage hybrid systems in 2:1 configuration, and 1 MW of distributed storage. The plan also adds the low-cost bundle of RAP DSM which has a maximum peak demand savings of 15 MW in the late 2020's.

Liberty believes there is value in investing in some level of distributed resources from an energy security and reliability perspective: distributed resources can help improve local reliability, prevent blackouts and outages, avoid distribution system investment, and improve energy security in the event of large-scale disruptions at the transmission level. Distributed resources also have the benefit of less locational concentration, as they are smaller in scale and more widely dispersed, which diversifies outage risk and further contributes to grid stability and resilience. More advanced applications of distributed resources could also provide grid islanding and isolation during bulk system outages. Furthermore, distributed resources have the benefit of enabling the deferral of needed distribution system upgrades, which Liberty accounted for in the IRP. They may also provide benefits associated with compliance of distributed resource programs and FERC Order 2222 implementation.

Liberty analyzed demand-side and supply-side generation and storage resources on an equivalent basis with other options for meeting load requirements. For portfolio resource adequacy modeling in the IRP, the capacity of the generation and storage resources is de-rated to account for forced outages and guidance on proposed SPP accreditation, representing the amount of capacity that is "firm" or available to operate during peak hours on a probabilistic basis. Capacity accreditation of these distributed resources contributes to resource adequacy on an equivalent basis to larger grid-scale resources of the same type. For market participation, distributed RICE, solar, and storage were modeled to be small-scale assets to sell energy to the broader SPP market and hence respond to market pricing. This implies positioning of the assets near load (i.e., community solar), although not behind-the-meter at the load site.

Energy efficiency resources did not include consideration of RTO treatment at this time, although their assumed energy and peak savings implicitly provides avoided energy and capacity value to the Liberty portfolio. Liberty's RTO does not currently have a market for demand-side resources. In the absence of a market and market rules, there is no firm basis for estimating additional value of these resources at the RTO level. Moreover, these resources may require time-variant pricing and accordingly require the availability of detailed participant billing determinants at the hourly or sub-hourly level of granularity, which can be addressed with two-way Advanced Metering Infrastructure ("AMI"). Liberty implemented two-way AMI across its service territory.

At the onset of Liberty's evaluation of various demand response technologies, FERC Order 2222 had not been in place. However, Liberty pre-emptively considered the impacts of aggregation of Distributed Energy Resources ("DERs") on its transmission and distribution networks as supplemental to FERC Order 2222. In anticipation of FERC Order 2222, Liberty considered establishing fiber-optic networks which could also be used in the real-time system awareness and aggregation efforts for DERs. In doing so, Liberty would be poised for implementation to comply with plans set forth by the Regional Transmission Organization ("RTO"). Integration of DERs along with new innovative technologies should yield a more robust electrical network to serve Liberty's customers and a more fluid implementation of near-term regulatory requirements.

(E). In light of emerging developments around Distributed Energy Resources (DER) and VPPs, address what efforts the Company made in its IRP modeling to address distribution planning opportunities and challenges.

Positioning a distributed energy resource in an area with historically high congestion or delivery costs could yield benefits to Liberty's system and customers by way of injection at the load site as opposed to the transmission of energy across various delivery systems. While determining the exact value of such benefits is complex, it can be estimated by quantifying the ability of distributed energy resources to defer certain distribution system upgrade costs.

To assess the value of distributed energy resources, such as distributed solar and distributed storage (paired or unpaired), Liberty identified a set of planned and/or representative distribution upgrade projects that could be deferred if transformer current was reduced. Assuming that distributed solar and storage resources can be placed at specific sites on the distribution grid to avoid system upgrades, Liberty incorporated the value of these representative upgrade projects as offsets to the capital and fixed costs of distributed solar and storage resources.

At the onset of Liberty's evaluation of various Advanced Transmission and Distribution Network Technologies ("ATDNT"), FERC Order 2222 had not existed nor materialized at various public engagements with FERC. Liberty could not foresee Order 2222's potential impacts to their respective system. However, preemptive evaluations/implementations of ATDNT will function as supplementation to Order 2222, whereby varying technologies will enable the facilitation of energy aggregation which could potentially alter the trajectory of a resource strategy but will aide in bringing to market potential renewable energy resources. As the prescriptive requirements are delineated by the RTO, Liberty will gain a better understanding as to the positive traction gained by their presently evaluated ATDNT technologies.

An immediate benefit brought by the ATDNT under consideration and practice on the Liberty system point to the facilitation of AMI. Meters were installed on the system and the data collection efforts will hinge on the communications platforms associated with several technologies: Optical Ground Wire ("OPGW"), Dielectric Self-supporting ("ADSS"), Fiber Optic Substation Network, and Substation Data Archive, Server and Database. Rollout of these technologies allows for bidirectional communications between the utility and the customers. AMI paired with the communications platforms allow for higher penetration of DSM due to real-time awareness for either entity and will encourage focused investment efforts for needed infrastructure improvements/postponements accordingly. Liberty looks forward to the near-term horizon for utilizing both the technologies of present interest and the yet to be vetted technologies to further enhance AMI applications.

Liberty places section 22.045 compliance into a context of long-term ATDNT aspirations while also determining any specific nexus of ATDNT to supply and/or demand-side resource choices (involving the identification of associated costs, benefits, and other assumptions). Part of this context setting involves explaining its progress on several areas of ATDNT piloting and implementation described in its 2019 IRP.

In its recent IRPs, Liberty described the role of advanced technologies on its system, including but not limited to microprocessor relaying, fiber optic relaying and communications, transformer oil dissolved gas monitoring ("DGM"), transformer bushing monitoring, transformer bushing monitoring with partial discharge, transformer fiber optic winding temperature sensors, transformer monitoring, comprehensive transformer health monitoring, fiber optic substation data network, substation data archive, server, and database, 69-kV vacuum circuit breakers. Also discussed were automatic throw-over switching schemes, dynamic voltage control, conservation voltage reduction, energy storage, communications, Liberty's Operation Toughen Up ("OTU"), a feeder automation demonstration, expanded recloser utilization, an advanced fusing study, event analysis activities, and inspection of load profile data.

In the context of the 2022 IRP, many of these efforts form an activity baseline that continues indefinitely, reflects sound engineering practice, comports with current and emerging standards, stays aligned with vendor innovation, applies advanced asset management techniques, stays true to fundamental functional and technology dependencies (such as Supervisory Control and Data Acquisition ("SCADA") communications), and proceeds prudently in recognition of core grid functions (i.e. safety, security, reliability, resiliency, capacity, and contingency). For example, Liberty expects that it will continue to apply advanced network technology such as OPGW, ADSS, microprocessor relaying for protection, automatic throw-over switching schemes on the 69-kV system, use of smart fuses and reclosers, OTU will continue to harden the system, and SCADA communications will continue to enable more grid functions. Increase of communication platforms allow for future implementation of real-time system awareness and auto-healing networks, which will increase the penetration efforts of DSM as well as DER potentiality.

(F). Consider discussing storage deployment strategies, including the repurposing of retired automotive batteries, exemplified by the Tesla Pilot program in Australia. Additionally, explore investments in energy storage pilot programs with the specific objective of enhancing the reliability and capacity accreditation of renewable energy resources.

As a part of the candidate resources available for portfolio construction in the 2022 IRP, Liberty shortlisted paired solar and storage systems, where the storage component is intended to firm and balance the output of the solar component, resulting in more effective dispatchability and enhanced capacity accreditation of solar output. For these systems, Liberty has assumed single axis tracking solar and lithium-ion batteries with a combined capital cost based on both a 4:1 ratio and a 2:1 ratio of solar to storage at the utility scale and a 2:1 ratio of solar to storage at the distributed scale due to the need to manage Liberty's winter peak.

Liberty also considered how storage deployment can play a role in maximizing interconnection value by placing paired solar + storage systems at existing wind sites – Neosho Ridge, North Fork Ridge, and Kings Point. These sites host a combined 600 MW of installed wind and interconnection capacity over a sizable land footprint. With an average capacity factor of 45-50%, the interconnection at these wind sites sits idle with spare capacity for more than half of the time, which provides an opportunity to avoid costs of new interconnection by locating solar capacity at these sites paired with complementary storage capacity to minimize curtailment when total output exceeds interconnection capacity. This arrangement also has the potential to increase capacity accreditation achieved through the wind site interconnection.

To determine the amount of solar and/or paired storage resources that could be co-located at the existing wind sites of Neosho Ridge, North Fork Ridge, and Kings Point, CRA developed an optimization model that considered as inputs the expected 8760 wind generation profile at each site, the expected 8760 solar generation profile, key operational parameters for a storage asset (e.g., duration, efficiency, etc.), the capital costs to build and operate the new solar and storage assets, the value of capacity of the new solar and storage assets, and the hourly market power price defining the value of the generation. For each wind site, the optimization model evaluated the optimal installed MW amount of solar and storage that could be co-located at the site, defined as the combined amount of solar and storage that, in conjunction with output from the wind resource, would maximize the value of the site over the 30-year life of the project. The model limited wind and solar curtailment such that the NPV of the lost value of curtailed energy over the 30-year life of the project was below $225/kW (i.e., the cost of interconnecting a resource at a greenfield site). To understand how the value of these resources might change over time, CRA developed outputs for all sites for a scenario where resources were installed in 2025 and for a scenario where resources were installed in 2035.

In regard to automotive battery repurposing for power system usage, Liberty understands this application although recognizes its associated challenges. Automotive battery repurposing can refer to grid storage services provided by either vehicle-to-grid applications from current use electric vehicles while plugged-in, or from the batteries of decommissioned vehicles repackaged for grid duty. In either case, the idea is that an EV battery can provide the same functionality as a purpose-built grid application battery, hence avoiding the full cost of the new purpose-built facility. For vehicle-to-grid applications, protocols for dispatch communication with the system operator have not been deployed to fully enable this functionality in Liberty and SPP territory. Moreover, for existing vehicle applications, economic mechanisms would be required to compensate the vehicle owner for any incremental cycling wear resulting from dispatch instruction to serve the grid. For decommissioned vehicle battery applications, challenges arise with inconsistent and compromised performance of the battery cells due to lifetime wear during vehicle usage, and limited availability of decommissioned vehicles from which to source the batteries.

Repurposing old batteries from electric vehicles in alternative energy storage applications – like at fast-charging stations or rooftop and microgrid storage systems – is one of the ways to extend EV battery lifespans and electrify the transportation sector in a more sustainable manner. Although large-scale utility grid projects employing retired EV batteries are in early stages, substantial progress has been achieved in smaller-scale storage applications. These advancements affirm the viability of repurposing retired EV batteries and foreshadow potential expansion into larger-scale grid integration. Companies like Australian firm Infinitev demonstrate the potential by repurposing old Nissan Leaf batteries for localized applications, powering small-to-medium warehouses, or supporting industrial facilities as backup power sources. Additionally, Nissan Australia's plan to partially power EV component production at the Nissan Casting Australia Plant (“NCAP”) using Leaf batteries showcases a novel industrial application, highlighting the versatility of this technology in various sectors.

As the technology matures, efforts by companies like Smartville Inc and Cactos illustrate the progression towards scaled-up utility grid storage. Smartville's MOAB product, powered by repurposed Tesla and Nissan Leaf battery packs, represents an early step in this direction, with installations like the one at UC San Diego library annex serving as pilot projects. Supported by a $6 million grant from the Department of Energy, Smartville is poised to further develop its enclosure system for second-life energy storage systems, laying the groundwork for larger-scale deployments.

Similarly, Cactos, having raised significant funding, is focused on commercializing its behind-the-meter Energy Storage System ("ESS") product, utilizing repurposed Tesla EV batteries sourced from a recycling company in Norway. Their strategy of supplementing second-life systems with new batteries indicates a shift towards more extensive grid-level storage solutions to meet growing demand. As both Smartville Inc and Cactos scale up their production capacities, they pave the way for broader integration of repurposed automotive batteries into utility grid service, addressing grid stabilization and energy storage challenges at a larger scale.

Liberty will continue to monitor developments in this space and consider repurposed vehicle batteries in future planning.