BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	Docket No. 23-06007
Application of Nevada Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric and common accounts.	Docket No. 23-06008

At a general session of the Public Utilities Commission of Nevada, held at its offices on February 13, 2024.

PRESENT: Chair Hayley Williamson
Commissioner Tammy Cordova
Commissioner Randy J. Brown
Assistant Commission Secretary Trisha Osborne

MODIFIED FINAL ORDER

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The Public Utilities Commission of Nevada ("Commission") makes the following findings and conclusions:

I. INTRODUCTION

On June 5, 2023, Nevada Power Company d/b/a NV Energy ("NPC") filed with the Commission an application, designated as Docket No. 23-06007, for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

On June 5, 2023, NPC filed with the Commission an application, designated as Docket No. 23-06008 (together with the application in Docket No. 23-06007, the "Applications"), for approval of new and revised depreciation and amortization rates for its electric and common accounts.

II. SUMMARY

The Commission grants in part NPC's Applications as modified by this Order.

III. PROCEDURAL HISTORY

- On June 5, 2023, NPC filed the Applications.

- NPC filed the Applications pursuant to the Nevada Revised Statues ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to, NRS 704.100, NRS 704.110, NAC 703.2201 through 703.2481, NAC 703.2715 through 703.278, NAC 703.535, NAC 704.6502 through NAC 704.6546, NAC 704.655 through NAC 704.665, and NAC 704.673. Pursuant to NRS 703.196 and NAC 703.527 et seq., NPC requests that certain material receive confidential treatment.

- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.

- On June 9, 2023, the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS in Docket Nos. 23-06007 and 23-06008.

- On June 20, 2023, the Commission issued a Notice of Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and Notice of Prehearing Conference in Docket No. 23-06007 and the Commission issued a Notice of Application for Approval of New and Revised Depreciation and Amortization Rates and Notice of Prehearing Conference in Docket No. 23-06008.

- On June 20, 2023, NPC filed corrected testimony and workpapers in Docket No. 23-06007.

- On June 28, 2023, Nevada Cogeneration Associates #1 and #2 ("NCA") filed a Petition for

Leave to Intervene ("PLTI") in Docket No. 23-06007 ("NCA's PLTI").

- On June 29, 2023, Nevada Workers for Clean and Affordable Energy ("Nevada Workers") filed a PLTI in Docket No. 23-06007 ("Nevada Workers' PLTI").

- On June 30, 2023, Western Resource Advocates ("WRA") and the Southwest Energy Efficiency Project ("SWEEP") (collectively, the "Conservation Advocates") filed a PLTI in Docket No. 23-06007 ("Conservation Advocates' PLTI").

- On July 5, 2023, Walmart Inc. ("Walmart"), Google LLC ("Google"), the Southern Nevada Water Authority ("SNWA"), Caesars Enterprise Services, LLC ("Caesars"), Wynn Las Vegas, LLC ("Wynn"), Smart Energy Alliance ("SEA"), Circus Circus Las Vegas, LLC ("CCLV"), HR Nevada, LLC ("The Mirage," together with Wynn, SEA, and CCLV, "Joint Petitioners"), MGM Resorts International ("MGM"), Boyd Gaming Corporation ("Boyd"), Station Casinos LLC ("Station"), and Venetian Las Vegas Gaming, LLC ("Venetian," together with Boyd and Station, "Southern Nevada Gaming Group" or "SNGG") filed PLTIs in Docket No. 23-06007. Also on July 5, 2023, Joint Petitioners and SNGG filed PLTIs in Docket No. 23-06008 (individually, "Walmart's PLTI," "Google's PLTI," "SNWA's PLTI," "Caesars' PLTI," "Joint Petitioners' PLTI," "MGM's PLTI," "Boyd's PLTI," and "SNGG's PLTI(s)").

- On July 7, 2023, NPC filed a response to the Conservation Advocates' PLTI in Docket No. 23-06007.

- On July 10, 2023, the Conservation Advocates filed a Reply in Docket No. 23-06007 ("Conservation Advocates' Reply").

- On July 10, 2023, the Presiding Officer held prehearing conferences in Docket Nos. 23-06007 and 23-06008. NPC, Staff, BCP, NCA, Nevada Workers, the Conservation Advocates, Walmart, Google, SNWA, MGM, Joint Petitioners, SNGG, Caesars, and The Kroger Co. ("Kroger") made appearances and discussed a procedural schedule, PLTIs, consolidating dockets, discovery procedures, and a consumer session.

- On July 12, 2023, Kroger filed a late-filed PLTI in Docket No. 23-06007 ("Kroger's PLTI"). On that same day, the Commission issued a Notice of Consumer Session.

- On July 20, 2023, the Commission issued a Notice of Hearing.

- On July 21, 2023, Southern Nevada Home Builders Association ("SNHBA") filed a late-filed PLTI ("SNHBA's PLTI") in Docket No. 23-06007.

- On July 26, 2023, the Presiding Officer issued a Procedural Order consolidating Docket Nos. 23-06007 and 23-06008 for hearing purposes; establishing that the hearings in these dockets would occur in three phases: (1) Cost of Capital; (2) Depreciation/Revenue Requirement; and (3) Rate Design; and adopting a procedural schedule and discovery process.

- On August 4, 2023, the Federal Executive Agencies ("FEA") filed a late-filed PLTI Docket

No. 23-06007 and Docket No. 23-06008 ("FEA's PLTI(s)"). Also on this day, NPC filed its cost of capital certification filing.

- On August 14, 2023, the Commission issued an order granting the PLTIs of NCA, Nevada Workers, WRA, Walmart, Google, SNWA, Caesars, Joint Petitioners, MGM, SNGG, Kroger, SNHBA, and FEA in Docket No. 23-06007 and granting the PLTIs of Joint Petitioners, SNGG, and FEA in Docket No. 23-06008.

- On August 21, 2023, NPC filed its revenue requirement certification filing. Also on this day, NPC filed an errata to its Applications.

- On September 1, 2023, NPC filed its rate design certification filing. Also on this day, Staff, Google, Walmart, Joint Petitioners, Caesars, SNWA, MGM, FEA, and the BCP filed testimony.

- On September 5, 2023, the Presiding Officer held a prehearing conference. At the prehearing conference, the parties' attendance was excused and the prehearing conference was continued.

- On September 7, 2023, NPC filed an errata to its revenue requirement certification filing.

- On September 13, 2023, the Commission held two consumer sessions. On that same day, Moms Clean Air Force, Make the Road Nevada, and CHISPA Nevada filed comments.

- On September 14, 2023, the Faith Organizing Alliance filed comments.

- On September 18, 2023, NPC filed rebuttal testimony.

- On September 25, 2023, Staff, Joint Petitioners, SNGG, BCP, and FEA filed testimony. On that same day, the Presiding Officer issued Procedural Order No. 2, adopting hearing procedures for the cost of capital hearing.

- On September 26, 2023, Staff filed corrected testimony.

- On October 2, 2023, the Commission held a hearing on the cost of capital phase. NPC, Staff, BCP, Nevada Workers, Conservation Advocates, Walmart, Google, SNWA, Caesars, MGM, Joint Petitioners, SNGG, Kroger, SNHBA, and FEA made appearances.

- On October 6, 2023, Staff, Caesars, MGM, SNWA, Conservation Advocates, Joint Petitioners, Walmart, Google, Kroger, and BCP filed testimony.

- On October 9, 2023, Staff, Joint Petitioners, BCP, MGM, Caesars, SNWA, and SNGG filed legal briefs. On that same day, NPC filed rebuttal testimony.

- On October 10, 2023, the Presiding Officer issued Procedural Order No. 3, establishing hearing procedures for the revenue requirement and depreciation phase.

- On October 12, 2023, Staff, NPC, and BCP filed workpapers.
- On October 16, 2023, NPC filed a reply legal brief.
- On October 19, 2023, Staff filed a motion ("Staff's Motion") to strike certain portions of NPC's rebuttal testimony.
- On October 20, 2023, NPC filed workpapers and rebuttal testimony.
- On October 23, 2023, the Commission held a hearing on the revenue requirement and depreciation phase. NPC, Staff, BCP, SNWA, Caesars, MGM, Joint Petitioners, SNGG, Kroger, SNHBA, and FEA made appearances.
- On October 24, 2023, NPC filed a response ("NPC's Response") to Staff's Motion.
- On October 26, 2023, the Presiding Officer issued Procedural Order No. 4, establishing a procedural schedule and discovery process. On that same day, NPC filed a late-filed exhibit.
- On October 30, 2023, NPC filed an errata to its Applications. On that same day, the Presiding Officer issued Procedural Order No. 5, establishing hearing procedures for the rate design hearing.
- On November 3, 2023, Staff filed corrected testimony and workpapers.
- On November 6, 2023, the Commission held a hearing on the rate design phase. NPC, Staff, BCP, NCA, Conservation Advocates, Walmart, Google, SNWA, Caesars, MGM, Joint Petitioners, SNGG, Kroger, SNHBA, and FEA made appearances. On that same day, Staff filed a reply ("Staff's Reply") to NPC's Response. Also on that same day, Staff, BCP, MGM, Caesars, SNWA, Joint Petitioners, and SNGG filed legal briefs.
- On November 8, 2023, NPC filed a late-filed exhibit.
- On November 15, 2023, NPC filed a reply legal brief.

IV. COST OF CAPITAL

NPC's Position

1. NPC requests an increase in its authorized rate of return ("ROR") from the current rate of 7.14% to a proposed rate of 7.79% based on the cost of debt, cost of equity, and capital structure. (Ex. 101 at 5.) In its Applications, NPC requests an increase in its return on equity ("ROE") from 9.4% to 10.2% and a capital structure of 46.7% debt and 53.3.9% equity. (*Id.*) Through its Certification filing, NPC requests that the Commission establish an ROR reflecting

its May 31, 2023, capital structure of 45.76% debt and 54.24% equity, a weighted average cost of debt of 5.12%, and an authorized ROE of 10.20% -- resulting in an ROR equal to 7.88%. (Ex. 112 at 64.)

2. NPC requests a ROE of 10.20%. (Ex. 127 at 8.) NPC states that, to arrive at its requested ROE, it applied several traditional estimation methodologies to a proxy group of comparable utilities, including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Bond Yield Risk Premium ("BYRP" or "Risk Premium"). (*Id.* at 2.)

3. The results of NPC's analyses are summarized in the following table:

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Constant Growth DCF - Mean			
	Mean Low	**Mean**	**Mean High**
30-Day Average	8.54%	9.82%	10.90%
90-Day Average	8.48%	9.75%	10.83%
180-Day Average	8.48%	9.75%	10.83%
Constant Growth Average	8.50%	9.77%	10.85%
Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	9.12%	9.62%	10.09%
90-Day Average	9.02%	9.53%	10.03%
180-Day Average	8.93%	9.49%	10.02%
Constant Growth Average	9.02%	9.55%	10.05%
CAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.06%	11.06%	11.07%
Bloomberg Beta	10.48%	10.47%	10.50%
Long-term Avg. Beta	10.07%	10.06%	10.09%
ECAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.33%	11.32%	11.33%
Bloomberg Beta	10.89%	10.88%	10.90%
Long-term Avg. Beta	10.58%	10.57%	10.60%
Risk Premium			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Risk Premium Results	10.27%	10.26%	10.31%

(Ex. 127 at Bulkley Exhibit AEB-2.)

4. NPC provides that current and projected conditions in capital markets have had an effect on investors' return requirements and the cost of equity. (*Id.* at 5.) NPC states that authorized ROEs for vertically-integrated utilities have increased in an environment with rising interest rates and inflation. (*Id.*) NPC notes that increasing inflation will increase the operating risk of NPC during the period in which rates are to be in effect. (*Id.* at 6.) NPC argues that utility

dividend yields are less attractive than the risk-free rates of government bonds, which has resulted in a decline in utility share prices, which in turn indicates that investors are demanding higher returns for holding utility stocks. (*Id.*) Because of the current and projected conditions in the capital markets, NPC argues that the results of the DCF model, which relies on current utility share prices, is likely to understate the cost of equity during the period that NPC's rates will be in effect. (*Id.*)

Google's Position

5. Google argues that no increase in NPC's ROE should be permitted based on increased deferred energy balances. (Ex. 500 at 3.)

6. Google offers that NPC's Base Tariff Energy Rate ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") fuel adjustment mechanism does not protect ratepayers from excessive risk and further does not incentivize NPC to reduce such risks. (*Id.*)

7. Google states that NPC is pointing to increased deferred energy balances, particularly deferred fuel and purchased power ("F&PP") costs, as the justification for the proposed increase in ROE. (*Id.* at 4.) Google rejects the notion that increased F&PP costs justifies an increase in NPC's ROE. (*Id.* at 6.) Instead, while Google does not dispute that increased F&PP costs have had an impact on NPC's liquidity, Google reasons that this is a result of NPC's own making. (*Id.*) Google points out that NPC's resource portfolio is predominantly gas-fired and that natural gas prices are notoriously volatile. (*Id.*) Google provides that NPC could reduce its exposure to the risks posed by natural-gas-fired generation; however, NPC instead continues to invest in, and prolong the operation of, carbon-based resources as evidenced by its recent choices to build the 400-megawatt ("MW") Silverhawk combustion turbines, extend

the retirement dates of most of its gas-fired generation fleet, and to propose 261 MW or 440 MW of new gas-fired generation at the Valmy location. (*Id.* at 6-7.)

8. Google argues that the Commission should balance the interests of the utility and its customers in the determination of the ROE. (*Id.* at 10.) Google provides that, in the case of fuel cost recovery, customers bear far greater risk than the utility. (*Id.*) Google states that, while increased fuel costs result in deferred recovery (with interest) for NPC, NPC's customers must pay for 100% of NPC's natural gas costs. (*Id.*) Thus, Google concludes that an increase in ROE would benefit the NPC's shareholders but ignores the harm caused to customers as a result of NPC's risky resource decisions. (*Id.*)

9. Google provides that, in 2022, approximately 75% of NPC's electric generation was produced using natural gas. (*Id.* at 13.) Google states that this lack of diversification exposes both NPC and its customers to excessive risk. (*Id.* at 14.) Further, Google argues that NPC's reliance on gas stands in stark contrast to the aims of the 2020 State Climate Strategy, which calls for a transition away from fossil-fuel electricity generation. (*Id.*)

10. Google provides that NPC recovers F&PP costs within months after they are incurred, earns interest on amounts that are deferred, and faces little or no risk of non-recovery. (*Id.* at 16.) Conversely, Google states that customers must pay F&PP costs within months after they are incurred, with interest, bearing the full force of NPC's fuel choice decisions. (*Id.*) Google goes on to argue that NPC has little incentive to reduce F&PP costs because reducing them does not benefit shareholders and instead disproportionally burdens customers with F&PP risk. (*Id.*) Google recommends that the Commission put in place an incentive mechanism to correct NPC's decision-making. (*Id.*) Google proposes that the mechanism exposes shareholders

to the risk of high F&PP costs and reward shareholders if NPC can reduce F&PP costs below a baseline amount. (*Id.*)

11. Google provides that participation in a regional organization such as the Western Resource Adequacy Program ("WRAP"), a day-ahead market, and a regional transmission organization ("RTO") will reduce NPC's risk with respect to F&PP. (*Id.* at 22.) Google explains that a day-ahead market and an RTO will allow the integration of new low-cost renewable resources into regionally integrated markets. (*Id.*) Google provides that regional integration pools diverse demand profiles, weather conditions, and generation technologies, reducing the risk of outages to any individual load-serving entity that will allow the reduction in reserve margins and the associated costs. (*Id.*) Google concludes that a day-ahead and ancillary services markets will result in more efficient unit operation with possible savings in the billions of dollars. (*Id.*)

12. Google notes that NPC is required under Nevada law to join a RTO by 2030; however, Google argues that joining a RTO before 2030 and/or taking immediate incremental action toward joining one would allow NPC and its customers to start benefiting from increased access to a more diverse set of resources earlier. (*Id.* at 23.)

Walmart's Position

13. Walmart argues that the Commission should thoroughly and carefully consider the impact on customers when examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in NPC's rates is the minimum necessary to provide safe, adequate, and reliable service while also providing NPC the opportunity to recover its reasonable and prudent costs and earn a reasonable return on its investment. (Ex. 1000 at 3-4.) Walmart recommends that the Commission closely examine

NPC's proposed revenue requirement and ROE increases in light of the customer impact of the resulting revenue requirement, recent rate case ROEs approved by the Commission, and recent rate case ROEs approved by other commissions nationwide. (*Id.* at 4.)

14. Walmart states that—if using NPC's proposed rate base, cost of debt, and capital structure—the impact of changing NPC's currently-approved ROE of 9.4% to NPC's proposed ROE of 10.2% is approximately $32.6 million. (*Id.* at 5-6.)

15. Walmart notes that the Commission has issued orders with stated ROEs in two dockets since 2020 with an average approved ROE of 9.48%. (*Id.* at 6.) Walmart states, therefore, that NPC's proposed 10.2% ROE is counter to recent Commission actions regarding ROE. (*Id.* at 7.)

16. Walmart notes that, according to S&P Global Market Intelligence, the average of the 121 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities in 2020, 2021, and so far in 2022, is 9.43%. (*Id.*) The range of reported authorized electric ROEs for the period is 7.36% to 10.6%, and the median authorized electric ROE is 9.5%. (*Id.*) Accordingly, Walmart reasons that NPC's proposal of an ROE of 10.2% is counter to broader electric industry trends. (*Id.*)

17. Walmart notes that authorized ROE for vertically-integrated utilities in 2020, 2021, and so far in 2022, is 9.58%, with the overall average generally falling from year to year. (*Id.* at 8.) Walmart therefore argues that NPC's proposed total ROE of 10.2% is counter to broader electric industry trends and would be among the highest approved ROEs since 2020. (*Id.*) Walmart notes that the difference in revenue requirement between the proposed 10.2% ROE and a 9.58% ROE is approximately $25.8 million. (*Id.* at 9.) Walmart states that, while decisions of other state regulatory commission are not binding on this Commission, recently-

authorized ROEs in other jurisdictions can provide a general gauge of reasonableness for the various cost-of-equity analyses presented in this case. (*Id.*)

FEA's Position

18. FEA provides the following rate-of-return analysis:

Rate of Return (May 31, 2023)				
Description	**Amount ($ 000)**	**Weight**	**Cost**	**Weighted Cost**
Long-Term Debt	$3,237,896	46.47%	5.09%	2.37%
Short-Term Debt	$100,000	1.44%	6.32%	0.09%
Customer Deposits	$55,505	0.80%	4.55%	0.04%
Common Equity	$3,574,568	51.30%	9.30%	4.77%
Total	$6,967,968	100%		7.26%

(Ex. 1400 at Exhibit-Gorman-Direct-2)

19. FEA recommends that the Commission award a return on common equity within a recommended range of 9.10% to 9.60%, with an approximate midpoint of 9.30%. (*Id.* at 5-6.) FEA's recommended return on equity produces an overall rate of return of 7.26% for NPC. (*Id.*)

20. FEA criticizes NPC's recommended return on equity because it seems to be based solely on changes in interest rates, without regard to the stark changes in investment risk in the current marketplace and without regard to the particular differences in how those market factors are affecting the investment risk of equity securities or stocks and bond investments. (*Id.* at 10.)

21. FEA argues that NPC's proposed ratemaking capital structure is inappropriate for ratemaking purposes because it includes an increased weight of common equity which is not needed and imposes an unreasonable and excessive cost on retail customers. (*Id.* at 30.)

22. FEA states that increasing the common equity ratio as proposed by the Company significantly increases the cost of service and should only be approved to the extent NPC can prove an increase in common equity ratio is needed to support its bond rating or financial integrity. (*Id.* at 31.)

23. FEA proposes a more balanced capital structure that reflects NPC's actual capital structure as of December 31, 2022, and closer aligns with the capital structure approved by the Commission in Docket Number 17-06003. (*Id.* at 34.) FEA provides that its proposed capital structure reflects a common equity ratio of 51.30%, which has been shown to support NPC's financial integrity and access to capital but at a more reasonable cost to customers than NPC's proposal. (*Id.* at 34.)

24. FEA notes that NPC's capital structure has greater common equity ratio in comparison to authorized rate-setting capital structures allowed for electric utilities over the last several years. (*Id.* at 37.)

Joint Petitioners, Caesars, MGM, and SNWA's Position

25. Joint Petitioners, Caesars, MGM, and SNWA recommend that the Commission adopt a 49.94% equity and 50.06% debt hypothetical capital structure, a 9.0% cost of equity, a 4.95% cost of debt, and a 6.97% weighted average cost of capital. (Ex. 900 at 1.)

26. Joint Petitioners, Caesars, MGM, and SNWA recommend a 9.0% cost of equity based on the application of the DCF model, the CAPM, and the ECAPM. Joint Petitioners, Caesars, MGM, and SNWA state that after updating NPC's model assumptions to reflect current data and modern finance literature, these models support a reasonable ROE range from 8.5% to 9.5%. (*Id.* at 2.) Joint Petitioners, Caesars, MGM, and SNWA recommend 9.0% as the authorized ROE because it is the midpoint of the reasonable range, and because NPC has a similar risk profile as the proxy group. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA state that the primary difference between NPC's approach to ROE and their approach to ROE is that their focus is on the ROE required by NPC to attract capital and NPC favors forecasts of expected returns. (*Id.* at 5.)

27. Joint Petitioners, Caesars, MGM, and SNWA state that NPC's models rely heavily on analyst forecasts from Value Line, Yahoo, and Zacks. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA provide that the use of analyst forecasts alone is not problematic but that NPC combines these forecasts in a manner that filters out a greater share of low forecasts, which exacerbates the bias inherent in analyst forecasts. (*Id.*) In addition to filtering out low forecasts, Joint Petitioners, Caesars, MGM, and SNWA state that NPC's projected "high" scenarios presumably represent the potential for market outcomes to exceed expectations. (*Id.* at 6.)

28. Joint Petitioners, Caesars, MGM, and SNWA's DCF models estimate an ROE range from 7.8% to 9.65%, their CAPM models estimate an ROE range from 7.96% to 8.98%, and their ECAPM models estimate an ROE range from 8.73% to 9.49%. (*Id.* at 6, 10, 19.) While Joint Petitioners, Caesars, MGM, and SNWA report ECAPM for informational purposes, they do not recommend giving the model's results material weight or consideration because it over-represents the risk of utility companies. (*Id.* at 20.)

29. Joint Petitioners, Caesars, MGM, and SNWA argue that the only market conditions that are relevant to evaluating cost of equity are those that are inputs to the ROE estimation models. (*Id.* at 21.) Outside of these, Joint Petitioners, Caesars, MGM, and SNWA state that NPC's arguments about the condition of the market are speculative and irrelevant, in that the arguments are not theoretically or empirically linked to the models used to estimate ROE. (*Id.*)

30. Joint Petitioners, Caesars, MGM, and SNWA state that NPC has not faced any difficulties in attracting capital and that NPC is not aware of any other utilities that have been unable to. (*Id.* at 21.) Joint Petitioners, Caesars, MGM, and SNWA provide that, not only has NPC been able to attract capital, but NPC is also seeking to increase its capital ratio above its

historic levels. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA state that this indicates an investor appetite for NPC's existing ROE. (*Id.*)

31. Joint Petitioners, Caesars, MGM, and SNWA provide that another factor indicating that NPC's ROE is excessive is that utilities are experiencing excessive market-to-book ratios. (*Id.* at 22.) Joint Petitioners, Caesars, MGM, SNWA state that if return on equity for the utility industry is sufficient but not excessive, the market-to-book ratio for the utility industry should be at or near one. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA explain that a market-to-book ratio above one indicates that return on equity exceeds that which is necessary for an investment of comparable risk. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA state that average market-to-book ratios have exceeded one since 1996 and are currently at their highest levels. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA state that this data indicates that the proxy group, on average, earns returns on equity substantially higher than necessary. (*Id.*)

32. Joint Petitioners, Caesars, MGM, and SNWA argue that NPC's effort to increase its equity ratio indicates the current ROE is excessive. (*Id.* at 23.) Joint Petitioners, Caesars, MGM, and SNWA also argue that NPC mistreated partial-requirements customers by using biased methodologies to unfairly shift costs to these customers. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA state that in NPC's recent application to update its 2021 Integrated Resource Plan, NPC specifically asks that $1.5 billion in new generation be company-owned, rather than be contracted through a third party. (*Id.*)

33. Joint Petitioners, Caesars, MGM, and SNWA recommend the use of a hypothetical capital structure with 49.94% common equity, 1.44% short-term debt, 0.80% customer deposits, and 47.83% long-term debt. (*Id.*) Joint Petitioners, Caesars, MGM, and

SNWA state that this structure is based on NPC's actual capital structure modified to reflect the issuance of $300 million in long-term debt in 2021 and $300 million in dividend distributions in 2021. (*Id.* at 29.) Joint Petitioners, Caesars, MGM, and SNWA state that this recommendation is based upon the observation that NV Energy has systematically increased its equity percentage since 2013, when Berkshire Hathaway Energy acquired both NPC and Sierra Pacific Power Company. (*Id.* at 29-30.)

34. Joint Petitioners, Caesars, MGM, and SNWA argue that a capital structure that is weighted at over 54% equity is unreasonable and not in line with other similarly situated utilities. (*Id.* at 35.) Joint Petitioners, Caesars, MGM, and SNWA state that the average authorized equity ratio for utilities ranged from 48.9% to 49.98% between 2017 and Q1 of 2021. (*Id.*) Furthermore, Joint Petitioners, Caesars, MGM, and SNWA also state that a 90-basis-point increase in four months is not reasonable. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA caution that such an increase only exacerbates the upward trend on equity levels for NV Energy's two utilities in Nevada. (*Id.*)

35. Joint Petitioners, Caesars, MGM, and SNWA point out that the Commission has the power to impute a hypothetical capital structure that is more reasonable, as was done in the 2022 General Rate Case for Sierra Pacific Power Company. (*Id.* at 36.) Joint Petitioners, Caesars, MGM, and SNWA explain that, in Docket 22-06014, at the request of Staff and other parties, the Commission issued an order imputing a hypothetical 52.4% equity ratio, notwithstanding the fact that the actual equity ratio was 54.76%. (*Id.*) Joint Petitioners, Caesars, MGM, and SNWA recommend the use of a hypothetical capital structure with 49.94% common equity, 1.44% short-term debt, 0.80% customer deposits, and 47.83% long-term debt. (*Id.*)

BCP's Position

36. BCP provides a summary of its ROE analyses in the following table:

Cost of Equity Estimates

Model	Range	Midpoint
DCF	9.28% - 9.48%	9.38%
Two-Stage DCF	9.26% - 9.56%	9.41%
CAPM	9.25% - 9.39%	9.32%
ECAPM	9.42% - 9.53%	9.48%
Model Average	9.30% - 9.49%	9.40%
Model Median	9.27% - 9.50%	9.40%
Bond Risk Premium	10.23% - 10.46%	10.35%

(Ex. 400 at 4.)

37. Based on these foregoing analyses, BCP recommends a 9.30% ROE in this case. (*Id.* at 4.) BCP explains, however, that if NPC's requested 54.24% equity capital structure is adopted, the ROE should be adjusted (reduced) for considerations of financial risks relative to the comparable risk of electric companies. (*Id.*) BCP states that when the 9.30% ROE recommendation is combined with BCP's proposed capital structure of 51.29% equity and 48.71% debt, it results in a recommended overall weighted average return on rate base investment of 7.264%, which is consistent with current market capital costs in the utility industry and consistent with just and reasonable rates for consumers. (*Id.* at 5-6.)

38. BCP states that risks for NPC are lower than the average electric operation given cost recovery through credit-supportive regulation and the support of Berkshire Hathaway ownership. (*Id.* at 34.)

39. BCP states that it agrees with NPC's selection of screening criteria for the comparable group analysis in this case and that it employs the same 17-company comparable group as NPC has identified. (*Id.* at 35-36.)

40. BCP states that in its constant growth DCF analysis, the comparable group mean and median results fall in a range of 9.28% - 9.48%, with about a 9.38% midpoint. (*Id.* at 42.) BCP states that it also conducted a two-stage non-constant-growth DCF analysis and found comparable group mean and median results indicating a cost of equity range of 9.26% to 9.56%, with a 9.41% midpoint. (*Id.* at 44.)

41. BCP states that it performed a bond yield equity risk premium analysis to evaluate the risk/return differential between the authorized electric utility ROE relative to 30-year U.S. Treasury bond yields for the period 1981 through 2022. (*Id.* at 45.) BCP states that the resulting risk premium range of results for electric utilities is 10.23% to 10.46%, with a midpoint of 10.35%. (*Id.* at 45-46.) BCP states that it performed CAPM analyses yielding an equity return range of 9.25% - 9.39%, with a 9.3% midpoint. (*Id.* at 49.) BCP states that it also performed ECAPM analyses yielding an equity return range of 9.43% - 9.53%, with a 9.48% midpoint. (*Id.*)

42. BCP states that it holds concerns regarding NPC's proposed capital structure. (*Id.* at 54.) BCP points out that NPC's proposed equity ratio reflects a substantial upward increase in equity capital, which was accomplished by suspending dividends in 2022 and equity infusions of approximately $400 million by its parent company. (*Id.* at 55.) BCP notes that this increased equity ratio alone will result in approximately $8.35 million of added profits to shareholders and cost consumers about $12.8 million in annual revenue requirements. (*Id.*) Accordingly, the BCP recommends that the Commission deny NPC's proposed equity ratio and maintain the 51.29% December 31, 2022, historical test-year end equity ratio in this case. (*Id.* at 56.) BCP provides that NPC's proposed equity ratio substantially exceeds the comparable group equity average while NPC's financial risk is less than the comparable group. (*Id.* at 59.)

43. Alternatively, BCP argues that, should the Commission accept NPC's proposed 54.24% equity ratio, the equity return should be reduced to address NPC's lower financial risk profile relative to the comparable-risk proxy group. (*Id.* at 58.)

44. BCP takes issue with NPC's DCF analyses. (*Id.* at 65.) Particularly, BCP argues that it is inappropriate for NPC to discard low-end DCF analysis results that do not support NPC's 10.2% ROE recommendation and that removing such results does not support a balanced ROE recommendation in this case. (*Id.*) BCP also criticizes NPC's CAPM and ECAPM models as producing results that are out of line with their DCF and Bond Yield Risk Premium models. (*Id.* at 67-68.)

Staff's Position

45. Staff recommends that the Commission accept a capital structure in which the ratio of total equity to total capital is 52.72% and total debt to total capital is 47.28%. (Ex. 300 at 1.) Staff recommends that the Commission accept NPC's cost of debt at 5.12%. (*Id.* at 1.) Staff recommends that the Commission adopt an allowed ROE of 9.55%, with a reasonable range of 9.30% - 9.90%, and the resulting ROR of 7.45%. (*Id.* at 1.)

46. Staff summarizes its recommendations in the following table:

	Fraction	Cost of Capital	ROR Contribution
Total Debt	47.28%	5.12%	2.42%
Common Equity	52.72%	9.55%	5.03%
All Capital Sources	**100.00%**		**7.45%**

(Ex. 300 at 2.)

47. Staff argues that there are two factors that appear to be artificially increasing NPC's capital structure. (*Id.* at 8.) First, Staff states that there is an incorrect assumption and resulting calculation regarding the exclusion of $201 million of long-term debt that NPC claims to be allocated to a project (Dry Lake Solar) outside of rate base from NPC's certified capital

structure. (*Id.* at 8.) Secondly, Staff states that NPC's capital structure seems to reflect somewhat unusual circumstances for NPC, as the capital structure at the end of the certification period reflects $400 million of equity contributions to NPC. (*Id.* at 8-11.) Staff also notes that NPC suspended dividend payments to its parent company in 2022. (*Id.* at 11.)

48. Staff states that it does not have any issues with NPC's certified cost of debt. (*Id.* at 15.) Staff provides that NPC's certified cost of debt is 5.12%, which is comprised of the weighted cost of NPC's long-term debt of 5.09%, the cost of short-term debt of 6.32%, and the cost of customer deposits of 4.55%. (*Id.*) Staff states that NPC's cost of long-term debt includes its most recent $400 million debt issuance at an interest rate of 5.90%. (*Id.*)

49. Staff states that it has two issues with NPC's proxy group and its screening criteria. (*Id.* at 17.) First, Staff states that NPC has employed screening criteria not previously used, namely the criteria of company-owned generation contributing to at least 40% of sales and 60% of regulated operating income coming from regulated electric operations. (*Id.* at 18.) Staff states that NPC's selected thresholds for their criteria are unclear and has resulted in the exclusion of certain companies from the proxy group. (*Id.*)

50. Secondly, Staff argues that some of NPC's screening criteria for its proxy group were incorrectly applied. (*Id.*) Staff notes that NPC excludes one company based on an announced merger. (*Id.*) However, Staff explains that the referenced merger was announced on December 21, 2021, and completed on June 1, 2022, about one year before the instant docket was filed and well outside the analytical period considered. (*Id.*) In the past, Staff states that mergers that have been announced or completed within six months of the analytical period are excluded. (*Id.*) While Staff generally agrees with the use of the merger criteria, Staff argues that the way NPC uses it appears to reach outside of a period when a merger could affect a

company's financials. (*Id.*) Second, Staff notes that another company was excluded solely because it did not have growth rates from at least two of the following sources: Value Line, Yahoo (First Call), or Zacks Investment Research. (*Id.*) However, Staff states that it was able to find growth-rate information for this company from all three sources. (*Id.*) Staff notes that eight companies were excluded from the proxy group based on the use of the criteria described above and the erroneous application of some criteria. (*Id.* at 19.) Staff provides that these are companies that have been included in at least some, if not all, of NPC's previous cases. (*Id.*)

51. Staff provides its own proxy group as an alternative to NPC's proxy group because Staff believes that NPC's proxy group has too many screening criteria that were applied incorrectly and resulted in the inappropriate limitation of the size of NPC's proxy group. (*Id.* at 20.) Staff states that it believes that removing some of NPC's criteria and correcting the application of the merger and growth-rate criteria results in a proxy group that balances the objectives of obtaining a sufficient sample size and a group that is comparable to the subject company, NPC. (*Id.*)

52. Staff's constant-growth DCF results in an average ROE of 9.56%, with a range of 9.53% to 10.12%. (*Id.*) Staff's constant-growth DCF results are summarized in the table below:

Constant Growth DCF Results				
	Value Line	**Yahoo Finance**	**Zacks**	**Average**
60-day Average Price	9.83%	10.12%	9.64%	9.59%
90-day Average Price	9.77%	10.07%	9.59%	9.53%
Mean	9.80%	10.10%	9.62%	9.56%

(*Id.* at 23.)

53. Staff provides results from a three-stage DCF, which Staff argues is theoretically superior to the constant growth model, as investors' expectations regarding the short-run growth

rate versus the long-run growth rate are likely to differ. (*Id.*) Staff's three-stage DCF results are summarized in the table below:

Three-Stage DCF Results			
	Third-stage growth rate (4.30%)	**Third-stage growth rate (5.68%)**	**Average**
60-day Average Price	8.52%	9.49%	9.00%
90-day Average Price	8.49%	9.45%	8.97%
Mean	8.51%	9.47%	8.99%

(*Id.* at 26.)

54. Staff's CAPM model results in an average ROE of 10.10%, with a range of 9.96% to 10.24%. (*Id.* at 30; Tr. at 130.) Staff's ECAPM model results in an average ROE of 10.32%, with a range of 10.17% to 10.46%. (*Id.*) Staff's CAPM and ECAPM results are summarized in the table below:

CAPM and ECAPM Results			
	CAPM	**ECAPM**	**Mean**
3.94% Risk Free Rate	10.24%	10.46%	10.35%
3.65% Risk Free Rate	9.96%	10.17%	10.06%
Mean	10.10%	10.32%	10.21%

(*Id.*)

55. Staff states that it also conducted an allowed ROE/bond-yield analysis via a regression model. (*Id.* at 31.) Staff provides that, given the relevant 20-year Treasury bond yield for Q4 2023 of 3.87% (the average from Q3 2022 to Q2 2023), the projected average allowed ROE for electric utilities is 10.22%. (*Id.* at 36.) Applying the NPC-specific adjustments of a 12-basis-point reduction, Staff's allowed ROE/bond-yield analysis shows that an ROE of 10.10% or lower is appropriate for NPC. (*Id.*)

56. Staff argues that NPC's analysis of regulatory risk is unsupported and one-sided. (*Id.* at 43.) Staff asserts that the evidence provided in NPC's testimony does not support NPC's

argument that the regulatory risk for NPC is higher than the proxy group; rather, NPC's testimony shows that regulatory risk appears to be in line with the proxy group. (*Id.*)

57. In particular, Staff notes that the risk factors identified by credit agencies, S&P and Moody's, regarding NPC's regulatory environment do not support the conclusion that NPC faces more regulatory risk than the proxy group. (*Id.* at 46.) Instead, Staff argues that it shows that NPC operates in an adequate and generally supportive regulatory environment. (*Id.*)

NPC's Rebuttal

58. NPC disagrees with Staff's amended screening criteria and, as a result, Staff's proposed proxy group. (Ex. 130 at 22.) NPC also does not agree with Staff's significant reliance on the DCF methodology and failure to consider that the CAPM and ECAPM, while sensitive to interest rates, may be the more relevant models to consider in the current market conditions, where interest rates have changed considerably since March 2022, based on the policies of the Federal Reserve. (*Id.*)

59. NPC argues that its proxy group is appropriate and points out that Staff is the only party that has not relied on the proxy group offered by NPC. (*Id.* at 22-23.) NPC maintains that its proxy group is appropriate and provides a better basis for analysis than the proxy group identified by Staff. (*Id.* at 25.)

60. NPC criticizes Staff's constant-growth DCF because NPC states that Staff did not adjust its dividend growth rate to account for timing differences in quarterly dividends throughout the year. (*Id.*) NPC explains that it is common practice to adjust the expected dividend yield by applying one half of the expected annual dividend growth rate to ensure that the expected first-year dividend yield is, on average, representative of the coming annual period, and does not overstate the aggregated dividends to be paid at that time. (*Id.* at 26.)

61. NPC also disagrees with Staff that only mean and median results from DCF models should be used. (*Id.*) NPC explains that, to ensure the results of the DCF are robust, NPC calculates the entire range of results based on the minimum, maximum, and average of these growth rates. (*Id.* at 27.) NPC then provides its recommendation as to which sections of these ranges are most appropriate given the current macroeconomic and financial conditions. (*Id.*) Therefore, NPC argues that providing the entire range of possible results, based on different long-term EPS growth rates, is appropriate. (*Id.*)

62. NPC states that Staff ignored examples provided by NPC from orders of other public utility commissions that conclude that DCF results underestimated a utility's cost of equity. (*Id.* at 29.)

63. NPC disagrees with Staff's use of a multi-stage DCF because NPC states that the utility industry is considered a mature industry due to its regulated status and relatively stable demand. (*Id.* at 30.) Thus, NPC argues that financial projections such as earnings growth rate projections are also likely to be relatively stable over the long-term. (*Id.*) NPC further provides that the relative stability of the financial forecasts for utilities supports the use of a constant-growth DCF model to estimate the cost of equity for a mature industry like utilities. (*Id.*)

64. NPC takes issue with Staff's CAPM analysis. (*Id.* at 34.) Specifically, NPC objects to Staff's assumptions regarding the risk-free rate and market premium used in Staff's CAPM. (*Id.*) Additionally, NPC notes that Staff places little to no weight on the results of its CAPM analysis to support its recommended ROE. (*Id.*) NPC states that Staff similarly places little weight on its ECAPM results to support its recommended ROE. (*Id.*) NPC also states that Staff employed the same flawed risk-free rate and market risk premium in its ECAPM as Staff did in its CAPM. (*Id.*)

65. NPC states that Staff's Allowed ROE/Bond Yield analysis supports NPC's requested ROE of 10.20%, as Staff's Allowed ROE/Bond Yield analysis results in a projected allowed ROE of 10.22%. (*Id.* at 44.) NPC states that, even after Staff applied an NPC-specific adjustment that results in a 12-basis point reduction, Staff's recommended result for this method is 10.10%, which is only 10 basis points lower than NPC's requested ROE. (*Id.*)

66. NPC disagrees with the constant-growth DCF analyses conducted by Staff, BCP, and Joint Petitioners, Caesars, MGM, and SNWA. (*Id.* at 51.) More specifically, NPC disagrees with FEA's and BCP's reliance on sustainable growth rates for their constant growth DCF models. (*Id.* at 52.) NPC states that FEA and BCP incorrectly rely on the premise that future earnings growth is directly a function of the amount of earnings retained and not paid as dividends to shareholders. (*Id.*) However, NPC provides that the amount of earnings retained and not paid as dividends varies as a result of management decisions as opposed to earnings that are largely market-driven. (*Id.*) As such, NPC states that these decisions can and do influence the amount of earnings retained versus paid out as dividends. (*Id.*)

67. NPC states that it disagrees with Joint Petitioners, Caesars, MGM, and SNWA's reliance on historically-derived growth rates to support their DCF modelling. (*Id.* at 54.) NPC states that reliance on historical earnings per share ("EPS") growth rates results in growth rates that are greatly affected by the historic context or period in which they were collected. (*Id.*) NPC argues that it is more appropriate to utilize analyst-projected EPS growth rates for the determination of future expected growth rates. (*Id.*)

68. NPC argues that the results of FEA's multi-stage DCF analysis are inconsistent with previously-authorized ROEs. (*Id.* at 56.) NPC provides that the mean and median results of FEA's multi-stage DCF analysis produces a cost-of-equity result of 8.59% to 8.62%. (*Id.*) NPC

states that these results are well below the range of comparable authorized ROEs for vertically integrated utilities over the past 40 years. (*Id.*) As a result, NPC argues that it is reasonable to conclude that the results of FEA's multi-stage DCF models are unreasonably low and would not meet the comparable return standard of *Hope* and *Bluefield*. (*Id.*)

69. NPC states that it disagrees with the CAPM analyses provided by other parties for 3 primary reasons: (1) FEA solely relied on *Value Line* betas; (2) Joint Petitioners, Caesars, MGM, and SNWA used unadjusted betas; and (3) Joint Petitioners, Caesars, MGM, and SNWA; BCP; and FEA used incorrect assumptions regarding the market risk premium. (*Id.* at 65.)

70. NPC criticizes FEA's expert witness Gorman for inconsistently utilizing current betas in another jurisdiction's rate proceeding but failing to use current betas in FEA's analysis for this proceeding. (*Id.* at 66.) NPC also disagrees with Joint Petitioners, Caesars, MGM, and SNWA's use of unadjusted betas. (*Id.* at 67-68.) NPC explains that the use of adjusted betas in the CAPM is important because if beta trends towards 1.00, then the adjusted beta will be more reflective of the beta that can be expected over the near term. (*Id.* at 68.)

71. NPC disagrees with BCP's use of the historical market risk premium on a conceptual level because the market risk premium is a forward-looking concept. (*Id.* at 69.) NPC also states that BCP's calculation of the historical market risk premium is incorrect because it is deducting the return on the bond as well as the return of the principle of the bond. (*Id.* at 70.) NPC explains that the measure of the market risk premium is the return premium required above the return on the risk-free asset. (*Id.*)

72. NPC objects to FEA's risk-premium calculation because FEA's method sums a projected or current interest rate (i.e., a Treasury bond yield or a utility bond yield, respectively) that is different than the historical average interest rate over the historical time period used to

estimate the risk premium. (*Id.* at 87.) In doing so, NPC argues that FEA invalidates its results by failing to appropriately account for the dynamic and inverse relationship between risk premia and interest rates. (*Id.*) NPC explains that the error in this calculation is that it relies on interest rates from two different time periods, which would represent different equity risk premiums. (*Id.*)

73. NPC disagrees with FEA that the results of NPC's bond-yield risk-premium ("BYRP") analysis should not be considered because FEA believes it does not consider factors other than interest rates that investors consider in the equity risk premium. (*Id.* at 92.) NPC states that FEA's own risk-premium analysis also considers only long-term interest rates (i.e., either Treasury bond yields or utility bond yields) in estimating the implied equity risk premia that FEA relies on for its analysis. (*Id.*) Thus, NPC argues that there is no basis for FEA's critique. (*Id.*)

74. NPC states that Staff's use of NPC's historical average equity ratio to propose a capital structure did not take into consideration NPC's ongoing financing requirements. (*Id.* at 97.) NPC also states that it is inappropriate for the BCP to compare the capital structure of NPC to the capital structures of the holding companies in the proxy group. (*Id.*) NPC further provides that it is inappropriate for the BCP to rely on the capital structures of the proxy group companies at the holding-company level because the use of book value of debt and equity for the proxy group companies at the holding-company level creates a mismatch between the capital structure data. (*Id.*)

75. NPC states that intervenors have failed to recognize the capital expenditures needed by NPC over the near term for resource adequacy. (Ex. 131 at 4.) NPC points out that, with its Applications, NPC provided a picture of the debt and equity components over the next

few years as it completes policy-driven significant capital expenditure projects. (*Id.*) NPC states that this analysis showed that the current debt and equity components are very much the norm for the next few years. (*Id.*) Therefore, NPC argues that the testimony of interveners who propose an imputed equity structure is not based on the actual facts and circumstances facing NPC and should be disregarded. (*Id.*)

76. NPC states that all of the interveners, except Staff, propose capital structures that impute an equity ratio which is unjustified and is not supported by the facts presented in this docket. (*Id.* at 5.) NPC further provides that Staff's position is not based on an imputed capital structure and provides that Staff's calculation is not unreasonable; therefore, NPC states that it could find the 52.72% equity ratio proposed by Staff as a reasonable equity ratio. (*Id.*)

77. NPC rejects intervenor arguments that the equity contributions received by NPC were intended to inflate the equity ratio for the purposes of this general rate case. (*Id.* at 10.) NPC points out that if it did not obtain the equity contributions at the time it did, NPC would not have had sufficient liquidity to pay its bills. (*Id.*) NPC explains that it did not issue debt and repay the equity in the months following the equity contributions for two primary reasons: (1) the deferred energy balance is just a cash timing issue, and going to the market to issue long-term debt would not have been a good business decision in the long-term view; and (2) with high capital expenditures coming in the following months, the funding that came from equity would be needed anyway. (*Id.* at 11.)

78. NPC disagrees with assertions by intervenors that regulatory lag impacts are not a reason to increase equity profit through capital-structure infusions. (*Id.* at 15.) NPC explains that every day NPC is faced with having to have enough funds on hand to pay its bills, whether they are recovered currently or deferred with carry for future recovery. (*Id.*) NPC states that even

temporary regulatory lag items require the lag item to be paid. (*Id.*) NPC provides that paying a lag item uses cash that could be otherwise used for ongoing projects and that capital infusions from both debt and equity sources are the backstop that NPC has when the cash from operations does not cover these ongoing capital needs. (*Id.*)

79. NPC points out that a number of intervenors have failed to consider NPC's growing capital expenditures and offers that these capital expenditures should be factored into the capital structure that the Commission approves. (*Id.* at 16.) NPC explains that higher levels of capital expenditures create some regulatory lag, and having a strong capital structure will help generate more cash to maintain NPC's financial strength. (*Id.*)

80. NPC argues that Google's concerns regarding fuel and purchased power recovery and the generating fleet are not appropriately addressed in this docket and that Google's concerns on these topics should have been addresses in the annal deferred energy accounting adjustment filings. (*Id.* at 18.)

Commission Discussion and Findings

Return on Equity

81. In determining an appropriate ROE, the Commission relies upon frameworks contained in Nevada law and the two seminal United States Supreme Court decisions regarding ratemaking: *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942) and *Bluefield Water Works and Improvement Company v. Public Service Company Commission of West Virginia,* 262 U.S. 679 (1923). Pursuant to *Hope* and *Bluefield*, regulators must consider numerous factors when setting a utility's ROR. (*Hope* 320 U.S. at 605; *Bluefield* 262 U.S. at 692.) As the *Hope* Court stated, regulators can and should consider "appropriate protection to the relevant public interests, both existing and foreseeable," and "it is the result reached not the

method employed which is controlling." (*Hope*, 320 U.S. at 605.) Nevada utilities are entitled to the opportunity to earn an authorized and reasonable ROR that is "adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." (*Nevada Power Co. v. Pub. Serv. Comm'n*, 91 Nev. 816, 825, 544 P.2d 428, 434-35 (1975)). In establishing a zone of reasonableness and determining an ROE within that range, the Commission relies upon expert testimony and evidence that apply the principles of finance, accounting, and economics to the cost of a particular utility's common equity. This evidence includes the results of each expert's ROE studies, the expert's judgment in assessing macroeconomic conditions, capital markets, and NPC's particular circumstances (e.g., capital structure, risk profile, and regulatory environment.)

82. The Commission finds, based upon the evidence in the record and as proposed by Staff, that the range of reasonableness for NPC's ROE falls between 9.30% and 9.90%, and approves an ROE of 9.50%, which is within that range. In conjunction with its approval of an ROE of 9.50%, the Commission approves a 7.43% recommended overall cost of capital, based on a 9.50% ROE and 52.72% equity ratio. The Commission finds that an ROE of 9.50% with an equity ratio of 52.72% is just and reasonable.

83. Overall, the Commission finds that a capital structure in which the ratio of total debt to total capital is 47.28% and total equity to total capital is 52.72%, with a cost of debt at 5.12% and an allowed ROE of 9.50%, within a reasonable range of 9.30% to 9.90%, and the resulting cost of capital of 7.43%, results in just and reasonable rates for the following reasons.

84. The Commission approves Staff's recommended ROE range of reasonableness, which is based on Staff's use of the following: two DCF models (Constant Growth and Three-Stage); CAPM and ECAPM; and an Allowed ROE/Bond Yield model. Staff's Constant Growth

DCF analysis estimates an average ROE of 9.56% with a range of 9.53% to 10.12%, summarized in the following chart:

Staff's Constant Growth DCF Results

	Value Line	Yahoo Finance	Zack's	Average
60-day Average Price	9.83%	10.12%	9.64%	9.59%
90-day Average Price	9.77%	10.07%	9.59%	9.53%
Mean	9.80%	10.10%	9.62%	9.56%

Staff produced two different three-stage DCF results using different third-stage growth rates;[1] however, it relied on the 5.68% third-stage growth rate over the 4.30% third-stage growth rate to be consistent with analyses from previous dockets. Staff's three-stage DCF analysis results in an ROE of 9.47% as summarized in the following chart:

Staff's Three-Stage DCF Results

	Third-stage growth rate G_3 = 4.30%	Third-stage growth rate G_3 = 5.68%
60-day Average Price	8.52%	9.49%
90-day Average Price	8.49%	9.45%
Mean	8.51%	9.47%

The Commission accepts Staff's conclusion that the results from both of its DCF analyses indicate an ROE range of 9.45% to 9.56% and notes its use of the higher third-stage growth rate of 5.68% results in a higher average DCF ROE estimate and range than using the lower 4.30% third-stage growth rate or averaging or otherwise blending the results produced from both of the third-stage growth rates.

85. Staff used two different risk-free rates in its CAPM and ECAPM analyses to account for the rising 20-year treasury bond yields: (1) the 3.94% risk-free rate that is the average 20-year Treasury bond yield in Q2 of 2023; and (2) the 3.65% risk-free rate that attempts to account for the projected increase in the average 20-year Treasury bond yield for the

[1] NPC did not conduct a three-stage DCF analysis.

remainder of 2023. Staff's CAPM analysis returns an ROE of 10.21% with a range of 9.96% to 10.24%, and its ECAPM analysis returns an ROE of 10.32%, with a range of 10.17% to 10.46%, as summarized in the following chart:

CAPM and ECAPM Results

	CAPM	ECAPM	Mean
3.94% Risk Free Rate	10.24%	10.46%	10.35%
3.65% Risk Free Rate	9.96%	10.17%	10.06%
Mean	10.10%	10.32%	10.21%

As Staff notes, however, these estimates incorporate the Treasury yields that have been increasing steadily since last year, which, given the models' sensitivity to changes in the Treasury yields, returns higher results. Therefore, the Commission agrees with Staff that the CAPM and ECAPM analyses should be viewed with some caution.

86. Staff also performed an Allowed ROE/Bond Yield model, which analyzes the relationship between ROEs awarded by state regulators and the long-term U.S. Treasury bonds that prevailed when those ROEs were awarded. Staff's Allowed ROE/Bond Yield model (averaging the relevant Treasury bond yield from Q3 2022 to Q2 2023) projects an average allowed ROE for electric utilities of 10.22%.

87. The Commission finds that NPC's DCF analysis should be adjusted to exclude the Mean Low/High and Media Low/High results, as this information is included in the mean and median DCF results. The Commission agrees with Staff that only the Mean and Median DCF results in NPC's analysis should be used in determining an appropriate ROE.

88. The Commission finds that the forward-looking estimated market risk premiums ("MRP") used by NPC to produce the CAPM and ECAPM result in inflated results. The Commission agrees with Staff that NPC's estimated MRP used in the CAPM and ECAPM

analyses are higher than current market expectations and the historical MRP referenced by Staff in its CAPM and ECAPM analysis.

89. The Commission agrees with Staff that when appropriate adjustments are made, NPC's analysis results in an average ROE of 9.89%, which is significantly lower than NPC's requested 10.20% ROE, and within Staff's recommended ROE range of reasonableness of 9.30% to 9.90%.

90. For the reasons stated above, and consistent with the substantial evidence provided in these dockets, the Commission finds that an ROE of 9.50% continues to balance the interests of ratepayers and shareholders appropriately and results in just and reasonable rates. The Commission approves an ROE of 9.50% for NPC with a reasonable range of 9.30% to 9.90% based on the results of Staff's DCF (Constant Growth and Three-Stage), CAPM/ECAPM, and Allowed ROE/Bond Yield analysis. The Commission further finds that, based upon the evidence (*see*, *e.g.*, Ex. 300 at 42-47.), an ROE of 9.50% (with a reasonable range of 9.30% - 9.90%) is commensurate with returns on investments in other enterprises having similar corresponding risks and is both sufficient to assure confidence in the financial integrity of the utility and for NPC to attract capital.

Cost of Debt

91. The Commission accepts NPC's cost of debt at certification of 5.12%[2] and finds it appropriate. In making this determination, the Commission notes Staff's recommendation to accept NPC's certified cost of debt.

Capital Structure

[2] Ex. 112 at 11.

92. The Commission approves Staff's recommended capital structure and finds that a capital structure in which the ratio of total debt to total capital is 47.28% and total equity to total capital is 52.72% results in just and reasonable rates. Staff's recommended capital structure calculation includes a reclassification to reflect the Dry Lake project long-term debt into the mixture of debt and equity. In approving Staff's proposal, the Commission notes that NPC does not find Staff's capital structure calculation, inclusive of the Dry Lake project debt reclassification, to be unreasonable.

V. DEPRECIATION

93. NPC requests the approval of new and revised depreciation rates for its electric and common accounts. (Ex. 133 at 10.) NPC provides that the depreciation and amortization rates for most categories of electric plant in service currently utilized by NPC were established in 2017. (*Id.* at 11.)

94. NPC provides that the probable retirement dates for NPC's production facilities are established using the Commission-approved Life Span Analysis Process ("LSAP"), which is developed and approved during NPC's integrated resource planning process. (Ex. 136 at 13.) NPC explains that, with the exception of the Nellis Solar and Goodsprings plants, the resulting life spans are longer than those currently in effect for depreciation purposes for each of NPC's other generating facilities. (*Id.*) NPC states that these increases in life span, which range from 5 to 20 years depending on the generating unit, are the primary driver of the decrease in depreciation resulting from the 2023 Depreciation Study. (*Id.*)

95. NPC states that it utilized Iowa-type survivor curves to estimate the service life characteristics of each property group. (*Id.* at 10.) NPC explains that Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. (*Id.*

at 11.) NPC states that Iowa curves and truncated Iowa curves were used in this study to describe forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. (*Id.*) NPC states that the estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. (*Id.*) For example, NPC provides that the Iowa 50-R2 indicates an average service life of 50 years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 2, for the mode (possible modes for R type curves range from 1 to 5). (*Id.*)

96. NPC also reports net salvage percentages for depreciable assets. (*Id.* at 15.) NPC provides that the net salvage estimate for each plant account is based on informed judgment that incorporates the analysis of historical net salvage data. (*Id.*)

A. Estimated Survivor Curves and Net Salvage Percentages for Other Production Plant Accounts

i. Account 348 – Energy Storage Equipment

NPC's Position

97. NPC recommends using a 15-S3 Iowa-type survivor curve for Account 348 – Energy Storage Equipment. (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 348 – Energy Storage Equipment. (*Id.*) Further, NPC proposes a proposed depreciation expense of $31,302 for Account 348 – Energy Storage Equipment. (*Id.*)

Staff's Position

98. Staff recommends setting the depreciation expense for Account 348 – Energy Storage Equipment to zero, which results in a decrease in depreciation expense of $31,302, as compared to the depreciation expense proposed by NPC. (Ex. 302 at 26.) Staff explains that it is the position of Staff that the single project (the Jean Airport Flow Battery project) that comprises

the totality of the depreciation rate and the depreciation expense for Account 348 is not energized, used and useful, and should never have closed to plant in 2020. (*Id.* at 31.)

NPC's Rebuttal

99. NPC provides that Staff proposes to set the depreciation expense to zero, as Staff proposes to remove the assets in the account from rate base. (Ex. 138 at 23.) NPC states that it agrees to remove this asset from rate base for this case. (*Id.*) NPC explains that as the Jean Airport Battery is the only asset in Account 348 at the date of the Depreciation Study, there would, therefore, be no depreciation expense for the account if this asset were removed. (*Id.*) NPC states that Staff also suggests that a 20-year life would be more appropriate than a 15-year service life and, while there would be no dollar impact on the instant case for such a change, NPC argues that, given the considerations and factors discussed above about new technologies and changes to the grid, a 15-year average service life is more reasonable for energy storage assets. (*Id.*) NPC asserts that, while Staff does discuss specific projects, as well as manufacturer recommendations for specific projects, as a general proposition a 15-year average service life is more reasonable, particularly given considerations such as functional and technological obsolescence. (*Id.*)

Commission Discussion and Findings

100. The Commission agrees with NPC and Staff that the Jean Airport Battery is the only asset in Account 348 and should be removed from rate base. However, the Commission also finds that it is appropriate to set an average service life of 15 years for this account for energy storage assets. The approval of the 15-year average service life should have no dollar impact on rates at this time.

B. Estimated Survivor Curves and Net Salvage Percentages for Transmission Plant Accounts

i. Account 350.2 – Land Rights (Transmission)

NPC's Position

101. NPC recommends using a 70-R4 Iowa-type survivor curve for Account 350.2 – Land Rights (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 350.2 – Land Rights (Transmission). (*Id.*)

Joint Petitioners' Position

102. Joint Petitioners recommend using a 90-R4 Iowa-type survivor curve for Account 350.2 – Land Rights (Transmission). (Ex. 901 at 2.) Joint Petitioners state that they disagree with NPC's curve selection and that the original survivor curves for this account could otherwise support a nearly indefinite lived Iowa curve. (*Id.* at 19.) Joint Petitioners state that the 90-R4 curve produced the lowest residual sum of squares ("RSS") value of any curve studied for Account 350.2. (*Id.*)

Commission Discussion and Findings

103. The Commission approves a 70-R4 Iowa-type survivor curve because it is a closer fit to the historical data. The Commission also approves NPC's request for a zero net salvage percentage for Account 350.2 – Land Rights (Transmission).

ii. Account 352 – Structures and Improvements (Transmission)

NPC's Position

104. NPC recommends using a 60-R3 Iowa-type survivor curve for Account 352 – Structures and Improvements (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (10) net salvage percentage for Account 352 – Structures and Improvements (Transmission). (*Id.*)

Joint Petitioners' Position

105. Joint Petitioners recommend using a 60-R3 Iowa-type survivor curve for Account 352 – Structures and Improvements (Transmission). (Ex. 901 at 2.) Joint Petitioners provide that they do not oppose NPC's curve selection for this account. (*Id.* at 22.)

Commission Discussion and Findings

106. The Commission approves NPC's request because no party opposed the survivor curve or net salvage.

iii. Account 353 – Station Equipment (Transmission)

NPC's Position

107. NPC recommends using a 60-R2 Iowa-type survivor curve for Account 353 – Station Equipment (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (5) net salvage percentage for Account 353 – Station Equipment (Transmission). (*Id.*)

Joint Petitioners' Position

108. Joint Petitioners recommend using a 60-R2 Iowa-type survivor curve for Account 353 – Station Equipment (Transmission). (Ex. 901 at 2.) Joint Petitioners state that they support NPC's curve selection for this account. (*Id.* at 24.)

Commission Discussion and Findings

109. The Commission approves NPC's request because no party opposed the survivor curve or net salvage.

iv. Account 354 –Towers and Fixtures (Transmission)

NPC's Position

110. NPC recommends using a 65-R4 Iowa-type survivor curve for Account 354 – Towers and Fixtures (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (10) net salvage percentage for Account 354 – Towers and Fixtures (Transmission). (*Id.*)

Joint Petitioners' Position

111. Joint Petitioners recommend using a 75-S4 Iowa-type survivor curve for Account 354 – Towers and Fixtures (Transmission). (Ex. 901 at 2.) Joint Petitioners provide that they oppose NPC's curve selection for this account because the account had very limited retirements and an incomplete, truncated original survivor curve. (*Id.* at 25.) Joint Petitioners provide that their proposed curve for this account more closely matches the retirements analyzed. (*Id.* at 25-26.)

FEA's Position

112. FEA recommends using a 70-R4 Iowa-type survivor curve for Account 354 – Towers and Fixtures (Transmission). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (10) net salvage percentage for Account 354 – Towers and Fixtures (Transmission). (*Id.*)

Commission Discussion and Findings

113. The Commission approves a 75-S4 Iowa-type survivor curve because NPC's survivor curve was incomplete, and the 75-S4 Iowa-type survivor curve more closely matches the retirements analyzed. The Commission further approves the continued use of a (10) net salvage estimate for this account as recommended by NPC and FEA.

v. Account 355 – Poles and Fixtures (Transmission)

NPC's Position

114. NPC recommends using a 60-R2.5 Iowa-type survivor curve for Account 355 – Poles and Fixtures (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (20) net salvage percentage for Account 355 – Poles and Fixtures (Transmission). (*Id.*)

Joint Petitioners' Position

115. Joint Petitioners recommend using a 74-R4 Iowa-type survivor curve for Account 355 – Poles and Fixtures (Transmission). (Ex. 901 at 2.) Joint Petitioners argue that the tail end of their proposed curve will better represent the expected retirement pattern after the end of the truncated original curve. (*Id.* at 27.)

FEA's Position

116. FEA recommends using a 63-R2.5 Iowa-type survivor curve for Account 355 – Poles and Fixtures (Transmission). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (20) net salvage percentage for Account 355 – Poles and Fixtures (Transmission). (*Id.*)

BCP's Position

117. BCP recommends a 65-R2 Iowa-type survivor curve for Account 355 – Poles and Fixtures (Transmission). (Ex. 403 at 15.) BCP argues that its selected Iowa curve is a closer mathematical fit to the observed life table ("OLT") curve for this account. (*Id.* at 17.)

NPC's Rebuttal

118. NPC provides that Intervenor estimates are all significant changes in service life from the currently-approved estimate of the 55-R2 Iowa-type survivor curve. (Ex. 138 at 21.) NPC states that FEA's (63-R2.5) and BCP's (65-R2) estimates are 8- and 10-year increases, respectively, and Joint Petitioners' estimate (83-R1.5) is an 18-year increase. (*Id.*) NPC states that these are larger increases than should be expected from one depreciation study to the next

without sufficient support, especially when the available data are not definitive, as is the case for this account, which is also an account that will face significant changes in the future. (*Id.*) NPC provides that, as mentioned in the Depreciation Study, the assets in this account are relatively young, so the life characteristics of assets beyond about age 50 years are not well represented in the historical data. (*Id.*) As a result, NPC explains that the focus of its curve fitting was on points through age 60. (*Id.*)

119. NPC states that Joint Petitioners' estimate was selected based on a fit to the entire original curve, but the resulting curve selection, 83-R1.5, is an unrealistic choice for these assets. (*Id.*) NPC explains that, with an average life of 83 years and a maximum life over 150 years, this curve does not reflect expectations for these assets. (*Id.*)

120. NPC states that BCP's (65-R2) and FEA's (63-R2.5) estimates are fits to a similar portion of the curve as NPC's estimate, but both proposals are a significant change in average service life from the current estimate without sufficient support for making such a change. (*Id.*) Further, NPC argues that both of their estimates extend the maximum lives of assets to well over 100 years of age and predict that 20 to 30 percent of assets will survive beyond age 80. (*Id.*) NPC states that, given the considerations discussed previously related to the transition to clean energy and the changes expected to NPC's transmission system, it would not be appropriate to significantly increase the service lives for assets in this account. (*Id.* at 21-22.)

Commission Discussion and Findings

121. The Commission approves a 65-R2 Iowa-type survivor curve. This Iowa curve is a closer mathematical fit to the OLT curve for this account. The Commission also approves the continued use of the (20) net salvage percentage supported by NPC and FEA.

vi. Account 356 – Overhead Conductors and Devices (Transmission)

NPC's Position

122. NPC recommends using a 65-R2.5 Iowa-type survivor curve for Account 356 – Overhead Conductors and Devices (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (30) net salvage percentage for Account 356 – Overhead Conductors and Devices (Transmission). (*Id.*)

Joint Petitioners' Position

123. Joint Petitioners recommend using a 76-R4 Iowa-type survivor curve for Account 356 – Overhead Conductors and Devices (Transmission). (Ex. 901 at 2.) Joint Petitioners explain that their expectation is that the retirements in this account will proceed at a much more rapid rate after the end of original survivor curve period. (*Id.* at 28.) Accordingly, Joint Petitioners selected an R4 Iowa curve for this account and determined the average life which produced the lowest residual measure. (*Id.*)

BCP's Position

124. BCP recommends using a 70-R2 Iowa-type survivor curve for Account 356 – Overhead Conductors and Devices (Transmission). (Ex. 403 at 17.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 19.)

Commission Discussion and Findings

125. NPC, the Joint Petitioners, and the BCP all recommend survivor curves with longer average service lives than the currently used 60-R2 curve. The Commission approves the 76-R4 Iowa-type survivor curve for three reasons. First, the 76-R4 curve more accurately captures the longer lives experienced than the 65-R2.5 proposed by NPC. Second, the 76-R4 appears to anticipate a more rapid retirement rate for those longer-lived assets. And finally, the

curves recommended by the Joint Petitioners and the BCP have average service lives that are longer than the curve recommended by NPC, and both of the curves with longer service lives are a better mathematical fit of the data. The Commission also approves the continued use of NPC's (30) net salvage percentage.

vii. Account 357 – Underground Conduit (Transmission)

NPC's Position

126. NPC recommends using a 55-R2 Iowa-type survivor curve for Account 357 – Underground Conduit (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 357 – Underground Conduit (Transmission). (*Id.*)

Joint Petitioners' Position

127. Joint Petitioners recommend using a 55-S4 Iowa-type survivor curve for Account 357 – Underground Conduit (Transmission). (Ex. 901 at 2.) Joint Petitioners state that this is an account that has had zero retirement activity over its 25-year history. (*Id.* at 29.) Joint Petitioners explain that because the account is limited to a few specific investments, they recommend retaining the 55-year average life that NPC assumed, albeit with a sharper curve profile. (*Id.*)

Commission Discussion and Findings

128. The Commission approves NPC's requested 55-R2 Iowa-type survivor curve and (0) net salvage percentage. Given the limited retirement activity, the Commission finds no basis to deviate from NPC's request.

viii. Account 358 – Underground Conductors and Devices (Transmission)

NPC's Position

129. NPC recommends using a 45-R3 Iowa-type survivor curve for Account 358 – Underground Conductors and Devices (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 358 – Underground Conductors and Devices (Transmission). (*Id.*)

Joint Petitioners' Position

130. Joint Petitioners recommend using a 55-S4 Iowa-type survivor curve for Account 358 – Underground Conductors and Devices (Transmission). (Ex. 901 at 2.) Joint Petitioners state that this account is limited to a handful of distinct investments, the retirement activity of which has not deviated materially from the conduit. (*Id.* at 30.) Accordingly, Joint Petitioners recommend this account follow the same depreciation parameters as Account 357. (*Id.*)

FEA's Position

131. FEA recommends using a 50-R4 Iowa-type survivor curve for Account 358 – Underground Conductors and Devices (Transmission). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (0) net salvage percentage for Account 358 – Underground Conductors and Devices (Transmission). (*Id.*)

Commission Discussion and Findings

132. The Commission approves a 55-S4 Iowa-type survivor curve as the closest curve fit of any proposal. The Commission also approves the continued use of (0) net salvage percentage.

ix. Account 359 – Roads and Trails (Transmission)

NPC's Position

133. NPC recommends using a 60-R4 Iowa-type survivor curve for Account 359 – Roads and Trails (Transmission). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 359 – Roads and Trails (Transmission). (*Id.*)

Joint Petitioners' Position

134. Joint Petitioners recommend using a 70-S6 Iowa-type survivor curve for Account 359 – Roads and Trails (Transmission). (Ex. 901 at 2.) Joint Petitioners state that, like land rights, it is likely that many of the transmission roads and structures will remain in place for as long as NPC owns the adjacent transmission assets. (*Id.* at 31.) Joint Petitioner further state that it is also appropriate to pay down this account balance over time so that the impacts are spread to ratepayers in a fair manner. (*Id.*)

Commission Discussion and Findings

135. The Commission approves a 70-S6 Iowa-type survivor curve as the best-fitting survivor curve. Further, the Commission agrees that like land rights, it is likely that many of the transmission roads and structures will remain in place for as long as NPC owns the adjacent transmission assets. The Commission also approves the requested (0) net salvage percentage.

C. Estimated Survivor Curves and Net Salvage Percentages for Distribution Plant Accounts

i. Account 360.2 – Land Rights (Distribution)

NPC's Position

136. NPC recommends using a 65-R4 Iowa-type survivor curve for Account 360.2 – Land Rights (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 360.2 – Land Rights (Distribution). (*Id.*)

Joint Petitioners' Position

137. Joint Petitioners recommend using a 90-R4 Iowa-type survivor curve for Account 360.2 – Land Rights (Distribution). (Ex. 901 at 2.) Joint Petitioners state that they disagree with NPC's curve selection and that the original survivor curves for this account could otherwise support a nearly indefinite lived Iowa curve. (*Id.* at 19.) Joint Petitioners state that the 90-R4 curve produced the lowest RSS value of any curve studied for Account 350.2 (Transmission). (*Id.*) Given the similar nature of the land rights accounts, Joint Petitioners deem it appropriate to use the same curve across all three land rights accounts, including Account 360.2. (*Id.* at 19-20.)

Commission Discussion and Findings

138. The Commission approves NPC's requested 65-R4 Iowa-type survivor curve and (0) net salvage percentage. The Commission agrees with the Joint Petitioners' perspective that despite the survivor curves theoretically supporting a nearly indefinite lived Iowa curve, it is important to return the costs of the easements over a reasonable timeframe. The Commission finds that 65 years remains a reasonable timeframe and is generally aligned with the lives of the assets for which the easements are necessary.

ii. Account 361 – Structures and Improvements (Distribution)

NPC's Position

139. NPC recommends using a 55-R3 Iowa-type survivor curve for Account 361 – Structures and Improvements (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (5) net salvage percentage for Account 361 – Structures and Improvements (Distribution). (*Id.*)

Joint Petitioners' Position

140. Joint Petitioners recommend using a 55-R3 Iowa-type survivor curve for Account 361 – Structures and Improvements (Distribution). (Ex. 901 at 2.) Joint Petitioners provide that they do not oppose NPC's curve selection for this account. (*Id.* at 22.)

Commission Discussion and Findings

141. The Commission approves NPC's requested 55-R3 Iowa-type survivor curve and (5) net salvage percentage as they are unopposed.

iii. Account 362 – Station Equipment (Distribution)

NPC's Position

142. NPC recommends using a 60-R2.5 Iowa-type survivor curve for Account 362 – Station Equipment (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (10) net salvage percentage for Account 362 – Station Equipment (Distribution). (*Id.*)

Joint Petitioners' Position

143. Joint Petitioners recommend using a 85-R4 Iowa-type survivor curve for Account 362 – Station Equipment (Distribution). (Ex. 901 at 2.) Joint Petitioners state that NPC's survivor curve analysis omits about 20 years of the end of the original survivor curve, which may have influenced the decision to use a shorter duration curve. (*Id.* at 32.)

BCP's Position

144. BCP recommends a 66-R2 Iowa-type survivor curve for Account 362 – Station Equipment (Distribution). (Ex. 403 at 19.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 21.)

Commission Discussion and Findings

145. The Commission approves BCP's recommended 66-R2 Iowa-type survivor curve because it is a closer mathematical fit to the OLT curve for this account and it is a better fit

visually than the other proposed curves. The Commission also approves NPC's requested (10) net salvage percentage.

iv. Account 364 – Poles, Towers, and Fixtures (Distribution)

NPC's Position

146. NPC recommends using a 55-R0.5 Iowa-type survivor curve Account 364 – Poles, Towers, and Fixtures (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (45) net salvage percentage for Account 364 – Poles, Towers, and Fixtures (Distribution). (*Id.*)

Joint Petitioners' Position

147. Joint Petitioners recommend using a 60-R1 Iowa-type survivor curve for Account 364 – Poles, Towers, and Fixtures (Distribution). (Ex. 901 at 2.) Joint Petitioners state that their recommendation is based on an expectation that the retirement activity in the tail end of the original survivor curve will flatten out as more retirement data is accumulated. (*Id.* at 34.) Joint Petitioners also state that use of a shorter curve is also appropriate because it is expected that the ongoing procedures in the context of the Natural Disaster Protection Plan will otherwise require poles to be proactively replaced more rapidly than they had been in the past. (*Id.*)

Commission Discussion and Findings

148. The Commission approves a 60-R1 Iowa-type survivor curve for Account 364 – Poles, Towers, and Fixtures (Distribution). This curve is a better fit and considers that the retirement activity in the tail end of the original survivor curve will flatten out as more retirement data is accumulated. The Commission also approves NPC's requested (45) net salvage percentage.

v. Account 365 – Overhead Conductors and Devices (Distribution)

NPC's Position

149. NPC recommends using a 65-R2 Iowa-type survivor curve for Account 365 – Overhead Conductors and Devices (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (25) net salvage percentage for Account 365 – Overhead Conductors and Devices (Distribution). (*Id.*)

Joint Petitioners' Position

150. Joint Petitioners recommend using an 80-R4 Iowa-type survivor curve for Account 365 – Overhead Conductors and Devices (Distribution). (Ex. 901 at 2.) Joint Petitioners disagree with NPC's proposal for this account because Joint Petitioners state that this is another account where NPC omitted much of the later years from the original survivor curve data. (*Id.* at 35.)

BCP's Position

151. BCP recommends a 70-R1.5 Iowa-type survivor curve for Account 365 – Overhead Conductors and Devices (Distribution). (Ex. 403 at 21.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 23.)

Commission Discussion and Findings

152. The Commission approves the BCP's recommendation of a 70-R1.5 survivor curve for Account 365 – Overhead Conductors and Devices (Distribution) and the continued use of a (25) net salvage percentage. The 70-R1.5 curve is a better mathematical fit of the data than the 65-R2 curve and is similar to the curve for Account 356 – Overhead Conductors and Devices (Transmission), but slightly shorter to account for capacity and damage history.

vi. Account 366 – Underground Conduit (Distribution)

NPC's Position

153. NPC recommends using a 50-R3 Iowa-type survivor curve for Account 366 – Underground Conduit (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (20) net salvage percentage for Account 366 – Underground Conduit (Distribution). (*Id.*)

Joint Petitioners' Position

154. Joint Petitioners recommend using a 41-R4 Iowa-type survivor curve for Account 366 – Underground Conduit (Distribution). (Ex. 901 at 2.) Joint Petitioners state that their proposed curve results in a more accelerated depreciation profile than NPC's proposal. (*Id.* at 36.)

Staff's Position

155. Staff recommends using a 55-R2 Iowa-type survivor curve for Account 366 – Underground Conduit (Distribution). (Ex. 302 at 17-18.) Staff states that this recommendation results in a depreciation rate of 2.16% and depreciation expense of $7,510,178, which results in a decrease in depreciation expense of $1,215,758, as compared to the depreciation expense proposed by NPC. (*Id.*) Staff explains that the statistical outputs and summary of curve fits for this account shows that the 55-R2 Iowa-type survivor curve is the better fit as compared to NPC's proposed 50-R3 Iowa-type survivor curve. (*Id.* at 18.) Staff further states that the visual fit for Staff's proposed 55-R2 Iowa-type survivor curve is better than the visual fit of NPC's proposal. (*Id.*)

Commission Discussion and Findings

156. The Commission approves Staff's recommended 55-R2 Iowa-type survivor curve because it is a better fit than NPC's recommended 50-R3 curve and aligns better with the life of

the conduit and associated conductor than the Joint Petitioners' recommended 41-R4 curve. The Commission also approves a (20) net salvage percentage as requested by NPC.

vii. Account 367 – Underground Conductors and Devices (Distribution)

NPC's Position

157. NPC recommends using a 50-R4 Iowa-type survivor curve for Account 367 – Underground Conductors and Devices (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (20) net salvage percentage for Account 367 – Underground Conductors and Devices (Distribution). (*Id.*)

Joint Petitioners' Position

158. Joint Petitioners recommend using a 51-R5 Iowa-type survivor curve for Account 367 – Underground Conductors and Devices (Distribution). (Ex. 901 at 2.) Joint Petitioners state that NPC incorrectly presents its recommended curve as a truncated curve in its depreciation study, which omits the tail end of the original survivor curve. (*Id.* at 37.)

FEA's Position

159. FEA recommends using a 53-R3.5 Iowa-type survivor curve for Account 367 – Underground Conductors and Devices (Distribution). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (20) net salvage percentage for Account 367 – Underground Conductors and Devices (Distribution). (*Id.*)

BCP's Position

160. BCP recommends a 57-R3 Iowa-type survivor curve for Account 367 – Underground Conductors and Devices (Distribution). (Ex. 403 at 23.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 26.)

NPC's Rebuttal

161. NPC provides that Account 367 is the largest plant account and has the most significant impact on depreciation expense. (Ex. 138 at 20.) NPC states that the currently-approved estimate for this account is the 50-R4 survivor curve, which is a relatively good fit of the historical data, and NPC recommends continuing to use the approved 50-R4 survivor curve. (*Id.*)

162. NPC argues that BCP and FEA's curves do not fit the data as well beyond age 50, which means that their analysis gives limited consideration to the portion of the curve below 70 to 80 percent surviving. (*Id.*) However, NPC states that when more data points are considered, NPC's estimate better matches the data. (*Id.*) NPC provides that Joint Petitioners' curve does fit the middle portion of the curve well. (*Id.*) However, NPC points out that it is a higher mode that is not common for the assets in this account. (*Id.*) For these reasons, NPC argues that there is not a compelling reason to change the service life estimate, and particularly to lengthen it as some intervenors propose. (*Id.*)

Commission Discussion and Findings

163. The Commission approves FEA's recommended 53-R3.5 Iowa-type survivor curve. This curve is a moderate adjustment from NPC's recommendation, is mathematically supported, and takes into consideration the cable injection program that is purported to extend the lives of the treated conductors by up to 20 years. (Ex. 157 at 8.) The Commission also approves NPC's requested a (20) net salvage percentage.

viii. Account 368 – Line Transformers (Distribution)

NPC's Position

164. NPC recommends using a 40-R2 Iowa-type survivor curve for Account 368 – Line Transformers (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (10) net salvage percentage for Account 368 – Line Transformers (Distribution). (*Id.*)

Joint Petitioners' Position

165. Joint Petitioners recommend using a 47-R0.5 Iowa-type survivor curve for Account 368 – Line Transformers (Distribution). (Ex. 901 at 2.) Joint Petitioners explain that NPC's depreciation study omitted approximately 15 years of original survivor curve data for this account, which may have influenced NPC's curve selection. (*Id.* at 38.)

FEA's Position

166. FEA recommends using a 43-R2 Iowa-type survivor curve for Account 368 – Line Transformers (Distribution). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (10) net salvage percentage for Account 368 – Line Transformers (Distribution). (*Id.*)

BCP's Position

167. BCP recommends a 45-R1.5 Iowa-type survivor curve for Account 368 – Line Transformers (Distribution). (Ex. 403 at 26.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 28.)

Commission Discussion and Findings

168. The Commission approves FEA's recommended 43-R2 Iowa-type survivor curve. This curve is a moderate adjustment from NPC's recommendation, is mathematically supported, and is in balance with the recommendations of the other parties. The Commission also approves NPC's request to increase the negative net salvage from (5) to (10).

ix. Account 369 – Services (Distribution)

NPC's Position

169. NPC recommends using a 55-R4 Iowa-type survivor curve for Account 369 – Services (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (60) net salvage percentage for Account 369 – Services (Distribution). (*Id.*)

Joint Petitioners' Position

170. Joint Petitioners recommend using a 87-R4 Iowa-type survivor curve for Account 369 – Services (Distribution). (Ex. 901 at 2.) Joint Petitioners comment that, like many other accounts, this account is problematic because of the highly truncated survivor curve. (*Id.* at 39.) Joint Petitioners provide that they did not find any reason to deviate from the best-fitting curve in this instance (*Id.*)

FEA's Position

171. FEA recommends using a 60-R4 Iowa-type survivor curve for Account 369 – Services (Distribution). (Ex. 1402 at Exhibit-Andrews-Direct-2.) FEA also recommends a (60) net salvage percentage for Account 369 – Services (Distribution). (*Id.*)

BCP's Position

172. BCP recommends a 60-R4 Iowa-type survivor curve for Account 369 – Services (Distribution). (Ex. 403 at 28.) BCP argues that its selected Iowa curve is a closer mathematical fit to the OLT curve for this account. (*Id.* at 30.)

Commission Discussion and Findings

173. The Commission approves the 60-R4 Iowa-type survivor curve because it is a better mathematical fit of the existing data than the 55-R4 survivor curve. Although the best mathematical fit of the data using an R4 curve is the 87-R4 curve, the Commission finds that the

dataset is insufficiently developed to support such an increase at this time. The Commission also approves NPC's request to increase the negative net salvage from (50) to (60).

x. Account 370.1 – AMI Meters (Distribution)

NPC's Position

174. NPC recommends using a 20-R3 Iowa-type survivor curve for Account 370.1 – AMI Meters (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 370.1 – AMI Meters (Distribution). (*Id.*)

Staff's Position

175. Staff recommends that NPC use a 24-R2 Iowa-type survivor curve for Account 370.1 – AMI Meters (Distribution) (Ex. 302 at 7.) Staff states that this recommendation results in a depreciation rate of 3.74% and depreciation expense of $5,563,431, which results in a decrease of $2,273,669, as compared to NPC's proposal. (*Id.*) Staff explains that although Staff agrees that the mode for this account is shifting toward the right direction, which means a lower mode curve is more appropriate, Staff believes that the average service life for this account should also be increased. (*Id.* at 7-8.)

NPC's Rebuttal

176. NPC states that Staff discusses several aspects of the data in support of its proposal but does not discuss factors other than the data. (Ex. 138 at 22.) NPC states that the historical data only decline to approximately 90 percent surviving and do not provide definitive results. (*Id.*) As a result, NPC asserts that many curves fit the data well. (*Id.*) As an example, NPC provides that, in the curve-fitting results Staff shows, there are several curves with residual measures below 2.0. (*Id.*) NPC states that these are all good mathematical fits of the data and have average service lives that range from 17 to 32 years (excluding the 0-type curves). (*Id.*)

NPC states that the 20-R2.5 is a very good fit of the data, and the best-fitting R3 curve is the 17-R3. (*Id.*) Thus, NPC maintains that there are curves that both fit the available data well and incorporate commonly used curve types with average service lives of 20-years or less. (*Id.*) NPC argues that this provides a compelling reason to not increase the average service life, particularly given the type of meters in this account. (*Id.*)

177. NPC provides that other factors that support a 20-year average service life include the potential for obsolescence with newer technologies and that the industry range of average service life estimates is typically between 15- to 20-years. (*Id.* at 22-23.) NPC argues that not only does the data not decline below 90 percent surviving, but the historical experience for this account does not include forces of retirement such as obsolescence that will be more pronounced in the future. (*Id.* at 23.)

Commission Discussion and Findings

178. The Commission approves Staff's recommendation of the 24-R2 Iowa-type survivor curve as this curve is visually and mathematically better when using the full dataset. The Commission also approves NPC's requested (0) net salvage percentage.

xi. Account 372 – Leased Property on Customers' Premises (Distribution)

NPC's Position

179. NPC recommends using a 30-R1 Iowa-type survivor curve for Account 372 – Leased Property on Customers' Premises (Distribution). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (5) net salvage percentage for Account 372 – Leased Property on Customers' Premises (Distribution). (*Id.*)

Joint Petitioners' Position

180. Joint Petitioners recommend using a 57-R2 Iowa-type survivor curve for Account 372 – Leased Property on Customers' Premises (Distribution). (Ex. 901 at 2.) Joint Petitioners remark that NPC omitted approximately 13 years of the original survival curve from its analysis, which may have influenced its decision to select a shorter-lived Iowa curve. (*Id.* at 40.)

Commission Discussion and Findings

181. The Commission approves the 57-R2 Iowa-type survivor curve due to the limited data used to calculate NPC's recommendation. The Commission also approves NPC's request of a (5) net salvage percentage.

D. Estimated Survivor Curves and Net Salvage Percentages for General Plant Accounts

i. Account 389.2 – Land Rights (General Plant)

NPC's Position

182. NPC recommends using a 65-R4 Iowa-type survivor curve for Account 389.2 – Land Rights (General Plant). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (0) net salvage percentage for Account 389.2 – Land Rights (General Plant). (*Id.*)

Joint Petitioners' Position

183. Joint Petitioners recommend using a 90-R4 Iowa-type survivor curve for Account 389.2 – Land Rights (General Plant). (Ex. 901 at 2.) Joint Petitioners state that they disagree with NPC's curve selection and that the original survivor curves for this account could otherwise support a nearly-indefinite-lived Iowa curve. (*Id.* at 19.) Joint Petitioners state that the 90-R4 curve produced the lowest RSS value of any curve studied for Account 350.2 (Transmission). (*Id.*) Given the similar nature of the land rights accounts, Joint Petitioners deem it appropriate to use the same curve across all three land rights accounts, including Account 389.2. (*Id.* at 19-20.)

Commission Discussion and Findings

184. The Commission approves NPC's requested 65-R4 Iowa-type survivor curve as well as the requested (0) net salvage percentage. The Commission agrees with the Joint Petitioners' perspective that despite the survivor curves theoretically supporting a nearly indefinite lived Iowa curve, it is important to return the costs of the easements over a reasonable timeframe. The Commission finds that 65 years remains a reasonable timeframe and is generally aligned with the lives of the assets for which the easements are necessary.

ii. Account 390 – Structures and Improvements (General Plant)

NPC's Position

185. NPC recommends using a 40-R2 Iowa-type survivor curve for Account 390 – Structures and Improvements (General Plant). (Ex. 136 at Exhibit-Allis-Direct 2.) NPC also recommends a (10) net salvage percentage for Account 390 – Structures and Improvements (General Plant). (*Id.*)

Joint Petitioners' Position

186. Joint Petitioners recommend using a 40-R2 Iowa-type survivor curve for Account 390 – Structures and Improvements (General Plant). (Ex. 901 at 2.) Joint Petitioners provide that they do not oppose NPC's curve selection for this account. (*Id.* at 22.)

Commission Discussion and Findings

187. The Commission approves NPC's request for a 40-R2 Iowa-type survivor curve and a (10) net salvage percentage as it was not opposed.

E. Theoretical Reserve Imbalance

NPC's Position

188. NPC states that, in the 2023 Depreciation Study, the theoretical reserve imbalance is calculated to be $262,948,421 as of December 31, 2022, meaning that the book reserve is

greater than the theoretical reserve. (Ex. 136 at 30.) NPC provides that this is approximately 7 percent of the calculated theoretical reserve, which is not large or atypical. (*Id.*) NPC explains that the vast majority of the theoretical reserve imbalance, $253.8 million, is due to production plant accounts and is the result of the increases in life span estimates discussed above. (*Id.*) NPC argues that it is most appropriate to address these over the new remaining lives of the facilities through the use of the remaining life technique. (*Id.*) For all other accounts, NPC states that the theoretical reserve imbalance is only $9.2 million, or less than 1 percent of the theoretical reserve. (*Id.*)

189. As such, NPC recommends that NPC should continue to use the remaining life technique and that there should be no accelerated amortization of the theoretical reserve imbalance. (*Id.*)

BCP's Position

190. BCP states that it is not proposing a separate adjustment relating to the theoretical reserve imbalance. (Ex. 403 at 31.) BCP explains that, when using the remaining life technique, it is not absolutely necessary to conduct a separate rebalancing or amortization of the theoretical reserve imbalance. (*Id.*) However, BCP provides that this issue can be considered on a case-by-case basis, and under particular circumstances, a separate amortization or rebalancing of the theoretical reserve imbalance beyond the use remaining life depreciation rates may be warranted. (*Id.*) BCP agrees with NPC that a separate adjustment related to the theoretical reserve imbalance is not necessary. (*Id.*)

Commission Discussion and Findings

191. The Commission makes no finding regarding the theoretical reserve balance.

F. Decommissioning Cost Estimates

NPC's Position

192. NPC states that the estimates of decommissioning costs used in the 2023 Depreciation Study are based on the estimates ordered by the Commission in NPC's 2011 depreciation case, Docket No. 11-06007. (Ex. 136 at 16.) NPC provides that the estimates in that filing were developed for steam production and other production facilities based on site-specific studies performed for NPC by URS Corporation ("URS"). (*Id.*) NPC explains that the URS study was finalized in April of 2011 and was modified by the Commission's order in Docket No. 11-06007. (*Id.*) NPC states that, for the next depreciation study, the 2017 Depreciation Study filed in Docket No. 17-06004, rather than perform a new decommissioning study, the decommissioning costs approved in the Commission's order for Docket No. 11-06007 were escalated by the Company to 2016 for the 2017 Depreciation Study. (*Id.*) NPC states that, for the Las Vegas and Sun Peak generating stations, the estimates were based on comparable generating units. (*Id.*)

193. NPC provides that decommissioning estimates for the Nellis Solar facility are based on the same estimate developed for NPC and used in the 2017 Depreciation Study. (*Id.*) NPC explains that the net salvage estimates for Nellis Solar were compared with those used for other solar facilities. (*Id.* at 16-17.) However, NPC states that there are unique characteristics of Nellis Solar, including that it is built on a closed landfill and has specific requirements related to the plant's closure, which make the estimates to other facilities less directly comparable. (*Id.* at 16.) NPC argues that the NPC-specific estimate for Nellis Solar is, therefore, most appropriate to use for the net salvage estimates for this facility. (*Id.*)

194. NPC maintains that, for each of these facilities, the estimated decommissioning costs were escalated to 2022 to use for the 2023 Depreciation Study. (*Id.*) NPC states that these escalated decommissioning costs were then used to develop a percentage by account. (*Id.*) NPC provides that this net salvage percentage was then added to the interim retirement net salvage percentage to develop an overall net salvage percent for each generating station by account. (*Id.*)

FEA's Position

195. FEA states that the decommissioning cost estimates presented by NPC for the production facilities contain an excessive contingency adder that artificially inflates the cost estimates. (Ex. 1402 at 18.) FEA states that inspection of the workpapers supporting decommissioning costs and NPC's response to FEA discovery requests reveal that there is a 15% contingency added on all of the costs, excluding any scrap credits, which burdens the ratepayers with excessive and unnecessary depreciation expense. (*Id.*) FEA asserts that any cost contingency to decommissioning costs will not be known or realized for many years, after NPC's production plants have been retired and removed from service. (*Id.*) FEA provides that, because they do not reflect a known and measurable cost, contingencies inappropriately increase the estimated decommissioning costs, unreasonably safeguarding the utility at the expense of current ratepayers in the event that the cost estimates are low. (*Id.*)

196. FEA states that, under NPC's proposed depreciation rates, if the cost estimates, excluding contingencies, are accurate, then ratepayers will be paying depreciation rates higher than they should be. (*Id.* at 18-19.) Further, FEA cautions that the inclusion of contingencies provides NPC with a disincentive to control actual terminal demolition costs. (*Id.* at 19.) Also, FEA warns that the contingencies NPC included only assume that prices can change in a single direction, resulting in higher costs for customers. (*Id.*) FEA argues that this is unreasonable and

that it is very possible that the total cost to demolish a power plant could be significantly less in the future as a result of improvements in technology and demolition processes, or higher scrap values. (*Id.*) FEA provides that the contingencies do not reflect this potential outcome. (*Id.*)

197. For these reasons, FEA asserts that the contingencies requested by NPC are improper and should be removed from the calculation of depreciation rates. (*Id.*)

NPC's Rebuttal

198. NPC argues that FEA appears to misrepresent the purpose of contingency in project cost estimates. (Ex. 137 at 2.) NPC points to testimony provided in Docket No. 11-06007, explaining that the contingency decreases as the project scope is more clearly defined and that the contingency is not excess money in an estimate – it should be spent if the project proceeds to fruition. (*Id.* at 2-3.) NPC provides that the Commission agreed with the purpose of contingency and the need to include contingency in the decommissioning cost estimates in that docket. (*Id.* at 3.) More specifically, NPC asserts that the Commission agreed to reduce the contingency to 15 percent in Docket No. 11-06007. (*Id.*)

199. As such, NPC argues that the 15% contingency should continue to be used and included in the decommissioning cost estimates. (*Id.*)

Commission Discussion and Finding

200. The Commission agrees with NPC that the purpose of the contingency for decommissioning cost estimates is reasonable to ensure the ratepayers that utilized the asset contribute to the cost of decommissioning and intergenerational inequities are avoided. The Commission finds that it is reasonable to include contingency costs in the decommissioning cost calculation. However, no party presented substantial evidence about the reasonableness of

NPC's 15% contingency. The Commission approves NPC's 15% contingency based on the best available information in the evidentiary record.

VI. REVENUE REQUIREMENT

A. Reid Gardner Battery Energy Storage System ("BESS")

NPC's Position

201. NPC explains that the Reid Gardner BESS is a 220-MW Lithium-Ion battery with two hours of energy storage (440 MWh) that is currently being constructed to help close the capacity open position of NPC and Sierra Pacific Power Company ("Sierra"), specifically the critical summer peak capacity. (Ex. 165 at 4.) NPC states that it will also help shift solar energy production to times when the energy is needed more. (*Id.*) NPC describes that the BESS is comprised of 208 containerized battery enclosures as well as inverters and other power electronics. (*Id.*) NPC explains that the battery enclosures are manufactured by BYD, and the main Engineer, Procure, Construct ("EPC") contractor for the site is Energy Vault, Inc. (*Id.*) NPC provides that the project is located on reclaimed land at the former Reid Gardner facility and interconnects at 230 kV voltage to the Reid Gardner Substation. (*Id.*) NPC outlines that the Reid Gardner BESS is expected to begin commercial operation on December 29, 2023. (*Id.* at 5.) NPC states that the total costs of the project, which are reasonably known and measurable with reasonable accuracy as of the date of this rate case filing, are expected to be $255.6 million, including allowance for funds used during construction ("AFUDC"). (*Id.*) NPC notes that this cost is before application of the Investment Tax Credit ("ITC"), expected to be 40 percent, recently made available by the Investment Reduction Act ("IRA"). (*Id.*)

SNGG's Position

202. SNGG provides that, although the in-service date and related costs may be reasonably known and measurable, there seems to be enough uncertainty regarding this large project for the Commission to add regulatory protection for customers. (Ex. 1100 at 2.) SNGG points out that unforeseeable events could easily disrupt the expected in-service date and/or costs. (*Id.*)

203. SNGG explains that if the project is delayed beyond 2023, SNGG holds two concerns. (*Id.* at 3.) First, SNGG notes that the Commission could approve this large adjustment to rate base when it potentially may come into service or expenditures incurred beyond the 210 days after the filing date, possibly in violation of the spirit of NRS 704.110(4). (*Id.*) SNGG provides that, if the Commission allows one adjustment beyond the 210 days, then all adjustments, such as accumulated depreciation, must be updated to whatever that date becomes. (*Id.*) Second, SNGG notes that a lengthy delay would have customers paying for an asset not yet providing service and benefits to customers. (*Id.*)

204. SNGG cautions that when a company has approval for inclusion of projected plant in rate base and approved rates, there is no guarantee that the plant will come into service at the cost expected and customers end up paying for something that is not providing service to them. (*Id.* at 4.)

205. To protect against such outcomes, SNGG offers that the Commission could approve the rate base and corresponding expense adjustments, as proposed by NPC, but also order the creation of a regulatory liability account for monthly accrual of the full revenue requirement associated with BESS if the in-service date is delayed beyond December 31, 2023. (*Id.*) SNGG explains that, because the in-service date would be beyond the 210-day period, the accrual would continue until conclusion of the next general rate case. (*Id.*) SNGG provides that

the same regulatory liability account should also capture any portion of the revenue requirement associated with the BESS rate base adjustment for any projected capital expenditures not actually incurred by NPC by December 31, 2023. (*Id.* at 4-5.) SNGG states that Commission consideration and disposition of this regulatory liability can occur in the next general rate case. (*Id.* at 5.)

206. As such, SNGG recommends that the Commission approve the rate base and corresponding expense adjustments for the Reid Gardner BESS as proposed by NPC and order the creation of a regulatory liability account for the BESS revenue requirement in the event the project is delayed beyond December 31, 2023, or revenue requirement associated with any projected expenditures not incurred by December 31, 2023. (*Id.*)

BCP's Position

207. BCP also holds concerns that the completion date of the BESS will extend beyond the 210-day period, which ends January 1, 2024. (Ex. 401 at 5.) To alleviate concerns about the project completion date and a potential adverse impact on ratepayers, BCP provides several recommendations. (*Id.* at 2.)

208. BCP recommends that the Commission issue a compliance item that NPC schedule an onsite inspection for BCP and Staff engineers and accountants on or before December 31, 2023, to verify that the Reid Gardner BESS is commercially available and closed to plant-in-service (FERC Account No. 101) by December 31, 2023. (*Id.*)

209. BCP also recommends ordering NPC to create a regulatory liability, with carrying charges at the pretax rate-of-return, to refund to customers in NPC's next general rate case the total revenue requirement associated with the Reid Gardner BESS if the onsite investigation by

BCP and Staff determines that the project is not commercially available and closed to plant-in-service by December 31, 2023. (*Id.*)

210. BCP provides that if the Reid Gardner BESS is commercially available and closed to plant-in-service by December 31, 2023, the Commission should order NPC to create a regulatory liability, with carrying charges at the pretax rate-of-return, to refund to customers in the next general rate case the costs of the premium portion of all overtime and 10% of double-shift hours that NPC paid to the EPC contractor work to complete the Reid Gardner BESS project on or before December 31, 2023. (*Id.*)

211. BCP also provides that, if the Reid Gardner BESS is not commercially available and closed to plant-in-service by December 31, 2023, the Commission should order NPC to create, in conjunction with the regulatory liability in BCP's above recommendation, a separate accounting of the costs of the premium portion of all overtime and 10% of double-shift hours that NPC paid to the EPC contractor to complete the Reid Gardner BESS project on or before December 31, 2023, so parties can recommend a permanent disallowance of these additional capital expenditures that provide no additional benefit to NPC's customers. (*Id.* at 2-3.)

212. BCP recommends that, if the Reid Gardner BESS is not commercially available and closed to plant-in-service by December 31, 2023, the Commission should order NPC to create a regulatory liability, with carrying charges at the pretax rate-of-return, to refund to customers in NPC's next general rate case the total revenue requirement associated with the NPC 156 interconnect at the Reid Gardner Substation to support the BESS. (*Id.*)

213. BCP notes that it agrees with the ECIC adjustment in part; however, BCP recommends that the adjustment be limited to the actual expenditures made by NPC for the Reid Gardner BESS project during the prescribed 210-day ECIC period. (Ex. 405 at 12.) BCP

explains that actual investment levels during the 210-day period should be used for two reasons: (1) the 210-day period is prescribed by statute and (2) all of the offsetting adjustments for load growth, accumulated depreciation, and accumulated deferred incomes taxes are limited to the 210-day period. (*Id.*) BCP elaborates that this means that all ECIC investment levels and offsetting adjustments must be synchronized at a specific point in time, which is the 210-day cutoff date for the ECIC adjustments. (*Id.*) BCP asserts that the ECIC investment levels must be limited to the actual investment levels at the end of the 210-day ECIC period because that is the date to which all of the offsetting adjustments are synchronized. (*Id.*)

Staff's Position

214. Staff recommends approving the Reid Garnder BESS project as an ECIC project but denying recovery of approximately $50.5 million of costs associated with the Reid Gardner BESS project as those costs do not meet the ECIC requirements in NRS 704.110(4). (Ex. 315 at 1-2.)

215. Staff provides that final payments to the project contractors, BYD and Energy Vault, Inc. ("Energy Vault"), occur after the ECIC period, and thus they cannot be considered in the instant Docket. (*Id.* at 10.) Staff states that allowing these costs to be recovered would equate to Nevada ratepayers paying a return on and a return of an investment NPC has yet to make and could be partially offset from liquated damages if the project is delayed or there are performance issues with the Reid Gardner BESS project once it is placed into operation. (*Id.*) Staff asserts that approval of these costs through the ECIC process will result in unjust and unreasonable rates. (*Id.*) Staff also provides that contingency costs associated with the Reid Gardner BESS should be denied because the project's contingency costs are not reasonably known, measured

with reasonable accuracy, and have an objectively high probability of occurring in the amount expected. (*Id.* at 11-13.)

216. Staff also recommends deferring recovery of $5.0 million of costs associated with the Reid Gardner BESS project until NPC's next GRC. (*Id.* at 2.) Staff explains that, based on Staff's review of the current project schedule, it appears that NPC may have expedited the construction of the Reid Gardner BESS to ensure the battery would be placed into service prior to the end of the ECIC period such that it could maximize its return on the asset from customers and minimize shareholder depreciation expense. (*Id.* at 14.) Staff provides that the deferral of the $5.0 million to NPC's next GRC requires NPC to justify the reasonableness of expediting the Reid Gardner BESS project. (*Id.* at 15.) Staff points out that the $5.0 million deferral represents less than two percent of the total Reid Gardner BESS project cost and is considered a reasonable holdback amount to ensure just and reasonable rates for ratepayers. (*Id.* at 16.)

NPC's Rebuttal

217. NPC disagrees with Staff's recommendation to exclude the final completion payments costs of $50.5 million. (Ex. 195 at 3.) NPC asserts that these costs were incurred in 2023, and the value from those costs incurred in 2023 will be realized in 2023. (*Id.*) NPC states that the value of the equipment and labor was received in 2023 and will have contributed to the achievement of used and useful status of the Reid Gardner BESS in 2023. (*Id.*) Therefore, NPC argues that customers will be utilizing the benefit of 100 percent of the price of the facility, not 80 percent of the project, which is all that Staff is proposing to be in rate base. (*Id.*) NPC states that the fact that the actual payment itself will not occur until 2024 is a contracting mechanism to ensure the contractor completes post-commercial operation project closeout tasks such as final documentation turnover and relatively small punch-list construction tasks that do not impact

facility operations. (*Id.*) NPC argues that the timing of the final completion payments in 2024 does not detract from the reality that these costs were incurred in 2023 and that most of the value was realized in 2023, within the ECIC timeframe. (*Id.*)

218. NPC also rejects Staff's other recommendation to defer $5 million in costs to NPC's next GRC. (*Id.* at 4.) NPC argues that a December 2023 completion date for the Reid Gardner BESS does, in fact, provide material value to customers. (*Id.*) NPC explains that it is anticipated the Reid Gardner BESS would absorb approximately 4,500 MWhs of otherwise dumped or curtailed solar energy, would allow generation of a similar number of increasingly valuable portfolio energy credits, and provide capacity for NPC. (*Id.*) NPC asserts that each of these items provide immediate, direct, and tangible value to NPC customers. (*Id.*)

219. NPC provides that the Reid Gardner BESS is scheduled to be delivered on time and on budget and that if the Commission was to disallow or defer any costs, the corresponding portion of the ITC will not be credited to reduce rate base. (*Id.* at 5.)

220. NPC offers that while it is true that the contingency is an allowance for unknown, and therefore unplanned exigencies, contingency is a normal, reasonable, and an expected part of any project. (*Id.*) NPC suggests that, in lieu of denying recovery of $4.12 million in contingency, the Commission order NPC to track and true-up the actual amount of contingency used by the end of December 2023 so any unused amounts can be excluded from rates. (*Id.* at 6.)

221. In response to BCP's recommendations, NPC further provides that it is not necessary for the Commission to order a site visit. (*Id.* at 7.) NPC states that it has provided project binders that provided a considerable amount of project information for BCP, Staff, and intervenors to review that adequately address the project's completion before December 31, 2023. (*Id.*) Nonetheless, NPC notes that Staff and BCP are welcome to visit the facility. (*Id.*)

222. NPC states that the final payment costs that Staff references and BCP includes as an adjustment are expected to be incurred, and therefore recorded, in the financial statements within the 210-day ECIC period ending December 31, 2023. (Ex. 206 at 6.) NPC states that the costs are incurred by NPC at the point in which the terms of the contractual obligation are met by the supplier. (*Id.*) NPC asserts that Staff ignores accrual basis accounting and the fact that NPC expects that commercial operation will occur prior to December 31, 2023, meaning that the supplier will have satisfied its obligation and NPC will have incurred these costs. (*Id.*) NPC provides that if the project meets the expected commercial operation date of December 29, 2023, the final payment costs will be recorded by December 31, 2023, per the requirements of accrual accounting. (*Id.*) NPC asserts that Staff and BCP appear to confuse the recording of expenses and costs with the payment of those costs, which will occur at a later date. (*Id.*) NPC highlights that US Generally Accepted Accounting Principles ("GAAP") requires NPC to record expenses and costs on an accrual basis, not a cash basis. (*Id.*) In addition, NPC notes that, if the expenditures are incurred and the facility is placed in-service, the customers will be receiving the benefit of the asset available to them and therefore the incurred costs should be included in rate base for recovery. (*Id.*)

223. NPC points out that in Staff's recommendation to defer $5 million in costs from the Reid Gardner BESS, Staff fails to contemplate the accumulated deferred income tax ("ADIT") impacts on revenue requirement. (Ex. 204 at 12-13.) NPC also asserts that Staff's proposed adjustment to the ITC, should the Commission defer $5 million from the Reid Gardner BESS project, is not accurate. (*Id.* at 7.)

224. NPC notes, in response to BCP's assertions about facilities being installed to support the interconnection at Reid Gardner BESS, that such costs are not being included as part

of NPC's revenue requirement and that the NPC 156 interconnection at Reid Gardner is unrelated and was completed in December 2021. (Ex. 193 at 12.)

225. NPC emphasizes that, to the best of NPC's knowledge, the Reid Gardner BESS contractor has committed and will be able to complete the project before the end of the year and therefore within the ECIC period. (Ex. 208 at 17.) However, NPC states that it recognizes that the Commission needs to evaluate a scenario if the project is not completed by the end of the year. (*Id.*) NPC provides that it would find it prudent to record the daily revenue requirement for these projects into a regulatory liability for each day that the project is not in service until the project does go into service. (*Id.*) NPC states that another option would be to allow NPC to defer the depreciation and operations, maintenance administrative and general expenses for the ECIC projects into a regulatory asset, with carry charges at its authorized rate of return, until NPC is able to get the assets into rate base. (*Id.*) NPC offers that it would bring forward the regulatory asset for recovery at its next rate case. (*Id.*) Nonetheless, NPC reiterates that these projects will be completed in the ECIC period, and no contingency options are needed. (*Id.*)

Commission Discussion and Findings

226. The Commission finds that the Reid Gardner BESS qualifies as an ECIC pursuant to NRS 704.110(4) because the costs of the project were reasonably known and measurable with reasonable accuracy as of the date of this rate case filing. The Reid Gardner BESS contractor had been retained, construction had commenced, and material parts of the project had been ordered prior to the filing of the rate case. The Reid Gardner BESS is a unique project that will provide reliability benefits to customers when placed into service.

227. However, it is not clear to the Commission that the decision to change the in-service date from May 2024 to December 2023 will provide meaningful benefits to customers.

Further, many parties raised substantial concerns about the ability of the contractor, already working multiple shifts seven days a week, to complete the Reid Gardner BESS and place it in service by December 29, 2023.

228. The Commission finds Staff's recommendation to defer certain costs for recovery until NPC's next GRC an appropriate accommodation to ensure rates only include costs reasonably incurred within the ECIC period. To be clear, the Commission is not disallowing these costs; the Commission is simply delaying its review of the costs until the next GRC. All parties argued for some form of protection for ratepayers from paying rates that include an asset that may not be in service when the rates go into effect on January 1, 2024.

229. The Commission accepts Staff's recommendation to defer $50.5 million in final completion payments. Although the Commission recognizes that NPC uses accrual accounting, NPC confirmed that the contractual performance obligations for these payments will not occur until after the ECIC period. The ECIC is an exception to the historical test period in NRS 704.110; accordingly, the Commission finds that costs due and payable based on actions outside the ECIC period are not appropriate for inclusion in rates.

230. The Commission also accepts Staff's recommendation to defer $5 million in acceleration costs. NPC provided limited information in its direct case to explain the value of accelerating work on the Reid Gardner BESS project. In addition, many of these increased costs were being incurred as this case unfolded, allowing no opportunity for parties to review the reasonableness of costs associated with the acceleration of the project schedule. The Commission finds that it is reasonable to defer $5 million in costs until NPC's next general rate case when a more thorough accounting can occur of the Reid Gardner BESS costs.

231. The Commission finds NPC's alternative to record the daily revenue requirement for these projects into a regulatory liability for each day the project is not in-service until the project does go in-service reasonable to protect ratepayers from costs that were not incurred within the ECIC period.

B. Distributed Energy Resource Management System ("DERMS")

NPC's Position

232. NPC states that for the Applications, the total information technology ("IT") spend at the end of the test period (December 31, 2022) is $75,468,324, and the total spend is $88,552,025 at the end of the certification period (May 31, 2023). (Ex. 150 at 11-12; Ex. 151 at 2.) NPC states that it benefited from leveraging economies of scale across Berkshire Hathaway Energy ("BHE") affiliates with respect to hardware and software purchases. (Ex. 150 at 12.) NPC provides that several of the projects listed in their Applications were purchased with these bulk discounts. (*Id.*) In addition, NPC states that a new process was put in place to scrutinize all spend over $25,000 to ensure it aligned with their IT strategy. (*Id.*)

233. NPC provides that, among the IT projects included in NPC's Applications is the Distributed Energy Resource Management System ("DERMS"). (*Id.* at 12-13.) NPC states that the DERMS Phase 1A is the first release of the DERMS system described in Docket No. 21-06001 and approved in the Corrected Modified Final Order dated March 8, 2022. (*Id.* at 13.)

Staff's Position

234. Staff recommends denying the cost allocations proposed by NPC of 90 percent to NPC and 10 percent to Sierra for Phase 1A and all forthcoming phases of the DERMS project and instead order the Company to allocate 60 percent to NPC and 40 percent to Sierra. (Ex. 309 at 2.)

235. Staff provides that in NPC's response to Staff in discovery, NPC states that the cost allocations of 90 percent to NPC and 10 percent to Sierra is proportionate only to the current and expected distribution of megawatts of demand response capacity under each company, respectively. (*Id.* at 3.) However, Staff disagrees with this analysis. (*Id.*) Staff states that during discovery, NPC explained that industry-leading and proven demand response resources reduce peak demand and peak energy supply costs, potentially delay the need for higher-cost transmission and distribution infrastructure, and provide significant economic value in the form of a physical hedge against high peak energy prices and energy emergency situations. (*Id.*) Staff points to the DERMS business case summary that provides that DERMS will support utility-scale renewable energy adoption by creating the infrastructure that drives NV Energy's capability to shape load responsive to both system-level and distribution-level conditions. (*Id.* at 4.) In addition, Staff highlights the Key Decision Report, which lists DERMS benefits: increasing customer satisfaction, keeping rates flat, reducing the risk of cybersecurity related incidents, achieving Nevada's net-zero carbon goals, and generally benefiting NV Energy's departments. (*Id.*) As such, Staff concludes that DERMS is a multi-departmental support project, and its costs should be allocated as a standard corporate allocation. (*Id.*)

236. Staff states that it is recommending allocating 60 percent of the DERMS costs to NPC and 40 percent to Sierra for Phase 1A and all forthcoming phases because DERMS is an enterprise software "System of Systems" that will not only control distributed energy resources but will improve situational awareness, risk management, capital expansion options, customer satisfaction, and the operational capability required to accompany high levels of renewable energy supply. (*Id.*) In addition, Staff explains that it is part of NV Energy's IT strategy to consolidate, replace, and upgrade new IT systems across all BHE domestic utilities. (*Id.*) Staff

asserts that DERMS costs are general operations and maintenance expenses, which should be allocated based on a standard corporate allocation of 60 percent to NPC and 40 percent to Sierra as a "normal" business activity of NV Energy. (*Id.*)

237. Staff further recommends deferring a portion of the DERMS Phase 1A project actual costs in the amount of $213,163 that were added to Plant In Service through the close of the certification period in this filing until Sierra's next GRC. (*Id.*) Staff explains that this dollar amount consists of the difference between the actual costs ($639,491) associated with Phase lA of the DERMS project that were allocated 90 percent to NPC and the actual costs ($426,327) of Phase lA of the DERMS project that Staff is recommending be adjusted to a 60 percent allocation to NPC. (*Id.* at 4-5.) Staff provides that the total cost of Phase lA of the DERMS project is $710,546, and because Staff recommend that the costs be allocated 60 percent to NPC and 40 percent to Sierra, the resulting difference of $213,163 in costs should be deferred and requested for recovery in the upcoming Sierra GRC. (*Id.* at 5.)

NPC's Rebuttal

238. NPC states that in Staff's recommendation to defer the costs from the DERMS Phase 1A project, Staff fails to contemplate the accumulated deferred income tax ("ADIT") impacts on revenue requirement. (Ex. 204 at 12-13.) Further, NPC notes that in the proposed adjustment for the DERMS Phase 1A deferral, the wrong jurisdictional allocator has been applied. (*Id.* at 13-14.)

239. NPC disagrees with Staff's recommendation to change the allocation for DERMS Phase lA and defer a portion of those costs until Sierra's next GRC based on that reallocation. (Ex. 199 at 2.) However, in the alternative, NPC provides that if the Commission were to agree

with Staff's proposed allocation methodology, NPC believes that Staff's recommended allocation of DERMS costs should be implemented prospectively and not retrospectively. (*Id.*)

240. NPC explains that it based its DERMS cost allocation upon a "territory utilization" perspective (e.g., actual volume of customers enrolled, volume of customer support calls, devices dispatched, etc.) expressed in megawatts of dispatchable demand response capacity. (*Id.* at 3.) NPC explains that this method is focused on demonstrating from which territory avoided capacity benefits are derived and which territory most interacts with and uses the system. (*Id.*) NPC states that the vast majority of system benefits of the existing Demand Response Management System ("DRMS") accrue to NPC customers, at approximately 90 percent of such "system utilization" and avoided cost benefits. (*Id.* at 4.) As such, NPC states that it believes that its "system utilization" perspective represents a fair and equitable cost allocation for customers, particularly for DERMS Phase 1A. (*Id.*) NPC further states that it continues to expect the same type of "system utilization" to remain applicable for future DERMS software releases. (*Id.*)

241. NPC provides that while it maintains that a 90%/10% split is the most fair, Staff's position represents a different perspective about cost-allocation that could also be considered valid. (*Id.* at 5.)

Commission Discussion and Findings

242. The Commission accepts Staff's recommendation for NPC to allocate 60 percent to NPC and 40 percent to Sierra. The distributed energy and demand response benefits provide capacity and system reliability for the entire jointly-dispatched system. The Commission also accepts Staff's recommendation to defer a portion of the DERMS Phase 1A project actual costs in the amount of $213,163 that were added to Plant In Service through the close of the

certification period in this filing until Sierra's next GRC. Due to the concerns raised by NPC about the proper calculation of that amount, the Commission directs NPC to calculate the correct amount and share that information with Staff.

C. Jean Airport Flow Battery System

Staff's Position

243. Staff recommends denying recovery of the remaining balance in rate base associated with the Jean Airport Flow Battery System project (Work Order No. 0010009259) as the project is not energized or used and useful. (Ex. 302 at 1.)

244. Staff provides that despite NPC including this project in rates through its 2020 GRC certification, Staff has since discovered that the Jean Airport Flow Battery project was completed after its costs were closed to plant in May 2020 and was never actually energized or used and useful because it was an immediate failure and was ultimately decommissioned after years of failed repairs. (*Id.* at 8.)

245. Staff provides that, although the vendor has delivered a second containerized system at a different location in Q3 2023 in an effort to make NPC whole on its deliverables, the Clark Station battery energy storage system ("Clark BESS") is a completely different project that will not be in service at the time of filing this testimony (or even in Q4 2023). (*Id.*) Staff states that based on what it has discovered with the poor performance record of the original system at the Jean Airport, Staff is not confident that the Clark BESS will pass acceptance testing, not leak, or not have any other operational issues in the near term. (*Id.*) Staff states that it reserves the right to review the costs associated with the Clark BESS in NPC's next GRC. (*Id.*)

246. Staff concludes that, considering that NPC has already collected approximately $45,000 in depreciation and ratepayers have paid over $108,000 related to the debt and equity for

this asset, Staff recommends removing the remaining balance of the project's costs from rate base. (*Id.*)

NPC's Rebuttal

247. NPC states that in Staff's recommendation to remove the costs from the Jean Airport Flow Battery System project from rate base, Staff fails to contemplate the accumulated deferred income tax ("ADIT") impacts on revenue requirement. (Ex. 204 at 12-13.) Nonetheless, NPC finds it reasonable to remove the Jean Airport Flow Battery System project costs as recommended by Staff. (Ex. 195 at 8.)

Commission Discussion and Findings

248. The Commission finds that the Jean Airport Flow Battery System project costs should be removed from rate base. NPC concurs with Staff's recommendation to remove the project costs and, accordingly, the inclusion of the costs is no longer at issue.

D. Earnings Sharing Mechanism

NPC's Position

249. NPC states that an earnings sharing band in the earning sharing mechanism, equal to at least 30 basis points, is critical to mitigate NPC's risk as it continues to operate in a high-inflation environment and experience cash constraints. (Ex. 129 at 5.)

SNGG's Position

250. SNGG states that it appears that NPC is proposing to increase the band of the earning sharing mechanism from 30 basis points to at least 60 basis points. (Ex. 1100 at 6.) SNGG states that the inflationary conditions, which NPC cites as the rationale for altering the earning sharing mechanism and which may lead to underearning, are not alleviated by the

earnings sharing band whatsoever. (*Id.*) SNGG provides that when inflationary conditions lead to underearning, that is best addressed by filing a rate case. (*Id.*)

251. Accordingly, SNGG recommends that the Commission continue to approve the earnings sharing mechanism in its current form as a just and reasonable protection for customers that has worked well for many years. (*Id.*)

BCP's Position

252. BCP states that NPC is requesting to expand the earnings sharing mechanism by an additional 30 basis points. (Ex. 405 at 7.)

253. BCP recommends continuing the existing earning sharing mechanism for a number of reasons. (*Id.*) First, BCP states that the earnings sharing mechanism not only incentivizes cost-cutting measures by the utility, but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. (*Id.*) BCP notes that because NPC has a long and consistent history of over-earning, it is important to keep these ratepayer protections in place. (*Id.*) BCP maintains that the Commission should keep the earnings sharing mechanism safeguards in place at least until NPC is no longer over-earning on a consistent and significant basis. (*Id.*)

254. Nonetheless, BCP disagrees that the earnings sharing mechanism should be expanded by an additional 30 basis points to protect against high inflation and cash constraints. (*Id.* at 8; *see also* Ex. 407 at 11-12.)

Staff's Position

255. Staff recommends that the Commission approve the earnings sharing regulatory liability as filed in the Certification and the continuance of the earnings sharing mechanism utilizing the current methodology, incorporating the ROE as approved in this docket. (Ex. 319 at 9.)

NPC's Rebuttal

256. NPC states that there appears to be a misinterpretation of NPC's position regarding the earnings sharing mechanism. (Ex. 208 at 14.) NPC clarifies that it was not its intent to propose a change in the earnings sharing mechanism in this docket. (*Id.*) NPC states that if the earnings sharing mechanism is to continue, the band should remain at the current 30-basis-point level that is in place today. (*Id.* at 14-15.)

Commission Discussion and Findings

257. The Commission finds that it is a just and reasonable protection for customers to continue the earnings sharing mechanism, which has worked well for many years, in its current form at the 30-basis-point level.

E. Wynn Regulatory Asset

NPC's Position

258. NPC states that Schedule H-CERT-38 is the regulatory asset established per Docket No. 15-05006 and reflects the Base Tariff General Rate ("BTGR") and Energy Reduction and Capacity Replacement ("ERCR") components of Wynn's exit fee that were adjusted in that docket. (Ex. 189 at 4.) NPC states that this regulatory asset balance was inadvertently omitted from revenue requirement in NPC's last GRC and is, therefore, included in revenue requirement in this GRC. (*Id.*) NPC states that Docket No. 15-05006 specified that NPC could earn a carry charge on the regulatory asset in the same manner as energy efficiency program balances. (*Id.*) NPC provides that it calculated carry charges on the balance in compliance with the Commission's order in Docket No. 15-05006 from October 2018 through May 2020. (*Id.*) NPC states that because this balance was inadvertently omitted from revenue requirement in NPC's prior GRC, carry charges have not been calculated on the balance since May 31, 2020, which

was the end of the certification period of the prior GRC. (*Id.*) NPC states that it is requesting a three-year amortization of the balance of $2.179 million that was omitted from the prior GRC. (*Id.*)

BCP's Position

259. BCP disagrees that NPC should be permitted to recover the regulatory asset over a three-year period in this case. (Ex. 405 at 15.) BCP argues that, because NPC states that it inadvertently omitted the regulatory asset in the 2020 GRC, NPC's request in this GRC appears to run afoul of the prohibition against retroactive ratemaking in that it attempts to include in future rates perceived deficiencies in past rates. (*Id.*) BCP maintains that, regardless of the cause of NPC's omission of this regulatory asset in the 2020 GRC, NPC did not have Commission authority to continue its deferral of these costs. (*Id.*) BCP states that the only authorization NPC had to collect these costs was in the 2020 GRC, and that opportunity has now passed. (*Id.*)

260. BCP recommends a rate base adjustment of $2.179 million and an adjustment to amortization expense of $726,000. (*Id.*)

Staff's Position

261. Staff recommends denying NPC's request to classify and recover $2.179 million, with carrying charges, as a Wynn BTGR ERCR Impact Credit regulatory asset. (Ex. 319 at 3.)

262. Staff states that when Staff asked NPC to clarify the circumstances in which the regulatory asset was inadvertently omitted, NPC altered its response to state that the cause of the exclusion was due to a misinterpretation of the circumstances regarding the regulatory asset and that NPC chose to omit it at that time until decisions regarding the Reid Gardner Coal Generating Station ("Reid Gardner") and Navajo Coal Generating Station ("Navajo") decommissioning costs were determined. (*Id.* at 5.) Staff considers this explanation to be unreasonable as the

Order in Docket No. 15-05006 clearly directs the creation of a regulatory asset for the BTGR and ERCR components of Wynn's exit fee and specifically states the dollar amounts to be included for each. (*Id.*) Further, Staff provides that if NPC had purposefully chosen during the 2020 GRC to defer recovery of the asset to a future filing as they have indicated, this decision should have been memorialized somewhere in the Applications. (*Id.*) Staff provides that when NPC was asked by Staff if and/or how the inclusion of the Wynn asset in the 2020 GRC would have affected NPC's proposal and the outcome of that filing, NPC referenced the "black box" settlement and conveyed that it was difficult to determine how the inclusion of this regulatory asset at the time would have affected the outcome or would have influenced any other decisions. (*Id.*) Staff argues that, regardless of whether it was a conscious decision by NPC or was an inadvertent omission from the revenue requirement in the last GRC, it should have either been included in the prior GRC or a reason should have been provided to explain the omission, allowing the Commission to decide how to proceed. (*Id.*) Moreover, Staff conveys that valid questions exist as to if or how the inclusion of this asset in the 2020 GRC application or settlement would have made a difference, if any, in the end result of that docket. (*Id.*)

263. Accordingly, Staff recommends that the Commission deny the inclusion of the regulatory asset in rate base, resulting in a reduction to rate base of $2,178,513 and amortization expense of $726,171. (*Id.*)

NPC's Rebuttal

264. NPC states that it agrees that the Wynn regulatory asset should have been included in the 2020 GRC; however, NPC originally believed that the regulatory asset could not be requested for recovery until decisions raised in the 2017 NPC GRC order regarding the deferred Reid Gardner and Navajo decommissioning costs were resolved. (Ex. 205 at 3.) More

specifically, NPC provides that the Commission deferred any decommissioning and remediation costs for Reid Gardner and Navajo until the work was substantially complete, so NPC interpreted that there was no certainty that the regulatory asset should be presented in the 2020 GRC because the amount was uncertain. (*Id.*) Due to this interpretation, NPC states that it omitted requesting recovery of the balance in the 2020 GRC, but in hindsight, NPC states that it could have done so. (*Id.*)

265. NPC states that because the regulatory asset was not included in the revenue requirement in the 2020 GRC, NPC has not accrued carry charges since May 2020 on this balance. (*Id.* at 3-4.) NPC provides that the balance included in this proceeding is the same as it would have been in 2020 and what was ordered by the Commission. (*Id.* at 4.) NPC argues that Staff and BCP effectively propose to punish NPC for omitting this balance from the 2020 GRC and that Staff and BCP's proposals should be rejected. (*Id.*)

Commission Discussion and Findings

266. The Commission adopts and finds reasonable Staff's and BCP's recommendations to deny NPC's request to classify and recover $2.179 million, with carrying charges, as a Wynn BTGR ERCR Impact Credit regulatory asset. The Commission agrees with Staff that if NPC had purposefully chosen during the 2020 GRC to defer recovery of the asset to a future filing as indicated, this decision should have been memorialized somewhere in the applications and subsequent Order. Based on the failure of NPC to address this issue in the 2020 general rate case, the authority to continue this regulatory asset has expired and cannot be recovered from customers over a future period.

F. Transmission, Substation, and Distribution Requirements

NPC's Position

267. NPC states that capital maintenance projects performed on transmission facilities, substation facilities, overhead distribution facilities, underground distribution facilities and transformers were required to replace failed facilities and/or restore electrical service to customers. (Ex. 157 at 5.) NPC states that capital maintenance projects on services were performed (1) to restore electrical service to customers; (2) because the cable or conductor had reached or exceeded the end of its service life or had been damaged and was replaced to improve the reliability of the distribution system; or (3) to correct violations of various National Electric Safety Code ("NESC"), Occupational Safety and Health Administration ("OSHA"), and NPC safety standards. (*Id.*)

268. NPC states that most projects that fall into the Cable Replacement Program involve replacing segments of direct-buried cable that is more than 30 years old, with cable placed in conduits. (*Id.*) NPC explains that underground cable scheduled for replacement under this program is prone to failure and may have had multiple splices or corroded concentric neutral. (*Id.*) NPC states that projects under the Cable Replacement Program also include replacement of service transformers, service transformer pads, switches, vaults, and secondary boxes, which have failed or are unsafe. (*Id.*) NPC provides that capital expenditures under the Cable Replacement Program are $66.55 million through December 2022 and $45.32 million during the certification period. (Ex. 158 at 3.)

269. NPC states that Cable Injection Program targets direct-buried underground facilities, primarily distribution cable, at risk of failing due to their age and location. (Ex. 157 at 7.) NPC elaborates that cables are injected with a silicon-based fluid with insulation properties to mitigate future failure. (*Id.*) NPC provides that the maintenance program administrators conduct analysis utilizing reliability statistics based on number of faults to identify areas and

cables vulnerable to failure and assign cable injection crews to treat the identified areas. (*Id.* at 7-8.) NPC states that capital expenditures under the cable injection program are $19.5 million through December 2022 and $0.02 million during the certification period. (Ex. 158 at 3.)

270. NPC states that the Overhead Rebuild Program projects replace and/or retrofit total or partial overhead infrastructure. (Ex. 157 at 10.) NPC explains that this includes the replacement of distribution poles, overhead conductor, service transformers, switches and disconnects, the installation and replacement of line capacitor banks, line upgrades and associated work that allows NPC to maintain compliance with municipal agreements, ordinances, and codes, the NESC, OSHA regulations, and/or NPC safety standards, and other reliability improvement projects. (*Id.*) NPC provides that capital expenditures under the Overhead Rebuild Program are $9.38 million through December 2022 and $1.77 million during the certification period. (Ex. 158 at 3.)

BCP's Position

271. BCP states that it holds concerns regarding NPC's early retirement of its distribution facilities and equipment. (Ex. 405 at 21.) BCP points out that it has not produced any study or analysis that shows the failure rate of its distribution facilities and equipment by age, or the probability of failure by age. (*Id.*) BCP states that it is concerned that NPC is retiring a portion of its distribution facilities solely, or primarily, because these assets have reached or exceeded depreciable useful life. (*Id.*) Moreover, BCP has further concerns that there may be a lack of cost discipline over individual projects under the Cable Replacement, Cable Injection, and Overhead Rebuild programs because such programs are exempt from NPC's Authorization for Expenditure ("AFE") policy. (*Id.*) BCP argues that early retirement of functioning

distribution facilities is likely not in the public interest because this causes scarce capital to be diverted from higher-value-added capital projects and leads to higher customer rates. (*Id.*)

272. BCP recommends that the Commission open an investigatory docket to examine whether the potential early retirement of distribution facilities and equipment is in the public interest. (*Id.* at 22.) BCP provides that this investigation should include the following three components: (1) NPC should calculate the historical failure rate of its distribution facilities and equipment by age or the probability of failure by age; (2) NPC should demonstrate that its potential early retirement of selected NPC distribution facilities and equipment did not unreasonably divert scarce capital away from higher-value-added projects; and (3) NPC should demonstrate that its potential early retirement of selected NPC distribution facilities and equipment is more cost-effective than deferring retirement until failure is more imminent. (*Id.*)

NPC's Rebuttal

273. NPC states that BCP holds a misunderstanding that NPC's capital maintenance projects are limited to distribution facilities; rather, NPC asserts that these projects cover transmission, substations, and distribution facilities. (Ex. 192 at 2-3.)

274. NPC rejects BCP's assertion that the Cable replacements, Cable Injection, and Overhead Rebuild projects were speculative. (*Id.* at 3.) NPC explains that this work was performed due to actual reliability performance and as recommended through inspection and/or testing. (*Id.*) NPC provides that the studies proposed by BCP are more speculative than the actual failure data and prioritization that the three programs are based upon. (*Id.*)

275. NPC disagrees with the BCP that NPC is retiring a portion of its distribution facilities only or primarily because the assets have reached or exceeded their depreciable lives. (*Id.* at 5.) NPC highlights that the Cable Replacement, Cable Injection and Overhead Rebuild

projects are not exclusively based on age. (*Id.*) NPC explains that the large number of emergency and failure projects does not support the need for an analysis of failure rates nor failure probability studies. (*Id.*) NPC provides that it instead clearly indicates imminent failure of assets as a driver for the Cable Replacement, Cable Injection and Overhead Rebuild programs. (*Id.*)

276. NPC further disagrees with BCP's concerns regarding the potential for a lack of cost discipline over individual projects under the Cable Replacement, Cable Injection, and Overhead Rebuild programs. (*Id.*) NPC states that the Cable Replacement, Cable Injection and Overhead Rebuild programs are recurring capital expenditures and authorized through the annual budget. (*Id.*) As such, NPC states that adherence to the annual budget process provides adequate cost discipline. (*Id.*) NPC argues that its AFE policy in its Applications is sufficient and that separate formal AFEs for recurring capital expenditures and operating expenses are deemed overly burdensome and unnecessary as they are authorized through the annual budget process. (*Id.* at 5-6.)

Commission Discussion and Findings

277. The Commission rejects BCP's recommendation that the Commission open an investigatory docket to examine whether the potential early retirement of distribution facilities and equipment is in the public interest. The Commission regularly reviews plant replacements and retirements in general rate cases and depreciation studies.

G. Payroll Expense Adjustment

NPC's Position

278. NPC explains that Schedule H-CERT-17 shows the calculation of annualized payroll, benefits, and pension expense. (Ex. 186 at 9.)

279. NPC states that the payroll annualization results in an increase in payroll expense of $40.590 million as of the end of the certification period for the aggregate of NPC, Sierra, and their parent company, NV Energy, Inc., as compared to test period results. (*Id.* at 11.) NPC explains that the overall increase between test period and certification period was largely generated at NPC and Sierra, with a combined increase of $36.553 million, with a $4.037 million increase at the parent company. (*Id.*) NPC states that the $40.590 million overall increase was allocated to NPC, Sierra, and the parent company using each entity's test-period payroll distribution percentages. (*Id.*) NPC provides that the jurisdictional allocated increase at NPC is $16.450 million. (*Id.*)

BCP's Position

280. BCP states that it conducted a review of NPC's payroll annualization adjustment and found that base pay increased by less than the amount requested by NPC. (Ex. 405 at 23.) BCP states that it further found that NPC's direct payroll increased by 9.19% above test-year levels, which BCP believes is high, but not as high as NPC's annualization calculation that was 9.45% above the test-year level. (*Id.*) BCP states that shared-services payroll ("SSP") was similar. (*Id.*) For SSP, BCP states that it calculated an increase of 13.23% compared to NPC's requested increase of 14.24%. (*Id.*) Additionally, BCP states that it has calculated an increase for the ("Sierra Pacific Resources") SPR payroll of 6.74% compared to NPC's requested increase of 7.05%. (*Id.* at 23-24.)

281. BCP states that NPC's overtime portion of payroll costs was higher than the overall test year percentages, but BCP found that this increase in overtime was explained by a relative increase in the bargaining payroll compared to the non-bargaining payroll. (*Id.* at 24.)

282. BCP states that its analysis deemed that, for NPC and each affiliate, the pay increases requested by NPC in its payroll adjustments were consistently higher than NPC's actual results. (*Id.*)

283. Accordingly, BCP recommends that the annualized base payroll adjustment be reduced based on the actual data for the May 21, 2023, pay period provided by NPC. (*Id.*) BCP does not recommend an adjustment to NPC's overtime payroll expense. (*Id.*)

NPC's Rebuttal

284. NPC disagrees with BCP's recommendation regarding an adjustment of the annualized payroll expense. (Ex. 204 at 24.) NPC explains that BCP calculates the annualized payroll by taking the base pay amount from the final full pay period of the certification period, which ended May 21, 2023, and multiplying it by 26 to produce an annual amount. (*Id.*) NPC states that it calculates the annualized base pay amount by taking the annual salary of all employees as of May 31, 2023, and summarizes that to determine the annual requirement for base pay. (*Id.*) NPC provides that it is understandable that BCP discovered a discrepancy between what was filed and BCP's calculation, based on the differences in the methodology. (*Id.*)

285. NPC explains that a singular pay period is not necessarily representative of the requirement for the full year – it could potentially contain reduced wages for unpaid time off. (*Id.* at 24-25.) Additionally, NPC states that using the pay period ending May 21, 2023, would not capture any changes to base pay that potentially occurred during the last 10 days of the month for items such as new hires who started during that period, promotions or job changes, or any departures that could have taken effect during that period as well. (*Id.* at 25.) NPC argues that the BCP provides no compelling evidence for the Commission to order a change in the payroll

annualization methodology, which has been in place since at least 2000 at NPC, other than BCP's method results in a lower annualization, and thus BCP's recommendation should not be accepted. (*Id.*)

Commission Discussion and Findings

286. The Commission finds no basis to depart from the method that NPC has used since 2000 to calculate payroll annualization. NPC's approach to calculate the annualized base pay amount by taking the annual salary of all employees as of May 31, 2023, and summarizing that to determine the annual requirement for base pay is a reasonable and consistent method to determine annualized payroll for rate setting purposes.

H. Advertising Expenses

NPC's Position

287. NPC provides that Schedule K-2 analyzes recorded charges and credits in FERC Account 908, Customer Assistance Expenses; Account 909, Informational and Instructional Advertising Expenses; and Account 930.1, General Advertising Expenses. (Ex. 139 at 6.) NPC explains that the schedule describes services provided, names of firms rendering these services, and amounts recorded during the test year for such services. (*Id.*)

BCP's Position

288. BCP provides that NPC requests recovery for advertising expenditures for an electrical safety website, gas safety website, and letters sent to schools for public safety education. (Ex. 408 at 3.) BCP notes that the websites have been cancelled and are unavailable. (*Id.*) In addition, BCP states that the expenses have been incorrectly recorded in Account 930.1 instead of in Account 909. (*Id.*) BCP explains that because the websites have been cancelled and

are unavailable, these expenses are non-recurring and should not be factored into future rates. (*Id.*)

289. BCP provides that the appropriate account for recording such expenses would be FERC Account 909 as the only advertising account for which an electric utility in Nevada would be allowed to recover the costs from its customers rather than its shareholders. (*Id.* at 4.) BCP explains that recording such advertising expenses in Account 930.1 is incorrect because FERC Account 930.1 is intended for advertising expenses which are designed to improve the goodwill and image of the utility. (*Id.* at 5.)

290. BCP does not agree that these expenses should be recoverable because the websites have been cancelled. (*Id.* at 7.) Therefore, BCP states that these expenses should not be factored into future rates, as they will be considered non-recurring and will not have an impact on the future rates. (*Id.*) As such, BCP recommends that the Commission find the non-recurring advertising expenses for the cancelled websites ineligible for recovery in future rates. (*Id.*)

Commission Discussion and Findings

291. The Commission accepts BCP's recommendation that these expenses not be factored into future rates, as they will be considered non-recurring and will not have an impact on the future rates.

I. Customer Service Costs – Active TeleSource

Staff's Position

292. Staff recommends that the Commission deny recovery of $660,000 of the costs of NPC's customer service contract with Active TeleSource to reflect the poor quality of service that its customers received during the test period. (Ex. 306 at 1.)

293. Staff states that Staff's internal tracking of customer service complaints showed a sharp increase in NPC customer complaints and that customer complaints more than doubled in 2022. (*Id.* at 2.) Staff states that it was concerned about the metrics reported regarding "Cumulative Service Level" and the "Abandoned Calls Percentage" in Docket No. 23-03036. (*Id.* at 3.) Staff provides that, according to NPC, the Cumulative Service Level declined by 18 percent, from 80.6 percent in 2021 to 62.5 percent in 2022. (*Id.*) Staff further states that NPC reported that the percentage of Abandoned Calls skyrocketed in 2022 to 30%, up from 7% in 2021. (*Id.* at 3-4.)

294. Staff explains that NPC is requesting recovery of approximately $2.2 million dollars for its contract with Active TeleSource annually. (*Id.* at 4.) Staff states that this is problematic because the quality of service that ratepayers paid for during the test period, particularly from this subcontractor, fell far short of what should be reasonably expected from NPC. (*Id.*)

295. Accordingly, Staff recommends that the Commission disallow 30% of the costs of Active TeleSource from recovery in rates. (*Id.* at 5.) Staff states that it makes this recommendation based on the fact that Active TeleSource is contracted to provide customer service as an outside call center and the fact that 30% of the calls to the customer service department were abandoned. (*Id.*) Staff states that this implies that, at a minimum, 30% of customers were effectively denied prompt service during the test period. (*Id.*) Staff argues that it is unreasonable to expect customers to pay for a contract that effectively only provided 70% of the services that it was supposed to provide. (*Id.*)

296. Additionally, Staff argues that NPC should be able to communicate to its own customers about what it has filed with the Commission. (*Id.* at 6.) Therefore, Staff recommends

that NPC include, both in its training of its new employees and as needed for its seasoned call center employees, talking points regarding the filings that have been made at the Commission for each and every case. (*Id.*) Staff further recommends that NPC track customer complaint calls that come in and are handled internally by its customer service representatives, in addition to tracking the amount of time that a customer spends in its Interactive Voice Response ("IVR") system. (*Id.*) Finally, Staff recommends that NPC be able to provide customers with a three-year chart/spreadsheet of the customer's electricity usage, which Staff argues often helps the customer understand the problem or issue that they inquired about more clearly. (*Id.*)

NPC's Rebuttal

297. NPC disagrees with Staff's suggestion that the Commission deny recovery of $660,000 of the costs of NPC's customer service contract with Active TeleSource. (Ex. 200 at 3.) NPC states that the full amount of NPC's customer service contract should remain in NPC's revenue requirement because NPC uses Active TeleSource as a flexible solution for overflow management that supports NPC's continuity and mitigates employee-staffing needs. (*Id.*) NPC states that it recognizes that the percentage of calls abandoned during the test period was higher than ideal. (*Id.*) NPC explains that the attrition rate NPC faced had a profound impact on the contact center operations and overall performance. (*Id.*) However, NPC argues that that does not warrant a reduction to the revenue requirement for costs that were incurred to contract with Active TeleSource to assist in resolving the issue. (*Id.*) NPC provides that, at a time when high attrition was affecting NPC, Active TeleSource was able to ramp up quickly, which was a valuable resource for NPC. (*Id.*)

Commission Discussion and Findings

298. The Commission rejects Staff's recommendation to deny recovery of $660,000 of the costs of NPC's customer service contract with Active TeleSource because NPC continues to use Active TeleSource for overflow management and to mitigate employee staffing needs. However, the Commission agrees with Staff that the customer service that NPC customers received during the test period was inadequate. Rates are designed to cover adequate staffing to ensure that customers can access NPC in a timely fashion, particularly during periods of challenges for customers, and NPC must ensure that this is a priority.

299. Pursuant to the Order in Docket No. 15-06064, NPC and Sierra are required to make an annual filing with the Commission regarding quality-of-service metrics. During the hearing, witnesses for both Staff (Tr. at 614) and NPC (Tr. at 772) discussed additional metrics that could benefit customers. As a directive, NPC shall request additional metrics and actions that would be productive to ensure adequate customer service in its 2024 filing pursuant to Docket No. 15-06064. The Commission is aware that this filing is noticed as an informational filing; however, NPC or any other person may request Commission action in response to this directive.

J. NDPP Costs – FERC Account No. 588

Staff's Position

300. Staff recommends that the Commission deny recovery of $517,791 from the revenue requirement regarding Miscellaneous Distribution Expenses that were inappropriately included in FERC Account No. 588, and that were disallowed as a regulatory asset in the NDPP docket. (Ex. 306 at 7.)

NPC's Rebuttal

301. NPC agrees with Staff's recommendation to remove $517,791 from the revenue requirement relating to Miscellaneous Distribution Expenses that were incorrectly requested in this Docket. (Ex. 204 at 8.) NPC explains that these costs were inadvertently included expenses and should have been included in H/I-CERT-24, which would have removed the costs from revenue requirement. (*Id.*) NPC states that the appropriate adjustment will be reflected in the final revenue requirement filed at Compliance. (*Id.*)

Commission Discussion and Findings

302. The Commission finds that $517,791 shall be removed from the revenue requirement relating to Miscellaneous Distribution Expenses because they were disallowed as a regulatory asset in the NDPP docket. It remains NPC's responsibility to ensure that its general rate case filings comply with all other orders of the Commission.

K. Assembly Bill 405 Net Energy Metering Regulatory Asset

NPC's Position

303. NPC provides that the estimated balance of the Assembly Bill 405 ("AB 405") net energy metering ("NEM") Regulatory Asset at certification is $64,337,000 and, for consistency with the order in Docket No. 20-06003, it has been amortized over a six-year period, resulting in an annual amortization amount of $10,723,000. (Ex. 139 at 16.)

Joint Petitioners' Position

304. Joint Petitioners state that NPC includes net-metering customers in the rate calculation for the otherwise applicable rate schedule and prices net-metering customers and non-net-metering customers using the same rates. (Ex. 901 at 4.) Joint Petitioners explains that, when calculating revenue requirement, NPC includes a regulatory asset in the amount of $63,930,000 to recover alleged lost revenues from the requirement in AB 405 that net-metering

customers be charged the same rates as non-net-metering customers since the 2020 GRC. (*Id.*) Joint Petitioners provide that, in response to Joint Petitioners' Data Request 37, NPC stated that "[t]he amount included in the NEM AB405 regulatory asset is the difference between cost-based revenues and general rate revenues." (*Id.*) Thus, Joint Petitioners argue that, even though rates in the 2020 GRC were designed in conformance with AB 405 and were designed to recover 100% of NPC's costs, NPC is seeking to recover additional shortfall revenues from net-metering customers in this case. (*Id.*)

305. Joint Petitioners state that nothing in AB 405 required the Commission to establish a regulatory asset with respect to net-metering revenues. (*Id.*) Joint Petitioners offer that the existence of a regulatory asset came from the Commission's investigation in Docket No. 17-07026, which occurred simultaneously with the 2017 GRC. (*Id.*) Joint Petitioners state that the regulatory asset was necessary to address the short-term impacts of AB 405, which required customers to migrate to otherwise applicable rate schedules, without addressing the revenue impacts. (*Id.* at 5.) Joint Petitioners argue that the regulatory asset was meant to be a short-term measure to address the transition to the new AB 405 framework, not a perpetual ratemaking mechanism or rate design method for net-metering customers. (*Id.*) Joint Petitioners maintain that this understanding is congruent with the concluding statement of the Commission's order in the 2017 GRC, which states:

> While it may be speculative as to whether and how much NV Energy may under-collect, (if it does so at all), fairness swings both ways. The PUCN has a legal duty to ensure NV Energy has an opportunity to earn a fair rate of return on its investment and be kept financially viable, especially as energy goals and technologies in Nevada evolve and grow. However, this is not a guarantee that there is no risk to the utility. Good cause appearing, and to accommodate this period of regulatory lag, the PUCN authorizes regulatory assets to protect NV Energy against any under-collection of revenues as Nevada's rooftop solar laws develop.

(*Id.* (citing Docket No. 17-07026, Order at 13.))

306. Joint Petitioners offer that the legal structure surrounding rooftop solar and net-metering is now fully developed, and the period of regulatory lag associated with incorporating the AB 405 requirements into rates has now lapsed. (*Id.* at 5.) Joint Petitioners point out that NPC sought recovery for the AB 405 NEM Regulatory Asset in the 2020 GRC and that, because the 2020 GRC was settled, the overall reasonableness of, as well as the methods used for, calculating the AB 405 net-metering regulatory asset were not expressly considered by the Commission nor contested in that docket. (*Id.* at 6.)

307. Joint Petitioners explain that NPC calculated its proposed AB 405 NEM Regulatory Asset by attempting to derive the number of net-metering customers using a calculation of the total net-metering basic service charge revenues divided by the basic service charge rate. (*Id.* at 7.) Joint Petitioners disagree with NPC's approach, stating that calculating lost revenues based on a comparison back to the hypothetical, full cost-of-service rates that would have been paid in the absence of AB 405 is not a valid cost or lost revenue to NPC. (*Id.*) Joint Petitioners point out that the hypothetical, full-cost rates were never charged to net-metering customers, nor were they considered in establishing rates in Statement O. (*Id.*)

308. Joint Petitioners provide that Statement O does not calculate cost-based rates for net-metering customers; rather, the rates calculated in Statement O are designed in such a manner that requires other customer classes to provide a subsidy, either directly or indirectly, to net-metering customers. (*Id.* at 8.) Joint Petitioners argue that NPC's approach, by using the hypothetical full-cost net-metering rates, essentially aims to recoup the cost of the subsidy that is already covered by other customers' rates. (*Id.*)

309. Joint Petitioner state that the migration of customers to net-metering service did not produce a net-negative impact on NPC's overall margins because the subsidies paid by non-net-metering customers to cover the revenue shortfall from AB 405 increased by more than the load lost from net-metering migrations. (*Id.* at 12-13.) Joint Petitioners further state that, to the extent that NPC can affirmatively demonstrate that the revenues are included in the earnings sharing calculation, the earnings sharing amounts should also be adjusted to reflect the removal of the deferred revenues. (*Id.* at 13.)

BCP's Position

310. BCP explains that, in 2020 GRC, the AB 405 NEM Regulatory Asset was resolved by stipulation and that the stipulation did not address whether or to what extent NPC has experienced a revenue deficiency due to net metering. (Ex. 405 at 17.) Further, BCP provides that the stipulation did not defer this issue to a future proceeding and that the Commission did not specifically address the regulatory asset either during or after the 2020 GRC. (*Id.*)

311. BCP states that, in 2017, the Commission approved a stipulation among the parties to defer the decision regarding the NEM regulatory asset until NPC's 2020 GRC. (*Id.*) BCP maintains that because there was no further reference to maintain the NEM regulatory asset, NPC's NEM regulatory asset ceased to exist at the conclusion of that proceeding. (*Id.* at 17-18.) Accordingly, BCP recommends that the Commission reject NPC's proposed recovery of the NEM regulatory asset in this proceeding and adjust NPC's rate base and amortization expense by $63.9 million and $10.7 million, respectively. (*Id.* at 18.)

Staff's Position

312. Staff maintains that the Commission's authorization of the AB 405 NEM Regulatory Asset ended at the conclusion of NPC's 2020 GRC. (Ex. 318 at 6.) Staff explains that in NPC's 2017 GRC application, NPC requested that the Commission extend the AB 405 NEM Regulatory Asset approved in Docket No. 17-07026 until NPC's next GRC, which was the 2020 GRC. (*Id.*) Staff provides that the Commission approved the extension in its 2017 GRC order. (*Id.*) Staff states that no extension was authorized in the 2020 GRC. (*Id.* at 7.) Staff explains that NPC did not request an extension in its 2020 GRC application, the stipulation filed in NPC's 2020 GRC did not include an agreement to an extension, and the Commission's 2020 GRC order did not grant an extension. (*Id.*) Therefore, Staff argues that regulatory asset treatment for AB 405 ended at the conclusion of NPC's 2020 GRC. (*Id.*)

313. Staff further explains that in the 2017 GRC order, the Commission extended the AB 405 NEM Regulatory Asset because there was an ongoing investigation to determine what, if any, financial impact NEM may have on Nevada customer rates. (*Id.*) Staff provides that the 2017 GRC order extending the regulatory asset until the next GRC was based on the uncertainty surrounding NEM at the time. (*Id.*) Staff argues that uncertainty no longer exists. (*Id.*)

314. Regarding the risk of revenue under-collection if the regulatory asset is not approved, Staff states that the NEM AB 405 monthly balances are based on the increase of customers under the NEM-405 Rider since the end of the certification period in the 2020 GRC. (*Id.* at 8.) Staff states that this reflects a change in billing determinants used in the 2020 GRC. (*Id.*) Staff offers that any changes in billing determinants can cause revenue collection to deviate from the authorized revenue requirement. (*Id.*) Staff provides that there is no regulatory asset treatment for lost revenue. (*Id.*) Thus, Staff maintains that approved rates remain "just and reasonable" until new rates are established at the next GRC. (*Id.*)

315. To mitigate risks of under-collection, Staff points out that AB 524 (2023) allows NPC to file a GRC more often than every 36 months. (*Id.* at 9.) Staff explains that if NPC is concerned that it is under-collecting for whatever reason, it has the option to file a new rate case. (*Id.*) Additionally, Staff provides that NPC could also request a full revenue decoupling mechanism pursuant to NRS 704.785(1)(b) to ensure that actual revenue equals authorized revenue. (*Id.*) In any event, Staff notes that NPC has not been under-earning as NPC's ROR and ROE exceeded its authorized ROR and ROE for all but one quarter during the entire period since the rates from the 2020 GRC were effective. (*Id.* at 9-10.)

316. In conclusion, Staff recommends that the Commission deny NPC's request to recover $63.93 million, with carrying charges, as an AB 405 NEM Regulatory Asset. (*Id.* at 10.) Staff provides that if the Commission should allow recovery of the AB 405 NEM Regulatory Asset, Staff recommends that the Commission also determine if tracking and recovery should continue, and if so, at which point it should cease, what should be recorded, how it should be calculated, and if future recovery should be limited. (*Id.* at 10-11.)

NPC's Rebuttal

317. NPC asserts that the AB 405 NEM Regulatory Asset was vetted in prior GRCs and approved in a fully litigated GRC. (Ex. 210 at 13-15.) NPC points out that there was no objection to the inclusion of the AB 405 NEM Regulatory Asset in rate base by any of the parties in Sierra's 2022 GRC. (*Id.* at 15.) NPC states that the Commission has treated the cost-recovery associated with the AB 405 NEM Regulatory Asset the same between Sierra and NPC, and sees no reason why now the two utilities should be treated differently. (*Id.*)

318. NPC argues that the AB 405 NEM Regulatory Asset is still necessary as there is a cost difference between providing service to NEM customers and the other members of NPC's residential classes. (*Id.* at 16.)

319. NPC recommends that the Commission approve the request as filed, consistent with the 2022 Sierra GRC, Docket No. 22-06014, as well as prior GRCs. (*Id.* at 19.) NPC states that if there are questions about the future of the regulatory asset, those are not appropriately vetted in this docket but must be determined, communicated, and implemented in a prospective manner. (*Id.*)

320. NPC states that there are several reasons why recovery of the AB 405 NEM Regulatory Asset should be approved in this docket, consistent with Commission practice and decisions dating back to 2017. (Ex. 208 at 3.) NPC provides that, when looking back at Commission orders, there is no directive or even indicative language from the Commission for NPC or Sierra to cease use of the regulatory asset; to the contrary, there is a record of continuous approval, including the most recent decision that was rendered in December of 2022. (*Id.*) NPC explains that the fact that customers continue moving to NEM service means that NPC continues to under-collect the costs of service, and this under-recovery should be accounted for in the regulatory asset to provide NPC with a fair opportunity to earn its Commission-authorized revenue requirement. (*Id.*)

321. NPC argues that if the Commission were to disallow recovery of the AB 405 NEM Regulatory Asset, it would result in a $94.1 million 2023 adjustment, offset by what should be a $23.8-million earnings-sharing adjustment, and a $14.8-million tax adjustment, thus resulting in a $55.5-million immediate write-off for NPC in 2023. (*Id.* at 8.) NPC asserts that this is a serious punitive financial outcome against NPC when it was acting consistent with what

has been a historic practice since 2017 and a practice that was confirmed by the Commission as recently as December of 2022 in Sierra's general rate review. (*Id.* at 9.) NPC has calculated the need for a revenue requirement increase of $96.5 million to appropriately cover its cost of service and to have a fair return on its investment on behalf of customers. (*Id.*) NPC explains that terminating the AB 405 NEM Regulatory Asset in this proceeding and disallowing the balance in that regulatory asset would not only prevent NPC from the recovery of actually experienced costs of service, but would also be inconsistent with established Commission practice since at least 2017. (*Id.*)

322. At the Rate Design hearing, NPC introduced an errata to its testimony providing updated calculations to the AB 405 NEM Regulatory Asset in which NPC provides that the updated balance of the regulatory asset is $43.262 million, including $5.083 million in carry charges, amortized over six years at $7.210 million per year. (Ex. 213 at Exhibit Morley-Rebuttal-1.) Using this updated calculation, NPC further provides that, if the Commission were to disallow recovery of the AB 405 NEM Regulatory Asset, it would result in a $59.3-million 2023 adjustment, offset by what should be a $16.8-million earnings-sharing adjustment, and a $8.9-million tax adjustment, thus resulting in a $33.6 million immediate write off for NPC in 2023. (Ex. 214 at 8-9.) In light of the errata, NPC states that, after accounting for the change in earnings sharing, the resulting change to the revenue requirement would be a net decrease of $1.8 million. (Ex. 215. at 20.)

323. NPC also provides an explanation for the genesis of its errata and the resulting updated calculations to the AB 405 NEM Regulatory Asset. (*Id.* at 19.) NPC states that during the hearing in this proceeding on October 24, 2023, there were questions during Staff's cross-examination of an NPC witness related to the Commission-approved 2020 compliance Statement

O. (*Id.*) NPC explains that this discussion led to NPC re-reviewing the 2020 compliance Statement O on October 24, 2023. (*Id.*) Upon this review, NPC elaborates that it discovered an error in the calculation of the cost-based NEM rates that occurred in the 2020 Statement O compliance filing. (*Id.*) Specifically, NPC states that the distribution costs were mistakenly included in both the calculation of the basic service charge and the per-kilowatt-hour ("kWh") charge. (*Id.*) NPC further explains that this resulted in an overstatement of the cost-based rates and, therefore, an overstatement of the difference between those rates and the otherwise applicable non-NEM rates. (*Id.*) NPC notes that that difference is used solely to calculate the AB 405 NEM Regulatory Asset, and the cost-based NEM rates are not used in any other calculation or outcome from Statement O. (*Id.*) NPC highlights that the Statement O calculation error did not impact any other rate. (*Id.*)

324. In response to Joint Petitioners' calculation of the AB 405 NEM Regulatory Asset, NPC provides that NPC is using the calculation outlined by the Commission. (Ex. 205 at 5.) NPC states that this calculation has been used in calculating three AB 405 NEM Regulatory Assets in previous rate cases and has not been disputed by any party. (*Id.*)

325. NPC states that, if it was not for the AB 405 NEM Regulatory Asset, NPC would have to absorb all of the revenue shortfall. (Ex. 206 at 3.) NPC highlights that the earnings-sharing mechanism and the fact that NPC may or may not have over-earned in a given year is a very separate and distinct issue that needs to be independently analyzed separate from the AB 405 NEM Regulatory Asset. (*Id.*) NPC explains that the fact that the earnings-sharing mechanism has been triggered does not justify ignoring the under-collection of $63.9 million in AB 405 NEM-related costs (or $43.3 million if the Commission accepts the revised AB 405 NEM Regulatory Asset calculation), which are true costs of service. (*Id.*; Ex. 213 at 4.) NPC

points out that the dramatic increase in the number of AB 405 NEM customers in recent years has made the AB 405 NEM Regulatory Asset even more important. (Ex. 206 at 3.)

326. NPC provides that contrary to the assertions of Joint Petitioners, NPC does not utilize hypothetical rates for NEM customers, in either the calculation of the NEM regulatory asset or when designing rates. (Ex. 207 at 2.) NPC states that as required by AB 405, NPC must charge the same rates to both the NEM and non-NEM customers from the same class. (*Id.*) NPC states that cost-based rates are used for NEM customers in the calculation of the NEM regulatory asset. (*Id.* at 3.) NPC further rejects Joint Petitioners' assertion that the rates designed in the 2020 GRC reflect all revenue shortfalls related to NEM. (*Id.*) NPC also rejects that customer migration to NEM service results in a decrease in kWh sales as suggested by some intervenors. (*Id.* at 6.)

327. NPC provides that the current mechanism in place for NEM customers in Nevada allows for the monthly netting of their excess energy production against their energy usage as opposed to a more equitable mechanism that would net production to their usage on a fifteen-minute or hourly basis, as the production occurs. (*Id.* at 7.) NPC elaborates that monthly netting allows for NEM customers to avoid more of the costs to serve them by compensating them at 100 percent of the full retail rate of energy for all excess production up to the amount of energy provided to them by the utility in that month. (*Id.*)

328. NPC states that the interclass rate rebalancing ("IRR") mechanism is in place to implement policy decisions from the State legislature and the Commission to ensure that the appropriate revenue requirement is recovered from all existing customers while incorporating other policy considerations. (*Id.* at 9.) Conversely, NPC provides that the AB 405 NEM Regulatory Asset is in place to track and recover the shortfall from new NEM customers, or in

other words, customers who take NEM service subsequent to those included in the previous GRC. (*Id.*) NPC offers that the IRR occurs when the revenue requirement for any class is set at a level different from their cost-based level, and therefore is not directly related to NEM customers. (*Id.*) NPC asserts that the use of the IRR in Statement O does not negate the need for the AB 405 regulatory asset. (*Id.* at 10.)

Commission Discussion and Findings

329. The Commission agrees with NPC that the AB 405 NEM Regulatory Asset was initiated in the 2017 GRC as a methodology to allow for implementation of the statutory requirements of AB 405 while holding NPC harmless for any potential GRC revenue shortfall. The existence and amount of the NEM potential shortfall has been discussed, litigated, and reviewed in dockets going back to Docket Nos. 15-07041 and 15-07042, and was discussed in SPPC's GRC, Docket No. 16-06006, prior to AB 405 being signed into law. While rates are set in a GRC docket to take any potential NEM GRC revenue shortfall into consideration as of the end of the certification period, these rates do not in themselves account for any incremental NEM customers after that date and in the rate-effective period (i.e., those who subsequently take service pursuant to NPC's AB 405 tariff).

330. There is no explicit indication in the order in Docket No. 17-06003 that the regulatory asset established was to expire or that the approval was evergreen. The order in that docket appears to contemplate that the regulatory asset would be addressed in NPC's next GRC, which was Docket No. 20-06003. That docket was settled without any specificity regarding the AB 405 NEM Regulatory Asset, either to continue or to cease. NPC had no basis to believe that the regulatory asset methodology would not continue to be allowed and proceeded to record its calculated NEM revenue shortfall in the AB 405 NEM Regulatory Asset. Nonetheless, the

Commission reminds NPC that the scope of requests made in a general rate case are NPC's responsibility.

331. NPC is requesting to recover an adjusted AB 405 NEM Regulatory Asset in the amount of $43.262 million, including $5.083 million in carry charges, amortized over six years at $7.210 million per year. (Ex. 213 at Exhibit Morley-Rebuttal-1.) The Commission finds that NPC shall exclude carry charges on the regulatory asset and recover $38.179 million over three years at $12.726 million per year. In addition, the Commission finds that the balance of the AB 405 NEM Regulatory Asset shall not be included in rate base for the purposes of determining the revenue requirement in the instant docket.

332. The Commission also finds that the regulatory liability established for the earnings-sharing mechanism should be reduced as necessary for the AB 405 NEM Regulatory Asset carry charge adjustment as well as the correction to the calculation decreasing the regulatory asset balance to approximately $43 million from approximately $64 million.

333. The AB 405 NEM Regulatory Asset is not a traditional regulatory asset in that it does not reflect recorded costs as they are incurred, as is the case with the regulatory assets established for the Natural Disaster Protection Plan or for the Energy Efficiency and Conservation programs, for example. The amounts recorded in the AB 405 NEM Regulatory Asset are based on the assumptions and cost allocations of cost of service at certification in the previous GRC. It is a calculated revenue shortfall based on that information at a singular point in time, and is the best available information, but may not reflect current costs or any incremental revenues, such as from increases in non-NEM customers in the affected class or in the IRR revenues that may have been collected from other rate classes.

334. The Commission finds that carry charges should not accrue on the AB 405 NEM Regulatory Asset as the calculation already includes a return component. It is not appropriate for this regulatory asset to earn a return on the return and compound the revenues calculated in the regulatory asset. Similarly, the Commission finds that the balance of the AB 405 NEM Regulatory Asset should not be included in rate base as that would also provide a compounding of returns on the revenues calculated.

335. NPC is also ordered to cease recording any amounts to the AB 405 NEM Regulatory Asset subsequent to the end of the certification period. The Commission is not authorizing the AB 405 NEM Regulatory Asset going forward, but rather directs NPC to explore methodologies or regulatory solutions to address the AB 405 NEM GRC potential revenue shortfall. Despite the language in NRS 704.773, there are other methodologies to limit the impact of NEM customers not paying the full cost of service. NPC shall include in its next general rate case application a recommendation or recommendations that could address such potential revenue shortfall associated with NEM.

L. Relocation Expense

NPC's Position

336. NPC provides that it pays signing bonuses, retention bonuses, and other bonuses, as well as severances and relocation expenses to its employees, based upon particular circumstances. (Ex. 177 at 42.) NPC states that relocation costs, signing bonuses, other bonuses, and retention payments for non-executives are included in the revenue requirement calculation for this case. (*Id.*)

Staff's Position

337. Staff recommends that the Commission disallow the entirety of NPC's relocation expense, resulting in a $252,060 reduction to NPC's revenue requirement. (Ex. 304 at 6-7.)

338. Staff provides that NPC states that it is common across all industries to provide relocation assistance for hard-to-fill and/or critical positions. (*Id.* at 7.) Through BHE, Staff states that NPC provides the Relocation Benefits Program to support and reduce relocation expenditures and disruptions. (*Id.*) Staff highlights that the program states that "at the time of the position posting, the hiring manager will determine if the position is eligible for relocation benefits." (*Id.*) Further, Staff points out that not all positions are eligible for relocation benefits, and some are only eligible for partial relocation benefits. (*Id.*)

339. Staff further explains that the BHE program provides 13 specific relocation benefits, one of which, described as a Miscellaneous Relocation Allowance, was given to each of the 22 employees for which NPC is requesting relocation expenses to be recovered in its revenue requirement. (*Id.*) For these eligible employees, Staff states that NPC may pay up to one month's salary to cover miscellaneous expenses. (*Id.*) Staff provides that NPC states that by offering a reasonable lump-sum payment and supportive services, expenses are capped, and the employee is given responsibility to make appropriate choices relating to their relocation. (*Id.*) Staff explains that the BHE relocation benefits program states that "the policy is not intended to cover all costs incurred during the relocation." (*Id.*) As defined by the program, Staff explains that relocation benefits are required to be repaid on a prorated basis if the employee quits or is terminated within a one-year period of the employee's start date. (*Id.*)

340. Staff states that the BHE relocation program uses HomeServices Relocation Consultant (a BHE affiliate) to provide benefits to relocating employees. (*Id.* at 8.) Staff explains that, for each eligible recipient, NPC pays HomeServices $385 for combined servicing

and software licensing fees. (*Id.*) Staff states that NPC defines its program as a lump-sum plan instead of a traditional relocation package where moving expense receipts are kept by the employee who is then reimbursed based on the validity and appropriateness of each expense. (*Id.*) Staff explains that this traditional type of package, according to NPC, requires ongoing management and administration expenses through a vendor resulting in higher costs, along with additional employee burdens, versus a lump-sum program. (*Id.*) Staff provides that the total relocation benefits included in the revenue requirement equal $252,060, which averages $11,457 per recipient. (*Id.*)

341. Staff states that it understands NPC's need to find and attract necessary talent; however, Staff questions how NPC implements the BHE Relocation Benefits Program. (*Id.*) First, Staff points out that the program allows the hiring manager to determine which positions are eligible for relocation benefits. (*Id.*) Staff highlights that the program does not list eligible positions, instead leaving it to the hiring manager's discretion. (*Id.*) Additionally, Staff explains that the program states that those employees receiving a "Miscellaneous Relocation Allowance" are entitled to up to one month's salary. (*Id.*) Staff asserts that NPC does not appear to have any program guidelines detailing specific instances when an employee should receive one month's salary or a lesser amount. (*Id.*) Staff argues that both the employee eligibility requirement and relocation payment amounts appear discretionary and arbitrary. (*Id.*) Staff states that it would prefer to see program guidelines where positions are eligible for relocation benefits, as well as criteria for any relocation payment given, such as, for example, payments based on the distance of a potential move or the number of family members included in a move (needs-based). (*Id.*) Staff offers that, without being provided a detailed accounting of each employee's relocation, Staff can contemplate an instance where a higher-salaried employee could be granted one

month's salary for a less-costly move versus an employee with a family receiving less than one month's salary with greater relocation expenses. (*Id.* at 8-9.) Staff states that it is especially concerning that the program does not address whether or how unspent payments should be returned to NPC. (*Id.* at 9.) Staff states that it believes that unspent relocation payments act as a de facto relocation bonus instead of a program to facilitate the reimbursement of just and reasonable moving expenses. (*Id.*)

342. As such, without specific program guidelines addressing position eligibility requirements, equitable payment amounts, and financial accountability measures, Staff proposes a 100% disallowance, thus insulating ratepayers from any unreasonable and arbitrary relocation costs. (*Id.*) In future NV Energy rate case proceedings, Staff states that it intends to request historical relocation costs to compare with those being requested in rates. (*Id.*)

343. Staff recommends that the Commission accept Staff's calculation to disallow the entirety of NPC's relocation expense, resulting in a $252,060 reduction to Statement I. (*Id.*) Staff explains that it calculated the relocation disallowance by summing test-year relocation payments, related gross-up amounts, and total affiliate fees, which totaled $252,060. (*Id.*) However, Staff notes that at the time of filing its testimony, NPC had not provided the necessary jurisdictional allocator percentage or the amount of the repayments to be removed from the total, thus hindering Staff's attempt to calculate a more accurate disallowance. (*Id.*)

NPC's Rebuttal

344. In response to Staff's critiques of the relocation program, NPC provides that there are defined eligibility requirements that provide relocation assistance for hard-to-fill and/or critical positions. (Ex. 177 at 8.) NPC explains that hard-to-fill and critical designations are not limited by job title and may vary based on changing market and business conditions. (*Id.*) NPC

notes that the lump-sum payment amount offered under the program is defined as up to one month's salary to cover miscellaneous expenses and provides that this guideline allows for flexibility up to a fixed maximum to ensure equity. (*Id.*) NPC explains that any relocation requests are approved and processed through human resources to ensure eligibility requirements are met and payment amounts are equitable. (*Id.*) NPC disagrees with Staff that the relocation program costs are unreasonable and arbitrary. (*Id.*)

345. NPC also disagrees with Staff's calculations of the relocation disallowance. (Ex. 204 at 15.) NPC notes that the total of the test-year relocation payments and related gross-up amounts attributable to NPC is $275,641.04, which is more than the adjustment regardless of affiliate fees. (*Id.*)

346. NPC highlights that Staff requested a specific calculation showing the reduction to the revenue requirement should the Commission disallow 100% of the requested relocation payments in Staff DR 327. (*Id.*) NPC states that, in its response to Staff, NPC summarized the total adjustment, including the tax gross-up. (*Id.*) NPC notes that the adjustment provided to Staff totaled $216,000, a difference of $36,060 from Staff's calculation, which represents the jurisdictionalized OMAG portion of both the relocation payments and tax gross-up, plus any necessary payroll tax adjustments. (*Id.*)

347. NPC also disagrees with Staff's representation that only 22 employees received a relocation bonus. (*Id.* at 15-16.) NPC notes that, during discovery, NPC provided Staff with information that depicted 24 employees that have received this relocation bonus. (*Id.*) NPC clarifies that this would result in an average payout per recipient, utilizing Staff's recommended adjustment, of $10,502.50. (*Id.* at 16.) NPC provides that based on the total adjustment of

$216,000 provided by NPC to Staff, each recipient received $9,000 on average, an almost $2,500 per person differential from Staff's representation. (*Id.*)

Commission Discussion and Findings

348. The Commission rejects Staff recommendation to disallow the entirety of NPC's relocation expense. The Commission agrees with NPC that this is a reasonable tool to recruit qualified employees during a period of employee turnover. Further, NPC's clarification on rebuttal of the costs of the program demonstrates that its current program is likely more cost-effective than a traditional relocation package where moving expense receipts are kept by the employee who is then reimbursed based on the validity and appropriateness of each expense.

M. Insurance Coverage

NPC's Position

349. NPC states that NPC's allocable share of the annualized cost of property insurance has increased from $661,000 (as recorded on December 31, 2022) to $865,000 (estimated as of May 31, 2023). (Ex. 147 at 2.) NPC's allocable share of the annual cost of excess liability insurance has increased from $5,630,000 (as recorded on December 31, 2022) to $5,914,000 (as of May 31, 2023). (Ex. 149 at 1-2.) NPC's annual cost of fiduciary liability insurance has remained the same at $63,000. (Ex. 147 at 3.)

350. NPC states that, during the certification period, NPC's property values and exposures increased slightly relative to other insured assets in the program; thus, NPC's allocated share of premium costs increased. (*Id.*)

351. NPC experienced $2,168,065 in uncompensated costs to replace plant that was damaged by third parties. (Ex. 148 at 2.) NPC estimates that an additional $57,060 will be accounted during the certification period for this case. (*Id.*) NPC provides that these costs in

total reflect the costs incurred to replace the damaged plant, over and above the amounts collected from the individual(s) responsible for damaging the plant. (*Id.*)

BCP's Position

352. BCP argues that it is unreasonable to recover this $2,225,125 for third-party plant damage from captive ratepayers, as it creates an undue burden to already overly extended working families who struggle to pay their utility bills. (Ex. 408 at 10.) BCP states that the damaged assets were not covered by general insurance owned by NPC. (*Id.*)

353. BCP recommends that the Commission direct NPC to maintain an insurance policy which covers assets damaged by third parties to avoid undue burden to ratepayers. (*Id.* at 11.)

NPC's Rebuttal

354. NPC disagrees with the BCP that NPC should purchase insurance for damages to NPC's plants. (Ex. 197 at 2.) NPC explains that an insurance purchase for these damages is neither practical nor possible because this type of insurance does not exist in the market. (*Id.*) NPC provides that the type of insurance that pays for NPC's plant damage is property insurance, which NPC states it has and has always maintained. (*Id.*)

355. NPC states that transmission and distribution equipment is not commonly insured by utilities, including NPC, for several reasons:

a. There are no insurers who would sell insurance for damage to transmission and distribution lines;

b. The deductibles/retentions would be too high to result in insured events, resulting in a low likelihood of insurance ever paying; and

c. Insurance is based on a law of large numbers where many uniform or similar risks are needed to create a large enough pool to avoid adverse risk selection. (*Id.* at 4.) Each of NPC's transmission and distribution facilities differs in its location and exposure to outside forces; therefore, the transmission and distribution system would not be considered uniform enough to form an insurance product around. Conversely, properties like substations that are evaluated based on a defined geographic location are readily insured. (*Id.*)

356. NPC further disagrees that it is unreasonable to recover these expenses from ratepayers. (*Id.*) NPC explains that when NPC experiences damage to its facilities as a result of the actions of third parties, NPC makes reasonable efforts to recover the costs to repair that damage from the third party that caused the damage. (*Id.*) However, NPC provides that if NPC is unable to recover those costs from the third party, then costs are included with all of NPC's other plant additions for recovery in NPC's rate case. (*Id.*) NPC asserts that damaged facilities must be repaired or replaced to ensure the safe and reliable operation of the system, and because that provides a benefit to customers, it is reasonable to include those costs in rates for recovery. (*Id.* at 4-5.) NPC states that this is a normal expense in NPC's business to provide safe and reliable service. (*Id.* at 5.)

Commission Discussion and Findings

357. The Commission rejects BCP's recommendation to require NPC to maintain an insurance policy which covers transmission and distribution assets damaged by third parties given the lack of applicable insurance options in the market.

N. Economic Recovery Transportation Electrification Plan ("ERTEP") Regulatory Asset

NPC's Position

358. NPC is requesting recovery of approximately $1.545 million of costs associated with the ERTEP in the Applications. (Ex. 114 at Schedule 1-CERT 27.)

Staff's Position

359. Staff provides the context that Section 49 of Senate Bill ("SB") 448, passed by the 2021 Nevada Legislature, required NPC and Sierra to file a plan with the Commission to make capital investments to accelerate transportation electrification in Nevada not to exceed $100 million for the period January 1, 2022, through December 31, 2024, that are designed to provide the greatest economic recovery benefits and opportunities in Nevada. (Ex. 315 at 22.)

360. Staff states that, in reviewing supporting documentation for the ERTEP, Staff had difficulty discerning between ERTEP costs and Transportation Electrification Program ("TEP") and/or Clean Energy Program costs. (*Id.* at 23.) Staff recommends that NPC delineate the costs allocated for each program on all documentation supporting the request to recover those costs. (*Id.*)

361. Staff states that it has concerns regarding the ERTEP costs that NPC is seeking to recover, specifically the $1,404.02 of costs associated with travel, meals, and lodging that should not have been included in the revenue requirement requested in this GRC. (*Id.*) Staff asserts that NPC provided no indication of whether or how the costs would be removed and did not make any additional filings to correct these amounts. (*Id.*)

362. As such, Staff recommends that the Commission deny recovery of approximately $1,404.02 of costs associated with travel, meals, and lodging costs that are recorded in the ERTEP regulatory asset. (*Id.*)

NPC's Rebuttal

363. NPC agrees with Staff's recommendation to remove $1,404.02 of costs from the ERTEP regulatory asset. (Ex. 204 at 7.)

Commission Discussion and Findings

364. The Commission accepts Staff's recommendation to remove $1,404.02 of costs from the ERTEP regulatory asset due to NPC's agreement that these costs were improperly recorded.

O. Miscellaneous Projects for Approval/Recovery

NPC's Position

365. NPC states that it procured a spare transformer, rated at 230/138/13kV, 336 megavolt amperes ("MVA") that included provisions for long-term outdoor storage, including oil containment and foundation. (Ex. 159 at 69.) NPC provides that the transformer is suitable to replace the 336 MVA, 230/138 kV banks in southern Nevada in the case of a catastrophic event. (*Id.*) NPC states that the spare unit is stored at Substation "P." (*Id.*) NPC provides that the estimated total cost of the project was $3,682,051 (without AFUDC). (*Id.* at 70.) NPC states that the total completion cost of the project during the test period is $4,116,321 (with AFUDC). (*Id.*) NPC states that the projected costs during the certification period are $88,138. (*Id.*)

366. NPC provides that the Sunshine Valley Solar Affected System Upgrades (ABT) project is a transmission project involving the replacement of 27 structures along the existing Jackass Flats – Mercury 138 kV line to increase the maximum operating temperature to increase the rating of the line. (*Id.* at 65.) NPC states that the estimated total cost of the project was $2,296,782 (without AFUDC). (*Id.* at 66.) NPC provides that the total at completion cost of the project during the test period is $1,185,125 (with AFUDC). (*Id.*) NPC provides that projected costs during the certification period are $16,405. (*Id.*)

367. NPC states that the Lynnwood Substation Wall Rebuild (AA3) project involves the rebuild of the Lynnwood Substation perimeter wall due to severe deterioration and cracking in multiple places. (*Id.* at 53.) NPC states that the wall also enclosed the adjacent NPC-owned parcel. (*Id.*) NPC states that the estimated total cost of the project was $1,283,414 (without AFUDC). (*Id.* at 54.) NPC provides that projected total cost of the project during the certification period is $1,089,037 (with AFUDC). (*Id.*)

368. NPC presents critical substation physical security ballistic shield addition ECIC projects that provide for the acquisition, engineering, and installation of multi-sided critical transformer ballistic protective shields for 14 transformers located at two critical substations in NPC's service territory. (Ex. 162 at 3.) NPC explains that these projects improve the physical security posture of NPC's critical assets to mitigate impacts from ballistic attacks on the most critical substation transformers. (*Id.* at 5.) NPC states that the estimated total cost of the completed projects through December 31, 2023, is $31,672,839 (with AFUDC). (*Id.* at 9.)

369. NPC states that the Mojave High School Solar project is a 350-kW solar photovoltaic project located at Mojave High School, a Title 1 school on Clark County School District ("CCSD") property in North Las Vegas, Nevada, and has been in service since December 21, 2021, its commercial operation date ("COD"). (Ex. 165 at 9.) NPC states that the project includes newly-constructed carports that house a fixed-tilt solar system of approximately 1,000 photovoltaic modules that generate at least 773,000 kWh per year. (*Id.*) NPC provides that it is owned and operated by NPC and is the first Community Based Solar Resource as part of NPC and Sierra's Expanded Solar Access Program ("ESAP") mandated by Assembly Bill 465 ("AB465"). (*Id.*) NPC states that the project was approved by the Commission in Docket No.

20-07023. (*Id.*) NPC provides that the total estimated project cost is $1,615,937.49, including AFUDC. (*Id.* at 10.)

370. NPC states that the Network Infrastructure Project is set up as an annual "evergreen" program to provide the timely replacement of aged network infrastructure equipment. (Ex. 150 at 21.) NPC provides that the cost of the project through December 31, 2022, was $2,238,055 and that the total estimated cost through May 31, 2023, is $1,068,301 for an estimated total project cost of $3,306,355. (*Id.* at 23.)

371. NPC states that the Container Management Platform and Passport Upgrade ("Maximo") and its affiliated enhancement projects replaced Passport, Energy Supply's work management system. (*Id.* at 12.)

372. NPC states that the Infrastructure — Laptop PC project provides new and existing employees and contractors with the necessary equipment to perform their business functions and responsibilities. (*Id.* at 73.) NPC states that the estimated total project cost of the Laptop PC Project is $2,940,793. (*Id.* at 74.)

373. NPC states that the Intel Evergreen project is an ongoing process implemented shortly after Sierra and NPC first merged in 1999 to address growth in their respective IT needs, and to ensure adequate application performance through a scheduled technology refresh cycle. (*Id.* at 24.) NPC explains that the Intel Project is an annual process to refresh older hardware that has reached its end of life, specifically for Intel servers (Windows operating systems) and virtualized infrastructure. (*Id.*) NPC provides that the cost of the Intel Project through December 31, 2022, was $1,674,133. (*Id.* at 26.)

374. NPC states that the Oracle CX Engagement software is used as a customer relationship management ("CRM") tool that creates one repository of information for all things

related to a customer, including additional account contacts, important notes and billing, and usage history. (*Id.* at 55.) NPC provides that the purpose of CXM Communications, the customer experience ("CX") communications software, was to deploy a set of Oracle CX modules: Eloqua, Responsys, and Infinity. (*Id.*) NPC states that the estimated total cost for CX Engagement is $1,478,358, and the total estimated cost for CXM Communications is $862,526. (*Id.* at 61-62.)

375. NPC provides that the M365 project supported the purchase of Microsoft 365, cloud security, and Windows Enterprise Client licensing. (*Id.* at 62.) NPC states that the total cost of the project through December 31, 2022, was $1,026,639. (*Id.* at 63.)

376. NPC provides that the Clark Peaker Ovation Migration project will migrate the Emerson Ovation Control System now in place, from its current version to the most recent version. (Ex. 155 at 67-68.) NPC states that the existing version of the Ovation Control System at Clark is Ovation 1.9 and that current production version of Ovation is 3.7. (*Id.* at 67.) NPC states that the upgrade will improve cybersecurity, physical security, and the reliability of the systems. (*Id.*)

377. NPC states that the Walt Higgins Distributed Control System (Ovation) Replacement project is required to replace its Siemens T3000 (T3K) Control System with the Emerson Ovation Control System in order to install a patchable (security) package and to ensure compliance with the Vulnerability Management Program ("VMP") and current NV Energy cybersecurity standards. (*Id.* at 72.)

378. NPC states that the Las Vegas Generating Station previously used a Glegg/GE designed Reverse Osmosis ("RO") system to produce the required high purity demineralized water for operations of plant equipment. (Ex. 156 at 17.) NPC states that the Las Vegas

Generating Water Treatment Building project replaced the existing RO system and supports facilities with a system that has greater efficiency, reducing OMAG cost and achieving greater dependability. (*Id.* at 18.)

BCP's Position

379. BCP recommends that the Commission issue a compliance item in its order that NPC schedule an on-site inspection for BCP and Staff engineers and accountants on or before December 31, 2023, to verify that the Clark Peaker Ovation Migration Project is complete and closed to plant-in-service (FERC Account No. 101) by December 31, 2023. (Ex. 401 at 4.)

380. BCP recommends the Commission order NPC to create a regulatory liability, with carrying charges at the pretax rate-of-return, to refund to customers in NPC's next general rate case the total revenue requirement associated with the Clark Peaker Ovation Migration Project if the onsite investigation by BCP and Staff determines that the project is not complete and closed to plant-in-service by December 31, 2023. (*Id.*)

381. BCP recommends that the Commission issue a compliance item in its order that NPC schedule an on-site inspection for BCP and Staff engineers and accountants on or before December 31, 2023, to verify that the Higgins Distributed Control System (Ovation) Migration Project is complete and closed to plant-in-service (FERC Account No. 101) by December 31, 2023. (*Id.*)

382. BCP recommends the Commission order NPC to create a regulatory liability, with carrying charges at the pretax rate-of-return, to refund to customers in NPC's next general rate case the total revenue requirement associated with the Higgins Distributed Control System (Ovation) Migration Project if the onsite investigation by BCP and Staff determines that the project is not complete and closed to plant-in-service by December 31, 2023. (*Id.*)

383. BCP recommends that the Commission disallow recovery from NPC's retail ratepayers the revenue requirement associated with the Sunshine Valley Solar affected system upgrades. (*Id.*)

384. BCP recommends that the Commission disallow recovery from NPC's ratepayers the revenue requirement associated with the following IT projects that had a payback period greater than 10 years: (1) Network Infrastructure; (2) Maximo for Generation; and (3) Laptop PC. (*Id.*)

385. BCP recommends that, during the rate-effective period, the Commission disallow recovery from NPC's ratepayers the revenue requirement associated with the following IT projects for which NPC failed to provide a cost-benefit analysis in its application: (1) Intel Server Evergreen; (2) CX Engagement and CXM Communications; and, (3) M365. (*Id.* at 4-5.)

Staff's Position

386. Staff recommends denying the request to approve the Spare 336 MVA 230/138/13.09 kV Transformer (TSIHV). (Ex. 313 at 1.) Staff states that it believes that NPC has not justified the need for three spare transformers to operate and follow the guidelines provided by the Edison Electric Institute Spare Transformer Equipment Program ("EEI"). (*Id.* at 3.) Staff provides that, according to NPC, only two spare transformers are required to meet the amount of transformer capacity required by EEI, and yet, with this new project, NPC will have three. (*Id.*)

387. Staff recommends denying the request to include the Beltway Substation New Driveway project in rate base and ordering NPC to place the cost of this project into Plant Held for Future Use. (*Id.* at 2.) Staff provides several reasons why it believes the project to be unnecessary and has not been justified at this time. (*Id.* at 5.) First, Staff states that NPC simply

justifies widening the gate entrance by four feet to help accommodate larger vehicle access by stating that the 20-foot gate entrance leads to longer deliveries. (*Id.*) Staff argues that this is not a reasonable justification to expend capital on a larger entrance. (*Id.*) Staff states that it understands that NPC procures transportation of large equipment deliveries; however, Staff believes that NPC could request a trailer size that would accommodate the 20-foot entrance. (*Id.*) Staff states that the second issue involves NPC's claim that it has plans to use the Beltway Substation for spare storage. (*Id.*) Staff states that NPC is currently not using the Beltway Substation for spare storage and has not indicated why the site is needed for storage, so Staff argues that making the entrance larger to accommodate spare storage is unreasonable at this time. (*Id.*) Staff provides that because the Beltway Substation is not being used for spare storage, the larger gate which was needed to allow for spare storage is not yet used and useful, and NPC has not outlined any timeframe for putting spares (such as transformers) at the site. (*Id.*) Staff notes that, in times where Nevada ratepayers are struggling with high energy prices, Staff believes that longer, undefined delivery times are insufficient justification for approval of this project. (*Id.*)

388. Staff recommends denying the request to include the Lynnwood Substation Wall Rebuild (AA3) project in rate base, which specifically pertains to the fencing around the adjacent North Parcel of Land (Parcel 1621011102), and order NPC to place the cost of this project into Plant Held for Future Use. (*Id.* at 2.) Staff states that the adjacent land has been owned by the Company since the 1960s and has not been used for any utility purposes since. (*Id.* at 7.) Staff asserts that it would be more prudent to enclose the area at the time of expansion, making the land and fencing used and useful. (*Id.*)

389. Staff recommends denying the request to include the Sunshine Valley Solar Affected System Upgrades (ABT) project in rate base and ordering NPC to place the cost of this project into Plant Held for Future Use. (*Id.* at 2.) Staff argues that this project is not providing any direct benefit to Nevada ratepayers. (*Id.* at 8.) Staff states that the project is really a subsidy being provided to California as it is a Nevada cost that allows the output of the resource to flow to California customers. (*Id.*) Staff provides that the increase in the maximum operating temperature that NPC claims its system receives by doing this project was not necessary for the Nevada transmission system, and the new capacity rating that the high thermal rating provides has not been used. (*Id.*) Staff further notes that, while Staff understands the FERC Order No. 2003 may have required NV Energy to pay for the upgrades, Staff asserts that FERC Order No. 2003 does not force the Commission to mandate that Nevada retail customers pay for the costs until the extra capacity is used and useful and providing a direct benefit to Nevada. (*Id.* at 9.)

390. Staff recommends that the Commission deny recovery of approximately $30.6 million of costs associated with the ballistic shield additions as the ballistic shield additions do not meet the ECIC requirements. (Ex. 315 at 19.) Staff explains that NPC identified the ballistic shield projects as qualifying for ECIC with an in-service date of December 29, 2023. (*Id.* at 18.) However, Staff states that at the time NPC filed its Applications (June 5, 2023), NPC had not contracted to install and commission the ballistic shields. (*Id.*) Furthermore, Staff states that even as of the date of its certification filing (August 21, 2023), NPC still had not contracted to install and commission the ballistic shields. (*Id.*) As such, at the time of filing, Staff asserts that there was clearly not an objectively high probability of these projects occurring because there are no guarantees that NPC will be able to find a contractor able to construct the ballistic shields by

the end of the ECIC period and/or execute a contract at a reasonable cost due to the expedited schedule. (*Id.*)

391. Staff recommends denying recovery of approximately $1.62 million of capital costs and approximately $1,430 of operations and maintenance ("O&M") costs associated with the Mojave High School Solar Project. (*Id.* at 19.) Staff explains that NPC included the Mojave High School Solar Project capital and O&M costs for recovery in the Expanded Solar Program Cost ("ESPC") rate in Docket No. 23-03005. (*Id.* at 20.) Staff states that the parties to Docket No. 23-03005 entered into a partial stipulation on July 19, 2023, agreeing that NPC will recover the Mojave High School Solar Project costs through the ESPC rate, and the Commission approved the partial stipulation on August 2, 2023. (*Id.*) As such, Staff argues that by including the costs associated with this project in this rate case, NPC is attempting to double-recover the costs of the Mojave High School Solar Project from customers. (*Id.*)

392. Staff recommends that the Commission deny NPC's request to recover the costs associated with the two projects identified as the Clark Peaker Ovation Migration project (project I.D. CS2207) and the Walt Higgins Distributed Control System (Ovation) Migration project, (project I.D. WH2159) because these routine, ongoing maintenance activities do not qualify as ECIC projects and should be excluded from the rate base additions in this docket. (Ex. 314 at 2.)

393. Staff recommends denying NPC's request to recover costs associated with the project identified as the Las Vegas Generating Water Treatment Building (project I.D. LC2192) because NPC failed to bring the project forward in its original filing and instead presented the project for the first time in its certification filing. (*Id.*) Staff states that the project should be excluded from the rate base additions in this docket. (*Id.*)

NPC's Rebuttal

394. NPC disagrees with Staff's recommendation to deny the Spare 336 MVA 230/138/13.09 kV Transformer (TSIHV) and provides that only two, not three, spare 230/138/13.09 kV transformers are required for the purpose of meeting NPC's obligation for participation in EEI, one of which has been submitted under this project. (Ex. 193 at 2.) NPC further explains that the third transformer referenced was provided as part of the Grid Resilience 230/138 kV 336 MVA Spare Transformer (TSI7E) project, which addresses the need for the unit. (*Id.* at 3.)

395. NPC disagrees with Staff's recommendation to deny the Beltway Substation New Driveway project. (*Id.* at 4-5.) NPC provides that the newly rebuilt gate and driveway is complete and is used and useful. (*Id.* at 5.) NPC states that it is being used on a regular basis as intended and is the primary access point for the substation. (*Id.*) As such, NPC asserts that the total costs should be included as part of the revenue requirement under this general rate case. (*Id.*)

396. NPC disagrees with Staff's recommendation to deny the Lynnwood Substation Wall Rebuild (AA3) project. (*Id.* at 6-7.) NPC provides that NPC crews are called to mobilize a few times a month to address intrusions onto the property, repairing the fence, clearing out encampments of unhoused persons, and cleaning up garbage and debris. (*Id.* at 7.) NPC states that these efforts are estimated to be costing upwards of $30,000 annually in O&M expenses. (*Id.*) NPC states that, as with all other substation perimeter wall projects, the entire wall is included in the revenue requirement upon completion of the project. (*Id.*)

397. NPC disagrees with Staff's and BCP's recommendations regarding the Sunshine Valley Solar Affected System Upgrades (ABT) project. (*Id.* at 7.) NPC provides that, as has been the practice with previous line-uprating projects that have been constructed to ensure

compliance with North American Electric Reliability Corporation ("NERC") defined transmission planning contingency standards, upon completion and re-energization of the transmission line, resulting in the increased capacity or maximum operating temperature of the line, the costs are considered plant in-service and can be included in the revenue requirement as part of the general rate case. (*Id.* at 11.)

398. NPC disagrees with Staff's recommendation regarding the ballistic shield additions. (Ex. 194 at 3.) NPC explains that the ballistic shield projects have an objectively high probability of occurring to the degree, in the amount, and at the time expected. (*Id.*) NPC provides that if NPC was not confident it could meet the ECIC requirements, it would have pulled this project from cost recovery in this case at certification; however, NPC provides that it now has two contracts in place to accomplish the installation and commissioning of the ballistic shields to meet the projected in-service dates. (*Id.* at 3-4.)

399. NPC agrees with Staff's overall recommendation to remove costs related to the Mojave High School Solar Project, and stated during discovery that it would do so. (Ex. 204 at 9.) However, NPC does not agree with the amounts proposed and states that the total costs for removal should be $1,404.02. (*Id.* at 11.)

400. NPC disagrees with BCP's recommendations to implement regulatory liabilities in the event ECIC projects are not closed to plant-in-service by December 31, 2023. (*Id.* at 21.) NPC states that it expects that the three ECIC projects that BCP addresses (1. Reid Gardner BESS; 2. Clark Peaker Ovation Migration; and 3. Higgins Distributed Control System (Ovation) Migration project) will be closed to plant-in-service on or before December 31, 2023, thus meeting the criteria for the consideration of an ECIC project to be included in the annual revenue requirement. (*Id.*)

401. NPC disagrees with BCP's recommendation for the Commission to order a visit to the Clark Generating Station and the Walt Higgins Generating Station. (Ex. 196 at 3.) NPC states that it provided Staff and BCP detailed project binders that included a considerable amount of project information for interveners to review that adequately address the project' completion before December 31, 2023. (*Id.*) In addition, NPC states that its generating facilities have always welcomed Staff and BCP to visit its generating stations, both during major outages and during normal operation, so a compliance order is not needed. (*Id.*)

402. NPC also provides that the Clark Generating Station and the Walt Higgins Generating Station projects should remain in rate base because these two ECIC projects are projects designed to replace control systems that no longer meet cyber-security standards, could be vulnerable to attack and, therefore, could put these generating plants at risk. (*Id.* at 4.) NPC notes that the existing control systems do not allow security patches to be installed to address the growing cyber-security threats. (*Id.*)

403. NPC disagrees with BCP's recommendation to disallow IT projects with a payback period of greater than 10 years. (Ex. 199 at 7.) These projects did not exceed budgeted amounts for the test or certification period and therefore did not require additional documentation. (*Id.*) NPC asserts that it is an essential cybersecurity issue to replace hardware, consistent with manufacturer recommendations, and not doing so would be imprudent. (*Id.* at 8.) NPC provides that BCP relied on unreliable sources regarding NPC's proposed IT programs and that enterprise software can last in an environment for 10 years, as long as appropriate upgrades are made for cybersecurity and user enhancement purposes. (*Id.*) NPC notes that many of the same IT programs at issue in this docket were previously filed, vetted, and ultimately approved by the Commission in Sierra's most recent rate review proceeding. (*Id.* at 9.)

Commission Discussion and Findings

404. The Commission approves for inclusion in rates the Spare 336 MVA 230/138/13.09 kV Transformer (TSIHV) as part of the Grid Resilience 230/138 kV 336 MVA Spare Transformer (TSI7E) project. Transformers are critical components for reliable service and require longer lead times for acquisition.

405. The Commission approves for inclusion in rates the Sunshine Valley Solar Affected System Upgrades (ABT) project involving the replacement of 27 structures along the existing Jackass Flats – Mercury 138 kV line to increase the maximum operating temperature to increase the rating of the line. The Commission agrees with Staff and NPC that FERC Order No. 2003 may require NPC to pay for the upgrades for the reliability of the transmission system. Nonetheless, NPC has provided limited transparency to ensure that all transmission customers who benefit from the upgrades are paying the appropriate cost share. Accordingly, similar to the directive in the section regarding the FERC transmission allocation, as a directive, NPC must meet and confer with Staff in advance of filing any future general rate case to discuss the information necessary to ensure all transmission customers are paying the appropriate cost share. Further, in any future general rate case, NPC shall provide details about its most recent FERC rate case and provide an explanation about NPC's plans for future rate-setting proceedings at FERC.

406. The Commission approves the Lynnwood Substation Wall Rebuild (AA3) project for inclusion in rates. The Commission finds that the perimeter fence increases the security of NPC's facilities and property and therefore, is used and useful.

407. The Commission rejects for inclusion in rates the substation physical security ballistic shield addition ECIC project as it does not qualify as an ECIC under NRC 704.110(4).

The Commission agrees with NPC and Staff that these projects provide valuable security upgrades to NPC's substations. However, the ECIC statute requires a project to be reasonably known and measurable with reasonable accuracy at the time when NPC files its application, with an objectively high probability of occurring to the degree, in the amount, and at the time expected. At the time of filing its application, NPC had not yet contracted for these projects and had limited details regarding the projects. The ECIC statute is not designed to capture all new plant projects that could close to plant between the end of the test period and 210 days later.

408. The Commission accepts Staff's recommendation regarding the Mojave High School Solar project is a 350-kW solar photovoltaic project located at Mojave High School. Docket No. 23-03005 provides that NPC will recover the Mojave High School Solar Project costs through the Expanded Solar Program Cost rate. The Commission finds that NPC's calculation of the rate base and amortization amount on rebuttal is correct.

409. The Commission approves the cost of the following information technology projects into rates:

i. The Network Infrastructure Project for an estimated total project cost of $3,306,355.

ii. The Maximo project and its affiliated enhancement projects.

iii. Infrastructure — Laptop PC project for an estimated total project cost of $2,940,793.

iv. The Intel Evergreen Project at an estimated cost of $1,674,133.

v. The Oracle CX Engagement software at an estimated cost for CX Engagement of $1,478,358 and at an estimated cost for CXM Communications of $862,526.

vi. The M365 project at a total cost of the project of $1,026,639.

410. The Commission finds that the purpose of the long-term IT strategy is to implement a common approach to replace legacy systems, improve cybersecurity, and enhance the customer and employee experience by leveraging buying power for IT procurement aggregation to drive cost-efficient pricing beyond what NPC can achieve alone. Many of these information technology system upgrades were reviewed in 2022 in Sierra's general rate case, and this is NPC's share of the common project.

411. The Commission accepts Staff's recommendation that the two projects identified as the Clark Peaker Ovation Migration project (project I.D. CS2207) and the Walt Higgins Distributed Control System (Ovation) Migration project (project I.D. WH2159) do not qualify as ECIC project pursuant to NRS 704.110(4) because these are routine, ongoing maintenance activities. The Commission recognizes that these projects are designed to replace control systems that no longer meet cyber-security standards. Similar to the discussion of the ballistic shields above, the ECIC statute is not designed to capture all new plant projects that could close to plant between the end of the test period and 210 days later.

412. The Commission accepts Staff's recommendation that the project identified as the Las Vegas Generating Water Treatment Building (project I.D. LC2192) does not qualify as an ECIC project because NPC failed to bring the project forward in its original filing and instead presented the project for the first time in its certification filing.

P. Vehicle Lease Transition

413. In its Applications, NPC provides that the total cost of vehicle fleet additions is $23,456,463. (Ex. 169 at 3.) NPC elaborates that total fleet additions were primarily due to the purchase of 68 vehicles and fleet equipment for $22.2 million, the buyout of 76 leased vehicles

and fleet equipment with an approximate residual value of $0.8 million, and the installation of safety systems (cameras and sensor technology) for $0.2 million. (*Id.*)

414. NPC states that NPC's Fleet Services performs vehicle lifecycle analysis to gauge the optimal replacement plan for each vehicle and fleet equipment class to achieve the ideal total cost to own and maintain vehicles and fleet equipment over their useful lives. (*Id.*)

415. NPC explains that NPC's finance department uses a present worth of revenue requirement ("PWRR") model to assess the economic impact of different alternatives for vehicle and fleet equipment analysis. (*Id.* at 4.) NPC states that the PWRR model allows NPC to compare the economic impact to the customer from buying versus leasing the vehicles and fleet equipment. (*Id.*)

416. NPC states that the PWRR analysis determined that it was not advantageous for NPC to purchase most of the existing leased vehicles before the end of the lease terms. (*Id.* at 5.) However, NPC states there were two leases that were set to expire within 12 months where the analysis showed that there was virtually no cost difference between an early lease buyout and a buyout at the end of the leases. (*Id.*) For this reason, NPC bought out the remaining two leases prior to the end of the lease term. (*Id.*)

417. NPC provides it expects longer useful lives for all vehicles versus the lease terms. (*Id.* at 4.) NPC explains that a leased vehicle is initially modeled as a lease with buyout at the end of the lease, typically a 5-7 year lease with an average age at retirement of 13.1 years. (*Id.*) Therefore, NPC states that as long as the vehicles meet safety and other condition-based standards and continue to be needed as determined by the overall fleet lifecycle analysis, vehicle buyouts at the end of the lease term will result in a lower PWRR than more frequent vehicle replacements via a lease or purchase. (*Id.*) NPC states that it purchased 74 vehicles and fleet

equipment at the end of the lease terms to continue to utilize the vehicles for the benefit of customers. (*Id.* at 4-5.)

418. NPC states that its PWRR analysis used a 3% marginal cost of capital and a 19-year total vehicle useful life. (Ex. 171 at 2.) NPC explains that under these assumptions, purchasing the vehicles was more favorable than leasing the vehicles and then buying at the end of term by $575,147 in PWRR terms. (*Id.* at 2-3.) NPC states that the PWRR for the lease-then-buy scenario equaled $7.0 million, and the PWRR for the purchase scenario equaled $6.4 million. (*Id.* at 3.)

Staff's Position

419. To maintain consistency across NV Energy GRCs, Staff recommends that the Commission, at a minimum, implement the same decision that it made in Sierra's last GRC (Docket No. 22-06014) with respect to NPC transition from leased vehicles to directly-purchased vehicles, and order NPC to create a separate rate base account that only earns a 3% ROR and require NPC to place all of the vehicle purchase costs in this new account. (Ex. 311 at 1-2.) Furthermore, Staff believes an additional adjustment is warranted in this case. (*Id.* at 2.) Based on Staff's review of the information provided by NPC, Staff states that there is substantial evidence that NPC utilized imprudent business practices in making the decision to transition from leased vehicles to directly-purchased vehicles and did not provide accurate information to the Commission. (*Id.*)

420. Staff provides that, if the Commission finds that substantial evidence of imprudent business practices and the provision of inaccurate information exists, the Commission should disallow NPC from earning any rate of return on the purchased vehicles. (*Id.*)

421. Staff explains that the effect of ordering NPC to utilize the 3% rate of return equates to a revenue requirement adjustment of approximately $1.1 million. (*Id.*) Staff further provides that the effect of disallowing any rate of return on the purchased vehicles investments likely equates to a revenue requirement adjustment of approximately $1.7 million. (*Id.*)

422. Staff provides that NPC stated, when asked about the ordering of $250,000 to $500,000 vehicles via verbal means, that these vehicles are the result of the "fleet team" reserving build slot space on the manufacturing line, and that the "fleet team" can order vehicles whenever it deems it necessary. (*Id.* at 7.) Staff argues that this type of loose control over who can order high-dollar vehicles is concerning. (*Id.*)

423. Staff argues that NPC's transition from the more than 15-year practice of leasing, rather than owning, vehicles was apparently not conducted in a prudent manner that followed commonly known "management of change" practices. (*Id.* at 10.) Staff asserts that the change had already been predetermined because BHE, whose master material contract NPC utilizes to purchase vehicles from Altec Industries Inc., already had the policy of purchasing vehicles as opposed to leasing vehicles. (*Id.* at 6-7; 11.)

NPC's Rebuttal

424. NPC rejects Staff's assertion that reserving build slot space on the manufacturing line is a loose control and that the fleet department can order vehicles whenever it deems it necessary. (Ex. 202 at 6.) NPC provides that the fleet department complies with NPC and Sierra's internal control policies and procedures including annual budget authorization and authorization for expenditures. (*Id.*) NPC further states that the fleet department requests authorization for additional expenditures, as needed, prior to exceeding the annual capital or operating budgets per the policy requirements. (*Id.*) Additionally, NPC provides that purchase

orders are issued for all purchased vehicles, and lease agreements are executed for all leased vehicles, which are reviewed internally to ensure proper procedures are followed. (*Id.*)

425. NPC also disagrees that it has had a 15-year practice of leasing vehicles. (*Id.* at 6-7.) NPC provides that NPC and Sierra have both leased and purchased vehicles over the last several GRCs, depending on which arrangement was the best option at a given time. (*Id.*)

426. NPC states that there is no BHE policy that directs NPC and Sierra to purchase versus lease vehicles. (*Id.* at 7.)

427. NPC points out that Staff does not challenge the prudency of the purchased vehicles and does not argue that the vehicles are not used and useful. (*Id.*)

428. NPC asserts that Staff misrepresents NPC's position in using a 3% discount rate in its economic analysis. (Ex. 203 at 2.) NPC disagrees with Staff's representation that a 3% discount rate was used by NPC because there is no industry standard to evaluate lease-then-buy scenarios versus purchase-only scenarios. (*Id.*) NPC clarifies that the reference to the 3% discount rate was to be clear and candid with Staff and the Commission that this is the method in which those specific vehicles were evaluated. (*Id.* at 4.) However, NPC provides that it has taken a fresh look and re-evaluated the analysis and its plan going forward. (*Id.*)

Commission Discussion and Findings

429. The Commission starts with the finding that the vehicles addressed above are used and useful. NPC has modified its financial analysis going forward due to concerns that the financial analysis of determining the cost/benefit to customers from purchasing vehicles instead of leasing them was not ideal in either the Sierra GRC or this case. The Commission is faced with determining not whether the use of vehicles is a prudent and reasonable cost, but what level of cost is prudent and reasonable. In its analysis, NPC applied a 3% discount rate to the costs

associated with purchasing vehicles instead of the 6.76% weighted average cost of capital ("WACC") rate that will be charged to customers. NPC's WACC is used in most financial analyses of the cost impact to customers of plant investment alternatives, but instead NPC used the marginal cost of debt for the discount rate used in the vehicle lease versus purchase analysis.

430. The Commission finds that the most reasonable outcome results in an adjustment to the revenue requirement that reflects the same 3% discount rate that was used by NPC to make the decision to purchase the vehicles rather than continuing to lease them. This adjustment results in an approximately $1.1 million reduction to the revenue requirement. The Commission finds this to be the most reasonable outcome because the modeling that NPC used to compare vehicle leasing to purchasing was based on a common set of mathematical assumptions, and the Commission finds that these assumptions should be consistent – including the 3% discount rate. Because neither SPPC nor Staff question the used and usefulness of the vehicles, the Commission finds that an adjustment in this case from applying a 3% WACC to the purchased vehicles' rate base amount is reasonable and consistent with the 3% discount rate NPC used to support its decision to switch from leasing to purchasing vehicles.

431. The Commission is also concerned about the inability of NPC to provide succinct answers regarding the decision to switch from leasing to buying, as well as a lack of clear documentation to support that decision. NPC is a regulated utility, and as such, decisions to purchase or order $250,000 to $500,000 vehicles should be well-documented and easily audited.

Q. GRC Costs

Staff's Position

432. Staff explains that, typically, labor costs are not included for recovery in a GRC regulatory asset as they would not be considered incremental. (Ex. 319 at 3.) Staff provides that

in the preparation and filing of the 2020 GRC, NPC contracted with a former employee for rate case related services and work on other projects. (*Id.*) Staff states that it is not specifically objecting to the hourly labor costs related to the use of this former employee as a contractor. (*Id.*) Staff highlights that the costs in question concern $25,000 included in GRC costs that was paid to the contractor as incentive pay in addition to the $123,352.50 paid to this contractor as 2020 GRC hourly labor, at a rate of $60 per hour plus overtime at $90 per hour. (*Id.*) Staff provides that if only internal labor had been utilized by NPC, neither incentive pay nor overtime costs would have been incurred for labor performed by salaried employees and no labor would have been recorded as GRC costs. (*Id.*)

433. Accordingly, Staff recommends that the Commission disallow $25,000 from rate base and $8,333 from amortization expense for the costs requested by NPC for the contractor's incentive pay. (*Id.*)

Commission Discussion and Findings

434. The Commission accepts Staff's recommendation to disallow $25,000 from rate base and $8,333 from amortization expense for the costs requested by NPC for the contractor's incentive pay. The Commission agrees that labor costs are not normally included for recovery in a GRC regulatory asset as they would not be considered incremental, and NPC provided no rebuttal on this issue.

R. Legal Expenses

NPC's Position

435. NPC states that Schedule K-3 provides an analysis of recorded charges and credits in FERC Account 923, Outside Services, for the test year. (Ex. 139 at 6.) NPC states that the schedule lists activity by type of service, names of firms rendering the services, and amounts

paid for these services during the test year. (*Id.*) NPC provides that invoices from vendors were reviewed to determine the nature of services being provided, and to determine whether these expenses were reasonable. (*Id.* at 7.) NPC explains that Schedule H-CERT-24, Adjustments for Non-Recurring Items, includes an adjustment to the expenses reflected on Schedule K-3. (*Id.*) NPC states that the adjustment removes costs related to the merger application, Docket No. 22-03028, recorded during the test year in Account 923 in the amount of $118,022. (*Id.*)

BCP's Position

436. BCP states that it reviewed all invoices for outside legal services recorded in Account 923, Outside Services. (Ex. 408 at 9.) BCP argues that the inclusion of expenses for billing periods before the beginning of the test year — expenses before January 1, 2022, in the amount of $37,593.32 — would not result in just and reasonable rates. (*Id.* at 9-10.)

NPC's Rebuttal

437. NPC disagrees with BCP that NPC should be directed to record legal expenses for billing periods before the beginning of the test year as below-the-line items and deny recovery of those expenses for billing periods before the beginning of the year in amount of approximately $38,000. (Ex. 206 at 7.) NPC states that while invoices are recorded when received, NPC also records accruals for legal expenses. (*Id.*) NPC explains that the purpose of these accruals is to record expenses as incurred which results in the removal of the cost of invoices recorded in the test year that were incurred prior to the test year. (*Id.*) NPC argues that it would be unjust to deny recovery of expenses that are already materially removed from recorded test-year expenses presented in the filing because of accrual accounting entries. (*Id.*) Additionally, NPC asserts that the figure provided by BCP is overstated by $8,319.98 because two invoices, 30290399 and 30290406, were evenly split between NPC and Sierra. (*Id.*) NPC provides that, even if the

Commission is inclined to disallow these specific legal expenses, it should not make the accounting change proposed by BCP because it is unwarranted considering NPC's use of the accrual method of accounting, which is performed according to well-established US GAAP principles, and would unnecessarily complicate NPC's accounting processes. (*Id.*)

Commission Discussion and Findings

438. The Commission rejects BCP's recommendation to disallow the amount of $37,593.32 for outside legal services. NPC correctly uses accrual accounting in accordance with US GAAP, and such accrual amounts are reversed when invoices are received and recorded. The invoices have no effect on test year expenses with the reversal of the prior accrual of the expense.

S. Executive Travel, Meals, and Entertainment

NPC's Position

439. NPC states that in preparation of Docket No. 03-10001, NPC's 2003 GRC, an audit of executive travel and business expenses was conducted, which resulted in an elimination of 40.27% of such expenses from cost of service. (Ex. 139 at 13.) NPC provides that the purpose was to adjust cost of service for expenses that, consistent with the Employee Expense Reimbursement Guidelines, were more properly considered NPC expenses. (*Id.*) NPC states that it later determined that the significant internal labor cost required to conduct such an audit was not cost-beneficial and, therefore, proposed in Docket No. 06-11022 to adopt a simplified process of eliminating 40.27% of expenses related to executive travel and business expense from cost of service. (*Id.*) NPC provides that the Commission approved the approach, and this process was adopted by NPC. (*Id.* at 14.)

440. NPC states that it has reviewed cost of service for the period that ended December 31, 2022, as well as the Employee Expense Reimbursement Guidelines, and has determined that executive expenses have been properly included in cost of service with no adjustment necessary. (*Id.*) NPC maintains that all employees, including executives, are required to adhere to the same guidelines contained in the Employee Expense Reimbursement Policy effective December 20, 2013, and last revised January 1, 2023. (*Id.*) NPC explains that this policy requires employees and executives to request reimbursement only for valid expenses that are directly, wholly, exclusively, and necessarily related to conducting NPC company business, and that comply with all NPC policies including the Code of Business Conduct. (*Id.*) NPC states that these policies include very specific guidelines for booking travel and lodging, daily reimbursement caps for meals, permitted tipping ranges, and a specific list of ineligible items such as political contributions, gifts, membership fees, and entertainment expenses not incurred as a necessary part of entertaining a business guest. (*Id.*) NPC states that any expense that is not ordinary and necessary, such as those for spouse travel, alcoholic beverages, or if the business discussion is only incidental to the expense, must be charged to a below-the-line account and will not be included in NPC's cost of service. (*Id.*) NPC offers that, given the improved stewardship around business travel and expenses, adherence to NPC policy and codes of conduct, and the resulting reduction in costs over time, NPC asserts that all recorded travel and business expenses are prudent and should be included in revenue requirement going forward. (*Id.*)

BCP's Position

441. BCP states that even though the reliability of the review process is emphasized in NPC's Applications, during the discovery process, numerous transactions were identified as more suitable for recovery from the shareholders, rather than from the ratepayers. (Ex. 408 at 7.)

BCP has adjusted these items before the certification date. (*Id.* at 8.) Therefore, BCP does not recommend adjustments for these items. (*Id.*)

442. Ultimately, BCP recommends that the Commission should direct NPC to incorporate an enhanced oversight over these expenses to include an annual review by the internal or external audit team. (*Id.*)

NPC's Rebuttal

443. NPC disagrees with BCP's recommendation to enhance controls and procedures over executive travel, meals, and entertainment expense reports. (Ex. 206 at 8.) NPC notes that the current policies, procedures, and controls around these items are materially effective as noted by the minor amount of items identified in the Applications. (*Id.*) NPC states that BCP's recommendation to include an annual review by the internal or external audit team would not be an efficient, or in the case of external audit functions, cost-effective improvement to the oversight of these expenses due to the minor amount. (*Id.*) While NPC states that it disagrees with BCP's recommendation, it does recognize the matter addressed and will provide further internal communications on the matter stressing compliance with existing policies. (*Id.*)

Commission Discussion and Findings

444. The Commission rejects the BCP's recommendation to enhance controls and procedures over executive travel, meals, and entertainment expense reports because the BCP did not provide specific concerns or recommendations.

T. Cash Performance Awards

NPC's Position

445. NPC states that, in addition to the STIP payments, all non-represented employees are eligible to receive cash performance awards ("CPAs") for performance results that far exceed

expectations or for performance results that are achieved in addition to the assigned scorecard key performance indicators. (Ex. 177 at 29.) NPC states that funding of all performance awards is included within the annual STIP budget allocation. (*Id.*)

BCP's Position

446. BCP states that it disagrees with NPC's CPA payout. (Ex. 407 at 10.) BCP states that the CPAs awarded do not follow this specific intent of the 2023 Performance Award Program. (*Id.*) BCP notes that there is no written policy that outlines specific criteria regarding CPAs. (*Id.*) BCP finds this lack of establishing criteria and subsequent lack of documentation troubling given that the utility is seeking recovery from ratepayers. (*Id.*) BCP explains that the CPA adds yet another layer of excessiveness given the corporate scorecard payouts were far from being attained or earned. (*Id.*) In the interest of fairness and just and reasonable rates, the BCP does not agree with the CPA payout being sought for recovery from ratepayers – especially given the unearned and excessive scorecard payout. (*Id.* at 11-12.)

Staff's Position

447. Staff recommends that the Commission disallow 100 percent of the traditional and non-traditional CPA costs from the revenue requirement. (Ex. 303 at 17.)

448. Staff argues that the traditional and non-traditional CPAs are unreasonable for inclusion in rates. (*Id.*) First, Staff states that NPC has not provided any additional information in its filing or prepared direct testimony as to why a category of costs that was disallowed in the 2022 Sierra GRC should now be included in the revenue requirement. (*Id.*) Second, Staff states that rates should not be set based on costs that are not reasonably expected to occur over the next three years. (*Id.*) Staff provides that, while a prudent utility can expect unplanned situations to occasionally arise that would necessitate an employee performing tasks beyond normal duties, it

is unclear whether the number of special projects that occurred during the test period is indicative of situations that NPC should reasonably expect to happen annually over the next three years. (*Id.*) Staff states that while someone could argue that some amount of CPAs should be expected to be awarded every year for the next three years, due to the expectation of facing unplanned situations every year, Staff questions why the constant expectation that a salaried employee may occasionally be asked to perform duties outside of day-to-day job descriptions is not treated as a normal course of business. (*Id.*) Without a CPA policy that explains the specific criteria that must be met to earn an award, and what factors dictate the dollar amount awarded, Staff states that it is hard to tell whether any one award is arbitrary or if the situation truly was far beyond the normal course of business that a CPA was merited and can be expected to occur habitually for the next three years. (*Id.*)

NPC's Rebuttal

449. NPC disagrees with the BCP that CPAs add a layer of excessiveness to compensation. (Ex 201 at 5.) NPC states that it expects its employees to perform at a high level, and the compensation award is commensurate with the level of work performed. (*Id.* at 5-6.) Moreover, NPC states that CPAs are largely allocated from the annual STIP funded amount, meant to incentivize high performers, and limited in why they are awarded. (*Id.* at 6.)

450. NPC disagrees that CPAs should be removed from the revenue requirement because these costs are not reasonably expected to occur in the future. (*Id.*) NPC explains that most CPA dollars are part of the annual incentive plan funded amount, which is established based on the assessment of corporate performance results. (*Id.*) NPC asserts that incentive pay is a critical component of NPC's market-competitive compensation program. (*Id.*) Although the individual employees that receive these awards vary, NPC states utilization of the annual

incentive pay program to recognize and reward performance has not varied and is expected to continue in the future. (*Id.*) NPC provides that, for awards given outside of annual incentive plan funding, which are those related to leadership responsibilities and operational emergency response, the dollar values have been consistent. (*Id.*) NPC states that these awards are given when employees work a significant number of additional hours to provide coverage of critical leadership responsibilities or emergency management of field operations during an unplanned operational event. (*Id.*) NPC provides that many of these situations cause employees to have to rearrange their personal schedules, including cancelling scheduled time off and vacations at the last minute to cover critical duties. (*Id.*) NPC offers that, while it is not known where these impacts will be experienced within the business, it is a reasonable expectation that unplanned events such as these will continue to occur, and coverage will be required. (*Id.* at 7-8.) NPC states that NPC and its customers need to rely on the commitment and sacrifices of these employees to maintain effective operations. (*Id.* at 8.)

Commission Discussion and Findings

451. The Commission accepts NPC's request to include cash performance awards for performance results that far exceed expectations in the revenue requirement. Although Staff and BCP raise concerns, the Commission notes the continuing turnover of employees in many positions of responsibility at NPC. Employees need to be adequately supported by management, and management needs to reward employees who make sacrifices to maintain effective operations.

U. Short-Term Incentive Pay ("STIP")

NPC's Position

452. NPC provides that all non-represented employees are eligible for STIP. (Ex. 177 at 12.) NPC states that STIP payments are based on corporate goals with a target of 100 percent and vary from year-to-year depending upon the achievement of Company-wide goals, and a combination of the achievement of business unit, or departmental goals, and the individual employee's performance. (*Id.*) NPC states that its Company-wide goals are aligned with the following six core principles: Customer Service, Employee Commitment, Environmental Respect, Regulatory Integrity, Operational Excellence, and Financial Strength. (*Id.*) NPC states that STIP payments were only paid to eligible employees who are deemed to be meeting performance expectations based on assessment by their leader. (*Id.*)

453. NPC elaborates that the STIP is funded at an aggregate payout of 100 percent of target assuming achievement of incentive plan goals. (*Id.* at 34.) NPC explains that the 100 percent target payout is then modified based on an evaluation of organizational performance results across the six core principles. (*Id.*) NPC provides that the annual corporate scorecard is one tool used to determine annual incentive funding with adjustments made to reflect performance results that are not captured within the scorecard or not measured based on the established targets. (*Id.* at 34-35.) NPC states that the scorecard key performance indicators and targets are generally established as stretch targets to keep the organization focused on what it has been able to achieve historically to help drive continuous improvement across the six core principles. (*Id.* at 35.) NPC states that, in 2022, the scorecard results delivered a mathematical outcome of 56.9 percent. (*Id.*) However, NPC explains that the annual incentive payout was awarded at 95 percent, which is higher than the mathematical result in recognition of several performance achievements. (Ex. 178 at 1.)

454. NPC states that the revenue requirement calculations in this filing reflect 100.0 percent of STIP costs paid in December 2022. (*Id.* at 38.) NPC provides that its calculated annual revenue requirement includes $5.75 million for STIP expense. (*Id.*)

BCP's Position

455. BCP states that NPC should update its STIP payout criteria provided in the Applications, as neither NPC nor Sierra has been adhering to such concepts for many years. (Ex. 407 at 3.) BCP argues that scorecard targets are compromised annually in the sense they do not matter when it comes to what is paid out to employees. (*Id.*) In addition, BCP asserts that it appears from the historical information that NPC's employee compensation is at minimal risk since the actual payout is always above what has been achieved. (*Id.*) BCP maintains that these variable costs are consistently incurred regardless of NPC achieving the desired results. (*Id.*) BCP highlights that this has been a recurring issue in GRC proceedings for STIP payouts. (*Id.*)

456. BCP states that the STIP payout for 2022 was set at 95% out of 100%. (*Id.* at 4.) BCP states that NPC did not achieve the year-end result of 95% out of 100%. (*Id.*) In reality, BCP states that NPC achieved 56.94% out of 100%. (*Id.*) BCP asserts that NPC decided to undeservedly payout at 95% and that NPC is seeking the full recovery of the 95% payout from ratepayers. (*Id.*)

457. BCP argues that NPC provided excuses to justify the STIP payout that deviates from actual scorecard results. (*Id.* at 5.) First, BCP states that NPC continues to define the key performance indicators (metrics) as stretch goals. (*Id.*) BCP argues that this significant dilution of obligation in meeting goals continues to be unacceptable. (*Id.*) BCP points out that the use of the word stretch implies that the scorecards now "give" or are elastic. (*Id.*) BCP asserts that these targets are no longer fixed. (*Id.*) Secondly, BCP states that NPC claims the scorecard is

just one tool and that other adjustments can be made which are not captured on the scorecard. (*Id.*) BCP highlights that these adjustments are not documented anywhere and appear arbitrary and are at the discretion of NV Energy's CEO and BHE's CEO. (*Id.*)

458. BCP objects to NPC's proposed 95% STIP payout because employees did not earn the payout per the corporate scorecard. (*Id.* at 5-6.) As such, BCP argues that the STIP payout is excessive and imprudent. (*Id.* at 6.)

459. BCP recommends adjusting NPC STIP payout from 95% to 48.63%. (*Id.*) The adjustment begins with the 56.94% earned by the company on the scorecard. (*Id.*) A second adjustment is accounted for by an 8.33% reduction to a Financial Strength Metric. (*Id.*) The STIP payout reduction (to both represented and non-represented employees) impact to the revenue requirement is a decrease of $3.241M. (*Id.* at 7.)

460. BCP further offers that it is unclear whether NPC is requesting permission to change the corporate scorecard scoring for future rate cases under the guise of a prayer of relief in NPC's Applications. (*Id.*) BCP points to prayer of relief item 10 which states, "Grant any other requests as are specifically set forth in the testimony and exhibits filed herewith, both those that are directly addressed and those that are not directly addressed in this Application." (*Id.*) BCP argues that this all-encompassing phrase used by NPC should be prohibited by the Commission in all filings. (*Id.* at 7-8.) BCP also asserts that, to the extent that NPC is requesting to change the STIP scoring, BCP recommends that the Commission deny this request. (*Id.* at 8.) To clarify, BCP opposes any of NPC's purported methodology changes to the scoring of the corporate scorecard. (*Id.*) BCP argues that consistent overpaying for non-earned achievements and/or the inequity in the weight assigned to key performance indicators leads to unjust and unreasonable results. (*Id.* at 8-9.)

Staff's Position

461. Staff recommends that the Commission disallow the STIP payout amount that was awarded to represented, non-officer, and officer employees that is above the 56.9% earned on the fourth quarter corporate scorecard. (Ex. 303 at 7.)

462. Staff provides that the corporate scorecard delivered a mathematical outcome of 56.9%. (*Id.* at 9.) Staff further provides that NPC stated that the annual incentive payout was awarded at 95%, which was higher than the mathematical result in recognition of several performance achievements. (*Id.*)

463. Staff points out that NPC has consistently given a STIP payout greater than the earned results of the STIP scorecard. (*Id.* at 10.) Staff states that this practice is problematic because NPC has created an employee expectation that regardless of their actual effort and the resulting corporate scorecard achievement, the STIP will be funded at or near 100%. (*Id.* at 11.) Staff argues that this negates the STIP's purpose of being variable, at-risk compensation that has to be re-earned every year. (*Id.*) Staff asserts that asking for 95% of STIP funding to be recovered in rates creates a situation where ratepayers are being asked to pay for STIP costs that do not have corresponding, measurable ratepayer benefits. (*Id.*)

464. Further, Staff provides that it appears that the overall STIP payout amount is discretionary. (*Id.* at 12.) Staff states that NPC states that the corporate scorecard is one tool used to determine annual incentive funding with adjustments made to reflect performance results that are not captured mathematically within the scorecard or not measured based on the established targets. (*Id.*) Staff provides that when asked to elaborate on how the final STIP payout was determined, NPC states that the STIP payout amount is determined based on the recommendation of NPC's President and CEO and subject to approval by the BHE President and

CEO, and that the percentage is determined based on their assessment of business performance achievements. (*Id.*) Staff states that NPC adds that there is no mathematical formula for consideration of the performance achievements that funded the STIP at 95%. (*Id.*)

465. Staff offers that, while it understands paying the STIP at 100% puts the non-officer and officer employees' total cash compensation at a level that is representative and competitive, as measured by benchmarking data, that alone is not reason enough to require ratepayers to fund STIP payouts above what was earned, as measured by the corporate scorecard. (*Id.* at 13.)

466. Accordingly, Staff recommends that the non-officer and officer employees' STIP scorecard payout cost and the represented employees' Safety Bonus lump-sum STIP payout cost amounts included in revenue requirement should be no more than the 56.9% earned on the STIP scorecard, minus the financial metric related costs that NPC elected to remove in certification. (*Id.* at 14.) Staff provides that, as stated in NPC's collective bargaining agreement, the Safety Bonus payout related to the STIP will be paid out at the same percentage paid out to non-represented employees. (*Id.*) As such, Staff asserts that any STIP payout adjustments made for the non-officer and officer employees' STIP should also be made to represented employees' Safety Bonus payout related to the STIP. (*Id.*)

NPC's Rebuttal

467. NPC disagrees with the BCP that scorecard targets are compromised annually and that NPC provides excuses to deviate from the actual scorecard and justify increased STIP payouts. (Ex. 201 at 2.) NPC explains that scorecard targets are established at the start of the calendar year and remain unchanged throughout the year. (*Id.*) NPC states that scorecard performance results are measured against those targets that are established at the start of the year.

(*Id.*) NPC provides that it has not deviated from measuring and reporting corporate scorecard results against the established targets. (*Id.*) NPC states that BCP appears to be confused that STIP funding and individual award amounts are determined based on a combination of business performance, scorecard results, and individual contributions. (*Id.*) NPC elaborates that the corporate scorecard is not the sole determinant of STIP funding or level of awards to employees. (*Id.* at 2-3.) NPC states that a description of corporate performance outcomes, not excuses, is used to define overall business performance, which is assessed in addition to corporate performance results against scorecard targets to determine STIP funding. (*Id.* at 3.)

468. NPC states that it disagrees with Staff's and BCP's assertion that employees did not earn the payout per the corporate scorecard and that the STIP costs do not provide corresponding, measurable ratepayer benefits. (*Id.*) NPC reiterates that the corporate scorecard is not the sole determinant of STIP funding and is not the sole determinant of individual employee STIP awards. (*Id.*) NPC explains that performance against corporate scorecard targets is one tool used to determine the funding level. (*Id.*) In addition, NPC states that organizational performance results are evaluated across the six core principles to ensure that desired outcomes that are beneficial to customers are achieved. (*Id.*) For 2022, NPC provides that there were five areas specifically identified to highlight successful corporate performance results. (*Id.*) NPC states that improvement in wildfire risk and severity mitigation has a direct benefit to customers. (*Id.*) NPC states that resource adequacy improvements directly benefit customers with increased reliability as demonstrated during the September 2022 heatwave. (*Id.*) NPC offers that the steps NPC has taken to advance the state's decarbonization policies allow for expedited development and maximization of tax benefits which benefit customers. (*Id.*) NPC states that customer satisfaction improvements as measured by J.D. Power, while short of the consolidated scorecard

target, far exceeded the targets set for those customer classes. (*Id.*) Lastly, NPC maintains that achievement of best-ever safety performance, in terms of the lowest number of injuries, benefits customers. (*Id.*) NPC provides that advancing the business across the six core principles has been the focus of business operations for the last 10 years and has not been self-selected in hindsight. (*Id.* at 4.) NPC asserts that achievement of corporate outcomes is a direct result of the cumulative efforts of individual employees, and financial rewards are earned. (*Id.*)

469. NPC also disagrees that there is employee expectation of STIP being paid at or near 100 percent, which removes variability and turns the STIP into a second form of base pay. (*Id.*) NPC provides that there are two elements of the STIP payout. (*Id.*) NPC states that the first is corporate performance results. (*Id.*) NPC explains that NPC's outcomes and performance results are used to determine the funded percentage at the NPC level. (*Id.*) NPC states that this performance is measured collectively across the six core principles and across all business units within NPC. (*Id.*) NPC provides that it is a comprehensive view of overall organizational performance. (*Id.*) NPC states that the second element is an employee's individual performance results, which are assessed annually by a direct supervisor. (*Id.*) NPC states that a review of the STIP awards paid in 2022 shows that a majority (57.7%) of employees received an incentive award amount in 2022 that fell below the funded amount of 95%, less than 10% received an award at the funded amount, and approximately 33% received an award above the funded amount. (*Id.* at 5.) NPC explains that NPC's focus on varying incentive pay based on individual performance results ensures that employees do not view the STIP as a second form of base pay. (*Id.*)

Commission Discussion and Findings

470. The Commission adjusts NPC's certification revenue requirement by disallowing the STIP payout amount that was awarded above the 56.9% that was earned on the fourth quarter

corporate scorecard for employees above the level of manager. The corporate scorecard measures numerous key performance indicators that track NPC's achievement on action items related to SPPC's core principles. Employees earned a score of 56.9% for 2022, as shown on the fourth quarter corporate scorecard; however, the annual incentive payout was awarded at 95%.

471. The Commission agrees that it is NPC's prerogative to pay its employees STIP amounts above what was achieved on the corporate scorecard; however, it appears that NPC has created an employee expectation that the STIP will be funded at or near 100%, regardless of the corporate scorecard achievement. The Commission agrees with Staff that this negates the STIP's proposed purpose of being variable, at-risk compensation that has to be re-earned every year. The Commission finds that NPC's request to recover 95% of STIP funding in rates creates a situation where ratepayers are being asked to pay for STIP costs that do not have corresponding, measurable ratepayer benefits. However, in recognition of the current labor environment and staffing issues NPC faces in hiring and retaining front line and customer facing staff, the Commission approves the STIP payout at the 95% level, subject to the exclusion of the Finance Strength metric component noted below, for employees at the manager level and below. The Commission's decision to allow full recovery of STIP payments to NPC's lower-level employees reflects evidence that NPC has recently experienced a high rate of voluntary turnover and that NPC's STIP-eligible employees are under-compensated compared to industry benchmarks. (Tr. at 477-480; Ex. 177 at 18, attach. Ex. Oswald Direct-7.)

472. Additionally, while the degree of NPC's success in achieving corporate scorecard targets is used to determine the percentage of STIP funding at the company level, NPC considers individual performance in determining the specific STIP payment amount for each employee. (Ex. 201 at 4-5.) The assessment of an employee's individual performance considers individual

achievement of established objectives, performance results related to assignments made throughout the year, and achievement of behavioral expectations. (*Id.*) Accordingly, the Commission finds that it was appropriate for NPC to issue the STIP payouts that it did for employees at the level of manager and below, as those employees were awarded for their individual performance. The Commission further finds that the opportunity for employees to be rewarded for individual performance is important for recruitment and retention, and the Commission declines to find that STIP payments for employees at the manager level and below should have been reduced based on corporate performance results over which such employees had relatively little influence.

473. The Commission also agrees with Staff that removing the ability to be earned as variable pay essentially turns the STIP into a second form of base pay and removes the incentive for employees to go above and beyond to earn a higher STIP payout. The Commission finds that in exchange for paying for the STIP, it is important that the employee actions being rewarded are tied to ratepayer benefits; otherwise, paying the STIP at a higher percentage than what was earned creates a situation where ratepayers are paying bonuses that do not provide them with direct, commensurate benefits.

474. The Commission finds that the evidence in this record does not support recovering STIP costs associated with the Financial Strength category from customers. Consistent with decisions made by the Commission in prior GRCs, the Commission finds in this docket that the Financial Strength metrics have a direct and positive correlation to shareholder interests that do not directly correlate to benefits to customers.

475. Accordingly, the Commission accepts the adjustment proposed by Staff and BCP to only allow 48.63% of the STIP payout costs for employees above the manager level. For

employees at the manager level and below, the Commission approves STIP payout costs at the 95% achievement level, excluding the STIP amounts associated with Financial Strength category.

476. As a compliance item, 30 days after the issuance of this Order, NPC will file with the Commission the amount of STIP compensation awarded to employees that reflects the Commission's decision in the preceding paragraph.

V. Federal Energy Regulatory Commission ("FERC") Transmission Allocation

NPC's Position

477. In its Applications, NPC provides that Statement N shows NPC's adjusted and allocated results of operations and illustrates the flow of data starting with recorded numbers and finishing with the jurisdictional electric amounts. (Ex. 186 at 7.) NPC explains that each page in Statement N depicts the recorded values from NPC's books and records, adjustments to reflect regulatory treatment that is not otherwise recorded on the books, and the allocation of NPC electric results of operations adjusted to reflect regulatory treatment not otherwise recorded on the books between Nevada and FERC jurisdictions. (*Id.*)

478. NPC states that the results of operations and rate of return calculations for NPC's Nevada and Federal electric jurisdictions are shown on Statement N. (*Id.*) NPC elaborates that, like prior general rate review filings, the allocation methodology used in this schedule closely follows the methodology recommended by the National Association of Regulatory Utility Commissioners in its Cost Allocation Manual with one minor adjustment. (*Id.*)

479. Regarding the one adjustment, NPC states that all known long-term firm transmission contracts that are expected to change prior to the rate-effective date of January 1, 2024, were normalized to the new contract load to align transmission demand more closely with

the rate-effective period. (*Id.* at 8.) NPC provides that contracts that are due to end prior to the beginning of the rate-effective period were removed from the allocation. (*Id.*)

480. NPC provides that this adjustment to the retail transmission allocator causes it to increase from 81.349% to 82.105%, slightly increasing the Nevada jurisdictional test-period costs. (*Id.*)

Staff's Position

481. Staff states that as part of the Statement N workpapers, NPC tabulated native load, bundled network transmission service load, and firm point-to-point transmission contracts to derive a percentage allocation factor to determine which set of customers (i.e., native load or FERC customers) are utilizing the transmission system and how the costs should be allocated. (Ex. 311 at 14.) Staff asserts that, unlike Sierra who utilizes a 12 coincident peak ("CP") methodology for transmission allocations, NPC uses a 4 CP methodology using just the four summer months of June, July, August, and September. (*Id.*) NPC provides that the transmission allocation filed by NPC is provided in Attachment PRM-11, and it shows that NPC is requesting that native load customers be assigned 82.1049% of the transmission costs, thereby leaving 17.8951% of the transmission costs to be assumed/assigned to FERC customers. (*Id.*) Staff notes that NPC did not provide any detailed information in its Applications on how it created the transmission allocation factor workpaper. (*Id.*)

482. Staff asserts that NPC selectively manipulated the transmission loads/billing determinants in the Statement N workpaper, thereby increasing the amount of transmission costs allocated to native load customers. (*Id.* at 15.) Staff states that, looking at the Air Liquide Hydrogen Energy ("Air Liquide") loads that are listed in the workpaper, one can plainly see in that data set that in at least two of the four months used in the calculation, Air Liquide was in

start-up/commissioning mode as its loads were almost zero. (*Id.*) However, Staff states that NPC never forecasted out for 2024 (like it did other contracts) the full load of the Air Liquide facility, nor even included the Air Liquide loads that NPC experienced just prior to filing this GRC. (*Id.*) Staff offers that if NPC had forecasted the Air Liquide operations, that load would have been magnitudes higher and would have transferred costs away from native load customers and placed more costs onto the FERC side of the cost equation. (*Id.*) Secondly, Staff states that in at least one area of the calculations in this GRC filing, NPC used the unadjusted test-period allocation factor. (*Id.*) Staff explains that this clearly shows that NPC first calculated the transmission allocation factor based upon the exact test-period billing determinants and loads, used that allocation percentage, but then later decided to alter the calculation resulting in the higher amount of cost being allocated to native load customers. (*Id.* at 15-16.)

483. Staff argues that the Commission should order NPC to adjust the transmission allocation factor because Nevada is a historic test-period state. (*Id.* at 16.) Staff asserts that ignoring the historic test-period data and just selectively adjusting certain line items that go in NPC's favor is not an appropriate practice and would not result in just and reasonable rates being set. (*Id.*)

484. Staff recommends that the Commission order NPC to use the actual test-period load/billing determinants to determine the FERC-jurisdictional transmission allocation factor to be used to derive native loads' responsibility for transmission costs. (*Id.*) Staff asserts that utilizing the actual test-period load/billing determinants lowers the FERC-jurisdictional transmission allocation factor from 82.1049% to 81.3489% and results in a native load revenue requirement reduction of approximately $1.335 million. (*Id.*)

485. Further, although Staff does not support, and does not believe that the GRC statutes and regulations allow NPC to use, a future test period, Staff asserts that annualizing end-of-the-year loads and cost data is something that is commonly done in every GRC proceeding. (*Id.* at 17.) Staff provides that, given that the Air Liquide plant is now in full operation and that its load in December 2022 was considerably higher than what the loads were in the summer months of 2022, it is reasonable to have NPC annualize this large customer load and recalculate the allocation factor. (*Id.*) Staff did not recommend this additional modification given concerns that NPC would claim Staff is looking outside the test period, which an annualization of ending test-period data is not. (*Id.*) However, Staff offers that this is an additional adjustment that the Commission should consider ordering, rather than authorizing NPC to receive the windfall profits associated with the higher Air Liquide loads for the next several years. (*Id.*)

NPC's Rebuttal

486. NPC explains that the jurisdictional transmission allocator within Statement N allocates the transmission costs between the Nevada and FERC jurisdiction, and thus its only purpose is to specifically assign costs to the appropriate jurisdiction. (Ex. 204 at 17.) NPC states that it has no incentive to manipulate the allocation to assign more costs to a certain jurisdiction, let alone the Nevada ratepayers, as fundamentally, the overall costs can be recovered, just from a different subset of customers. (*Id.*) NPC maintains that it has no implicit bias as to who it recovers the costs from. (*Id.*)

487. NPC asserts that there was no intention to skew the results of the Nevada portion of the transmission allocation factor, but instead the intent was to align the methodologies more closely to that which was suggested by Staff in Docket No. 22-06014. (*Id.* at 18.) NPC notes that discussions were held with Staff during that case regarding the transmission allocation factor

after Staff discovered an error in the treatment of the Newmont/Nevada Gold Mines load. (*Id.*) NPC states that Sierra acknowledged the error and corrected Statement N in its Certification filing. (*Id.*) NPC offers that normalizations to contracts that were known and measurable and would reflect the rate-effective period were made in that case as well, as suggested by Staff. (*Id.*) NPC explains that NPC's intent in this case is to reflect the agreed-upon methodology from the Sierra case, regardless of its impact on NPC or customers. (*Id.*)

488. NPC also rejects Staff's assertions that NPC did not provide any detailed information in the filing on how it created the transmission allocator factor workpaper. (*Id.* at 19.) NPC explains that the executable file of Statement N was provided to Staff and other intervenors, and the adjusted long-term firm contracts were highlighted to easily identify the changes that were made. (*Id.*)

Commission Discussion and Findings

489. The Commission declines to make any adjustment to the FERC transmission allocation. Staff raised concerns that warrant further inquiry. As a directive, NPC must meet and confer with Staff in advance of filing any future general rate case to discuss the appropriate FERC transmission allocator. Further, in any future general rate case, NPC shall provide details about its most recent FERC rate case and provide an explanation about NPC's plans for future rate-setting proceedings at FERC.

W. Investment Tax Credit ("ITC")

NPC's Position

490. NPC explains that NPC is able to reduce rate base for the Reid Gardner BESS ITC balance because NPC included a request for a waiver of NAC § 704.6546 in its Fourth Amendment to the 2021 Joint Integrated Resource Plan, Docket No. 22-11032, which the

Commission approved. (Ex. 179 at 8.) As such, NPC included the effect of that waiver in this GRC. (*Id.* at 9.)

491. NPC provides that Schedule I-EC-15 depicts the ITC that will be recorded for the Reid Gardner BESS project and includes the related amortization of the ITC balance and the rate base adjustment. (*Id.* at 15.) NPC explains that the deferred ITC balance in Account 255 is usually not offset in rate base and that this will be the first time that account 255 is included in rate base. (*Id.*) NPC notes that the Inflation Reduction Act allows utilities to opt out of the normalization requirements for ITC for battery storage projects. (*Id.*) As such, NPC states that it included the estimated amount of the ITC incurred for Reid Gardner BESS as a reduction to rate base. (*Id.*)

Staff's Position

492. Staff provides that the amount of the ITC expected from the Reid Gardner BESS project is approximately $98.4 million as of December 31, 2023. (Ex. 305 at 12.) Staff explains that NPC can reduce the rate base for the ITC balance of approximately $98.4 million from the Reid Gardner BESS project, and this rate base reduction is currently reflected in Schedule I-EC-15. (*Id.*) Staff provides that the annual amortization of ITC, approximately $4.9 million, is also reflected in Schedule I-EC-15. (*Id.*)

493. Staff provides that if the Commission accepts Staff's recommendations pertaining to the Reid Gardner BESS project, which would reduce the capital costs of the Reid Gardner BESS project, the amount of ITC should be adjusted accordingly because the ITC is calculated based on the amount of eligible capital costs of a project. (*Id.*) Staff recommends decreasing the capital costs of the Reid Gardner BESS project by approximately $50.48 million, and therefore the amount of ITC should be decreased by approximately $19.6 million, lowering the rate base

reduction from approximately $98.4 million to approximately $78.8 million. (*Id.*) Staff provides that the annual amortization of ITC should also be adjusted to approximately $3.9 million. (*Id.*)

494. Staff provides that, if the Commission accepts Staff's other recommendation for the Reid Gardner BESS project, which would reduce the capital costs of the Reid Gardner BESS project, the amount of ITC should be adjusted accordingly because the ITC is calculated based on the amount of eligible capital costs of a project. (*Id.* at 13.) Specifically, Staff provides that it is recommending an adjustment to decrease the capital costs of the Reid Gardner BESS project by $5 million, and therefore the amount of ITC should be further decreased by approximately $2 million, further lowering the rate base reduction by $2 million. (*Id.*) Staff notes that the annual amortization of ITC should also be further decreased by approximately 0.1 million. (*Id.*)

495. In sum, Staff recommends that the Commission accept the adjustments to update the ITC expected from the Reid Gardner BESS project if the Commission accepts Staff's other two recommendations pertaining to the Reid Gardner BESS. (*Id.*)

NPC's Rebuttal

496. NPC disagrees with Staff's recommendation for adjustments should the Commission defer $5 million from the Reid Gardner BESS project. (Ex. 204 at 7.)

497. NPC states that Staff's ITC adjustment has an incorrect ADIT adjustment and ITC amortization adjustment. (Ex. 198 at 5.) NPC provides that the adjustment included in Staff's workpapers does not include the reduction in basis for plant ineligible for ITC. (*Id.*) NPC estimates that 3% of the plant basis will not be eligible, and therefore 3% of the proposed adjustment should have been excluded from the ITC calculations. (*Id.*) NPC provides that the revised amount of ITC rate base reduction is $1,940,000, and the revised amortization of ITC is $97,000. (*Id.*)

Commission Discussion and Findings

498. The Commission accepts NPC and Staff's recommendation and approves the waiver of NAC 704.6546. Further, the Commission has accepted Staff's recommendations regarding the Reid Gardner BESS; therefore, NPC should calculate the correct adjustment based on that reduction in basis for plant ineligible for ITC.

X. Meter Maintenance Costs

Staff's Position

499. Staff provides that, as part of its normal course of business, NPC tracks and records the operations and maintenance costs of the Maintenance of Meters. (Ex. 302 at 9.) Staff states that FERC Account 597, Maintenance of Meters, includes the cost of labor, materials used, and expenses incurred in the maintenance of meters and meter-testing equipment, the book cost of which is includable in Account 370 – Meters, Account 370.1 – AMI Meters, and Account 395 – Laboratory Equipment. (*Id.*) Staff explains that these costs are tracked quarterly (and, thus, annually) by FERC under Form No. 1, as part of NPC's comprehensive financial and operating report. (*Id.*)

500. Staff recommends a normalization adjustment to NPC's Maintenance of Meters costs to reflect that the refurbishment meter practices will conclude at the end of 2024. (*Id.* at 11.) Staff states it utilized the data reported to FERC and the fiscal years 2020, 2021, and 2022 to normalize the test year costs accordingly. (*Id.*) Based on this normalization calculation, Staff recommends a normalization adjustment NPC's recorded costs for the Maintenance of Meters of $466,596. (*Id.*)

Commission Discussion and Findings

501. The Commission accepts Staff's recommendation for a normalization adjustment to NPC's Maintenance of Meters costs to reflect that the refurbishment meter practices will conclude at the end of 2024. NPC provided no rebuttal on this issue.

Y. Work Order #0010009886

Staff's Position

502. Staff explains that, in NPC's Applications, NPC includes $2,168,065 in uncompensated costs through the end of the test period, and estimated that an additional $57,060 would be expended during the certification period. (Ex. 302 at 12.) Staff states that it appears that this total is comprised of 256 work orders categorized with a "Claims" Budget ID. (*Id.*) Among those 256 line items included in the current GRC, Staff states that 94 of those work orders were associated with uncompensated claims that were carried over from NPC's prior GRC in 2020. (*Id.*)

503. Staff states that among these 94 work orders, Work Order No. 0010009886 ("Work Order 9886"), briefly described as "Emgncy SNT-SN 138k Line D," was of particular concern. (*Id.* at 12.) Staff states that Work Order 9886 is the largest of the uncompensated costs included in the current GRC. (*Id.* at 12-13.) However, Staff states that it found it difficult to understand the genesis of the costs related to Work Order 9886, despite working with NPC to determine whether there were other adjustments to uncompensated costs that needed to be made. (*Id.* at 13.) Staff states that Work Order 9886 was created and used to track costs related to repairs required due to excavation that resulted in damage to a portion of the Sinatra to Suzanne 138 kV line. (*Id.*)

504. Staff provides that, based on the information provided in discovery, Staff is unable to evaluate whether these costs are just and reasonable. (*Id.* at 19.) Furthermore, Staff

explains that given the numerous delays in discussions, delays in receiving substantive information pertaining to a non-existent global settlement, NPC's inability to produce responsive and knowledgeable personnel to accurately address the issues in question, the lack of evidence that NPC made sufficient efforts to recover uncompensated plant costs or proof that any recovered costs were appropriately applied to all applicable work orders discussed above, there appears to be no path forward for Staff to determine a precise amount of disallowance related to all of the outstanding claims for which the line-locating service company, US Infrastructure Company ("USIC"), was indirectly responsible. (*Id.* at 19-20.)

505. Nonetheless, Staff states that it can identify at least one certainty — that there is an uncompensated plant balance of $214,258.29 attributed to Work Order 9886. (*Id.* at 20.) Based on the numerous issues discussed above, Staff recommends that the Commission deny the recovery of the uncompensated plant costs for Work Order 9886, as this work order closed to plant in NPC's GRC in 2020 with a zero balance at the end of the last rate case, and because NPC should have sought the full amount of outstanding claims when it settled with its line-locating services provider. (*Id.*)

NPC's Rebuttal

506. NPC disagrees with Staff's recommendation and states that the costs related to Work Order 9886 should remain included in NPC's revenue requirement because the decision to settle the amounts owed to NPC by USIC was reasonable, and therefore, the inclusion of the unrecovered costs in rate base is prudent. (Ex. 197 at 7.)

507. NPC explains that in NPC's 2020 GRC, $536,670.50 was the test-period capital balance in Account 107. (*Id.*) NPC asserts that Staff incorrectly identifies an equivalent negative value for the 2020 certification period as a payment. (*Id.*) NPC states that the equivalent

negative is not a payment, it is an entry to remove the balance from 2020 rate recovery and move it to accounts receivable when the initial bill to USIC was generated. (*Id.*) NPC provides that the settlement with USIC did not occur until December 2020 and funds were not received until January 2021. (*Id.*) Therefore, NPC asserts that it would have been impossible for the negative entry Staff identifies to be the payment from USIC. (*Id.*) NPC argues that Staff continues to erroneously assert that NPC applied an additional $214,258.29 to the work order as NPC's receipt of payment. (*Id.* at 7-8.) NPC states that it removed the $536,670.50 from its 2020 request as NPC was still attempting to recover from USIC at that time (*Id.* at 8.) NPC explains that the $214,258.29 represents the balance closed to plant and requested for recovery in NPC's current proceeding, after the application of a settlement with USIC in December 2020. (*Id.*)

508. NPC further provides that, in Staff's recommendation to remove the costs associated with Work Order 9886 from rate base, Staff fails to contemplate the ADIT impacts on revenue requirement. (Ex. 204 at 12-13.) Further, NPC notes that, in Staff's proposed adjustment for Work Order 9886, Staff utilizes the incorrect depreciation rate associated with Utility Plant 357 instead of the correct account, which is Utility Plant 358. (*Id.* at 13.) NPC explains that this results in a slight change to accumulated depreciation for this adjustment. (*Id.*)

Commission Discussion and Findings

509. The Commission accepts Staff's recommendation to not allow recovery of an uncompensated plant balance of $214,258.29 attributed to Work Order 9886 due to a claim settled with USIC in 2020. Although NPC's decision to settle the amounts owed to NPC by USIC may have been reasonable in NPC's view, Staff was unable to evaluate whether these costs are just and reasonable. The Commission cannot allow NPC to recover costs from ratepayers that are not just and reasonable.

VII. RATE DESIGN

A. Tariff Modifications

NPC's Position

510. NPC explains that, on April 26, 2022, the Commission approved temporary modifications to the Street Lights ("SL") tariff, effective in Docket No. 21-10008 allowing auxiliary devices such as public safety and wireless communications equipment to be temporarily installed and billed up to a limited twenty-five percent of total load per service. (Ex. 221 at 15.) NPC provides that these changes were approved as a temporary measure, with the intent that a more permanent solution would be presented in this GRC for Commission consideration as more information became available regarding these installations. (*Id.*) NPC states that it was to provide an analysis regarding the cost responsibility impact of these wireless devices on the SL customer class, which was provided in the Applications. (*Id.*) NPC proposes that the temporary 25 perfect threshold be eliminated. (*Id.* at 17.) NPC proposes to modify the applicability section of the tariff to allow tribal governing bodies to take service under the SL tariff in order to allow for those entities to be treated similarly to other local governments currently billed under the tariff. (*Id.*) NPC also proposes the dusk to dawn provision in the applicability section of the tariff be removed. (*Id.*)

511. NPC states that it conducted a wireless device analysis in which NPC identified approximately 490 customers who were being inappropriately billed on the SL tariff. (*Id.* at 9.) NPC states that a system solution is currently underway to automatically limit the SL schedule option to only eligible customers when a request for new lighting service is submitted. (*Id.*) NPC provides that the identified premises were removed from the historical SL class loads and billing determinants for this filing and are reflected in the General Service ("GS") rate schedule. (*Id.*)

NPC states that this change accounts for a decrease of approximately five percent of the historical SL class loads, but only 0.89 percent of the GS schedule. (*Id.*)

512. Based on NPC's analysis, NPC states that wireless devices installed on existing street lights within the SL class currently have a minimal impact to the overall class. (*Id.*) NPC notes that roughly only 1.6 percent of the total class usage can be assigned to these wireless devices. (*Id.* at 15-16.)

513. Further, NPC states that the modelled usage attributed to the wireless devices on the 265 meters used in the analysis is estimated to be 22 percent of the total usage on these premises. NPC provides that this does not exceed the 25 percent limitation currently defined in the tariff. (*Id.* at 16.)

514. Based on NPC's analysis, NPC explains that the impact of installing wireless devices on the identified street light installations are lower than the class average, and have an overall slight positive impact on the SL class cost of service. (*Id.*)

515. NPC recommends that the Commission should approve NPC's proposed SL tariff modifications to allow for these devices on metered installations meeting the revised applicability requirements. (*Id.*) NPC asserts that supporting the ability of these customers to install these facilities behind the meter on their customer-owned poles will allow for these customers to better provide services to their constituents as they best deem fit. (*Id.* at 16-17.) NPC offers that it should not try to overly limit the use of these poles for city and county governments that may serve to support the expansion of more efficient lighting, Wi-Fi, and other services that may be viewed largely as services related to public safety/public service considerations. (*Id.* at 17.)

516. NPC recommends that the installation of these meters be continued going forward, as long as the customer pays for the additional energy usage related to the wireless devices. (*Id.*) To effectuate this recommendation, NPC states that the tariff must be revised. (*Id.*) NPC provides that this includes removing the temporary 25 percent threshold implemented in Docket No. 21-10008, as well as eliminating the dusk to dawn usage limitation within the applicability section of the tariff. (*Id.*; *see also* ex. 216 at 5.) Additionally, NPC recommends adjusting the tariff's applicability section to permit tribal governing bodies to be billed under the SL tariff. (Ex. 221 at 17.) NPC explains that this change would ensure that these entities are treated in a manner similar to other local government entities. (*Id.*)

517. Because these installations are metered, NPC states that any change in the overall usage will be paid solely by the street light pole owners. (*Id.*) Further, NPC notes that any change in the hourly load usage pattern of the SL class will be reflected in upcoming GRCs and used to inform final rates paid by these customers, like all other customer classes. (*Id.*)

518. NPC is also proposing to revise the Electric Vehicle Recharge Rider – Time of Use ("EVRR") period from the current EVRR period of 10:01 p.m. - 8:00 a.m. to 12:01 a.m. to 12:00 p.m. (Ex. 223 at 18.) NPC provides that functionalized costs are becoming more concentrated over time in the later evening hours. (*Id.*) Also, NPC states that its proposed Summer On-Peak ("SON") period ends at 9:00 p.m., at which time customers may bring on loads that were curtailed during the SON period. (*Id.*) Due to increasing adoption of electric vehicles ("EV"), NPC argues that it is prudent to move the beginning of the EVRR period, two hours later when marginal generation costs are lower, from 10:01 p.m. to 12:01 a.m. (*Id.*) Additionally, NPC proposes to extend the end of the EVRR period from 8:00 a.m. to 12:00 p.m.

following the lower marginal costs in early morning hours, when solar generation is ramping up prior to the increases in customer loads. (*Id.*)

Staff's Position

519. Staff recommends approving in part NPC's proposed modifications to its EVRR schedules by approving NPC's proposal to begin the EVRR period at 12:01 a.m., but deny NPC's proposal to extend the EVRR period to 12:00 p.m. (Ex. 326 at 2.)

520. Staff explains that EV owners on the EVRR schedule receive a reduced rate, and in some cases, possibly a rate credit, on all energy consumed during the discount period, not just energy consumed for EV charging. (*Id.* at 9.) Staff objects to the inequity of offering the discounted period to only those customers on the EVRR schedules. (*Id.*) Staff states that moving the discount period out to 12:00 p.m., when load is ramping up, increases the inequity. (*Id.* at 10.)

521. Staff provides that the current EVRR period, 10:01 p.m. to 8:00 a.m., is during a time when most customers have lower loads (e.g., businesses are closed, households are sleeping). (*Id.*) Therefore, Staff asserts that the rate inequity between EV owners and non-EV owners is limited. (*Id.*)

522. Staff recommends that the Commission accept NPC's wireless meter device installation analysis and SL Rate Schedule and tariff modifications. (Ex. 325 at 1.)

NPC's Rebuttal

523. NPC disagrees with Staff's recommendation to limit the EVRR rate period to 8 a.m. (Ex. 231 at 13.) NPC asserts that the benefit to non-EV customers is maximized by customers shifting load to NPC's proposed EVRR period. (*Id.* at 13-14.) NPC provides that an alternative, that retains the same amount of hours as the current EVRR period, is 12:01 a.m. to

10:00 a.m. (*Id.* at 14.) NPC states that the average per-kWh benefit is similar to NPC's proposal and reduces the overall kWh that the EVRR discount is applied to when compared to the current EVRR period. (*Id.*) NPC argues that Staff's proposed EVRR has better average per-kWh benefit than the current EVRR period but an average per-kWh benefit that is less than NPC's proposal due to lower late-morning marginal costs. (*Id.*)

Commission Discussion and Findings

524. The Commission finds that the proposed rate schedule and tariff modifications to the SL class and tariff are appropriate and deems them approved. The Commission notes that NPC states that any change in the hourly load usage pattern of the SL class will be reflected in an upcoming GRC submitted to this Commission. The Commission finds the removal of the twenty-five percent threshold approved in Docket No. 21-10008 to be reasonable. The Commission approves the proposed modifications to the tariff's applicability section as follows: (1) allow tribal governing bodies to be served under the SL tariff, and (2) the removal of the dusk to dawn provision.

525. On the EVRR schedule modifications, the Commission agrees in Part with NPC's proposal and in part with Staff's proposal. Specifically, the Commission agrees with NPC, and approves NPC's proposal to begin the EVRR period at 12:01 a.m. In addition to the modification of the start period time, the Commission agrees with Staff, and approves Staff's recommendation to deny NPC's proposal to extend the EVRR period to 12:00 pm. The current EVRR period is from 10:01 p.m. to 8:00 a.m. The new EVRR period will begin at 12:01 a.m. and will continue to 8:00 a.m., consistent with Staff's recommendation. The Commission notes that setting this modification results in just, and reasonable rates for all rate payers.

B. Residential Rate Cap

NPC's Position

526. NPC proposes setting a residential single-family cap of zero percent above the system percent increase of 3.3 percent. (Ex. 225 at 22.)

527. NPC explains that it supports a rate design that follows the cost causation of customer classes informed by the Marginal Cost Study. (Ex. 191 at 16.) NPC notes that rates can be set above or below cost for classes to effectuate goals of the Commission or public policy set by the Nevada Legislature. (*Id.*)

528. NPC states that the cap is implemented in Statement O by proposing the percent change in class revenue for standard bundled customer classes. (*Id.*) NPC explains that a cap implements a limit on the highest change that a class will experience. (*Id.*) NPC elaborates that any required revenue above the capped level will be shifted to other classes to ensure that the overall total revenue requirement is appropriately recovered through rates. (*Id.*) In this case, NPC offers that the RS class percent change is proposed to equal the overall change of 3.3 percent. (*Id.*) Practically, NPC states that the cap is set at zero to return the 3.3 percent overall system change (3.3 percent plus 0 percent cap in this filing). (*Id.*)

529. NPC highlights the cap mechanism only applies to the classes that are included in the cost-of-service studies and through the reconciliation process in Statement O. (*Id.*) NPC states that those customer classes that have rates based on their otherwise applicable schedule ("OAS") may show an increase (or decrease) in revenue beyond the set cap or floor amount. (*Id.*)

530. NPC provides that a 0 percent cap above the 3.3 percent overall revenue requirement increase for RS mitigates the rate impact of the cost-based result that would otherwise implement a 9.0 percent increase for these customers. (*Id.*) NPC explains that, to limit

the overall impact on standard RS customers, but to still make a measured movement towards the combined cost-based levels, NPC believes that an increase set at the system average increase is appropriate in this filing. (*Id.*)

Caesars, MGM, and SNWA's Position

531. Caesars, MGM, and SNWA recommend that the Commission cap the rate increase for the residential classes as a whole (including NEM) to no greater than 5 percentage points above the system average increase. (Ex. 1500 at 9.) Caesars, MGM, and SNWA state that, based on the cost allocation methods presented by NPC in its various Statement O analyses, such a cap can likely be realized without any subsidization from other classes. (*Id.* at 9-10.)

Joint Petitioners' Position

532. Joint Petitioners recommend applying a rate cap equal to two times the average rate increase or 4.5%, whichever is higher. (Ex. 902 at 11.) Joint Petitioners argue that NPC has proposed a cap that is effectively equal to the average, overall rate increase. (*Id.*) Joint Petitioners state that, in principle, if a rate schedule below cost of service is consistently allocated rate increases based on the overall average increase, the rate schedule will never move closer to cost of service. (*Id.*) Correspondingly, Joint Petitioner provide that if a cap is set at the average rate increase and it applies to all customer classes in a unform manner, it will result in all customers receiving the average rate increase: moving customers down to the average requires moving all other customers up to the average. (*Id.* at 11-12.) Therefore, Joint Petitioners assert that utilizing the average as the cap within the IRR will never produce any progress toward achieving cost. (*Id.* at 12.)

533. Joint Petitioners state that it recommends a minimum cap of 4.5 percent because the objective of the IRR is to mitigate excessive rate impacts to certain customer classes. (*Id.*)

Joint Petitioners provide that this implies that there is some level of rate increase that is not excessive. (*Id.*) Joint Petitioners explain that a principal goal of the rate spread is to move rate classes closer to cost of service over time. (*Id.*) Joint Petitioners state that, recognizing that the expected rate increase in this proceeding is likely to be small, if not a reduction, it is important to still allocate some non-excessive rate increase to rate classes that are significantly below cost of service. (*Id.* at 12-13.) For purposes of this case, Joint Petitioner state that it chose a 4.5% minimum cap because it would equate to an average annual rate increase of 1.5% per year. (*Id.* at 13.)

FEA's Position

534. FEA states that, based on NPC's claimed revenue deficiency, FEA recommends a cap on the RS/RS-NEM increase of 2 times the system average in order to make a greater movement toward cost of service for NPC's customer classes. (Ex. 1403 at 5.) FEA provides that, to the extent that the approved retail system average increase is less than 3.0 percent, a cap greater than 2 times the system average increase could be imposed while avoiding rate shock. (*Id.*)

BCP's Position

535. BCP recommends that the Commission adopt a revised revenue distribution including NPC's proposed cap to single-family residential rates but relies on an accurate measure of costs to provide service. (Ex. 415 at 51.) BCP states that its proposed revenue distribution modifies NPC's proposed rate cap for the single-family rate by removing fuel and purchase power costs. (*Id.* at 42.)

Staff's Position

536. Staff recommends that the Commission use Staff's cost of service study ("COSS"), Statement O excluding energy revenue to create rates, and NPC's proposed class revenue requirement cap for all customer classes. (Ex. 330 at 4.) Staff provides that, given the evidence of a shift in customer class revenues and depending on the final revenue requirement determined by the Commission, it is prudent to expand the application of the cap mechanism to all customer classes (and not just the RS customer class). (*Id.* at 20.) Staff explains that by implementing such an expanded cap mechanism, the risk of a sudden and significant customer class revenue requirement increase can be mitigated. (*Id.*)

537. Staff states that energy revenue should be removed from the reconciliation process in the COSS and Statement O. (*Id.* at 6.) Staff points out that NAC 704.032 clearly states how the costs of energy should be collected. (*Id.*) As such, Staff cautions the Commission to be wary of a tendency of parties to intermingle issues outside the scope of this proceeding. (*Id.*) Staff agrees that costs for energy vary. (*Id.*) However, Staff asserts that this is not the docket where that is addressed. (*Id.*) As such, Staff provides that the costs of energy should not be used to adjust the costs of service, even though they tend to be incurred in combination, because the energy costs are recovered and addressed in other proceedings. (*Id.*)

538. Staff states that, if the Commission decides not to accept Staff's COSS, then Staff recommends that the Commission order NPC to use NPC's hybrid cost of service study ("HCS") developed using NPC's stand-alone dispatch ("SAD") scenario, use Exhibit Prest Certification-28 (Statement O-ECS-E-MA, ECIC, New TOU, NPC Only Dispatch) as its corresponding Statement O with the appropriate BSC for the residential customer classes, and establish a class revenue requirement cap for the residential single-family cap. (*Id.* at 22.)

539. Staff states that, if the Commission decides to not accept Staff's above recommendations and accepts NPC's marginal cost of service methodology, the Commission should order NPC to use Exhibit Bohrman Certification-4 (MCS – Proposed TOU, Nevada Power Standalone Dispatch), which is NPC's marginal cost of service developed using the SAD scenario, and update Exhibit Prest Certification-20 (Statement O-MCS, ECIC, New TOU, NPC Only Dispatch, GE Separated) with the appropriate BSC for the residential customer classes to reflect the class revenue requirements but exclude cost-based class energy revenues (which happens to be included as revenues to be collected from classes to cover the cost of energy in designing rates). (*Id.* at 23.)

NPC's Rebuttal

540. NPC states that it interprets Intervenor's recommendations as general support for the inclusion of a cap for the single-family residential class. (Ex. 237 at 5.) NPC states that, even with the 3 percent increase in base rates in this case, customer overall bills are forecasted to decline in 2024 in the event the current projections for the base tariff energy rates and deferred energy accounting adjustment rates decline as forecasted. (*Id.*) NPC provides that the Commission can consider an appropriate cap based on the forecasted decline in bills as well as the final outcome of the cost of capital and revenue requirement phases of this case. (*Id.*) NPC offers that the Commission could also determine whether or not a cap is necessary depending on the proposed BSC. (*Id.*) NPC states that it continues to support a 3 percent residential increase regardless of the outcome of the other phases of the case given the forecast for 2024 shows a decline in customer bills. (*Id.*) However, NPC notes that it would also support removing the cap if the BSC approved by the Commission results in an overall impact to the residential class that continues to forecast a decline in bills in 2024 based on the information currently on hand. (*Id.*)

Commission Discussion and Findings

541. In conjunction with the Commission's discussion and findings with respect to cost of service and revenue allocation, the Commission agrees with NPC that a rate cap is appropriate at the system average increase for the single-family residential rate class. When applied, the amount that would need to be recovered from other rate classes through the IRR is attributable to a portion of the calculated NEM GRC revenue shortfall. The Commission finds that all rate classes should share in any cost responsibility which may be the result of statutory policy. This is also supported by NPC's testimony in recognizing that the increased reliance on renewable generation shifts costs of generation to hours that are later in the evening. (*See* Ex. 228 at 9.) Such hours are traditionally those of higher use by the residential rate classes.

542. The Commission also agrees with Staff that all bundled rate classes should be capped at the system average increase. Given the evidence of a shift in customer class revenues, the Commission finds it is prudent to expand the application of the cap mechanism to all bundled customer classes (and not just the RS customer class). By implementing such an expanded cap mechanism, the risk of a sudden and significant increase arising from this proceeding could be mitigated. This provides rate mitigation to classes that demonstrate proposed rate increases and takes into consideration that the rates set in NPC's 2020 GRC were stipulated; the Commission did not review the basis for these and while the parties all agreed, the rates set there may have contributed to the rate class impacts flowing to the instant docket.

C. Distribution-Only-Service ("DOS") Customer Interclass Rate-Rebalancing ("IRR")

NPC's Position

543. NPC does not include DOS customers in their IRR allocation and calculation. (Ex. 226 at Exhibit Prest Cert-3, p. 9.)

544. NPC proposes an IRR cap of 3.0 percent, which results in a total IRR revenue requirement of $102,597,000. (*Id.* at 10, Table Prest-Certification-3.)

Joint Petitioners' Position

545. Joint Petitioners provide that while it does not object to the general concept of an IRR, especially considering Nevada's history of using IRR for rate mitigation, Joint Petitioners provide that it is vital that the IRR is applied fairly to all customers, including DOS customers. (Ex. 902 at 1.) Joint Petitioners argue the NPC's approach to applying the IRR to DOS customers is inequitable because it incorporates DOS customer IRR revenues outside of the IRR calculation, based on rates derived from the otherwise applicable bundled service rate schedule. (*Id.* at 1-2.) Joint Petitioners explain that this treatment essentially means that the DOS IRR revenues function more as a general subsidy from DOS customers to bundled service customers, rather than a rate mitigation measure. (*Id.* at 2.) Joint Petitioners assert that such a subsidy runs counter to the purpose of the impact fees paid by DOS customers to offset the cost impacts on bundled service customers from DOS customers' departure from cost of service rates. (*Id.*) Accordingly, Joint Petitioners recommends that the Commission reject NPC's approach and ensure that DOS customers are treated consistently with all other customers in the IRR. (*Id.*)

546. Joint Petitioners argue that providing rate mitigation only to residential service customers, without considering others, raises questions of fairness, and the current IRR method, which assigns DOS customers an IRR surcharge based on the IRR rates calculated for the otherwise applicable rate schedules, is not equitable to DOS customers. (*Id.*) Accordingly, Joint Petitioners recommend that the Commission adopt the following four modifications to NPC's IRR calculation:

a. Adopt an IRR method that considers DOS customers explicitly in the IRR calculation;

b. Applies a rate cap that is set at the higher of 2-times the average rate increase or 4.5 percent, which based on the certification filing, resulted in a 6.00 percent cap;

c. Applies the cap equally to all highly impacted rate schedules, including DOS customers, rather than exclusively to residential service customers; and,

d. Recovers the cost of the IRR through a rate floor, rather than a percentage of revenues. (*Id.*)

NPC's Rebuttal

547. NPC disagrees that the DOS IRR be limited to only the distribution portion of the IRR. (Ex. 235 at 16.) NPC highlights that this incorrectly assumes that the only costs that are relevant to the DOS IRR rates are the distribution costs imposed by other customer classes and should therefore be reduced to reflect only an estimated distribution amount. (*Id.*) NPC points out that Joint Petitioners' suggestion that the IRR should be limited to only distribution costs for DOS customers ignores an important point: the IRR rate is not based upon the costs of DOS customers. (*Id.*) Rather, NPC explains that the DOS IRR rate is a Commission approved rate created by legislative policy that does not reflect the costs of DOS customers, but in fact is more related to the difference of costs for fully bundled customers relative to the rates that they pay. (*Id.*)

548. NPC disagrees that the current IRR calculation causes DOS customers to pay for generation costs. (*Id.* at 18.) NPC maintains that the IRR is not a cost-based rate and is therefore not related to the functional revenue groups of distribution, transmission, and generation. (*Id.*) NPC provides that the IRR is a policy decision to limit rate increases for certain classes, which is

then spread to the remaining classes. (*Id.*) NPC states that by limiting DOS customers' contribution to this policy decision creates an inequitable result between DOS customers and their fully bundled OARS. (*Id.*)

549. NPC rejects Joint Petitioners' IRR allocation proposal because the cap is based only on some of the DOS revenue, and not the total DOS revenue including the IRR, BTGR impact fees, and decommissioning costs. (*Id.* at 19.) NPC notes that the DOS customer revenue ends up being higher than the Joint Petitioners' proposed cap. (*Id.*) Further, NPC points out that Joint Petitioners' proposal contains a number of technical errors and uses an inferior methodology. (*Id.* at 19-20)

Commission Discussion and Findings

550. The Commission agrees with NPC's calculation of the IRR and it's applicability to DOS customers. NPC correctly points out that the IRR is a policy rate and not directly attributable to functionalized costs of service. NPC also correctly identifies that the IRR is applied consistently between fully bundled and DOS rate classes.

D. Basic Service Charge ("BSC")

NPC's Position

551. Amongst its rate design proposals, NPC states that it is proposing to implement a movement towards cost-based rates in the residential classes (RS, RM, and LRS) Basic Service Charge ("BSC") while maintaining the remaining classes at their current levels. (Ex. 225 at 22.)

552. NPC proposes to increase its BSC from $12.50 to $18.50 per month for Residential Service classes RS, ORS-TOU, and ORS-CPP; from $7.70 to $8.20 per month for Multi-Family classes RM, ORM-TOU, and ORM-CPP, and from $70.70 to $98.70 for Large Residential Service classes LRS, OLRS-TOU, and OLRS-CPP. (Ex. 230 at Exhibit Bohrman

Cert-8 at 38; *see also* Ex. 191 at 18-19.) For commercial customers, NPC proposes maintaining the BSC at current levels. (Ex. 191 at 18.)

553. As part of NPC's moderate class revenue increase, NPC proposes to not allocate the entire kWh component of the rates to the RS class but instead increase the BSC, which represents an increase in absolute terms of about $6 per month for all customers. (Ex. 227 at 38.) NPC notes that this revenue would otherwise be recovered through the per-kWh charges. (*Id.*)

Conservation Advocates' Position

554. Conservation Advocates recommend that the Commission should deny NPC's request to increase the BSC for residential and general service customers. (Ex. 800 at 6.) Conservation Advocates explain that increasing BSC should be rejected because such increases will decrease customer control of bills and reduce the customer incentive to engage in energy efficiency and conservation. (*Id.*) Additionally, Conservation Advocates provide that increasing the BSC, as a rate design policy, does not align with other state policies enacted to promote energy efficiency and conservation. (*Id.*)

555. Conservation Advocates provides that, given that NPC's BSC calculation includes several unquantified components that are not appropriate to recover through a customer charge, Conservation Advocates also recommend ordering NPC to track the cost of the individual components that comprise facilities costs in order to allow stakeholders to compare NPC's proposal with cost-based rates in future proceedings. (Ex. 801 at 23.)

556. Conservation Advocates point out a number of concerns regarding NPC's BSC increase: (1) the BSC calculation is inflated by NPC's subjective and unsupported decision to include inappropriate costs in the calculation of marginal customer and facilities costs that do not reflect cost causation; (2) the BSC increase contradicts state policy goals encouraging energy

efficiency and conservation; (3) the BSC increase disproportionately harms low-use customers, who also tend to be low-income; and (4) NPC lacks justification for their proposed BSC increase. (*Id.* at 24.)

BCP's Position

557. BCP recommends that the that the Commission reject NPC's proposed increase in residential customer charges, including the BSC. (Ex. 413 at 49.) BCP estimates that NPC's current customer charge revenues for each of NPC's residential service classes already fully account for total customer-related costs. (*Id.* at 49-50.) Thus, BCP argues that an increase in customer charges is not warranted at the current time. (*Id.* at 50.) Further, BCP provides that NPC's customer charge increase proposal would detrimentally impact the public policy goals of promoting energy efficiency. (*Id.*) BCP asserts the increase would burden low-use customers with a greater than average portion of any proposed increase in the case. (*Id.*)

Staff's Position

558. Staff recommends that the Commission adjust the BSC to $22.50 per month for the Single-Family Residential Service class and to $123.50 per month for the Large Residential Service. (Ex. 330 at 26-27.) Staff explains that a utility should attempt to have a consistent recovery of costs by each rate recovery mechanism, in this case, the BSC. (*Id.* at 28.) As such, Staff recommends that the Commission adjust the BSC for the Single-Family Residential Service as well as the Large Residential Service to recover the same percentage as the Multi-Family Service. (*Id.*)

NPC's Rebuttal

559. NPC states that it continues to support increasing the residential BSC, and therefore, generally supports Staff's position. NPC explains that increasing the BSC sends

appropriate price signals and limits intraclass customer subsidies resulting in lower volumetric rates which reduces customer bills during the higher usage summer season. (Ex. 237 at 2.) NPC states it proposed a more moderate and gradual increase compared to Staff's proposal. (*Id.*)

560. NPC provides that it is critical to note that while increasing the BSC results in a decrease to the cost differences included in the AB 405 NEM Regulatory Asset, it does not remove all the cost differences resulting in a continued need for the AB 405 NEM Regulatory Asset. (*Id.* at 3.) Further, NPC states that due to combining the RS and RS-NEM classes through rate design, an increase in the BSC lowers the percent increase to the RS class while increasing the percent increase to the RS-NEM class. (*Id.*)

561. NPC states that it disagrees with both Conservation Advocates and BCP's recommendations. (Ex. 234 at 34.) NPC asserts that Conservation Advocates propose to increase the kWh charge further, to add the cost of local distribution facilities, on top of energy and generation, transmission and distribution substation cost components. (*Id.*) NPC argues that adding a facilities cost component on top of per- kWh costs is not economically efficient or equitable. (*Id.* at 34-35.) NPC adds that BCP's rejection of applying marginal cost information for rate design is inconsistent with the discipline of prices to reflect efficient price signals. (*Id.* at 38.)

562. NPC states that using arguments from Conservation Advocates and BCP are arguments that are often used by those who lobby for residential customers and these arguments are inaccurate and are also biased in favor of residential customers. (*Id.* at 39.)

Commission Discussion and Findings

563. The Commission accepts NPC's proposed increases to the respective residential BSCs. A higher BSC will allow for a lower per kWh rate and provides for mitigation in times of

high kWh usage. The proposed single-family increase is $6.00 per month. Considering that NPC has calculated the average monthly single-family bill as approximately $202.18 per month for 1,138 kWh, the $6 increase to the BSC is reasonable. There is significant opportunity for energy efficiency and conservation efforts even with the increase in the BSC. The increased BSC will also help mitigate any potential calculated AB 405 NEM revenue shortfall.

564. The Commission recognizes that changes in rates may disproportionately impact low-income customers. While some programs exist to address these impacts, notably the Expanded Solar Access Program, the Commission finds that this topic merits additional review and a potentially more holistic approach. Accordingly, in its next GRC, NPC is directed to include a proposal to establish low-income rates as allowed pursuant to NRS 704.110(14)(b).

E. Time-Of-Use ("TOU") Periods

NPC's Position

565. Regarding NPC's proposed TOU periods, NPC is proposing an on-peak period that will start at 3:01 p.m. and end at 9:00 p.m., every day of the week during the summer months of June through September. (Ex. 227 at 45.) NPC provides that the current TOU period is from 1:01 p.m. to 7:00 p.m. (*Id.*) NPC also proposes to eliminate the Summer Mid-Peak period for large commercial customers. (Ex. 216 at 4.) NPC proposes to add weekend days to the Summer On-Peak period for residential and small commercial customers. (*Id.*) NPC is also proposing that non-holiday weekend days be added to the Critical Peak Pricing ("CPP") event days for residential customers. (*Id.*) NPC states that these proposals are a notable update to existing peak period definition. (Ex. 227 at 45.) NPC states that currently the peak period only exists on weekdays for residential optional TOU classes, while weekends are entirely off-peak. (*Id.*) In addition, NPC states that the existing peak period begins at 1 p.m. and ends at 7 p.m.

(*Id.*) NPC states that it is not proposing modify the winter TOU period definition, which considers all hours as off-peak, May through October. (*Id.*)

566. In Docket No. 17-07026, NPC states that the Option A and Option B residential TOU were closed to new customers. (Ex. 223 at 4.) NPC provides that, for the optional residential and the optional general service rate classes a Summer-On-Peak period was implemented from 1:01 p.m. to 7:00 p.m. Monday-Friday and Summer Off-Peak period was implemented from 7:01 p.m. to 1:00 p.m. for all days. (*Id.*) The Winter Off-Peak period is October through May for all hours. (*Id.*)

567. NPC explains that, during the TOU period review performed for this GRC, NPC compared historical marginal cost data to NPC's test period data, and to NPC's forecasted data. (*Id.*) As a result of this process, NPC states that it determined that it was appropriate to revise NPC's TOU period definitions given the ongoing shift in the daily timing of functionalized costs which provide the basis for TOU period rate design. (*Id.*) NPC explains that, as the marginal cost of providing electricity shifts to later in the day due to NPC's heavy reliance on solar generation to meet state statutory guidelines, NPC believes that modifying the TOU periods sends the appropriate price signal to customers. (*Id.* at 2.)

Walmart's Position

568. Walmart states that it does not oppose NPC's proposed TOU periods or the elimination of the summer mid-peak period. (Ex. 1001 at 2.)

Conservation Advocates' Position

569. Conservation Advocates recommend that the Commission should adopt it's proposal to create a unique Summer TOU window of 6 – 9 p.m. for residential customers, which it believes better reflects the highest cost hours and would likely be more attractive to customers.

(Ex. 801 at 22.) Conservation Advocates state that its proposal aligns with the three highest cost hours, even if one accepts NPC's flawed marginal cost of service study assumptions. (*Id.*) Conservation Advocates provide that correcting those assumptions simply makes the cost reflectiveness of a shorter Summer peak more pronounced. (*Id.*) Conservation Advocates state that NPC should recalculate its rates under Conservation Advocates' updated TOU definition. (*Id.*) Conservation Advocates state that the shorter peak period will likely increase the peak to off-peak ratio, which NPC has acknowledged should be higher, in order to be cost reflective. (*Id.* at 23.) However, Conservation Advocates provide that to shield customers from abrupt rate spikes, Conservation Advocates recommend that the on to off peak price ratio increase to no more than 4:1, inclusive of riders. (*Id.*)

570. Conservation Advocates state that the Commission should also plan to iterate on TOU rate design in the future, as the grid continues to evolve. (*Id.*) In particular, Conservation Advocates state that it will likely be necessary to implement time-differentiated non-summer rates as electrification increases over the coming years. (*Id.*)

571. Conservation Advocates also recommend that the Commission order NPC to reduce the length of the proposed on-peak window to a period of three hours, down from the current proposed window length of six hours. (Ex. 800 at 5.) Conservation Advocates provide that price signals will not produce the desired results and core objectives of TOU rates if customers are unable to respond to them. (*Id.*) Conservation Advocates explain that most customers cannot shift daily behavior out of the proposed 6-hour window, as it is too long. (*Id.*)

572. Conservation Advocates state that its recommendation amounts to a simple and basic TOU rate structure that is easily understandable by customers, but also alludes to the objectives of TOU rates in general. (*Id.* at 6.) Conservation Advocates state that this basic rate

structure will act as an introductory rate for Nevadans to become familiarized with TOUs and the benefits they offer. (*Id.*) Conservation Advocates state that in the years to come, this basic rate structure can be added onto, changed, and overall made more complex as customers become more sophisticated users of TOU rates. (*Id.*)

Staff's Position

573. Staff recommends that the Commission approve NPC's proposed modifications to the current TOU period definitions. (Ex. 326 at 2.)

574. Staff also recommends that the Commission approve NPC's proposal to eliminate the optional TOU Option A and Option B residential rate classes and move these customers to the proposed optional schedule. (*Id.*)

575. Staff provides that NPC's TOU review clearly shows that marginal generation and energy costs peak later in the day and the proposal has a higher R^2 value than the current TOU periods. (*Id.* at 6-7.) Additionally, Staff notes that the proposed TOU definition aligns NPC's TOU periods with Sierra's revised TOU periods approved by the Commission in Docket No. 22-06014. (*Id.* at 7.)

NPC's Rebuttal

576. NPC disagrees with Conservation Advocates' three-hour SON period. (Ex. 231 at 4.) NPC points out that Conservation Advocates do not provide a direct comparison of its proposal to NPC's proposal. (*Id.*) NPC states that Conservation Advocates recognize that NPC utilizes an Analysis of Variance ("ANOVA") model as one of its tools to compare various TOU definitions to provide the Commission with a comparison of similar TOU periods. (*Id.*) NPC explains that the ANOVA model provides the percentage of variation in costs captured by the TOU periods. (*Id.*) NPC states that it is important to remember that if the sole focus is on

selecting the set TOU periods with the highest coefficient of determination ("r^2") it may result in choosing a set of TOU definitions that fails to include hours that should be included for theoretical or operational reasons, for example, peak system demand hours that might not be peak marginal cost hours. (*Id.*)

577. NPC provides that when it compares the coefficient of determination values for NPC's TOU proposal with Conservation Advocates' proposal, the results demonstrate that the coefficient of determination for NPC's proposed TOU periods (r^2=0.468) is greater than the coefficient of determination for Conservation Advocates' proposal (r^2=0.405). (*Id.* at 5.) Thus, NPC states that its proposed TOU periods better capture the variation in marginal costs in the SON period than Conservation Advocates' proposed 3-hour SON captures the three highest marginal cost hours and fails to include hours that belong in the SON period, which is why the coefficient of determination for NPC's proposed SON is greater than the coefficient of determination for Conservation Advocates' proposed SON period. (*Id.*)

Commission Discussion and Findings

578. The Commission acknowledges there is a benefit in offering TOU rates to customers, despite the low adoption rate of such schedules in the state of Nevada. The Commission acknowledges that changes in peak hours and pricing of rates during such hours is a growing concern for the general body of ratepayers in Nevada. The purpose of TOU rates in the state is to encourage more customers to take service under TOU schedules, and to structure peak and off-peak periods to send appropriate price signals to customers. The Commission knows that structuring rates in rate design aspects of a general rate case is not black and white and is a balancing act for all customers. The Commission finds that there may be a slight benefit in offering shorter TOU rate structures than what is proposed by NPC in this case.

579. The Commission finds that the arguments and recommendations presented in this case by Conservation Advocates are compelling. Therefore, the Commission adopts Conservation Advocates' recommended three-hour TOU period for residential TOU customer classes. The Commission finds that an on-peak three-hour period ending at 9 P.M. sends the appropriate price signal to customers at this time. The Commission finds that a TOU period from 6 P.M. to 9.P.M. is appropriate and shall be incorporated into NV Energy's TOU rate schedules. The Commission believes that this type of rate structure sends the appropriate price signals to residential TOU customers during peak hours and therefore will encourage more residential customers in the state to take service under TOU rate schedules. Furthermore, as stated by the Conservation Advocates, this type of TOU rate structure is simple and easily understandable by customers.

F. LGS-2S Customer Class Rate Design

NPC's Position

580. NPC provides its comparison of proposed revenue changes by rate class as a resulting from NPC's proposed rate design. (Ex. 226 at 9, Table Prest Certification-2.) NPC proposes a $3,036,000 increase in rates from the LGS-2S class. (*Id.*)

581. NPC explains that transmission demand costs are recovered through TOU-based demand charges for large commercial and industrial customers. (Ex. 225 at Exhibit Prest Direct-2, p. 34.) NPC states that there is a portion of generation demand costs that are also recovered through the proposed energy rates. (*Id.*) NPC explains that this methodology is sometimes referred to as "rate tilt." (*Id.*) NPC provides that, given that there is an interrelationship between the generation and energy functions, even though a disconnect exists between the development of the hourly costs and the imposition of the demand charges that are based on a maximum kW

demand across the billing period, it is appropriate to recover a certain portion of demand costs through the energy component. (*Id.* at Exhibit Prest Direct-2, pp. 34-35.) In this filing, NPC is proposing to keep the same rate tilt as utilized in the 2020 filing. (*Id.* at Exhibit Prest Direct-2, p. 35.)

582. NPC states that the general rate design practice of rate tilt is to recover system generation capacity costs through the $/kWh energy charge, without impacting the allocation of embedded revenue requirement among customer classes but that does affect the revenue that is collected from customers within a given class. (*Id.*) NPC states that generally, if the customer has a higher load factor, that customer will pay more because an additional generation demand revenue is collected through the energy kWh charge; while a customer who has a lower than average load factor for the class would generally pay less as the rate tilt is increased (more revenue is collected through the energy charge). (*Id.*) However, NPC notes that this practice is important for cost of service and rate design because it allows rates to more closely follow how costs are developed across all hours of the year and helps to provide customers with information as to how their energy consumption patterns affect these costs. (*Id.*)

Kroger's Position

583. Kroger states that NPC's rate design for the LGS-2S rate schedule understates demand-related charges while overstating the energy charges relative to the underlying cost components. (Ex. 1200 at 4.) Kroger provides that NPC's proposed rate design for the LGS-2S class would only recover 66.5 percent of the demand-related costs through demand-related charges while the energy charges would recover 130.1 percent of the energy-related costs, based on NPC's own cost of service study. (*Id.*) Kroger recommends a modest increase to the demand-related charges that would recover 73.2 percent of the demand-related costs while

reducing the energy charges by a corresponding amount so that my recommended rate design would be revenue neutral to NPC. (*Id.*) Kroger states that its recommended rate design would improve the alignment between charges and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts (*Id.*)

Walmart's Position

584. Walmart states the Commission should require NPC to set the rate tilt for the LGS-2S class to no greater than 51 percent. (Ex. 1001 at 16.)

585. Walmart states that NPC proposes to collect approximately 53 percent of LGS-2S transmission and generation demand-related costs, which are incurred on a per kW basis, through energy rates, which are charged to customers on a per kWh basis. (*Id.* at 15.) Walmart states that the shift of demand costs to the per kWh energy charges results in a shift in transmission and generation demand cost responsibility from lower load factor customers to higher load factor customers and results in a subsidy from high load factor customers to low load factor customers. (*Id.*) Walmart states lower load factor customers on LGS-2S will pay less than the transmission and generation demand costs incurred by NPC to serve them, while higher load factor customers on those schedules will pay more than the transmission and generation demand costs incurred to serve them. (*Id.*)

NPC's Rebuttal

586. NPC disagrees with Walmart's proposal that the rate tilt be limited to 51 percent. (Ex. 235 at 23.) NPC states that Walmart's recommendation is based on its analysis that NPC is moving from a rate tilt proposal of 51 percent in NPC's 2020 certification filing to a proposal of 53 percent in this filing, and that is a movement away from costs. (*Id.*) NPC does not agree that reducing the rate tilt is the same as moving closer to costs. (*Id.*) On the contrary, NPC states that

the two rate tilt analyses provided by NPC before shows that a significant rate tilt moves classes closer to cost. (*Id.*) Additionally, NPC states that its proposed certification rate design in Docket 20-06003 included a rate tilt of 53 percent for the LGS-2S class, not 51 percent as Walmart suggests. (*Id.* at 23-24.) Contrary to Walmart's assertion, NPC provides its proposed rate tilt of 53 percent for the LGS-2S class in this case is consistent with the rate tilt proposed in the 2020 NPC GRC. (*Id.* at 24.)

587. NPC also disagrees with the LGS-2S rates proposed by Kroger. (*Id.*) NPC states that Kroger's rate design results in a rate tilt of 42 percent for the LGS-2S class based on NPC's direct filing. (*Id.*) NPC provides that this rate design would unfairly push costs to low load factor LGS-2S customers while benefiting high load factor customers. (*Id.*) NPC states that it is already increasing the demand rates in this case due to both the removal of the Summer Mid-peak TOU period and the increased generation demand costs compared the 2020 NPC GRC and would oppose increasing them much further. (*Id.*)

Commission Discussion and Findings

588. The Commission agrees with NPC to maintain the current rate design for the LGS-2S customer class and finds that NPC's approach is reasonable. The Commission does not find the proposals made by Kroger and Walmart to be necessary at this time.

G. Compliance Filing

Google's Position

589. Google recommends that the Commission should require NPC to file all rates, calculations, and workpapers for the entire rate period in a single compliance filing made ten calendar days after the Commission's final order in this case. (Ex. 501 at 3.) Google notes that in Sierra's most recent general rate case, Docket No. 22-06014, the Commission ordered Sierra to

file its final Statement I, Statement O, rate design, and additional workpapers to support the calculations in Statement I and Statement O in hard copy and electronic executable form within ten calendar days of the date of the final order. (*Id.* at 1-2.)

Staff's Position

590. Staff recommends that the Commission Order NPC to file a compliance filing updating the DOS Decommissioning Revenues that should be used to determine the revenue requirement for rate design. (Ex. 330 at 30.)

NPC's Rebuttal

591. In response to Google's recommendation, NPC provides that two compliance filings were necessary for Sierra's 2022 GRC. (Ex. 236 at 37.) NPC states that, as discussed in the Sierra 2022 GRC proceeding, the timing of the proposed and approved changes to Sierra's TOU definitions necessitated a delayed implementation of rates. (*Id.*) NPC asserts that a full rate design compliance filing was always planned to be made for June 1, 2023, the first day of the newly defined summer season. (*Id.*) NPC explains that because a compliance filing includes approved tariffs and rate design that incorporates all rate components in effect at the time of the rate effective date, these components cannot be completed, approved and stamped by Staff, and filed ahead of time. (*Id.*) NPC offers that the compliance filing made by Sierra, on May 10, 2023, incorporated all rate design files and workpapers, as well as the approved tariffs, that would become effective on June 1, 2023. (*Id.*)

592. NPC states that NPC will not require the same delayed implementation of rates in this proceeding. (*Id.*) NPC explains that NPC is not proposing a change to the seasonal definitions as was approved at Sierra in 2022. (*Id.*) NPC notes that the summer season already

includes the month of June, which was the change that was incorporated at Sierra and necessitated the delayed rate implementation. (*Id.*)

Commission Discussion and Findings

593. The Commission agrees with NPC that there should not be a delay in the filing of the rates and supporting workpapers in the instant docket. The Commission orders NPC as a compliance to file these within ten business days of the date of the Commission's Order, and all schedules should be filed in executable form with formulas and links intact.

594. The Commission agrees with Staff, and orders NPC to file as a compliance the DOS Decommissioning Revenues ultimately used in revenue requirement for rate design within ten business days of the date of the Commission's Order.

H. DOS Rates

NPC's Position

595. For DOS customers, NPC states that a 180.39 percent rate increase is only the percent increase of their distribution rates included in this filing. (Ex. 225 at 24; ex. 226 at 9, Table Prest-Certification-2.) NPC states that looking at these customers' entire bill, including Open Access Transmission Tariff and energy rates paid to their energy providers, the overall impact of the GRC is significantly smaller. (Ex. 225 at 24.)

596. NPC provides that customers billed in optional or partial-requirements categories (Standby, Optional TOU, NEM Optional TOU, and DOS) are presented as separate groups in the table referenced above and show an average increase of 26.5 percent. (*Id.*) NPC explains that this increase is mostly due to NPC's proposed increase in the BSC for the residential classes, which causes NEM customers to pay more of their fixed costs that they were previously able to

avoid, as well as an increase to the IRR that the DOS customers are required to pay as a direct result of the residential subsidy in this case. (*Id.*)

Caesars, MGM, and SNWA's Position

597. Caesars, MGM, and SNWA recommend that, in the interest of gradualism, DOS customer rates should be set exactly at cost of service, with no subsidy payments unless necessary to keep overall residential rates within 5 percentage points of the system average increase. (Ex. 1500 at 10.)

NPC's Rebuttal

598. NPC rejects assertions that NPC's proposed increase to DOS customers is inappropriate. (Ex. 235 at 13.) First, NPC provides that the DOS cost-based rates are developed by combining fully bundled and DOS customers through the development of the cost-based distribution revenue requirement for these classes, and the customer rates are set to the same level as their otherwise applicable rate class ("OARS") in Statement O. (*Id.* at 13-14.) NPC provides that this is done because there is essentially no difference in the cost to serve DOS customers and their OARS counterparts when it comes to NPC's distribution system. (*Id.* at 14.) NPC explains that if NPC were to apply different rates towards DOS customers simply based on the percentage increase that would lead to a disparity between rate classes creating the same type of costs on the system. (*Id.*)

599. Second, NPC states that it is misleading to compare the percentage change to DOS customers to any of the bundled classes. (*Id.* at 15.) NPC explains that the DOS percentage changes shown in Statement O are based purely on their distribution charges, while the bundled classes include revenue from transmission and generation costs. (*Id.*) NPC notes that no matter

how consistently NPC treats DOS customers, their percentage change will always look different than their OARS since one is only looking at a subset of their costs. (*Id.*)

600. NPC also argues that it is inappropriate to cap the DOS classes similar to other classes. (*Id.* at 16.) NPC explains that DOS customers purchase energy services from an alternative provider. (*Id.*) NPC elaborates that if the same cap/floor were imposed on these classes, then this would lead to separate rates between the different service options, thereby leading to inconsistencies between customer choices. (*Id.*)

Commission Discussion and Findings

601. The Commission agrees with NPC with respect to the calculation of the DOS rates. Optional and partial requirements customers cannot be simply compared to their OARS since they do not pay all of the same functional costs. NPC demonstrated that when looking at the overall bill for these customers, the rate increase requested in this docket is substantially smaller. In addition, the calculation of the percentage increase was based on NPC's preferred Statement O and will be reduced as a result of the Commission's findings with respect to cost of service discussed elsewhere in this Order.

I. Weather Normalization

NPC's Position

602. NPC states that it is using the same weather normalization methodology to adjust test period billing determinants as was presented and ultimately approved by the Commission in Sierra's 2022 GRC. (Ex. 221 at 9.) NPC provides that the methodology incorporates a 20-year trended normal adjustment for adjustments in Statement J, to account for the impact of weather during the test period. (*Id.*)

603. NPC notes that, in the Commission's Order in NPC's 2020 GRC, directive paragraph 8 ordered that the weather normalization methodology adopted in Sierra's 2019 GRC (Docket No. 19-06006) should be used in NPC's next GRC. (*Id.*) However, NPC provides that in Sierra's 2022 GRC, the Commission approved a trended 20-year methodology for weather normalization that was not opposed by any party. (*Id.*) As a result, NPC states that it incorporates the most recently approved methodology in this proceeding. (*Id.*)

Staff's Position

604. Staff recommends accepting NPC's weather normalization adjustments to its certification period sales provided in Statement J. (Ex. 326 at 2.)

605. Staff explains that the weather normalization process utilized by NPC can be summarized in the following three steps: (1) determine trended normal weather conditions defined by Cooling Degree Days ("CDD") and Heating Degree Days ("HDD"), (2) estimate the relationships between consumption and CDD, and consumption and HDD using linear regression models, and (3) apply the difference between trended normal CDD and HDD and recorded CDD and HDD to the relationships established in Step 2. (*Id.* at 3.) Staff states that the monthly ratio of weather-normalized sales to recorded are used in Statement J to derive the weather normalization adjustments to Statement J recorded sales. (*Id.*) Staff notes that NPC's weather normalization adjustments reflect warming temperature trends and result in reasonable normalized sales. (*Id.* at 4.)

Commission Discussion and Findings

606. The Commission finds that NPC's weather normalization adjustments reflect the growing trend in warmer temperatures. The Commission approves the trended 20-year methodology and NPC's weather normalization adjustments to its certification period sales

provided in Statement J. The methodology used for weather normalization in this case is also consistent with the previous Commission order in Sierra's last GRC. The Commission finds that NPC's adjustment to weather normalization, provided in Statement J recorded sales, results in just and reasonable normalized sales.

J. RS-NEM Subsidy

NPC's Position

607. NPC provides that with no movement towards cost-based rates, the RS interclass subsidy is $69.2 million, which is comprised of a subsidy of $89.8 million from RS-NEM that is partially offset by $20.6 million in revenue from the full-requirements RS customers. (Ex. 225 at 25.) NPC provides that this amount is allocated to all other customer classes as part of the methodology presented in Statement O. (*Id.*) NPC updated these figures as of the certification date to an RS interclass subsidy of $102.6 million, of which $98.5 million is due the RS NEM class. (Ex. 226 at 10.)

FEA's Position

608. FEA states that the RS-NEM Subsidy is a significant issue that needs to be resolved before more customers switch to RS-NEM, the subsidy becomes even larger, and rates for all other customer classes continue to be priced above their respective cost of service. (Ex. 1403 at 19.) FEA provides that RS-NEM customers pay the same rates as RS customers, which consists of a monthly Basic Service Charge, and an energy charge. (*Id.*) FEA asserts that, because RS-NEM customers have behind-the-meter generation which reduces the amount of energy purchased from NPC, these customers are not making an adequate contribution to the fixed production, transmission and distribution costs incurred to provide service to them when their on-site generation does not fully cover their load requirements. (*Id.*)

609. FEA provides that, in order to improve the fixed cost recovery from these customers, and reduce the RS-NEM subsidy, the rates should be redesigned to increase the Basic Customer Charge, and/or implement a demand charge for the recovery of fixed costs, granted considerations may need to be made to accommodate low-income customers. (*Id.* at 21.)

610. Accordingly, FEA recommends the Commission direct NPC to explore alternative rate designs for the RS/RS-NEM classes that would improve fixed cost recovery from RS-NEM customers, and reduce the subsidy paid by NPC's other customer classes. (*Id.*)

Commission Discussion and Findings

611. The Commission agrees with FEA that the potential RS NEM GRC revenue shortfall continues to grow exponentially and will exacerbate rate design in future proceedings. As noted in the discussion in this Order relative to the AB 405 NEM Regulatory Asset, the Commission has directed NPC to file in its next GRC alternative rate methodologies or regulatory solutions to mitigate the calculated shortfall.

K. Revenue Allocation

NPC's Position

612. NPC provides its overall revenue allocation via Statement O. (Ex. 225 at 8, Table Prest-Direct-1; ex. 226 at 8, Table Prest-Certification-1; *see also* ex. 226 at 9, Table Prest-Certification-2.) NPC explains that NAC § 703.2445 sets forth the requirements and purposes of Statement O. (Ex. 225 at 11.) NPC states that, consistent with the direction provided in NAC § 703.2445, NPC has set forth and described the development of proposed rates for all classes of customers, including fully-bundled service and DOS customers. (*Id.*)

FEA's Position

613. FEA states that the allocation methodology used to spread the system revenue requirement across rate classes should offer the most accurate reflection of how NPC incurs cost to provide service across its rate classes, and total retail system. (Ex. 1403 at 4.) FEA asserts that the principle should be upheld regardless of whether a marginal cost of service ("MCS") study or an embedded class cost of service ("ECS") study methodology is adopted to develop each rate class's cost of service. (*Id.*)

614. FEA maintains that the class cost of service studies do not reflect the reality of NPC's operations. (*Id.* at 6.) FEA explains that several of the class cost of service studies do not reflect the fact that NPC and Sierra jointly manage and dispatch their system. (*Id.*) In addition, FEA offers that certain studies do not capture TOU generation cost differences between rate classes. (*Id.*) Therefore, FEA argues that the studies that: (1) do not reflect joint dispatch; (2) do not reflect the combined reconciliation of generation demand and energy marginal costs; and (3) exclude the energy component of the generation revenue requirement, should be given little, if any, weight for establishing each class's revenue apportionment and rate design. (*Id.*)

Caesars, MGM, and SNWA's Position

615. Caesars, MGM, and SNWA state that NPC's revenue allocation proposal should be rejected by the Commission, as it is well outside the bounds of reasonableness. (Ex. 1500 at 3.) Caesars, MGM, and SNWA state that NPC is seeking an overall revenue requirement increase of 3.1 percent and recommends imposing an average rate increase on its DOS customers of 136.5 percent, the large majority of which consists of unjustified subsidy payment purportedly intended to cap the rate increase to the RS class at the system average. (*Id.*) Caesars, MGM, and SNWA argue that NPC's proposal to increase DOS rates by more than 136% is grossly disproportionate. (*Id.*)

616. In determining revenue allocation, Caesars, MGM, and SNWA state that it is important to align rates with cost causation to the greatest extent practicable. (*Id.* at 6.) Caesars, MGM, and SNWA provide that properly aligning rates with the costs caused by each customer group is essential for ensuring fairness and, just and reasonable rates, as it minimizes cross subsidies among customers. (*Id.*) Caesars, MGM, and SNWA state that it also sends proper price signals, which improves efficiency in resource utilization. (*Id.*) At the same time, Caesars, MGM, and SNWA state it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. (*Id.*) Caesars, MGM, and SNWA explain that this principle of ratemaking is known as "gradualism." (*Id.*) Caesars, MGM, and SNWA argue that does not reasonably adhere to these principles. (*Id.*)

Walmart's Position

617. Walmart states that if the Commission approves NPC's proposed revenue requirement, Walmart does not oppose NPC's revenue allocation proposal per their certification filing. (Ex. 1001 at 2.) However, Walmart provides that if the Commission approves a lower revenue requirement for NPC, the Commission should (1) hold the NEM classes at the increases proposed by NPC in its Certification filing, (2) apply half of the reduction only to customer classes that are proposed to pay subsidies to other classes through the IRR, and (3) apply the other half of the reduction on a pro rata basis to all customer classes, with the exception of the NEM classes. (*Id.*)

618. Walmart states that the existence of subsidies is problematic and that NPC proposes that that the LGS-2S class pay subsidies to other customers, which is inequitable. (*Id.* at 11-12.)

BCP's Position

619. BCP recommend the Commission reject NPC's proposed class-specific revenue distributions as being based on inaccurate measures of cost of service. (Ex. 413 at 3.) BCP recommends that the Commission instead adopt a revised revenue distribution including the same proposed cap to single-family residential rates but relies on an accurate measure of costs to provide service. (*Id.*)

620. BCP states that, while NPC's recommendation to temper rate increases for the residential class is warranted, it bases the ranges for that distribution on an inaccurate measure of cost of service which are the results from NPC's marginal cost of service study. (*Id.* at 42.) BCP recommends that the Commission adopt NPC's revenue allocation approach but use BCP's proposed embedded cost of service study. (*Id.*)

Staff's Position

621. Staff recommends that the Commission find that the BTGR during the EV recharge periods applicable to the EVRR, EVCCR, and NV Energy Electric Vehicle Charging Network ("NVEVCN") Schedules must be no less than zero. (Ex. 326 at 12.)

622. Staff explains that the EVRR schedules are applicable to EV owners who are on one of the residential or general service optional TOU schedules. (*Id.* at 12-13.) Staff provides that the current EVRR discount period is 10:01 p.m. to 8:00 a.m., although NPC is proposing to change it to 12:01 a.m. to 12:00 p.m. (*Id.* at 13.) Staff explains that Schedule EVCCR is offered to bundled service commercial customers who are on the optional large general service TOU schedule or a large general service schedule who install separately metered direct current fast-charging EV charging stations, and Schedule NVEVCN is designed specifically for retail service by NPC owned EV chargers. (*Id.*) Staff notes that the current EVCCR and NVEVCN recharge

period is 12:01 a.m. to 12:00 p.m. (*Id.*) Staff states that the discount is equal to ten percent of the sum of the off-peak BTGR and BTER. (*Id.*) Staff asserts that this can result in a negative BTGR. (*Id.*) For example, Staff provides that NPC's proposed BTGR during the summer discount period for the ORS-TOU Schedule is ($0.00968). (*Id.*) Staff states that its recommendation is to limit the discount so that the BTGR in the EV charging discount period is equal to zero or greater. (*Id.*)

NPC's Rebuttal

623. NPC states that its analyses demonstrate that NPC is treating DOS customers consistently with other classes, which is consistent with Caesars, MGM, and SNWA's recommendation. (Ex. 235 at 14.) NPC maintains that it is accurately and fairly calculating the DOS rates, including the IRR. (*Id.* at 3.)

624. NPC disagrees with the notion that IRR calculations cause DOS customers to pay for generation costs. (*Id.* at 18.) NPC explains that the IRR is not a cost-based rate and is therefore not related to the functional revenue groups of distribution, transmission, and generation. (*Id.*) NPC states that the IRR is a policy decision to limit rate increases for certain classes, which is then spread to the remaining classes. (*Id.*) NPC cautions that, by limiting DOS customers' contribution to this policy decision creates an inequitable result between DOS customers and their fully bundled OARS. (*Id.*)

625. NPC further notes that, to the extent that there is a state policy for other customers to subsidize NEM customers, it is unclear why DOS customers should be exempt from supporting this policy, especially considering that only a portion of costs related to NEM costs are related to generation functions. (*Id.*)

626. With respect to Staff's recommendation regarding the EV BTGR, NPC maintains that the current calculation of the 10 percent discount on both the BTGR and BTER is accurate and is based on a policy consideration designed to encourage the adoption of EVs. (*Id.* at 26.) However, NPC provides that, if the Commission would like to adapt the current policy decision and decides that it is necessary to implement a limit of zero on the EV BTGR rate, NPC would not oppose implementing this recommendation. (*Id.*)

Commission Discussion and Findings

627. The Commission agrees with NPC with respect to its revenue allocation, subject to the Commission's findings in the other sections of this Order. The Commission agrees with NPC in its characterization that NPC is treating DOS customers consistently with other classes.

628. The Commission also accepts Staff's recommendation with respect to the EV BTGR. While encouraging EV adoption is a state policy, the Commission does not find that this would hold true to the extent that the EV BTGR became negative. The Commission orders that NPC implement a limit, or floor, of zero for the EV BTGR rate.

629. The Commission appreciates FEA's statement that the revenue allocation should reflect how NPC's system is run. However, as further discussed in the cost of service section, there is currently an inherent disconnect between how the system may be run and how the costs to do so are recovered from ratepayers, including the potential impact of state policy objectives.

L. Non-Bypassable Decommissioning Charges

NPC's Position

630. NPC provides its workpapers depicting decommissioning costs specific to DOS customers in Ex. 226 at Exhibit Prest Cert-3, p. 18.

Caesars, MGM, and SNWA's Position

631. Caesars, MGM, and SNWA state that the non-bypassable decommissioning charges for MGM and Caesars should be recalculated based on their respective proportionate load shares during the test period in this case, after fully taking account of the properties that MGM and Caesars no longer own and for which MGM and Caesars have no ongoing energy cost responsibility. (Ex. 1500 at 4.) Caesars, MGM, and SNWA provide that making this change reduces MGM's annual decommissioning charge from $436,089 to $306,947 and reduces Caesars' annual decommissioning charge from $243,415 to $221,882. (*Id.*) In addition, Caesars, MGM, and SNWA argue that MGM should be permitted to apply any remaining credit balance as identified in its approved exit stipulation, toward the non-bypassable decommissioning charge. (*Id.*)

Staff's Position

632. Staff recommends that the Commission find that MGM, Rio, Circus Circus, The Mirage, and Caesars are only subject to their certification load-ratio share of the Reid Gardner station and Navajo station decommissioning and site remediation costs recovered through the DOS tariff. (Ex. 327 at 3.) Additionally, Staff recommends that the Commission should order NPC to collect Rio's, Circus Circus' and The Mirage's load ratio share of the Reid Gardner and Navajo costs from those entities through their DOS rates. (*Id.*)

633. Staff notes that there is a possibility that the Reid Gardner and Navajo decommissioning and site remediation costs NPC recovers from MGM, Circus Circus, and Mirage will be less than the amount allocated to MGM in NPC's cost of service study. (*Id.* at 6.) Staff explains that loads may be reduced from corporate demand side management programs enacted by each entity. (*Id.* at 7.) Staff provides that, although the difference should be *de minimus*, any costs not allocated to DOS customers would be reallocated to bundled retail

electric service customers in Statement O. (*Id.*) Staff asserts that NPC should provide an updated cost allocation that reflects load ratio share of the Reid Gardner decommissioning and site remediation costs for MGM, Circus Cirus, and Mirage in this proceeding. (*Id.*)

634. Staff provides that, per the terms of MGM's stipulation, MGM should be allocated its Certification load ratio share of the Reid Gardner and Navajo decommissioning and site remediation costs, which should include the loads of The Cosmopolitan of Las Vegas ("Cosmopolitan") but exclude the loads of the Circus Circus, and The Mirage. (*Id.* at 6.)

635. Staff recommends that the Commission find that NPC allocate the Reid Gardner and Navajo decommissioning and site remediation costs to Caesars based upon their actual kWh at certification, which excludes Rio's load. (*Id.* at 8.) Additionally, Staff provides that the Commission should order NPC to collect Rio's load ratio share of the Reid Gardner decommissioning and site remediation costs from Rio. (*Id.*)

636. Staff recommends that the Commission find that any remaining credit provided to MGM in Paragraph 3(b) of the Stipulation filed on May 24, 2017, in Docket No. 15-05017, may be applied to MGM's remaining Reid Gardner and Navajo net book value and decommissioning and remediation cost liability. (*Id.* at 9.)

637. Staff explains that MGM's impact fee was based off of MGM's departure from NPC's bundled retail electric service in February 2016. (*Id.*) However, Staff notes that MGM did not depart NPC's bundled retail electric service until October 2016, due to NPC's long lead time needed to order metering and communications equipment and for installation. (*Id.*) Because of the delay, Staff states that the impact fee paid by MGM included costs for the February to October 2016 period, while MGM was still paying bundled electric rates during that period. (*Id.*) Therefore, Staff provides that MGM, Staff, and BCP stipulated that MGM should be credited

$16 million as an offset against remaining MGM liabilities that were yet to be paid under Staff's impact fee methodology. (*Id.*) Staff states that MGM may apply the credit to its share of the Reid Gardner and Navajo net book value costs, decommissioning and site remediation costs, and as an offset to MGM's renewable base tariff energy rate ("R-BTER"), renewable energy program rate ("REPR"), and temporary renewable energy development ("TRED") rate liabilities pursuant to Section 3(b), 3(c), 3(i), and 3(j) of MGM's stipulation. (*Id.* at 9-10.)

638. Staff further recommends that the Commission find that MGM, Caesars, and other DOS customers are not entitled to any offsets to their Reid Gardner decommissioning and site remediation cost liabilities due to any savings that may result from siting a BESS at the Reid Gardner site. (*Id.* at 10.) Staff explains that Staff reviewed a data request propounded by MGM, Caesars, and SNWA (DR 3-04) to NPC on September 26, 2023. (*Id.*) From this data request, Staff states that MGM and Caesars may be seeking a credit or offset to their Reid Gardner decommissioning and site remediation costs from any cost savings from siting a BESS at the Reid Gardner site. (*Id.* at 10-11.) Staff is concerned with MGM's and Caesars' pursuits. (*Id.* at 11.)

639. Staff asserts that MGM and Caesars are not entitled to any offsets to their Reid Gardner and Navajo decommissioning and site remediation cost liabilities due to any savings related to siting the BESS at the decommissioned Reid Gardner station. (*Id.*) Staff explains that MGM and Caesars departed NPC's bundled electric service and do not pay for NPC's generation costs. (*Id.*)

NPC's Rebuttal

640. NPC explains that there are different interpretations for determining MGM's required load-proportionate share regarding the recovery of the Reid Gardner and Navajo

decommissioning costs. (Ex. 232 at 2.) NPC states that the "then current" term used in the MGM stipulation is interpreted by NPC as the load-proportionate share determined at the time of the original exit docket order. (*Id.*) NPC asserts that it is most logical to employ the load ratio share that most closely influenced the use of the generating facilities. (*Id.*) NPC states that Staff, Caesars, MGM, and SNWA interpret that the term "then current" refers to the load-proportionate share of the properties consistent with the period used for this proceeding. (*Id.*) NPC states that the result of this interpretation is potentially allocating decommissioning costs away from the loads that benefitted from the output of the generating facilities to loads that may have never benefitted from the plant output. (*Id.* at 2-3.) NPC also notes that the Commission's order is silent on how to assess decommissioning charges in the event the applicant sells properties. (*Id.* at 3.) Therefore, NPC states that it does not take a position on the interpretation of the parties to consider changes in ownership for locations that have been either sold or purchased by MGM since the order in each 704B docket at this time. (*Id.*)

641. NPC also explains that there are different interpretations for determining Caesar's required load-proportionate share regarding the recovery of the Reid Gardner and Navajo decommissioning costs. (*Id.*) NPC states that, while it still finds it most logical to employ the load ratio share that most closely influenced the use of the generating facilities, Caesars' exit docket order more clearly specifies the loads at the time of approval of the decommissioning costs. (*Id.*) Therefore, NPC states it is not opposed to updating this allocation for Caesars in a compliance to reflect Caesars' load at the end of the certification period in this proceeding, if the Commission deems that this is the reasonable approach. (*Id.*)

642. NPC states that it cannot agree with Staff, Caesars, MGM, and SNWA's recommendation to impose a charge on different premises from those included in each

corresponding exit order. (*Id.* at 4.) NPC explains that it is not aware of specific terms and conditions of the sale of the properties, and therefore cannot appropriately opine on how those terms and conditions may or may not influence a decision regarding the fees. (*Id.*)

643. NPC disagrees with Staff that a separate charge should be developed for Cosmopolitan because Cosmopolitan is currently a bundled-service customer and will pay for its share of these costs through its bundled rates. (*Id.*) Therefore, NPC argues that a separate fee for this customer to recover its share of decommissioning costs is unnecessary. (*Id.*)

644. NPC states that, since the Caesars' order appears more definitive that the load ratio share is as of the time of the Commission's order approving the decommissioning costs into rates, NPC provides that it supports using the same time period for MGM's load since the intent is the same. (*Id.* at 5.) NPC states that it will utilize the load proportionate share for the certification period sales as proposed by Staff, Caesars, MGM, and SNWA. (*Id.*)

645. NPC notes that, without knowing the terms and conditions of the sale of properties from the original applicant, NPC recommends that the Commission seek those details to make an informed recommendation. (*Id.*) NPC explains that this would allow the Commission additional information to evaluate the approach proposed by Staff, Caesars, MGM, and SNWA or perhaps whether the original applicant should pay those costs for all loads under the original application. (*Id.*)

Commission Discussion and Findings

646. The Commission finds that all properties included in prior NRS 704B dockets where the customers were ordered to pay a share of the Reid Gardner and Navajo decommissioning and remediation costs shall do so for the applicable costs in this docket on a load ratio basis as of the end of the certification period. The Commission finds this is the most

reasonable application of the requirements for those customers to meet their responsibilities with respect to the costs of retirement for those plants. Whether or not this was addressed in any contractual agreement for the sale of the property subsequent to the original NRS 704B order does not obviate the fact that those customer premises were included in the prior exit orders and are responsible for their appropriate share of the costs.

647. The Commission also finds that applying any remaining MGM credit to the MGM's share of the decommissioning and remediation costs is appropriate as discussed by Staff and NPC.

M. Class Cost of Service

NPC's Position

648. NPC states that it is proposing an MCS as the basis for the rate design proposal in this proceeding because, as has been the case in each GRC for several decades, the MCS is NPC's preferred methodology to inform rate design. (Ex. 228 at 9.) NPC explains that marginal costing methodologies are forward-looking studies that provide for a more robust and useful result that can be used to provide economically efficient price signals more accurately. (*Id.*) NPC provides, for example, that with the increased reliance on renewable generation, and in particular solar generation, NPC is experiencing a shift in the costs of generation and energy to hours that are later in the evening when the solar generators are not producing. (*Id.*) NPC explains that these shifts are reflected in the MCS, but this shifting of costs is not shown as clearly when relying on the historical information in the ECS. (*Id.*)

649. NPC elaborates that, as with Nevada's MCS methodologies – which have been developed and refined over almost 40 years through numerous GRCs, investigatory dockets and rulemakings – any reliable model will be improved through interested and expert hands over

time. (*Id.* at 10.) As such, NPC maintains its reluctance to rely on relatively untested ECS studies as tools that are used to inform rate design for its customers and recommends relying on the MCS. (*Id.*)

650. NPC recommends that the Commission should accept NPC's proposed MCS in this filing as the basis for informing rate design for the recovery of the approved revenue requirement. (*Id.* at 83.) NPC explains that, in this case, the proposed MCS that should be accepted is shown in Ex. 228 at Exhibit Bohrman Direct-2. (*Id.*) NPC states that its proposed MCS reflects NPC's proposed TOU period definitions and reflects the jointly dispatched nature of the system. (*Id.*) NPC asserts that this MCS model provides the most informative cost information that should be used to develop accurate price signals for NPC customers. (*Id.*)

651. NPC states that, when evaluating the way energy costs are treated in the ECS study allocations, Staff's proposal in the most recent Sierra GRC – which endorses removing energy costs from the ECS allocation of generation costs to customers – is unjustified. (Ex. 227 at 37.) NPC explains that it is proposing to include energy cost in the ECS study, before adjusting (subtracting) the final class revenue requirement to account for revenue obtained from BTER rates. (*Id.*) NPC explains that this cost allocation method is superior to the method in Staff's proposal for revenue apportionment. (*Id.*) NPC states that it is important that the initial cost allocation includes both energy and demand-related costs in the ECS, to identify each class's cost share of the embedded costs as a first step, according to the respective adopted class energy and demand, irrespective of how and whether a share of those costs are being recovered outside of standard rates. (*Id.*) NPC notes that energy and demand-related generation embedded cost elements should not be separated because NPC plans its generation portfolio as a joint energy and fixed cost optimization effort. (*Id.*) NPC provides that, once the appropriate class's

embedded cost allocation has been undertaken using the combined Energy and Generation approach, any revenue collected outside standard rates, including BTER revenues can then be subtracted as a revenue offset. (*Id.* at 37-38.) NPC states that the extent to which BTER revenue does not fully offset the allocated costs, will provide information to the Commission and NPC as to the current distortions or inequities that are built into the flat BTER rate. (*Id.* at 38.) NPC explains that those customers with a relatively higher on peak energy usage compared to the average customer in the class, currently underpay through the flat BTER rate. (*Id.*) NPC asserts that a combined energy and generation cost allocation in the ECS study, using the appropriate hourly marginal cost allocators, can correct that inequity by partly capturing a share of the attributable BTER costs through the standard rate and this can create stronger alignment of class allocation with time-differentiated marginal costs. (*Id.*)

652. NPC argues that the overall MCS methodology used by NPC in this GRC is consistent with the methodology used in numerous prior cases of NPC, as well as with common practice in utility MCS that employs long-run marginal cost proxy approaches. (*Id.* at 50.) NPC asserts that its proposed method to allocate revenue requirement to customer classes is a sound approach from an economic efficiency standpoint, as it uses the relative differences in class marginal cost responsibility as the starting point and only deviates in a manner to provide for gradual and not sudden bill impacts. (*Id.* at 50-51.)

FEA's Position

653. FEA recommends that NPC's preferred marginal cost of service study ("MCS") be used to determine each class's cost of service and to guide the revenue apportionment and rate design in this case. (Ex. 1403 at 4.)

654. Alternatively, FEA recommends that, if the Commission adopts an embedded class cost of service study ("ECS") method, it should reflect joint dispatch and include the generation energy component of the cost of service. (*Id.*) In addition, FEA provides that, if an ECS is selected, the Commission should reject the Peak and Average ("P&A") and 12 coincident peak ("CP") methods for capacity cost allocation purposes. (*Id.*) FEA asserts that these two allocation methodologies do not accurately reflect cost-causation. (*Id.* at 5.)

Walmart's Position

655. Walmart does not oppose NPC's proposed MCS to be used as the basis for the ratemaking proposals in this docket. (Ex. 1001 at 2.) However, Walmart notes that the Commission should not disregard the inclusion of the various ECS, which can serve as a check of reasonableness on NPC's proposed MCS and inform revenue allocation. (*Id.*)

BCP's Position

656. BCP recommends that the Commission not rely on any MCS results to determine appropriate class revenue responsibilities in the current proceeding. (Ex. 413 at 2.) BCP explains that, as the Commission has recognized, these methods have significant methodological shortcomings and are not commonly used in current utility regulation. (*Id.*)

657. BCP further recommends that the Commission reject NPC's proposed cost of service results which rely on a problematic marginal cost framework. (*Id.* at 3.) Instead, BCP recommends that the Commission utilize the results of an embedded cost of service analysis utilizing an Average and Peak ("A&P") cost allocation approach to allocate costs associated with production plant assets. (*Id.*) BCP explains that this proposed cost allocation approach correctly recognizes the joint functional nature of electric generation units in serving both the energy and capacity needs of NPC customers. (*Id.*) In the alternative, if the Commission decides to adopt a

hybrid cost of service study, BCP recommends that the Commission rely on the results of such a study which removes energy-related costs and utilizes an NPC-only dispatch model. (*Id.*)

Staff's Position

658. Staff recommends that the Commission use Staff's COSS, Statement O excluding energy revenue to create rates, and NPC's proposed class revenue requirement cap for all customer classes. (Ex. 330 at 4.)

659. Staff states that, if the Commission decides not to accept Staff's COSS, then Staff recommends that the Commission order NPC to use NPC's HCS developed using NPC's SAD scenario, use Ex. 226 at Exhibit Prest Certification-28 (Statement O-ECS-E-MA, ECIC, New TOU, NPC Only Dispatch) as its corresponding Statement O with the appropriate BSC for the residential customer classes, and establish a class revenue requirement cap for the residential single-family cap. (*Id.* at 22.)

660. Staff states that, if the Commission decides to not accept Staff's recommendations and accepts NPC's marginal cost of service methodology, the Commission should order NPC to use Ex. 230 at Exhibit Bohrman Certification-4 (MCS – Proposed TOU, Nevada Power Standalone Dispatch), which is NPC's marginal cost of service developed using the SAD scenario, and update Ex. 226 at Exhibit Prest Certification-20 (Statement O-MCS, ECIC, New TOU, NPC Only Dispatch, GE Separated) with the appropriate BSC for the residential customer classes to reflect the class revenue requirements but exclude cost-based class energy revenues (which happens to be included as revenues to be collected from classes to cover the cost of energy in designing rates). (*Id.* at 23.)

661. Staff states that, if the Commission decides not to accept Staff's recommendations and accepts a COSS that is developed using a joint dispatch ("JD") scenario, the Commission

should order NPC to use one of the following in order of priority: (i) Staff's COSS featuring JD; (ii) Ex. 230 at Exhibit Bohrman Certification-15 (ECS-E-MA – Proposed TOU, Joint Dispatch, Proposed Revenue Requirement, Marginal Allocation methodologies, with Energy removed) and Ex. 226 at Exhibit Prest Certification-24 (Statement O-Embedded Cost Study With Energy Removed Using Marginal Allocators, ECIC, New TOU) with the appropriate BSC for the residential customer classes; or (iii) Ex. 230 at Exhibit Bohrman Certification-2 (MCS – Proposed TOU, Joint Dispatch) and Ex. 226 at Exhibit Prest Certification-16 (Statement O-MCS, ECIC, New TOU, Joint Dispatch, Generation and Energy Separated) with the appropriate BSC for the residential customer classes. (*Id.* at 3.)

662. Staff also recommends that the Commission should order NPC not to use any of the ECS studies that were presented in this filing to allocate costs. (*Id.*)

663. Staff notes that it has been critical of incorporating energy revenue into the COSS and Statement O, especially in the recent GRC, Docket No. 22-06014, of Sierra and NPC did not provide any new evidence to address the issues raised by Staff in Sierra's most recent GRC. (*Id.* at 5.)

NPC's Rebuttal

664. NPC states that its goal is to send the appropriate price signals to all customers that reflects the cost to serve while balancing the impact of the resulting changes. (Ex. 237 at 6.) NPC reiterates its request to the Commission to approve the NPC's proposal. (*Id.*) In the event the Commission rejects NPC's proposal, NPC recommends utilizing the hybrid cost-of-service study, implemented through the rate design proposed by NPC, with any adjusted policy considerations recommended by the Commission for the BSC and rate design cap. (*Id.*)

665. NPC states that, if the Commission approves NPC's proposal or the hybrid cost-of-service study, NPC suggests that the Commission direct NPC to file future rate cases with either approved model, removing any prior directives. (*Id.*) NPC explains that these studies have been developed in response to feedback from other parties, including the Commission, while continuing to provide NPC's preferred approach. (*Id.*) NPC argues that it is untenable for intervenors as well as NPC to continue to file numerous different studies for review and consideration on top of NPC's proposal. (*Id.*) NPC suggests that NPC and all intervenors could then focus on one proposal and suggest modifications for consideration. (*Id.*) NPC also offers that Staff's model is not viable for development of rates. (*Id.*)

666. NPC states that it continues to support its proposal to utilize the MCS as the basis for rate design as presented in its filings. (Ex. 236 at 3.) NPC provides that its preferred rate design is presented in the primary Statement O, which was based upon the MCS using a JD model, NPC's proposed TOU period definitions, and with revenue results at full marginal costs that are reconciled to the embedded revenue requirement with the generation and energy functions. (*Id.*) NPC asserts that its proposed study provides the most fundamentally sound basis for informing rate design and results in the most balanced outcome for all customer classes. (*Id.*)

667. NPC states that it is perplexed by Staff's claim that additional support was not provided for its positions in this case as NPC point out it retained an energy economist to provide a thorough review and analysis of NPC's MCS in this proceeding, as well as to evaluate NPC's approach to use those results for revenue requirement allocation. (*Id.* at 16.)

668. NPC also rejects the BCP's claim that the BCP identified a reconciliation error in NPC's ECS. (*Id.* at 31.) NPC states that the BCP's analysis is based upon a misunderstanding of what the ECS is showing and what is being used to calculate rates. (*Id.* at 32.) NPC explains that

BCP provides that the BCP's analysis examines the fuel and purchase power costs used in NPC's primary ECS and the associated assumed BTER revenues removed in NPC's associated revenue distribution calculations. (*Id.*) NPC states that this is incorrect because BCP's analysis pulls data from two different places in the NPC's ECS: first, the BTER revenue from an informational tab that compares the cost-based revenue to the present rate revenue for each customer class in the study, and second, the actual fuel and purchased power cost allocation tab. (*Id.*)

669. NPC further provides that Staff's model cannot be accurately used for rate design in this case and, therefore, NPC recommends that the Commission reject Staff's proposal to rely on the model for setting rates. (Ex. 235 at 4.) NPC explains that the results provided by Staff's model are both illogical and inadequate when it comes to informing rate design, so while it may be technically possible to partially link Staff's preferred cost allocation into the Statement O model currently, the results it would provide would be problematic and incomplete. (*Id.*) NPC provides that, if NPC were ordered to design rates from Staff's model in this filing, the Commission would also need to accept one of NPC's presented cost studies to be used in conjunction with Staff's model to design every rate that NPC is required to calculate. (*Id.*)

Commission Discussion and Findings

670. The Commission accepts Staff's Recommendation 2 with respect to the COS. NPC shall use Exhibit Prest Certificaiton-28 and Exhibit Bohrman Certification-16, with NPC's recommended BSC and Staff's recommended cap to all bundled rate classes of no greater than the system average increase.

671. While there is much testimony with respect to the applicability and perceived superiority of a marginal cost of service study, including the energy component, and joint system dispatch, the concerns that have been raised by the Commission remain and if anything, are

amplified by NPC's statement that increased requirements for renewable generation push the generating costs to the later time periods.

672. Energy costs remain charged as a fixed rate to each customer class regardless of hourly costs and related customer class usage. Joint dispatch costs are recovered through the deferred energy accounts, again part of the flat per kWh charge. The Commission cannot by statute require residential customers to take service under TOU rates. Including the energy component in a MCS to establish BTGR rates does not send a price signal that is meaningful when the rates charged do not align. Setting a BTGR rate to in some form overcome the reality of how BTER rates are charged to customers only results in both BTER and BTGR rates not being reflective of the purported costs to serve.

673. The Commission appreciates the work that was put into Staff's model and finds there is merit in continuing to refine the model for potential use in a future GRC. NPC is directed to work with Staff and include in its next GRC an updated version of Staff's model, excluding the energy component and with stand-alone dispatch.

674. The Commission also finds that NPC shall file an HCS and related Statement O, excluding the energy component and with stand-alone dispatch, in NPC's next GRC.

675. NPC may also file other cost of service studies for consideration by the Commission as it desires.

VIII. Staff's Motion to Strike Certain Portions of NPC's Testimony

Staff's Motion

676. Staff filed a motion to strike portions of the Phase II rebuttal testimony of Josh Langdon and Shane Pritchard. Staff requests that the Commission strike Question and Answers 6 and 7 in their entirety; the first paragraph of Question and Answer 8 of Mr. Langdon's

testimony (Ex. 194); and Question and Answer 8, lines 9-17, of Mr. Pritchard's testimony (Ex. 195). (Staff's Motion at 1.)

677. Staff argues that parts of Mr. Langdon's testimony should be stricken because it violates NAC 703.2793 by offering new evidence supporting NPC's initial burden of proof contrary to NRS 704.110(4) as an ECIC. (*Id.* at 4-7.) According to Staff, the evaluation of whether NPC has satisfied the requirement for an ECIC is based on its initial filing. (*Id.*) Staff argues that additional information provided in rebuttal cannot provide the basis for meeting this burden of proof. (*Id.*)

678. Staff provides multiple examples where Mr. Langdon's testimony is offering improper new evidence on rebuttal. (*Id.*) First, Staff states that Mr. Langdon's testimony includes updated cost information to show that NPC has met its burden that the ballistic shield project has a high probability of occurring to the degree, in the amount, and at the time expected. (*Id.*) Next, Staff states that Mr. Langdon uses project milestones that occurred between direct and rebuttal testimony. (*Id.*) Staff provides that Mr. Langdon introduces testimony that outlines the request for proposals process and the contracts that NPC entered into for the ballistic shields, all of which occurred following the filing of NPC's application. (*Id.*)

679. Staff also states that Mr. Langdon's testimony argues that the Commission should approve the ballistic shield projects even if there is no high probability that the projects will be completed by the end of the ECIC period because the ballistic shield project was prudent. (*Id.*) Staff indicates that this is not the standard pursuant to NRS 704.110(4), under which the Commission must evaluate an ECIC project. (*Id.*)

680. Staff argues that Mr. Pritchard's testimony should be stricken because it introduces improper evidence of the benefits of an earlier in-service date for the Reid Gardner

BESS. (*Id.* at 8-11.) Staff had argued in testimony that NPC provided no evidence of the benefits of changing the Reid Gardmer BESS in-service date from May 2024 to December 2024 in its Applications, and therefore, introducing this evidence for the first time in rebuttal is improper pursuant to NAC 703.722. (*Id.*) Staff provides that parties to the proceeding had no opportunity to investigate Mr. Pritchard's analysis on these benefits. (*Id.*) In addition, Staff notes that this information was available when the Applications were filed because the decision to change the in-service date had been made prior to April 4, 2023. (*Id.*) Accordingly, if the information was not provided with the Applications, Staff argues that it should not be provided for the first time in rebuttal. (*Id.*)

NPC's Response

681. NPC argues in its Response that Staff misconstrues the requirements in NAC 703.2793. (NPC's Response at 5.) According to NPC, this section limits only the use of the statement of updated revenue and expense data that the applicant files, not all other information. (*Id.*) NPC further states that it can never anticipate in its initial filing all of the relevant information; therefore, the ability of parties to engage in discovery and provide additional information is a part of the process. (*Id.* at 7.)

682. Regarding Mr. Langdon's testimony, NPC argues that it did comply with the requirements of NAC 703.2793, as Mr. Langdon's testimony contains additional information about the request for proposals, contracts, and costs to rebut positions taken by Staff. (*Id.* at 6-8.) NPC states that "[p]roviding this information allows the Commission to evaluate the application based on facts as they have developed, not just the information available when the ECIC application was filed." (*Id.* at 8.)

683. NPC also indicates that Staff misunderstands Mr. Langdon's Question and Answer 8. (*Id.* at 9-10.) NPC argues that Mr. Langdon was advocating for deferral until the next rate case in lieu of outright disallowance if the Commission believes that the ballistic shields do not qualify as an ECIC. (*Id.*)

684. Responding to Staff's challenge to Mr. Pritchard's testimony, NPC outlines several flaws that it perceives in Staff's argument. (*Id.* at 10-15.) First, NPC states that it did provide an explanation in Ms. Wells's testimony as to the change to the in-service date for the Reid Gardner BESS, contrary to Staff's argument otherwise. (*Id.* at 10-11.) Next, NPC argues that Mr. Pritchard's testimony is directly rebutting Staff witness Danise's testimony, consistent with NAC 703.722. (*Id.* at 10-15.) NPC explains that NRS 704.110(4) does not require that NPC demonstrate that completing an ECIC project provides an independent benefit to customers. (*Id.* at 12-13.) Therefore, Staff's argument about NPC's failure to demonstrate those benefits is not a failure under NRS 704.110(4). (*Id.*) Finally, NPC argues that Staff's concern over inadequate support for Mr. Pritchard's material is not a basis to strike the testimony. (*Id.* at 14-15.)

Staff's Reply

685. In Staff's Reply, Staff asserts that "Nevada Power can only use information that that was either provided in the initial statement or available when the initial statement was filed to meet its burden of proof for these ECIC projects." (Staff's Reply at 2.) Staff distinguishes its argument based on the purpose for which NPC is using certain information – whether the information is being used to meet the initial burden of proof regarding whether the project is reasonably known and reasonably measurable because it has a high probability of occurring to the degree, in the amount, and at the time expected. (*Id.* at 2-4.) Staff states that certain information can be used for other purposes, but not for this specific purpose, in meeting the

burden of proof. (*Id.* at 3-4.) Staff asserts that "Staff is not arguing that the cost information filed in the ECIC update is improper, only that Nevada Power's use of that information or other information provided in the ECIC update that was not available at the time the application was filed to prove through rebuttal evidence that its burden was met is improper." (*Id.* at 4.)

686. Staff clarifies that its argument regarding NAC 703.2793 is based on its reading of NRS 704.110(4), which permits Commission consideration of the statement of updated revenue and expense data that the applicant files pursuant to NAC 703.2793 only after the Commission determines that the applicant has met its burden of proof. (*Id.* at 3-5.) Staff asserts that, once the Commission determines that the burden of proof for the ECIC has been met, at that time the Commission may consider additional information under NRS 704.110(4). (*Id.* at 2-4.)

687. In addition, Staff states that its objection is to Mr. Pritchard's calculation of a cost-benefit analysis to show that the cost of accelerating the project outweighs any potential benefits in his rebuttal testimony. (*Id.* at 7-8.) According to Staff, general statements, such as those Ms. Wells provided, may not require the same type of technical review by Staff as a spreadsheet with numerical analysis. (*Id.*) Staff provides that NPC did not provide a cost-benefit analysis in its application, discovery, or certification, of the type attached to Mr. Pritchard's testimony. (*Id.*)

Commission Discussion and Findings

688. The Commission grants Staff's Motion in part and denies Staff's Motion in part. The Commission agrees with Staff that the Commission must make two separate determinations regarding a request for recovery of an ECIC project in rates pursuant to NRS 704.110(4). First, the Commission must determine whether the information available at that time demonstrates that the project is reasonably known and measurable and has a high probability of occurring to the

degree, in the amount, and at the time expected. Following that determination, the Commission can use additional information to establish just and reasonable rates.

689. Staff's testimony of Mr. Danise appears to go to the heart of the first question, whether NPC has met its burden to demonstrate that the ballistic shields meet the NRS 704.110(4) standard as an ECIC. Accordingly, the introduction of additional evidence to meet this standard in rebuttal would be impermissible. However, in reviewing Mr. Langdon's rebuttal testimony, only Question and Answer 6, lines 21-26 and 1-4, and all of Question and Answer 7, rebut Mr. Danise on this specific issue with new evidence. The balance of Question and Answer 6, and all of Question and Answer 8, although construed as rebutting Mr. Danise, provides additional detail for the Commission to consider in setting just and reasonable rates. Therefore, the Commission orders the testimony of Mr. Langdon, Exhibit 194, to be stricken on page 3, lines 21-26, and page 4, lines 1-21.

690. In considering the cost-benefit analysis proffered by Mr. Pritchard in his rebuttal testimony, the Commission denies Staff's request to strike this testimony. Mr. Danise has recommended disallowances related to the amount of costs for the Reid Gardner BESS which should be included in rates if the Commission approves the ECIC request. Mr. Pritchard rebuts this recommendation by producing a cost-benefit analysis to demonstrate that the disallowances are not warranted because the Reid Gardner BESS will produce benefits above its cost. This rebuttal testimony does not seem designed to address the question of whether NPC met its burden pursuant to NRS 704.110(4), but rather what amount of costs are properly included in just and reasonable rates.

691. NAC 703.722 only allows rebuttal evidence that directly explains, repels, counteracts or disproves facts offered in evidence by other parties of record who oppose the

application. The determination of whether new evidence, such as a cost-benefit analysis, is proper rebuttal is a fact-based evaluation based on the testimony that it is offered to rebut. The Commission does not strike any of Mr. Prichard's rebuttal testimony (Ex. 195). Nonetheless, the Commission shares Staff's concern that although not technically improper, information such as a cost-benefit analysis, provided for the first time in rebuttal, is of limited evidentiary value to the Commission due to the inability of other parties to adequately review the evidence for errors.

IX. PAST DIRECTIVES

692. The Commission finds that NPC met the directive in directive paragraph 3 of the Modified Final Order in Docket No. 20-06003, ordering that all cost-of-service studies filed by NPC in its next general rate case shall include one version with generation and energy costs separately reconciled and that NPC may include a cost-of-service study or studies with its generation and energy combined using the generation and energy allocator and must provide detailed testimony supporting the use of the generation and energy allocator should it choose to do so.

693. The Commission finds that NPC met the directive in directive paragraph 4 of the Modified Final Order in Docket No. 20-06003, ordering NPC to file in its next general rate case a complete embedded cost-of-service study with enough detail to allow for transparent review and vetting by the parties, and to include the results of the embedded cost allocators discussion pursuant to paragraph 45 of the Stipulation from that docket. NPC was further ordered to, not later than January 5 of the year in which it files its next general rate case, meet with Staff and the BCP, and other interested stakeholders, to discuss embedded cost allocators.

694. The Commission finds that NPC met the directive in directive paragraph 5 of the Modified Final Order in Docket No. 20-06003, ordering NPC to file in its next general rate case

a complete hybrid cost-of-service study using the Staff's methodology with enough detail to allow for transparent review and vetting by the parties and Commission.

695. The Commission finds that NPC met the directive in directive paragraph 6 of the Modified Final Order in Docket No. 20-06003, ordering NPC to file in its next general rate case a detailed analysis of its evaluation process for the marginal unit used in its marginal cost-of-service study.

696. The Commission finds that NPC met the directive in directive paragraph 7 of the Modified Final Order in Docket No. 20-06003, ordering NPC to provide an updated review of time-of-use periods in the next general rate case.

697. The Commission finds that NPC met the directive in paragraph 739 of the Modified Final Order in Docket No. 22-06014, ordering NPC to file an embedded-cost-of-service study.

698. The Commission finds that NPC met the directive in directive paragraph 8 of the Modified Final Order in Docket No. 22-06014, ordering NPC to file in its 2023 general rate case a complete hybrid embedded-cost-of-service study using stand-alone dispatch and using the Staff's methodology with enough detail to allow for transparent review and vetting by parties and the Commission. Further, the Commission directed NPC to consult with Staff in advance of filing this study regarding its preparation.

699. The Commission finds that NPC met the directive in directive paragraph 11 of the Modified Final Order in Docket No. 22-06014, ordering NPC to file in its 2023 general rate case its marginal-cost-of-service study with generation and energy costs separately reconciled, with energy costs allocated on a stand-alone basis.

700. The Commission finds that NPC met the directive in directive paragraph 12 of the Modified Final Order in Docket No. 22-06014, ordering that NPC may file other cost-of-service studies, including combined generation and energy or allocated using joint dispatch, and must provide detailed testimony supporting these studies.

701. The Commission finds that NPC met the directive in directive paragraph 10 of the Order in Docket No. 22-09006, ordering that NPC must conduct and file an analysis of the impact of adding electric vehicle charger allowances on the Rule 9 study median cost in its next general rate case.

THEREFORE, it is ORDERED:

1. The Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, designated as Docket No. 23-06007, is granted in part as modified by this Order.

2. The Application of Nevada Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric and common accounts, designated as Docket No. 23-06008, is granted in part as modified by this Order.

Compliances

3. Nevada Power Company d/b/a NV Energy shall file the rates and supporting workpapers in the instant dockets, in executable form with formulas and links intact, within ten calendar days of the issuance of this Order.

4. Nevada Power Company d/b/a NV Energy shall file the Distribution-Only-Service decommissioning revenues ultimately used in the revenue requirement for rate design in the instant dockets, within ten calendar days of the issuance of this Order.

5. As a compliance item, 30 days after the issuance of this Order, NPC will file with the Commission the amount of Short-Term Incentive Pay compensation awarded to employees that reflects the Commission's decision in accordance with Paragraph 474 of this Order.

Directives

6. Nevada Power Company d/b/a NV Energy or Sierra Pacific Power Company d/b/a NV Energy shall meet and confer with the Regulatory Operations Staff in advance of filing any future general rate case, filed by either Nevada Power Company d/b/a NV Energy or Sierra Pacific Power Company d/b/a NV Energy, to discuss the information necessary to ensure all transmission customers are paying the appropriate cost share.

7. Nevada Power Company d/b/a NV Energy or Sierra Pacific Power Company d/b/a NV Energy shall meet and confer with the Regulatory Operations Staff in advance of filing any future general rate case, filed by either Nevada Power Company d/b/a NV Energy or Sierra Pacific Power Company d/b/a NV Energy, to discuss the appropriate Federal Energy Regulatory Commission transmission allocator.

8. In any future general rate case filings, Nevada Power Company d/b/a NV Energy or Sierra Pacific Power Company d/b/a NV Energy shall provide details about its most recent Federal Energy Regulatory Commission rate case and provide an explanation about Nevada Power Company d/b/a NV Energy's or Sierra Pacific Power Company d/b/a NV Energy's plans for future rate-setting proceedings at the Federal Energy Regulatory Commission.

9. In its next general rate case filing, Nevada Power Company d/b/a NV Energy shall file a proposal to establish low-income rates as allowed pursuant to NRS 704.110(14)(b).

10. In its next general rate case filing, Nevada Power Company d/b/a NV Energy shall file alternative rate methodologies or regulatory solutions to mitigate the calculated shortfall for the Assembly Bill 405 Net-Energy-Metering Regulatory Asset.

11. In its next general rate case filing, Nevada Power Company d/b/a NV Energy shall work with the Regulatory Operations Staff to file an updated version of the Regulatory Operations Staff's cost-of-service study model, excluding the energy component and with stand-alone dispatch.

By the Commission,

HAYLEY WILLIAMSON, Chair

TAMMY CORDOVA, Commissioner and Presiding Officer (Dissenting to Paragraphs 470-476)

RANDY J. BROWN, Commissioner

Attest: Trisha Osborne
TRISHA OSBORNE,
Assistant Commission Secretary

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

Dated: Carson City, Nevada

2/16/24

(SEAL)