BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	Docket No. 10-06001
Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto.	Docket No. 10-06002
Application of Sierra Pacific Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric operations.	Docket No. 10-06003
Application of Sierra Pacific Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its gas operations.	Docket No. 10-06004

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 20, 2010.

PRESENT: Chairman Sam A. Thompson
Commissioner Rebecca D. Wagner
Commissioner Alaina Burtenshaw
Assistant Commission Secretary Breanne Potter

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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PRESENT: Chairman Sam A. Thompson
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Assistant Commission Secretary Breanne Potter

ORDER

The Public Utilities Commission of Nevada in these Dockets makes the following findings and conclusions:

I. PROCEDURAL HISTORY

- On June 1, 2010, Sierra Pacific Power Company d/b/a NV Energy ("Sierra") filed an Application with the Public Utilities Commission of Nevada ("Commission"), designated as Docket No. 10-06001, for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

- On June 1, 2010, Sierra filed an Application with the Commission, designated as Docket No. 10-06002, for authority to increase its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto.

- On June 1, 2010, Sierra filed an Application with the Commission, designated as Docket No. 10-06003, for approval of new and revised depreciation and amortization rates for its electric operations.

- On June 1, 2010, Sierra filed an Application with the Commission, designated as Docket No. 10-06004, for approval of new and revised depreciation and amortization rates for its gas operations.

- These Applications are filed pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including but not limited to NRS 704.110, and NAC 703.2715 through 703.278.

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

- On June 9, 2010, the Commission issued a Notice of Application and Notice of Prehearing Conference for each filing in Docket Nos. 10-06001, 10-06002, 10-06003, and 10-06004, and set a Prehearing Conference for July 13, 2010 for all dockets. In its Applications, Sierra asked that the Commission consolidate all four dockets, and the request was renewed at the Prehearing Conference through an oral motion made by Sierra. The motion was granted and Docket Nos. 10-06001, 10-06002, 10-06003, and 10-06004 are consolidated for hearing purposes pursuant to an Order to Consolidate Dockets issued on July 26, 2010 (hereinafter referred to collectively as the "Consolidated Dockets").

- On June 9, 2010, BCP filed a Notice of Intent to Intervene, pursuant to NRS 228.360 in Docket No. 10-06001.

- On June 25, 2010, Newmont USA, Ltd., d/b/a Newmont Mining Corporation ("Newmont") filed a Petition for Leave to Intervene in Docket No. 10-06001.

- On June 30, 2010, a Petition for Leave to Intervene was filed by Cyanco Company, LLC; EP Minerals, Inc.; Heavenly Valley, Limited Partnership; Wimar Tahoe Corporation; John Ascuaga's Nugget, Nevada Cement Company; Premier Chemicals, LLC; The Ridge Tahoe Property Owner Association, and Renown Health; collectively referred to as the "Northern Nevada Industrial Electric Users" ("NNIEU") in Docket No. 10-06001.

- On June 30, 2010, the Truckee Meadows Water Authority ("TMWA") filed a Petition for Leave to Intervene in Docket No. 10-06001.

- On June 30, 2010, NSHE filed a Petition for Leave to Intervene in Docket No. 10-06001.

- On July 1, 2010, the Circus and Eldorado Joint Venture, a Nevada General Partnership d/b/a The Silver Legacy Resort Casino Reno ("Silver Legacy") filed a Petition for Leave to Intervene in Docket No. 10-06001.

- On July 1, 2010, Eldorado Resorts LLC ("Eldorado") filed a Petition for Leave to Intervene in Docket No. 10-06001.

- On June 9, 2010, the Attorney General's Bureau of Consumer Protection filed a Notice of Intent to Intervene, pursuant to NRS 228.360 in Docket No. 10-06002.

- On June 28, 2010, Mr. Eddie Chae filed Comments in Docket No. 10-06002.

- On June 30, 2010, the Board of Regents of the Nevada System of Higher Education ("NSHE") filed a Petition for Leave to Intervene in Docket No. 10-06002.

- On July 13, 2010, the Commission conducted a Prehearing Conference. Appearances were made by Staff; BCP; Newmont; NNIEU; TMWA; NSHE; Silver Legacy; and Eldorado.

- On July 26, 2010, all of the Petitions for Leave to Intervene were granted pursuant to an Order Granting Interventions.

- On July 13, 2010, a Prehearing Conference was conducted. The scheduling of the filing of Sierra's certification filing, pre-filed testimony, hearing dates, and the date of a consumer session were discussed at the Prehearing Conference. Procedural Order #1 was issued on July 26, 2010, following the Procedural Conference.

- On July 27, 2010, the Commission issued a Notice of Consumer Session and Notice of Hearings.

- On July 30, 2010, Sierra filed its Certification filing in Docket Nos. 10-06001 and 10-06002 related to the cost of capital component of the Applications.

- On July 30, 2010, Sierra made a Certification filing related to the Cost of Capital component ("Phase I") of its general rate case filings.

- On August 20, 2010, the Commission issued a Protective Order related to portions of the Application in Docket No. 10-06001, requiring certain portions of the Application to be re-filed in unredacted form, while granting confidential protection to other portions of the Application.

- On August 26, 2010, the Commission issued a Revised Procedural Order No. 1.

- On August 27, 2010, Sierra filed replacement Volumes 4 and 13 of the Application in Docket No. 10-06001 with unredacted information, in accordance with the Protective Order of August 20, 2010.

- On August 30, 2010, Sierra filed a corrected replacement Volume 13 of the Application in Docket No. 10-06001.

- On August 31, 2010, Sierra made a Certification filing in Docket Nos. 10-06001 and 10-06002, related to the Revenue Requirement and Rate Design Components of the Applications.

- On September 8, 2010, Staff, BCP, and TMWA/El Dorado/Silver Legacy filed pre-filed direct testimony related to the Cost of Capital component of Docket Nos. 10-06001 and 10-06002.

- On September 15, 2010, the Commission conducted a Consumer Session in Reno, Nevada for the Consolidated Dockets.

- On September 17, 2010, the City of Sparks filed an amended late-filed petition for leave to intervene in Docket No. 10-06001.

- On September 21, 2010, Staff and BCP filed pre-filed testimony related to the depreciation filings in Docket Nos. 10-06003 and 10-06004.

- On September 22, 2010, the Commission issued an Order Granting Late-Filed Petition for Intervention to the City of Sparks.

- On September 22, 2010, Sierra filed pre-filed rebuttal testimony related to the Cost of Capital component of Docket Nos. 10-06001 and 10-06002.

- On September 27-29, 2010, the Commission held hearings related to the Cost of Capital component of Docket Nos. 10-06001 and 10-06002.

- On October 5, 2010, Staff and BCP filed pre-filed direct testimony related to the Revenue Requirement component (part of "Phase III") of Docket Nos. 10-06001 and 10-06002.

- On October 7, 2010, Sierra filed pre-filed rebuttal testimony related to the Depreciation ("Phase II") filings in Docket Nos. 10-06003 and 10-06004.

- On October 12, 2010, Staff and BCP filed pre-filed direct testimony related to the Rate Design component (also part of "Phase III") of Docket Nos. 10-06001 and 10-06002.

- On October 13, 2010, the Commission held a hearing related to the Depreciation filings in Docket Nos. 10-06003 and 10-06004.

- On October 20, 2010, Sierra filed a Motion to Strike Staff Testimony Recommending Disallowances Violating Prohibition Against Retroactive Ratemaking.

- On October 20, 2010, the City of Sparks filed a Motion to Deviate from Revised Procedural Order No. 1 to Produce Late-Filed Testimony of Peter Etchart.

- On October 22, 2010, Staff filed a Response to the City of Sparks filed a Motion to Deviate from Revised Procedural Order No. 1 to Produce Late-Filed Testimony of Peter Etchart.

- On October 22, 2010, Sierra filed pre-filed rebuttal testimony related to the Revenue Requirement component of Docket Nos. 10-06001 and 10-06002.

- On October 25, 2010, Staff filed a Response to Sierra's Motion to Strike Staff's Testimony.

- On October 26, 2010, Staff filed a Motion for Post-Hearing Briefs, and filed a memorandum thereto under seal with the Commission.

- On October 26, 2010, Sierra filed pre-filed rebuttal testimony related to the Rate Design component of Docket Nos. 10-06001 and 10-06002.

- On November 1, 2010, the Parties filed a Stipulation which was intended "to settle, fully an finally" all issues raised by Staff in Docket No. 10-06001 related to Sierra's Tracy Combined Cycle Facility ("Tracy CC").

- On November 1- 5, 2010, the Commission held hearings related to the Revenue Requirement and Rate Design Components of Docket Nos. 10-06001 and 10-06002.

- On November 22, 2010, post-hearing briefs were filed by Staff, Sierra, BCP, Newmont, NNIEU, and NSHE.

II. MOTIONS TO STRIKE

1. on October 20, 2010, Sierra filed a "Motion to Strike Staff Testimony Recommending Disallowances Violating Prohibition Against Retroactive Ratemaking". On October 25, 2010, Staff filed a Response to Sierra's Motion to Strike Staff's Testimony. During the Hearing, the Presiding Officer denied the Motion to Strike and

indicated the Commission would subsequently issue a written Order with regard to the legal issues raised therein (Tr. at 2444-2445).

2. Sierra argues that Staff witness Gary Cameron's testimony, which proposed certain adjustments to electric and gas rate base, would require the Commission to engage in retroactive ratemaking and remove electric plant in service that had been deemed "prudent" by adjudication in prior proceedings. Therefore the Commission should not consider Mr. Cameron's testimony as evidence as to these adjustments in this proceeding.[1] For reasons set forth below, the Commission finds that Sierra has misstated both the rule on the prohibition against retroactive ratemaking and the rule concerning prudency findings in its Motion, and mixes and confuses those rules with other legal principles.

3. Staff's response sets forth the historical background for Mr. Cameron's proposed adjustments in the instant case, indicating that in Sierra's last general rate case proceeding, Docket No. 07-12001, the Commission had agreed with an adjustment proposed by Staff related to Sierra's failure to have followed its own Rule No. 9 in collecting the proper amounts of monies up front known as "Contributions in Aid of Construction" ("CIACs") to extend electric and gas service to a new WalMart located at the Tahoe Regional Industrial Center ("TRIC")[2]. Rather than following its own Rule No. 9, Sierra had entered into a special contract with TRIC, which was never brought before

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[1] Sierra also moves to strike the testimony of Staff witnesses Mary E. Pistoresi and Matthew D. Rice, whose testimony calculates the accounting impact of Mr. Cameron's proposed disallowances to the overall revenue requirement.

[2] "Contributions in aid of construction" made under Sierra's Rule No. 9 are paid for by the developers rather than the general body of ratepayers. By failing to collect such monies up front, the costs of the extensions were paid for by Sierra, which has added those costs to its rate base for plant in service upon which it has the opportunity to earn a return on its investment from all ratepayers .

the Commission. This special contract evidently did not require new customers at the TRIC to contribute to the costs of line extensions as is ordinarily required under the Rule No. 9 tariff. In agreeing with Staff's disallowance, the Commission pointed out that Sierra had admitted to violating its own Rule No. 9 tariff.[3]

4. Subsequent to the Commission's decision in Docket No. 07-12001 and in preparation for the instant case, Staff auditors investigated other projects that had also been constructed at the TRIC and, according to the testimony of Staff witness Gary Cameron, discovered that these other projects had also been constructed without Sierra's collecting of CIACs as was required under its Rule 9 tariff. Mr. Cameron thus proposes making a similar disallowance for the other projects as was done for the WalMart case in Docket No. 07-12001.

5. Sierra objects to Mr. Cameron's disallowances on two different, though intertwined, bases. First, Sierra contends that the Commission is prohibited from looking at these other projects because "Mr. Cameron's proposed disallowance[s] were the subject matter of several pervious general rate proceedings filed by Sierra and adjudicated by the Commission as PUCN Docket Nos. 01-1120, 03-12002, 05-10003, and 07-12001." (Motion, p. 2) Sierra further indicates that the Commission in Docket No. 05-10005 adjudicated the gas facilities that are the subject of Mr. Cameron's proposed disallowance. Sierra goes on to state "[t]he prudence of Sierra's investments in the electric and gas facilities that are the subject of Mr. Cameron's proposed disallowance was never challenged in any of these dockets, and the rates implemented as a result of each of these proceedings included the costs of the investment in the very items [of] electric and gas plant that Mr. Cameron proposes to now remove from rate base".

[3] Docket No. 07-12001 at p. 69.

6. Secondly, Sierra states that "Staff's proposed disallowances violate the prohibition against retroactive ratemaking, ***a legal doctrine barring the Commission from reaching backward to previous adjudications of general rates and removing previously approved items of plant in service from rate base***". (Emphasis added)

7. Sierra has completely misstated the doctrine of retroactive ratemaking. In 1932, the United States Supreme Court discussed what is now known as the "prohibition against retroactive ratemaking" in the historic case of *Arizona Grocery Co. v. Atchison, T. & S.F.Ry.Co.* 284 U.S. 370, 52 S.Ct.183, 76 L.Ed. 348. In that case, the Interstate Commerce Commission ("ICC") had both set a prospective tariff for the transportation of sugar from California to Arizona, and found that the railroad had over collected monies in the past and ordered the railroad to make reparations to the shippers, notwithstanding the fact that the railroad had been charging the then-approved ICC tariff rate. In striking down the ICC's attempt to order such reparations, the Court first made a distinction between the ICC's legislative role and judicial roles, and noted that there is no distinction in this respect between the federal and the state legislatures:

> "When [ ] the Commission declares a specific rate to be the reasonable and lawful rate for the future, it speaks as the Legislature, and its pronouncement has the force of a statute. This Court has repeatedly so held with respect to the fixing of specific rates by state commissions, and in this respect there is no difference between authority delegated by state legislation and that conferred by congressional action."

The Court then indicates that in attempting to adjudicate reparations, the ICC was performing a judicial role:

> "As respects its future conduct, the carrier is entitled to rely upon the declaration as to what will be a lawful, that is, a reasonable, rate; and if the order merely sets limits, it is entitled to protection if it fixes a rate which falls within them. Where,

as in this case, the Commission has made an order having a dual aspect, it may not in a subsequent proceeding, acting in its quasi judicial capacity, ignore its own pronouncement promulgated in its quasi legislative capacity and retroactively repeal its own enactment as to the reasonableness of the rate it has prescribed.

The Commission in its reports confuses legal concepts in stating that the doctrine of res judicata does not affect its action in a case like this one. It is unnecessary to determine whether an adjudication with respect to the reasonableness of rates theretofore charged is binding in another proceeding, for that question is not here presented. The rule of estoppel by judgment obviously applies only to bodies exercising judicial functions; it is manifestly inapplicable to legislative action. The Commission's error arose from a failure to recognize that when it prescribed a maximum reasonable rate for the future, it was performing a legislative function, and that, when it was sitting to award reparation, it was sitting for a purpose judicial in its nature. In the second capacity, while not bound by the rule of res judicata, it was bound to recognize the validity of the rule of conduct prescribed by it, and not to repeal its on enactment with retroactive effect. ***It could repeal the order as it affected future action, and substitute a new rule of conduct as often as the occasion might require, but this was obviously the limit of its power, as of that of the Legislature itself.***" (Emphasis added)

8. As Staff points out in its Response, Staff is not recommending that any monies be refunded that may have been collected (or over collected) by Sierra over the years as a result of its failure to follow its Rule 9 tariff and collect CIACs from developers. Its adjustment is *prospective*. Were the Commission to attempt to quantify the amount of monies that Sierra may have over collected as a result of violating its own Rule No. 9 tariff, and then order Sierra to refund that money to the ratepayers, then the Commission would indeed be engaged in retroactive ratemaking. But Staff's recommended disallowance does not suggest the Commission perform such an exercise.

9. Sierra's other argument, combined with the retroactive ratemaking argument, essentially is an equitable estoppel argument. Because the Commission and/or Staff did not raise the issue of the TRIC CIACs in earlier cases, it should somehow be prohibited, or estopped, from doing so now. Sierra further mixes into this argument the notion of "prudence", seeming to suggest that if imprudence of a rate base item was not alleged in a prior case when Staff may arguably have had the opportunity to make an adjustment, that the Commission is prohibited from looking at it under the doctrine of the prohibition against retroactive ratemaking.

10. Outside of specific areas identified by the legislature, such as plant facilities pre-approved (in concept) as part of a utility's triennial integrated resource plan ("IRP")[4] where the Commission is required to make a specific finding of prudence prior to their construction[5], the Commission generally makes no such findings of prudence as to rate base plant additions. The Commission certainly does not make such prudence approvals by default simply by having not addressed them, one way or the other, in prior decisions. Sierra's argument would essentially permit Sierra to grandfather into its ratebase any and all things that have ever been added to the ratebase prior to the specific test year at issue, if unaddressed in prior rate orders, even if it later can be shown that their original inclusion was unlawful.

11. It is the Commission's legislatively delegated responsibility to set just and reasonable rates for public utilities in Nevada, and unjust and unreasonable charges are unlawful. (NRS 704.040) NRS 704.120 states: "if, upon any hearing and after due investigation, the rates, tolls, charges, schedules or joint rates shall be found to be unjust

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[4] NRS 704.751
[5] NRS 704.110(11)

unreasonable, or unjustly discriminatory, or to be preferential, or otherwise in violation of any of the provisions of this chapter, the *Commission shall have the power to fix and order substituted therefore such rate or rates, tolls, charges, or schedules as shall be just and reasonable*." (Emphasis added)

12. This statute charges the Commission to set just and reasonable rates, and if existing rates are found to be unjust and unreasonable, to fix and substitute those rates with rates that are just and reasonable. The statute makes no mention of restricting the Commission's general rate case investigation into costs and rate base inclusions.

13. For the foregoing reasons, Sierra's Motion to Strike is denied.

14. During the Hearing, Staff moved to strike portions of the testimony of Sierra witness Patricia M. Franklin concerning Exhibits 231 to 236 related to Ms. Franklin's testimony at hearing concerning the meaning of NRS 704.110. The Presiding Officer indicated the Commission would dispose of this Motion in its written Order as well (Tr. at 2441-2442).

15. The Commission denies Staff's Motion to Strike. However, the Commission recognizes that an interpretation as to the meaning of NRS 704.110 is a legal question, not a factual matter upon which a nonlegal witness typically provides testimony. The Commission is very familiar with NRS 704.110, one of the most significant Nevada statutes under which it operates. The Commission believes it is capable of rendering its own legal judgments concerning the meaning of NRS 704.110. Therefore, while Staff's Motion is denied, the Commission will weigh this testimony accordingly for its relevance.

III. PHASE III: STIPULATION RELATED TO TRACY CC

16. At the commencement of Phase III of the Hearing related to Revenue Requirement and Rate Design, the Parties to the proceeding presented the Commission a Stipulation (Exhibit 102), which resolved several significant issues in Docket No. 10-06001 related to the construction of the Tracy Combined Cycle Facility ("Tracy CC"). Staff presented a review of the Stipulation the next day prior to the continuation of the Hearing (Tr. at 1015-1021). Following this explanation, the Presiding Officer indicated that it appeared to be a good settlement of the contentious, lengthy, and ongoing issues surrounding the Tracy CC.

IV. PHASE I: COST OF CAPITAL

A. Cost of Capital—Electric Department

1. Capital Structure

Sierra's Position

17. As of May 31, 2010, Sierra's ratios of total debt to total capital and total equity to total capital were 55.89 percent and 44.11 percent respectively (Exhibit 12 at Statement F), as shown below:

	Capital Amounts ($000)	Capital Ratio
Long-Term Debt	$1,143,575	55.32%
Customer Deposits	$11,771	0.57%
Total Debt	$1,155346	55.89%
Common Equity	$911,681	44.11%
Total Capital	$2,067,027	100.00%

Commission Discussion and Findings

18. No party took exception to Sierra's proposed capital structure. Therefore, the Commission approves Sierra's proposed capital structure as of the end of the Certification period, on May 31, 2010.

2. Long-Term Debt

Sierra's Position

19. Sierra reported the following costs for the long-term debt portion of the capital structures as of the end of certification on May 31, 2010 as follows:

- 6.14 percent Long-term debt;
- 0.17 percent Customer deposits;
- 6.08 percent Weighted cost of debt (Exhibit 12 at Schedule F).

Staff's Position

20. Staff recommends the Commission set the customer deposit rate in its capital structure at 0.22 percent for the customer deposit portion of the capital structure (Exhibit 46 at 1).

BCP's Position

21. BCP agrees with Sierra that the customer deposit rate should be set at 0.17 percent per annum. BCP proposed no changes to Sierra's 6.08 percent weighted cost of debt as of the end of certification (Exhibit 38 at 30).

TMWA/Eldorado/Silver Legacy ("TMWA/Resorts") Position

22. TMWA/Resorts proposes no changes to the cost of debt as of the end of certification (Exhibit 33 at Schedule 1).

Commission Discussion and Findings

23. Nevada law clearly establishes the calculation by which the rate of interest accrues on customer deposits. Specifically, NRS 704.655 provides, in pertinent part:

> 1. Every public utility which furnishes the public with light and power, telephone service, gas or water, or any of them, shall pay to every customer from whom any deposit has been required interest on the deposit at the rate fixed for 6-month Treasury bills of the United States at the first auction:
> (a) On or after December 1 of any year for the period from January 1 to June 30 of the succeeding year; or
> (b) On or after June 1 of any year for the period from July 1 to December 31 of that year, from the date of deposit until the date of settlement or withdrawal of deposit.

24. The Commission finds that the customer deposit rate should be based on the rate that was in effect at the end of certification on May 31, 2010, which was 0.17 percent per annum. This is consistent with the practice of accepting the capital structure, and cost of long-term debt that were in place as of the end of certification. Staff provides no rationale for its recommended rate for customer deposits. The Commission therefore approves 0.17 percent as the customer deposit rate for the purposes of this proceeding.

3. Rate of Return on Equity ("ROE")—Electric

Sierra's Position

25. Sierra requests an increase in its Commission authorized rate of return on common equity ("ROE") from its current level of 10.60 percent. In Sierra's direct and rebuttal pre-filed testimony Sierra recommended a return of no less than 10.75 percent (Exhibit 28 at 8). However, during the hearing, Sierra's expert revised his recommendation, based on more current information, to 10.40 percent. Each recommended rate of return was based on the average return estimates for the two

samples used in the analyses. This recommendation was formed on the bases of studies performed using the follow methods:

- Capital Asset Pricing Model ("CAPM"),
- Risk Premium (historical and allowed returns)
- Discounted Cash Flow ("DCF") methodologies.
- Empirical Approximation of the CAPM ("ECAPM") (Exhibit 28 at 21)

26. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one methodology may vary depending on unusual circumstances in capital market conditions (Exhibit 28 at 21-22). Each methodology requires the exercise of considerable judgment concerning the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and to apply the methodology, especially in the current atmosphere of turmoil and volatility in capital markets (Exhibit 28 at 22-23). Reliance on any single method or preset formula is hazardous when dealing with investor expectations (Exhibit 28 at 56). Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others, as seen in the chart below:

Methodology	ROE Exhibit 28 at 56	ROE Revised at Hearing Tr. at 59
CAPM	9.90%	8.80%
Empirical CAPM	10.30%	9.30%
Historical Risk Premium Electric	10.80%	9.70%
Allowed Risk Premium	10.90%	10.40%
DCF Integrated Electric utilities Value Line Growth	10.60%	11.00%

DCF Integrated Electric Utilities Zacks Growth	11.10%	11.20%
DCF S&P Elect. Utilities Value Line Growth	9.70%	10.00%
DCF S&P Electric Zacks Growth	10.90%	10.20%
Average	10.50%	10.10%
Capital Structure Adjustment	0.25%	0.25%
Recommended ROE	**10.75%**	**10.40%**

27. The results were then summed and divided by eight yielding the recommended ROE. Updated results of the study were presented at hearing, which indicated an ROE of 10.10 percent. Sierra increased its recommended ROE by 25 basis points and then rounded this estimate to 10.40 percent to reflect Sierra's more leveraged capital structure (Tr. at 33-34). Sierra states that lower interest rates contributed to the downward revision of the ROE. The reason for the slight increase in DCF results is based on analysts' long-term growth forecasts being slightly higher because they are anticipating an eventual recovery of the economy and the resumption of more normal growth rates (Tr. at 57).

28. Sierra testified that it has a substantial construction program relative to its size for required environmental upgrades, infrastructure replacements, and upgrades in targeted renewable generation resource additions (Tr. at 37). According to Sierra, a substantial construction budget is viewed by the investment community as a construction risk. The $800 million projected capital expenditures for the next five years is almost equal to Sierra's equity base of $900 million. Sierra's expert asserts that this money has to be raised externally, and therefore Sierra is dependent on the very fragile or very fickle capital market condition over the next five years (Tr. at 29).

29. Sierra's financial witness states that: 1) Sierra's construction budget is under constant scrutiny by the Sierra in light of the economic environment; 2) Sierra's

plans have been scaled back; and the Sierra's senior officers have made repeated statements about paring back the capital expenditure budget (Tr. at 14). Sierra's cost of capital witness did not evaluate the items that Sierra has delayed outside the five-year horizon or cancelled when making the statement that Sierra has a substantial construction program, asserting instead that Sierra has to raise money externally in competition with everybody else in the industry (Tr. at 42). Even if the program were pared down from nearly 100 percent to 20 percent, Sierra's outside expert asserts it will still have to raise money externally and compete with every other utility in capital markets that have become very, very discriminatory (Tr. at 30 and 40).

30. Sierra's witness asserts that if the Sierra wishes to maintain its capital structure ratios of 44 percent equity, 56 percent debt, it will try to respect those proportions when raising capital. Therefore, of the $800 million, approximately $400 million would be raised by the sale of debt, and the balance by equity. A portion of the equity would be raised through retained earnings, and the difference raised from new common stock issues (Tr. at 38).

31. Sierra's expert also asserts that the Nevada renewable portfolio standard ("RPS")[6] increases the risks for Sierra by requiring it to make a lot of related investments, even though Sierra faces the prospect of low customer growth for the next few years. Questioned whether it would make a difference in terms of risk assessment if "Sierra had enough renewable portfolio credits in the bank to keep it going until the middle of the next decade," Sierra's expert witness acknowledged that it would be a positive factor if it were true (Tr. at 83-84).

TMWA/Resorts' Position

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[6] NRS 704.7821

32. TMWA/Resorts presented a study (Exhibit 33) which used a subpopulation of companies consisting of electric and combination electric/gas utilities similar to Sierra. The criteria were as follows:

(1) Market cap of $1 billion to $5 billion;

(2) Electric-revenues 50 percent or greater;

(3) Common equity ratio 40 percent or greater;

(4) Value Line Safety Rank of 1, 2 or 3;

(5) S&P stock ranking of A or B;

(6) S&P and Moody's bond ratings of A or Baa; and

(7) Currently pays dividends

TMWA/Resorts also conducted studies of the cost of equity for the "Integrated Electric Group," "Western Electric Companies Group" and the "S&P Utility Index Electric Utilities Group" selected by Sierra's witness (Exhibit 33 at 21).

33. The results of TMWA/Resorts' analyses suggested a cost of equity range for Sierra of 9.5 percent to 10.5 percent. This range was supported by DCF and CE analyses, and slightly exceeded the CAPM findings. The respective mid-points of TMWA/Resorts' DCF and CE analyses are 9.875 percent and 10.0 percent respectively, with an average of 9.94 percent. TMWA/Resorts recommended a cost of equity of 9.95 percent, or the mid-point average in order to give some consideration to Sierra's ratepayers given the economic distress due to the recent recession (Exhibit 33 at 4).

34. An issue raised by TMWA/Resorts concerns the effects of the economic downturn, on the results of the ROE studies and how the Commission should weight the results of the ROE analyses, in particular the impacts of very low yields on U.S Treasury

bonds and a lower stock market. These lower yields for Treasury bonds result in lower results for the capital asset models, which skew the average ROE downward. TMWA/Resorts asserts that this is only one-half of the story. The other half of the impact is higher DCF results, due to the higher yields (the annual dividend as a percentage of the price of the stock) that are attributable to the decline in stock prices. TMWA/Resorts asserts that it is not proper to disregard the lower CAPM results, while not also discounting the higher DCF results (Exhibit 33 at 36-37).

Methodology	Range
Discounted Cash Flow	9.5-10.25% (9.875% mid-point)
Capital Asset Pricing Model	7.6-7.9% (7.75% mid-point)
Comparable Earnings	9.5-10.50% (10.00% mid-point)

35. With respect to the issue of an adjustment to reflect a more leveraged capital structure, TMWA/Resorts notes that Sierra's proposed capital structure contains approximately 44 percent common equity. The average capital structure for the combination electric and gas utilities, as reported by AUS Utility Reports, was 43 percent in 2008 and 45 percent in 2009. These are not meaningfully different from those of Sierra (Exhibit 33 at 45).

36. With respect to the issue of reducing the ROE from 10.6 percent to 9.95 percent, TMWA/Resorts notes that:

- the current cost of capital is lower than it was a few years ago
- interest rates are lower
- the equity expectations for earnings of both regulated and unregulated firms are lower
- the cost of capital has declined

- Commission authorizations on returns on equity have declined in recent years
- every witness has a lower cost of capital in this case than in prior Commission cases for Nevada Power Company ("Nevada Power")
- using different slants on the methodologies, each party has reached the same conclusion that the cost of capital is declining; and in fact,
- Sierra's recommended ROE went from 10.75 percent in April to 10.40 on an apples-to-apples basis in August and September, or 35 basis points in four months (Tr. at 201-202, 2016). If an investor decides to invest in NV Energy or ConEd or the Mirage Casinos, or Delta Airlines, expectations are lower than they were three or four or five years ago.

(Tr. at 202)

BCP's Position

37. BCP employs the DCF methodology for estimating the cost of equity, while keeping in mind the general premise that any utility's cost of equity capital is the risk free return plus the premium required by investors for accepting the risk of investing in an equity instrument. Other return on equity modeling techniques such as the CAPM or Risk Premium methods are often used to check the reasonableness of the DCF results. BCP stated that it employed all these modeling methods to arrive at its recommendations in this case (Exhibit 38 at 5-6).

Method	**BCP**
CAPM	9.00%-9.50%
Risk Premium	9.70%-10.50%
DCF	9.90%10.20%
Recommendation	10.00%

BCP further recommended a return on equity of 10.00 percent; and an overall cost of capital to be earned on rate base investment of 7.81 percent (Exhibit 38 at 2).

38. With respect to the additional 25 basis points Sierra requested to compensate for its leveraged capital structure, BCP stated there was no basis to conclude that the Sierra's equity return needs to be increased by 25 basis points, or about $2.5 million in revenue requirement, for financial risk (Exhibit 38 at 45). BCP states that for 2009, the average electric utility for BBB was 43.24 percent equity Sierra has 44.1 percent (Tr. at 223). As a result, a "negative adder" would be necessary. However, BCP did not elect to in clude a negative adder (Tr. at 224). In noting that Sierra's base recommendation falls from 10.60 percent to 10.10 percent, before it adds back 25 basis points for this risk adder to go to the marketplace, BCP concludes that throughout the industry the ROE is coming down to 10.00 percent and under (Tr. at 222-223). Basically the cost of capital has decreased, and utility commissions around the country are lowering the cost of capital to reflect the cost (Tr. at 241).

39. BPC asserted that a 10.00 ROE was sufficient to maintain the financial integrity of Sierra. The sum of profits, depreciation, amortization expense and deferred taxes would be approximately $194 million per year. Sierra's overall budget is roughly $800 million over the next five years, or $160 million per year, and that averages less than $190 million (Tr. at 220). An ROE of 10.00 percent will generate sufficient cash flow to fund Sierra's near-term capital expenditures without going to capital markets.

40. In terms of return, experts typically recommend ROEs that are sufficient to allow the company to borrow in the competitive marketplace. Typically experts will

provide a range of acceptable returns. But every number within a reasonable range is reasonable (Tr. at 246).

41. With respect to the RPS requirement, Sierra's base load forecast predicts a surplus of portfolio credits and compliance through 2024, with Sierra showing a small deficit in solar credits beginning in 2013. BCP asserts that Sierra's most cost-effective option will be to borrow from Nevada Power's surplus of solar portfolio credits (Exhibit 41 at 5).

Staff's Position

42. Staff recommends a 9.83 percent ROE, which is the mid-point of its 9.66 percent - 10.00 percent range. The recommendation includes a risk deduction factor associated with the new electric demand-side management ("DSM") revenue decoupling regulations (Exhibit 46 at 30, 32-33). Staff's ROE study was based on various analyses of the universe of data for 71 public utilities, and it applied six models in developing these analyses. The data was from the second quarter of 2010 for electric, natural gas, electric and natural gas combined, and water utilities. The models used in Staff's analyses were 1) Comparable Earnings, 2) Discounted Cash Flow; 3) Risk Premium; 4) Capital Asset; and 5) Models, and Market to Book approaches (Exhibit 46 at 5).

Model for 2nd Quarter 2010 ROE	Utility Industry Average
DCF/ Value Line Dividend Growth Rate	10.11%
DCF/ Sustainable Growth Rate	9.94%
CA+I Risk Premium	9.66%
VL Blume Adjusted CAPM	8.11%
Decile-size ECAPM	9.14%
Farma-French 3-Factor	7.78%
Average	**9.12%**

43. The average ROE estimate is applied only to the average capital structures of 51.22 percent debt and 48.19 percent equity. Instead of adjusting on the basis of equity and debt ratios, Staff instead relies on an after-tax weighted average cost of capital, which reflects the after-tax effects of capital structure. Staff asserts that this metric was a better indicator of the relative business risk faced by a utility than equity and debt ratios (Exhibit 46 at 5-7). Staff also considered the statistical relationships between the 71 firms and found there was no empirical basis to screen or eliminate firms from the database. Based on the results of these analyses and the adjustment for after-tax cost weighted cost of capital, Staff recommends an ROE of 9.66 percent for Sierra. Staff concludes that a range between 9.66 percent to 10.00 percent is a reasonable ROE for Sierra. In an abundance of caution and with all other things being equal, Staff is inclined to recommend a value nearer or at the higher figure of 10.00 percent for Sierra's allowed ROE (Exhibit 46 at 32-33).

44. However, Staff notes that all things are not equal. On July 2, 2010, in Docket No. 09-07016, the Commission adopted regulations affecting revenue decoupling that apply to Sierra in order to give it increased incentives to promote energy efficiency and conservation measures during the time the rates to be adopted in this Docket will be in effect. By their very nature and intent, these regulations reduce Sierra's risk associated with earning its allowed ROE and should be recognized as a risk-reducing factor in setting Sierra's ROE (Exhibit 46 at 30). The Commission's Order in Docket No. 09-04003(Southwest Gas Corporation's general rate case) noted that the 25 basis points figure was within the range proposed by Staff. Staff asserts that in view of the clear risk-reducing effect of the decoupling measure adopted for and the comparability of the two

decoupling mechanisms a reduction in the ROE, that would otherwise be allowed, is clearly in order. In recognition of the decoupling mechanism adopted for Sierra and the rest of the evidence, Staff concludes that 9.83 percent is the more reasonable value to reflect the midpoint of the 9.66 percent -10.00 percent range and recommends that the Commission adopt 9.83 percent as the allowed ROE for Sierra (Exhibit 46 at 30).

Sierra's Rebuttal Position

45. Sierra asserts that the statement indicating that ROEs are trending down is incorrect. The average through the third quarter of 2010 (between July 15 and September 15) was 10.21 percent, and for integrated electrics it is approximately 10.35 percent (Tr. at 432). An allowed ROE that deviates substantially from the trends in the industry would not be welcomed by the bond rating agencies or, for that matter, by the stock market either. Sierra contends that it is hard to quantify a substantial deviation, but there are trigger points. An awarded ROE of 10 percent would be a trigger point. Below that level would be a cause for some alarm. The financial community would not be surprised by a decrease in the currently allowed ROE, but they would be extremely surprised if it were below 10 percent (Tr. at 431-432).

46. The $800 million of capital expenditures projected between 2010-2014 will not necessarily represent net rate base additions. This is not a new layer in addition to what Sierra has on the balance sheet today (Tr. at 517). The financial plan filed as part of Sierra's current IRP filing[7] is consistent with BCP's testimony regarding the funding of the IRP and base capital requirements. The financial plan demonstrates that the Sierra can fund its base capital requirements throughout that time frame through internally generated funds (Tr. at 461).

[7] Docket No. 10-07003

Commission Discussion and Findings

47. The Commission's central task is to establish an ROE that protects and balances the interests of ratepayers and shareholders and that fulfills the legal requirements for so doing. To arrive at a decision on the appropriate ROE, this Commission relies on the Nevada Revised Statutes, the Nevada Administrative Code, and two seminal decisions of the United States Supreme Court: *Bluefield Water Works and Improvement Company vs. Public Service Commission,* 262 U.S. 679 (1923) and the *Federal Power Commission vs. Hope Natural Gas Company,* 320 U.S. 591 (1944). The return should be sufficient for maintaining financial integrity and capital attraction. It is axiomatic that a public utility is entitled to a return equal to that of investments of comparable risks. In the *Hope* decision, the Court re-affirmed a standard set in the earlier Bluefield decision and found that methods for determining a return are not reasonableness tests, but rather, the result and impact of the results.

48. In establishing an ROE, the Commission relies on the testimony and evidence presented by several capable and expert witnesses, all of whom have testified before this Commission on multiple occasions, by applying principles of finance, accounting and economics. The Commission's reliance includes both the results of the ROE studies of each of the witnesses, as well as their expert judgment.

49. In this proceeding there has been extensive testimony regarding Sierra's financial, business and regulatory risks compared to other investment alternatives. The recommended ROEs range from a low of 9.83 percent to 10.75 percent. *We particularly note* Sierra's decision at hearing to modify its request downward from 10.75 percent to 10.40 percent as being significant. The Commission further understands that the basis for

Sierra's 10.40 percent ROE is the updated results of Dr. Morin's study, which yielded an ROE of 10.10 percent, plus a 25 basis point positive adjustment associated with Sierra's capital structure, equaling 10.35 percent. Therefore, the range of recommended ROEs among the parties is very narrow compared with many other Commission general rate case proceedings: between 9.83 percent and 10.35 percent.

50. In considering these recommendations, Staff's 9.83 percent proposal reflects a downward adjustment of 17 basis points, ostensibly to reflect the lower risk associated with what is described as decoupling. The Commission rejects this approach at this time. Because all revenues were decoupled for gas utilities (as opposed to electric utilities), the revenue decoupling mechanism approved for natural gas utilities is fundamentally different than the mechanism allowed for electric utilities, as adopted in Docket No. 09-07016. Removing this risk reduction adjustment brings the Staff's recommendation to 10.00 percent.

51. The Commission finds that the ROE for Sierra's electric department should be set at 10.10 percent. This will provide Sierra a sufficient opportunity to earn a fair rate of return and to attract capital investment. This finding is also substantially supported by the testimony of all the witnesses that testified.

52. In considering the Sierra's recommendation, the Commission examined its capital needs. There was extensive testimony regarding the magnitude of Sierra's capital budget over the next five years. The capital budget is estimated to be approximately $800 million between 2010 and 2014, or approximately $160 million per year. Contrary to Sierra's cost of capital witness's assertion, Sierra's own Chief Accounting Officer (and

the BCP) testified that Sierra could fund this program with internally generated capital (Tr. at 461, 473).

53. There was also testimony regarding the financial risk associated with the costs and capital requirements associated with RPS compliance in Nevada. The Nevada RPS requirement increases from its current level of 12 percent to 25 percent by 2025. Sierra's cost of capital witness testified that the RPS would create additional risk for Sierra compared to other utilities, given its modest load growth. However, the Commission finds that Sierra's own IRP contradicts this assertion, and indicates that Sierra is particularly well positioned to meet its RPS requirements well into the future with minimal capital requirements. Sierra is estimated to have sufficient non-solar generation resources under contract to meet the RPS until 2024. With respect to the solar requirements, Sierra has a small need which, based on the evidence presented at the hearing, can be met by a number of options which appear to require few capital expenditures. Sierra's witness did acknowledge that this situation was a "positive" one.

54. Sierra's cost of capital witness appeared to be laboring under a misunderstanding about the external financial needs as they related to the capital budgets and Nevada's renewable portfolio standard. In this instance the Commission finds that these factors tend to point to the middle of the range of recommendations and not the high end recommended by the Sierra's witness.

55. In adopting a 10.10 percent ROE in this proceeding the Commission relies on substantial, and even overwhelming evidence presented at hearing and the application of law to this evidence. The ROE is within midpoint of the range provided by all expert

testimony and is reasonable and adequate to maintain Sierra's financial integrity, attract investment and offer Sierra a reasonable and fair rate of return.

4. Weighted Cost of Capital--Electric

56. Based on the foregoing findings and conclusion the Commission finds that Sierra's electric department's weighted cost of capital should be 7.85 percent. This is based on the capital structure as of the end of certification and the cost of debt reported as of that date. It also reflects the adopted ROE of 10.10 percent set in this Docket.

Electric Summary	Capital Amount	Capital Ratio	**Commission Adopted**
Long-Term Debt	$1,143,575	55.32%	**6.14%**
Customer Deposits	$11,771	0.057%	**0.17%**
Total Debt	$1,155,346	55.89%	**6.08%**
Equity	$911,681	44.11%	**10.10%**
Weighted Cost of Capital	$2,067,027	100.00%	**7.86%**

B. Cost of Capital Gas Department

1. Capital Structure—Gas Department

Sierra's Position

57. On May 31, 2010, Sierra's ratios of total debt to total capital and total equity to total capital were 55.89 percent and 44.11 percent, respectively, as set forth below.

	Capital Amounts ($000)	Capital Ratio
Long-Term Debt	$122,842	55.32%
Customer Deposits	$1,264	0.57%
Total Debt	$124,806	55.89%
Common Equity	$97,933	44.11%
Total Capital	**$222,039**	**100.00%**

Commission Discussions and Findings

58. No party disputes Sierra's proposed capital structure. The Commission finds that this capital structure shall be used for purposes of determining the cost of capital in this proceeding.

2. Long-Term Debt—Gas Department

Sierra's Position

59. Related to the long-term debt portion of the capital structure, Sierra reported the following costs for long-term debt as of the end of certification on May 31, 2010, which included a customer deposit rate at 0.17 percent per annum:

Long-Term Debt	$122,842	1.34%
Customer Deposits	$1,264	0.17%
Weighted Cost Debt	$124,806	1.33%

Staff's Position

60. Staff recommends the Commission set the customer deposit rate at 0.22 percent (versus 0.29 percent requested in Sierra's filing) (Exhibit 46 at 1).

BCP's Position

61. BCP agrees that the customer deposit rate should be set at 0.17 percent per annum. BCP proposed no changes to the cost of debt as of the end of certification (Exhibit 38 at 30).

Commission Discussion and Findings

62. The cost of long-term debt is the weighted average of the long-term debt and customer deposits. With the exception of Staff's adjustment to the customer deposit

rate, no party proposes any adjustments to the cost of long-term debt reported as of the end of certification on May 31, 2010.

63. Nevada law clearly establishes the process by which the rate of interest accrued on customer deposits is calculated. Specifically, NRS 704.655 provides, in pertinent part:

> 1. Every public utility which furnishes the public with light and power, telephone service, gas or water, or any of them, shall pay to every customer from whom any deposit has been required interest on the deposit at the rate fixed for 6-month Treasury bills of the United States at the first auction:
>
> (a) On or after December 1 of any year for the period from January 1 to June 30 of the succeeding year; or
>
> (b) On or after June 1 of any year for the period from July 1 to December 31 of that year, from the date of deposit until the date of settlement or withdrawal of deposit.

64. The Commission finds that the customer deposit rate should be based on the rate that was in effect at the end of certification, on May 31, 2010. This rate was 0.17 percent per annum. This is consistent with the practice of accepting the capital structure and cost of long-term debt that were in place as of the end of certification. The Commission accepts 0.17 percent as the appropriate rate for customer deposits for the purposes of this proceeding.

3. ROE—Gas Department

Sierra's Position

65. In its Application Sierra requests an increase in its Commission authorized ROE from its current level of 10.60 percent to no less than 10.75 percent (Exhibit 29 at 8). The recommended ROE was based on the average return estimates for two samples

used in Sierra's analyses. This recommendation was formed on the bases of studies performed using the follow methods:

- CAPM
- Risk Premium (historical and allowed returns)
- DCF methodologies
- EPCAM

66. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one methodology may very well vary depending on unusual circumstances in capital market conditions. Each methodology requires the exercise of considerable judgment concerning the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology, especially in the current atmosphere of turmoil and volatility in capital markets (Exhibit 29 at 21-22).

67. The average result from all the methodologies is 10.20 percent, and the median result is 10.30 percent. The truncated mean is also 10.30 percent. From a broad methodological perspective, the average result from the three principal methodologies is also 10.20 percent. Sierra noted that the estimate of 8.90 percent obtained from the DCF analysis of natural gas utilities using Value Line growth forecasts was clearly an outlier. From all these results, Sierra concluded that the cost of equity for an average risk natural gas utility is 10.30 percent (Exhibit 29 at 85).

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Methodology	ROE Exhibit 29 at 56
CAPM	9.60%
Empirical CAPM	10.10%
Historical Risk Premium Utility Industry	10.80%
Allowed Risk Premium Gas Industry	10.80%
DCF Natural Gas Utilities Value Line Growth	8.90%
DCF Natural Gas Utilities Zacks Growth	10.40%
DCF Combination Gas and Electric Value Line Growth	10.90%
DCF Combination Electric and Gas Zacks Growth	10.90%
Truncated Average (DCF-Value Line was not included)	10.30%
Capital Structure Adjustment	0.48%
Recommended ROE	10.75%

68. The empirical literature suggested an adjustment of 52 basis points, and the Hamada procedure suggested an adjustment of 59 basis points from the gas company group and 33 basis points from the combination gas and electric group. The average of the three adjustments is 48 basis points. Sierra increased its recommended ROE by 48 basis points, from 10.30 percent to 10.78 percent, rounded to 10.75 percent, in order to account for Sierra's more leveraged capital structure (Exhibit 29 at 63). At the hearing, Sierra revised its recommended ROE downward from 10.75 percent to 10.30 percent. Lower interest rates contributed to downward revision of the ROE (Tr. at 33).

Staff's Position

69. Staff's ROE study was based on analyses of the universe of data for 71 public utilities and applied using six models. The data was from the second quarter of 2010 for electric, natural gas, electric and natural gas combined, and water utilities. The models used in the analyses were 1) Comparable Earnings, 2) Discounted Cash Flow; 3) Risk Premium; 4) Capital Asset models; and 5) and Market to Book approaches.

Model for 2nd Quarter 2010 ROE	Utility Industry Average
DCF/ Value Line Dividend Growth Rate	10.11%
DCF/ Sustainable Growth Rate	9.94%
CA+I Risk Premium	9.66%
VL Blume Adjusted CAPM	8.11%
Decile-size ECAPM	9.14%
Farma-French 3-Factor	7.78%
Average	**9.12%**

70. The average ROE estimate applied only to the average of 51.22 percent debt and 48.19 percent equity. Instead of adjusting on the basis of equity and debt ratios, Staff instead relied on an after-tax weighted average cost of capital, which reflects the after-tax effects of capital structure. Staff asserted that this metric was a better indicator of the relative business risk faced by a utility than equity and debt ratios. (Exhibit 46 at 5-7). Staff also considered the statistical relationships between the 71 firms and found there was no empirical basis to screen or eliminate firms from the database. Based on the results of these analyses and the adjustment for after-tax cost weighted cost of capital, Staff concluded that a range of 9.66 percent to 10.00 percent would be a reasonable return on equity for Sierra. Staff recommended an ROE of 9.83 for the gas department (Exhibit 46).

BCP's Position

71. BCP based its analysis on the same group of comparable companies as employed by Sierra, thereby narrowing equity cost calculation to the methodology of estimation. BCP employed the DCF methodology for estimating the cost of equity, keeping in mind the general premise that any utility's cost of equity capital is the risk free return plus the premium required by investors for accepting the risk of investing in an equity instrument. Other return on equity modeling techniques such as the CAPM or

Risk Premium methods are often used to check the reasonableness of the DCF results. BCP stated that it employed all these modeling methods to arrive at its recommendations in this case (Exhibit 38 at 11). In this proceeding, BCP's DCF results ranged from 9.3 percent to 9.7 percent. The CAPM and risk premium approaches ranged from 8.7 percent to 10.4 percent; the midpoint of the range is 9.5 percent. Eliminating the high and low values from the range results in an equity return range of about 9.3 percent to 10.0 percent. The midpoint of this truncated range is 9.7 percent. Given the two ranges of results, a cost of equity of 9.7 percent is reasonable for Sierra.

Methodology	Results
DCF Constant Growth Gas Utility Group	9.3%
DCF Constant Growth Combined Gas and Electric Utility Group	9.5%-9/7%
DCF Two-Stage Gas Utility Group	9.3%-9.4%
DCF Two stage Combined Gas & Electric Utility Group	9.5-9.6%
AVERAGE DCF	**9.4%-9/5%**
Updated CAPM	8.7%
Updated ECAPM	9.2%
Updated Historical Risk Premium S&P Utility Index	9.7%-9.9%
Updated Historic Risk Premium Authorized gas Utility Returns.	9.9%
Alternative Historic Risk Premium Authorized Gas Utility Returns	9.7%-10.4%
CAPM/Risk Premium Average	**9.4%-10.2%**

72. BCP concludes that Sierra's overall cost of capital to be earned on rate base investment should be set at 5.02 percent, which is adequate for Sierra to maintain its financial integrity. Based on the Sierra's capital structure, an ROE of 9.7 percent provides sufficient financial metrics for the Gas Department (Exhibit 39 at 35). In terms of return, experts typically recommend ROEs sufficient so that a company can borrow in a competitive marketplace. Experts typically provide a range of returns but every number within a reasonable range is reasonable (Tr. at 246).

Sierra's Rebuttal Position

73. With respect to BCP, Sierra asserts that it relied on the DCF approach and places little weight on the Risk Premium and CAPM approaches. Sierra asserts that BCP contradicted this position and placed considerable weight on the Risk Premium and CAPM results to derive a result at the bottom of its recommended range (Exhibit 57 at 3-4).

74. The core of Staff's approach to setting a fair and reasonable rate of return for a public utility is to apply various methodologies to a universe of all utility companies, regardless of their comparative risk. The rate of return standard articulated in *Hope* and *Bluefield* is to allow an equity return commensurate with returns on investments in other enterprises having corresponding risks. This fundamental paradigm clearly suggests the analysis of comparable risk investments, and not the entire spectrum of utility risks. The fact that the results from Staff's model are out of step with the results applied recently by regulators to utilities like Sierra demonstrates that Staff's 71-company sample is flawed (Exhibit 57 at 33).

Commission Discussion and Findings

75. The Commission must establish an ROE that protects and balances the interests of ratepayers and shareholders and that fulfills the legal requirements for so doing. To arrive at a decision on the appropriate ROE, the Commission relies on the Nevada Revised Statutes, the Nevada Administrative Code, and the *Bluefield* and *Hope* decisions of the United States Supreme Court. The return should be sufficient for maintaining financial integrity and capital attraction. It is axiomatic that a public utility

is entitled to a return equal to that of investments of comparable risks. In the *Hope* decision, the Court re-affirmed a standard set in the earlier Bluefield decision and found that methods for determining a return are not reasonableness tests, but rather, the result and impact of the results.

76. In establishing an ROE for Sierra's gas department, the Commission relies on the testimony and evidence presented by several capable and expert witnesses, all of whom have testified before this Commission on multiple occasions, by applying principles of finance, accounting and economics. The Commission's reliance includes both the results of the ROE studies of each of the witnesses, as well as their expert judgment.

77. In the instant proceeding, the experts' recommendations resulted in a narrow range—from 9.70 percent to 10.30 percent—with a mid-point of 10.00 percent. The Commission finds that an ROE of 10.00 percent is appropriate, reflects the business risk faced by Sierra's Gas Department, and is sufficient to provide a reasonable rate of return and attract capital.

4. Weighted Cost of Capital—Gas Department

78. Based on the foregoing findings and conclusions the Commission finds that the Sierra gas department's weighted cost of capital should be 5.15 percent. This is based on the capital structure as of the end of certification and the cost of debt reported as of that date. It also reflects the ROE of 10.00 percent adopted by this Order.

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Gas Department	Capital Amount	Capital Ratio	Commission Adopted
Long-Term Debt	$122,842	55.32%	1.34%
Customer Deposits	$1,264	0.57%	0.17%
Total Debt	$124,806	55.89%	1.33%
Equity	$97,933	44.11%	10.00%
Weighted Cost of Capital	$222,039	100.00 %	5.15%

V. ELECTRIC DEPARTMENT DEPRECIATION

A. Transmission and Distribution

Sierra's Position

79. Sierra proposes a change in depreciation and amortization rates for electric power operations based upon the findings of its Application (Exhibit 59 at 4). Sierra's new and revised depreciation and amortization rates, if fully implemented, are forecasted to result in a decrease in current annual depreciation and amortization expenses of approximately $5,831,000, as noted below:

Plant	Amount
Intangible	$452,000
Production	(6,100,000)
Transmission	(775,000)
Distribution	(553,000)
General	(82,000)
Common	1,227,000
Total	($5,831,000)

(Exhibit 89 at Schedule I-12A.)

Account No. 355—Transmisison Poles

80. Sierra recommends a net salvage rate of (40) percent for Account 355. The current approved rate is (30) percent. Sierra states that most of the transmission

poles are wood and that there is no replacement program in place. They also identify that the main cause of retirements is deterioration. Sierra's retirement activity for this account indicates a trend toward higher costs (Exhibit 60 at 101-102, Appendix A at 9).

Account No. 365-Overhead Conductors and Devices, Net Salvage Rate

81. Sierra proposes a change in the net salvage rate from (100) percent to (70) percent for Account 365. Sierra asserts that for overhead conductors and devices net salvage is declining because the cost of removal has decreased. The trend in the database for the past five years shows a (69) percent net salvage. This rate is not only more reflective of the industry standard but also is in line with the database trend shown in the most recent five years (Exhibit 60 at 107, Appendix A at 16).

Account No. 366, Underground Conduit, Net Salvage Rate

82. Sierra proposes a net salvage rate of (75) percent for Account No. 366. The current approved rate is (10) percent. Sierra asserts there are very few retirements to date for this account. When retirement occurs, most of the time the underground conduit for distribution is replaced with conductors. Further, the retirements for distribution conduit are included with the retirements for distribution underground conductors: therefore the rates (salvage) should be the same (Exhibit 60 at 108, Appendix A at 16).

Account No. 367-Underground Conductors and Devises, Net Salvage Rate

83. Sierra proposes a change in the net salvage rate from (50) percent to (75) percent for Account No. 367. Sierra asserts there has been a trend over the past few years that show the net salvage value to be over (100) percent. Sierra also stressed that it has addressed and corrected prior data quality issues, resulting in a comparative increase in

the reliability and accuracy of the 2010 Depreciation Study results (Exhibit 60 at 109, Appendix A at 17; Exhibit 65 at 3-6; Exhibit 67 at 10-11).

Account No. 369- Distribution Services, Net Salvage Rate

84. Sierra recommends a net salvage rate of (25) percent for Account No. 369-Distribution Services. Current approved net salvage is (60) percent. Sierra's net salvage rate database shows that the 14-year average a (15) percent and the five year net salvage rate average was only (10) percent. Sierra contends the net salvage showed a rise in the past four years to around (25) percent with the median at (30) percent (Exhibit 60 at 111, Appendix A at 19).

Account No. 373, Street Lighting and Signal Systems, Net Salvage Rate

85. Sierra proposes to change the net salvage rate from (15) percent to (50) percent for Account No. 373. Sierra contends that the database shows that the overall net salvage rate average is (53) percent and that the most recent five-year average is (58) percent. Within the last several years, Sierra has implemented an inspection process for these assets. The streetlights are now inspected on a regular basis and this has caused more retirements and consequently more removal costs (Exhibit 60 at 114, Appendix A at 21).

BCP'S Position

86. BCP takes exception to Sierra's recommended net salvage values for the following transmission and distribution accounts:

Account No. 355-Transmission Poles

87. BCP recommends that the net salvage rate remain at (30) percent. BCP states it identified several accounting problems with this account, which demonstrate that

retirements and costs associated with those retirements were not accounted for in the same year. BCP also states that Sierra made errors in recording historical data and failed to capture actual retirements. Therefore, BCP contends there is no valid basis to change the existing (30) percent net salvage value (Exhibit 69 at 57-58).

Account No. 365-Overhead Conductors and Devices, Net Salvage Rate

88. BCP recommends a net salvage rate of (45) percent. BCP asserts that the historical data for the period since 2000 indicates net salvage has only exceeded a (45) percent in three years (Exhibit 69 at 59-60).

Account No. 366, Underground Conduit, Net Salvage Rate

89. BCP recommends a net salvage rate of (10) percent. BCP alleges that Sierra's historical database is still less than accurate. Sierra's proposal to use a proxy value from Account No. 367 -- Distribution Underground Conductors and Devices is inappropriate. BCP also states that Sierra admits that it rarely, if ever, removes or replaces conduit. The normal practice in the industry is to abandon underground conduit in place. The database has only identified $56 of retirement activity in the last 14 years (Exhibit 69 at 61).

Account No. 367-Underground Conductors and Devises, Net Salvage Rate

90. BCP recommends a net salvage rate at (50) percent. BCP is also requesting the Commission order Sierra to perform an appropriate and thorough investigation and analysis of its claimed cost of removal for investment in this account. BCP alleges Sierra's own consultant (Gannett Fleming) states that the industry data for this account indicates a mean of approximately a negative 15 percent with a median and mode of a negative 10 percent. BCP also alleges Sierra admits that it has two different

types of cables reflected in this account: direct buried cable and cable in conduit. These different cables, if reviewed separately, would produce more accurate results (Exhibit 69 at 63-64).

Account No. 369- Distribution Services, Net Salvage Rate

91. BCP recommends a net salvage rate at (15) percent. BCP asserts the vast majority of the investment in this account should be associated with underground services. It is normally less costly to retire underground services than to retire overhead services since most underground services are abandoned in place. BCP alleges that the historical data during the most recent period reflects a disproportionate amount of overhead services compared to underground services. BCP further asserts its analysis of the historical data indicates that a (15) percent net salvage rate is conservative (Exhibit 69 at 66).

Staff's Position

92. Staff takes exception to Sierra's recommended net salvage values for the following transmission and distribution accounts:

Account No. 365-Overhead Conductors and Devices, Net Salvage Rate

93. Staff recommends the (100) percent net salvage rate for this account be retained. Staff proposes to retain the existing net salvage rate of (100 percent). Staff reviewed the database and the recent retirement activity and identified an unusual skewing in 2005. In that year, the database showed an unusually low cost of removal. When that year's data is removed, then the current net salvage rate of (100) percent seems reasonable (Exhibit 72 at 22-23).

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Account No. 366, Underground Conduit, Net Salvage Rate

94. Staff recommends a (10) percent net salvage rate for Account No. 366. Staff states that the existing net salvage rate of (10) percent should be retained because Sierra has no retirement expense with this account (Exhibit 72 at 5-6, 24).

Account No. 367-Underground Conductors and Devises, Net Salvage Rate

95. Staff recommends retaining the existing (50) percent net salvage rate. Staff asserts Sierra has not been recording accounting activity during the period between the years of 2000 to 2004. Staff also asserts the database appears to have over-compensated costs which may indicate excess costs are being charged to retirements (Exhibit 72 at 5, 19-20).

Account No. 373-Street Lighting and Signal Systems, Net Salvage Rate

96. Staff recommends retaining the existing (15) percent net salvage rate. Staff contends Sierra's accounting policies, not increased inspections, have caused the observed increase in negative net salvage. In addition, Staff continues to reiterate that due to the difficulties with the data, they believe it is premature to increase the net salvage rate at this time (Exhibit 72 at 21-22).

Sierra's Rebuttal Position

Account No. 355—Transmission Poles

97. Sierra reiterates that industry statistics show a (30) to (90) percent net salvage with an increasing trend toward a higher range. Sierra's net salvage data over the most recent five or six years clearly shows a trend to higher net salvage for this account. The data also shows that during this time the net salvage for every year was (40) percent or in most years much greater (Exhibit 77 at 41-43).

Account No. 365-Overhead Conductors and Devices, Net Salvage Rate

98. Sierra asserts the underlying data supports both a reduction in net salvage and the proposed (70) percent net salvage rate. The major cause of retirements for this account is upgrading (not fire damage), which will cause normal retirements in the future (Exhibit 77 at 43-44).

Account No. 366-Underground Conduit, Net Salvage Rate

99. Sierra agrees with BCP and Staff the current (10) percent net salvage should be retained (Exhibit 77 at 46).

Account No. 367-Underground Conductors and Devises, Net Salvage Rate

100. Sierra asserts retirement costs should be accounted for as cost of removal and not included as installation costs as proposed by BCP. Additionally, Sierra asserts the data demonstrates considerable cost of removal has been incurred and in many years the net salvage rate is in excess of (100) percent (Exhibit 77 at 47). .

Account No. 369-Distribution Services, Net Salvage Rate

101. Sierra stands by its analysis that shows net salvage rates reflected a rise in the past four years to around (25) percent. Sierra cites the (30) percent median of the industry range of (10) to (85) percent. Additionally, Sierra states this account does not distinguish between an overhead or underground retirement (Exhibit 77 at 48-49).

Account No. 373, Street Lighting and Signal Systems, Net Salvage Rate

102. Sierra cites the industry statistics that show a range of 0 – (60) percent net salvage value. Further, the historic data disclosed in some years show the net salvage exceeded (100) percent. Sierra contends that Staff is incorrect in their interpretation of Sierra's statement that a new program for inspecting streetlights would increase

retirements and cost of removal. In fact, increased retirements only affect the accrued removal costs. Finally, Sierra states that the overall net salvage for the account increased whether there were changes within certain years or not and that the 14 year average net salvage went from the current amount of (15) percent to (53) percent and that the recent five year data trend shows a (58) percent net salvage rate (Exhibit 77 at 49).

Commission Discussion and Findings

103. The following table summarizes the parties' positions and the Commission decision:

ITEM	Sierra Proposed	STAFF	BCP	Commission
Account No. 355-Transmission Poles, Net Salvage Rate	(40) Percent	No direct testimony filed on this item.	(30) percent	(40) percent
Account No. 365, Overhead Conductors and Devices, Net Salvage Rate	(70) percent	(100) percent,	(45) percent	(70) percent
Account No. 366, Underground Conduit, Net Salvage Rate	Initially Proposed (75) percent but in Rebuttal agreed with BCP and Staff	(10) percent	(10) percent	(10) percent
Account No.367-Distribution Underground Conductors and Devices, Net Salvage Rate	(75) Percent	(50) Percent	(50) Percent	(50) percent
Account No. 369-Distribution Services, Net Salvage Rate	(25) Percent	No direct testimony filed on this item.	(15) Percent	(25) percent
Account No. 373, Street Lighting and Signal Systems, Net Salvage Rate	(50) Percent	(15) Percent,	No direct testimony filed on this item.	(50) percent

Account No. 355—Transmission Poles

104. The Commission approves Sierra's proposed (40) percent net salvage value, as this recommendation best supported recent observed cost trend.

Account No. 365-Overhead Conductors and Devices, Net Salvage Rate

105. The Commission approves Sierra's proposed (70) percent net salvage value, as it is better supported by the underlying data.

Account No. 366, Underground Conduit, Net Salvage Rate

106. No party proposes changing the current rate, which indicates a reasonable basis to retain the current net salvage rate. Therefore, the Commission finds the current (10) percent net salvage rate shall be retained.

Account No. 367-Underground Conductors and Devises, Net Salvage Rate

107. The Commission approves BCP's and Staff's recommendation to retain the current (50) percent net salvage rate. While the underlying data for the years 2007-2009 indicates a trend toward increasing costs, the trend is not sufficient to warrant increasing the net salvage rate in this proceeding.

Account No. 369- Distribution Services, Net Salvage Rate

108. The Commission approves Sierra's proposed (25) percent net salvage rate. The Commission is persuaded by Sierra's arguments that a (25) percent is representative of the recent underlying historical data and the account addresses both overhead and underground installations.

Account No. 373-- Street Lighting and Signal Systems, Net Salvage Rate

109. The Commission approves Sierra's proposed (50) percent net salvage value, as this recommendation is best supported by the recent observed cost trend.

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B. Production Plant Retirement Dates

Sierra's Position

110. Sierra provides retirement dates for each of its production plants as set forth in the table below:

		Retirement Date		
Plant	In-Service	2005 study	2007 IRP	Proposed
Clark Mt. 1	1961	2036	2011	2011
Clark Mt. 2	1963	2038	2013	2013
Clark Mt. 3	1994	2021	2024	2024
Clark Mt. 4	1994	2021	2024	2024
Ft. Churchill 1	1968	2018	2018	2018
Ft. Churchill 2	1971	2018	2021	2021
Tracy 1	1963	2013	2013	2013
Tracy 2	1965	2015	2015	2015
Tracy 3	1974	2024	2024	2024
Tracy 4 & 5	1996	2023	2031	2031
Tracy 8-10	2008	2043	N/A	2043
Valmy 1	1981	2018	2021	2021
Valmy 2	1985	2022	2025	2025
Battle Mt.	1960	2036	2010	2010
Brunswick	1960	2035	2010	2019
Gabbs	1969	2043	2019	2019
Kings Beach	2008	N/A	N/A	2038
Valley Road	1960	2035	2010	2010
Winnemucca	1970	2025	2020	2010
Kings Beach	1969	2038	2019	Retired
Portola	1960	2030	N/A	Retired

(Exhibit 64 at Lescenski-Direct-2)

111. Sierra asserts that in order to ensure the production plant capital investment is recovered over the units' useful lives, it is critical to develop realistic production plant retirement dates (Exhibit 64 at 3). The proposed dates are identical to those used in the 2010 IRP filing (Exhibit 64 at 5).

BCP's Position

112. BCP recommends adopting a 56-year life for the Valmy units (Exhibit 69 at 31). BCP asserts industry statistics indicate a 60-year life as reasonable for coal-fired generation (Exhibit 69 at 23, 31-33). BCP notes the Commission recently extended the Nevada Power owned Reid Gardner 1-3 coal fired units span to 56, 45, and 45 years, respectively (Exhibit 69 at 23). Further, Sierra has not performed a Life Span Analysis Process ("LSAP") or any other analysis justifying its proposed 40-year life span (Exhibit 69 at 21, 23, 27).

Staff's Position

113. With the exception of the Valmy Units and Fort Churchill Unit No. 1, Staff recommends the Commission accept Sierra's proposed production plant retirement dates (Exhibit 73 at 2). Staff recommends that the Fort Churchill Unit No. 1 retirement date of 2018 coincide with Fort Churchill Unit No. 2's retirement—of 2021 (Exhibit 73 at 2, 9-10). Staff asserts Sierra's latest 10-year business plan for the Fort Churchill station did not reveal any significant risks that would prevent Fort Churchill Unit No. 1 from being able to operate until 2021 (Exhibit 73 at 6). Staff also contends that without any new major transmission infrastructure improvements constructed by 2018, Sierra will be unable to retire Fort Churchill Unit No.1 (Exhibit 73 at 9; Tr. at 649-650).

114. Staff also recommends that Valmy Unit No. 1's retirement coincide with Valmy Unit No. 2's in 2025 (Exhibit 73 at 2, 11). Further, Sierra should be required to perform a Life Span Analysis Process ("LSAP"), the results of which to be used in its next depreciation study (Exhibit 73 at 11-12). Staff asserts its recommendation mirrors the Commission's recent decision to extend Nevada Power's Reid Gardner Units lives based upon current information and require the LSAP be performed for consideration in

its next deprecation study (Exhibit 73 at 11). Staff contends that, other than adding a scrubber to Unit No. 1 and updating the Unit No. 2 scrubber, nothing precludes increasing the depreciable life (Exhibit 73 at 12-13; Tr. at 659-661).

Sierra's Rebuttal Position

115. Sierra recommends denying BCP's and Staff's recommendation until a LSAP has been performed (Exhibit 74 at 9). Sierra recommends the adoption of the LSAP in determining production plant lives as adopted by the Commission for Nevada Power (Docket No. 08-08002) should be applied to Sierra. The process provides for a specific, facts-based decision as to the appropriate life span, which is superior to an industry statistics-based determination (Exhibit 74 at 4-5). Typically, it takes approximately a year to complete (Tr. at 675).

116. In addition to the LSAP (which focuses on mechanical issues), Sierra proposed in its 2010 IRP to develop a team charged with studying potential legislative and regulatory actions brought about by environmental concerns. The team's analysis will result in recommendations concerning: altering operating limits or investments in retrofit equipment and alternatives to meeting customer demand. Sierra anticipates completing this analysis by the end of 2010 (Exhibit 74 at 6).

117. Regarding Staff's Fort Churchill recommendation, the LSAP should be required to determine if the required investment in unit condition and emission controls are cost justified and should be completed by 2011 (Exhibit 74 at 8).

118. In addition to the use of the LSAP, Sierra argues BCP's Valmy Units' recommendation based upon industry statistics relies upon generation facilities that have not been demonstrated to have similar investment profiles (Exhibit 74 at 5, 11-12).

Additionally, BCP ignores the potential disconnect between historic industry statistics and future life spans caused by changes in environmental legislation or regulations and enforcement action (Exhibit 74 at 11-12).

119. In addition to the use of the LSAP, Sierra disagrees with Staff's recommendation to extend the Valmy Unit No. 1 life span. Sierra states not every major component was obtained from the same manufacturer (e.g., Boiler). Valmy Unit No. 1 is facing inquiry from the US Environmental Protection Agency ("EPA"), which could result in significant investment in order to retain the facility. No economic analysis has been performed to determine if any required investment would be justified (Exhibit 74 at 10-11).

Commission Discussions and Findings

120. The Commission must establish the appropriate retirement dates for Fort Churchill and Valmy Units Nos. 1 and 2 in the absence of complete LSAPs. Conservative retirement dates, such as that proposed by Sierra, create financial burdens on current ratepayers for depreciation expenses that should be paid in the future if their plants operate beyond the expected retirement dates. Alternatively, by extending the plant lives and reducing the current depreciation expense to reflect the longer plant lives there is a risk that future ratepayers will be responsible for a large balance after the plants are retired. Reliable information regarding production plant retirement dates is critical for resource planning purposes to ensure that adequate resources are available in a timely manner to optimize economic efficiency and system reliability. The Commission's decision addresses both the depreciation rates resulting from this proceeding and on a

going-forward basis to ensure that adequate and reliable information is available to inform decision-making.

121. Until the next depreciation study and completion of the LSAP, the Commission accepts for purposes of this proceeding Sierra's proposed retirement dates for all units except for the generation retirement dates for the remote units that were adopted by the Commission's Order in consolidated Dockets Nos. 09-12002 and 10-07033 dated December 8, 2010. In considering the cases of Fort Churchill Unit No. 1 and Valmy Units Nos. 1 and 2, the Commission finds at this time that there was inadequate information to form a decision to extend the retirement dates as proposed by Staff and BCP.

122. Establishing a service life for any asset requires reliable information. For production plant, there are many items that need to be analyzed including plant equipment efficiencies, cost effective plant upgrades, system wide operational requirements, future economic considerations, and current and future permitting requirements. The Commission previously approved a procedure in developing and establishing a comprehensive LSAP for Nevada Power, Docket No. 08-08002, to address these issues. All parties acknowledge that an LSAP would identify more accurate retirement dates and is an effective process that reviews a wide range of engineering economic and regulatory challenges. This is the Commission's preference as well.

123. The Commission notes the complications presented by the depreciation case cycle, rate case cycle, the IRP proceeding cycle, and the age of the assets and their retirement dates. Currently, pursuant to NAC 703.276(1), Sierra is not required to file a depreciation case until 2016. However, given the schedule for completion of the LSAP

for Valmy Unit No. 1 and Ft. Churchill, the Commission directs Sierra to file a depreciation case not later than at the time of its next general rate case in 2013. This will allow Sierra to complete the LSAP for the Fort Churchill and for the Valmy No. 1 units and provide a depreciation study incorporating those results. This approach will provide the necessary information to determine the appropriate retirement dates and depreciation rates for Fort Churchill and Valmy Unit No. 1 in 2013. The referenced depreciation rates for Valmy Unit No. 1 and Ft. Churchill will be revisited at that time as well.

C. Corrections to Certain Production Plant Accounts

Staff's Position

124. Staff states that Sierra erroneously used incorrect probable retirement dates for some of its other production plant units in Account Nos 341, 342, 344, 345 and 346. Staff also asserts Sierra failed to include some if not all of the remaining net-book-value associated with the retired Kings Beach units as a reserve adjustment in the depreciation study. Unless, Sierra makes the corrections Sierra will double recover costs associated with these retirements. Though Sierra has made some corrections to date, Staff proposes to make the remaining corrections in the depreciation rate schedules (Exhibit 73 at Attachment PRM-2). However, Staff recommends the King Beach reserve amount be corrected in the regulatory asset request included in the revenue requirement portion of this Docket (Exhibit 73 at 29-31).

Commission Discussion and Findings

125. The Commission approves Staff's proposed adjustments to Account Nos. 341, 342, 344, 345 and 346. Sierra did not respond to any of the proposed corrections in its rebuttal testimony. The Commission can only conclude that Sierra has accepted

Staff's proposal. However, the Commission denies Staff's request to correct the Kings Beach error in the regulatory asset. The error affects the depreciation rates and thus should be reflected in the development of the depreciation rates.

D. Production Plant Interim Retirements

Sierra's Position

126. According to Sierra, its steam production plant is comprised of several pieces of equipment, each of which with a distinct life span. The individual equipment life spans may need to be shortened to reflect when the utility anticipates retiring the generating unit (e.g., Tracy Unit No. 1 planned retirement date is December 2013) (Exhibit 60 at Appendix A, p. 32; Exhibit 64 at 13). Sierra developed the interim retirements using Iowa curved determined life spans and the unit planned retirement dates (Exhibit 60 at Appendix A, p. 3). The steam production plant net salvage rates incorporate the interim retirement rates of:

Account	%
311	(2.95)
312	(4.59)
314	(3.28)
315	(1.65)
316	(2.33)

(Exhibit 60 at Appendix A p. 3, 32)

BCP's Position

127. BCP recommends the Commission accept interim retirement rates developed using Sierra specific information (Exhibit 69 at 42-43). Specifically, BCP recommends adjusting steam production net salvage to incorporate the following interim retirement rates, which were developed using 1996 – 2009 data:

Account	%
311	0.11
312	0.49
314	0.40
315	0.38
316	0.77

(Exhibit 69 at 43, Attachment JP-3)

128. BCP assertes this Commission has previously approved the use of the company specific methodology, which is set forth in the California Public Utilities Commission's ("CPUC's") publication entitled "Determination of Straight-Line Remaining Life Depreciation Accruals Standard Practice U-4" (Exhibit 69 at 42-43).

129. BCP asserts Sierra's actuarial methodology produces an excessive level of interim retirements (Exhibit 69 at 4, 42). The actuarial methodology does not distinguish between the different types of plant recorded in a particular account. For example, Account No. 312 (Boiler Plant Equipment) includes electric motors and smoke stacks, which are noticeably different (Exhibit 69 at 38). Further, Sierra's use of only a five-year experience band is inappropriate, as very short time periods increase the potential for significant variability into the process. Longer periods minimize the influence of annual events (Exhibit 69 at 39-40).

Sierra's Rebuttal Position

130. Sierra asserts its actuarial methodology produces more accurate estimates than BCP's methodology. The actuarial methodology selects an Iowa curve that incorporates variable retirement dispersion (Exhibit 77 at 23). The variable dispersion pattern considers that different plant recorded within an account will be retired at different ages (Exhibit 77 at 28). BCP's methodology produces a curve that assumes a constant level of annual interim retirements, which is unrealistic (Exhibit 77 at 23, 30).

The methodology fails to address the variability that annual retirements and interim retirements increase with age (Exhibit 77 at 30-31). Additionally, Sierra noted that its proposed industry established methodology and identical Iowa curves were accepted in Sierra's 2005 depreciation study (Exhibit 77 at 22).

131. Sierra further asserts that it used the entire 38-year data base information not a five-year band (Exhibit 77 at 24). A five-year band had inadvertently been included in the Application. Upon realizing the mistake, Sierra corrected the filing. In June 2009, BCP was informed of the error (Exhibit 77 at 25, Attachment CRC-5).

Commission Discussion and Findings

132. The Commission finds Sierra's methodology for estimating interim retirement is reasonable and should be approved. The Commission is persuaded that Sierra's methodology incorporates the variability of interim retirements and addresses the variability of plant within an account. Further, by applying the identical rate to all the steam generation stations with plant recorded in the particular account, BCP did not address the potential variability caused by the type of plant (coal or natural gas) or age of the plant.

E. Production Plant Net Salvage--Decommissioning

Sierra's Position

133. Sierra recommends production plant net salvage percentages that are based upon decommissioning costs approved by the Commission in Nevada Power's 2008 general rate case (Exhibit 65 at 14). The decommissioning costs were developed using a 2005 Black & Veatch Study (updated in 2008) of Nevada Power's plant decommissioning costs and modified for previous Commission decisions. Sierra

converted these costs to a per megawatt basis and applied the per megawatt cost to Sierra's generation fleet. The resulting amounts were converted to a percentage of original plant cost (Exhibit 60 at Appendix A at 4-6, 33-36; Exhibit 65 at 12-14, Attachment McElwee-Direct-2). The Commission accepted this methodology in its 2005 depreciation study and in Sierra's 2007 general rate case when it adopted a depreciation rate for the new Tracy generation facility (Exhibit 65 at 8, 10-11).

BCP'S Position

134. BCP recommends the Commission order Sierra to perform a detailed cost analysis of not only decommissioning but also alternatives to complete demolition. The Study should include more cost effective demolition techniques (e.g., explosive techniques) (Exhibit 69 at 55). BCP asserts Sierra's study is generally unacceptable because the Black and Veatch study still yields excessive negative net salvage values (Exhibit 69 at 50, 55). Sierra assumes the worst-case scenario of total dismantlement (with land restored by backfill and grading) and no option other than sale of equipment for scrap. Further, Sierra fails to provide the ratepayer any value for the restored site, which promotes intergenerational inequities by limiting future customers to only receiving any of the value related to restoration at the time of its sale (Exhibit 69 at 50).

135. While BCP contends Sierra's study is generally unreliable, the BCP recommends only two adjustments. BCP recommends the net salvage rate for the combined cycle units reflect the low end of the range, not the high end, as proposed by Sierra, i.e., $8 million versus $10 million. BCP argues Sierra provides no basis for its selection and that the Commission had previously disallowed consideration of inflation in net salvage rates (Exhibit 69 at 54).

136. Further, BCP recommends a 6.3 percent additional reduction to the combined cycle aboveground site restoration costs (Exhibit 69 at 54). BCP argues Sierra overstates the cost by withholding the land sale or reuse value (Exhibit 69 at 52).

Staff's Position

137. Staff recommends the Commission accept Sierra's recommended steam production net salvage values (Exhibit 73 at 2, 21). Staff concurs with Sierra it will incur a net cost to dismantle and decommission its steam production plants. Sierra's estimates are reasonable (Exhibit 73 at 20-21).

138. Staff recommends the Commission accept Sierra's recommended other production plant net salvage values for Tracy Units Nos. 5 & 6 and 7-9 and the solar facilities (Exhibit 73 at 2, 23). Staff concurs with Sierra it will incur a net cost to dismantle and decommission its steam production plants. Although Staff disagrees with Sierra updating the 2008 combined cycle cost estimates of $8 million for inflation to $10 million, Staff argued this difference would not produce a material change in net salvage values, as it gets lost in rounding the value to two decimal places (i.e., low end produces a 1.78 percent and the high end 2.24 percent). Therefore, Sierra's estimates are reasonable (Exhibit 73 at 21-23).

139. Staff recommends the net salvage rates for the diesel units and combustion turbines be set at 0.0 percent (Exhibit 73 at 2, 26, 29). Staff asserts the information for these facilities indicate values less than those proposed by Sierra. While Sierra adjusted downward the 2005 Black & Veatch study values for steam production by 60 percent, Sierra used the 2005 Black & Veatch study values for diesels and combustion turbines. Over the years, Sierra has presented information indicating that at the time of retirement

the market value of these facilities exceeds the dismantling cost, which was demonstrated by Sierra's retirement of the old Kings Beach diesel (Exhibit 73 at 24-25). Establishing a 0.0 percent net salvage value balances the risk of market value changes and the goal minimizing any unrecovered costs (Exhibit 73 at 26).

Sierra's Rebuttal Position

140. Sierra reiterates the Commission's previous acceptance of the 2005 depreciation Application Black & Veatch study (as adjusted), as the best information available (Exhibit 75 at 9). Subsequent to that acceptance, the study has been updated three times (including revision for actual experience) (Exhibit 75 at 10-11). Sierra argues the modified study still represents the best information available (Exhibit 75 at 12).

141. In response to BCP's combined cycle adjustments, Sierra adopted the higher end of the range to reflect the passage of time, with the mid-point being reasonable. BCP did not justify its use of the lower end of the range (Exhibit 75 at 12-13).

142. Sierra argues Staff's 0.0 percent net salvage value for diesel and combustion turbines ignores that Sierra experienced a negative net salvage when it retired the Portola diesel units (Exhibit 75 at 14). Further, Sierra anticipates the retirement of the ten remote diesel units in 2011, as requested in its 2010 IRP, which will result in a $3 million negative net salvage. Sierra has sought in the current IRP filing[8] to establish regulatory asset treatment for these costs (Exhibit 75 at 15).

Commission Discussion and Findings

143. The Commission finds that the production net salvage values shall be those proposed by Sierra. The Black & Veatch study as modified provides the best

[8] Docket No. 10-07003

information available to establish net salvage rates in this proceeding. Further, Staff demonstrated that modifying the combustion turbine value to eliminate inflation has an immaterial effect. In addition, in Sierra's IRP the Commission approved Sierra's request for regulatory asset treatment for the retirement of the remote diesel units with an offset for depreciation expense.[9] This ratemaking treatment protects the ratepayer from any overstatement of negative net salvage values.

144. However, if the land is intended to be retained as a "brown field" site and the study does not reflect this condition, future studies should include this consideration.

F. Production Plant Net Salvage

Sierra's Position

145. Sierra asserts the data in this study is reliable for establishing of net salvage rates. Over the past three and half years, Sierra made significant strides in improving the quality of the data (Exhibit 65 at 6). On July 2006, Sierra filed its plan to correct the data errors identified by the Commission in its 2005 depreciation study (Exhibit 65 at 3-4). Staff supported Sierra's corrective action plan. By December 31, 2006, Sierra had completed the corrective actions (Exhibit 65 at 4). In developing the data for this depreciation Study, Sierra performed an internal review of the net salvage data. The internal review disclosed a noticeable change in the recorded net salvage activity, and data was synchronized to correspond with the year of retirement (Exhibit 65 at 5-6; Exhibit 67 at 10). Certain "outliers" were noted and excluded from the data (Exhibit 65 at 6).

[9] Commission Order issued December 8, 2010 in Docket No. 10-07003, at pp. 31-32, where the Stipulation is accepted. The Stipulation at section 2(2) addresses the requested accounting treatment.

Staff's Position

146. Staff acknowledges Sierra has expended significant resources and time in improving the quality of its data (Exhibit 72 at 17; Tr. at 631). However, several large Transmission and Distribution ("T&D") accounts have relatively flat retirement activity indicating significantly long lives (e.g., Account No. 353 – transmission station equipment- at age 65 years 78 percent of original equipment still in-service) or retirements are not being recorded (Exhibit 72 at 15-17; Tr. at 623). Staff's investigation indicates data errors exist. (Tr. at 622). While Sierra's proposed lives are still reasonable in this proceeding, and no study is error free, Sierra should make additional efforts to track retirement data and perform periodic audits (Exhibit 72 at 15, 17; Tr. at 618, 622, 628-629).

Sierra's Rebuttal Position

147. Sierra concurs with Staff that continuous review is appropriate and the quality of accounting information can always be improved. Sierra will continue to strive to improve its business practices (Exhibit 75 at 18). Currently, Sierra continues to perform internal audits on its data (Tr. at 718-719). It will never be perfect, but the errors should be immaterial (Tr. at 737-739).

148. Further, other than the $1.5 million Mira Loma study, the data errors noted in response to Staff data requests ($174,000 retirements not included in the depreciation study) would not have affected the study (Exhibit 82; Tr. at 721, 769-770, 772-773).

Commission Findings and Discussion

149. The Commission concurs with Staff and Sierra and finds the data used in the 2010 depreciation to be generally reliable. However, while Sierra has made

significant strides in improving the quality of its accounting data, Staff's comments about T&D plant retirements raises the possibility that additional improvement are possible. In order to identify and implement those potential improvements, the Commission directs Sierra to perform an audit of its data. Further, the Commission directs:

- Sierra, in consultation with Staff and BCP, shall jointly develop the scope of the audit;
- In the development of the scope, BCP should be consulted; and
- The results of the audit should be completed in time to be considered in the next depreciation study to be filed with the Commission in 2013.

150. Sierra estimated it would take up to 18 months to complete this type of audit. The cost of this audit would be not known until the scope of the report is agreed to. The audit process should be a joint undertaking by Sierra, BCP, and Staff, where an agreement the scope of work would be developed with the goal of significantly improving the existing plant asset database.

VI. GAS DEPARTMENT DEPRECIATION

151. Sierra is recommending a change in depreciation and amortization rates for its gas operations based upon the findings of a study of gas plants in service as of December 31, 2009. These new and revised depreciation and amortization rates, if fully implemented, are forecasted to result in an increase in current annual depreciation and amortization expenses by $1,956,000 (Exhibit 63 at 6-10; Exhibit 89 at Schedule I-12A).

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A. Service Lives

Sierra's Position

152. Sierra recommends either retaining existing service lives or extending the service lives. The underlying data supports that the proposed service lives and the proposed lives are within industry norms. (Exhibit 63 at Appendix A.)

Staff's Position

153. Staff does not recommend any changes to Sierra's proposed service lives (Exhibit 72 at 3).

Commission Discussion and Findings

154. The Commission approves Sierra's proposed service lives as reasonable.

B. Net Salvage

Sierra's Position

155. Sierra recommends retaining the current (5) percent net salvage rate for Account Nos. 378 and 390 and increasing the net salvage for the following three accounts:

ITEM	Sierra PROPOSED
Account No. 376-Mains, Net Salvage Rate	(70) Percent
Account No. 380-Services, Net Salvage Rate	(100) Percent
Account No. 381-Meters, Net Salvage Rate	(100) Percent

(Exhibit 63 Statement A(1)(a), Appendix A)

Account No. 376 Mains Net Salvage

156. Sierra recommends increasing the net salvage rate from (20) percent to (70) percent. Sierra asserts its analysis demonstrates the trend in net salvage exceeds

(100) percent, with more recent experience exceeding (200) percent. Sierra cites the increase causes as: asbestos removal, traffic control, labor, and pipe insertion, with nearly non-existent salvage value (Exhibit 63 at Appendix A, pp. 4-5).

Account No. 380-Services, Net Salvage Rate

157. Sierra recommends increasing the net salvage rate from (60) percent to (100) percent. Sierra asserts, while retirements are small but consistent on an annual basis, more recent experience exceeds (200) percent. Sierra cites the increasing cost of removal (e.g., cost of repairing concrete and landscaping in older neighborhoods) and declining salvage value rate to support its (100%) net salvage rate (Exhibit 63 at Appendix A, p. 7).

Account No. 381-Meters, Net Salvage Rate

158. Sierra recommends increasing the net salvage rate from (25) percent to (100) percent. Sierra asserts its analysis demonstrates over the past 14 years the cost of meter removal has increased substantially with more recent experience exceeding (100) percent. Salvage value has been nearly non-existent (Exhibit 63 at Appendix A, p. 8).

BCP's Position

Account No. 376 Mains Net Salvage

159. BCP recommends a (45) percent net salvage rate. BCP asserts Sierra inappropriately relied on unrepresented asbestos removal costs and uses increased labor costs as justification for the proposed net salvage value. Further, BCP argues Sierra fails to properly account for costs allocated between the new replacement pipe and the cost to remove the retired pipe (Exhibit 70 at 6, 16-19).

Account No. 380-Services, Net Salvage Rate

160. BCP recommends a (60) percent net salvage rate. BCP asserts the historical data, in conjunction with its proposed treatment of insertion costs results in the relatively consistent range of (55) percent to (60) percent for net salvage (Exhibit 70 at 6, 19-21).

Account No. 381-Meters, Net Salvage Rate

161. BCP recommends retaining the existing net salvage rate of (25) percent. BCP asserts Sierra relied on false indications of higher costs. BCP believes this is indicated by a comparison of the range of costs to remove a meter for 2007-2009 in the earlier part of the decade, $240 to $640 and $50 to $60; respectively (Exhibit 70 at 6, 22-23).

Staff's Position

Account No. 376 Mains Net Salvage

162. Staff recommends a (40) percent negative net salvage rate (Exhibit 72 at 3). Staff asserts Sierra is over emphasizing the more recent data ((26) percent for 1990-1999 and (71) percent for 2006-2009). The more recent period increase is primarily attributed to increased emphasis on accounting detail (Exhibit 72 at 10-11). Further, Staff disagrees with Sierra's policy of charging as cost of removal the expense of cutting open old pipe to insert new pipe. Staff argues these costs should be recorded as new installation costs (Exhibit 72 at 9, Attachment FWR-7).

Account No. 380-Services, Net Salvage Rate

163. Staff recommends a (60) percent net salvage rate. Staff asserts that like mains (Account 376), the standard operating practice is to retire services in place, which

reduces costs. Commencing in 2006, Sierra changed its accounting policy to record costs of installing new services when retiring pipe as a cost of removal rather than new installation costs (Exhibit 72 at 4, 13, Attachment FWR-10).

Account No. 381-Meters, Net Salvage Rate

164. Staff recommends the Commission: (1) authorize a (0) percent net salvage rate, (2) allocate all costs of removal to Account No. 382- Meter Installations, and (3) require a change in accounting policies to charges for the cost of removing a meter. Staff asserts recording meter replacement costs in Account No. 382 versus Account No. 381 will allow Sierra to recover its full costs for removing an old meter. Sierra's proposed (100) percent produces $1.1 million annually. Over the past 20-years, Sierra has averaged an annual $92,000 in negative net salvage (Exhibit 72 at 4, 13; Tr. at 623-624).

Sierra's Rebuttal Position

Account No. 376 Mains Net Salvage

165. Sierra argues its recommended net salvage rate is supported by the twenty years of historical data (1990-2009) (Exhibit 72 at 8-9). BCP's recommendation should be rejected as inconsistent with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA") (Exhibit 72 at 8).

166. Sierra asserts its retirement accounting policies are consistent with the FERC USOA and presented in the compliance filing made pursuant to the Commission's Order in its 2005 depreciation study application (Exhibit 72 at 2-5, 13-14). The USOA defines replacement as two activities: the removal of existing property, together with the construction or installation of gas plant in place of property retired (Exhibit 72 at 3-5).

Sierra's policies delineate the account for costs associated with insertion of new facilities in older facilities should be retired. Sierra classifies the costs of the following activities as costs of removal: cutting old line, purging the old line, and capping the old line (Exhibit 72 at 12-13; Exhibit 78 at 2-4; Tr. at 710-711).

Account No. 380-Services, Net Salvage Rate

167. Sierra's arguments were similar to that provided in response to BCP and Staff's Account No. 376 recommendations. BCP's recommendation should be rejected as inconsistent with the USOA. The USOA defines replacement as two activities: the removal of existing property, together with the construction or installation of gas plant in place of property retired. Sierra's policies delineate the account for costs associated with insertion of new facilities in older facilities should be retired. Sierra classifies the costs of the following activities as costs of removal: cutting old line, purging the old line, and capping the old line (Exhibit 72 at 3-5, 12-14; Exhibit 78 at 2-4, 10; Tr. at 710-711).

Account No. 381-Meters, Net Salvage Rate

168. Sierra asserts that FERC allows the utility discretion in utilizing either Account No. 382, which is installation, or Account No. 381, which is the meter itself, for charging meter cost. Sierra contends that it records the cost of retirement to Account No. 381 (Meters) as opposed to Account No. 382 (Meter Installation) because Sierra does not have a net salvage estimate for the meter installation account. Sierra explains that a better comparison would be to look at the industry statistics for both Account Nos. 381 and 382 when making comparisons to Sierra's net salvage estimate for Account No. 381 (Exhibit 78 at 12; Exhibit 76 at 14-15; Tr. at 716).

Commission Discussions and Findings

Summary of Party Positions

FERC Account	Sierra PROPOSED	STAFF	BCP	Commission Finding
376-Mains, Net Salvage Rate	(70) Percent	(40) Percent	(45) Percent	(70)
380-Services, Net Salvage Rate	(100) Percent	(60) Percent	(60) Percent	(100) percent
381-Meters, Net Salvage Rate	(100) Percent	0 Percent & allocate all costs to Account 382-Meter Installations	(25) Percent	100) Percent

Account No. 376 Mains Net Salvage

169. The Commission accepts Sierra's recommended (70) percentage net salvage. Sierra's recommendation appropriately balances the historical data and recognizes the change in accounting policies. Further the Commission finds Sierra's classification of activities associated with installation of mains or services in existing facilities as removal or new installation to be reasonable.

Account No. 380-Services, Net Salvage Rate

170. The Commission finds Sierra's recommended (100) percentage net salvage is reasonable. Service replacement activities in established neighborhoods require higher construction costs due to existing surface and subsurface conditions. The data presented in this account shows consistent retirements and recent net salvage ranges exceeding (200) percent.

Account No. 381-Meters, Net Salvage Rate

171. The Commission approves Sierra's recommended (100) percentage net salvage. Sierra's recommended rate is supported by the (114) percent average for the 20-year historical period and the (150) percent average for the past five years. The

Commission finds Sierra's accounting of cost of removal in Account No. 381, Meters, is reasonable. The FERC USOA allows a utility the option of accounting for meter costs in either Account Nos. 381 or 382. Sierra has consistently applied this accounting policy. The Commission has not been persuaded that Sierra should change its accounting policy.

VII. PHASE III REVENUE REQUIREMENT

A. Theoretical Excess Depreciation Reserve ("TEDR")

Sierra's Position

172. Sierra did not raise issues related to the TEDR in its direct case.

BCP's Position

173. BCP recommends the Commission reduce Sierra's annual depreciation expense (and thus its revenue requirement) by $13.2 million[10] by refunding one-half of Sierra's "TEDR" on its T&D plant to ratepayers over a six-year period. Sierra, Staff, and BCP all agree that Sierra had a TEDR of $182.6 million for T&D plant at the time Sierra's 2009 depreciation study was conducted (Exhibits 69, 72, and 75). A "theoretical reserve", or "theoretical depreciation reserve" is a calculation of what a depreciation reserve *should be,* based on the *current* estimates of average service life, survivor curves, and a net salvage estimate, as opposed to "book" or "actual" reserve. When a depreciation study is conducted, a comparison between "book reserve" and the "theoretical reserve" provides a way to measure the accuracy of past depreciation rates (Exhibit 72 at 25). When the theoretical reserve is less than the actual booked reserve, there is a theoretical reserve surplus or excess (the "TEDR"), and when the theoretical

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[10] Six-year amortization reduces depreciation expense by $15.2 million, but the reduced reserve balance increases the deprecation rates, thus expense by approximately $2 million (Exhibit 69 at 11).

reserve is greater than the actual booked reserve, there is a theoretical reserve deficit (Exhibit 77 at 2-3).

174. BCP states that Sierra's T&D plant TEDR grew by approximately $60 million from the $120.7 million estimated in the 2004 depreciation study (Exhibit 38 at 48; Exhibit 45; Exhibit 69 at 10). The following table denotes the change to the theoretical reserve balances between the 2009 and 2004 studies (amounts in thousands):

	2009 Study		2004 Study	
	$ Amount	**%**	**$ Amount**	**%**
Intangible	$92	0.7%	$0	0.0%
Steam Production	12,786	4.2	(31,530)	(13.0)
Other Production	1,143	1.3	(6,170)	(14.3)
Transmission	55,478	27.5	26,500	18.8
Distribution	133,123	23.8	94,208	22.4
General	(1,948)	(7.5)	(5,308)	(30.1)
Total	**$200,674**	**16.8%**	**$77,700**	**9.0%**

(Exhibit 45)

175. BCP submits that the Commission should address the approximate 50 percent growth in T&D excess TEDR (Tr. at 270-271). BCP asserts that Sierra's existing depreciation rate returns the funds over the remaining lives of the assets, approximately 50 years (Exhibit 69 at 10, Tr. at 557), creating an intergenerational inequity by increasing the probability that the customers which paid the excess will never see the excess amount they have paid refunded to them (Exhibit 38 at 48, Attachment DL-10; Exhibit 69 at 10, 13-14, 18; Tr. at 556, 561, 598-599). BCP's proposal would propose a more equitable period of six years for "conservatively" refunding one half of Sierra's "massive over-recovery position that has resulted in material levels of intergenerational customer inequity" (Exhibit 69 at 9). A TEDR of 30 percent or more is significant, and the TEDR for Sierra's T&D plant has now reached that level. The New York Public

Service Commission starts investigating the cause when the difference is 10 percent (Tr. at 272). BCP asserts two other state Commissions (Florida and Connecticut) have elected to return excess theoretical depreciation reserve amounts to customers (Exhibit 69 at 15-16).

176. BCP recommends the Commission reduce Sierra's annual depreciation expense (and thus its revenue requirement) by $13.2 million. This would effectively refund one-half of Sierra's TEDR (Tr. at 270-271). BCP asserts that its proposed refunding of the TEDR will not harm Sierra's financial integrity, as measured by various financial metrics (Exhibit 38 at 52; Tr. at 562). While the cash flow metrics will decline slightly, Sierra's cash flow metrics are still within industry averages (Exhibit 38 at 49, 51-52, Attachment DL-9).

Staff's Position

177. Since Staff's analysis of Sierra's depreciation study disclosed several retirement data errors, Staff is not recommending an accelerated return of any TEDR at this time. However, if the Commission were to determine some refunding level is appropriate, Staff recommends limiting the amount to 25 percent of the excess, or approximately $50 million until the data problems are addressed. Staff indicates that if the TEDR continues to grow over the next six years the Commission would be faced with an even larger intergenerational issue by the time Sierra files its next depreciation case (Exhibit 72 at 26).

178. The Commission should not accelerate a return of any excess if the excess is 10 percent or less, as this level addresses study inaccuracies and changes in assumptions that may contribute to the variance, such as increasing plant service life from

50 to 60 years (Exhibit 72 at 25-26, 28; Tr. at 615-616, 618-619, 625). Previously, Staff's consultant has made excess theoretical reserve recommendations on an account-by-account basis (Tr. at 630-631).

179. Staff contends that a 10 percent to 19 percent variance between the theoretical and book reserve amounts raises a concern that the balance may be out of line. At a certain level, the variance should not be ignored, for example a Connecticut utility had a 67 percent variance (Tr. at 624-625).

180. Staff asserts a $20 million reduction in annual depreciation expense would not materially affect Sierra's financial condition. Staff's opinion is based upon a review of Sierra's 2010 IRP (Docket No. 10-07003) financial plan model, which assumes a $20 million reduction in annual depreciation expense (Exhibit 73 at 31-32 of 33; Tr. at 643).

Sierra's Rebuttal Position

181. Sierra acknowledges that at the end of the December 31, 2009 depreciation study period, a TEDR existed and totaled approximately $183 million. However, Sierra argues that BCP's adjustment is unnecessary as depreciation is self-correcting. Sierra states that when the six-year accelerated amortization of one half the TEDR ends, the then existing customers will experience a significant cost increase in the cost of depreciation (Exhibit 75 at 3; Exhibit 77 at 6, 12).

182. Sierra states that the theoretical depreciation reserve is measured as of a single point in time using assumed depreciation parameters. As such, the theoretical reserve amount will change with every depreciation study (Exhibit 77 at 6-7). For those utilities and states using the Average Remaining Life methodology (which has been employed by this Commission), the way to address this excess is to allow depreciation

rates to self correct over time (Exhibit 77 at 6, 15). Further, the National Association of Regulatory Utility Commissioners' ("NARUC's") "Public Utility Depreciation Practices" publication states in part:

> When depreciation reserve imbalances exist, <u>one should investigate why</u> past depreciation rates, average service lives, salvage, or cost of removal amounts differ from current estimates. <u>Care should be taken to analyze these effects before correcting for the reserve imbalances.</u> (Emphasis added)

(Exhibit 77 at 7-8, Attachment CRC-Rebuttal-1 at 4)

183. Sierra contends that a decision to refund a significant level of TEDR will send a negative signal to both the credit rating agencies and the investment community, which could reduce Sierra's access to the capital markets and increase the cost of acquiring capital. Sierra states that even a 10 percent adjustment in the TDER would be considered significant (Exhibit 75 at 5-6; Exhibit 81 at 7-9; Tr. at 753).

Commission Discussion and Findings

184. The Commission agrees with Staff that caution should be taken in evaluating if and to what extent any TEDR amortization should be accelerated to alleviate intergenerational inequity. Any acceleration should be premised upon significant and unique circumstances, and after balancing the long-term interests of both ratepayers and shareholders. This is consistent with NARUC's suggested approach found in "Public Utility Depreciation Practices" publication.

185. While the evidence in this record suggests a significant variance between the 2004 and 2009 studies, the Commission is persuaded by both Staff's and Sierra's recommendation urging caution in adjusting the balances here until more information is available and data errors are addressed. Given that the next depreciation study will be

filed in three years, not six, the concern over continuing variances in the theoretical reserve is mitigated and the correct balance is struck between addressing the issue in a reasonable period of time to address intergenerational inequities while gaining the necessary additional information to appropriately address the issue.

186. The Commission intends to perform a balanced evaluation of the TEDR-related issues in Sierra's next general rate case proceeding. In an effort to obtain the information to perform the analysis, the Commission directs Sierra to prepare, as part of its next depreciation study, a report identifying the cause(s) for the TEDR, and why there appears to be such a significant excess in the T&D plant account, and why similar results are not seen in other plant accounts. To the extent not addressed above, the Commission further finds the study will reconcile in total and on an account-by-account basis any significant change between the next deprecation study TEDR and the 2009 depreciation TEDR.

B Domestic Production Activities ("DPAD") Deduction

Sierra's Position

187. Sierra testified that the method ordered by the Commission in Nevada Power's last general rate case, Docket No. 08-12002, is an incorrect calculation of the DPAD tax deduction and, in Sierra's opinion, would not be allowed for filing a federal income tax return. Sierra further testified that the method approved by the Commission in Docket No. 08-12002 allowed removal of all book to tax differences other than those associated with depreciation. This approach results in flowing tax benefits to ratepayers that do not exist. Sierra proposes to reflect all book to tax timing differences in calculating the DPAD deduction (Exhibit 152 at 8).

Staff's Position

188. Staff recommends that the method for calculating the DPAD, adopted by the Commission in Docket No. 08-12002, be re-affirmed (Exhibit 178 at 3). In Docket No. 08-12002, the Commission accepted BCP's deduction calculation methodology (Exhibit 178 at 5, 8). Staff argues Sierra's net operating loss for income tax purposes does not preclude including the DPAD deduction for ratemaking purposes. The Internal Revenue Service ("IRS") issued a private letter ruling to Nevada Power addressing the same issue. The IRS determined that including the DPAD for ratemaking purposes did not violate the normalization regulations (Exhibit 178 at 4-5). Using data from the instant case and the calculation method adopted by the Commission in Docket No. 08-12002, Sierra estimated a DPAD deduction of $4,559,000 (Exhibit 178 at 8, Attachment KJP-7).

BCP's Position

189. BCP recommends a DPAD consistent with the method it proposed and the Commission adopted in Nevada Power's last general rate case, Docket No. 08-12002, which, using BCP's revenue requirement, generates a $3.6 million deduction with a revenue requirement impact of $1.9 million (Exhibit 167 at 36-38, 51-52, Attachment C-9).

190. BCP testified that in setting rates, the Commission increases income tax expense based upon the assumption that the utility will earn its authorized rate of return. The calculation of the DPAD should likewise be based upon the assumption that the production function will earn its authorized rate of return (Tr. at 1376). Additional adjustments were made to reflect income from the Tracy unit and DSM incentives

(Exhibit 167 at 37-38, Attachment C-9). BCP concurs with Sierra that the appropriate methodology for calculating generation function taxable income is to use its unbundling study (Exhibit 167 at 41).

191. BCP asserts Sierra's failure to use the "ongoing" or "normalized" level of book and tax timing differences results in understatement of the generation function taxable income, which then understates the potential DPAD (Exhibit 167 at 42). For example, Sierra reflects an annual DSM tax deduction in excess of booked expense of $16,248,000 for the three-year period rates set in this proceeding are anticipated to be in effect (Exhibit 167 at 43).

192. The following table reflects the actual expected excess of tax deductions for DSM over the booked amortization for 2010-2012:

Excess of DSM Tax Deduction for Tax Return over Amortization on Financial Books			
Year	Tax Deduction	Booked Amortization	Excess Tax > Book
2010	$ 9,211,000	$10,108,000	($ 897,000)
2011	$12,080,000	$10,108,000	$1,972,000
2012	$12,100,000	$10,108,000	$1,992,000

(Exhibit 167 at 43, 44)
The excess DSM tax deduction never exceeds the DSM book amortization amount by more than $2 million annually (Exhibit 167 at 43-45).

193. As additional examples of Sierra's tax deduction overstatement, BCP cites Sierra's treatment of the regulatory assets for the Pinion Pine hot gas clean up costs, the Pinion Pine separation costs, the Ely Energy Center study and permitting cost, and the Kings Beach Diesel decommissioning. Sierra is seeking cost recovery by way of an

amortization of these deferred costs in this case. The costs were expended in prior years and taken as a tax deduction in the year incurred. Thus the tax timing difference for the next three years will be an "add back" (or book deduction greater than tax deduction) to taxable income in calculating the DPAD deduction. However, Sierra is reflecting the opposite result in its DPAD calculation. Sierra reflects a reduction to production taxable income of $6,976,000 for the Pinion Pine regulatory asset, $10,016,000 for the Ely Energy Center regulatory asset, and $10,507,000 for the Kings Beach regulatory asset (Exhibit 167 at 46-48).

194. BCP testified that consistent with Nevada Power's general rate case in Docket No. 08-12002, it recommends all tax-timing differences, except for the depreciation difference, were assumed to zero out for purposes of calculating the DPAD. Sierra has over 100 tax timing differences that can fluctuate between both "additions" to taxable income and "reductions" to taxable income in any given year. It is therefore reasonable to assume that these timing differences in total do not produce a consistent impact on taxable income without a detailed analysis that has not been done by Sierra (Exhibit 167 at 49).

195. BCP asserts that Sierra's argued inability to take the DPAD due to a "Net Operating Loss Carry-Forward" should be ignored because it is due to significant tax timing differences that reduce taxable income for the IRS tax liability, but have not been reflected in setting rates in Nevada. The Commission has adopted normalization accounting for tax timing differences that allow income tax expense recovery based upon booked income instead of IRS taxable income. A normalization accounting assumption should be consistently applied to the DPAD deduction (Tr. at 1378-1382).

196. BCP testified that if all tax timing differences were used in the DPAD calculation, as proposed by Sierra, the value of the tax timing differences used must reflect a normal ongoing level (Tr. at 1408). BCP cited four specific adjustments:

A. The DSM timing difference should be $2 million, not $16 million (Tr. at 1410-1413 and 1417).

B. The Pinion Pine decommissioning costs of $450,000 should be added back to taxable income rather than a $6.9 million deduction to arrive at taxable income (Tr. at 1417).

C. The Ely Energy Center amortization cost amount should be added back to taxable income rather than a $10 million deduction to arrive at taxable income (Tr. at 1418-1420).

D. Depreciation timing differences, flowed through in the manner previously approved by this Commission, which is consistent with the DPAD calculation in other jurisdictions (Tr. at 1409-1410).

Sierra's Rebuttal Position

197. Sierra argues Staff's and BCP's DPAD tax deductions should be rejected because the evidence in the current case indicates that Sierra does not qualify for a DPAD deduction. If the Commission approves BCP's proposed calculation of the DPAD deduction, Sierra's customers will receive an additional windfall of approximately $6 million over the next three years (Exhibit 205 at 2).

198. Sierra agrees with BCP and Staff that the issue between the parties relates to whether book to tax differences reflected in the calculation of production function taxable income should be limited to the book to tax difference for depreciation as

proposed by BCP, or whether all book to tax differences should be reflected in the calculation (Exhibit 205 at 3). Sierra testified that BCP is incorrect in its characterization of the book to tax timing differences for three regulatory assets related to DSM Programs, Pinion Decommissioning, and the Ely Energy Center as being a gross misstatement of a book to tax timing difference. Sierra states that amounts reflected for book to tax differences for these regulatory assets are consistent with the *pro forma* adjustments in this case to establish regulatory assets for these costs (Exhibit 205 at 4).

199. Sierra asserts the book to tax differences for the three regulatory assets have also been used to generate deferred taxes which reduces rate base. Therefore, the deductions should not be characterized as excessive when included in the DPAD calculation (Exhibit 205 at 4). Sierra further asserts BCP has been inconsistent in its application of timing differences because it ignores the tax to book difference for capitalized repairs, Allowance for Funds Used During Construction ("AFUDC"), CIAC and other items associated with fixed assets that reverse in later years through the depreciation calculation (Exhibit 205 at 5).

200. Sierra testified that if the Commission does adopt a "regulatory calculation" of a hypothetical DPAD, the DPAD deduction should be calculated using the same book-to-tax differences used to calculate income taxes for revenue requirement calculation purposes (Exhibit 205 at 6). The unbundled generation revenue requirement reflects consistent timing differences, which results in a negative taxable income, thus making Sierra unable to take a DPAD deduction (Tr. at 1894-1895).

201. In response to the Commission's clarification questions, Sierra provided all on-going tax timing difference for 2010 through 2012. This data included the actual

known timing differences for deferred DSM costs, deferred Pinion Pine Decommissioning cost, Kings Beach decommissioning cost, and deferred Ely Energy Center development and permitting costs. The Production Function taxable income based upon this additional data is as follows:

Production Function Taxable Income				
	Certification	2010	2011	2012
	Schedule I-2	000's Timing Differences	000's Timing Differences	000's Timing Differences
Operating Income before Income Tax	$ 94,853	$ 94,853	$ 94,853	$ 94,853
Less Total Tax Timing Differences	$ 102,637	$ 87,874	$ 56,742	$ 50,681
Production Function Taxable Income	($ 7,785)	$ 6,979	$ 38,111	$ 44,172

(Schedule I-2, Certification Volume 2 – Exhibit 84 and Exhibit 244; Tr. at 1929)

Commission Discussion and Findings

202. The Commission finds the existence of a net operating loss for income tax purposes does not preclude the ability to calculate a DPAD for ratemaking purposes. The inclusion does not violate the IRS normalization rules. Further, no evidence was presented indicating that including the DPAD deduction would violate NAC 704.6536. Because income tax expense for ratemaking purposes is established on a prospective basis, ratepayers do not benefit from the lower income tax expense that results from a net operating loss.

203. The Commission finds Sierra shall calculate a DPAD deduction using the methodology proposed by Staff and BCP. Sierra's methodology significantly overstates the timing differences expected to occur during the rate effective period by ignoring the current tax status of several regulatory assets (e.g., DSM). Sierra assumes the initial tax deduction occurred in the test year and effectively applies this assumption through the rate effective period. Additionally, the inclusion of on-going DSM expenditures inappropriately ignores the change in the recovery mechanism for these costs.

204. Further, with one exception, Staff and BCP's methodology is consistent with this Commission's use of normalized accounting for income taxes in the establishment of revenue requirement. Income tax expense calculated on *pro forma* book income is not taxable income. By including the depreciation timing differences, Staff and BCP reasonably acknowledge that production taxable income is significantly affected by depreciation timing differences. In fact, this difference is the primary variable between book and taxable income.

C. 2009 Severance Plan Costs

Sierra's Position

205. Sierra seeks rate base recognition and amortization to operations and maintenance ("O&M") expense over three years for the costs of its voluntary and involuntary workforce reduction severance plans which were initiated by its parent, NV Energy ("NVE") in 2009 for Sierra and Nevada Power. Sierra testified that it implemented a voluntary and involuntary workforce severance program in 2009 as a result of a dramatic decline in commercial and residential construction resulting from the economic downturn (Exhibit 95 at 5). The reduction in projected load growth and capital

construction projects necessitated a reduction in the labor force in order to manage labor costs.

206. The voluntary severance program achieved approximately 60 percent of the target reduction. An involuntary severance program was implemented to achieve the balance of the targeted reductions. A total of 155 positions were eliminated, 69 of which were eliminated at Sierra (Exhibit 95 at 7).

207. Sierra's share of the severance program costs is the unamortized balance of $4.2 million and $1.4 million, as of the May 31, 2010 certification date for the electric and gas operations, respectively. Sierra requests a three-year amortization of these costs for rate recovery and rate base treatment (Exhibit 95 at 5).

208. Sierra testified that the annual salary reduction results in revenue requirement savings (total annual savings excluding the cost of the severance plans) of $4.9 million and $687,000 for Sierra's electric and gas operations, respectively. The net labor savings (total annual savings net of the cost of the severance plans) during the three-year amortization period were estimated at $2.8 million and $421,000 for Sierra's electric and gas operations, respectively (Exhibit 95 at 9).

Staff's Position

209. Staff testified that the labor cost reduction resulting from the 2009 voluntary and involuntary severance plans was in the public interest and, based upon the estimated savings that will flow to ratepayers, the cost of the severance plans should be recovered in rates (Exhibit 165 at 16).

210. Staff recommends two changes to Sierra's proposed adjustments to recover the cost of the 2009 severance plans. First, with respect to Sierra's proposal to

allocate 100 percent of the annual amortization of the severance plan costs to O&M expense, Staff recommends allocating the severance plan costs between O&M and construction, based upon a historical capital loading percentage for Account No. 920 of 19.24 percent. This change increased the net adjustment to amortize the severance plan costs over three years by $539,000 and $103,000 for Sierra's electric jurisdictional and gas operations, respectively (Exhibit 165 at 17).

211. Second, as to Sierra's proposed rate base treatment for 100 percent of the costs of the severance plan costs as of the May 31, 2010 certification date; Staff proposes adjustments to reduce Sierra's proposed rate base amount to reflect the allocation of the annual amortization to construction at 19.24 percent, and to reflect the first year amount of the three-year amortization. The two adjustments reduce the regulatory asset in rate base by ($2,410,000) and ($369,000) for Sierra's electric jurisdictional and gas operations (Exhibit 165 at 18).

212. Staff testified that its recommended adjustment to reduce the regulatory asset by the first year amortization amount is inconsistent with the Commission's recent order in Docket No. 09-12017 for Utilities Inc. of Central Nevada. In that proceeding the Commission's found that regulatory assets and liabilities should be valued at the actual value at the test year ending date or certification date, and not at a value one year out. Staff testified that its recommended rate base treatment was consistent with historical practice and was reasonable considering the fact that Sierra will earn a return on the amount of the regulatory asset over the life of the asset (Exhibit 165 at 18, 19).

BCP's Position

213. BCP recommends that the Commission reject Sierra's proposed rate base recognition and amortization expense for the cost of implementing the 2009 voluntary and involuntary severance programs for the following reasons:

- The costs of the severance programs are abnormal and non-recurring;
- All labor cost savings that occur as a result of the workforce reductions prior to the effective date of rates set in this proceeding will accrue to the benefit of Sierra's shareholders;
- All reductions in indirect labor costs including payroll taxes, medical and dental coverage and 401K matching contributions will also accrue to the benefit of Sierra's shareholders until the effective date of rates set in this proceeding (Exhibit 167 at 8-12).

214. BCP estimates the net labor savings, which will occur prior to the effective date of rates established in this proceeding, total approximately $3.9 million, of which approximately $3.3 million would be realized by Sierra's electric department and $570,000 by its gas department (Exhibit 167 at 11). BCP testified that the estimates do not reflect the additional savings attributable to payroll tax, avoided medical/dental insurance benefits, as well as 401K company match savings (Exhibit 167 at 12). BCP further testified that when the direct labor savings in 2010 are increased to reflect the additional benefits and payroll tax savings ratio reflected in Exhibit 147, the only remaining unrecovered cost for the severance program is $63,000 and $124,000 respectively, for Sierra's electric and gas operations (Tr. at 1400). BCP further testified that in addition to the payroll, benefits and payroll tax savings, Sierra has also realized

additional savings from the downsizing of fleets and reductions in other programs that have not been quantified (Tr. at 1361).

215. BCP testified that a June 19, 2009, presentation to the NVE Board of Directors indicated an expectation that the one-time upfront costs would be immediately offset by savings in 2010. Management expected that the upfront costs of the severance program would be offset by retained savings within a short period of time. There was no representation made of a need or plan to amortize such costs in the development of retail rates (Exhibit 167 at 16).

216. BCP testified that if Sierra's position were adopted, shareholders would have received both 100 percent of the savings that have occurred prior to the rate effective date and recovered 100 percent of the costs through rates established in this proceeding (Tr. at 1384). BCP testified that the Sierra's response to a BCP Data Request (Exhibit 147) reflected additional projected savings from a reduction in involuntary severance and reorganization costs that should also be considered in the comparison of savings to costs for the severance programs (Tr. at 1399).

217. BCP testified that neither Sierra nor its parent NV Energy sought an accounting authority order from this Commission prior to this rate case to allow for deferral of the costs of the severance programs as a regulatory asset for recovery in a later rate case. Therefore, BCP states that there were no expectations made to shareholders or the investment community for anticipated rate recovery of these costs on a prospective basis (Exhibit 167 at 17).

218. BCP testified that it disagreed with Staff's position that savings from the severance program should not be considered beyond the certification date. The

severance program is a unique event that was expected to result in immediate savings to Sierra. It is both fair and equitable to look at both costs and savings that have occurred prior to the rate effective date to determine whether the company needs rate recovery for the costs of the severance program (Tr. at 1363-1364).

Sierra's Rebuttal Position

219. Sierra testified that BCP's analysis reflects a net loss to shareholders (Exhibit 237 at 18). Sierra testified that while Sierra achieves savings between rate cases, it was important to remember that Sierra also incurs costs that are not included in effective rates (Exhibit 237 at 19).

220. Sierra testified that it disagrees with Staff's recommendation to reduce the severance cost regulatory asset by the first year amortization amount. Sierra testified that should the Commission adopt the Staff's adjustment to the regulatory asset, the electric jurisdictional rate base should be increased by $844,000 and the gas department rate base should be increased by $129,000 to reflect the related deferred income tax impact.

221. Sierra testified that the costs supplied to BCP in response to BCP 22-01B include all costs incurred through September 7, 2010. The voluntary and involuntary costs requested for rate recovery are costs incurred through the May 31, 2010 certification date (Tr. at 2327). Sierra testified that Exhibit 233 was a more accurate calculation of annual savings as of May 31, 2010 from the voluntary and involuntary severance programs in that it reflects more current overhead rates and shows that all terminated employees were not "off the payroll" by December 31, 2009 (Tr. at 2265-2268).

Commission Discussion and Findings

222. The central issue is the appropriate ratemaking treatment to be afforded Sierra's severance program. A threshold issue is whether the severance event should be treated as a normal or unique event. In this instance, the Commission agrees with BCP that a significant severance program represents a unique event that seldom occurs for a regulated utility. It is therefore reasonable to examine both the costs and savings retained by a company in determining the severance program costs that can be justified for rate recovery.

223. A second issue is the amount to be recovered. Sierra proposes 100 percent rate base recognition and a three-year amortization to its O&M expenses, beginning on the rate effective date of January 1, 2011.

224. NRS 704.110(3) limits proposed changes to a company's cost of service, to the end of the certification period, unless an expected change in circumstances is proposed initially by Sierra under NRS 704.110(4). BCP's proposed adjustment considers savings retained by Sierra from June 1, 2010 to December 31, 2010 that is beyond the certification period and therefore inconsistent with NRS 704.110(3).

225. The Commission finds that netting the savings retained through May 31, 2010 against the costs incurred through May 31, 2010 is reasonable and consistent with the statute. Sierra's cost as of May 31, 2010 is not 100 percent as requested, because of the savings retained from January through May 31, 2010. Therefore recovery and rate base recognition for the net cost as of May 31, 2010 should be based upon the data supplied in Exhibit 233, as set forth below:

Net Severance Program Costs as of May 31, 2010		
Severance Plan Costs as of May 31, 2010		$5,613,000

Annual Labor & Benefit Savings at May 31, 2010	$4,920,103	
Ratio to Reflect Savings through May 31, 2010	5/12	
Labor & Benefit Savings Retained by Sierra		$2,050,043
Net Severance Program Costs for Rate Recovery		$3,562,957

226. Staff's recommendation to reduce the rate base amount by the first year amortization results in a rate base amount that will not appear on Sierra's financial records until December 31, 2011, 19 months beyond the certification date and 12 months beyond the rate effective date. The Commission therefore rejects Staff's recommended rate base treatment as inconsistent with NRS 704.110(3). Sierra is directed to use the data in Exhibit 233 and appropriate allocation factors to determine a consistent amount for the severance program costs to be included for rate recovery for its gas operations.

D. Payroll/Benefits Proposed Disallowance

Sierra's Position

227. Sierra proposes to recover its annualized payroll, benefits and pension costs for its electric and gas operations as of May 31, 2010. Sierra proposes adjustments to reduce its test year 2009 payroll, benefits and pension costs by $14 million and $1.7 million, respectively, for its electric jurisdictional and gas operations (Exhibit 84 at I- 1, p.1 and Exhibit 89 at I- 1, p. 1).

228. Sierra testified that its philosophy regarding executive compensation is to offer executive compensation that is competitive and prudent for an investor-owned utility. To achieve this goal, the total compensation program which includes base pay, short-term incentive pay ("STIP") and long-term incentive pay ("LTIP") is targeted near

the 50th percentile, or the median range, of compensation in the industry (Exhibit 113 at 6).

229. Fredrick W. Cook & Co. was retained by Sierra to prepare an analysis of Sierra's executive compensation to determine whether its compensation was both fair and competitive. Sierra testified that being within +/- 10 percent to 15 percent of the targeted levels for cash compensation and 20 percent for long-term incentives would allow it to remain competitively positioned to retain and recruit a talented workforce (Exhibit 113 at 11). The analysis found:

1) Executive base salaries are positioned 4.5 percent above the median;

2) STIP is positioned 10 percent above the median;

3) Total base salaries and STIP are positioned 6.5 percent above the median. (Exhibit 113 at 12)

230. Sierra asserts that it has made changes to manage its cost for pensions and other post employment benefits ("OPEBs"). These include the following actions:

- In September 2009, Sierra capped contributions for retiree medical plans at 2009 levels, which is expected to result in an annual savings of $4 million;

- In 2009, the Sierra and Nevada Power implemented voluntary and involuntary severance programs with annual savings from permanent reductions in the labor force that will exceed the cost of the severance program; and

- In 2008, the post retirement plan was amended to provide that all management, professional, administrative and technical ("MPAT") employees hired after April 1, 2008 will not be eligible for retiree medical coverage. Those hired after January 1, 2009 will not be eligible for retiree life insurance coverage (Exhibit 106 at 8, 9).

231. Sierra testified that it benchmarked the salaries paid to bargaining unit employees against the "EAP Data Information Solutions 2008 Energy Technical Clerical Survey." A comparison of Sierra's salaries to a selected peer group of 13 companies indicated that Sierra's average salaries were 11 percent higher than the peer group, but still within the target of 15 percent of the median. A comparison of Sierra bargaining unit salaries to the median salary for the Western region companies indicated that Sierra's salaries were 3% lower than the companies in the Western region. Sierra states that the Western region results are important because Sierra competes with Western region companies for skilled employees (Exhibit 106 at 22).

232. Sierra testified that a comparison of the base pay for MPAT employees to a CompAnalyst survey data and a Towers Watson's 2009 Energy Services Middle Management and Professional Database survey confirm that Sierra is achieving mid-range status with respect to base pay. The average base salary for the benchmarked positions for Sierra is within 2.8 percent of the average base salary for the benchmarked positions in the CompAnalyst survey (Exhibit 106 at 24).

Staff's Position

233. Staff recommends that the Commission accept certain adjustments, which lower Sierra's employee compensation and benefits by 3.89 percent to reflect the current

economic climate and productivity levels at Sierra. Staff recommends that Sierra's employee compensation cost be reduced $3,072,000 and $495,000 for its electric and gas operations, respectively (Exhibit 165 at 14). These adjustment amounts include labor, STIP and pension, other employee benefits and overhead ("PB&O") (Exhibit 165, Footnote 1).

234. Staff testified that its overall perspective on utility employee compensation is that if Sierra is managing its business in an economically efficient manner - that is, in the public interest – then its compensation levels should be affected by and measured relative to the market forces that determine trends in employment, pay levels and overall compensation in Nevada's labor market. Sierra's per-capita and total compensation levels should reflect Nevada labor market and overall economic conditions (Exhibit 188 at 5).

235. Staff's recommended disallowance of 3.89 percent of Sierra's payroll and benefits cost includes two components:

1) Staff contends that Sierra has increased its total compensation over the last three years by 3.72 percent, more than the most liberal market average that would be in the public interest.

2) Further Staff compares Sierra's gains in per employee productivity with half the productivity gain in the rest of the economy and identifies that Sierra's gains fall short – but only by 0.17 percent. The one-half level is used in recognition that, historically and due to slow technological progress and business innovation, the utility sector has experienced much slower productivity gains than the rest of the economy (Exhibit 188 at 2).

236. Staff testified that its analysis of Sierra's headcount and per-capita pay levels since 2007 indicate that employment head-counts have been cut moderately by 5.91 percent, and that per-capita pay levels have risen by 5.67 percent, resulting in net reduction to employment compensation levels of 0.23 percent. For comparison, Staff states that it could have compared Sierra's results to the reduction in Nevada's total statewide wage payments that have dropped 17.8 percent. As a conservative measure, Staff chose to compare Sierra's results with Nevada's per-capita income change that includes not only employee compensation but also unemployment compensation. Nevada's reduction to personal income of 3.95 percent, compared to Sierra's reduction in employment compensation of 0.23 percent, results in the 3.72 percent excess salary compensation adjustment percentage proposed by Staff (Exhibit 188 at 10).

237. Staff testified that it computed productivity for Sierra's electric operations from 2008-2010 by dividing megawatt hour ("MWH") loads, megawatt ("MW") annual peak loads, and electric customer counts by Sierra's allocated electric employee headcounts (Exhibit 188 at 8, 9). Staff testified that the productivity results of 3.29% for electric and 7.95% for gas, were then weighted based upon electric and gas payroll which resulted in a weighted productivity percentage of 3.96% for Sierra's electric and gas operations. The 3.96% productivity percentage was then compared to one half of the overall national productivity growth figures, that being defined as the change in output for all persons working in the business sector. The three year accumulated productivity percentage from the U.S. Bureau of Labor Statistics was 8.27% (Exhibit 188 at 9).

238. By using only one half of the national productivity percentage from 2008-2010, 4.13% for comparison to Sierra's 3.96% productivity percentage, Staff asserts that

it has been very conservative in favor of Sierra in its productivity analysis (Exhibit 188 at 11). The negative productivity result of 0.17% (4.13 percent less 3.96 percent) was added to Staff's excess employment compensation percentage of 3.72 percent to get to Staff's total recommended 3.89 percent disallowance of Sierra's compensation and benefit costs (Exhibit 188 at RLK-12). Staff's witness testified to being an expert at the macro level regarding the question of prudently incurred expenses based upon a comparison of the actual performance of a utility to market standards (Tr. at 1662). Staff testified that its recommended disallowance, based upon per capita income, was conservative because an analysis based on "labor only" generated a much higher reduction recommendation (Tr. at 1690-1691).

239. Staff testified that in implementing Sierra's recommended 3.89 percent payroll and benefits reduction, Sierra had options in addition to a reduction in salary. Other options included a reduction in medical insurance, other benefits, the STIP, or further headcount reductions (Tr. at 1656, 1671). Staff testified that in the last two years, State of Nevada employees have seen reductions in health care benefits, suspension of longevity pay, frozen salary levels, and the imposition of furloughs (Tr. at 1676).

Sierra's Rebuttal Position

240. Sierra asserts that Staff's approach employs flawed metrics in order to develop a point estimate that supposedly represents Sierra's "employment cost excess" without any tolerance for errors in measurement or methodology. It is common practice in a measurement exercise to incorporate a tolerance range to account for error (Exhibit 242 at 12). Sierra asserts that Staff's comparison of Sierra's cash compensation to personal income for Nevada residents is inappropriate because personal income includes

not only wage income, but also rental income, dividends and interest income (Exhibit 242 at 13).

241. Sierra testified that Staff has ignored the relevant benchmarking data that matches each internal job to an external job of similar content within a similar industry and industry size. The practice among human resources professionals and the practice used by Sierra are to benchmark total compensation against similar positions in the appropriate labor market (Exhibit 237 at 9).

Commission Discussion and Findings

242. The issue in this case is whether the payroll costs proposed by Sierra provide reasonable and sufficient compensation to attract and retain qualified personnel at all levels.

243. Economic times are presently difficult in most areas around the country, in the region, and especially in Nevada. Nevada currently ranks number one in the United States for unemployment at 14 percent.[11] The impact of the recession on Nevada residents deserves some consideration in deciding this issue. The Commission commends Sierra for reducing its payroll and benefit costs by approximately $16 million to reflect the reduction in growth that has occurred during the recession. The annualized payroll requested for recovery in this case does not include the increase in 2010 for Sierra's MPAT and bargaining unit employees. For these reasons, the Commission will not adopt the Staff recommendation to reduce all payroll and benefit costs by another 3.89 percent.

244. Given the range of acceptable salary levels for executive personnel, coupled with the dismal economic conditions in Nevada, the Commission cannot justify

[11] Tr. at 146, Exhibit 167 at 31-32

executive salary levels that exceed the median by 4.5 percent and salaries plus STIP that exceed the median by 6.5 percent. Sierra's base salaries for executive employees are 19.5 percent higher than the low end of the acceptable range. Sierra's base salaries plus STIP are 21.5 percent higher than the low end of the acceptable range as defined by Sierra. The 9.3 percent[12] increases granted to executives in 2010 was no doubt a significant factor in raising the executive salaries (plus STIP) to 6.5 percent above the median for the peer group.

245. The evidence in this case does not provide justification for a 9.3 percent salary increase for executive personnel as proposed by Sierra. The Commission orders Sierra to reduce its annualized payroll adjustment and STIP adjustment for executive personnel by 4.5 percent. The resulting salary and STIP levels will be well within the range, as defined by Sierra, for offering competitive salaries and recruiting a talented workforce.

E. Supplemental Executive Retirement Plan ("SERP") Costs

Sierra's Position

246. Sierra requests rate recovery for its SERP benefit costs accrued for grandfathered employees and retirees as of March 31, 2008.

Staff's Position

247. Staff recommends that 35 percent of the cost of SERP costs be excluded from rate recovery, consistent with the Commission's decision in Docket No. 08-12002. SERP costs represent supplemental pension benefits paid to executive employees (Exhibit 165 at 5, 6). Staff testified that Sierra's decision to freeze participation in the SERP as of March 31, 2008, contradicts Sierra's argument that the supplemental benefits

[12] Exhibit 113, Attachment Kim Direct 2, p. 6

are required to attract and retain qualified executives (Exhibit 165 at 6). Staff testified that, based upon the reasoning and decision arrived at in Docket No. 08-12002, it recommends that the Commission disallow 35 percent of the SERP paid to executive management.

BCP's Position

248. BCP recommends that 35 percent of Sierra's SERP costs be eliminated from cost of service based upon the findings in the most recent Nevada Power general rate case order (Exhibit 167 at 28). BCP testified the Employee Retirement Income Security Act of 1974 (ERISA), the Pension Protection Act of 2006 (PPA) and the Internal Revenue Code (IRC) dictate minimum and maximum contribution limits for a defined benefit pension plan. Adherence to the contribution limits is required in order for the plan to be considered "qualified", meaning that all earnings on the fund are tax deferred (Exhibit 167 at 29).

249. BCP believes that it would be reasonable and appropriate to eliminate all costs of the SERP from retail rate development given that:

(1) Such highly paid employees are already entitled to "normal" retirement benefits pursuant to the "qualified" retirement plan offered;

(2) The plan is expensive to offer, given that it is not tax efficient like the qualified plan;

(3) The fact that NVE has discontinued the SERP for new hires reveals an indication that the plan is not necessary to retain qualified employees and;

(4) It is reasonable to question whether it is equitable to have ratepayers continue to pay for retirement benefits to a select group of already highly compensated employees at a time when the state of Nevada is experiencing in excess of 14 percent unemployment and significant budget cuts in many local and state governmental agencies (Exhibit 167 at 31, 32).

Sierra's Rebuttal Position

250. Sierra testified that in Docket No. 08-12002, the Commission allowed Nevada Power to continue to recover 65 percent of its SERP costs consistent with its prior general rate case order. The Commission denied an increase in cost recovery, primarily because the company had closed the program to new participants. Sierra argues that consistent treatment in this case would allow recovery of at least 75 percent of the SERP costs consistent with the decision in the prior general rate case for Sierra, Docket No. 07-12001 (Exhibit 237 at 16). Sierra testified that it has submitted transparent benchmarking data in its expert's testimony that support its total executive compensation levels. Since Sierra's total executive compensation levels are prudent, the SERP component of total executive compensation should be allowed for rate recovery (Exhibit 237 at 17).

251. Sierra submits that a finding in the Commission's decision in Docket No. 09-04003 for Southwest Gas Corporation is relevant:

> ....SERP and EDP are standard components of executive pay in the industry. The Commission has no specific evidence regarding impairment of the functioning or status of Southwest as a company to suggest that these costs should be disallowed. Finally, there is no evidence in the record to

indicate why, as a policy matter, SERP and EDP are inappropriate costs for ratepayers to bear.

252. Sierra testified that SERP has been a standard component of executive pay in the utility industry and should be recoverable in Sierra's rates for enrolled officers (Exhibit 237 at 17). Sierra asserts that SERP plans actually address two things: A restoration benefit makes up for the IRS contribution limits that impact higher compensated employees. And any SERP benefit above the restoration level is discretionary. Ninety-nine percent of companies have a SERP restoration benefit. SERP plans with additional benefits above the restoration benefit are being reduced (Tr. at 914, 915).

253. Sierra testified that disallowances approved by the Commission for SERP costs in prior cases have been limited to SERP benefits that exceed the restoration benefit of the plan. Sierra has up to now been allowed full recovery for the SERP restoration benefit (Tr. at 2310).

Commission Discussion and Findings

254. The SERP benefit has been a matter of contention in all of the Sierra and Nevada Power general rate cases. The disallowances ordered for Nevada Power in Docket No. 06-11022[13] and for Sierra in Docket Nos. 05-10003 and 07-12001[14] were based upon a finding by the Commission that the two company's financial condition had improved but that additional improvement was expected. The Commission's decision in Docket No. 08-12002 extended the disallowance approved in Docket No. 06-11022[15] for Nevada Power. The issue here is whether the 65/35 split should continue.

[13] Commission's Order in Docket No. 06-11022 ¶ 185
[14] Commission's Order in Docket No. 07-12001 ¶ 100 and 109
[15] Commission's Order in Docket No. 08-12002 ¶ 557

255. In recent cases, the issue of SERP was linked in part to improvement of the companies' finances. Exhibit 246 reflects that NV Energy and Sierra have an investment grade credit rating with S&P, Moody's and Fitch. A disallowance of SERP benefit costs based upon the financial condition of Sierra is not justified in this case.

256. The Commission finds the SERP restoration benefit to be a reasonable cost because it allows plan participants to receive pension benefits in relationship to salary equal to the employees of Sierra and Nevada Power, the pension plan contributions for which do not exceed the IRS maximums. Sierra's SERP benefit levels that exceed the restoration benefit are discretionary and result in special treatment for Sierra's already highly compensated employees. Southwest Gas must compete in the same labor market for attracting competent executive management personnel. The SERP offered by Southwest Gas and approved for rate recovery in Docket No. 09-04003 was limited to a restoration benefit which results in pension benefits for executive personnel in relationship to salary consistent with other employees not affected by the IRS contribution limit.

257. SERP benefit costs that exceed the restoration benefit are becoming less common in the market place. The Commission finds SERP benefit costs above the restoration benefit to be an unnecessary cost and disallows all SERP benefit costs that exceed the restoration benefit.

F. Stock Issuance Costs

Sierra's Position

258. Sierra incurred stock issuance costs related to a stock issuance in December 2007 that were amortized over three years in their financial statements. The

test year in the current docket includes one year of the three-year amortization. None of the 2007 costs were included for recovery in Sierra's last general rate case, Docket No. 07-12001. Sierra proposes to recover the 2007 stock issuance costs, included in the 2009 test year, as a recurring cost by not adjusting the amortization amount reflected in the test year.

Staff's Position

259. Staff recommends that the Commission deny recovery of the amortization of stock issuance costs related to a stock issuance in December 2007 which was allocated to both electric and gas operations (Exhibit 184 at 6). Staff testified that the issuance of common stock in December 2007 resulted in stock issuance costs that have been amortized over three years, beginning in January 2008, and will be fully amortized in November of 2010. These issuance costs were not included for rate recovery in Sierra's last rate case, Docket No. 07-12001 (Exhibit 184 at 7-8).

260. Staff testified that the Commission's Order in Docket No. 07-12001, Sierra's last general rate case,[16] limited rate recovery for stock issuance costs to those incurred during the test period (Exhibit 184 at 8). Staff testified that the Commission's decision in Docket No. 08-12002[17] changed the Commission's position on the recovery of stock issuance costs by directing Nevada Power to accrue stock issuance costs, incurred outside of a test year in a rate case, to a regulatory asset and amortize those costs over three years in a subsequent rate case (Exhibit 184 at 8). Staff testified that the Commission's Order in Docket No. 08-12002[18] denied Nevada Power's request to recover stock issuance costs incurred during the test period as a recurring cost, but rather,

[16] See Order, Docket No. 07-12001 at ¶ 167
[17] See Order; Docket No. 08-12002 at 98.
[18] See Order Docket No. 08-12002 at ¶ 409

allowed these costs to be amortized over the three-year rate effective period (Exhibit 184 at 8).

261. Staff asserts that Sierra's request that the 2007 stock issuance costs, (included in the 2009 test period) be treated as a recurring cost is inconsistent with the Commission's prior decisions on this issue and therefore recommends disallowance of the 2007 stock issuance costs reflected in the test period (Exhibit 184 at 8, 9).

262. Staff testified that as of May 31, 2010, there was an unamortized balance for the December 2007 stock issuance costs representing six months, or one-half of the annual amortization amount (Tr. at 1602). Staff testified that the test year for Sierra's electric operations includes a full year of the amortization of the December 2007 stock issuance costs in the amount of $1.1 million. Sierra has made no adjustment for this amount that will result in a $3.3 million recovery of the December 2007 costs in electric rates during the rate effective period (Tr. at 1610). Staff testified that the unamortized balance, as of May 31, 2010 for the December 2007 stock issuance costs, was approximately $739,000 for both electric and gas operations (Tr. at 1610).

Sierra's Rebuttal Position

263. Sierra testified that the stock issuance costs incurred in December 2007 were not considered in Sierra's revenue requirement in Docket No. 07-12001. Sierra states that in Docket No. 08-12002 for Nevada Power, the Commission decided that stock issuance costs issued between rate cases should be deferred in a regulatory asset and recovered in the next rate case. Paragraph 409 of that Order states: "if common stock issuance costs are incurred by Nevada Power between this proceeding and its next

general rate case, Nevada Power shall treat such costs as a regulatory asset and request recovery in Nevada Power's next general rate case" (Exhibit 238 at 7).

264. Sierra testified that in Docket No. 08-12002, Nevada Power was allowed to treat its allocated share of the same December 2007 stock issuance costs as a regulatory asset and amortize the costs over three years (Exhibit 238 at 7). Sierra testified that it began to amortize its allocable share of the costs of the December 2007 issuance immediately after the stock issuance in accordance with past practices at that time, before the Commission's Order in Docket No. 08-12002. A full year of the costs of the December 2007 issuance is therefore included in the test period for this proceeding. Leaving the costs in the test year has the same effect as amortizing the costs of the December 2007 issuance as a regulatory asset over three years commencing January 2011, the rate effective date of the order for this case. Sierra asserts that this treatment is consistent with the Commission's decision in Docket No. 08-12002 (Exhibit 238 at 8).

Commission Discussion and Findings

265. The 2009 test year for Sierra's electric operations includes approximately $1.1 million in stock issuance costs representing a full year amortization for stock issuance costs that were incurred in December 2007. There is no disagreement regarding the ratemaking treatment used in 2007. Stock issuance costs incurred between rate cases were to be set up as a regulatory asset and amortized immediately over three years.

266. Prior to the Commission's Order in Docket No. 08-12022, stock issuance costs incurred between rate cases were expected to be deferred as a regulatory asset and amortized immediately over three years. This treatment assumed that existing rates

provided rate recovery for normal costs during the three-year rate effective period and provide the utility an opportunity to earn a fair return on investment.

267. In the Commission's Order for Nevada Power in Docket No. 08-12002, the Commission allowed Nevada Power to defer stock issuance costs, incurred between rate cases, as a regulatory asset and to defer the amortization until the rate effective date in the next rate case.[19] Stock issuance costs actually incurred during the test year/certification period are also deferred as a regulatory asset and amortized over three years. This treatment results in all stock issuance costs, incurred during the test year/certification period or between rate cases, to be specifically included in a general rate case with the rate effective date as the start date for the three-year amortization.

268. Sierra has not adjusted the $1.1 million amortization of the 2007 stock issuance costs reflected in the 2009 test year that will result in recovery of $3.3 million during the rate effective period. This proposed treatment assumes that none of the prior amortizations of these costs between January 2008 and May 31, 2010 was recovered in existing rates. Rates in effect between January 2008 and May 31, 2010 were assumed to recover Sierra's normal costs and provide an opportunity to earn a fair return on investment. Stock issuance costs are normal operating costs that do not occur every year and are amortized for ratemaking purposes for that reason.

269. The Commission agrees with Staff that the $1.1 million amortization included in the test year for the 2007 stock issuance costs should be eliminated. These costs have been recovered in existing rates. Leaving the $1.1 million amortization cost in the test year at an unadjusted amount treats the test year amortization as a recurring

[19] Commission's Order in Docket No. 08-12002, ¶ 409

annual cost for the three-year rate effective period. The Commission's Order in Docket No. 08-12002 rejected this ratemaking treatment proposed by Nevada Power.

270. The intent of the Commission's decision in this case is consistent with the Commission's Order in Docket No. 08-12002. All stock issuance costs, reasonably incurred, should be recovered in rates whether they were incurred in a test year/certification period or between rate cases. Allowing Sierra to recover the $1.1 million amortization annually during the rate effective period for this case would result in reamortizing the December 2007 issuance costs.

271. Sierra has an unamortized balance for the December 2007 stock issuance costs of $738,917 as of certification date, May 31, 2010. Sierra is directed to allocate this cost between its electric and gas operations and amortize it over three years and include the May 31, 2010 balance in its rate base.

G. Independence Lake Gain on Sale

Sierra's Position

272. Sierra sold the Independence Lake property on April 29, 2010. Sierra proposes to begin the amortization of the gain on sale in May of 2010. Sierra testified that it sold the Independence Lake property for a gain of $6.651 million for the Nevada jurisdiction, as of May 31, 2010. Sierra proposes to amortize the gain over three years (Exhibit 156 at 17). Sierra asserts that the amount of the gain allocated to ratepayers was based upon the ratio of the number of years the asset was in rate base, 34 years, compared to the total number of years that Sierra has owned the property, 70 years (Exhibit 156 at 17). Sierra testified that its recommended ratemaking treatment for this gain is consistent with the treatment of the Truckee Canyon land sale in Docket No. 07-12001.

Staff's Position

273. Staff recommends that the Commission deny Sierra's request to begin the amortization of the gain from the sale of Independence Lake property in May 2010 and instead delay the amortization to the effective date of rates set in this case (Exhibit 184 at 10). Sierra recognized a gain from the sale of the Independence Lake property on April 29, 2010 and began amortizing the gain in May of 2010 (Exhibit 184 at 10).

274. Staff testified that it supports an accounting policy that begins the amortization for insignificant gains from the sale of assets in the next month following the date of the transaction. However, for significant gains, Staff recommends that the amortization be delayed until the effective date of new rates in order for ratepayers to receive the full benefit of the gain (Exhibit 184 at 10). Staff asserts that in prior cases in which a significant gain on the sale of utility assets was addressed, the Commission has delayed the amortization until the effective date for new rates in order to balance the interests of utility stakeholders (Exhibit 184 at 11).

275. Staff notes that in Docket Nos. 03-10001 and 03-10002, the Commission noted the significance of the gain from the sale of the Flamingo Corridor by Nevada Power and recognized it differently for ratemaking[20] (Exhibit 184 at 11). Staff testified that Sierra is requesting special accounting treatment for the decommissioned Kings Beach and Portola generating units, and that such treatment should also be applied to regulatory liabilities that benefit customers (Exhibit 184 at 11). Staff asserts that the amortization amount should be recalculated based upon the total beginning balance of the regulatory liability (Exhibit 184 at 11).

[20] See Order, Docket Nos. 03-10001 & 03-10002 at ¶ 258

Sierra's Rebuttal Position

276. Sierra testified that Staff's recommendation to defer amortization of the gain on the Independence Lake Land sale represents a deviation from the Commission's accepted treatment of land sale gains. Consistent with prior Commission orders, the amortization of the gain began in May of 2010, following the sale in April of 2010 (Exhibit 243 at 2-3).

277. Sierra testified that in Docket No. 03-10001, the Commission recognized the gain on sale of Flamingo Land, even though the sale occurred in December 2003, two months after the October 2003 certification period (Exhibit 243 at 3).

278. Sierra states that its proposed treatment is consistent with the Commission's treatment in Docket No. 07-12001 for the gain on the Truckee Canyon land sale. That sale occurred in April of 2007 with immediate amortization starting in May of 2007. The remaining balance, as of the end of test year date of June 30, 2008, was recognized in rate base (Exhibit 243 at 4).

Commission Discussion and Findings

279. Specific regulations do not exist for the ratemaking treatment for gains on sale of utility property. The Commission's prior decisions have been based upon the facts for that specific case.

280. Prior decisions on this issue, in Docket No. 03-10001 for Nevada Power and in Docket No. 09-12017[21] for Utilities Inc. Central Nevada, indicate the Commission's intent for ratepayers to receive the full benefit of a significant gain on the sale of utility property. Because ratepayers are responsible for paying a return on a utility's investment and a return of that investment through depreciation expense, it is fair

[21] Commission Order in Docket No. 09-12017, ¶ 142-144

for ratepayers to receive the full benefit of any significant gain on sale of utility assets. The $6.7 million gain on the sale of Independence Lake land represents a significant gain on the sale of utility property.

281. The Commission orders Sierra to reflect the full amount of the gain in rate base and that the amortization be delayed until the January 1, 2011 rate effective date.

H. Directors and Officers Insurance

Sierra's Position

282. Sierra testified that its cost for Directors and Officers ("D&O") insurance has increased from $665,000 in 2009 to $689,000 estimated as of May 31, 2010 (Exhibit 95 at 209).

Staff's Position

283. Staff recommends that the cost for D&O insurance be shared 50/50 between ratepayers and shareholders, consistent with the Commission's findings in Docket Nos. 08-12002 and 09-04003 for Nevada Power and Southwest Gas Corporation, respectively. Staff recommends that insurance expense be reduced by $300,000 and $48,000 for Sierra's electric and gas operations and that prepaid insurance in rate base be reduced by $166,619 and $26,065 for the electric and gas operations respectively (Exhibit 165 at 6).

284. Staff states that D&O insurance provides liability coverage to protect company shareholders, officers and directors against lawsuits brought against them based upon executive management actions or inactions (Exhibit 165 at 7). Staff's recommended 50 percent disallowance of D&O insurance cost is based upon the

Commission's prior findings that this liability coverage benefits both shareholders and ratepayers (Exhibit 165 at 7).

BCP's *Position*

285. BCP argues that Sierra identified a securities holder's suit filed against Sierra Pacific Resources for the failure of its board of directors to sell Nevada Power to the Southern Nevada Water Authority. While the case was dismissed, its existence provides evidence that NVE's shareholders can be expected to be the beneficiary of NVE carrying D&O insurance (Exhibit 167 at 21).

286. BCP testified that the Arkansas Public Service Commission has, in four contested cases, adopted a 50-50 sharing of D&O insurance cost based upon the same rationale that shareholders as well as ratepayers benefit from D&O insurance coverage. Further, since 1996 the CPUC has required a 50-50 sharing of D&O costs (Exhibit 167 at 22).

Sierra's Rebuttal Position

287. Sierra testified that D&O insurance is a necessary, prudent and recurring cost for an investor owned utility. D&O insurance is required to protect Sierra's assets and attract quality officers and directors (Exhibit 190 at 2).

288. Sierra provided decisions from prior dockets in which the Commission denied either a partial or full disallowance of D&O insurance costs:

- Docket No. 91-7079 - Sierra Pacific Power Company – The Commission denied an allocation of D&O insurance costs between ratepayers and shareholders.

- Docket No. 91-5055 – Nevada Power – The Commission denied Staff's proposal to disallow 100% of the cost for D&O insurance.
- Docket No. 04-3011 – Southwest Gas Corp. – The Commission denied Staff's proposal to disallow 100% of the costs for D&O insurance.
- Docket No. 04-3011 – Southwest Gas Corp. – The Commission denied Staff's proposal to disallow 100% of the costs for D&O insurance.

(Exhibit 190 at 3-4)

289. Sierra testified that BCP's assertion that D&O insurance is acquired to pay for impudent actions of the utility's officers that would never otherwise be charged to ratepayers is not correct. In many cases D&O insurance claims are not for judgments rendered against directors and officers, but for legal fees associated with defending the director or officer in actions that do not result in any liability (Exhibit 190 at 7). Sierra testified that elimination of necessary, prudently incurred and recurring operating costs from rate recovery negatively impacts its ability to earn its allowed rate of return (Exhibit 190 at 9).

Commission Discussion and Findings

290. The Commission finds that D&O insurance is a necessary and prudent cost for a regulated utility, a portion of which should be recovered in rates. D&O insurance provides protection to both ratepayers and shareholders against legal suits alleging harm as a result of the actions or inaction of NVE's board of directors. It is therefore appropriate to share the insurance cost between ratepayers and shareholders.

291. Sierra would have difficulty attracting competent directors and officers without D&O insurance. Both ratepayers and shareholders benefit from competent directors and officers. Therefore, insurance that provides protection against significant legal costs and possible judgments that could result from litigation filed against NVE's officers and board of directors is a cost that should be equally shared by shareholders and ratepayers.

I. Short Term Incentive Plan ("STIP")

Sierra's Position

292. Sierra requests rate recovery of $3.762 million (O&M) for the Electric Department and $541,000 (O&M) for the Gas Department for the STIP (Exhibit 106 at 39). Sierra states that the STIP places a portion of each employee's total compensation at risk based upon the achievement of corporate goals, company-wide performance targets and individual performance. STIP awards are determined each year and do not increase an employee's base pay. Sierra asserts that variable pay has many advantages over other forms of compensation:

- STIP does not result in a fixed increase in base pay. STIP payments must be earned every year based upon meeting the specific performance goals for the current year. If excellent performance is not sustained, variable STIP pay can be reduced or eliminated.

- Variable pay programs enable Sierra to offer a fair and attractive compensation package that is critical to attract, engage and retain talented staff. Variable pay targets compensation dollars in the right way to the right people and ensures that top performers are rewarded for their performance.

- Variable STIP provides stronger motivational potential because employees know exactly what is expected of them.

293. Sierra asserts that a wide body of research supports the view that variable pay works. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22 percent (Exhibit 106 at 33). Sierra testified that most organizations use variable pay as a significant element of their total rewards package. A 2009 study by Hewitt Associates indicates that variable pay spending as a percentage of payroll increased to 12 percent, up from 6.4 percent in 1994 (Exhibit 106 at 34).

294. Sierra's 2009 STIP plan for MPAT and bargaining unit employees included three components:

<u>(1) Corporate Financial Performance – 35 percent weight</u>

Selected metrics include cost controls, return-on-equity, cost of debt, liquidity, and financial performance of major projects,

<u>(2) Corporate Customer Perception – 35 percent weight</u>

Selected metrics utilize an external survey source to assess customer satisfaction and internal measures of customer service; and

<u>(3) Key Performance Indicators (KPI's) – 30 percent weight</u>

Selected metrics vary according to annual establishment goals in various areas, such as safety, reliability, cost to generate power, cost to deliver service and environmental and renewable energy targets

(Exhibit 106 at Tripp 7A, p. 81).

295. Sierra testified that it did not meet its customer perception goals in 2009 and the STIP payment was significantly reduced as a result. However, the reduced STIP payment of $4.3 million recognized achievements in the following areas:

<u>2009 Financial Performance Metrics</u>

- O&M Spending – Budget to Actual
- Completion of Major Capital Projects
- Reduction in Regulatory Cost of Long Term Debt

<u>Key Performance Indicator Metrics</u>

- Reliability
- Distribution Expense Per Customer
- Energy Efficiency / Environmental

(Exhibit 106 at 38)

Staff's Position

296. Staff recommends a disallowance of Sierra's STIP costs of $143,341 and $26,290 respectively, for Sierra's jurisdictional electric and gas operations. The proposed disallowance represents 35 percent of STIP costs paid to executive management consistent with the disallowance percentage approved by the Commission in Nevada Power's prior rate case, Docket No. 08-12002 (Exhibit 165 at 4, 5).

297. Staff testified that the STIP program rewards non-executive employees for achieving goals that are beneficial to both ratepayers and shareholders. It is reasonable to allow rate recovery for STIP payments made to non-executive employees (Exhibit 165 at 4). Staff states that executive management has direct control over the financial

management and strategic direction of Sierra. The Commission has previously found that STIP payments to executive employees are more aligned with shareholder interests and therefore should be excluded from rate recovery (Exhibit 165 at 4).

BCP's Position

298. BCP proposes to eliminate 35 percent of the cost of STIP for executive and officers, representing the payout for financial metrics that are closely aligned with shareholder interests (Exhibit 167 at 34).

299. BCP testifies that in Docket No. 08-12002, BCP argued for a 50/50 sharing of the STIP cost for executives and officers and still believes this approach to be reasonable. For this case BCP is recommending a 35 percent disallowance of such costs consistent with the Commission's decision in Docket No. 08-12002 (Exhibit 167 at 35).

Sierra's Rebuttal Position

300. Sierra testified that it has provided evidence in this case demonstrating that the financial metrics in the current STIP provide a benefit to customers, which justifies rate recovery for STIP payments made in recognition of achievement of the financial goals. The financial goals include:

- O&M Budget versus Actual. This metric motivates employees to manage O&M expense levels. This metric represents 10 percent of the 35 percent total for financial goals.

- Growth of O&M versus Growth of Energy Demand. This metric motivates employees to manage O&M expense levels in light of changes in the local economy. This metric represents 7 percent of the 35 percent total for financial goals.

- Actual vs. Budgeted Cost of Major Capital Projects. This metric encourages efficient investment by setting pre-determined budget limits and keeping completion dates in-line with customer needs. This metric represents 5 percent of the 35 percent total for financial goals.

- Reduction in Long Term Cost of Debt. This metric encourages Sierra to carefully manage the cost of capital that is passed through to customers in rates. This metric represents 3 percent of the 35 percent total for financial goals.

- Financial Liquidity. This metric encourages prudent financial management to ensure sufficient liquidity to meet its needs for fuel and purchase power and other operational requirements. This goal was not met in 2009. This metric represents 3 percent of the 35 percent total for financial goals.

- Earned versus Allowed Return on Equity. This metric affects the cost of capital that is passed through to customers in rates. No payout for this metric was made in 2009. This metric represents 7 percent of the 35 percent total for financial goals.

(Exhibit 237 at 14-15)

301. Sierra testified that STIP is the competitive standard for variable pay within the utility industry and the percentages paid by Sierra are competitive within the industry. Without a combination of base pay and STIP, Sierra cannot maintain

competitive compensation levels. Compensation levels that attract executive talent are a benefit to both customers and shareholders (Exhibit 237 at 15).

Commission Discussion and Findings

302. The Commission finds that the issue with respect to the STIP costs paid to executive management for financial goals is whether the identified goals further the interests of shareholders or those of ratepayers. The recommendations of both Staff and BCP are grounded in distinguishing between the two.

303. Adoption of the disallowance for 35 percent of the STIP payment, made for achievement of financial goals as recommended by Staff and BCP, requires evidence and analysis of the specific financial goals. The evidence must be sufficient to demonstrate that the achievement of the specific financial goals in 2009 resulted in a primary benefit to Sierra's shareholders.

304. The testimony of Staff and BCP on this issue fails to address the three achieved financial goals that support the STIP payment in 2009. Staff and BCP rely on the Commission's decision in Docket No. 08-12002 as support for their recommendation –in this case for disallowance of all STIP payments related to the achievement of specific financial goals, by executive management, included in the 2009 STIP. A reference to the evidence provided by the parties in Docket No. 08-12002 on this issue is not sufficient to justify a partial disallowance of the STIP cost in this case.

305. Sierra's testimony indicates that the reduced STIP payment made in 2009 for financial goals was limited to the recognition of meeting the following performance measures:

- O&M Spending – Budget to Actual

- Completion of Major Projects
- Reduction in the Regulatory Cost of Long Term Debt

306. Sierra has provided sufficient evidence in this case that achievement of these specific financial goals flow directly in to rates, for the benefit of ratepayers. The Commission finds that the evidence in this case does not support a finding that 35 percent of the STIP payments in 2009, related to financial goals for executive management, should be disallowed. The evidence does not support a finding that the achievement of the 2009 financial goals should be viewed as a primary benefit to shareholders when achieved by executive management and at the same time be viewed as primarily beneficial to ratepayers when achieved by the MPAT and bargaining unit employees. The Commission finds no basis for the disallowance as proposed by Staff and BCP.

J. Employee Relocation Expense Disallowance

Sierra's Rebuttal Position

307. Sierra testifies that it has decided not to pursue the issue of Staff's recommended disallowance for relocation costs (Tr. at 2280).

Commission Discussion and Findings

308. The Commission adopts Staff's recommended disallowance for relocation costs paid to employees representing reimbursement for a loss on the sale of their home. Sierra decided not to pursue this issue in this case and accepted the Staff's recommendation for the disallowance.

K. Tracy Issues Resolved by Stipulation

Stipulation – Agreements

309. In Paragraph 7 of the Stipulation attached hereto as Attachment 1, Sierra agreed to withdraw Schedule I-CERT-43 (Tracy Regulatory Liability) and Schedule I-CERT-44 (Tracy Outside Services). Sierra also agreed that it would not seek recovery of the outside consultant fees shown in Schedule I-CERT-44 (Exhibit 102 at 3).

310. In Paragraph 8 of the Stipulation, Sierra agreed to offset its Nevada jurisdictional rate base, as of May 31, 2010, by $4.7 million, to be amortized over a period commencing January 1, 2011, and continuing through the remaining life of the Tracy CC (Exhibit 102 at 3).

311. In Paragraph 9 of the Stipulation, the parties agreed to use the Nevada jurisdictional Tracy CC rate base as of May 31, 2010 for purposes of calculating the Tracy CC ROE incentive. Sierra agreed to reduce the Nevada jurisdictional Tracy CC rate base as of May 31, 2010 by $3.3 million prior to the application of the Tracy CC ROE incentive. Sierra also agreed that capital investments in the Tracy CC that are recorded subsequent to May 31, 2010 shall not be eligible for the ROE incentive (Exhibit 102 at 3).

312. In Paragraph 10 of the Stipulation, Sierra agreed not to defer in a regulatory asset or seek to recover in a future rate case the costs charged by Mr. Connell, Mr. Gohlke, or Mr. Wickersham in connection with litigation of the Tracy CC issues in Docket No. 10-06001 (Exhibit 102 at 4).

313. Staff presented the Stipulation on behalf of the parties and represented that it was an opportunity to bring some fairly contentious issues together and settle them in one document. The Stipulation further provides a definite and immediate revenue requirement reduction and will continue to do so for many years. The Parties to the

Stipulation found the proposed adjustments for ratemaking purposes attractive given the current economic times[22] (Tr. at 1015 to 1016).

Commission Discussion and Findings

314. The Stipulation settles several contentious issues raised by Staff, namely: (1) the Tracy CC Regulatory Liability; (2) the Tracy CC Outside Consultant Fees; (3) Staff's proposed adjustments to the Tracy CC rate base; and (4) the date to use for the Tracy CC plant balance on which to calculate the enhanced return. Settlement of these issues provided a direct savings to the Commission in hearing time, expenses, and resources and to Sierra as well in outside consultant costs.[23] Furthermore, the Stipulation provides finality to the Tracy CC construction issues which have been a long and ongoing concern since Sierra's last general rate case (Docket No. 07-12001) and Sierra's last two deferred energy cases (Docket Nos. 09-02030 and 10-03004).

315. The Commission agrees with the Parties that the Stipulation will provide a revenue requirement reduction in this case, absent the inclusion of the Tracy Regulatory Liability, and a revenue requirement reduction through the life of the Tracy CC generating plant. This revenue requirement reduction will partially offset the increased AFUDC costs that resulted from the construction delay of the Tracy CC generating plant.

316. The Commission finds that the Stipulation is a reasonable settlement and compromise of the issues, and to be in the public interest. The Commission therefore approves the Stipulation.

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[22] The Stipulation actually increased the revenue requirement in this case compared to Sierra's application because of the Tracy Regulatory Liability issue contained in I-CERT-43. However, the revenue requirement in future cases will be reduced as a result of the Stipulation.

[23] Absent the Stipulation, it is likely that the Commission would have required at least two additional days of hearing which would have necessitated travel for the following week. Sierra would have incurred additional costs for its outside consultants to testify at the hearing.

L. Tracy/Pinion Pine Amortization Expense

Sierra's Position

317. Sierra physically separated the non-operating Pinion Pine gasifier from the operating Tracy Unit Nos. 4 & 5 combined cycle. Also, portions of the coal unloading and conveying system that originally were designed to provide fuel for the gasifier were decommissioned and removed to allow construction of the Tracy CC plant. (Exhibit 98 at 17–18). The entire gasifier was not demolished as part of this effort due to the high cost estimates for removing the unit. Initial cost estimates from demolition bids indicated that it would have cost an additional $1 million to remove and remediate the unit (Exhibit 98 at 18). Sierra is requesting recovery of the separation costs because they were determined to be necessary costs to ensure plant functionality and allowed Sierra to delay the cost of decommissioning the gasifier (Exhibit 98 at 19).

Staff's Position

318. Staff found no abnormalities in its review of requests for proposals ("RFPs"), contracts, and purchases of equipment and services for the Pinion Pine separation project. Staff recommends regulatory asset treatment of these costs (Exhibit 170 at 15).

Commission Discussion and Findings

319. The Commission accepts Sierra's amortization expense given that Staff has reviewed the costs and found no abnormalities. Ratepayers benefit from this stand-alone treatment of the Pinion Pine separation costs from the full decommissioning costs by not having the full rate impact of these costs at one time. If Sierra is required to defer these costs until the full decommissioning of Pinion Pine, then Sierra will not be

compensated for the time value of money and ratepayers will experience a larger rate increase in the future.

M. Ely Energy Center ("EEC") Project Development Costs

Sierra's Position

320. Sierra requests approval to reclassify the EEC project development costs of $7,871,000 from Account No. 182.3 (Miscellaneous Deferred Debits) to Account No. 186 (Other Regulatory Assets). Sierra requests recovery of these costs over a six year amortization period (Exhibit 84).

321. Sierra performed a variety of tasks necessary to develop, permit and license a major new coal-fired generating station. The EEC was a complex project, and involved a variety of activities. Sierra had invested $68.1 million dollars in the EEC through December 31, 2009. Sierra's 20 percent share[24] is $13.6 million[25] (Ex. 101 at 8).

Staff's Position

322. In Docket No. 10-02009, the Commission determined that while the EEC was postponed indefinitely, it was not cancelled, and as such was still an ongoing project. The Commission should not consider these costs until after the project has ended; either the EEC is deemed canceled by the Commission in a future resource plan proceeding or the proposed generating facility is deemed commercial and therefore should be put into rate base (Exhibit 170 at 16). Staff notes several reservations related to the oversight, management, and handling of costs for the EEC (Exhibit 170 at 19). Staff believes more analysis of these costs is required in a future rate case (Exhibit 170 at 18).

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[24] The EEC Project is a joint project between Sierra and its sister utility, Nevada Power, which holds an 80 percent share in the Project.

[25] The EEC project development costs are $8,482,000 of the $13.6 million. The EEC water rights and farming assets are $5,137,000 of the $13.6 million. At certification, these amounts were updated to $7,871,000 for the project development costs and $5,364,000 for the water rights and farming assets.

BCP's Position

323. The time to consider recovery of the EEC development costs is either 1) when the plant is constructed and the total cost of the plant – including the noted studies and permitting efforts – is presented for rate base inclusion, or 2) when the project is officially cancelled (Exhibit 167 at 28).

Sierra's Rebuttal Position

324. The fact that Sierra prudently decided to postpone the EEC indefinitely, thereby limiting expenditures and further ratepayer exposure, should not be met with arguments that Sierra should be denied recovery of its prudently incurred development costs, especially costs that were deemed necessary to demonstrate the viability of the proposed plant (Exhibit 191 at 3). Moreover, these costs are not transferable to a future project in the Steptoe Valley. Stated differently, these costs will not become more or less useful with the passage of time, whether the EEC is ultimately cancelled or revived (Exhibit 191 at 4).

Commission Discussion and Findings

325. The Commission accepts Staff and BCP's recommendation to deny reclassification from Account No. 186 (Miscellaneous Deferred Debits) to Account No. 182.3 (Other Regulatory Assets) and a six year amortization of the EEC project development costs at this time. However, the Commission agrees with Sierra that the EEC project development costs are not transferrable to another project and therefore will not be more or less useful with the passage of time. Therefore, Sierra should be allowed to recover the EEC project development costs as soon as practicable to avoid the need to

apply carrying charges on these costs, thereby increasing the amount that ratepayers will ultimately pay for the EEC project development costs.

326. Staff has raised concerns about the EEC project development costs and believes more analysis of these costs is required in a future case. To address Staff's concerns and to allow Sierra to recover these costs as soon as practicable, Sierra shall file a separate application no later than January 31, 2011, to determine the reasonableness of the EEC project development costs and propose reclassification of these costs from a deferred debit to a regulatory asset. This would allow Staff and any other interested parties sufficient time to investigate the EEC project development costs for reasonableness and allow NV Energy to include Nevada Power's 80 percent share of the project development costs in Nevada Power's upcoming general rate case scheduled to be filed in June of 2011.

N. EEC Water Rights and Farming Assets

Sierra's Position

327. Sierra requests approval to reclassify the EEC water rights and farming assets from a deferred debit to a regulatory asset. These costs represent $5,364,000 of the $13.6 million (adjusted to $13.2 million in certification) for Sierra's 20 percent share of the EEC development costs. Sierra is not requesting carrying charges on the regulatory asset. The water rights and farming assets continue to have value to a potential future generating station project in or near the Steptoe Valley. Sierra therefore proposes to retain and maintain these assets on behalf of future customers until such time as a final determination is made related to future generating assets in this geographic area. In order to accomplish this and to avoid the potential of writing off these assets for financial

statement purposes, Sierra is requesting authority to reclassify the costs of these assets from the deferred debit account into a regulatory asset account (Exhibit 93 at 15–16).

Staff's Position

328. The Commission already denied Sierra's request to reclassify the EEC's water rights and farming assets as a regulatory asset without carrying charges in the Eighth Amendment to Sierra's 2008-2027 IRP. The Commission directed Sierra to file a future resource plan amendment to address the disposition of the EEC's water rights and farming assets (Exhibit 184 at 4). Staff suggests that Sierra file an amendment to the 2008 – 2027 IRP to address disposition of these assets as soon as practicable. If Sierra holds onto these assets for an extended period, customers could be exposed to a loss when these assets are ultimately sold (Exhibit 184 at 5).

Sierra's Rebuttal Position

329. Docket No. 10-03023 is Sierra's Eighth Amendment to its 2008-2027 IRP and as such, any decision by the Commission applies prospectively to Action Plan approvals sought in that case. A decision in this general rate case allowing Sierra to move costs already incurred into a regulatory asset account, in order to prevent a potential write off, is certainly not precluded by the IRP decision (Exhibit 191 at 13).

Commission Discussion and Findings

330. The Commission accepts Staff's recommendation and denies reclassification of these costs at this time. First, Sierra provided no written support for its claim that not reclassifying these assets could result in write-offs for financial statement purposes. Second, Sierra has not complied with Paragraph 104 of the Commission's Order in Docket Nos. 10-02009, 10-03022, and 10-03023, which states:

"104. If the Companies wish to seek a regulatory asset for these costs, they shall have to cure these deficiencies in a future resource plan amendment and should file, at a minimum, information related to the following issues:

- Evidence of the Companies' water strategy;
- The current status of all water rights and permits held by the Companies
- The implications of the January 2010 Nevada Supreme Court Decision on water permits issued by the State Engineer
- How controlling 42,000 acre feet of water in White Pine County furthers this strategy;
- Any bilateral or other contracts involving water rights or water resources with the SNWA or other entities that control or regulate water resources
- How the continued drought in southern Nevada will impact the NPC's plan to provide adequate service at just and reasonable rates; and
- A demonstration of why the creation of a regulatory asset for the costs of acquiring and maintaining these rights would further the public interest, compared to selling these assets to reduce the balances related to the planning and development of the EEC."

331. The Order on Sierra's Eighth Amendment was issued on July 28, 2010, and Sierra has had ample time to prepare an Amendment or other filing to comply with this request. Any write-offs that could occur as result of this delay are the result of Sierra's choice and not the actions of this Commission.

O. EEC Generation Studies Amortization Expense

Sierra's Position

332. Sierra requests recovery of its 20 percent share of six studies. The first study is the 2006 Integrated Gasification Combined Cycle ("IGCC") study that investigated boiler technologies that could be used at any facility and was intended to determine the feasibility of using an IGCC unit as an alternative to conventional pulverized coal steam boilers (Exhibit 98 at 23). The five EEC studies related to the early development of the EEC. These studies were used to determine the potential sites

for a future coal resource for Sierra and Nevada Power, and later, per a Commission Order (Docket No. 03-7004, Nevada Power IRP), due diligence to investigate other prospective sites, including the existing Reid Gardner site, and the two proposed independent power producer projects, White Pine Power and Toquop (Exhibit 98 at 24).

Staff's Position

333. The Ely Site Screening Study, the Ely Study Toquop, and the Reid Gardner Expansion Study are studies specific to Nevada Power. Sierra's ratepayers should not bear the burden of studies that are specific to Nevada Power, especially given that Sierra's ratepayers are being asked to pay for 100 percent of the Valmy studies that were performed (Exhibit 170 at 14). The studies were undertaken as alternative generating sites to the EEC in the case of Toquop and Reid Gardner, or were for potential natural gas sites in the case of the Ely Site Screening Study. It is Staff's position that if any of these sites were selected, it would not be reasonable for Sierra to construct 200 miles of transmission lines solely for any of these projects. Therefore these three studies were only useful to Nevada Power's ratepayers (Exhibit 170 at 14).

Sierra's Rebuttal Position

334. The Ely Site Screening Study, which was originally a Nevada Power study, was the study that determined the best place to develop a greenfield coal-fired power plant in Nevada. This study benefited Sierra's ratepayers by providing the direction to develop EEC (Exhibit 203 at 15). The studies for Toquop and the Reid Gardner expansion were alternatives to the EEC and could have benefited Sierra's customers. The recently approved ON Line could have supported transmission from these facilities (Exhibit 203 at 16).

Commission Discussion and Findings

335. The Commission agrees with Staff's recommendation that Sierra ratepayers not incur a 20 percent share of three studies that were specific to Nevada Power. These three studies and Sierra's 20 percent share of the recorded costs, as of May 31, 2010, are: (1) $46,000 for the Ely Site Screening Study; (2) $53,000 for the Ely Study Toquop; and (3) $3,000 for the Reid Gardner Expansion Study. Nevada Power will be able to request 100 percent cost recovery for these three studies when it files its general rate case in June of 2011.

P. Valmy Expansion Studies Amortization Expense

Sierra's Position

336. Sierra requests a three-year amortization of the certification-recorded costs associated with three Valmy expansion studies. Sierra is responsible for 100 percent of the $2,011,000 of these studies. The Nevada jurisdiction allocation for amortization of these costs is $626,000 per year over the three years of the rate effective period (Exhibit 84 – Schedule I-CERT-40). The first study of $1,901,000 was approved in Docket No. 04-7004. Its purpose was to investigate and later complete early development activities to pursue an expansion of the Valmy Station to accommodate future coal units, as a possible alternative to, or in addition to, the EEC (Exhibit 98 at 22). The second study of $97,000 was approved in Docket No. 07-06049 and was conducted to study whether Sierra should continue to operate the meteorological station at the Valmy Station in aid of future expansion (Exhibit 98 at 21). The third study of $13,000, the Valmy Master Plan study, was not approved in a resource plan filing, but was a study that identified the

opportunity to add additional units at the Valmy Station, prior to Sierra's 2004 IRP request (Exhibit 98 at 22).

Staff's Position

337. Staff supports amortization of the costs of the Valmy Expansion studies (Exhibit 170 at 13 and Tr. at 1510).

Commission Discussion and Findings

338. The Commission accepts Sierra's request to amortize the three Valmy generation studies over the three-year rate effective period. Two of these studies had prior Commission approval and the third study was a minor study, costing approximately $13,000, which identified the opportunity for expansion at Valmy.

Q. Valmy 2 Overhaul Production Plant Expense

Sierra's Position

339. Sierra identified the Valmy 2 overhaul project as one that would occur during the certification period. The Valmy 2 overhaul is a semi-annual outage during which the unit is taken off line to allow maintenance of the unit's major systems. This outage includes a generator rewind, major boiler tube replacements, and other smaller projects (Exhibit 98 at 12–13). The final costs for the Valmy 2 overhaul project were $5,582,854 which was less than the $7,151,500 identified in the original filing (Exhibit 99 at 2).

Staff's Position

340. Staff recommends that the Commission adjust production plant by $206,564 to account for three items that were not included in the direct testimony of Sierra. These three items and costs are: $32,839 for the Tricsector Air Heater, Pinion

Gear and Pin Rack; $77,291 for Major Fans Lube Oil System; and $96,434 for the Tower Gearbox Fan (Exhibit 181 at 9). The discussion of these three items was first included in the certification testimony of Sierra (Exhibit 181 at 9). Staff maintains that projects must be contemplated at the time of the original filing in order to be known and measurable with reasonable accuracy at the time of filing, and subsequently certified as part of the certification filing (Exhibit 181 at 10).

Sierra's Rebuttal Position

341. Sierra only includes certification capital projects greater than $100,000 in the direct testimony of witnesses due to their materiality. However the three projects for which Staff seeks an adjustment were actually shown in the workpapers supporting the capital additions on Schedule H-CERT-13 (Exhibit 203 at 8). To disallow these capital projects would indicate a new requirement that Sierra submit direct testimony on every single capital project completed prior to the end of the test year or expected to be completed during the certification period. This would be an unworkable standard given the large number of small projects that Sierra completes every year (Exhibit 203 at 9).

Commission Discussion and Findings

342. The Commission disagrees with Staff's recommendation because the recommended disallowance items were supported in the work papers (Exhibit 7 at 172). In particular, the Commission finds that Sierra complied with subsections 2 and 4 of NAC 703.2245 which require the following:

> "2. If a utility includes adjustments which will be experienced and certified pursuant to subsection 3 of NRS 704.110, such adjustments must be reported in a separate column or columns so that the recorded data, the adjustments thereto and the certification adjustments, if any, are clearly disclosed.

> [ ]
>
> 4. All adjustments to recorded data which are submitted pursuant to subsection 1, 2 or 3 must be supported by workpapers detailing the calculations, units, unit rates and any other accounting or financial data necessary to completely explain and justify the proposed adjustments."

343. Furthermore, none of the three capital projects for which Staff recommends an adjustment had a cost that exceeded the $100,000 materiality threshold used by Sierra in its direct testimony to identify certification capital projects. Sierra's materiality threshold of $100,000 is the same as the one used in Master Data Request ("MDR") 106 to identify all work orders that have closed to plant since the end of the immediately preceding test period.[26] Sierra should not be required to use a lower materiality threshold to identify certification capital projects in its pre-filed direct testimony than the $100,000 threshold used in MDR 106.

R. Valmy Wells Production Plant Expense

Sierra's Position

344. Sierra requests the inclusion of $1,052,773 (before jurisdictional allocation) of production plant in rate base for the Valmy Wells Production Project that was completed during the certification period. In its certification filing, Sierra testified that redevelopment of several wells in the Valmy well field was completed during the certification period. The project was made up of several work orders totaling $1,052,773. This project did not meet the criteria of exceeding $1 million at the time of the filing of direct testimony (Exhibit 99 at 3).

[26] Staff was the party that proposed the $100,000 threshold for the MDR 106 in its Petition to Change the Illustrative Format for the Master Document for the Request for Data in Docket No. 02-8005. Staff's original petition proposed MDR 114, which was subsequently adopted as MDR 106 in Docket No. 02-8005.

Staff's Position

345. Staff states that the Valmy Production Wells Project was not included in Sierra's original application and that Sierra's witness did not discuss it in his direct testimony. This project was first discussed Sierra's certification testimony (Exhibit 181 at 11). It is Staff's interpretation of NRS 704.110(3) that when a utility files a rate case with the Commission under NRS 704.110(3) the utility must certify that which has already been filed with the Commission in its original rate case Application, but it cannot add new projects that may have been omitted (Exhibit 181 at 11).

Sierra's Rebuttal Position

346. Sierra states that the costs for the individual wells, PW 11 and PW 14, fell well below the $1 million threshold used to determine items for which testimony would be provided. The only reason they exceeded the $1 million mark is that capital improvements for these two wells were booked into a single work order (Exhibit 203 at 10).

Commission Discussion and Findings

347. The Commission finds Sierra's witness persuasive. The reason that all of the work orders associated with the PW 11 and PW 14 Projects were not included in the Schedule H-CERT-13 work papers was the result of a query error (Tr. at 1880–1881). In these work papers, there was a single work order listed for the Valmy Production Wells, PW 11 and PW 14 for an amount of $379,350 (Exhibit 7 at 172). The actual certification cost for this work order was $270,282 (Exhibit 99 at Lescenski-Certification-1).

348. While it is likely that, absent the query error, the full costs to be certified for the Valmy Wells Production Project would have been included in the workpapers and

in the pre-filed direct testimony of Sierra, the fact is that actual costs of $782,490 which Sierra now seeks to certify were not included in either the pre-filed direct testimony of Sierra or in the workpapers supporting Schedule H-CERT-13. These costs would not have been known and measurable with reasonable accuracy at the time of filing for anyone reviewing Sierra's original filing.

349. The Commission finds that Staff's proposed Valmy Wells Production Project adjustment of $1,052,773 should be reduced by $270,282 to account for the work order that was included in the original filing. Therefore, Sierra shall reduce its Valmy Wells Production Project certification rate base by $782,490.

S. Portola Diesel Amortization Expense

Sierra's Position

350. Sierra requests a three-year amortization of certification-recorded costs associated with the decommissioning costs and net book value of the Portola Diesel units. Sierra retired these units in August 2007. In Docket No. 06-07010, the Commission approved regulatory asset treatment for the decommissioning and net book value costs of the Portola Diesel units (Exhibit 84 – Schedule I-CERT-42). Sierra testified that it could not retrofit the Portola Diesel units with appropriate emissions control equipment to meet new California air emission standards. It was further determined that the Portola area could be adequately supported by the transmission system. Therefore, in Docket No. 06-07010, Sierra requested and received approval to decommission and remediate this site (Exhibit 98 at 20).

Staff's Position

351. Staff supports amortization of the Portola Diesel regulatory asset (Exhibit 170 at 15).

Commission Discussion and Findings

352. The Commission approves the amortization of the Portola Diesel regulatory assets costs for decommissioning and net book value. The annual amortization of these costs will be $185,000 over the three-year rate effective period.

T. King's Beach Decommissioning Costs

Sierra's Position

353. Sierra requests approval of a three-year amortization period for recovery of decommissioning costs and the net book value of the "old" Kings Beach diesel units. Sierra retired the old Kings Beach units in December 2008. In Docket No. 06-07010, the Commission approved special accounting treatment to move the decommissioning and salvage costs, and the net book value to a regulatory asset account. The Nevada jurisdiction annual amortization expense is $129,000 per year for the three-year rate effective period (Exhibit 84 – Schedule I-CERT-41). In Docket Nos. 06-4010 and 07-06049, Sierra requested and received Commission approval to replace the old Kings Beach diesel engines with new engines that would meet California air emission standards. Sierra requests a three-year amortization expense for Kings Beach units in decommissioning and net book value costs (Exhibit 97 at 9).

Staff's Position

354. The accumulated depreciation reserve in the depreciation study for the old Kings Beach diesel units was insufficient to cover the cost of the plant that was removed and the difference comprises the regulatory asset that Sierra is seeking to recover (Exhibit

164 at 3). Therefore, Staff recommends that the Commission deny recovery of the Kings Beach regulatory asset. Even with Staff's amortization expense disallowance, Sierra will recover some level of expense through its depreciation rates (Exhibit 164 at 4)

Sierra's Rebuttal Position

355. Staff correctly identified that reserve balances created by the retirement of the old Kings Beach units are impacting both the regulatory asset and the depreciation study (Exhibit 200 at 2). However, the Commission should reject Staff's recommendation because it does not address the proper regulatory recovery of the Kings Beach units, both old and new. Staff's recommendation would eliminate Sierra's right to full recovery of the old units that have been removed from service, and offset this loss through future depreciation recovery as a component of the new units (Exhibit 200 at 3). The appropriate way to address Staff's concern of double recovery is to correct the reserve balances in the depreciation study and set the appropriate depreciation rates going forward to reflect only the new asset (Exhibit 200 at 4).

Commission Discussion and Findings

356. The Commission approves Sierra's accounting method as appropriate. Sierra acknowledged that the reserve balances of the old Kings Beach units are impacting both the regulatory asset and the depreciation study. To reflect proper accounting of keeping the costs associated with the old and new Kings Beach units separate from each other, Sierra shall correct the reserve balances in the depreciation study to reflect only the new Kings Beach diesel units. Therefore, Sierra shall provide with its compliance tariff filing, workpapers demonstrating that Sierra used the correct reserve balances for the Kings Beach units to calculate the compliance revenue requirement.

U. King's Beach Deferred Energy Accounting Adjustment ("DEAA") Credits

Sierra's Position

357. Sierra proposes to establish a monthly DEAA credit equal to one-twelfth of the revenue requirement associated with the new Kings Beach units (Exhibit 156 at Franklin Direct-4) once the sale of these units, and the California distribution system, is finalized. Sierra has entered into an Emergency Back-up Service Agreement ("EBSA") with California Pacific Electric Company ("CalPeco") that will allow Sierra to continue to rely upon capacity from the new Kings Beach diesel units to serve its Nevada customers in and around Lake Tahoe in an emergency. After the sale, the cost of the new Kings Beach units will be in the EBSA contract in addition to the revenue requirement from this proceeding, and Sierra's proposal would prevent potential double recovery.

358. Sierra has entered into an agreement to sell its California service area to CalPeco. The sale includes ownership of the new Kings Beach units. Because the California sale was not final as of the certification date, all costs associated with the new Kings Beach units remain in the revenue requirement. After the sale, the costs of the Kings Beach units will also be included in the purchased power account (Account No. 555) that is recovered through the base tariff energy rate ("BTER") and the DEAA. Sierra proposes to offset the monthly EBSA expense by one-twelfth of the Kings Beach revenue requirement in order to prevent a potential double-recovery of Kings Beach costs (Exhibit 156 at 26).

Staff's Position

359. Staff recommends that the Commission accept Sierra's proposal, and accordingly order Sierra to post this monthly credit to its accounts beginning with the

month after the sale closes. Staff believes this is a reasonable method to resolve the double recovery issue (Exhibit 164 at 8).

Commission Discussion and Findings

360. The Commission agrees with Staff that Sierra's proposal is a reasonable method to prevent potential double-recovery of the new Kings Beach diesel units if the sale of the California service territory to CalPeco is finalized during the rate effective period. Therefore, Sierra shall file with its tariff compliance filing a Kings Beach Revenue Requirement that utilizes the Commission approved rates. If the sale of the California service area is finalized during the rate effective period, then Sierra shall credit monthly its electric DEAA account by one-twelfth of the Kings Beach Revenue Requirement until Sierra's general rates are reset.

V. Obsolete Generation Inventory Program

Sierra's Position

361. Sierra has accumulated inventory within its generation warehouses that has become obsolete as a result of engineering changes to the plants, asset retirements, operational modifications, process of work flow changes, and standard changes. Sierra's generation team conducted a comprehensive review in 2008 and 2009 to identify all material in warehouses that may be deemed obsolete. That analysis resulted in identification of $766,000 in obsolete parts. Sierra requests a regulatory asset be used to amortize the costs of obsolete generation over a three-year period (Exhibit 97 at 4).

BCP's Position

362. BCP believes there are savings offsets with the noted obsolete inventories that have not been fully reflected within Sierra's adjusted test year cost of service

(Exhibit 167 at 23). It would be unfair to amortize the cost side of inventory optimization efforts while ignoring the savings side of the same inventory optimization efforts that have materialized in the form of ongoing inventory balances during and following the historic test year (Exhibit 167 at 25).

Sierra's Rebuttal Position

363. Sierra's request for amortization of obsolete inventory is related to generation specific materials, not T&D materials (Exhibit 203 at 11). All of the cost savings undertaken to streamline the generation inventory process are reflected in this docket. For example, items deemed to be obsolete were removed from inventory balances and placed in a separate account so as to not be included in the inventory averaging process (Exhibit 203 at 11).

Commission Discussion and Findings

364. The Commission approves regulatory asset treatment for the generation obsolete inventory program.

W. Fort Sage 345 kilovolt ("kV") Substation Addition Project ("Fort Sage Project")

Sierra's Position

365. Sierra requests recovery of $632,025 as net transmission plant investment for the Fort Sage Project. The Fort Sage 345 kV Substation Addition Project involved the construction of a 345 to 25kV substation, a 345 kV transmission tap to the Alturas Line, 10 miles of 25kV distribution and telecommunications for the new substation in support of the Fish Springs Ranch Water Importation Project ("Fish Springs Ranch"). Sierra completed this project under a modified Rule No. 9 Agreement. The substation was placed into service on June 31 (sic), 2007. The distribution line was placed into

service on January 30, 2008 (Exhibit 117 at 12). The total cost of the project was $12.4 million. Approximately, $11.7 million was collected from the Fish Springs Ranch, with $4.8 million of that amount being a non-refundable CIAC. The remaining funds were collected as a potentially refundable cash advance (Exhibit 117 at 13). Sierra requests $632,025 be recovered as net transmission plant investment (Exhibit 117 at 15).

Staff's Position

366. Staff recommends a disallowance of Rule No. 9 costs that were not recovered from Fish Springs Ranch for additional plant facilities and the customer's construction allowance (Exhibit 184 at 12). Fish Springs Ranch's accounts did not meet the load threshold for the construction allowance since the test period peak for the accounts was 1,088 kilowatts ("kW") compared to 4,320 kW that was used to calculate the original construction allowance of $458,368 (Exhibit 184 at 14). Pursuant to the modified Rule No. 9 Agreement between Sierra and Fish Springs Ranch, Sierra can recover its investment if Fish Springs Ranch significantly curtails or reduces electric service (Exhibit 184 at 14). The additional plant facilities of $173,657 were not general system improvements, but this extension of service was only to serve Fish Spring Ranch's operations. Therefore, any improvement to extend the electric facilities to Fish Springs Ranch should be included in the costs that Fish Springs Ranch paid to Sierra. Otherwise, general ratepayers would be subsidizing the extension of service to one customer, contrary to Rule No. 9 (Exhibit 184 at 15).

Sierra's Rebuttal Position

367. Sierra states that it has trued-up the construction allowance which indicates that the customer's actual loads justify a Rule No. 9 allowance of $343,379.

Sierra is in the process of invoicing the customer $114,998. Sierra recommends that it be allowed to include the $343,379 in rate base (Exhibit 194 at 9). With regards to the additional plant facilities, Sierra recommends recovery of $21,931, which was the cost of a replacement cabinet for the damaged 345 kV breaker because this damage was discovered during construction activities. Sierra accepted the equipment from the delivery company and manufacturer, but was able to negotiate a new control cabinet at cost plus tax without any delivery charges. The cost of the replacement cabinet should not be attributed to Fish Springs Ranch. Sierra agrees with Staff that the remaining $151,726 should be removed from rate base (Exhibit 194 at 9).

Commission Discussion and Findings

368. The Commission finds a reasonable basis exists for adjustments to the CIAC allowance. There are two separate provisions of Section A.23 (Service to Large Projects) in Rule 9 that provide for adjustments to the construction allowance. The first provision is a 24-month true-up to actual demand contained in A.23.a of Rule No. 9 which states:

> <u>23. Service to Large Projects</u>
> As a condition for granting a construction allowance for line extension projects with new capacity of 1 MW or more or with estimated line extension construction costs exceeding $400,000 to a single customer, the Utility shall require an agreement providing for:
>
> > a. The adjustment of any construction Allowance to reflect the level of Allowance justified by the Applicant's actual demand or the number of units that have taken service within twenty-four months of the date the Applicant accepts permanent service.

The second provision is for the Reduction of Service part of Section A.25, which states the following:

> 25. Reduction of Service or Termination Charges
> When the Utility determines that a Line Extension requested by an Applicant would subject the Utility to Abnormal or Unusual Risk due to the nature, life or scope of the Applicant's project or when the scope of the project falls within the parameters of a large project pursuant to Section 23, the Line Extension Agreement shall include a Termination or Reduction of Service provision.

369. In Sierra's Rule No. 1, Reduction of Service is defined as follows:

> Where the Customer's demand and/or kilowatt-hours fall below twenty-five percent of that specified in the Line Extension Agreement and the Utility determines that there is a reasonable likelihood that the Customer's demand and/or kilowatt-hours will remain below that level for most periods in the foreseeable future.

370. While Sierra trued-up Fish Springs Ranch's estimated costs with actual costs within the 24 month period specified in Section A.23 of Rule No. 9, Sierra's true-up does not address Section A.25 of Rule No. 9 which provides for payment for Reduction of Service, which was the subject of Staff's recommendation.

371. It should have been clear to Sierra that Staff's adjustment was related to the Reduction in Service provision in Section A.25 given that Staff's testimony included Paragraph V. 2 of the Line Extension Agreement:

> If the Applicant fails to complete the Project, terminates or, as determined by the Sierra (sic), significantly curtails or reduces electric service thereto during the depreciable life of the facilities installed pursuant to this agreement, then within (60) days of written notification by Sierra, the Applicant must pay Reduction of Service or Termination Charges in accordance with Rule 9.

(Exhibit 184 at 14)

372. Staff's recommendation of adjusting $458,368 from the transmission rate base is due to the fact that Fish Springs Ranch's load during the test period was only 1,088 kW compared to the 4,320 kW that was used to calculate the original construction allowance. This Reduction in Service is considerably less than the 25 percent threshold established in Sierra's Rule No. 1. However, it is not clear from the record whether Sierra has determined if there is a reasonable likelihood that Fish Springs Ranch's demand and/or kilowatt-hours will remain at this lower level for the foreseeable future. Therefore, for purposes of setting rates in this proceeding, the Commission accepts Staff's recommendation to adjust transmission rate base by $458,368. However, if Sierra is able to demonstrate in its next general rate case that Fish Spring's demand and/or kilowatt-hours in years subsequent to the 2009 test year is within 25 percent of the level used for the 24-month true up, then Sierra will be allowed to adjust its transmission rate base in its next general rate case accordingly.

373. The Commission finds that the additional plant facilities of $173,657 should not be included in rates given that these facilities were not general system improvements. While Sierra's rebuttal largely agreed with Staff's testimony, Sierra additionally recommends that the $21,931 cost of a replacement cabinet for the 345 kV breaker be included in rates because this cost should not be attributed to Fish Springs. The Commission does not find Sierra's recommendation persuasive because the cost of the replacement cabinet should also not be attributed to ratepayers and therefore should not be included in rates.

X. Fort Churchill to Buckeye Environmental Mitigation Project ("Fort Churchill Mitigation Project')

Sierra's Position

374. Sierra requests $1,266,908 in transmission plant rate base related to the Fort Churchill Mitigation Project. In its certification filing, Sierra testified that the permit to construct the Fort Churchill to Buckeye line, which was completed in 2005, required annual monitoring of the environmental mitigation efforts until it was determined that the environmental mitigation was effective. In May of 2010, Sierra's environmental consultant issued a report that concluded that Sierra's environmental mitigation requirements, identified as part of the transmission line vegetative permit conditions, had been satisfied. It was originally anticipated that environmental monitoring and mitigation would need to continue into 2011. The total cost of this project was $1.3 million with AFUDC. The cost of this project is included in the certification revenue requirement (Exhibit 119 at 4).

Staff's Position

375. Staff states that Sierra did not include the Fort Churchill Mitigation Project in its original Application, but it nonetheless included the costs of this project for the first time in its certification revenue requirement based on a consultant's report received in May of 2010 (Exhibit 181 at 12). Staff interprets NRS 704.110(3) as that a utility may certify that which has already been filed with the Commission in the original application, but the utility cannot add new projects that may have been omitted from the original application (Exhibit 181 at 13). Staff recommends that the Commission disallow the total costs of the Fort Churchill Mitigation project of $1,266,908 (including AFUDC) from rate base (Exhibit 181 at 13).

Sierra's Rebuttal Position

376. Sierra states that it has specifically addressed in direct testimony all major projects expected at the time the rate case was prepared: 1) which exceeded $1 million; and 2) which would to be closed to plant in service at the end of certification. Sierra did not specifically discuss in pre-filed testimony a project estimated to be less than $1 million, based on Staff's recommended threshold in Docket No. 08-12002. However, all projects included in the estimate of plant additions in Schedule I-CERT-13 are identified in the workpapers supporting Schedule H-CERT-13 contained in Volume 11 filed as part of Sierra's initial Application (Exhibit 243 at 11).

Commission Discussion and Findings

377. Despite Sierra's rebuttal testimony that the direct testimony addressed all projects expected to exceed $1 million and closed to plant at the end of the certification period, the Fort Churchill Mitigation Project was not addressed in the pre-filed direct testimony of Sierra even though this projected cost exceeded $1 million and was closed to plant before the end of the certification period. Furthermore, there is no inclusion of these specific costs in the workpapers supporting Schedule H-CERT-13 (Exhibit 7 at 164–174).

378. No discussion of this project occurred until Sierra's certification testimony was filed on August 31, 2010, wherein Sierra stated that this project was expected to continue into 2011. Given that this project was not expected to be completed in the certification period when Sierra submitted its application on June 1, 2010, it is understandable that it was not included in the original application. However, this omission did not provide Staff or other interveners any notice, prior to certification, that

Sierra intended to include these costs in the certification rate base. NAC 703.2245(2) clearly states:

> If an applicant elects to make a certification filing pursuant to subsection 3 of NRS 704.110, statement H must also include a separate schedule, which specifically identifies the adjustments to be certified by the applicant.

379. While H-CERT-13 generally identified that transmission plant would be certified, there is no specific reference to the Fort Churchill to Buckeye Environmental Mitigation Project in Sierra's original filing. Therefore, the Commission finds that an adjustment of $1,266,908 to the transmission rate base is warranted.

Y. Fernley Substation Transformer Upgrade Project ("Fernley Project")

Sierra's Position

380. Sierra requests $5,060,612 be recovered for distribution plant rate base related to the Fernley Project. The Fernley Project involved the installation of a new 120/12 kV, 28 megavolt ampere ("MVA") bank in the existing Fernley substation and a line tap to the No. 113 Line. The original scope of work for this project was to replace the No. 2 transformer with a 120x60/12kV, 28 megavolt ("MVA") unit that would have initially been fed by the 60 kV source (Exhibit 117 at 19). Once design activities commenced, additional planning input determined that the 60 kV system in the area was already near maximum capacity, and new loads would need to be sourced from the 120 kV system. The existing 60 kV structures were thus removed and the entire substation was rebuilt for 120/12 kV operation with a single transformer and availability for a future transformer as load growth dictates. The transformer was placed into service on December 12, 2008 (Exhibit 117 at 20).

381. This project was necessary because the then existing two 60 kV Fernley transformer banks had exceeded or were expected to exceed their maximum ratings. The peak load on the old Fernley No. 1 transformer exceeded its maximum rating in 2005. A distribution capacity study performed in the fall of 2005 indicated the old Fernley No. 2 transformer would exceed its maximum rating within two years. Secondary benefits of this project included freeing up the 60 kV sub-transmission system capacity in the Fernley and Fallon area, and increasing the load transfer capability among the 12.5 kV distribution feeders in the Fernley area. Load transfers on the distribution circuits are often necessary to make system repairs and perform routine maintenance (Exhibit 117 at 20:- 21).

Staff's Position

382. Staff has serious concerns about the reasonableness of the load forecast Sierra developed and used to justify the Fernley Project. The Nevada State Demographer prepared a population forecast in July 2006 that predicted a five-year average annual increase of 4.52 percent from 2005 – 2010 for Lyon County, while Sierra predicted a 17 percent annual growth rate (Exhibit 161 at 3). Sierra used annual data for 2002 – 2005 for the Fernley No. 1, Fernley No. 2, and Eagle No. 2 substation forecasts, and annual data for 2003 – 2005 for the Lonely substation forecast. Four historical data points and one independent variable (time) do not provide a sufficient number of degrees of freedom from which to draw statistically valid conclusions or ascertain a trend (Exhibit 159 at 3). Furthermore, Sierra did not perform any distribution capacity studies beyond the 2005 study to ensure that the Fernley area load growth would continue as was forecasted in 2005 (Exhibit 161 at 3).

383. During the test period, the loading level on the new 28 MVA transformer was 10.1 MVA, which equates to what would have been approximately 5.55 MVA (84 percent of nameplate rating) on the old Fernley No. 1 transformer and 4.55 MVA (73 percent of nameplate rating) on the old Fernley No. 2 transformer (Exhibit 161 at 5). Based on the actual loading data for 2009 and 2010, Staff believes that the total load for the Fernley substation could have been served with the replaced transformers. Staff does not believe it reasonable for ratepayers to pay for the total cost of a project that is over-built with many years of future capacity (Exhibit 161 at 8).

384. The current loading on the new 28 MVA transformer is approximately 10 MVA, or only 35 percent of nameplate capacity. Staff's recommended adjustment doubles the current loading of 10 MVA to 20 MVA to account for secondary benefits of increased capacity, load transferability, and reliability. Staff recommends that the remaining 8 MVA, which equates to 28.6 percent of the transformer's maximum nameplate capacity, be removed from rates. Therefore, Staff recommends that 28.6 percent of the total project cost or $1.45 million should be adjusted from rates at this time. Staff further recommends that the $1.45 million be allowed into rates when Sierra can prove that loading levels are close to or above the 20 MVA that Staff is recommending for inclusion in rates (Exhibit 161 at 8 – 9).

Sierra's Rebuttal Position

385. Reliability was one of the justifications for construction of the Fernley Project (Exhibit 194 at 3). If Sierra had upgraded the two Fernley old transformers from their 12.86 MVA aggregate rating to 20 MVA as recommended by Staff, the new Fernley transformer would be subject to loads that are 144 percent of the 20 MVA rating when

the Lonely substation is out of service (Exhibit 194 at 4). The timing of Sierra's investment in the new Fernley substation was reasonable based on the information actually known or that should have been known at the time the decision was made. For the years leading up to the development of the load forecast, electric load growth for the Fernley area averaged 16.7 percent annually and the population increase in the Fernley area was nearly twice that of Lyon County (12.4 percent compared to 6.5 percent). Furthermore, if Sierra had used a 4.5 percent electric load growth rate for its load forecast (matching the Nevada State Demographer's July 2006 average annual population growth rate for the 2005 – 2010 period), the total forecasted loading on the Fernley Substation would have exceeded its total capacity rating of 12.85 MVA by summer 2009 (Exhibit 193 at 12).

Commission Discussion and Findings

386. The Commission considered several issues in its determination whether portions of the Fernley Project are used and useful; and therefore whether an adjustment to transmission plant-in-service is necessary. First, was Sierra's 2005 load forecast for the Fernley area a statistically valid forecast and should Sierra have updated its 2005 distribution capacity study for the Fernley area? Second, even if Sierra's 2005 load forecast was not statistically valid or the distribution capacity study was not updated, would Sierra have needed to upgrade the 12.85 MVA transformer capacity at the Fernley substation or build a new smaller substation to reliably serve load in the Fernley area? Third, would an alternative size transformer or new smaller substation have been less costly than the 28 MVA Fernley Project?

387. The Commission agrees with Staff that Sierra's 2005 load forecast for the Fernley area was not a statistically valid forecast. Sierra's own witness testified that four years of data are not enough to create a valid statistical model (Tr. at 1727). The Commission also agrees with Staff that Sierra's 2005 distribution capacity study for the Fernley area should have been updated when Sierra realized the Fernley area was no longer growing by the "leaps and bounds" used for project validation in the Planning Initiation Document (Exhibit 161 at JJW-9, Page 1).

388. However, when Sierra noticed that growth was slowing down it had become more apparent that the project was needed for reliability (Tr. at 1730). This need was evident by the 2007 coincident peak load of 35.8 MVA on the Fernley, Eagle, and Lonely substations. In 2007, the total distribution substation capacity for these three substations was 54.85 MVA. Under the contingency of the loss of the 28 MVA transformer at Lonely substation, the remaining capacity would have only been 26.85 MVA or 8.95 MVA less the coincident peak load (Exhibit 193 at 9). Therefore, it was necessary for Sierra to upgrade either the Fernley or Eagle transformers to account for the 8.95 MVA shortfall in the event of the loss of the 28 MVA transformer at the Lonely substation.

389. The option that Sierra chose was the Fernley Project with a new 28 MVA transformer. The Fernley Project increased capacity by 15.15 MVA (new 28 MVA minus old 12.85 MVA) for the Fernley area, or 6.2 MVA (15.15 MVA minus 8.95 MVA) greater than the potential 8.95 MVA shortfall in the event of the loss of the 28 MVA transformer at the Lonely substation during coincident peak load.

390. An alternative to the Fernley Project mentioned in the Planning Initiation Document would have been to build a new substation in southwest Fernley (Exhibit 161 at JJW-9, at 1). Other alternatives would have been increasing capacity at the Fernley or Eagle substations. However, there is no testimony from Sierra that its choice of the Fernley Project was the least cost option or from Staff that Sierra chose an option that was more costly than the alternatives. Therefore, the Commission has nothing in the record showing that Sierra could have added 8.95 MVA of capacity at a new substation or the existing Fernley and Eagle substations for less than the $5,060,612 that it cost for the Fernley Project.

391. Based on these particular circumstances, the Commission will not make a pro rata adjustment. First, Staff's allowance for 20 MVA only accounts for an additional 7.15 MVA above the 12.85 MVA capacity of the old Fernley transformers. However, when Sierra was deciding in 2007 whether to build the Fernley Project, the Fernley area had an 8.95 MVA shortfall in the event of the loss of the 28 MVA transformer at the Lonely substation during coincident peak load. Second, if an adjustment is warranted for the Fernley Project it should be based on the difference between the cost of the Fernley Project and the cost of an alternative project that would have added at least 8.95 MVA of capacity. Given that the Commission does not have this cost information, the Commission declines to make an adjustment to the Fernley Project.

Z. Greg Street No. 3 Transformer ("Greg Street Project")

Sierra's Position

392. Sierra requests recovery of $6.3 million for the costs of the Greg Street Project by inclusion of these costs in distribution plant in service. The Greg Street

Project involved the installation of a new 120/25 kV 36/48/60 MVA transformer and three new 25 kV distribution feeders. The transformer was placed into service on July 15, 2008. Feeder Nos. 1, 2, and 3 were placed into service on July 8, 2008, October 8, 2008, and February 28, 2009. The project was driven by increased capacity requirements for the distribution system between Greg Street Substation and Spanish Spring Substation (Exhibit 117 at 18). The total cost of the project was $6.3 million (Exhibit 117 at 19).

Staff's Position

393. During Staff's onsite investigation of transmission and distribution projects, an installed future feeder breaker was observed at the Greg Street Substation (Exhibit 161 at 10). Sierra stated that the installed future breaker would remain disconnected from the distribution system until the circuit is needed for load growth. During Staff's on-site investigation, it was noticed that the transformer low-side buss on Greg Street transformers No. 1 and No. 2 contained future spaces, empty slots for future feeders to be installed, without the actual circuit breaker, foundation pad, bushing leads or getaways being present. From this observation, Staff believes that it is not standard practice for Sierra to install future feeder breakers prior to the actual need for the equipment. Staff is concerned that Sierra has installed equipment that is not currently used and useful and therefore should be removed from rates (Ex 161 at 11). Staff recommends that the Commission remove $142,027, the total costs associated with the Greg Street future feeder breaker, from rates (Exhibit 161 at 11 – 12).

Sierra's Rebuttal Position

394. Sierra does not contest Staff's concern that there is an installed breaker that is disconnected from the distribution system and not currently used and useful.

However, some of the costs included in Staff's testimony were expended on buss work, switches, and associated foundations and supporting structures that will support the Greg Street breaker when it is placed into service (Exhibit 194 at 6). Staff's testimony does not challenge the prudence of the installation of buss work, switches, foundations and other supporting equipment/structures at Greg Street No. 1 and No. 2 future feeder positions. Projects with similarly minimal supporting buss work, switches, structures and foundations installed for future feeder positions have been approved in previous rate cases, which have led Sierra to understand that Staff and the Commission recognized the need for these facilities to be installed when substations are first constructed (Exhibit 194 at 7).

395. Sierra requests that the Commission allow for the costs of these support facilities that are installed when the substation is constructed in order to support the eventual deployment of future breakers and feeders. For the Greg Street Project, the costs of these support facilities of $62,025 should have immediate rate base treatment with the remaining $80,002 representing the direct breaker costs (Exhibit 194 at 8).

Commission Discussion and Findings

396. The Commission finds Staff's recommendation reasonable. First, it appears that Sierra has an understanding that it is acceptable to have support facilities included in rates for breakers and feeders that are not currently used and useful. While the Commission acknowledges that Staff's adjustment of $142,027 to rate base will have no impact on the rates set in this proceeding, the Commission agrees with Staff that its Greg Street adjustment is intended to avoid future problems, especially considering Sierra's current understanding (Staff Post-Hearing Brief). Second, in reviewing Staff's

adjustment, it is noted that only $232 is for concrete: $31,795 is for equipment, and $110,000 is for estimated labor and overheads (Exhibit 161 at JJW-13, Page 2). There is no reason that these costs should have been incurred before there was a need for a future breaker, especially the costs for labor and overheads.

AA. Heybourne Substation Addition Project ("Heybourne Project")

Sierra's Position

397. Sierra requests recovery of $6.8 million for the costs of the Heybourne Project by inclusion of these costs in distribution plant in service. The Heybourne Project involves the construction of a new substation with a 24/32/40 MVA, 120x60/12.5 kV transformer and 4-1200 amp feeder breakers and getaways (Exhibit 117 at 41). The project provides service reliability and voltage improvements for the Carson District's large commercial load in the southern portion of Carson City and the northern portion of Douglas County which includes various casinos, shopping centers and numerous critical loads such as the state prison, nursing homes and city sewer/water treatment plants on the Overland 1270 circuit (Exhibit 117 at 42). The total cost of the project was $6.8 million (Exhibit 119 at 2).

Staff's Position

398. During Staff's onsite investigation of transmission and distribution projects an installed future feeder breaker was observed at the Heybourne Substation (Exhibit 161 at 10). Sierra stated that the installed future breaker would remain disconnected from the distribution system until the circuit is needed for load growth. During Staff's onsite investigation, it was noticed that the transformer low-side bus on Heybourne transformers Nos. 1 and 2 contained future spaces, empty slots for future

feeders to be installed, without the actual circuit breaker, foundation pad, bushing leads or getaways being present. From this observation, Staff believes that it is not standard practice for Sierra to install future feeder breakers prior to the actual need for the equipment. Staff is concerned that Sierra has installed equipment that is not currently used and useful and therefore should be removed from rates (Ex 161 at 11). Staff recommends that the Commission remove $140,792, the total costs associated with the Heybourne future feeder breaker, from rates (Exhibit 161 at 11 – 12).

Sierra's Rebuttal Position

399. Sierra did not contest Staff's concern that there is an installed breaker disconnected from the distribution system and not currently used and useful. However, some of the costs included in Staff's testimony were expended on buss work, switches, and associated foundations and supporting structures that will support the Heybourne breaker when it is placed into service (Exhibit 194 at 6). Staff's testimony does not challenge the prudence of the installation of buss work, switches, foundations and other supporting equipment/structures at Greg Street No. 1 and No. 2 future feeder positions. Projects with similarly minimal supporting buss work, switches, structures and foundations installed for future feeder positions have been approved in previous rate cases, which have led Sierra to understand that Staff and the Commission recognized the need for these facilities to be installed when substations are first constructed (Exhibit 194 at 7). Sierra requests that the Commission allow for the costs of these support facilities that are installed when the substation is constructed in order to support the eventual deployment of future breakers and feeders. For the Heybourne Project, the costs of these

support facilities of $66,305 should have immediate rate base treatment with the remaining $74,487 representing the direct breaker costs (Exhibit 194 at 8).

Commission Discussion and Findings

400. The Commission finds Staff's recommendation reasonable. First, it appears that Sierra has an understanding that it is acceptable to have support facilities included in rates for breakers and feeders that are not currently used and useful. While the Commission acknowledges that Staff's adjustment of $140,792 to rate base will have no impact on the rates set in this proceeding, the Commission agrees with Staff Counsel that its Heybourne Substation adjustment is intended to avoid future problems, especially considering Sierra's current understanding (Staff Post-Hearing Brief). Second, in reviewing Staff's adjustment, it is noted that only $2,434 is for concrete and steel: $28,358 is for equipment, and $110,000 is for estimated labor and overheads (Exhibit 161 at JJW-13, p. 2). There is no reason that these costs should have been incurred before there was a need for a future breaker, especially the costs for labor and overheads.

BB. TRIC Rule No. 9 Adjustment

Sierra's Position

401. Sierra's present agreement with TRI Center provides that neither advances nor CIACs will be imposed on TRIC tenants (Exhibit 142 at 3 and Exhibit 144 at 3). In Schedule I-27, Sierra removes the total TRIC advances of CIACs that otherwise would have been initially collected under standard Rule No. 9 treatment from the rate base calculation in this general rate case (Exhibit 142 at 4 and Exhibit 144 at 4). TRIC electric projects with a construction completion date between the last electric test period (July 1, 2007) and the certification period in this case (May 31, 2010) were removed (Exhibit 142

at 3). The TRIC gas projects with a construction completion date between the last gas certification period (November 1, 2005) and the certification period in this case (May 31, 2010) were removed (Exhibit 144 at 3).

Staff's Position

402. Staff recommends that the Commission accept Sierra's Schedule I-27 adjustment calculation methodology, but not total dollar amount of the adjustment (Exhibit 180 at 4 and 15). In addition to Sierra's filed I-CERT-27 schedule, Staff recommends that the Commission accept adjustments to Schedule I-CERT-27 to account for all TRIC electric and gas projects that had no advances or CIAC imposed on them since the inception of the agreement between Sierra and the TRIC (Exhibit 180 at 7 and 17).

Commission Discussion and Findings

403. The Commission finds Staff's recommendation to remove all TRIC distribution plant for which Sierra did not collect advances or CIAC consistent with its Rule No. 9 to be reasonable. Ratepayers should not pay for Sierra's agreement with TRIC that violates Sierra's Rule No. 9 by allowing TRIC tenants to receive line extensions without paying any Rule 9 advances or CIAC. In Docket No. 07-12001, Sierra acknowledged that the TRIC agreement deviated from Rule No. 9 and should have been submitted to the Commission for review (Exhibit 180 at Attachment GMC-3, Page 2). While the Nevada statutes allow for special contract rates, these rates are subject to the supervision and regulation of the Commission pursuant to NRS 704.050:

> **NRS 704.050. Special contract rates.**
>
> 1. Nothing in this chapter shall be construed to prevent concentration, commodity, transit and other special contract rates,

> but all such rates shall be open to all shippers of a like kind of traffic under similar circumstances and conditions, and shall be subject to the provisions of this chapter as to the printing and filing of the same.
>
> 2. All such rates shall be under the supervision and regulation of the Commission.

404. While Sierra did not file the TRIC special contract with the Commission in 2001, it should have included the impact of this special contract on the revenue requirement in its next general rate cases filed subsequent to the February 2001 date of the special contract consistent with NRS 704.066 and 704.100 that defined a "schedule" and establishes the "procedures for changing a schedule", respectively.

> **NRS 704.066 "Schedule" defined.** "Schedule" means any schedule that establishes or otherwise sets the rates for a public utility and any individual or joint rule, regulation, practice, classification or measurement that in any manner affects those rates.
>
> **NRS 704.100 Procedure for changing schedule: Approval of Commission required.**
>
> 1. Except as otherwise provided in NRS 704.075 and 704.68861 to 704.68887, inclusive, or as may otherwise be provided by the Commission pursuant to NRS 704.095 or 704.097:
>
>> (a) A public utility shall not make changes in any schedule, unless the public utility:
>>
>> (1) Files with the Commission an application to make the proposed changes and the Commission approves the proposed changes pursuant to NRS 704.110; or
>>
>> (2) Files the proposed changes with the Commission using a letter of advice in accordance with the provisions of paragraph (f).

405. Rule No. 9 is a schedule as defined in NRS 704.066. Sierra's deviation from Rule No. 9 for the TRIC contract was a change in the Rule No. 9 schedule. Therefore, pursuant to NRS 704.100(1)(a), the burden was on Sierra to notify the Commission and the parties that it had made a change to a schedule that was going to impact the rates of all other customers. However, in Sierra's 2001 electric general rate case (Docket No. 01-11030) there was no request from Sierra to approve the terms of the TRIC special contract and its rate impact on remaining customers. Likewise, in Sierra's 2005 gas general rate case (Docket No. 05-10005) there again was no request from Sierra to approve the terms of the TRIC special contract and its rate impact on remaining customers. In these two general rate cases, the burden was not on the Commission and the interveners to discover Sierra's omission, but on Sierra to disclose the terms of the contract.

406. Staff's recommendation simply adjusts current rate base to account for Sierra's past disregard of the legal requirements in NRS 704.050, 704.066, and 704.100. Therefore, the Commission finds Staff's adjustments to both the gas and electric rate bases to be warranted. For the electric utility, this adjustment is based on Sierra's response to Staff Data Request 551 that provided a revised Schedule I-CERT-27 that accounts for all TRIC electric projects that had no advances or CIAC imposed on them since the inception of the agreement between Sierra and TRIC. Likewise, for the gas utility, this adjustment was derived directly from Sierra's response to Staff Data Request 98 that provided a revised Schedule I-CERT-27 that accounts for all TRIC gas projects that had no advances or CIAC imposed on them since the inception of the agreement between Sierra and the TRIC.

CC. Gardnerville Rule No. 9 CIAC Adjustment ("Gardnerville Project")

Sierra's Position

407. Sierra requests the inclusion of $1,190,012 of distribution gross plant in rate base. Included in this total would be the cost of a line extension for the Town of Gardnerville.

Staff's Position

408. During Staff's review of MDR 106, Staff noticed two projects that had CIAC amounts that seemed disproportionate to the activity cost. Sierra's response to Staff's discovery regarding these projects provided a reasonable explanation for one project, but did not adequately explain why the Gardnerville Project had an activity cost of $183,529 listed in MDR 106 when the response seemed to indicate that Sierra's capital outlay would be zero for this project (Exhibit 180 at 8).

409. In response to additional Staff discovery regarding the reason why Sierra incurred a cost of $183,529 for the Gardnerville Project when Sierra's Rule No. 9 requires that any project with a CIAC of greater than $20,000 be trued-up after completion, Sierra responded that $163,444 should have been billed to the customer (Exhibit 180 at 9). Staff's review of the Project Audit Summary confirms that the cost of removal was $20,085 less than the estimated amount, which explains the difference between the $163,444 and $183,529 (Exhibit 180 at 9 to 10).

410. Upon discovery of the Rule No. 9 true-up issues with the Gardnerville Project, Staff propounded additional discovery requesting that Sierra double-check all projects with a CIAC amount greater than $20,000 for similar problems but had not received responses as of on September 30, 2010 (Exhibit 180 at 10). Staff recommends

that the Commission adjust distribution plant by $163,444 because Staff believes this is the correct amount that should have been billed the Town of Gardnerville after completion of the project (Exhibit 180 at 10).

Sierra's Rebuttal Position

411. In response to Staff's discovery, Sierra identified 197 individual work orders for which the CIAC amount exceeded $20,000 (Exhibit 199 at 3). Out of the 197 work orders analyzed, 46 qualified for true-up under Rule No. 9. Of those 46, 38 had been trued-up and two projects did not qualify for adjustment because the difference between the CIAC and the actual cost was less than $1,000 (Exhibit 199 at 3 to 4). Staff's testimony correctly pointed out that the Gardnerville Project should have been trued-up to collect an additional $163,444 from the customer. Five additional customers should have had true-ups that total an additional $156,628 for CIAC true-ups (Exhibit 199 at 4 to 5). Thus, Sierra agrees that $320,072 should be removed from the electric department rate base. This amount represents the sum of $163,444 for the Gardnerville Project and $156,628 for projects for the five additional customers (Exhibit 199 at 5).

Commission Discussion and Findings

412. The Commission finds that Sierra should reduce its electric department ratebase by $320,072. This amount represents the sum of $163,444 for the Gardnerville Project and $156,628 for projects for the five additional customers for which CIAC should have been paid by these customers as provided by Rule No. 9.

DD. Blackwrap Replacement Program ("Blackwrap Program") (Gas)

Sierra's Position

413. Sierra requests recovery of $18.6 million dollars it has expended in the Blackwrap Program from 2005 to May 2010. Blackwrap is a type of gas pipe coating that represents the industry's first attempt to protect bare steel pipe from rusting or corroding. The coating, which was made up of coal tar and a paper wrap similar to roofing material, was applied to steel gas pipe as it was installed. Blackwrap steel piping was installed on Sierra's gas system between 1948 and 1959. Over time, the majority of the pipe being identified for replacement in the standard Main Replacement Program was Blackwrap steel pipe, which showed significantly more leaks per mile than other coating types as shown below, Figure Barbash-Direct-1, labeled "Leaks/Mile Ratio by Pipe Type". This analysis indicated that replacement of Blackwrap pipe should be addressed outside the standard Main Replacement Program and accelerated (Exhibit 122 at 4-5). Sierra instituted the Blackwrap Program to address issues of safety and cost. In particular, the Blackwrap Program addresses the following risks:

- **Safety and reliability risks:** Sierra installed Blackwrap pipe in its systems between the years of 1948 – 1956. Blackwrap was installed prior to the establishment of minimal federal standards.

- **Maintenance costs:** Anode replacements and failed insulating fittings continue to increase as the Blackwrap pipe ages and deteriorates.

- **Installation issues:** Blackwrap pipe was installed prior to code requirements for minimum depth and backfill type.

- **High probability of leaks:** With an average age of 50 years, Blackwrap pipe is exceeding its useful life and is more susceptible to leaks as the coating disbands or fails (Exhibit 122 at 6)

414. Since 2005, Sierra has spent approximately $17.5 million to replace 16.5 miles of Blackwrap. In this proceeding, Sierra requests recovery of $18.6 million dollars it has expended in the Blackwrap Program from 2005 to May 2010.

415. Sierra estimates that it will cost approximately $6 million per year over a 10- year period for a total proposed expenditure of $60 million to replace the remaining 50 miles of Blackwrap pipe in the system. Sierra spent $4.7 million for the program from 2005 to 2007, prior to beginning the more accelerated Blackwrap Program in 2008 (Exhibit 122 at 10 to 11).

Staff's Position

416. Staff testified that it had inspected some portion of nearly all Blackwrap projects since August 2007, approximately 100 jobs in total. Staff reviewed numerous leak surveys that Sierra has performed on its Blackwrap pipe and other types of pipe. The condition of the Blackwrap pipe and associated fittings has generally been good with little corrosion observed. However, when corrosion was observed, it was severe with substantial loss of pipe wall thickness or in some cases with fittings completely corroded and leaking during replacement. Additionally, some of the pipe being removed has been (in some instances) between just a few inches to a foot below the current street or sidewalk grade.

417. Staff recommends that the Commission support Sierra's continuance of the Blackwrap Replacement Program over the 10-year period and allow Sierra to recover reasonably expended costs for this program in rates (Exhibit 175 at 4).

Commission Discussion and Findings

418. The Commission finds that Sierra may recover of $18.6 million dollars it has expended in the Blackwrap Program from 2005 to May 2010. The Commission finds that Sierra may continue the Blackwrap Program. The program addresses safety and reliability concerns.

EE. Obsolete Remote Terminal Unit Replacement Project ("RTU Project")

Sierra's Position

419. Sierra requests recovery of the certification amount of $1,061,124 for general plant additions related to the RTU Project. The RTU Project involved the installation of new RTUs, including the removal and decommissioning of existing, obsolete RTUs. The total cost of the project was $1.1 million with AFUDC. The project was initiated because a variety of RTUs in Sierra's Supervisory Control and Data Acquisition ("SCADA") network were 15 to 30 years old and no longer supported by the manufacturer and/or the RTU would not support today's technological needs. Upgrading these units reduces maintenance costs and improves the reliability and functionality of critical SCADA systems. This project will result in higher SCADA system reliability and enable control and communications to modern substation devices (Exhibit 131 at 3 to 4).

Staff's Position

420. Staff recommends that the Commission approve Sierra's expenditures associated with the obsolete RTU Project (Exhibit 180 at 14). However, Staff is concerned about a disproportionately large expenditure in the outside services category that may be attributable to high initial costs. Staff intends to confirm in the future that these expenditures for outside services were indeed related to initial costs (Exhibit 180 at 13 to 14).

Commission Discussion and Findings

421. At the onset of the RTU Project, there were higher consulting services required for the development of standards for the equipment standards in the communication protocol standards from the remote back to the master, and these consulting services were incurred at the front end of the project (Tr. at 1081). Staff recommended approval of the RTU Project costs, but testified to its intention to confirm in the future that the disproportionate outside service expenditures were indeed related to initial costs. Therefore, the Commission approves the inclusion of the RTU Project costs in Sierra's rate base for the purpose of setting rates in this case.

FF. 800 Trunked Radio Channel Expansion Project ("Radio Channel Project")

Sierra's Position

422. Sierra requests recovery of the certification amount of $1,939,806 for general plant additions related to the Radio Channel Project. The Radio Channel Project involved increasing radio channels at existing sites, developing new mountain top radio sites to provide coverage where no radio communication capability previously existed, and improving coverage in existing areas and other radio improvements. This project was a result of the lessons learned during the Waterfall Fire in Carson City in 2005 when it was evident that existing mobile radio coverage/capacity was inadequate (Exhibit 131 at 5).

Staff's Position

423. Staff conducted an investigation of Sierra's Radio Channel Project and concluded that the project was a necessary upgrade of Sierra's radio communications.

Staff recommends that the Commission approve Sierra's expenditures associated with the Radio Channel Project (Exhibit 180 at 14).

Commission Discussion and Findings

424. The Commission finds that Sierra may recover $1,939,806 associated with the Radio Channel Project. Based on the results of the investigation conducted by Staff, the Commission finds that the upgrades were necessary and the costs should be recovered in general rates.

GG. DSM Costs for Electric and Gas

Sierra's Position

425. Sierra requests recovery, through an amortization expense and enhanced rate base treatment, of Period 3 DSM costs of $26,357,000 that were accumulated in a deferred account from July 1, 2007 to May 31, 2010. The costs are related to planning and implementation of DSM programs approved by the Commission.

426. In addition to the Period 3 DSM costs, Sierra's enhanced rate base treatment also includes $5,120,000 of unamortized costs as of May 31, 2010 for Period 1 and Period 2 DSM costs. The three-year amortization expense for Period 3 and for unamortized balances from Period 1 and Period 2 is $8,131,000 per year for the three-year rate effective period (Exhibit 84, Statement I and I-CERT-16).

427. For its gas department Sierra requests recovery through an amortization expense and enhanced rate base treatment of Period 1 DSM costs of $2,129,000 that have accumulated in a deferred account from June 1, 2006 to May 31, 2010 (Exhibit 89, Statement I and I-CERT-16). These costs were incurred for five DSM programs approved by the Commission in Docket Nos. 05-10021 and 07-06049 (Exhibit 149 at 4).

Staff's Position

428. Staff addressed each of the three components of Sierra's request. The May 31, 2010 FERC Account Nos. 182.330, 182.333 and 182.334 balance total of $31,476,816.98 for the Periods 1, 2 and 3 DSM program costs have been included as an other addition to rate base (rounded to $31,477,000) in Statement I. This total was also used in determining the revenue requirement.

429. With respect to the Period 1 and Period 2 DSM program costs, Staff reviewed the amortizations specified in the prior dockets, Docket No. 05-10003 and Docket No. 07-12001, respectively, and the amounts recorded in FERC Account Nos. 182.330 and 182.333; and traced these balances to the general ledger.

430. With respect to the Period 3 DSM costs for which Sierra is seeking recovery, the Commission should accept the SPPC-E DSM program cost balances in FERC Account Nos. 182.330, 182.333 and 182.334 as certified through May 31, 2010, and the requested three year amortization schedule as shown in Schedule I-CERT-16 contained in the SPPC-E Application, Docket No. 10-06001.

431. Staff stated that this was the first time that Sierra has requested recover of costs related to its gas DSM programs since they were implemented after Docket No. 05-10021. Staff reviewed the monthly charges, traced the account balance to the general ledger FERC Account No. 182.337, examined a sample of invoices for the DSM programs and reviewed the implementation vendor contracts, as well as the current contract with the measurement and verification provider. Staff also recalculated the DSM carrying charges. Staff reviewed the labor and related overhead expense reclassification proposed in Schedule I-CERT-16 and the supporting schedules to verify

the clerical accuracy of the figures in Schedule I-CERT-16 for SPPC-G. Accept the SPPC-G DSM program cost balance in FERC Account No. 182.337 as certified through May 31, 2010 and the requested labor and related overhead expense reclassifications as shown in Schedule I-CERT-16.

432. Staff recommends that the Commission accept Sierra's electric and gas DSM costs contained in the FERC regulatory asset accounts (182.330, 182.333, and 182.334 for electric and 182.337 for gas) and the requested three-year amortizations shown in the respective I-CERT-16 schedules (Exhibit 177 at 1-2).

Commission Discussion and Findings

433. The Commission finds that Sierra may recover its incurred Period 3 DSM costs for its electric utility and Period 1 and 2 DSM costs for its gas utility over a three-year period.

434. With respect to the gas department DSM, the Commission accepts Sierra's request to amortize these programs over a three-year period. This acceptance is based on the testimony of Staff with respect to its review of the program costs and related overhead and subsequent recommendation.

HH. Cash Working Capital ("CWC")—Electric and Gas

Sierra's Position

435. CWC is a component of rate base representing the cash required to meet the utility's current operating obligations. A standard methodology for calculating CWC is to perform a detailed lead/lag study, which measures the amount of time ("expense lead") before expenses must be paid and the amount of time ("revenue lag") before

revenues are received. A lead-lag study thus provides a measurement of the cash that is used to operate the business. (Exhibit 115 at 3, and Exhibit 116 at 3).

Staff's Position

436. For Sierra's electric utility, Staff recommends that the Commission decrease CWC by $668,000 to account for Staff's corrections to Sierra's lead/lag study (Exhibit 176 at 3:18-20). For Sierra's gas utility, Staff recommends that the Commission accept Sierra's requested CWC because Staff's corrections to Sierra's lead-lag study do not have a material impact on the revenue requirement (Exhibit 176 at 5).

Sierra's Rebuttal Position

437. Sierra has no issue with Staff's lead day adjustments (Exhibit 238 at 6).

Commission Discussion and Findings

438. The Commission corrects Sierra's lead/lag study and decreases CWC by $668,000 for the electric utility. For the gas utility, the Commission finds that its corrections do not have a material impact on CWC.

II. IS-2 Penalty Revenue

Sierra's Position

439. Sierra excluded the Non-Curtailment Peak Rate ("NCPR") revenues in the determination of both revenue requirement and rates by using the pre-curtailment period (2008 irrigation season) IS-2 class hourly load shape (Exhibit 213 at 8).

Staff's Position

440. Staff recommends the Commission accept an adjustment to reduce revenue requirement by $171,000. Specifically, Staff recommends the 2009 irrigation season non-recurring NCPR revenues be deferred, with carrying charges to compensate

for the time value of money, and amortize over the expected rate effective period. The deferral methodology allows all customer classes paying the subsidy to benefit (Exhibit 162 at 1, 8-9; Exhibit 164 at 4, Attachment FCB-3; Tr. at 1281, 1287-1288, 1304). Recognizing that the NCPR was implemented subsequent to Sierra's last general rate case, Staff reduced the 2009 NCPR recorded revenue for the estimated lost revenue associated with the curtailment program (Exhibit 162 at 6-7).

441. Staff asserts that the ratepayers have not benefited from the tariff as contemplated (Exhibit 162 at 5). Staff asserts the NCPR tariff was developed to balance the legislative intent to maximize demand benefits while acknowledging IS-2 customers needed flexibility to manage their operations (Exhibit 162 at 4). The NCPR pricing revenues were to offset the IS-2 subsidy (Exhibit 162 at 7, Attachment JCA-4 at 1; Tr. at 1285). In Docket No. 07-09009, Sierra filed a report estimating the targeted $1 million in subsidy reduction had been achieved in 2009:

Benefit	Amount
NCPR Revenues	$705,000
Energy Costs	311,000
Total	$1,016,000

(Exhibit 162 at Attachment JCA-4 pp. 1, 2, 4)

Sierra's Rebuttal Position

442. Sierra asserts if the NCPR tariff had not been suspended any benefits beyond those flowing through the deferred energy process would have been reflected in this general rate case application. But the tariff was suspended therefore no additional benefits exist (Exhibit 243 at 15). Additionally, Sierra disagrees with Staff's proposed adjustment because "no excess revenue" exists to refund (Exhibit 243 at 11).

443. Sierra argues without revenue decoupling no process exists to attribute the cause for Sierra's calendar year 2009 revenue shortfall of $3 million. The shortfall indicates Sierra has paid a portion of the subsidy (Exhibit 243 at 12). Additionally, Sierra argues no process exists to ensure the IS-2 subsidy was actually paid by the other customer classes. Unless the subsidy has been collected in total no basis for a refund exists (Exhibit 243 at 14).

444. If the Commission accepts Staff's adjustment, Sierra recommends the adjustment be treated as a regulatory liability, not a revenue credit, and further suggests to compensate the ratepayer for the time value of money, the regulatory liability earns a carrying charge (Tr. at 2351-2352).

Commission Discussion and Findings

445. The central issue concerns the treatment of revenues generated by the NCPR adjustment in 2009. The Commission does not believe that the creation of a regulatory liability is appropriate in this case.

446. The calendar year 2009 revenue shortfall of $3 million is not relevant to this issue. Under the current regulatory framework used by electric utilities in Nevada, general rates are designed to collect revenues sufficient to meet a specified level of costs prospectively. The actual level of expenditures and revenues experienced by the utility may be higher or lower than those considered in the rate case. Rates are designed to provide the utility with a reasonable opportunity to earn its authorized rate of return. It is not a guarantee. The Commission does not normally adjust costs and revenues retrospectively to guarantee a return. In the case of a revenue shortfall, the utility has the

option to file a general rate case pursuant to the provisions of the Nevada Revised Statutes.

447. In this particular case, Staff has argued that the Commission should create a regulatory liability that would essentially credit ratepayers for the value of the NCPR adjustment in 2009. As is the case for regulatory assets as well as regulatory liabilities, the Commission finds that these accounting mechanisms are only appropriate under *extraordinary* circumstances and should not be a normal part of regulatory practice for electric utilities in Nevada. No such demonstration has been made. Therefore the Commission denies Staff's adjustment.

448. The Commission states again that regulatory assets and liabilities are created to address extraordinary circumstances. This requires that any party seeking such accounting treatment must make such a showing.

VIII. COST OF SERVICE AND RATE DESIGN

A. Undergrounding Costs Related to the Phase II Tracy to Silver Lake Transmission Project

449. Sierra requests authority to recover $24,940,209 of costs related to the Phase II Tracy to Silver Lake Transmission Line Project. Sierra originally proposed the Project be built in order to increase the electric capacity to the Spanish Springs and Stead areas and to reinforce reliability to those areas (Exhibit 117 at 8-9).

450. Phase II of the Project involves the costs to construct 17.6 miles of transmission lines and related facilities from the Sugarloaf to Silver Lake Substations. Of the 17.6 miles, 7.6 miles involved the placement of transmission facilities underground. It is estimated that the total cost to underground the 7.6 miles was $14,781,245, for a net cost increase (or "incremental cost") of $11,112,741 above the $3,668,504 had these

facilities been constructed overhead (Exhibits 195 and 196). The line was placed into service on August 19, 2009 (Exhibit 117 at 8).

451. The route that had been selected as the "Preferred Route", but also referred to in the record as the "Red Rock" route, was selected as part of the Environmental Impact Statement ("EIS") permitting process. The process also identified and studied two alternative routes including the route that was ultimately constructed or the "Alternative Route." (Tr. at 955-956).

452. The Preferred Route was designed for overhead transmission lines and would have cost less than the alternative routes. Washoe County, however, required that utility facilities constructed along the Preferred Route be placed underground. While the Preferred Route was appropriate for an overhead facility, Sierra asserts that undergrounding the Preferred Route would have been significantly more expensive than the alternative routes (Tr. 956-957). The Preferred Route was not well-suited for an underground transmission line due to the rocky and steep terrain and lengthy traffic disruptions with the loss of one lane of a two-lane road that would be required during the construction process, severely limiting ingress and egress for property owners in the area for a six-month period (Exhibit 197; Tr. at 956).

453. Sierra selected and constructed the Alternative Route, which ran through the Stead Area. For the Alternative Route eventually chosen and permitted, Washoe County also required two segments of the line to be undergrounded, both near airports. The first segment was a 1.5 mile segment near the Spanish Springs Airport (Exhibit 195; Tr. at 947, 950). While the Federal Aviation Administration ("FAA"), a federal agency, did not directly mandate undergrounding, it did restrict the aboveground facility height to

50 feet, which effectively mandated a 0.25 mile transmission line segment north of the Airport be installed underground (Exhibit 195; Exhibit 196; Tr. at 948-950, 991-992, 1749, 1792). The balance of the underground segment of 1.25 was located relatively near residential neighborhoods (Exhibit 196).

454. The second segment was a 6.1 mile segment near the Stead Airport (Tr. at 950-957, 1741, and Exhibit 195). A total of 3.5 miles runs along the western edge of the Airport and 2.6 miles north of the Airport were placed underground (Exhibit 195; Exhibit 196; Tr. 954, 957). Under normal airport operations, the FAA would not require undergrounding of these facilities (Tr. at 956-957, 973). However, the FAA indicated it would not issue a permit for the Reno Air Races, if the 3.5 miles segment on the western edge of the Airport was not installed underground, because the facilities would be located too near the air race flight path. The FAA took no issue with the facilities on the north side of the Airport, as these facilities were located outside of the air race pylons (Exhibit 195; Tr. at 956-957, 992-993, 1752, 1755).

Staff's Position

455. Staff recommends the Commission not require Washoe County ratepayers to pay a surcharge for the incremental costs related to the Phase II Tracy to Silver Lake Project. Staff believes there is no clear evidence of what caused Sierra to underground portions of the transmission line (Exhibit 224 at 6-7; Tr. at 2192-2193). In contrast to the facts and circumstances of Sierra's 2007 general rate case (Docket No. 07-12001), it is not clear that Washoe County caused a section of the transmission line to be located underground for purely aesthetic reasons (Exhibit 226 at 6-7; Tr. at 2174-2175, 2177-

2178).

456. Staff testifies that in the instant proceeding it is difficult to discern if the complete undergrounding costs were driven by Washoe County's requirements or by airport safety concerns and the ability to obtain FAA permits for the Reno Air Races (Exhibit 224 at 4-6: Tr. at 2190-2191). Staff does not oppose general rate making treatment for undergrounding costs incurred due to safety concerns (Tr. at 2214).

457. Staff noted that when Washoe County staff recommended approval of the Alternate Route, it stated the following:

> "[the] intent of the SUP is met and exceeded by the undergrounding of the line running along the Airport Authority. The existing neighborhoods will have no impact as a result of this construction. Again, staff finds the changes in substantial conformance with the issuance of the SUP as long as the easements obtained include a revegetation component guaranteeing revegetation of the disturbance in the easement area." (Emphasis added.) (Exhibit 224 at Attachment ML-3, p.3.)

Further, Staff noted that the Alternate Route, while requiring more undergrounding, cost an estimated $3 million less than the Preferred Route along Red Rock Road would have cost if undergrounded and avoided closures of Red Rock Road and associated traffic disruptions (Exhibit 224 at Attachment ML-3, p.3). Washoe County's Preferred Route required undergrounding near the Spanish Springs Airport. (Exhibit 226 at Attachment ML-6, pp. 39-41.)

458. If the Commission directly assigns the incremental costs of undergrounding to Washoe County ratepayers, Staff recommends the amount be the difference between the overhead construction costs of the Preferred Route and the lesser of the undergrounding costs of the Preferred Route or the undergrounding costs of the

Alternate Route (Tr. at 2213, 2215-2216). Further, Staff would recommend only charging those ratepayers within sight of the utility facilities; however, it seems that Sierra's billing system is limited to local government areas (Tr. at 2218-2119).

Sierra's Rebuttal Position

459. If the Commission determines that Washoe County ratepayers should be directly assigned a portion of the incremental costs for undergrounding the Phase II Project, Sierra recommends use of the surcharge mechanism proposed by Staff, as modified by Sierra for the Carson City undergrounding issues in this docket. The surcharge mechanism is identical to that established for the Phase I Tracy to Silver Lake Transmission Project (Tr. at 2352). While Sierra's billing system can differentiate between incorporated and unincorporated Washoe County, Sierra is unsure if the benefits derived from this undergrounding differ significantly from those associated with the Phase I Tracy to Silver Lake Transmission Line Project (Tr. at 2352-2353).

Commission Discussion and Findings

460. The Commission recognizes that transmission, generation and distribution facilities are necessary to provide adequate and reliable electric service. At the end of the certification period in this proceeding, Sierra reported a rate base of $1.6 billion, of which approximately $636 (40 percent) million was related to generation facilities, $315 million (20 percent) to transmission facilities, and $646 million (40 percent) to distribution facilities (Exhibit 89 at Schedule I-2 at 1). These facilities collectively serve approximately 400,000 electric customers and provide electric service in portions of Washoe, Pershing, Humboldt, Lander, Elko, Mineral, Churchill, Nye, Esmeralda, Douglas, Storey, and Lyon Counties, Nevada. These facilities are integrated to operate as

a single system throughout Sierra's system. The flow of electrons into and out of Sierra's system must be balanced, and that same system must respond to increases or decreases in demand in real time. Otherwise, reliability is compromised. This is why the costs of generation, transmission and distribution facilities are generally allocated among all ratepayers throughout Sierra's system. A transmission upgrade in Washoe County may benefit the entire system, and benefit ratepayers as far away as Elko or Mineral Counties, due to the nature and physics of electricity. Sierra generally must plan for the operation of its entire system, not for particular jurisdictions within its service territory.

461. Complications arise when a single electric system is superimposed over numerous local governmental authorities. While all ratepayers demand and expect reliable and safe electric service that is provided by the entire Sierra system, local authorities have authority to control the siting and permitting of facilities within their respective jurisdictions. A balance must be struck between the concerns and responsibilities of local authorities to site facilities in a way to further the interests of its citizens with the interests of all the ratepayers throughout the system. In most cases the utility and the local authorities work together to craft solutions to these challenges that strike a fair and reasonable balance between local interests and system-wide interests.

462. Once a decision to underground utility facilities is made, though, a question arises as to how these significant additional costs should be allocated among all of a utility's ratepayers. For instance, should ratepayers in Elko County, for instance, be expected to build and pay for underground utility facilities in another area of the State, when those costs are, as indicated in this instance, four times the cost to build a reliable, overhead utility facilities? What are the consequences to the system and all its ratepayers

if such requirements were to become commonplace?

463. Pursuant to NRS 704.020, the Commission may supervise, regulate and control all public utilities, subject to the provision of NRS Chapter 704 and to the exclusion of the jurisdiction, regulation and control of such utilities by any municipality, town or village, unless otherwise provided by law. While NRS Chapters 278 and 704A allow local governing boards to direct the placement of utility infrastructure, including poles and wires, the Commission has plenary authority over rate making for public utilities in the State of Nevada. The Commission recognizes that Washoe County has authority over land use planning for its jurisdiction. However, the Commission's rate-setting authority extends throughout the State so that when establishing just and reasonable rates, the Commission must consider all ratepayers, not just those in a particular geographic area.

464. Pursuant to NRS 704.001, the Commission has the responsibility to provide for the safe, economic, efficient, prudent and reliable operation and service of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing ratepayers with just and reasonable rates. Further, pursuant to NRS 704.040, all charges of a public utility must be just and reasonable. Every unjust and unreasonable charge for service of a public utility is unlawful. Pursuant to NRS 704.120, after hearing the Commission has the power to order rates to ensure they are just and reasonable.

465. The Commission does not question Washoe County's rationale for requiring the undergrounding of the utility facilities. However, a local governing body does not have the authority to dictate to the Commission how the incremental costs

associated with that decision shall be allocated amongst Sierra's ratepayers.

466. The Commission finds that it should adhere to the long-standing regulatory principle that cost causers pay the costs they impose upon the utility system. The Commission has adopted the marginal cost approach in the establishment of electric rates in NAC 704.655-704.665, inclusive. The Commission has always broken down general rates into class-based rates based on the cost-causing characteristics of the various rate classes, and that principle extends all the way to ratepayer-specific facilities charges. The allocation of costs is a routine aspect of ratemaking that the Commission applies to the particular set of facts presented to the Commission in all general rate proceedings.

467. The Commission could assign at least some of the incremental costs (those associated with the undergrounding of 1.25 miles of utility facilities in the vicinity of the Spanish Springs Airport) to those ratepayers located nearby, because they are receiving the most direct benefits from the utility facilities being placed underground. However, assigning those costs to so few ratepayers would result in unjust and unreasonable rates because it would unfairly burden a small group of ratepayers.

468. The Commission could assign the incremental costs to all of the ratepayers located in all of Sierra's service territory, because this approach would lessen the rate impact. However, it results in unjust and unreasonable rates, because it ignores the "cost causers pay" principle. Further, the benefits of undergounding the utility facilities do not accrue on a system-wide basis, but rather are localized to the ratepayers located near the utility facilities.

469. The Commission finds that assigning the incremental costs of

undergrounding the utility facilities to the ratepayers in Washoe County is the Commission's fairest and most equitable method in which to set just and reasonable rates for all of Sierra's ratepayers. Washoe County is the local governing body that made the decision resulting in increased incremental costs associated with undergrounding the utility facilities. Therefore, those ratepayers who are represented by the local governing body should pay for those costs.

470. In this proceeding Sierra seeks recovery of $24,940,209 related to Phase II of the Tracy to Silver Lake Transmission Line Project. The threshold issue is to determine the incremental costs to construct the Project that were incurred as a result of the decisions made by Washoe County regarding the special use permit for the Project. The record demonstrates that Washoe County's actions resulted in two categories of incremental costs.

471. The first category involves the 6.1 mile segment near the western boundary of the Stead Airport. The record indicates that but for the requirements of Washoe County, the Preferred Plan involved construction of overhead utility facilities along Red Rock Road, which was the lowest cost Plan. The record indicates, but for the requirement of Washoe County to underground the utility facilities along this route, the Preferred Plan would have been executed. It was only after Washoe County imposed the requirement to underground the utility facilities along this route that Sierra opted for the Alternative Plan and corresponding alternative route. Therefore, the Commission finds that Washoe County ratepayers should be responsible for the incremental costs between the Preferred and Alternative Plans because of the decision by Washoe County to require undergrounding along the route of the Preferred Plan.

472. The second category concerns the allocation of the incremental costs to underground utility facilities along the 1.5 mile segment located north of the Spanish Springs Airport. The record indicates that regardless of whether the Red Rock or alternative routes were selected the transmission line would have to pass in the vicinity of the Spanish Springs Airport, and pursuant to the FAA requirement, 0.25 miles would have been undergrounded. The incremental costs associated with the decision to construct the Alternative as opposed to the Preferred Plans are zero. Therefore, the Commission finds that the costs associated with undergrounding the 0.25 miles of transmission line required by the FAA will be included as part of general rates for all of Sierra's ratepayers.

473. The remaining 1.25 miles that were undergrounded near the Spanish Springs Airport resulted from Washoe County's decision to underground the utility facilities located relatively near residential areas. Therefore, the Commission finds that the incremental costs of undergrounding the additional 1.25 miles of transmission line shall be allocated to Washoe County ratepayers as well. It is unclear from the record whether the estimated costs to construct the Preferred Plan included these costs and how they were reflected. Nevertheless, the costs associated with undergrounding the 1.25 miles of utility facilities shall be allocated to Washoe County ratepayers. Sierra is directed to make this determination in a compliance filing with the Commission as described below.

474. Until the funds have been collected from ratepayers in Washoe County, Sierra has effectively loaned funds to Washoe County. Therefore, the Commission finds that Sierra is entitled to recover all of the corresponding financing costs (carrying

charges) associated with the incremental costs, since the installation of the utility facilities.

475. Sierra shall file with the Commission as part of its compliance filing to implement rates authorized in this order the total costs that will be allocated to Washoe County ratepayers based on the following methodology:

- The actual cost to construct Phase II of the Tracy to Silver Lake Transmission Line Project less the estimated cost to construct the Project under the Preferred Plan = Gross Incremental Cost.
- To the extent not included above, incremental cost to underground the 1.25 miles of utility facilities near the Spanish Springs Airport.
- The carrying charges on the incremental costs.
- The determination of the levelized rate per kilowatt-hour.

476. In order to recover these costs, the Commission finds that the costs should be recovered through the separate line item surcharge on the bills of ratepayers in Washoe County that already contains the following phrasing: "Washoe Co. Underground Surcharge." The Commission believes that bills should be informative, providing a breakdown of the monthly costs for ratepayers in their monthly bills whenever possible. Similarly, separate line items already appear for the Temporary Renewable Energy Development Program, Universal Energy Charge, and franchise fees.[27]

477. The Commission agrees with Sierra that the surcharge should be a levelized per kWh rate. The utility facilities were installed to meet ratepayers' increased

[27] These appear as "Temp. Green Power Financing (TRED)", "Universal Energy Charge", and the "Public Utility Business License Fee" on ratepayers' monthly bills.

electricity demands on the system. The levelized per kilowatt-hour rate recovers the incremental costs from the ratepayers in Washoe County based upon their individual usage and the associated impact on the system as a result of that usage.

478. The Commission agrees with Sierra that the incremental costs should be amortized over a period of three years, or until the incremental costs are paid. A three-year period matches the three-year general rate case cycle for Sierra. (NRS 703.110(3)(a)). Further, it minimizes intergenerational subsidies by ending ratepayer payments for those incremental costs expeditiously. Finally, it reduces the ultimate costs for which Sierra's ratepayers in Washoe County will be responsible by limiting the amount of total carrying charges.

B. Undergrounding Costs Related to the Carson City Fairview 900 Amp Distribution Feeder Facilities

Sierra's Position

479. Sierra requests recovery of costs related to the Fairview 900 Amp Distribution Feeder Facilities, located in Carson City. The project consisted of 6,015 circuit feet of overhead and 4,030 feet of underground utility facilities, with a total cost of $1,706,583. The undergrounded utility facilities cost was $1,445,571, of which $961,624 was related to the incremental undergrounding costs (Exhibit 117 at 31, 33). Sierra would not have underground the utility facilities for safety reasons (Tr. at 974-975).

480. Sierra intended to commence construction in September 2008. Sierra noted the following time line associated with this project:

- As of July 2008, Sierra had secured an engineer's permit (Building Permit No. 08-583) from Carson City to construct the Fairview 900 Amp Distribution Feeder Facilities overhead.

- On November 6, 2008, in response to property owner objections based upon aesthetics that commenced about September 2008, Carson City Board of Supervisors requested that Sierra suspend the project and investigate the possibility of using the highway corridor as an alternative route.
- Sierra agreed to suspend construction and to discuss with NDOT the possibility of using the freeway corridor. Following discussion with NDOT, Sierra determined the alternative route was inappropriate based upon safety and reliability issues (Tr. at 995).
- On January 14, 2009, the Carson City engineer issued a letter revoking the permit allowing overhead construction. (Exhibit 117 at 32.)

481. Sierra asserted that it informed Carson City several times, with one occurring at the January 15, 2009 Carson City Board of Supervisors meeting, that Carson City residents could potentially be held responsible for the incremental costs incurred for undergrounding the facility (Exhibit 117 at 32-33; Tr. at 997). Further, Sierra noted Carson City was placed on notice of this possibility because the Commission had rendered its decision in Sierra's 2007 general rate change proceeding (Docket No. 07-12001) to directly charge Washoe County residents for incremental undergrounding costs prior to any special use permit discussions with Carson City (Tr. at 996-997).

Staff's Position

482. Staff recommends the ratepayers residing in Carson City pay for the incremental costs associated with undergrounding the Fairview 900 Amp Distribution Feeder Facilities over a three year period, or until costs have been collected, via a

surcharge. Further, Staff recommends the surcharge appear as a separate line item on the customer's bill with the following phrasing "Carson City Undergrounding Surcharge" (Exhibit 224 at 10).

483. Staff asserts the undergrounding was clearly incurred for aesthetics and provides no benefits to customers residing outside Carson City (Exhibit 224 at 9). Further, Staff asserts that the residents' school safety concerns are spurious because larger 120 kV facilities further south on Saliman Road, which have not been considered unsafe, are located on the same side of the street as both Fremont Elementary School and Carson City High School (Exhibit 224 at 9).

484. Staff recommends the total surcharge amount be that for the entire incremental cost not the depreciated value, with the kilowatt-hour charge being a levelized per kilowatt-hour rate (Exhibit 181 at 5). Staff further recommends the carrying charge on the balance not commence until the rate effective date of January 1, 2011 (Exhibit 181 at 6). Staff's rationale for deferring the carrying charges is that the project will not specifically be included into rates until the rates that are the subject of this proceeding are in effect (Exhibit 181 at 6).

Sierra's Rebuttal Position

485. Sierra argues the carrying charge should commence accruing from the date the plant was placed into service (Exhibit 243 at 5). Sierra argues Staff's proposal requires Sierra not Carson City to bear the financing costs from the date the facilities were placed into service, November 2009 through December 2010. Staff's proposal for treatment associated with a non-standard installation should be consistent. (Exhibit 243 at 6). Sierra asserts its proposal assigns all costs associated with this CIAC to the

customer. Effectively, until the funds have been collected from Carson City, Sierra has loaned the funds to Carson City and is entitled to recover financing costs (Tr. at 2349).

Commission Discussion and Findings

486. Pursuant to NRS 704.020, the Commission may supervise, regulate and control all public utilities, subject to the provision of NRS Chapter 704 and to the exclusion of the jurisdiction, regulation and control of such utilities by any municipality, town or village, unless otherwise provided by law. While NRS Chapters 278 and 704A allow local governing boards to direct the placement of utility infrastructure, including poles and wires, the Commission has plenary authority over rate making for public utilities in the State of Nevada.

487. Pursuant to NRS 704.001, the Commission has the responsibility to provide for the safe, economic, efficient, prudent and reliable operation and service of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates. Further, pursuant to NRS 704.040, all charges of a public utility must be just and reasonable. Every unjust and unreasonable charge for service of a public utility is unlawful. Pursuant to NRS 704.120, after hearing the Commission has the power to order rates to ensure they are just and reasonable.

488. The Commission recognizes that Carson City made a decision to order Sierra to underground the Fairview 900 Amp Distribution Feeder Facilities as a condition of its permit. The Commission also recognizes that Carson City has authority over land use planning for its jurisdiction. However, the Commission's rate-setting authority extends throughout the State so that when establishing just and reasonable rates, the

Commission must consider all ratepayers, not just those in a particular geographic area.

489. The Commission does not question Carson City's rationale for requiring the undergrounding of the Fairview 900 Amp Distribution Feeder Facilities. However, a local governing body does not have the authority to dictate to the Commission how the incremental costs associated with that decision shall be allocated amongst Sierra's ratepayers.

490. The Commission finds that it should adhere to the long-standing regulatory principle that cost causers pay the costs they impose upon the utility system. The Commission has adopted the marginal cost approach in the establishment of electric rates in NAC 704.655-704.665, inclusive. The Commission has always broken down general rates into class-based rates based on the cost-causing characteristics of the various rate classes, and that principle extends all the way to customer-specific facilities charges. The allocation of costs is a routine aspect of ratemaking that the Commission applies to the particular set of facts presented to the Commission in all general rate proceedings.

491. The Commission could assign the costs to those ratepayers located near the line, because they are receiving the most direct benefits from the utility facilities being placed underground. However, assigning those costs to so few ratepayers would result in unjust and unreasonable rates because it would unfairly burden a small group of ratepayers.

492. The Commission could assign the costs to all of the ratepayers located in all of Sierra's service territory, because this approach would lessen the rate impact. However, it results in unjust and unreasonable rates, because it ignores the "cost causers

pay" principle. Further, the benefits of undergrounding the utility facilities do not accrue on a system-wide basis, but rather are localized to the ratepayers located near the utility facilities.

493. The Commission finds that assigning the incremental costs of undergrounding the utility facilities to the ratepayers in Carson City is the Commission's fairest and most equitable method in which to set just and reasonable rates for all of Sierra's ratepayers. Carson City is the local governing body that made the decision resulting in increased incremental costs associated with undergrounding the utility facilities. Therefore, those ratepayers who are represented by the local governing body should pay for those costs.

494. The Commission finds that the total incremental costs for undergrounding the utility facilities are $961,624 plus the carrying charges that have accrued since installation of the utility facilities. The Commission agrees with Sierra that it has effectively loaned these monies to the ratepayers of Carson City to fund the incremental costs for undergrounding the utility facilities. Therefore, Sierra is entitled to recover these financing costs.

495. In order to recover these costs, the Commission agrees with Staff that the costs should be recovered through a separate line item surcharge on the bills of ratepayers in Carson City with the following phrasing: "Carson City Undergrounding Surcharge." The Commission believes that bills should be informative, providing a breakdown of the monthly costs for ratepayers in their monthly bills whenever possible. Similarly, separate line items already appear for the Temporary Renewable Energy Development Program,

Universal Energy Charge, and franchise fees.[28]

496. The Commission agrees with Staff that the surcharge should be a levelized per kilowatt-hour rate. The utility facilities were installed to meet ratepayers' increased electricity demands on the system. The levelized per kilowatt-hour rate recovers the incremental costs from the ratepayers in Carson City based upon their individual usage and the associated impact on the system as a result of that usage.

497. The Commission agrees with Staff that the incremental costs should be amortized over a period of three years, or until the incremental costs are paid. A three-year period matches the three-year general rate case cycle for Sierra (NRS 703.110(3)(a)). Further, it minimizes intergenerational subsidies by ending ratepayer payments for those incremental costs expeditiously. Finally, it reduces the ultimate costs for which Sierra's ratepayers in Carson City will be responsible by limiting the amount of total carrying charges.

498. Over the past several years, the Commission has encountered several instances in which Sierra has expended additional monies for the construction of utility facilities as a result of directives from local governing bodies through local ordinances and/or the permitting process during land use planning activities. In order to provide the Commission with accurate information concerning these incremental costs and the proper allocation of these incremental costs to the appropriate cost causers, Sierra shall identify any such incremental costs and explain the reasons for incurring the incremental costs in its next general rate change filing.

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[28] These appear as "Temp. Green Power Financing (TRED)", "Universal Energy Charge", and the "Public Utility Business License Fee" on ratepayers' monthly bills.

C. Marginal Generation Costs

Sierra's Position

499. Currently, Sierra has a high excess reserve capacity caused by the recession[29] (Exhibit 213 at 6; Exhibit 215 at 6). To deal with methodological problems stemming from the excess reserve capacity, Sierra proposes to modify the marginal generation cost[30] customer class allocation methodology from past practice (using the average loss of load probability ("LOLP")[31] for the three year rate effective period) to a four-year future period, i.e. 2015 through 2018.[32] Sierra contends that its proposed modification would improve cost allocation stability and better reflect the long-run marginal costs. (Exhibit 213 at 5-6).

500. Sierra asserts its new methodology better reflects the Commission's long-run marginal costing policy by sending a price signal more reflective of future costs, thus deterring customers from making investment decisions in the near future that they will later regret (Tr. 2139-2140).

Staff's Position

501. Staff takes a similar approach (Tr. at 2242-2243, 2245-2246), but has a different opinion about the appropriate period that should be used in determining the LOLP allocator for marginal generation demand costs (Tr. at 2245-2246). Staff asserts the period 2011 to 2018 provides a reasonable and a wide distribution of hourly LOLPs

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[29] Sierra also cited its 8th amendment to its 2007 IRP wherein the next generation addition expected to occur in 2022 (Exhibit 215 at 6).

[30] The long-run marginal cost of generation demand is the cost adding pure generation capacity to the system to meet an increase in one kW of demand or the cost to remove pure generation capacity for the decrease of one kW demand, with no change in energy requirements. The least cost unit is a combustion turbine (Exhibit 215 at 27).

[31] Loss of load probabilities distributes hourly generation demand costs to each customer class based upon the class contribution to the load for that hour (Exhibit 215 at 14).

[32] Sierra used its 2010 IRP calculated LOLPs (Exhibit 214 at 3-4; Exhibit 216 at 5-6).

across a year (Exhibit 229 at 6). Unlike Sierra's method, Staff's proposed period covers the summer period concentration observed by Sierra for the 2011-2013 rate effective period (Exhibit 229 at 6, Attachment JCA-3-RD). Staff argues the 2011-2013 period necessary to recognize that excess capacity will exist during the rate effective period (Exhibit 229 at 6-7; Exhibit 230; Tr. 2239-2241).

BCP's Position

502. BCP recommends the Commission address Sierra's excess generation capacity by discounting the cost of a combustion turbine by 50 percent (Exhibit 201 at 5).

503. BCP notes that Sierra's 30-year forecast has no generation additions for the first 10 years and that Sierra may be able to reduce operation and maintenance costs or to sell power into the wholesale market (Tr. at 1850-1851). Further, BCP observed Sierra's intent to fill its 2013-2015 open position with low-priced resources (Exhibit 201 at 5). BCP cites Pacific Gas and Electric's ("PG&E") recent marginal generation demand cost calculation, as an example supporting its methodological approach (Exhibit 201 at 5-6).

Sierra's Rebuttal Position

504. Sierra asserts that both BCP's and Staff's proposed methodologies incorporate short-run conditions, BCP through modification of cost and Staff through the allocator, and should be denied (Exhibit 249 at 4-5, 11; Exhibit 251 at 3). Since the Commission's adoption of marginal costing in the early 1980's, the Commission has preferred long-run marginal costing for the pricing stability it provides and positive effect upon customer acceptance and understanding (Exhibit 249 at 6).

505. Sierra argues BCP's 50 percent discount is insufficiently supported ,thus should be deemed arbitrary (Exhibit 249 at 7-8). Sierra also argues Staff's proposed inclusion of years 2011-2014 in the determination of the LOLP inappropriately includes a period of recession (Exhibit 249 at 9-10; Exhibit 251 at 3).

Commission Discussion and Findings

506. Long-run marginal costs serve as the basis of allocating revenue requirement. In contrast to previous proceedings, Sierra now has excess capacity. For instance, it does not appear that Sierra will need to build additional generating capacity until 2022, which is significantly past the rate effective period for this case and a time period in which there will be four intervening rate cases. The Commission agrees with BCP witness that that fact renders inadequate the normal methods for measuring marginal costs.

507. Focusing on the LOLPs used to allocate costs to peak and off-peak periods, neither Sierra nor Staff tackled the question of whether the measurement of marginal generation cost should itself be adjusted downward to reflect the excess capacity that is expected during the period the rates set here will be in effect. However, BCP's witness directed his testimony to that core issue and provided evidence supporting marginal generation capacity costs that are lower than would obtain under conditions when there is no excess capacity. The Commission finds the BCP argument persuasive, and, therefore, the Commission adopts BCP's proposed 50 percent discounting approach as reasonable.

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D. Marginal Energy Costs

Sierra's Position

508. Sierra incorporated the RPS into its marginal energy cost by adding an RPS per mega-watt hour rate (which includes DSM measures as DSM energy savings are allowed to account for 25 percent of annual compliance) to the average time-of-use period marginal energy costs (Exhibit 213 at 9; Exhibit 215 at 20). Sierra modeled contracts for RPS compliance as "must take" in developing its marginal energy cost (Exhibit 213 at 10; Exhibit 215 at 21). Sierra asserts the "must take" nature justified by the RPS requirement being a percentage of total kilowatt-hours sold, regardless of when the actual energy is produced (Exhibit 213 at 10-11).

Staff's Position

509. Staff recommends the Commission approve Sierra's methodology for incorporating the RPS into the marginal cost of service study (Exhibit 224 at 1, 3, 16). Staff contends Sierra's modification of marginal energy cost, using a weighted average cost approach reasonably incorporates the RPS cost into the marginal cost of service study (Exhibit 224 at 2).

BCP's Position

510. BCP recommends the Commission adjust marginal energy costs upwards to include ancillary services and exclude extremely inexpensive DSM (Exhibit 201 at 1, 6, 8). BCP agrees with Sierra in principle that it marginal energy costs can only be partially met with market based purchases, the other with probably more expensive renewable energy (Exhibit 201 at 7). However, Sierra's marginal energy cost needs to include ancillary reserve requirements, spinning and non-spinning reserve requirements

(Exhibit 201 at 6). BCP argues DSM costs should be excluded because DSM costs are less expensive than marginal conventional resources. BCP testifies economic theory suggests these low cost resources should be pursued under all circumstances (Exhibit 201 at 7). Further, BCP asserted Sierra's DSM costs were understated as it failed to present a value for the programs' life cycle savings (Exhibit 201 at 7-8).

Sierra's Rebuttal Position

511. Sierra testified that BCP's ancillary service adjustment be denied. Marginal generation costs incorporate the cost of planning reserves. Sierra argues these planning reserves are sufficient to provide the operating (spinning and non-spinning) reserves necessary for every hour of the year. Further, the marginal energy costs include the cost of operating the spinning reserves (Exhibit 249 at 11-13).

512. Sierra concurs with the BCP, that current DSM program costs are less expensive than marginal conventional generation, which supports public policy to include DSM resources in RPS compliance (Exhibit 251 at 8-9). However, Sierra argues that DSM program implementation costs need to be incorporated into marginal energy costs (Exhibit 251 at 9). Further, present valuing of DSM program life cycle savings should have an insignificant impact upon the RPS adder (Tr. at 2431).

Commission Discussion and Findings

513. The Commission accepts Sierra's marginal energy cost, including the "RPS" adder. The Commission finds Sierra's methodology reasonably incorporates the RPS requirements into the determination of marginal energy cost. The Commission denies BCP's operating reserve adjustment on the basis that its inclusion would be redundant. The Commission finds that the DSM costs should be included in the RPS

adder. Sierra correctly observes RPS does allow DSM programs to be used to meet up to 25 percent of the annual compliance and these programs are not cost free. As to present valuing of DSM life cycle savings, no evidence was provided indicating the modification would be significant.

E. Marginal Customer Accounting Costs

Sierra's Position

514. Sierra proposes using the average cost per customer based upon an 11-year period, six years historic data, and five years forecasted data, to estimate customer accounting costs. All amounts are adjusted 2011 dollars (Exhibit 215 at Attachment Walsh Direct-4 table 12; Exhibit 216 at Attachment Walsh Certification-4 table 12).

515. Sierra's study indicated an approximate $2.5 million increase in the test year expenses over 2007 costs which Sierra primarily attributed to an increase in meter reading and uncollectible expenses (Exhibit 212 at 5).

Staff's Position

516. Staff recommends the Commission approve Sierra's marginal cost study, after adjusting the loss of load probabilities, because it reasonably allocates revenue requirement in this proceeding (Exhibit 224 at 2, 12, 17).

BCP's Position

517. BCP recommends the Commission reduce customer accounting costs to exclude unreliable future period budget forecasts; thereby, limiting the costs in this proceeding to the six years of historical data (Exhibit 201 at 1, 10). BCP's adjustment reduces marginal customer accounting costs from Sierra's $49.62 to $44.96 (Exhibit 201

at 10). BCP asserts Sierra was unable to reasonably explain why the forecasted future period costs exceed the historical period by approximately 20 percent (Exhibit 201 at 9).

518. Sierra simply cited Account Nos. 902 (meter reading) and 903 (billing) as accounting for the majority of the forecasted increase ($2.85 million of the 2010 forecasted $3.98 million increase). And, the forecasted amounts were based upon projected activity (Exhibit 201 at 9). Further, BCP noted that the 2007 study contained a similar forecasted 20 percent increase for the future period costs, which never materialized (Exhibit 201 at 9). Additionally, BCP contends that Advanced Service Delivery ("ASD") implementation will probably reduce these costs (Exhibit 201 at 9).

Sierra's Rebuttal Position

519. Sierra asserts that during the certification, modification to the marginal cost of service study addressed BCP's concerns (Exhibit 249 at 19-20; Tr. at 2433-2434). However, Sierra was unable explain what projected activity drove the increase (Tr. at 2424).

Commission Discussion and Findings

520. The Commission finds that the calculation of marginal customer accounting costs using only the historical period information is appropriate. Sierra's inability to identify the projected activity giving rise to the forecasted significant increase in future period costs raises concerns as to the reasonableness of the increase, particularly in light of Sierra's 2007 study forecasted future period cost increases never materializing.

F. Rate Increase Cap for Certain Classes of Customers

Sierra's Position

521. Sierra proposes capping individual customer class revenue requirement increases at the overall increase plus 10 percent (Exhibit 215 at 14). Sierra asserts that the need for such a cap arises from the fact that the 2010 marginal cost of service study gives results that differ significantly from the results of the 2007 marginal cost of service study (Exhibit 215 at 14).

522. Sierra asserted that the proposed cap would create a relatively small subsidy, as shown below:

Class	MC Study[33]	Cap	Subsidy ($1,000s)
Water Pumping	14.46%	13.61%	**$6**
Street Lighting	23.13%	13.61%	**$354**
Outdoor Lighting	29.42%	13.61%	**$119**
Total			**$479**

523. The subsidy would be somewhat greater if these customers were exempted from contributing to the costs of the legislatively mandated subsidy for the IS-2 rate (Exhibit 89 at Statement O, p. 3; Exhibit 207 at 11. Exhibit 208 at 6).

524. The Commission has previously implemented rate caps in order to balance subsidy creation against the rate shock entailed in creating the subsidy (Tr. at 2142-2143). Implementing a capping mechanism prevents these classes from having rates significantly affected by a single marginal cost of service study that has different results than those found in previous studies (Exhibit 215 at 15).

525. Sierra asserts street lighting marginal costs were primarily affected by significant inflation in the cost of lighting fixtures, including the pole, which may or may

[33] The percentage is before any allocation of IS-2 subsidy. If a cap were not in place these classes would also participate in the IS-2 (interruptible agricultural irrigation) subsidy of $12.19 million (Exhibit 89 at Statement O, p. 3).

not continue (Tr. at 2108). Additionally, the shift in marginal generation costs from the summer to winter period contributed to some of the increase (Tr. at 2108-2109).

Staff's Position

526. Staff recommends that the Commission deny Sierra's request to cap customer-class revenue requirement increases because doing so would violate the cost causation principle (Exhibit 224 at 2, 13, 14, 17). Staff has consistently advocated avoiding the creation of subsidies. Staff cites the Commission's decision in Docket No. 09-12017 as support for its position wherein the Commission stated, "The Commission's ultimate goal in ratemaking is to eliminate cross subsidization between rate classes."[34] (Exhibit 224 at 14).

527. Staff contends in the long-run more energy efficient streetlights will have minimal impact upon cost allocation, since the lighting facilities themselves are the primary cost driver in the marginal cost of service study (Exhibit 225 at 3).

City of Sparks' Position

528. The City of Sparks asserts Sierra owns the vast majority of the streetlights (4,967) for which it pays an annual cost of about $872,000 (Exhibit 223 at 3; Tr. at 2151). Due to its lack of control, the City of Sparks has been unable to implement cost control measures (i.e., removing certain mid-block street lights and replacing high pressure sodium light with light-emitting diodes ("LED") (Exhibit 223 at 4; Tr. at 2154-2155, 2161).

Sierra's Rebuttal Position

529. Sierra's proposed 10 percent cap, as applied to the street lighting and outdoor lighting service classes, mitigates the revenue-requirement shift at minor cost.

[34] Order dated July 16, 2010 at paragraph 364.

(Exhibit 250 at 10-11). The lighting classes' marginal cost of service study for the past four general rate cases and this proceeding has yielded fluctuating results for this rate class:

Class	2001	2003	2005	2007	2010
Street Lighting	(12.3%)	15.2%	(5.9%)	(4.4%)	23.1%
Outdoor Lighting	6.1%	31.6%	(8.9%)	(16.7%)	29.4%

(Exhibit 250 at 11).

530. Sierra's February 2009 LED net present value analysis estimates a 14-year payback period whereas the LED bulbs are estimated to have 12-year lives. In other words, the payback period exceeds the life of the bulb (Exhibit 248).

Commission Discussion and Findings

531. Setting rates that reflect cost causation is an important ratemaking principle. However, promoting rate stability in order to avoid rate shock is also an important and valid consideration. Because these two considerations are sometimes in conflict, they must be balanced. Here, the Commission finds that Sierra has recommended the best balance and, therefore, the Commission finds Sierra's proposal to cap the lighting classes' rate increase at the system average plus ten percent in order to promote rate stability and mitigate rate shock provides that balance.

532. With respect to the IS-2 subsidy, the Commission denies Sierra's request to exclude the lighting classes from an allocation of the statutory IS-2 subsidy. Sierra has supplied insufficient supporting rationale for its methodology.

533. The Commission finds that Sierra shall investigate the cause(s) for the significant variability in the lighting classes' marginal cost of service revenue allocation responsibility and provide the results of its investigation in its next general rate

application. Sierra shall identify what procedures, if any, should be used to address the identified causes.

G. Electric Rate Design Issues

Sierra's Position

534. Sierra proposed a rate design that it contends reduces intra-class subsidies by continuing movement toward cost based rates for all but the IS-2 customer class (rate set by statute) and the GS-4 NG customer class (rate set by contract) (Exhibit 207 at 18-44; Exhibit 208 at 6-14). Sierra explained its proposed rate design accomplishes this goal by increasing the level of fixed charges (e.g., monthly Basic Service Charge) and, for all applicable classes, demand related charges.

535. Rate Tilt. Sierra contends that it tried to avoid undue impediment to customers who would control their bills by moderating monthly usage. This is demonstrated by Sierra's proposed single-family residential (D-1) commodity rate decreasing only 1.1 percent and the minor reduction in the GS-2 class. The minor reduction in rate tilt which was achieved by capping the demand-related revenue increase at 15 percentis demonstrated by the table below:

Rate Class	2007 GRC	Certification
OGS-2 TOU	74.66%	72.53%
GS-2 TOU	73.01%	66.96%
GS-3	71.84%	65.40%
GS-4	66.51%	64.09%

(Exhibit 207 at 26-27; Exhibit 208 at 10; Exhibit 215 at 15)

536. Residential and Small Commercial Basic Service Charges and the DOS Class Additional Meter Charge. Sierra proposed increases for the residential (DM-1, D-1) and small commercial classes (GS-1). Sierra asserts that the residential and small

commercial customer classes' monthly Basic Service Charges should recover all customer costs and Rule No. 9 facilities cost plus a portion of the primary distribution costs. However, Sierra's proposal recovers all customer costs, but only a portion of the Rule No. 9 facilities costs:

Class	Current	Proposed	Increase	Proposed as % of Customer Costs & Rule 9 Facilities
DM-1	$5.50	$6.00	9.09%	95.8%
D-1	$8.25	$9.25	12.12%	90.2%
GS-1	$21.00	$24.00	14.29%	94.7%

(Exhibit 208 at 8)

537. Sierra proposed creating a new billing component, "Additional Meter Charge," for the Distribution Only Service ("DOS") class when more than one meter exists in compliance with the Commission's directive in Docket No. 08-03025 (Exhibit 208 at 13). Sierra proposed to charge all customers that it has currently identified as being served with more than one meter, one monthly Basic Service Charge plus an extra meter charge for each extra meter (Exhibit 209 at 21-24, Attachment Stack Direct-6 p. 2; Tr. 1976). Sierra's proposed Additional Meter Charge is designed to recover only the meter investment cost, meter reading expense, plus a portion of the billing expense related to personnel preparing the totalized billing determinants (Exhibit 209 at 24).

Staff's Position

538. Staff recommends the Commission approve Sierra's rate design methodology, including Sierra's proposed monthly Basic Service Charges and the establishment of an "Additional Meter Charge". Staff contends the methodologies are reasonable (Exhibit 224 at 2, 14-17).

BCP's Position

539. BCP recommends that the Commission deny Sierra's request to increase the residential class Basic Service Charge (Exhibit 201 at 21). In addition to allowing customers to retain more control over their bills through consumption decisions, BCP asserts that increasing the monthly fixed charge harms conservation efforts by discouraging customers from making energy efficiency investments (because increasing the Basic Service Charge would increase the investment payback period) (Exhibit 201 at 12-14).

540. However, BCP acknowledges rate design alone is insufficient to induce sufficient conservation, as evidenced by the significant ratepayer financed energy efficiency programs (Exhibit 201 at 14).

Sierra's Rebuttal Position

541. Sierra asserts that its proposed increase in the residential classes' monthly Basic Service Charge is necessary to maintain movement toward cost-based rates (Exhibit 250 at 4). The proposed Basic Service Charge increase allows customers to retain significant control over their bills and provides incentive to conserve (Exhibit 250 at 3, 6-7). Moreover, the proposed increase in the monthly Basic Service Charge promotes revenue stability (Exhibit 250 at 3).

542. Sierra testified that the Additional Meter Charge is intended to fairly address customers that have previously been totalized and served by several meters but treated as one for billing purposes. If other customers desire to be totalized, they need to design their system so only one meter is used for the provision of service (Tr. at 2428).

Commission Discussion and Findings

543. The Commission establishes a customer service charge that is based on costs and promotes revenue and customer energy bill stability, yet still provides meaningful opportunities for customers to control their monthly bills. Sierra's proposed residential monthly Basic Service Charges reduces intra-class subsidization while allowing customers to retain control over their bills. This modest increase to the monthly Basic Service Charge should provide more revenue stability than would occur under BCP's proposal. The Commission finds that Sierra's proposed increase in the basic service charge strikes a reasonable balance of the competing ratemaking objectives of reducing intra-class subsidies with fixed charges while allowing customers the opportunity to control their bills by reducing consumption. Allowing movement toward cost-based rates, promoting rate stability, and avoiding rate shock are all ongoing Commission objectives.

544. The Commission finds that the proposed multiple meter charge is in the public interest. The Additional Meter Charge is designed to recover only the meter investment cost, meter reading expense, plus a portion of the billing expense related to personnel preparing the totalized billing determinants. This is a step toward cost-based rates.

H. Proposed Change in Cost for Customer Visits (Electric)

Sierra's Position

545. Sierra proposed increasing the service restoration fee (and any visit involving dispatch of utility personnel) from $15.00 to $30.00. A same day or after hours visit would increase from the current fee of $22.50 to $40.00 per visit. Sierra testified it would continue to charge no fee for physical service disconnections for safety or tariff

related matters (Exhibit 209 at 18). Further, Sierra proposes to align its electric service tariff with the gas service tariff so that when a combination gas and electric service customer premise visit occurs, only one service fee would be charged (Exhibit 209 at 19, Attachment Stack Direct-4, p. 2).

546. Based on 2008-2009 customer disconnect and re-connect information, Sierra estimated the average visit cost is $42.73, which is nearly three times the existing charge[35] (Exhibit 209 at 20). Sierra further noted that these service fees were last modified in 1981 (Exhibit 209 at 19). Additionally, Sierra asserts, while the ASD program is expected to reduce the number of customer premise service disconnections and re-connections, customer premise visits will still occur and the administrative cost of these activities will continue to exist. (Exhibit 209 at 20-21).

Staff's Position

547. Staff recommends that the Commission approve Sierra's proposed increase in customer premise service fees, as it represents a gradual step toward cost based rates (Exhibit 229 at 2, 18, 19, 33). Staff asserts the proposed increase in premise visit charges is reasonable and cost justified (Exhibit 229 at 31, 32). Staff argues that current rates for this service were last set in 1981 and the existing fees no longer represent the cost of providing the service. For example, simply adjusting these fees for inflation (1981-2009) the $15 fee would have increased to $35.72 and the $22.50 fee to $53.57 (Exhibit 229 at 17-18).

548. Staff further recommends the Commission revisit the issue in Sierra's next general rate case. Staff argues that by Sierra's next general rate change application, the

[35] The amount was derived by dividing the fully loaded cost (including administrative loadings and transportation) of $70.04 by the average visit time of 0.61 hours (Exhibit 209 at Attachment Stack-Direct-5).

ASD program will have been fully implemented, thus allowing a more complete analysis of the costs in providing the service (Exhibit 229 at 19).

BCP's Position

549. BCP recommends the Commission deny Sierra its requested increases (Exhibit 201 at 21, 23). BCP asserts the service restoration fee is a regressive charge and therefore cost recovery should not be paramount (Exhibit 201 at 21). BCP argues that low-income customers are more likely to require the restoration service. This is indicated by the fact that in 2007 more individuals below the poverty line moved than those above the poverty line, i.e. 22.7 percent and 14.9 percent, respectively. Further, the BCP cites the disparity between the median income of those who moved and the median income of all households, $37,000 and $47,632, respectively (Exhibit 201 at 21-22).

550. BCP further argues that because the ASD program is scheduled for full operation in 2012, increasing the fee at this time is not reasonable because the ASD program will significantly reduce the cost of performing these services. Further, upon full ASD implementation these charges could be eliminated as service connection and disconnection will no longer require "truck rolls" (Exhibit 201 at 23). In order to aid the Commission in reviewing these fees in the next general rate case, BCP recommends that Sierra track the cost savings related to the elimination of truck rolls under the ASD program (Exhibit 201 at 24).

Sierra's Rebuttal Position

551. Sierra argues that the impact upon low-income customers is not a compelling reason to retain a fee that was set more than 20 years ago. Further, the partial movement toward cost based rates recognizes the impact a cost based fee would have on

low-income customers (Exhibit 250 at 12-13). Sierra concurs with Staff that the fee should be revisited in its next general rate case when the ASD program will have been fully implemented. This would allow Sierra to quantify changes in disconnection and reconnection activities. Additionally, even with full ASD deployment, other causes to visit customer service premises will exist and the tariff charge should reflect the cost of these services (Exhibit 250 at 13-14).

Commission Discussion and Findings

552. The Commission finds that an increase in the service restoration fee and any visit involving dispatch of utility personnel from the current $15.00 to $30.00 is reasonable. The same day or after hours visit will be increased from $22.50 to $40.00. The Commission finds that the proposed fees are an appropriate step toward cost based rates. Further, the Commission directs Sierra to submit in its next general rate case a revised customer premise service fee. Revisiting the charges in the next general rate case would provide a more complete analysis of how the fully implemented ASD program modifies the costs of providing the service.

I. IS-2 Special Condition Tariff for Disconnection

Sierra's Position

553. Sierra proposes to add an additional condition to IS-2 service that establishes a specific reconnection service fee for voluntary service disconnections under this tariff or the IS-1 tariff. Specifically, Sierra requests the following special condition:

> If a Customer voluntarily disconnects service while benefiting from the discounted rates under this schedule (or while taking service under the IS-1 schedule during the non-irrigation months), Customer shall pay to the Utility the job-specific costs associated with reconnection of such service. Failure to pay these costs

> shall preclude the Customer from eligibility for IS-2 service until such charges are paid in full. The minimum charge for reconnection of a single meter is estimated to be $500 (Exhibit 209 at 15, Attachment Stack Direct-2).

554. Due to the typically remote locations and the meters being instrument-rated[36], Sierra asserts it incurs a significantly greater cost to disconnect and reconnect these customers than is provided by the current $15 customer premise visitation disconnection and reconnection fee (Exhibit 209 at 16-17). Sierra estimates the average IS-2 disconnection or reconnection service cost at $525.02 per meter (Exhibit 209 at Attachment Stack Direct-3).

Staff's Position

555. Staff recommends the Commission approve Sierra's proposed new IS-2 additional condition but set the reconnection fee at $250 (Exhibit 229 at 2, 22, 33). Staff asserts a $250 fee should be sufficient to discourage IS-2 customers from voluntarily discontinuing service to avoid the $90.80 in Basic Service Charges.[37] Staff further asserts the $250 fee represents a gradual step toward cost based rates. Additionally, a stated fee would simplify the administrative process by eliminating the need to calculate a specific charge for each meter (Exhibit 229 at 21).

Sierra's Rebuttal Position

556. Sierra acknowledges Staff's recommendation would probably achieve a similar deterrent effect. However, Sierra argues collecting the job specific reconnection service costs is more direct and appropriate (Exhibit 250 at 15). Not only does it recover the actual cost of the reconnection service, it requires the customer to pay approximately

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[36] IS-2 meters requires two utility workers;(a troubleman and a meter technician), to either disconnect the service or reconnect the service (Exhibit 209 at 17).

[37] The Current IS-1 monthly Basic Service Charge is $22.70 for four months (Exhibit 229 at 21).

half the cost of the entire disconnect and reconnection service. Sierra proposes to continue its practice of not charging the customer for disconnection from service (Exhibit 250 at 15-16).

Commission Discussion and Findings

557. The Commission approves Sierra's proposed new special condition for IS-2 Disconnection. Consistent with other service fees under consideration in this docket, the Commission prefers to adopt an incremental approach toward cost based rates. In this case the Commission adopts a fee of $250, as recommended by Staff, which is one-half of the cost to reconnect the customer.

558. In terms of consistency with the applicable pricing provision found at NRS 704.225(1)(b) appears to allow implementation of the Special Condition Tariff for IS-2 since the payment of a service reconnection fee is not a rate for the provision of electric service, as those cited in the statute, but for the recovery of specific costs of connecting or disconnecting the meter. The statute does not prohibit such fees. This fee is consistent with fees imposed to collect costs for other rate classes.

J. Hybrid Electric Vehicle Tariff

Sierra's Position

559. Sierra proposes to implement residential and general service hybrid electric vehicle recharge rider tariff (Exhibit 207 at 33-34). Sierra explained that the tariffs were modeled after those approved for Nevada Power. The tariffs are only applicable to customers taking service under the optional single-family residential (OD-1) and general service (i.e. OGS-1 and OGS-2) time-of-use tariffs. The customers are provided a 10 percent off-peak period rate discount (Exhibit 207 at 34).

Commission Discussion and Findings

560. The Commission approves Sierra's proposed hybrid electric vehicle rider tariff. The Commission finds that the proposed tariff is reasonable. The design is similar to that previously approved by the Commission for Nevada Power. No party opposed the proposed tariff.

K. Allocation of Demand Side Management Charges

Sierra's Position

561. Sierra proposes to allocate to customer classes the Electric Department Demand Side Management (DSM-E) costs that were deferred through the end of the certification period using the combined marginal generation and marginal energy cost allocation ratio adopted in this proceeding (Exhibit 84 at Schedule I-2 pp. 1, 19, Statement O, at 1).

Staff's Position

562. Staff recommends the Commission approve Sierra's proposed combined marginal generation and energy cost allocation methodology for the DSM-E costs deferred from June 1, 2009 through May 31, 2010 (Exhibit 229 at 2, 16-17, 33). Staff concurs with Sierra that the DSM costs at issue in this proceeding should be allocated to the various customer classes using the marginal generation and energy allocation ratios approved in Sierra's 2007 general rate case (Exhibit 229 at 9-10).

563. While the new DSM regulations[38] require that the allocation methodology be established in a general rate case, Sierra did not include a request in this proceeding.

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[38] LCB File No. R042-10 at Section 4(2)(b)(1) (Exhibit 229 at 15)

Staff understands Sierra will be making an interim DSM filing to establish the appropriate allocation methodology[39] (Exhibit 229 at 15).

Sierra's Rebuttal Position

564. Sierra argues that the marginal generation and energy allocation methodology fairly allocates the DSM costs for it recognizes the program's primary purpose is to reduce peak demand on the energy supply system. All customers benefit from these programs (Exhibit 249 at 16-17).

Commission Discussion and Findings

565. The Commission approves Sierra's proposed customer class allocation of DSM program costs included in this proceeding. No party challenged the reasonableness of the costs or the allocation. Further, in order to allow interested parties to comment, the Commission defers the post July 22, 2010 customer class cost allocation issue to Sierra's current application before the Commission (Docket No. 10-10025) to establish interim rates for the recovery of 2011 energy efficiency and conservation program costs and estimated lost revenues.

L. Embedded Cost of Service Study (Gas)

Sierra's Position

566. Sierra asserts its embedded cost of service study was developed in accordance with the previous Commission's directive (Exhibit 219 at 3-4). Using test year information, the revenue requirement is allocated to functional cost categories (i.e., production (supply), distribution, and customer-related), which in turn are classified as

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[39] Sierra's interim filing, the Application of Sierra Pacific Power Company d/b/a NV Energy to establish interim base energy efficiency program rates and base energy efficiency implementation rates pursuant to NRS 704.785 and the Order issued in Docket No. 09-07016, is designated Docket No. 10-10025. In this proceeding, Sierra proposes to allocate 2011 estimated energy efficiency and conservation (formerly DSM) costs to customer classes using marginal generation and energy allocation ratios.

customer, commodity, or demand. The classified cost is allocated to each customer class (Exhibit 219 at 3, Attachment Shelton-Patchell Direct-2; Exhibit 221 at Attachment Shelton-Patchell Direct-2 Certification).

Staff's Position

567. Staff recommends the Commission approve Sierra's embedded cost of service study, as it is an adequate methodology for allocating costs between customer classes (Exhibit 229 at 2, 23-24). The embedded cost allocation methodology allocates costs based upon the underlying causation (Exhibit 229 at 23).

BCP's Position

568. BCP recommends that the Commission approve Sierra's embedded cost of service study, as it is an adequate methodology for allocating costs between customer classes (Exhibit 229 at 2, 23-24). The embedded cost allocation methodology allocates costs based upon the underlying causation (Exhibit 229 at 23).

Commission Discussion and Findings

569. The Commission finds that Sierra's embedded cost of service study is acceptable for allocating to costs to customer classes and as a basis for rate design. The embedded cost allocation methodology allocates costs based upon the underlying causation and is consistent with industry practices.

M. Incentive Natural Gas Rate Revenue ("INGR") Shortfall Allocation (Gas)

Sierra's Position

570. Sierra proposed allocating the INGR revenue deficiency, or shortfall, of $189,000 to the other natural customer classes, excluding transportation, on the basis of therms sold (Exhibit 89 at Statement O, at 3; Exhibit 219 at 18; Exhibit 221 at 5). Sierra

asserts the sales allocation methodology recognizes that all sales customers benefit from Sierra's ability to interrupt the flow of natural gas (Exhibit 219 at 18).

Staff's Position

571. Staff recommends that the Commission allocate the INGR revenue deficiency using the "equal percent embedded cost methodology." This approach would rely on the cost study allocation percentage (Exhibit 229 at 2, 27, 28). Staff argues that any revenue deficiency or subsidy fails to maintain the customer class cost relationships determined in the cost study, which causes an inappropriate allocation of costs (Exhibit 229 at 27). The table below denotes the estimated change in the combined INGR and transportation revenue deficiency ($217,000) allocation:

	Allocation Methodology		Change	
	Embedded	Therms	Percentage	Revenue
Residential - NG	63.3%	60.04%	3.26%	$7,000
Residential - LPG	0.15%	0.14%	0.001%	0
Small Commercial - NG	26.41%	29.31%	(2.90%)	($7,000)
Small Commercial - LPG	0.02%	0.02%	0.00%	0
Large Commercial	7.94%	8.98%	(1.03%)	($3,000)
INGR	1.31%	1.51%	(0.20%)	($1,000)
Transportation	0.86%	0.00%	0.86%	$2,000
Total	100.00%	100.00%		$0

(Exhibit 229 at Attachment JCA-12-RD)

Sierra's Rebuttal Position

572. While Sierra asserts that either allocation methodology is reasonable for allocating the INGR and transportation shortfalls, Sierra prefers allocating the INGR shortfall using therm sales volumes. Sierra argues that the methodology is consistent with that used in the 2005 general rate case and that allocation based upon therm sales is used extensively throughout the cost of service study. Due to the insignificant difference between methodologies (i.e. largest shift between customer classes is $7,000), allocation

upon therm sales does not distort proportional cost relationships between customer classes (Exhibit 253 at 2-3; Tr. at 2439).

Commission Discussion and Findings

573. The Commission finds that Sierra's INGR revenue shortfall allocation methodology is reasonable. Sierra's methodology of allocating the INGR revenue shortfall on the basis of therm sales provides for a better matching of costs and benefits given the ability to interrupt the INGR transportation service.

N. Combining Natural Gas ("NG") and Liquid Petroleum Gas ("LPG" customers for General Rate Purposes (Gas)

Sierra's Position

574. Sierra proposes to combine the LPG and natural gas customers for general rate purposes (Exhibit 219 at 21). Sierra asserts that because of the small size of the LPG class (381 residential customers and 11 small commercial customers), the base tariff general rate ("BTGR") revenue requirement for LPG operations is approximately $95,000. The modest cost per therm differential between LPG and natural gas customers is insufficient justification for separate rate classifications (Exhibit 89 at Statement O, p. 1; Exhibit 220 at 7).

575. Sierra estimated that the LPG residential class non-fuel revenue requirements would not change and the LPG small commercial class experienced an approximate $1,000 subsidy (Exhibit 89 at Statement O, at 1; Exhibit 221 at Attachment Shelton-Patchell Direct-2-Cert. p.1). Additionally, Sierra testified that administrative efficiencies could be obtained (e.g., billing system programming) (Tr. at 2149).

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Staff's Position

576. Staff supports the consolidation of the LPG and natural gas customer classes because the cost differences do not justify different rates for these two classes (Tr. at 2248-2249).

Commission Discussion and Findings

577. The Commission approves Sierra's unopposed proposal to combine the LPG and natural gas customer classes for general rate purposes. The Commission finds the cost differences do not justify different rates for these two services. Moreover, consolidating the two classes should produce administrative efficiencies.

O. Basic Monthly Service Charge (Gas)

Sierra's Position

578. Sierra proposes increasing the Basic Service Charge to better reflect the fixed underlying costs and lessen the intra-class subsidy (Exhibit 219 at 16, 19; Exhibit 220 at 13). Further, increasing the Basic Service Charge enhances the stability of Sierra's revenue as well as customers' energy bill charges (Exhibit 219 at 19; Exhibit 220 at 13). Sierra estimated that the standard deviation of residential class monthly revenue volatility was 3.4 percent. Sierra estimated that the proposed $8.50 Basic Service Charge retains the same level of monthly bill volatility whereas a lower monthly charge increases monthly revenue volatility. The corollary is that a higher rate reduces volatility (Exhibit 220 at attachment Walsh-Direct-3). Sierra' s cost based and proposed Basic Service Charge by customer class are set forth in the table below:

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	Cost Based	Proposed	Current	Proposed as % of Cost
Residential - NG	$13.63	$8.50	$6.50	62%
Residential - LPG	$13.53	$8.50	$6.50	62%
Small Commercial - NG	$21.23	$21.00	$16.00	99%
Small Commercial – LPG	$22.68	$21.00	$16.00	93%
Large Commercial	$1,023.05	$700.00	$300.00	68%
INGR	$2,476.13	$1,500.00	$700.00	61%
Transportation	$1,880.73	$700.00	$300.00	37%

(Exhibit 89 at Statement O, p.2; Exhibit 219 at 16-18)

579. Sierra asserts that the proposed increase in the INGR charge recognizes the significant amount of "customer care" required by this class (Exhibit 219 at 18). Sierra explained that the relatively low proposed transportation customer class charge is driven by the tariff requirement that this rate class must be equal to the Large Commercial class rate, which is the alternative service. Additionally, Sierra noted the transportation class is assessed a monthly administrative fee of $300, which increases the ratio to 51 percent (Exhibit 219 at 18).

Staff's Position

580. Staff recommends the Commission approve Sierra's proposed monthly Basic Service Charges (Exhibit 229 at 2-3, 30, 34). Staff asserts that the proposed Basic Service Charges are reasonable and offer a gradual movement toward cost based rates, which improves price signals and reduces intra-class subsidization (Exhibit 229 at 28-29). Additionally, Staff asserts increasing the Basic Service Charge enhances Sierra's revenue stability (Exhibit 229 at 29).

581. Staff contends that even with the proposed increase in the monthly Basic Service Charge, Sierra's customers retain significant control over their annual bills. This is indicated by the fact that the annual commodity costs still account for 87 percent and

94 percent of the annual Residential class and Large Commercial customer class bills, respectively (Exhibit 229 at Attachment JCA-13-RD). Further, while the proposed increase in monthly Basic Service Charges for large commercial classes (i.e., large commercial service, INGR, and transportation) increases are significant, the proposed charges are still significantly below cost based rates (Exhibit 229 at 29).

BCP's Position

582. BCP recommends that the Commission deny Sierra's request to increase the residential class Basic Service Charge (Exhibit 201 at 24). In addition to allowing customers to retain more control over their bills through consumption decisions, BCP asserts that increasing the monthly fixed charge harms conservation efforts by discouraging customers from making energy efficiency investments (because it increases the investment payback period). Obtaining a similar level of energy efficiency investment requires increasing energy efficiency program incentive payments (Exhibit 201 at 12-14).

583. BCP contends that encouraging conservation has a valuable hedging attribute; conservation reduces demand, which mitigates unforeseen upward price spikes caused by supply and demand imbalances (Exhibit 201 at 15-16).

584. BCP acknowledges that rate design alone is insufficient to induce sufficient conservation, as evidenced by the significant ratepayer financed energy efficiency programs (Exhibit 201 at 14-15).

Sierra's Rebuttal Position

585. Sierra reiterates its argument, with which Staff concurs, that the continued gradual movement toward cost based rates reduces intra-class subsidies. Further, Sierra

argues that, as demonstrated by Staff, BCP's conservation concerns are exaggerated. The commodity rate accounts for the largest share of the customer's annual bill (e.g., residential customers 88 percent[40]) (Exhibit 253 at 4).

Commission Discussion and Findings

586. The Commission establishes a customer service charge that balances the goals of reducing intra-class inequity, enhances revenue and customer energy bill stability, and provides meaningful opportunities for customers to control their monthly bills.

587. The Commission finds that Sierra's proposed increases to the monthly Basic Service Charges strikes a reasonable balance among these objectives.

588. With respect to the BCP's concern that the proposed increase will create a barrier that will limit opportunities to control their energy bills, the record in this proceeding indicates otherwise. As indicated by Staff, commodity costs represent approximately 87 percent of the total annual bill, which indicates significant customer control. Therefore the Commission finds that Sierra shall increase the monthly Basic Service Charge as proposed.

P. Cost of Customer Visits (Gas)

Sierra's Position

589. Sierra proposes to increase the service restoration fee (and any visit involving dispatch of utility personnel) from \$15.00 to \$30.00, with the same day or from \$22.50 to \$40.00 for same day or after hours visit. Sierra asserts the proposed increases represent considerable movement toward cost based rates but not out of proportion with

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[40] While Sierra cites 88%, Staff's calculation indicates that amount to be 87.18% (Exhibit 229 at Attachment JCA-13-RD).

the current fees (Exhibit 219 at 29). Sierra estimated the average visit fully loaded hourly field labor (labor and transportation) cost to be $66.83, with an expedited cost of $94.62 [41] (Exhibit 219 at 27, 30, Attachment Shelton-Patchell Direct-7). Sierra further noted that these service fees were last modified in 1981.

590. Sierra would continue to charge no fee for physical service disconnections for safety or tariff related matters. In a combination gas and electric service customer premise visit only one service fee would be charged (Exhibit 219 at 27). Further, the ASD program will not reduce the number of customer premise visits (Exhibit 219 at 30; Tr. at 2146).

Staff's Position

591. Staff recommends the Commission approve Sierra's proposed increase in customer premise service fees, as it represents a reasonable step toward cost based rates (Exhibit 229 at 3, 31, 32-34). Further, Staff observed that simply adjusting the existing fees for inflation (1981-2009) the $15.00 and $22.50 would have increased to $35.72 and $53.57, respectively (Exhibit 229 at 31). Additionally, Staff contends the ASD program will not significantly reduce customer premise visits for the gas department. For safety reasons, Staff expects Sierra's to continue to physically disconnect and reconnect service (Exhibit 229 at 32). However, Staff does recommend the fees for these services be re-examined in Sierra's next general rate case. This will allow any reduction in service costs stemming from the ASD program to be reflected in these fees (Exhibit 229 at 32-33).

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[41] $74.11 * 0.75 hours = $66.83 and after hours rate of 1.5 times $66.83 (Exhibit 219 at Attachment Shelton-Patchell Direct-7).

BCP's Position

592. BCP recommends that the Commission deny Sierra's requested increases (Exhibit 201 at 21, 24). BCP asserts the service restoration fee is a regressive charge because low-income customers are more likely to require the restoration service. This is indicated by the fact that in 2007 more individuals below the poverty line changed residences than those above the poverty line, i.e. 22.7 percent and 14.9 percent, respectively. Further, the BCP cites the disparity between the median income of those who moved and the median income of all households, $37,000 and $47,632, respectively (Exhibit 201 at 21-22).

593. BCP further argues that imminent implementation of the ASD program in 2012 renders its increase in the fee at this time unreasonable because the ASD program will significantly reduce the cost of performing these services. Further, upon full ASD implementation, these charges could be eliminated because service connection and disconnection will no longer require "truck rolls" (Exhibit 201 at 23). In order to aid the Commission in reviewing these fees in the next general rate case, BCP recommends that Sierra track the cost savings related to the elimination of truck rolls under the ASD program (Exhibit 201 at 24).

Sierra's Rebuttal Position

594. Sierra argues that the regressive nature of a fixed charge is insufficient reason to avoid moving toward cost based rates (Exhibit 253 at 5). Sierra reiterated its assertion that the ASD program will not reduce the number of customer premise visits. For safety reasons, Sierra will not automatically turn-on or turn-off gas services (Exhibit 253 at 5-6).

Commission Discussion and Findings

595. The Commission approves Sierra's proposed increase in customer premise visit fees from $15.00 to $30.00 and from $22.50 to $40.00 for same day or after hours visit. These charges have not been adjusted since 1981.

596. The proposed change is justified based on the cost study that indicates that the costs of these services average $66.83 for regular service and $94.62 for expedited service. These estimates were not challenged by any party, including BCP. The Commission notes that while this is a significant step toward cost based rates, the proposed rates are still less than one-half of the cost for such visits.

597. The Commission directs Sierra to 1) track the cost savings related to the elimination of truck rolls under the ASD program; and 2) revisit the customer premise visit charges in its next general rate case.

Q. Miscellaneous Tariff Language Clarifications (Gas)

Sierra's Position

598. Sierra proposes to make the following tariff changes to clarify language, match current practice, or correct and update references. The proposed changes are summarized below:

1) Include within the Statement of Rates the Basic Service Charge and Tier 1 non-interruptible rate and Tier 2 interruptible rate of Schedule INGR.

2) For Schedule INGR:

   a. Provide a statement within Schedule INGR referring to the location of the Basic Service Charge rate in the Statement of Rates.

Also describe the two tier non-interruptible and interruptible rate in a new paragraph within Schedule INGR.

b. Provide language stating that any facilities that must be installed as a result of a customer request must be constructed in accordance with Rule No. 9.

c. Make minor housekeeping updates to the NAC citations and BTER and DEAA terminology.

3) In Special Condition 1 of Schedule SCNG, clarify that a customer must have monthly consumption of less than 12,000 therms in all of the five winter months, November through March for Schedule SCNG to be applicable.

4) In Special Condition 3 of Schedule "LCNG", clarify that a customer must have monthly consumption of greater than 12,000 therms in one or more of the five winter months.

5) For Schedules "TF" and "TI":

a. Refer to sales rate schedules as retail rate schedules.

b. Include in Schedules TF and TI a provision for collecting monthly service charges of telemetering facilities.

c. Include a provision within Schedules TF and TI's Facility Additions section that a customer will be required to pay for all of the additional facilities required to facilitate a customer's new request for service.

d. Provide that the rates for service under both transportation rate schedules become effective on the effective date of a Commission decision.

e. Provide that all gas delivered on a daily basis in excess of firm service as specified in the service agreement will be considered interruptible gas under Schedule TI.

f. Under the Gas Cost Adjustment provisions of Special Condition 4.6.1, update the language to provide for either a payment or a credit for an outstanding DEAA balance for the applicable recovery period, rather than for 12 months.

g. Make a variety of minor rate schedule changes to better conform Schedules TF and TI to current business practice. This includes updating the labeling of customer charge to basic service charge and purchased gas adjustment provision to DEAA.

(Exhibit 219 at 31-32).

Staff's Position

599. Staff recommends that the Commission accept Sierra's proposed changes, plus make three additional clarification and corrections listed below:

1) Direct Sierra to use "Rule No. 9, Gas Main Extensions" when referencing this rule in the proposed tariff Gas No. 1. A review of the tariff disclosed referencing to Rule No. 9, Gas Main Extension, occurred in several different ways. Consistency in referencing is preferable.

2) Direct Sierra to use "PUCN Sheet No. 2H" when referencing the Basic Service Charge rate on proposed tariff Sheet Nos. 6A and 6E. 1. A review of the proposed tariff noted inconsistent references to the Basic Service Charge.

3) Direct Sierra to update PUCN Sheet No. 61, paragraph 9, General Terms and Conditions, to include material omitted during a previous revision. Specifically add the underlined language, "Except where specifically provided under this rate schedule, service under this <u>schedule is subject to all other provisions of this tariff</u>."

(Exhibit 163 at 1-5-Whitmore).

Sierra's Rebuttal Position

600. Sierra concurs with Staff's recommendation for consistency in referencing Rule No. 9, Gas Main Extensions and PUCN Sheet No. 2H reference to Basic Service Charge (Exhibit 206 at 2). However, Sierra does not accept Staff's first recommendation to accept Sierra's filed proposed tariff modifications. Instead, Sierra proposes to modify its initial proposed changes to delete Paragraph 4.2.4 on proposed tariff PUCN Sheets Nos. 6A(1) and 6E(1) to clarify that rate changes are effective as stated in the Commission's order. The proposed change clarifies the condition without adding additional language.

601. In lieu of Staff's proposed modification to Paragraph 9 of PUCN sheet No. 61, Sierra proposes the following modification (underlined language) to address the missing language, "Except where specifically provided under this rate schedule, service

under this schedule is subject to all other provisions of the Utility's tariff." (Exhibit 206 at 2-3).

Commission Discussion and Findings

602. The purpose of a tariff is to specify the terms and conditions of a utility-provided service. The language in the tariff should be clear and accessible. Sierra's and Staff's proposals clarify and/or correct Sierra's proposed tariffs. These do not represent policy changes, but rather clarify existing policies.

603. The Commission accepts Sierra's revisions to its tariff as modified in its rebuttal testimony. Sierra's revisions to Staff's recommendations clarify the tariffs.

THEREFORE, it is ORDERED THAT:

1. The Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, designated as Docket No. 10-06001, is GRANTED as MODIFIED by this Order and the Stipulation attached as Attachment 1.

2. The Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto, designated as Docket No. 10-06002, is GRANTED as MODIFIED by this Order

3. The Application of Sierra Pacific Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric operations, designated as Docket No. 10-06003, is GRANTED as MODIFIED by this Order.

4. The Application of Sierra Pacific Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its gas operations, designated as Docket No. 10-06004, is GRANTED as MODIFIED by this Order.

5. The Stipulation attached hereto as Attachment 1, resolving issues in Docket No. 10-06001 related to the construction of the Tracy Combined Cycle Facility, is approved.

6. The written Motion of Sierra Pacific Power Company d/b/a NV Energy to Strike Staff Testimony Recommending Disallowances Violating Prohibition Against Retroactive Ratemaking is hereby DENIED in accordance with this Order.

7. The oral Motion of the Commission's Regulatory Operations Staff to Strike portions of testimony presented at hearing by witness Patricia M. Franklin of Sierra Pacific Power Company d/b/a NV Energy, is hereby DENIED in accordance with this Order.

8. Sierra Pacific Power Company d/b/a NV Energy's rate of return on equity shall be set at 10.10 percent for its electric operations, in accordance with the terms of this Order.

9. Sierra Pacific Power Company d/b/a NV Energy's rate of return on equity shall be set at 10.00 percent for its gas operations, in accordance with the terms of this Order.

10. Sierra Pacific Power Company d/b/a NV Energy is ordered to meet the following compliances:

A. No later than January 31, 2011, Sierra Pacific Power Company d/b/a NV Energy shall file a separate application with the Commission to determine the reasonableness of project development costs for the Ely Energy Center and may propose reclassification of these costs from a deferred debit to a regulatory asset.

B. Contemporaneous with its compliance tariff filing following issuance of this Order, Sierra Pacific Power Company d/b/a NV Energy shall provide workpapers demonstrating that it used the correct reserve balances for the Kings Beach diesel units to calculate the compliance revenue requirement.

C. Contemporaneous with its compliance tariff filing following issuance of this Order, Sierra Pacific Power Company d/b/a NV Energy shall file a Kings Beach Revenue Requirement utilizing Commission approved rates.

D. No later than 30 days after the effective date of this Order, Sierra shall file with the Commission a compliance filing showing the total costs that will be allocated to Washoe County ratepayers based on the following methodology: The actual cost to construct Phase II of the Tracy to Silver Lake Transmission Line Project, less the estimated cost to construct the Project under the Preferred Plan=Gross Incremental Cost

E. Sierra Pacific Power Company d/b/a NV Energy shall file tariffs implementing the Commission's findings in this Order within 11 calendar days of the issuance of this Order.

11. Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to file a depreciation case for its electric operations no later than the time it files its next general rate case in 2013, and include therein a completed Life Span Analysis Process for its Ft. Churchill and Valmy 1 generating units.

12. In consultation with the Commission's Regulatory Operations Staff and the Attorney General's Bureau of Consumer Protection, Sierra Pacific Power Company d/b/a NV Energy, is DIRECTED to perform an audit of its own data in order to identify and implement improvements in the quality of its accounting data used to perform depreciation studies. This audit shall be completed in time to be considered in the next depreciation study to be filed with the Commission in 2013.

13. Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to perform a study to ascertain and identify the causes for the extreme variances between Sierra's transmission and distribution plant theoretical and book depreciation reserves and shall file this study in conjunction with its next depreciation study to be filed with the Commission in 2013.

14. In its next general rate case application, Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to provide the Commission accurate information concerning the incremental costs of constructing utility facilities in which additional monies must be spent above the costs to provide reasonable and reliable service as a result of directives from local governing bodies through local ordinances and/or the permitting process associated with land-use planning activities.

15. Prior to its next general rate case application, Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to investigate the cause(s) for the significant variability in the lighting classes' marginal cost of service revenue allocation, and provide the results of its investigation in its next general rate case application, as well as any procedures that may be used to address and mitigate the identified causes.

16. As part of its next general rate case filing, Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to submit a revised customer service fee and an analysis of how the fully implemented Advanced Service Directive program modifies the cost to provide at home visits by utility personnel.

17. Sierra Pacific Power Company d/b/a NV Energy is DIRECTED to track the costs saving related to the elimination or reduction of truck rolls under the Advanced Service Directive program, and to revisit the customer premise visit charge for natural gas services in its next general rate case for its gas division.

18. Sierra Pacific Power Company d/b/a NV Energy must continue charging its existing rates until it has updated its tariff. The new rates resulting from these Dockets will not take effect until after Sierra Pacific Power Company d/b/a NV Energy updates its tariff to reflect the new rates.

19. All arguments of the parties raised in these proceedings, including, but not limited to arguments raised in the hearings, not expressly discussed herein, have been considered and either rejected or found to be non-essential for further support of this Order.

20. The Commission may correct any errors that may have occurred in the drafting or issuance of this Order without further proceedings.

By the Commission,

SAM A. THOMPSON, Chairman

FOR

REBECCA D. WAGNER, Commissioner

ALAINA BURTENSHAW, Commissioner
and Presiding Officer

Attest:
BREANNE POTTER,
Assistant Commission Secretary

Dated: Carson City, Nevada
12-23-10

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

ATTACHMENT 1

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 11/1/2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In the Matter of the Application by **SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY**, filed pursuant to NRS §704.110(3) and NRS §704.110(4), for authority to increase its annual revenue requirement for general rates charged to all classes of customers.	Docket No. 10-06001

STIPULATION

Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") enters into this Stipulation with the Regulatory Operations Staff of the Public Utilities Commission of Nevada ("Staff"); the Office of the Attorney General, Bureau of Consumer Protection ("BCP"); Eldorado Resorts, LLC ("Eldorado"); The Circus and Eldorado Joint Venture d/b/a Silver Legacy Resort Casino Reno ("Silver Legacy"); the Truckee Meadows Water Authority ("TMWA"); Newmont USA, Ltd., d/b/a Newmont Mining Company ("Newmont"); and the City of Sparks (together, the "Parties"). The Parties have been advised that this Stipulation is not opposed by the Board of Regents of the Nevada System of Higher Education ("Board of Regents") or the Northern Nevada Industrial Electric Users (consisting of Cyanco Company, LLC; EP Minerals, Inc.; Heavenly Valley, Limited Partnership; Wimar Tahoe Corporation; John Ascuaga's Nugget; Nevada Cement Company; Premier Chemicals, LLC; The Ridge Tahoe Property Owner Association; and Renown Health the City of Sparks) ("NNIEU").

SUMMARY OF STIPULATION

1. On June 1, 2010, Sierra filed an Application with the Public Utilities Commission of Nevada ("Commission"), designated as Docket No. 10-06001, for authority to increase its annual revenue requirement for general rates charged to all classes of electric

customers and for relief properly related thereto. Staff conducted extensive discovery and filed testimony regarding costs associated with Sierra's Tracy Combined Cycle Facility ("Tracy CC"). No other party conducted discovery or filed testimony regarding the Tracy CC. This Stipulation resolves, fully and finally, all issues raised by Staff in Docket No. 10-06001 regarding the Tracy CC.

2. The Parties agree that the resolution of issues as set forth in this Stipulation is fair, just and reasonable and that the Stipulation is in the public interest. In addition, the Parties represent that the Stipulation settles only issues relating to Docket No. 10-06001, and does not seek relief the Commission is not empowered to grant. Accordingly, the Parties recommend that the Commission accept the Stipulation and implement all of the terms and conditions of the Stipulation.

RECITALS OF FACT

3. On June 1, 2010, Sierra filed an Application with the Public Utilities Commission of Nevada ("Commission"), designated as Docket No. 10-06001, for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

4. Staff and BCP participate in these proceedings as a matter of right. On July 13, 2010, the Commission conducted a Prehearing Conference during which the Commission granted Sierra's Motion to Consolidate Docket Nos. 10-06001, 10-06002, 10-06003, and 10-06004, and Granted Petitions For Leave To Intervene filed by Newmont, NNIEU, TMWA, the Board of Regents, Silver Legacy, and Eldorado. On September 21, 2010, the Commission issued an Order granting the late-filed Petition For Leave To Intervene of the City of Sparks.

5. Staff filed testimony regarding the Tracy CC on October 5, 2010. The Companies filed rebuttal testimony regarding the Tracy CC on October 22, 2010. No other party filed testimony regarding the Tracy CC.

6. This Stipulation resolves, fully and finally, all issues raised by Staff in Docket No. 10-06001 regarding the Tracy CC.

AGREEMENTS

In light of the recitals set forth above, and in consideration of the mutual promises set forth below, the Parties agree as follows:

TRACY CC

7. Sierra withdraws Schedule I-CERT-43 ("Depreciation Expense – Tracy Combined Cycle") and Schedule I-CERT-44 ("Removal of Outside Consultant Fees Supporting Regulatory Proceedings for Tracy Combined Cycle From Plant In Service"). The Company will not seek recovery of the outside consultant fees shown in Schedule I-CERT-44.

8. For purposes of calculating revenue requirements, Sierra shall offset Nevada jurisdictional rate base as of May 31, 2010 by an amount equal to \$4.7 million, to be amortized over a period commencing January 1, 2011, and continuing through the remaining life of the Tracy CC.

9. The Tracy CC ROE incentive shall be applied to Nevada jurisdictional Tracy CC rate base as of May 31, 2010, provided, however, that prior to the application of the Tracy CC ROE incentive, the Nevada jurisdictional Tracy CC rate base as of May 31, 2010 shall be reduced by \$3.3 million. Capital investments in the Tracy CC that are recorded subsequent to May 31, 2010 shall not be eligible for the ROE incentive.

10. Sierra shall not defer in a regulatory asset or seek to recover in a future rate case costs charged by Mr. Connell, Mr. Gohlke, or Mr. Wickersham in connection with litigation of the Tracy CC issues in Docket No. 10-06001.

11. The following testimony shall not be marked or admitted into evidence in Docket No. 10-06001:

Sierra's Direct Case

a) Section III.A. of the Pre-Filed Direct Testimony of C. Kevin Bethel

b) Pre-Filed Direct Testimony of David Gohlke and Andrew McNeil

c) Pre-Filed Direct Testimony of Charles A. Pottey

d) Pre-Filed Direct Testimony of James Connell

e) Section III.A. of the Pre-Filed Direct Testimony of John Lescenski

Sierra's Certification Case

f) The portions of the Pre-Filed Certification Testimony of Sathien Arulanantham that relate to Schedule I-CERT-44

g) The portions of the Pre-Filed Certification Testimony of David Sosa that relate to Schedule I-CERT-44

h) The portions of the Pre-Filed Certification Testimony of Patricia M. Franklin that relate to Schedules H-CERT-43 and I-CERT-43

Staff's Direct Case

i) Pre-Filed Direct Testimony of Paul Maguire

j) The portions of the Pre-Filed Direct Testimony of Gary Cameron that relate to his Recommendation #4

k) The portions of the Pre-Filed Direct Testimony of Mary Pistoresi that relate to her Recommendation #2 and #3

l) The portions of the Pre-Filed Direct Testimony of Fred C. Buck that relate to his Recommendation #3 and #5

m) The portions of the Pre-Filed Direct Testimony of Richard A. Phillips that relate to his Recommendation #5

Sierra's Rebuttal Case

n) Pre-Filed Rebuttal Testimony of David Gohlke and Andrew McNeil

o) Pre-Filed Rebuttal Testimony of James Connell

p) Pre-Filed Rebuttal Testimony of Roberto Denis

q) The portions of the Pre-Filed Rebuttal Testimony of John Lescenski that relate to Mr. Cameron's Recommendation #4, Ms. Pistoresi's Recommendation #2, and Mr. Maguire's testimony relating to the capacity of the Tracy CC at peak

r) The portions of the Pre-Filed Rebuttal Testimony of Kevin Bethel that relate to Mr. Maguire's Recommendation #4 and #5, and Mr. Buck's Recommendation # 3 and #5

s) The portions of the Pre-Filed Rebuttal Testimony of David Sosa that relate to Mr. Maguire's Recommendation #6 and Mr. Phillips's Recommendation #5

12. This Stipulation resolves, fully and finally, all issues raised by Staff in Docket No. 10-06001 regarding the Tracy CC.

GENERAL TERMS AND CONDITIONS

13. This Stipulation represents a compromise of the Parties. Neither this Stipulation, nor its terms, nor the Commission's acceptance of the recommendations contained in this Stipulation shall have any precedential effect in future proceedings.

14. This Stipulation represents a compromise of the issues raised in the consolidated dockets and this Stipulation is in the public interest. The Parties recommend that the Commission accept the Stipulation and all of its terms and conditions.

15. This Stipulation is made upon the express understanding that it constitutes a negotiated settlement. The provisions of this Stipulation are not severable. In the event the Commission does not adopt in total the recommendations contained in the provisions of this Stipulation, then this Stipulation shall be deemed to be withdrawn, without prejudice to any claims or contentions that may have been made or are made in the consolidated dockets; no part of this Stipulation shall be admissible in evidence or in any way described or discussed in any proceeding; and no signatory shall be bound by any of the agreements or provisions contained herein.

16. This Stipulation may be executed in one or more counterparts, all of which together shall constitute the original executed document. This Stipulation may be executed by signatures provided by electronic facsimile transmission, which facsimile signatures shall be as binding and effective as original signatures.

Respectfully submitted this 1st day of November, 2010.

SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

By___________________________ October 29, 2010
Elizabeth Elliot

PUBLIC UITLITIES COMMISSION OF NEVADA, REGULATORY OPERATIONS STAFF

By___________________________ October 29, 2010
Tammy Cordova, Staff Counsel

OFFICE OF THE ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION

By___________________________ October _____, 2010
David M. Norris

ELDORADO RESORTS LLC

By___________________________ October _____, 2010
Kathleen Drakulich

TRUCKEE MEADOWS WATER AUTHORITY

By___________________________ October _____, 2010
Kathleen Drakulich

THE CIRCUS AND ELDORADO JOINT VENTURE DBA SILVER LEGACY RESORT CASINO RENO

By___________________________ October _____, 2010
Kathleen Drakulich

**SIERRA PACIFIC POWER COMPANY
D/B/A NV ENERGY**

By________________________________ October_____, 2010
Elizabeth Elliot

**PUBLIC UITLITIES COMMISSION OF
NEVADA, REGULATORY OPERATIONS STAFF**

By________________________________ October _____, 2010
Tammy Cordova, Staff Counsel

**OFFICE OF THE ATTORNEY GENERAL'S
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By David M. Norris October 29, 2010
David M. Norris

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By________________________________ October _____, 2010
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By________________________________ October _____, 2010
Kathleen Drakulich

**THE CIRCUS AND ELDORADO JOINT
VENTURE DBA SILVER LEGACY RESORT
CASINO RENO**

By________________________________ October _____, 2010

SIERRA PACIFIC POWER COMPANY
D/B/A NV ENERGY

By_______________________________ October_____, 2010
Elizabeth Elliot

PUBLIC UITLITIES COMMISSION OF
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By Kathleen M. Drakulich October 29, 2010
Kathleen Drakulich

NEWMONT MINING CORPORATION

By______________________________ October _____, 2010
Timothy K. Shuba

CITY OF SPARKS

By Shirle Eiting October 29, 2010
Shirle Eiting

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing **SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY'S STIPULATION** filed In Docket No. 10-06001 upon the persons listed below by the following:

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DATED this 1st day of November, 2010.

/s/ Janice Baldarelli
Janice Baldarelli
Legal Secretary
Sierra Pacific Power Company