BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER of the Application of NEVADA POWER COMPANY, d/b/a NV Energy, filed pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers..	)))))	Docket No. 23-06___

NEVADA POWER COMPANY
d/b/a NV Energy

VOLUME 14 of 24

Recorded Test Year ended December 31, 2022
Certification Period ended May 31, 2023
Expected Change in Circumstance Period ending December 31, 2023

JACOB GUDMUNDSEN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Jacob Gudmundsen

Rate Design

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Jacob E. Gudmundsen. My current position is Pricing Analyst for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6100 Neil Road, Reno Nevada. I am filing testimony on behalf of Nevada Power.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Bachelor of Science degree in Economics from Brigham Young University. Since 2022, I have worked in the Rates and Regulatory Affairs department at the Companies where I focus on large customer facility projects, Rule 9 contract agreements and load analyses. More details regarding my professional background and experience are set forth in **Exhibit Gudmundsen-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A PRICING ANALYST.

A. My responsibilities as a Pricing Analyst include supporting pricing initiatives for the Companies, supporting regulatory filings and dockets, and assisting all departments in need of support specific to customer tariffs or rate design.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. No.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the Customer Weighting Factor Study ("CWFS"), attached as **Exhibit Gudmundsen-Direct-2**, which is an input to the Company's Marginal Cost of Service Study ("MCS"), Embedded Cost of Service Study ("ECS"), and Hybrid Cost of Service Study ("HCS"). Jeff Bohrman supports the Company's cost of service studies in this proceeding. As described in more detail below, the CWFS serves as an input to inform the development of the fixed Basic Service Charges ("BSC") that customers pay as a part of their monthly bills. Samantha Prest supports the Company's rate design proposals in this proceeding, including the BSCs.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

- **Exhibit Gudmundsen-Direct-1**, Statement of Qualifications;
- **Exhibit Gudmundsen-Direct-2**, Nevada Power Customer Weighting Factor Study.

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7. Q. WHAT IS THE ROLE OF THE CWFS IN THE DEVELOPMENT OF THE COST OF SERVICE FOR CUSTOMER CLASSES?

A. The CWFS establishes customer weighting factors that identify the share of customer accounts and customer service expenses attributable across rate classes. The Customer Accounts expenses portion of the CWFS represents Federal Energy Regulatory Commission ("FERC") Accounts 901-905. Those FERC Accounts are defined as:

- 901 (Customer Accounts Supervision);
- 902 (Meter Reading);
- 903 (Customer Records/Collections),
- 904 (Uncollectible Accounts); and
- 905 (Miscellaneous Customer Accounts Expense).

The Customer Services and Information expenses portion of the CWFS represents FERC Accounts 907-910. These FERC accounts are defined as:

- 907 (Customer Services Supervision);
- 908 (Customer Assistance);
- 909 (Informational and Instructional Advertising); and
- 910 (Miscellaneous Customer Service and Informational Expenses).

The allocation of these costs through the CWFS results is necessary for the calculation of each customer class's marginal customer cost, which is used to develop the cost basis for each class's BSC. The BSC is a flat monthly charge that is intended to recover fixed investment in meters and other distribution facilities not recovered in other charges, as well as customer-related expenses.

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8. Q. WHY IS IT NECESSARY FOR THE COMPANY TO PERFORM A CWFS?

A. The Company's accounting systems, structures, and procedures gather customer service and customer account expense data at the FERC account level, which are primarily labor-related expenses, but do not track this expense information at the customer class level. Thus, the expenses in FERC Accounts 901-905 and 907-910 must be allocated among all customer classes to accurately reflect cost causation when developing customer costs and determining the cost of service of individual customer classes. The CWFS provides a factual basis for determining how much time employees spend serving customers in each of the customer classes. The weighting factors determined through the CWFS capture the share of customer service and customer account expense attributable across rate classes. **Exhibit Gudmundsen-Direct-2** summarizes the inputs to and results of the CWFS.

9. Q. HOW ARE CUSTOMER CLASSES GROUPED IN THE CWFS?

A. The customer class weighting factors are derived by determining the allocation of customer service and accounts expenses among groups of Nevada Power customer classes. To simplify the CWFS, customer classes with similar costs for customer accounts or customer services accounts are grouped together. Customer groups used in the CWFS are:

i. Residential classes (including multi-family and optional residential Time-of-Use ("TOU") customers) and Residential Public Area Lighting ("RS-PAL");

ii. Residential Net Energy Metering ("NEM") classes (including multi-family NEM, and optional residential TOU NEM customers);

iii. General Service ("GS") classes (including optional GS TOU, GS-PAL & Street Lighting);

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iv. GS NEM classes;

v. Medium GS classes (LGS-1 and OLGS-1-TOU);

vi. Medium GS NEM classes (LGS-1 NEM);

vii. Large GS classes (LGS-2, LGS-3, OLGS-3P-HLF, LSR I and II, and WP); and

viii. Extra Large GS classes (LGS-X).

10. Q. ARE THE GENERAL STRUCTURE AND METHODOLOGIES USED IN DEVELOPING THE CWFS THE SAME AS THOSE APPROVED BY THE COMMISSION IN PREVIOUS PROCEEDINGS?

A. Yes, the majority of the CWFS structure and methodologies remain consistent with those filed with and approved by the Commission in previous general rate case ("GRC") proceedings. There was one minor change to the CWFS completed for this proceeding, however, in that the LGS-1-NEM customer class was identified separately in this CWFS. This customer class was previously rolled into its otherwise applicable rate schedule (LGS-1) but is included separately in the 2023 CWFS due to growth within the class since 2020. Separately identifying these LGS-1-NEM customers allows the Company to ensure that they are treated more consistently with the other NEM customer classes in the CWFS, and allows for the identification of the specific cost of service for these customers.

11. Q. HOW IS THE CWFS COMPLETED?

A. Historical expenses recorded in FERC accounts 901-905 and 907-910 over the test period are compiled to identify departments with more than $25,000 in annual expense charged to these accounts and then these departments receive the CWFS Survey (the "Survey"). The total expenses from the departments included in the

CWFS account for approximately 99.5 percent of all FERC account 901-905 and 907-910 expenses booked during the test period. End of year customer counts, department specific expenses and historical results, if available, are updated and reflected within the Survey, which is then distributed to the identified department representatives with instructions on how to complete the Survey. Survey recipients are asked to complete an allocation of the customer expenses recorded in the test period for their respective areas.

Upon receiving the Survey responses, the data is compiled and reviewed through discussions with department leaders and/or the individuals who were tasked with completing the Survey. This discussion step is in place to ensure that departments are completing their allocations while considering both the past and future operations of their group. Following this initial assessment, the customer class allocation percentage is calculated based on results from each department. The class allocations are applied to the total test period expenses recorded by each department (or to the expected annual expenses for the department in the rate-effective period) for the specific FERC account, allocating dollar amounts to each class grouping. Next, the total department expenses are summed by FERC account and by class grouping. This is shown in the table “Summary of Account Totals” on Page 2 of **Exhibit Gudmundsen-Direct-2**. The total expenses are then divided by the number of customers in each customer group to derive expense-per-customer amounts, as shown in the table “Cost per Customer by Account” on Page 2 of **Exhibit Gudmundsen Direct-2**.

12. Q. HOW ARE THE RESULTS OF THE CWFS PRESENTED?

A. The results of the CWFS are presented in Exhibit Gudmundsen-Direct-2 and are shown on a per customer basis. The residential classes' expense-per-customer serves as the foundation to determine the weighting factor for each remaining class on a relative expense-per-customer basis. The respective weights of the remaining classes in relation to the residential class, shown on Page 1 of **Exhibit Gudmundsen Direct-2**, are calculated as the ratio of the class expense-per-customer to the expense-per-customer of the residential classes. This provides a basis of comparison and supports a proper allocation of expenses between classes. For example, on Page 1 of **Exhibit Gudmundsen-Direct-2**, when examining the weights identified by category, the Large GS cost per customer is $109.51 compared to the Residential Service cost per customer of $37.84. This provides a weight of 2.89 for the Large GS category or, in other words, shows that each Large GS customer's costs are equivalent to 2.89 residential customers. The weights developed in the CWFS are then incorporated into page number 42 (Workpaper 12) of the MCS.

13. Q. ARE ALL FERC CUSTOMER ACCOUNTS AND SERVICES ACCOUNTS HANDLED IN THE SAME MANNER WITHIN THE CWFS?

A. No. Account 904 (Uncollectible Accounts) is handled differently pursuant to the Commission's order in Docket No. 06-11022, which requires that uncollectible costs be allocated using actual bad debt write-off amounts by customer group over the last three years. The expenses in Account 904 are isolated in the Uncollectible Expenses department (D434), therefore, this department's survey is replaced with the results of the three-year bad debt write-off amounts.

14. Q. HOW DID CUSTOMER ACCOUNTS AND SERVICES EXPENSES CHANGE IN THE TEST PERIOD COMPARED TO THOSE INCLUDED IN THE PREVIOUS CWFS?

A. The overall expenditures for departments included in the CWFS, adjusted for any expected changes in expense for specific departments, decreased 0.3 percent to $39,752,835 from $39,874,297 in Nevada Power's 2020 GRC (Docket No. 20-06003). Over the same timeframe, customer counts have increased in all class groupings excluding LGS-X customers. The primary drivers of differences between the 2023 CWFS and the 2020 CWFS are discussed in more detail in the following Q&As.

15. Q. WERE THERE ANY EXPENSES RECORDED IN FERC ACCOUNTS 901-905 OR 907-910 DURING THE TEST PERIOD THAT WERE NOT INCLUDED IN THE CWFS?

A. Yes. As discussed in Q&A 11, only departments with expenses in FERC accounts 901-905 and 907-910 greater than $25,000 are included in the CWFS. Departments with an expense below this threshold are not included. These excluded expenses account for 0.48 percent of total booked 901-910 expenses within the Company.

Additionally, the Support Services South department identified employees incorrectly charged $76,486 in expenses to FERC account 903. Upon further review, it was determined that these expenses should have been recorded to FERC account 921 – Office Supplies and Expenses. Similarly, the UNIX/Storage Systems department determined that $93,683 was misallocated to account 903 and should have been recorded to FERC account 921 – Office Supplies and Expenses. In total, these misallocated expenses accounted for approximately 0.26 percent of total FERC account 901-905 and 907-910 expenses booked within the Company.

16. Q. HOW DO THE CUSTOMER ACCOUNT EXPENSES (ACCOUNTS 901-905) IN THE 2023 CWFS COMPARE TO THE STUDY PRESENTED WITHIN THE 2020 NEVADA POWER GRC?

A. There was a slight increase in overall expenditure for departments included in this CWFS when compared to those in the 2020 CWFS. Total Customer Accounts expenditures increased 1.47 percent from $37,005,364 in the 2020 CWFS to $37,550,940.31 in the 2023 CWFS. Notable changes occurred for the General Service ("GS") NEM and Extra-Large General Service customer classes.

The primary factor behind the increase in the GS NEM class is a change in the allocation of expenses in the billing departments (NVE – South and NVE – North[1]). Billing NVE – South experienced an increase in allocated customer account expenses for GS NEM from $5,867 in the 2020 CWFS to $9,152 in the 2023 CWFS. Likewise, Billing NVE – North saw an increase in allocated customer account expenses for GS NEM from $472 in 2020 to $4,790 in 2023. Accompanied with the modest customer count increase from 112 in the 2020 CWFS to 126 in the 2023 CWFS, the Customer Account expense-per-customer increased.

There was also an increase for the Extra-Large General Service customer classes. Currently, three customers comprise the Extra-Large General Service class; thus, small adjustments in allocations can result in large shifts in per-customer costs. The primary factor behind the increase for these classes is the Billing NVE – South

[1] Note – customer service representatives in the north may respond to a south customer inquiry.

department increasing the allocated Customer Account expenses for Extra Large General Service customers from $2,288 in 2020 to $5,903 in 2023. **Figure Gudmundsen-Direct-1** provides a comparison between the 2023 CWFS to the 2020 CWFS of the revised customer account expenses on an expense-per-customer basis:

FIGURE GUDMUNDSEN-DIRECT 1:

CHANGE IN EXPENSE-PER-CUSTOMER FOR CUSTOMER ACCOUNTS EXPENSES

	Customer Accounts Expenses FERC 901-905		
	Expense-per-Customer Docket 23-06____	Expense-per-Customer Docket 20-06003	
Customer Class	Cost per Customer	Cost per Customer	Difference
Residential Service	$37.84	$40.15	-$2.31
Residential NEM Service	$34.32	$23.09	$11.23
General Service	$32.92	$27.98	$4.94
General NEM Service	$143.33	$82.06	$61.27
Medium General Service	$34.45	$34.09	$0.36
Medium General NEM Service	$111.92	-	-
Large General Service	$109.51	$128.36	-$18.84
Extra Large General Service	$2,102.83	$880.07	$1,222.76

17. Q. WHICH DEPARTMENTS COMPRISE MOST OF THE RECORDED EXPENSES IN THIS STUDY?

A. The largest departments by expense totals (excluding Uncollectable Expenses) are Call Centers – NVE South, Billing – NVE South, and Customer App Development. Together, these departments account for 44.9 percent ($17,829,755) of all expenses included in this study.

18. Q. WERE THERE ANY REALLOCATIONS MADE WITHIN THE CALL CENTER DEPARTMENTS FOR THIS STUDY?

A. Yes. The NVE -South Call Center reallocated $3,034 from FERC account 901 to account 907 and $1,338,345 from FERC account 903 to 908. The Call Center for NVE North reallocated $14 from FERC account 901 to 907 and $10,590 from FERC account 903 to 908.

19. Q. PLEASE DESCRIBE DIFFERENCES IN THE 2023 CWFS RESULTS FOR THE CALL CENTER DEPARTMENTS FROM THIS STUDY AS COMPARED TO THE RESULTS APPROVED IN NEVADA POWER'S 2020 GRC.

A. Call Center total expenses decreased to $10,245,459 in the 2023 CWFS from $11,079,651 in the 2020 CWFS. Per-customer costs increased for most customer classes, only decreasing for Residential Service and Medium GS. The largest expense-per-customer increases were for Residential NEM and GS-NEM customers. Through discussions with department leads, Residential NEM customers were identified to receive the same baseline service as standard Residential Service customers, with additional service for NEM system billing specific needs. As such, expenses were reallocated towards Residential NEM customers in comparison to the 2020 CWFS. This better represents the cost of Call Center services for these customers. The final expense-per-customer results are shown in **Figure Gudmundsen Direct-2** below:

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FIGURE GUDMUNDSEN DIRECT 2:

EXPENSE-PER-CUSTOMER FOR 2023 & 2020 CWFS FOR CALL CENTERS

Call Center Departments North and South Total Expenses
FERC 901-910

Customer Class	Expense-per-Customer Docket 23-06____ Cost per Customer	Expense-per-Customer Docket 20-06003 Cost per Customer	Difference
Residential Service	$10.67	$12.87	-$2.20
Residential NEM Service	$12.69	$3.13	$9.56
General Service	$7.02	$4.43	$2.60
General NEM Service	$7.02	$0.00	$7.02
Medium General Service	$0.34	$4.34	-$4.00
Medium General NEM Service	$0.56	-	-
Large General Service	$0.00	$0.00	$0.00
Extra Large General Service	$0.00	$0.00	$0.00

20. Q. PLEASE DESCRIBE DIFFERENCES IN THE CWFS RESULTS FOR THE BILLING DEPARTMENTS FROM THIS STUDY AS COMPARED TO THE RESULTS APPROVED IN NEVADA POWER'S 2020 GRC.

A. Customer Accounts expenses recorded by the Billing departments show a 13.57 percent decrease in expenses ($1,039,820) compared to 2020. The methodology used by the Billing departments was similar to the methodology used in the 2020 CWFS. Due to a general decrease in overall expenses accompanied by an increase in customer count for most classes, expense per-customer fell in all customer classes except for GS NEM and Extra-Large General Service. This is shown in **Figure Gudmundsen Direct-3** below.

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FIGURE GUDMUNDSEN DIRECT 3:

EXPENSE-PER-CUSTOMER FOR CUSTOMER ACCOUNTS FOR 2023 & 2020 CWFS FOR BILLING

Billing Departments Customer Accounts Expenses
FERC 901-905

Customer Class	Expense-per-Customer Docket 23-06____ Cost per Customer	Expense-per-Customer Docket 20-06003 Cost per Customer	Difference
Residential Service	$5.30	$7.16	-$1.86
Residential NEM Service	$10.01	$12.11	-$2.10
General Service	$9.64	$8.55	$1.09
General NEM Service	$110.65	$56.60	$54.05
Medium General Service	$12.15	$13.45	-$1.30
Medium General NEM Service	$92.04	-	-
Large General Service	$91.29	$114.32	-$23.03
Extra Large General Service	$2,028.92	$796.29	$1,232.63

21. Q. HOW DO THE CUSTOMER SERVICES EXPENSES (ACCOUNTS 907-910) IN THE NEW CWFS COMPARE TO THE STUDY APPROVED IN THE 2020 NEVADA POWER GRC?

A. Overall Customer Service and Informational expenses for departments included in this CWFS have decreased since 2020. Total Service expenditures for this CWFS are $2,201,894 compared to $2,868,932.45 included in the 2020 CWFS.

22. Q. PLEASE DISCUSS THE DECREASE IN EXPENSE-PER-CUSTOMER TOTALS FOR CUSTOMER SERVICES EXPENSES OBSERVED IN THE LARGE AND EXTRA-LARGE GENERAL SERVICE CUSTOMER CLASSES.

A. Downward adjustments in the expense-per-customer for Large GS and Extra-Large General Service customer classes can be attributed to three primary drivers.

First, the Major Accounts – NVE North department was included in the last Nevada Power CWFS in 2020, but it is not included in this study, as noted later in my testimony. In total, this department tracked $176,328 in expenses for Large GS and $12,225.85 for Extra-Large General Service in the 2020 CWFS.

Second, the Renewables department saw a decrease in expenses allocated to the Large GS class from $99,278.70 in 2020 to $24,750.00 in 2023. This decrease is largely due to a portion of these expenses being recovered outside of the Base Tariff General Rates being proposed in this proceeding and through the Renewable Energy Program Rate instead.

Third, the application fee for NEM systems was increased as a result of the approved stipulation in Nevada Power's 2020 GRC. This additional fee revenue acts to recover the related administrative expenses that were previously included in the O&M expenses included in the CWFS. **Figure Gudmundsen-Direct-4** shows the Customer Service and Information Expenses changes on an expense-per-customer basis when comparing 2023 to 2020:

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FIGURE GUDMUNDSEN-DIRECT 4:

CHANGE IN EXPENSE-PER-CUSTOMER FOR CUSTOMER SERVICE AND INFORMATION EXPENSES

	Customer Service Expenses FERC 907-910		
	Expense-per-Customer Docket 23-06____	Expense-per-Customer Docket 20-06003	
Customer Class	Cost per Customer	Cost per Customer	Difference
Residential Service	$1.42	$1.64	-$0.23
Residential NEM Service	$2.85	$10.39	-$7.54
General Service	$1.34	$1.22	$0.12
General NEM Service	$6.88	$26.86	-$19.98
Medium General Service	$2.88	$5.97	-$3.08
Medium General NEM Service	$13.55	-	-
Large General Service	$364.45	$491.58	-$127.13
Extra Large General Service	$12,221.82	$18,211.11	-$5,989.29

23. Q. PLEASE DESCRIBE HOW INFORMATION TECHNOLOGY ("IT") EXPENSES WERE TRACKED IN THIS CWFS COMPARED TO EARLIER STUDIES.

A. In 2022, a corporate level initiative was implemented to consolidate all Company IT related expenses to department D835, Customer App Development. The most significant impact of this initiative in this CWFS was for the Meter Services and Applications department. The FERC account 901-905 and 907-910 expenses for this department decreased from $1,014,420 in the 2020 study to $333,642 in 2023, or -67.11 percent. This decrease is due to the reallocation of all IT related expenses towards the Customer App Development department.

24. Q. HOW WERE THESE IT EXPENSES ALLOCATED ACROSS CUSTOMER CLASSES FOR THIS CWFS?

A. Due to the nature of IT costs coming from different departments, the methodology used to allocate IT expenses across customer classes differs from other departments included in the study. To allocate IT expenses from departments that were surveyed for the study, the provided allocations were used from said departments. These allocations were then weighted by the share of IT expenses from the departments relative to the total. For IT expenses from departments that were not surveyed for the study, customer count percentages were used for the allocations, again weighted by the share of IT expenses from each department relative to the total. Using customer counts as a method for non-surveyed departments is supported by IT resources being used for all customers across different classes.

25. Q. PLEASE DESCRIBE DIFFERENCES IN THE CWFS RESULTS FOR THE MAJOR ACCOUNTS DEPARTMENT FROM THIS STUDY AS COMPARED TO THOSE PRESENTED IN NEVADA POWER'S 2020 GRC.

A. In the 2020 CWFS, expenses were observed to have shifted towards Large GS categories and away from Small and Medium GS categories. The current study results are similar to the 2020 results, with only sight adjustments being made in allocations to the different customer classes. The large majority of expenses still lie within the Large GS customer classes. In anticipation of large events including but not limited to Super Bowl LVIII and Formula 1 racing, department heads have noted that continued time and resource investment into the Large GS classes is expected. Additionally, the Major Accounts department for NVE North was included in the Nevada Power CWFS in 2020. This department is not included in this study, as its total FERC account 901-905 and 907-910 expenses for Nevada Power only totaled $5,770.

26. Q. PLEASE PROVIDE A COMPARISON OF THE FINAL RESULTS OF THE 2023 CWFS TO THE 2020 CWFS.

A. A comparison between the results of the 2023 CWFS to the 2020 CWFS are provided below in **Figure Gudmundsen-Direct-5**.

FIGURE GUDMUNDSEN DIRECT 5:

2023 CUSTOMER WEIGHTING FACTOR STUDY RESULTS COMPARED TO 2020 RESULTS

2023 Nevada Power Customer Weighting Factor Study						
	Customer Accounts FERC 901-904		Customer Services FERC 907-910		Total FERC 901-910	
Customer Class	Cost per Customer	Weight	Cost per Customer	Weight	Cost per Customer	Weight
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	$37.84	1.00	$1.42	1.00	$39.26	1.00
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	$34.32	0.91	$2.85	2.01	$37.17	0.95
General Service - (GS, OGS-TOU, GS-PAL, SL)	$32.92	0.87	$1.34	0.95	$34.27	0.87
General Service - NMR (GS-NEM)	$143.33	3.79	$6.88	4.85	$150.21	3.83
Medium General Service - (LGS-1, OLGS-1-TOU)	$34.45	0.91	$2.88	2.03	$37.33	0.95
Medium General Service - NMR (LGS-1 NEM)	$111.92	2.96	$13.55	9.55	$125.46	3.20
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	$109.51	2.89	$364.45	257.01	$473.96	12.07
Extra Large General Service - (LGS-X)	$2,102.83	55.57	$12,221.82	8618.95	$14,324.65	364.87

2020 Nevada Power Customer Weighting Factor Study						
	Customer Accounts FERC 901-904		Customer Services FERC 907-910		Total FERC 901-910	
Customer Class	Cost per Customer	Weight	Cost per Customer	Weight	Cost per Customer	Weight
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	$40.15	1.00	$1.64	1.00	$41.80	1.00
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	$23.09	0.58	$10.39	6.32	$33.48	0.80
General Service - (GS, OGS-TOU, GS-PAL, SL)	$27.98	0.70	$1.22	0.74	$29.21	0.70
General Service - NMR (GS-NEM)	$82.06	2.04	$26.86	16.34	$108.92	2.61
Medium General Service - (LGS-1, OLGS-1-TOU)	$34.09	0.85	$5.97	3.63	$40.06	0.96
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	$128.36	3.20	$491.58	299.05	$619.93	14.83
Extra Large General Service - (LGS-X)	$880.07	21.92	$18,211.11	11,078.65	$19,091.17	456.77

27. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

EXHIBIT GUDMUNDSEN-DIRECT-1

STATEMENT OF QUALIFICATIONS

JACOB E. GUDMUNDSEN

My name is Jacob E Gudmundsen. My business address is 6100 Neil Rd, Reno, Nevada. I am a Pricing Analyst in the Rates and Regulatory Affairs department for Nevada Power Company, d/b/a NV Energy and Sierra Pacific Power Company, d/b/a NV Energy.

I graduated from Brigham Young University with a Bachelor of Science Degree in Economics in 2022.

I have been employed with the Rates and Regulatory Affairs department at NV Energy since July 2022. My primary responsibilities include providing rates and regulatory analyses for Rule 9 connection agreements, providing general research and analytical support for large customer projects, providing support for other departments within the company on relevant pricing or rates related projects, and support development of the triennial general rate cases.

EXHIBIT GUDMUNDSEN-DIRECT-2

Nevada Power Company - 2023 Customer Weighting Factor Study

	Customer Accounts Expenses FERC 901-905		Customer Services Expenses FERC 907-910		Total FERC 901-910	
Customer Class	Cost per Customer	Weight	Cost per Customer	Weight	Cost per Customer	Weight
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	$37.84	1.00	$1.42	1.00	$39.26	1.00
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	$34.32	0.91	$2.85	2.01	$37.17	0.95
General Service - (GS, OGS-TOU, GS-PAL, SL)	$32.92	0.87	$1.34	0.95	$34.27	0.87
General Service - NMR (GS-NEM)	$143.33	3.79	$6.88	4.85	$150.21	3.83
Medium General Service - (LGS-1, OLGS-1-TOU)	$34.45	0.91	$2.88	2.03	$37.33	0.95
Medium General Service - NMR (LGS-1 NEM)	$111.92	2.96	$13.55	9.55	$125.46	3.20
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	$109.51	2.89	$364.45	257.01	$473.96	12.07
Extra Large General Service - (LGS-X)	$2,102.83	55.57	$12,221.82	8,618.95	$14,324.65	364.87
Overall Weight		0.98		1.54		1.00

Customer Accounts Expenses FERC 901-905		Customer Services Expenses FERC 907-910	
901	Supervision	907	Supervision
902	Meter Reading	908	Customer Assistance
903	Customer Record/Collection	909	Advertising
904	Uncollectibles	910	Misc Cust Serv & Info

Cost per Customer by Account

Account Number	901	902	903	904	905	907	908	909
Customer Class								
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	$1.09	$2.11	$19.34	$15.31	$0.00	$0.01	$1.41	$0.00
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	$1.80	$1.58	$27.09	$3.85	$0.00	$0.36	$2.49	$0.00
General Service - (GS, OGS-TOU, GS-PAL, SL)	$1.38	$2.46	$24.18	$4.90	$0.00	$0.04	$1.31	$0.00
General Service - NMR (GS-NEM)	$17.12	$4.96	$121.25	$0.00	$0.00	$1.79	$5.08	$0.00
Medium General Service - (LGS-1, OLGS1-TOU)	$1.52	$2.43	$16.13	$14.37	$0.00	$0.24	$2.65	$0.00
Medium General Service - NMR (LGS-1 NEM)	$8.70	$7.70	$94.39	$1.13	$0.00	$0.22	$13.33	$0.00
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	$6.92	$5.67	$96.93	$0.00	$0.00	$9.97	$354.48	$0.00
Large General Service - (LGS-X)	$169.34	$7.74	$1,925.75	$0.00	$0.00	$199.27	$12,022.55	$0.00

2020 Customer Count

Customer Class	Customers	% of Total
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	820,481	81.39%
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	72,392	7.18%
General Service - (GS, OGS-TOU, GS-PAL, SL)	79,824	7.92%
General Service - NMR (GS-NEM)1	126	0.01%
Medium General Service - (LGS-1, OLGS1-TOU)	33,338	3.31%
Medium General Service - NMR (LGS-1 NEM)	363	0.04%
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	1,609	0.16%
Extra Large General Service - (LGS-X)	3	0.00%
Total	1,008,136	100.00%

Summary of Account Totals

Account Number	901	902	903	904	905	907	908	909
Customer Class								
Residential Service - (RS, RM, RSL, ORS, ORM, ORS-TOU, ORM-TOU, RS-PAL)	$ 895,590.92	$ 1,727,825.91	$ 15,864,539.07	$ 12,560,618.81	$ -	$ 4,816.96	$ 1,158,639.69	$ -
Residential - NMR (RS-NEM, RS-NEM-TOU, RM-NEM, LRS-NEM)	$ 130,478.80	$ 114,250.82	$ 1,961,435.15	$ 278,448.51	$ -	$ 25,846.14	$ 180,340.15	$ -
General Service - (GS, OGS-TOU, GS-PAL, SL)	$ 110,035.26	$ 196,485.49	$ 1,930,362.56	$ 391,281.16	$ -	$ 2,824.00	$ 104,260.21	$ -
General Service - NMR (GS-NEM)	$ 2,157.59	$ 625.36	$ 15,277.18	$ -	$ -	$ 226.16	$ 640.64	$ -
Medium General Service - (LGS-1, OLGS1-TOU)	$ 50,563.74	$ 80,972.22	$ 537,642.25	$ 479,161.76	$ -	$ 7,922.50	$ 88,242.66	$ -
Medium General Service - NMR (LGS-1 NEM)	$ 3,158.20	$ 2,794.43	$ 34,262.43	$ 411.30	$ -	$ 79.80	$ 4,837.42	$ -
Large General Service - (LGS-2, LGS-3, LSR-1, LSR-2, OLGS-3P-HLF, LGS-WP2, LGS-WP3)	$ 11,132.62	$ 9,126.83	$ 155,993.46	$ -	$ -	$ 16,047.14	$ 570,505.31	$ -
Extra Large General Service - (LGS-X)	$ 508.02	$ 23.21	$ 5,777.24	$ -	$ -	$ 597.82	$ 36,067.64	$ -
ACCOUNT TOTALS	$ 1,203,625.16	$ 2,132,104.27	$ 20,505,289.35	$ 13,709,921.53	$ -	$ 58,360.52	$ 2,143,533.72	$ -
			Customer Accounts Expense:	**$ 37,550,940**			**Customer Services Expense:**	**$ 2,201,894**

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JACOB GUDMUNDSEN, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: June 5, 2023

Jacob Gudmundsen

AMPARO NIETO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy

Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Amparo Nieto

Rate Design

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ATTACHED SCHEDULES

Exhibit Nieto-Direct-1 – Curriculum Vitae

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I. INTRODUCTION AND QUALIFICATIONS

1. Q. PLEASE STATE YOUR NAME AND JOB TITLE.

A. My name is Amparo Nieto. I am an Associate Partner with PA Consulting Group ("PA"). My office is in 348 6th Street, San Francisco, CA, 94103.

2. Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I am an economist with more than 25 years of advisory and testifying experience in the energy industry, across the United States, in various Canadian provinces, and overseas, particularly in matters of energy sector regulation, electricity and natural gas marginal cost studies, and time of use ("TOU") rate options that enhance customer incentives for beneficial electrification and investment in distributed energy resources ("DERs"). In 2021-22, I advised the energy division of the California Public Utilities Commission with regard to the replacement of the California investor-owned utilities' ("IOUs") Net Energy Metering ("NEM") program (NEM 3.0), for a net energy billing approach that would more closely align compensation of rooftop solar generation and battery storage with incremental value to the grid, leading to a more sustainable transition to decarbonization in the state. In New York, I was involved in the initial design stages of the commission's Reforming the Energy Vision proceeding, which set the conceptual basis for the development of compensation of exports to the grid based both on system-wide and locational marginal costs as part of the distribution value of DERs. For more than a decade, I have provided training on electricity marginal costing and electricity rate design for utility rate managers and energy commissions. I currently lead a membership-based utility working group that discusses rate innovation and regulatory strategies. Earlier in my career, I advised various energy regulatory commissions and independent system operators on market reforms to introduce higher transparency in wholesale energy markets, capacity payment mechanisms and better integration of demand response programs. I have been published in various energy journals and I often speak at industry and academic forums. I have a Master of Arts degree in Economics from the Madrid Institute for Fiscal Studies in Spain, and a Bachelor of Arts degree. in Economics from the University of Carlos III of Madrid, Spain. My Curriculum Vitae is set forth in Exhibit Nieto-Direct-1.

3. Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company").

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION") OR OTHER PUBLIC UTILITIES COMMISSIONS?

A. Yes. I testified on behalf of the Company before the Commission in 2016, in the context of Sierra Pacific Power Company d/b/a NV Energy's ("Sierra") General Rate Case ("GRC") in Docket No. 16-06006. I have extensively testified on marginal and embedded cost of service studies as well as on application of those results to set efficient residential and commercial rates on behalf of utilities in California, New York, Maine, New Hampshire, Minnesota, North Dakota, South Dakota, North Carolina, and Arizona. My statement of qualifications attached as Exhibit Nieto-Direct-1 includes the broader list of testimony in these areas.

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5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was retained by Nevada Power to conduct an in-depth review of its cost-of-service methods, reconciliation approaches and rate design decisions in the current Nevada Power GRC. I have assessed the suitability and robustness of both the marginal cost of service study ("MCOS"), and the embedded cost of service study ("ECOS") methods that the Company prepared in this GRC to be responsive to the Commission's directives. Additionally, I examined the Company's proposed rate design changes, and the development of new TOU periods. My testimony is primarily focused on MCOS methods, with a lower emphasis on the ECOS options. This testimony is organized as follows:

- In *Section 2*, I provide an overview of the goals and principles that guide class revenue requirement allocation and energy rate design.
- In *Section 3*, I summarize my assessment of the specific MCOS methods employed by the Company, the strength of the analysis and assumptions used, and any potential refinements that could be made to the study.
- In *Section* 4, I provide a brief overview on the relative merits of the "hybrid" ECOS and its use for revenue class allocation compared to MCOS.
- In *Section 5* I review the Company's proposed rate design, particularly those that involve rebalancing of cost recovery between the fixed and variable components in existing residential rates, and to what extent the Company's proposed changes are supported by the MCOS results while balancing other important rate design goals.
- In *Section 6*, I review the basis for the Company's proposed TOU periods and assess the hourly marginal cost profiles as the optimal starting point for TOU recommendations.

II. COST OF SERVICE GUIDING PRINCIPLES

6. Q. IN SELECTING A COST-OF-SERVICE STUDY METHOD FOR USE IN RATE MAKING, WHAT ARE THE GOVERNING PRINCIPLES?

A. To be useful in utility ratemaking, a cost-of-service study must be able to derive the correct information in order to allow setting rates that ultimately best serve the well accepted principles of economic regulation. These principles can be summarized as follows: (a) rates should reveal the incremental cost of usage in order to be conducive to economic efficiency in customer's marginal usage and investment decisions, (b) rates should provide for equitable treatment of customers, (c) rates should allow for revenue adequacy to enable appropriate rate return on investments needed to meet customer's demands and reliability, (d) rate changes should respect gradualism to account for affordability and avoidance of rate shock. Achieving rates that simultaneously preserve inter- and intra-class equity, and efficiency in price signals, requires a marginal cost approach. The results of a well-designed MCOS study will always provide unbiassed information on the size of fixed charges, the required time-differentiation, and the structure of the proposed rates consistent with the goals stated above. Additionally, a MCOS study can guide the rate structure that would least distort departures from an initial efficient allocation if needed to adopt a specific low-income program or meet specific temporary promotion of state or federal environmental policy goals.

7. Q. IS THE USE OF MARGINAL COSTS FOR REVENUE REQUIREMENT ALLOCATION PURPOSES BASED ON A SOLID THEORETICAL FOUNDATION?

A. Yes. The concept of marginal cost has a central place in regulatory pricing because sending economically-efficient price signals to consumers is grounded in the concept of marginal costs. By extension, standard economic theory also recognizes the critical role of marginal costs in setting class revenue targets and minimization of cross subsidies. The later requires understanding appropriately the term of "economic cost causation." The initial condition for equity as per the definition of economic causation is that no rate class should pay below the marginal costs of serving that class. The second condition is that when rates need to include cost recovery beyond marginal costs, each class must pay an efficient share of the revenue requirement, determined in such a way that prevents uneconomic bypass. Thus, the concepts of efficiency, fairness and equity are closely interrelated and defined by the foundation of the particular cost of service study.

8. Q. PLEASE EXPLAIN WHAT IS AN EFFICIENT ALLOCATION OF SUNK COSTS.

A. In absence of externalities, and in competitive markets, prices equal to marginal cost already provide economically efficient signals, and serve to allocate resources to those who value the product more than its marginal cost. In the context of natural monopolies, costs exhibit economies of scale, and therefore, investments tend to be "lumpy." [1] As a result, prices at marginal cost are not sufficient to recover revenue requirement. The costs associated with the existing system that do not vary with

[1] Economies of scale are a result of subadditivity of costs found in grid planning, meaning it is most cost-effective installing a larger than strictly necessary transmission, distribution transformer or feeder when load materializes, as opposed to smaller plant additions to exactly match annual demand growth as it materializes.

incremental demands are sunk costs that need to be apportioned to customers via regulated rates. The appropriate solution requires prices that maximize consumer surplus (the value of the product net of the price paid) subject to a revenue requirement constraint. One of the best-known marginal cost-based revenue requirement approaches to allocate sunk costs to customer classes was discussed by Ramsey in 1927.[2] Ramsey demonstrated that when allocating non-marginal costs to customer classes in a monopoly setting, maximum social economic welfare is achieved when consumers with relatively more price-elastic demands pay a lower mark-up over marginal cost, compared to customers that are less reactive to price changes, to make the utility whole. Price elasticity of demand is defined as the percentage change in quantity demanded divided by the percent change in price. Thus, in applying this inverse-price elasticity-based allocation method, the theory is that consumption levels seen in the context of a regulated sector will deviate the least from the optimal level of usage and customer investments expected in a perfectly competitive market in absence of a natural monopoly.[3]

9. Q. WHAT METHOD DOES THE COMPANY PROPOSE TO USE FOR CLASS REVENUE ALLOCATION?

A. The Company continues to endorse class revenue requirement allocations on the basis of equal percentage marginal cost ("EPMC"), a methodology that is commonly used by many utilities that use marginal costs for decisions on class revenue requirements. EPMC is a variant of Ramsey pricing, that, by definition, assumes all customer classes have equal price-elasticity of demand. EPMC allocates revenue requirement to classes based on their relative ratio of marginal

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[2] *Ramsey, F.P. 1927. A contribution to the theory of taxation.* Economic Journal 37, 47–61

[3] Externalities such as marginal environmental costs are also important from society's marginal cost perspective and to some extent measures will be put in place such as renewable portfolio standard ("RPS") requirements and decarbonization targets so that market players internalize these costs.

costs and revenue requirement. The Company does this reconciliation on a functional basis. In practice, different customers respond differently to rate changes and therefore EPMC allocations can be modified based on qualitative information on price elasticities of demand that may be available. The goal is assigning fixed costs in a manner that minimizes uneconomic bypass of the system. Uneconomic bypass implies customers opting for onsite solar distributed generation, or distributed generation paired with storage, that is more costly to generate than the cost to serve the customer loads with utility-scale renewable. The Company has taken this into consideration by relying on EPMC as a starting point, and subsequently capping residential and other classes' rate increases below EPMC-based allocations to account for potentially unacceptable customer bill impacts.

III. REVIEW OF MARGINAL COST STUDY

10. Q. PLEASE DEFINE MARGINAL COST.

A. Estimating marginal costs of electricity service requires answering the following questions: How would the utility's costs change to supply an additional kWh or kW at a particular time of day and month, and a given voltage level? How does the utility change when connecting a new customer, and what is the opportunity cost of providing that service? Marginal cost is a forward-looking concept that maximizes efficient price signal when it includes both private and social costs, consistent with prevailing impact of costs relevant to the particular utility, as well as its incremental cost of capital, market environment, regulatory constraints, and any public policy affecting the incremental cost of meeting demand. In an ideal setting, proper calculation of these marginal costs will provide efficient price signals to customers, which, in turn, will lead to more efficient consumption

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decisions and more efficient system expansion that balances the incremental costs of utility infrastructure with the value of incremental electricity to the customer.

11. Q. WHAT ARE THE TWO MAIN DEFINITIONS OF MARGINAL COST IN ECONOMIC THEORY?

A. Marginal costs are typically categorized in economics as either being estimated in the short-run or the long-run (i.e., the fundamental distinction between short-run and long-run marginal costs is the assumption over which inputs are variable when demand changes). Specifically, short-run marginal cost (or "SRMC") is defined as the cost associated with a customer's incremental change in demand in the very near term when plant (capacity) is fixed. In the energy cost of service studies, SRMCs do not just include variable expenses and losses, but also a marginal outage cost component, based on expected likelihood of curtailment or value of loss load ("VOLL"), in hours where capacity is insufficient to meet demand. Long-run marginal cost (or "LRMC'), by contrast, is the cost of an incremental change in demand assuming that all factors of production/delivery can be adjusted to meet incremental demand, and that such adjustment is done in a manner that restores optimality over time. This second concept does not have a specific timeframe, as it is defined as the least-cost combination of inputs consistently achieving an optimally-sized plant.

12. Q. HAS THE COMPANY TRADITIONALLY ADOPTED A LONG-RUN MARGINAL COST APPROACH IN ITS GENERAL RATE CASES, AND HAS THE COMMISSION ALWAYS EXPLICTLY EMBRACED THIS APPROACH?

A. Yes. Nevada's long-standing practice is to conduct a "LRMC" MCOS, where a LRMC approach is intended as the method that seeks to identify the on-going changes in long-term marginal cost of serving peak demand and energy. With the exception of the estimation of short-run marginal energy costs ("MECs"), the Company has estimated proxies for long-run marginal costs for all other components of service, in every GRC for NPC and SPPC, since the mid-80's, and the Commission has embraced conceptually speaking these methods in every GRC, including the most recent Sierra case. This means that the Nevada Commission has embraced marginal costs as the method for both class revenue allocation and rate design for about 30 years. It has also alluded to the benefits of long-run marginal cost approaches in generation and grid investment throughout numerous general rate cases. A primary advantage of these methods that the Commission recognized in several of its decisions is that they provide customers with a long-term view of demand-related unit costs which can assist them in investment decisions with long-term implications. An example is the long-term incremental cost of customer investments that may increase the customer's peak demand. The Commission also has recognized that it serves to produce relatively stable marginal cost, compared to shorter-term marginal cost approaches, which ultimately promotes rate stability. My review of the Company's methods is confined to assessing the Company's MCOS methods largely within this long-term marginal conceptual framework.

13. Q. COULD YOU PLEASE PROVIDE AN EXAMPLE WHERE THE COMMISSION HAS EXPLICITLY STATED ITS VIEWS OF SUCH ADVANTAGES OF A LONG-RUN MARGINAL COST APPROACH?

A. Yes. As I mentioned, the Commission has favored the use of long-run marginal cost approaches in both class revenue requirement and rate design, and the Commission's views of the specific advantages of this approach were explicitly mentioned in its concluding statements during the two-year Commission-led investigation proceeding that took place in 2012 and 2013, regarding the continued use of marginal cost of service studies. In the February 2013 Order, p.13, the Commission stated: "*The lumpy nature of utility plan investments in the real world does support the use of a long-run marginal costs in order to promote rate stability as opposed to the economic ideal of short-run marginal costs. The major investment decisions a consumer makes with regards to energy efficiency, such as the purchase of a home or air conditioning units, are long-term in nature.*" [4]

[4] Docket No. 11-12025, Order, at a general session of the Public Utilities Commission of Nevada, held at its offices on February 14. 2013, "Investigation regarding the continued use of marginal costs of service in determining the revenue required from each class and the from each class and the extent to which general marginal cost study guidelines should be established". On December 21, 2011, the Commission launched said investigation and it concluded with the February 2013 Order. In the same concluding statements of the 2011 Docket, the Commission also stated that the use of the MCOS methodology is consistent with the Nevada energy policy in NRS 701.010(d), which encourages public utilities to promote and take action toward energy conservation.

14. Q. DURING THE 2022 SIERRA GRC (DOCKET NO. 22-06014), DR. OTSUKA OF THE REGULATORY OPERATIONS STAFF ARGUED THAT THE USE OF A LRMC APPROACH IS NOT A REALISTIC SCENARIO THAT SHOULD BE CONSIDERED AND REFERRED TO A WORKSHOP THAT YOU CONDUCTED IN THE PAST. WHAT IS YOUR RESPONSE TO HIS STATEMENTS?

A. I reviewed the direct testimony of Dr. Otsuka, which included as an attachment to his testimony a copy of a subsection of a training seminar that I conducted in 2010 for utilities and commissioners. I organized this training almost once a year for about a decade, as part of helping utilities and regulators becoming familiar with the economic principles and approaches behind cost studies and rate setting. These workshops included a discussion of the relative merits of alternative marginal cost study approaches, usually employed in the industry. An attachment to Dr. Otsuka's testimony, included copies of a few introductory slides from the workshop materials. These bullets essentially stated that LRMC cannot result in a forecast of future prices, as by definition they are the result of an optimal system or equivalently, a system in equilibrium that is not a depiction of actual system marginal costs.[5] Dr. Otsuka uses this statement to invalidate any LRMC approaches (or proxy methods) in the context of ratemaking. This statement was taken out of context as it was not a conclusive statement regarding LRMC's relevance in ratemaking. To provide more context, during the referred training, I explained that rates would ideally be reflective of a utility's expected long-term planning response to changes in energy usage or demand. The main notion explained during that introduction, and later discussed further during the workshop, is that neither SRMC

[5] "Attachment Y0-4, Marginal Costing for Electric Utilities," National Economic Research Associates Economic Consulting ("NERA"), April 7-9, 2010.

or LRMC, in their strict standard textbook definition, provide the correct approach when estimating marginal-cost based signals in utility rates that need to be in place for a period of time. Specifically with regards to LRMC, my discussion alluded to the shortcomings of methods that try to estimate LRMC by adhering to the theorical condition that the system must be equilibrium, i.e., the point at which a utility's LRMC is equal to the SRMC.[6] Because the system is rarely entirely optimal, a situation where LRMC matches the prevailing marginal cost associated with meeting demand at a given time is not expected to materialize. My workshop in other materials of the same section (not attached by Dr. Otsuka) discussed that point and later illustrates this problem with examples of specific LRMC methods that heavily depart from actual long-term utility system planning and/or ongoing cost impact of demands on the system, largely diluting the efficiency benefits of marginal cost pricing. These included the "Differential Method" approach, which calculates LRMC as the difference in two hypothetical budgets, one with high load growth and another with low load growth, or the "Present Worth or Deferral Method" that has been applied in the past and assumes that a multi-year transmission project will be shifted by one year when load is reduced and calculates LRMC as the savings associated with the deferral assuming that the existing plan differs only from the new one in timing. I do not recommend these methods that try to recreate an 'reoptimized' planning since they are less reflective of actual relationships between long-term investment and added peak load. In contrast, marginal cost studies that use a multi-year timeframe to review a combination of historical and planned capacity additions per peak load growth have an important place in efficient utility ratemaking. They can do a reasonable job at capturing long-

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[6] SRMC may rise substantially in the event of scarce capacity and may therefore increase above LRMC. In general, SRMC is below LRMC in the presence of excess capacity. For grid purposes, SRMC is not directly applicable because the utilities plan for grid expansion sufficiently ahead of the need to avoid electricity service disruptions and/or quality of service penalties.

term cost impacts from ongoing planning decisions and still are generally considered valid for efficient rate design because they do not attempt to reflect an optimized system.

A long-term marginal cost study such as the one adopted by the Company in this rate case falls within that category, because the study relaxes the interpretation of LRMC in both generation costs (MECs are not estimated with an optimized generation resource portfolio in mind) and grid marginal costs approaches (long-term review of grid planned investment per kW of peak load growth is used to approximate marginal cost that will avert load curtailment, but it does not necessarily reflect optimality). To sum it up, the discussion that Dr. Otsuka is referring to was not intended to undermine the value of well-designed long-term marginal cost estimation methods.

15. Q. HOW DOES THE COMPANY ESTIMATE MARGINAL ENERGY COSTS IN THIS PROCEEDING AND DO YOU FIND IT IS THE CORRECT APPROACH?

A. The Company's MECs are based on PROMOD simulations using generation resources and loads in Nevada Power's system for the period 2024-2026, i.e., the expected rate effective period. The simulation uses the entire Company's resources and loads while recognizing that there are external markets in the north and the south and each market has an import limit. Upon review of the details of the simulation my conclusion is that PROMOD simulations of the Company's own combined system produce suitable short-run marginal energy costs that are based on accurate estimates of hourly system lambda, which is consistent with best practice methods in the context of a vertically integrated utility with ties to external markets. To maximize efficiency in price signals in rates, a near-term marginal energy cost projection needs to be used for years when the rates will be in effect, and the Company's MEC estimates satisfy that condition.

16. Q. DO YOU CONSIDER THAT THE COMPANY COULD IMPROVE THE MEC ESTIMATE APPROACH BY FORECASTING THE BROADER MARKET ENERGY PRICES?

A. The Company participates in the Energy Imbalance Market ("EIM"), buy buying or selling power in real-time as needed to minimize costs or maximize benefits which ultimately offset costs to native customers. EIM prices, in that sense, represent the opportunity cost when Nevada Power is supplying marginal units of native load in real-time (selling less energy in the market, or buying more from the market, if prices are lower than the Company's marginal unit). There are limitations in conceptually relying on real-time market energy prices as the basis for MECs for purposes of setting rates as the hourly EIM prices[7] are generally very volatile and do not reflect the typical marginal energy cost of meeting anticipated demands at a given hour. There is not yet a day-ahead ("DA") EIM market and therefore no history of EIM DA prices. Secondly, even if there was a history of DA EIM prices, relying on historical market prices may prove not fully representative of pure forward-looking market price profiles, particularly due to constantly evolving changes in the region's generation mix and load profiles. Thus, a simulation of forward prices shaped by hourly EIM prices would be suboptimal. Lacking a comprehensive simulation of the entire WECC region, which would prove very challenging for the Company to perform, given the current construct, I

[7] The historical profiles are not useful to allocate forward prices as they are sensitive to unique gas supply constraints and scarcity-related events that occurred in 2022, as demonstrated by EIM prices well exceeding $300/MWh during the top 80 hours of the year.

find that the Company's use of PROMOD to estimate MEC is reasonable. It is also an appropriate approach, particularly given the large size of Nevada Power's system, and the fact that it is as a summer-peaking utility experiencing a transition towards more heavily renewable generation mix, comparable to the rest of the region. Once a DA market is adopted and appropriate history is developed on DA market profiles, the Company may be able to consider expectations of EIM DA prices in its PROMOD simulations as it pertains to both purchases and sales in the broader interconnected region.

17. Q. DO YOU AGREE WITH THE CALCULATION OF THE RENEWABLE MARGINAL COST ADDER ESTIMATED BY THE MCOS?

A. Yes, I think it is appropriate, particularly given the lack of liquid market for Portfolio Energy Certificates in the region. Including the incremental Renewable Portfolio Standard ("RPS") cost into the calculation of MECs is attributed to all hours of the year, since all kWh sales on the system contribute equally to the RPS requirement. I agree that a renewable 'adder' is appropriate to reflect the higher cost of meeting *incremental* load to the extent that renewable resources have higher costs than conventional plants and assuming that current contracted renewable capacity does not largely exceed the required RPS level.

18. Q. DOES THE COMPANY'S MARGINAL GENERATION CAPACITY COST METHOD REPRESENTS THE LEAST-COST CAPACITY UNIT?

A. Yes. The Company's study correctly identifies the combustion turbine ("CT") as the least-cost unit to provide peaking capacity, based on its lower annualized investment cost compared to alternatives. The Company's choice of a CT is consistent with a system said to be in equilibrium, from the point of view of capacity entry, and the Company witness recognize that the CT is not necessarily the next generation unit that the Company plans to build to add peaking capacity. Using the cost of a CT is generally consistent with the fixed cost of adding pure capacity in a system that is approximately satisfying the target planning reserve margin requirement (i.e., reasonably near the target Loss of Load Hours ("LOLH")). In that context, an increase in expected curtailment-related cost resulting from an anticipated demand increment in hours of relatively higher system stress will be expected to approximately equal the annualized fixed costs of the least-cost unit of generation capacity that would be added to mitigate the curtailment cost increase. This approach can lead to undervaluing demand response in the near term if it includes several years when capacity is persistently insufficient and LOLH is above the target LOLH level, and overvaluing when the reverse is true. The Commission has recognized this potential departure from actual near-term marginal cost but as I discussed above, it has adopted the least-cost capacity unit concept for stability purposes, and to support a long-term cost view of incremental demand growth in hours of system or grid stress.

19. Q. DID YOU REVIEW THE APPROACH USED BY THE COMPANY TO ALLOCATE MARGINAL GENERATION CAPACITY COSTS TO HOURS?

A. Yes. The Company relies on a simulation of Loss of Load Probability ("LOLP") to assign the annualized marginal generation capacity costs to hours. Estimates of LOLP reflect the relative expected risk of each hour in the year to experience involuntary load curtailments (customer outage costs) or to trigger high-cost emergency purchases. LOLP allocators account for factors other than peak load conditions that may affect unserved energy, such as planned and unplanned outage

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d/b/a NV Energy

of generation resources. I reviewed the LOLP methodology and found it to be consistent with the standard approach. The resulting LOLP profile is reflective of a system that is experiencing expansion of non-dispatchable and variable renewable resources, together with growing climate and weather variability. All these factors lead to increased system variability and mean that the hour of highest load is no longer necessarily the most stressed hour of the year. The simulated LOLPs reveal that hours of risk are now centered around the evening hours in the summer and are significantly high after the system has experienced its gross peak demand. The LOLPs are mostly concentrated in the months of July and August (90 percent), with the remaining 10 percent split between June and September (6 percent, and 4 percent, respectively). It is reasonable to expect that hours when the Company experiences a high risk of unserved energy and bilateral emergency energy market transactions take place are likely to be among the critical hours expected in the Western Electricity Coordinating Council ("WECC") region, particularly WECC-CA and WECC-NW regions.[8]

20. Q. WHAT IS YOUR ASSESSMENT OF THE TIMEFRAME USED IN THE LOLP SIMULATION?

A. The years used in the Company's LOLP modeling are consistent with the rate effective period, i.e., 2024-2026. As a result, the simulation uses the system loads and generation resource mix expected in those years, after additions of renewable and battery systems, both standalone and paired with solar. This helps produce efficient time of use price signals in rates, because the generation costs, allocated to hours using LOLPs, are a critical input to the Company's proposed time of use

[8] NERC's 2033 Resource Adequacy report has identified increasing risk associated with renewable generation resource variability and the increased need of additional dispatchable capacity to limit risk in late evening hours, which is consistent with Nevada Power's LOLP modelling.

prices. By using the timeframe that overlaps with the rate effective period, customers will respond to TOU prices that reflect the prevailing time-differentiation in cost impact of their incremental usage decisions by time of day.

21. Q. DO YOU CONSIDER THAT THE COMPANY HAS ADEQUATELY MODELLED BATTERY DISPATCH IN LOLP CALCULATIONS?

A. Yes. I confirmed that the Company assumes all available battery systems are dispatched to offset the highest marginal energy costs, which is reflective of how batteries are typically dispatched, and generally coincide with the time of day when the sun is setting and solar generation output declines, while loads continue to be high. As a result, the highest LOLP values are found in late evening/early night of summer days, in particular between 6 pm and 10 pm in July, and between 5 p.m. and 9 p.m. in August. There is some LOLP continuing through 11 pm. This is driven to a large extent, by the effect of battery dispatch. In conclusion, the simulated LOLP results produce accurate results in that they signal the hours where generation capacity additions and/or increased demand response capability would have the highest value to the system, i.e., in early evening hours when battery is dispatched and immediately after. Given the relatively large geographical size of the Companies' system in the WECC-NW and NW-CA regions, and the fact that both the Company and WECC as a whole is summer-peaking, it is reasonable to expect that hours when the Company experiences a higher risk of unserved energy and where emergency bilateral energy transactions take place are also likely to be among the critical hours in the WECC-CA and WECC-NW regions. [9]

[9] NERC's 2033 Resource Adequacy report has identified increasing risk associated with renewable generation resource variability and the increased need of additional dispatchable capacity to limit risk in late evening hours, which is consistent with Nevada Power's LOLP modelling.

22. Q. DO YOU CONSIDER THAT THE COMPANY'S USE OF A "JOINT UTILITY" LOLP SIMULATION IS CORRECT, VERSUS RELYING EXCLUSIVELY ON NEVADA POWER'S SYSTEM?

A. Yes, I do. The Company's LOLP modelling has correctly simulated a joint dispatch of its north and south system resources. This allows the model to simulate the actual resource dispatch that the Company performs to meet system-wide hourly loads on a daily basis. The Company will dispatch the next least-cost generating unit in the merit order dispatch, regardless of whether that unit is located in the South or the North.[10] Thus, the notion of only using Nevada Power's system resources and loads in LOLP modelling would be at odds with the manner in which the Company dispatches its own system resources. The implication of using an LOLP simulation that only modelled the South's system resources is that it is susceptible to produce distorted outcomes in cost allocation. An example can serve to illustrate this distortion. Let's assume that at 4 p.m., Nevada Power expects that load will be 200 MW higher than the load experienced at 3 p.m. Let's also assume that the Company, in simulating LOLPs, is assuming that it can only rely on generation resources located in the South to meet that demand increase, and that the generation mix in the South is such that it has little generation or battery capacity available for dispatch at 4 pm, compared to the North generation non-renewable/battery resources that are not yet committed in that hour. As a result, in this scenario, the available generation in the South is insufficient to reliably meet the 200 MW load increase at 4 pm, and the modeling, other things equal, produces a very high LOLP at that hour, e.g., 5 times higher compared to LOLP in the prior hour, signaling that the Company would need to either curtail load or rely on high-cost emergency

[10] In doing so, the Company accounts for any interconnection limits that may exist at any given time, hence if there are any instances where constraints are expected to prevent the Company from meeting marginal demand in the north with generation located in the south, or vice versa, the corresponding LOLP impacts are factored in the simulation.

purchases. As a result, the Company allocates a significant share of the overall summer generation capacity cost to 4 pm. In practice, the actual Company-wide resource availability is much higher than what is modelled, meaning that the Company predictably has a reserve margin still close to the target 16 percent at 4 p.m., when considering the joint North and South resources and loads. Nevada Power-only LOLP generation capacity cost allocators would use the relatively proportions of LOLP across hours and effectively assign a disproportionate amount of generation cost responsibility to hour 4 pm, shifting away from the much riskier hours of 5 pm and into the early night. This LOLP analysis would lead to a much higher cost allocation to customers that use more energy at 4 pm, compared to 3 p.m. which would not be cost-based. When translated to rates, the South LOLP-model could lead to a shorter on peak period definition, e.g., consistent with only 3 pm to 7 pm, potentially leaving 7 p.m. to 9 p.m. treated as off-peak hours. The distortions would have implications as customers would have no incentive to shift usage away from 8 p.m. or to delay charging their electric vehicles ("EVs"). Finally, a South-only LOLP modeling would make the LOLP profile potentially depart even more from the overall risk profile of the Company as an active participant in the broader market. Given the impracticality of simulating the entire WECC regional resources and loads, as well as regional interconnection limits, the Company is correctly simulating LOLPs that take into account its entire system resources.

23. Q. HOW HAS THE COMPANY ESTIMATED MARGINAL TRANSMISSION AND DISTRIBUTION ("T&D") DEMAND COSTS?

A. The Company's MCOS computes T&D marginal costs using a method commonly used in the industry when the goal is a proxy LRMC estimate. This method is a linear regression analysis, also known as Ordinary Least Squares. The dependent variable is the annual cumulative growth-related plant over a 25-year period (2001-2022, plus a three-year forecast through 2025). The regression derives the incremental cost of capacity additions by estimating the coefficient of the independent variable (peak load). For transmission, peak loads are based on annual maximum Control Area loads, while for the distribution demand and the non-revenue feeder regressions, the Company uses distribution system loads that exclude transmission-served loads. Annual growth-related plant is estimated by the Company excluding projects related to meeting specific customer connections or projects driven by grid modernization unrelated to growth. These costs are stated in 2024 dollars using Handy-Whitman indexes. I also verified that the Company appropriately excluded investments associated with "source of supply" transmission for the calculation of marginal transmission costs.

24. Q. WHAT IS YOUR OPINION ON THE USE OF A REGRESSION APPROACH FOR OBTAINING LONG-TERM MARGINAL COST ESTIMATES OF T&D?

A. The Company's regression analysis fits well with a long-run approach that aims to reduce the impact of economies of scale typically exhibited by grid investments and found in least-cost utility planning process. This conceptual method that relies on a regression analysis is used by other utilities in the industry, including in California and New Hampshire. A regression relies on data from utility's actual /forecasted investment in growth-related plan, as opposed to a hypothetical planning process. Reliance in past investments is in this case necessary to produce a long-term view of incremental dollar of investments per kW of peak load growth, due to inherent uncertainty in a long-term forecast of peak load-driven investments over the long-term forward-looking horizon. The Company's use of a 25-year period is long enough to approximate a long-term view of investment cycles. At the same time, a longer timeframe would not be advisable, since the longer the timeframe is, the higher the possibility of the approach to be sensitive to one or more periods of economic recession, changes in technology, and/or changes in design standards over time, all of which have an impact on the ongoing relationship between cost change and per peak load addition. The Company has confirmed that grid planning design standards to meet peak load growth have not changed over that period. There are, however, other factors, beyond changes in utility planning design standards or economies of scale, that the analysis must attempt to control for, such as expansionary or recessionary economic cycles.

25. Q. PLEASE EXPLAIN HOW THE COMPANY'S REGRESSION ANALYSIS HAS ACCOUNTED FOR SHIFTS IN PEAK DEMAND GROWTH DUE TO THE 2008 ECONOMIC RECESSION OR OTHER FACTORS.

A. As I mentioned, any severe recession, just as an expansionary cycle of the economy, affects the pace of annual growth of demand and can create what is known in statistics as a "regression discontinuity".[11] For the regression model to produce the highest goodness of fit (understood as the ability of the model to explain the underlying on-going variability in cost per peak load), it may be necessary to adjust the model specification by adding a second independent variable, in particular a dummy variable, also known as a binary variable. The dummy or binary variable serves to isolate the expected impact of the recession and/or other factors that are causing a discontinuity with prior data.[12] A review of the peak load growth experienced through the 25-year period and used as independent variable in the

[11] The LOS regression is used to identify a linear equation that best fits the data or observations of investment and peak load data. A recession can either change the intercept or the slope, or both, of the fitted line across observations over time.

[12] The model is defined as having a Dummy (D) and a coefficient δ defined as $y=\beta0+\delta D+\beta1x+e$. Using this regression effectively results in a change in the intercept in years when D is assigned a value equal to 1.

regression, reveals that the annual peak demand growth rates have continued to exhibit years of negative growth as well as higher growth rate volatility beyond the years of the economic recession. [13] This trend in peak growth contrasts with the much more robust demand growth observed, on an annual basis, in the first seven years of the observations (the "pre-recession" period of 2001-2007). A combination of factors has influenced this moderate growth, including: (a) the impact of successful energy efficiency programs, (b) a partial shift to the evening system peak, (b) the persistent Covid lockdown effects in 2020. These factors created an overall disconnect in cumulative peak load growth, again compared to pre-2008 years. Thus, I recommended that the Company extended the use of the intercept dummy variable for the remainder of the period to effectively control for the lower growth relative to the initial years of the 25-year period. This approach increases the explanatory value compared to a regression that limits the binary variable to years 2008-2014.[14] The binary variable in the current MCOS study takes the value of 0 in years 2001-2007 and 1 in year 2008 throughout 2025.

26. Q. WOULD AN APPROACH THAT RELIES MORE HEAVILY ON LONG-TERM FORECASTED T&D INVESTMENT PRODUCE A MORE RELIABLE LONG-RUN MARGINAL COST PROXY ESTIMATE?

A. I find that the use of a regression approach such as the one adopted by the Company serves the purpose to provide a long-term expectation of the relationship between investment and peak load growth as it smooths out lumpiness of investment. Ideally, one would rely as much as possible on a forward-looking long-term view of marginal costs, that would take into account any expectation of planning design

[13] In recent years, annual peak demand growth has increased but continues to be slower growth at annual rates around or below 2 percent annually. This is in contrast with the first 7 years of the observations where demand growth averaged 6 percent annually.

[14] The Company used the use of an intercept dummy variable in past MCOS exclusively to capture the change in underlying peak demand growth due to the recession in the regression.

standards in the years to come. Forward-looking methods are useful to potentially capture a Company's expectation of heavier reliance on battery solutions or demand response resources, for example in lieu of traditional wires investments. However, this requires forecast data that is reasonably developed and reliable. I discussed with the Company exploring a more forward-looking long-term distribution marginal cost approach once substation-specific peak load projection information enables this type of analysis. To be successfully implemented as a long-run proxy cost, it would need long-term distribution peak load forecasts by distribution substation and feeder, which the Company's planning process currently does not produce. Nevada Power, as with most utility distribution planning, currently only needs to find a specific solution no more than three to four years prior to the expected capacity need.

27. Q. PLEASE PROVIDE A HIGH-LEVEL DESCRIPTION OF A LONG-TERM DISTRIBUTION MCOS METHOD THAT WOULD ONLY USE FORWARD-LOOKING DATA.

A. A forward-looking analysis would involve anticipating capacity needs in the long-term, for growth reasons, which would filter out any forecasted investment needed for reasons other than growth, and the specific capacity added for each planned investment solution, at each individual substation and non-revenue feeder in the system. Investment per MW of capacity added by the project over a long-term timeframe would need to be adjusted based on future threshold of peak load to nameplate rating that is expected to trigger capacity expansion to convert the dollar per MW of capacity to dollar of investment per MW of peak load growth. The resulting investment cost would then need to be adjusted to account by the share of the system that is not expected to experience capacity expansion within the specific timeframe to convert the capacity expansion area's specific marginal costs into a system-wide distribution marginal cost. This process requires data on individual substations and non-revenue feeders' peaks, and an effort to develop peak load projections and capacity solutions which are currently not typically available in timeframes greater than 3 to 4 years in the current utility planning process. Additionally peak load growth by substation is potentially sensitive to adoption of EVs and other DERs by distribution substation area. Due to the challenges of implementation given current information gaps for a forward-looking long-run distribution-demand marginal, I do not recommend this alternative approach until the Company's planning process has evolved to produce such information over the long-term future timeframe.

28. Q. DID YOU REVIEW THE APPROACH THAT ALLOCATES COSTS TO HOURS USING PROBABILITY OF PEAK ("POP") FOR T&D?

A. Yes. The Company uses a POP analysis, separately for transmission, distribution substation, and non-revenue feeder, to time-differentiate the corresponding annualized transmission and demand-related distribution and non-revenue feeder marginal costs. I will explain this concept using distribution substation POP as an example. Nevada Power plans additions of distribution substation capacity to ensure that the substation transformer can reliably meet expected growth in non-coincident peaks. Typically, planners will look at the expected maximum load at the distribution substation, and compare it with the transformer rating, before assessing the need for capacity expansion or a larger transformer. Thus, time-differentiation of these costs is appropriate because only the peak load occurring at the time of highest load in the substation will trigger investment. An hourly POP analysis can determine each hour's likelihood of experiencing the annual peak load at the distribution substation that will trigger the expansion decision. The analysis in practice is done using total distribution hourly loads and not done separately for each individual substation, given that it is intended for use in distribution rates that are not geographically differentiated. Because of the effect of weather on loads, it is important to use several years of hourly loads. The relative hourly probabilities of peak that are calculated are multiplied by the annualized system-wide marginal distribution substation cost to derive an hourly cost profile that can be expected to continue in the near term. This hourly cost analysis is useful in setting TOU periods and TOU price differentials across periods, along with the hourly marginal costs of other components that vary with time, such as MECs, generation capacity, transmission and non-revenue feeders.

29. Q. PLEASE EXPLAIN THE POP STEPS FOLLOWED BY THE COMPANY.

A. The relative hourly POP analysis requires averaging hourly loads by weekday and weekend day type for a given month, across a number of years. The Company's analysis used 10 years of historical hourly loads and one year of load forecast (2024). Since the POP analysis effectively combines several years of data, it is important to filter out the effect of customer growth from one year to the next. Thus, all hourly loads in a given year need to be divided by either the respective year's average annual load, or the respective year's peak load. The Company used the year's peak load adjustment. Once the hourly loads are divided by the year's peak load to isolate inter-annual organic load growth, they are averaged by day type (weekday versus weekends). Using the assumption that hourly loads are normally distributed, the Company's POP method calculates the probability that load in a given hour, of a given day type and month will exceed 90 percent of peak load to the year's peak ratio, which represents the delimiter of the normal distribution probability formula.

30. Q. DO YOU FIND THE POP ANALYSIS TO BE APPROPRIATE AS EMPLOYED BY THE COMPANY?

A. The Company's steps in the calculation of the relative probability of peak in any given hour is correct, and consistent with how I recommend undertaking this analysis. I do however, suggest two refinements of this approach. One is shortening the timeframe of T&D hourly loads from 10 to no more than six years, e.g., 5 historical years and one year of load forecast. Going back more than six years in historical loads entails the risk of underestimating the weight of a more recent trend in usage patterns (e.g., peakier loads around late afternoon or early evening hours). Therefore, the POP analysis would be potentially more representative of future load patterns with a shorter period. While it is important to use several years of data, increased penetration of AC, or EV home charging may affect the patterns at the substation level.

A second refinement I would recommend is to remove the 90 percent threshold that the Company's POP uses as the delimiter in the estimation of POP. Using 90 percent has the effect of more hours exceeding the threshold and therefore the current method allocates slightly more probability of peak to earlier afternoon and late evening hours, compared to using 100 percent as the delimiter. The Company uses this threshold to be conservative on the impact of load and potential peaking of distribution substations at 3:00 p.m. Using 100 percent of the peak load as the delimiter in the calculation is more consistent with how distribution planners decide on capacity expansion. I verified that the impact of such changes combined is relatively small, however it makes the PoP curve slightly peakier and more concentrated between 4 p.m. and 7 p.m.

31. Q. DO YOU CONSIDER THAT THE ADDITION OF FORECASTED LOAD PROFILES ARE HELPFUL FOR POP CALCULATIONS?

A. Yes. Given the current state of increased mix of customer options to self-generate, as well as access to large electric loads that are becoming more affordable, time variation of marginal costs is sensitive to the growth of DERs, such as EVs. Currently, the POP uses a combination of historical and a year of load forecast, and this forecast accounts for growth of EV charging loads. Once the Company has access to more granular transformer and peak load and capacity status on each transformer and feeder, system planners may more accurately predict a conservative, 'floor' level of rooftop solar generation at the time of gross peak load at the substation, i.e., how future additions of DER truly offset substation afternoon demands by location, and how EV growth impacts are distributed across the service territory. As I understand, Nevada Power is expanding its access to this level of data through the Distributed Resource Plan.

32. Q. WHAT IS YOUR OPINION REGARDING THE COMPANY'S APPROACH TO ESTIMATING MARGINAL DISTRIBUTION FACILITIES COSTS?

A. I have reviewed the Company's local facilities cost calculations, and my conclusion is that the Company (a) has correctly interpreted the factors that drive investment in local distribution facilities costs, and (b) has applied a robust method that produces accurate estimates of monthly marginal facilities costs by customer class and within the residential class, separate costs for single and multi-family homes. The MCOS identified marginal distribution facility costs for line transformers, primary lines and secondary cables, including service drops. Line transformers and local conductors are not driven by on-going changes in demand, compared to the more diversified distribution facilities upstream. This is because distribution planners do not expect to have to replace local transformers over time to accommodate expanded load of the customer served from it and as a result, these facilities are typically sized to have enough capacity to accommodate the expected long-term maximum demands of the customers to be served from them over the facilities' service life. The annualized cost of the local facilities that connect the customers' premises to the utility system is consistent with the Company's updated Rule No. 9 allowances. The Company calculated these costs using detailed Rule No. 9 interconnection project data during a historical period. The median project cost is used to set the connection allowance as well as the basis for the marginal facilities cost to be recovered in rates. I verified that these jobs take into consideration the number of customers who will eventually use those facilities and the *maximum expected* loads (or design demands) of those customers, over the life of the facilities.

33. Q. DO YOU AGREE WITH NEVADA POWER'S APPROACH TO ESTIMATING MARGINAL CUSTOMER COSTS?

A. Yes. The Company has performed the right calculation of customer-related costs. These costs reflect the carrying costs and related expenses associated with installed cost of meters currently being used for the average customer in each class. This is standard practice in marginal cost methods. In addition, marginal customer costs include customer accounting, customer services and associated working capital expense, all typical components of an MCOS. Because utilities rarely have a reliable and detailed forecast of customer accounts, marginal customer costs tend to be based at least partly on historical costs. Any adjustments needed to ensure that they are consistent with any expected change in the way resources are devoted to different customer groups are accounted for in the Company's study.

34. Q. HAVE YOU REVIEWED THE MANNER IN WHICH THE COMPANY PROPOSES TO RECONCILE THE FUCTIONAL REVENUE REQUIREMENT WITH THE CORRESPONDING MARGINAL COSTS REVENUES?

A. Yes, I have.

35. Q. WHAT IS YOUR OPINION REGARDING THE COMPANY'S PROPOSED JOINT RECONCILIATION OF ENERGY AND GENERATION CAPACITY MARGINAL COSTS WITH GENERATION REVENUE REQUIREMENTS?

A. The Company's proposed revenue reconciliation includes reconciling the combined energy and marginal generation capacity cost-based revenues by class with total generation function's revenue requirement. I agree with this reconciliation approach. Staff had proposed in the recent Sierra GRC to separately reconcile energy separate from generation marginal cost to its respective revenue requirement. That approach would not be justified on efficiency or even equity grounds. Other than renewable generation additions that are largely driven by the need to meet RPS goals, the Company typically chooses to build, acquire or contract for a new generation plant for either capacity need reasons, energy cost savings reasons, or a combination of both, as part of optimization of generation portfolio and cost minimization goal. Thus today's generation revenue requirement is a function of past investment decisions evaluating those two benefits jointly. The past decisions of the Company were made based on historical system loads, and cost conditions. It does not follow cost causation to separately reconcile those two components of the generation revenue requirement, because this is not an exercise to reconcile marginal costs of energy and capacity with a forward-looking or a "replacement cost" version of generation revenue requirement. The share of generation sunk costs that exceed the overall marginal generation costs (which can be termed the "marginal cost revenue gap") bears no relationship with going forward shares of energy and capacity incremental costs. To be consistent with the EPMC philosophy, if two customers, each with a different load factor and size contribute differently to NV Energy's overall marginal costs, they should be assigned a different percent of the total function's revenue gap, in proportion to their respective overall marginal cost shares of *total* generation marginal cost revenue calculated for the rate effective period. Cost impact of the marginal increase in on-peak usage of these customers is unrelated to past decisions of expansion of peaker plant. Thus, forward-looking on peak cost implications (the marginal peaking unit to be procured/built) does not bear a connection with implications for historical generation capacity-related revenue requirement. With the combined energy and capacity reconciliation, a peakier customer will already be assigned a relatively higher share of the overall generation revenue requirement due to the higher relative cost of on peak related marginal capacity costs compared to per unit energy costs.

36. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S MCOS STUDY.

A. The findings of my review of the MCOS can be summarized in three major points:

1) The MCOS methods that the Company has employed are conceptually sound, and consistent with standard practice in marginal cost methods that seek to identify a long-run marginal cost, as opposed to a near-term approach. The Company MCOS hourly system-wide marginal cost results, reconciled by function and class can effectively be used to improve the cost reflectiveness in existing rates and forward-looking TOU price differentials across periods and seasons. The Company correctly relies on joint dispatch instead of stand-alone utility dispatch for purposes of estimating both MECs and generation capacity marginal costs, reflecting the fact that the Company meets expected increments of Nevada Power's demand as a function of a joint optimization. Using only the resources and load located in the Nevada Power's system would not be reflective of marginal cost impact, hence introducing distortions in TOU price signals.

2) The Company adopted a number of my recommendations during the finalization of the MCOS, mainly where data was available to do so. Additional small refinements could be implemented in a few aspects of the study to strengthen the results, namely related to the POP calculation. Potentially, the Company could explore an alternative forward-looking methodology for distribution marginal costs, but this cannot be explored at the moment due to the need to have more granular data, such as current and forward-looking peak load data at the distribution substation and feeder level, but the Company noted that they would be considered and evaluated in future rate cases.

3) The Company's revenue allocation proposal is strongly tied to the results of its MCOS and the Company's use of EPMC-based revenue class as the basis for class revenue target decisions is reflective of commonly applied marginal cost-based class revenue allocation methods. The Company proposed reallocation of revenue by class produces sensible allocations based on adjustments that respond to gradualism and class-specific bill impacts.

IV. HYBRID EMBEDDED COST APPROACH

37. Q. HOW WOULD YOU QUALIFY AN EMBEDDED COST STUDY'S ROLE IN RATEMAKING COMPARED TO MARGINAL COST STUDY RESULTS?

A. An ECOS is a top-down approach that allocates test-year total cost (sunk costs defined by FERC net plant and test-year variable costs) to customer classes based on a notion of inter-generational equity. It does not allow to include the concept of economic efficiency in such allocations because by definition it does not bear any relationship with the forward-looking incremental cost of meeting demand or customer connections, which is the principal, overarching condition to maximize such efficiency outcomes. ECOS are not designed to produce appropriate time-differentiation as it does not reveal the variation in the level of costs that would be necessary to meet growth. Thus, ECOS methods do not provide the basis for the appropriate price differentials, or the Company's current cost in today's dollars, of connecting a new customer to the grid. ECOS studies prevent the goal of cost minimization by encouraging too little usage in low-cost periods, and potentially too much on-peak usage. ECOS studies defeat the premise of regulatory pricing which is encouraging an efficient, least-cost pace of grid infrastructure helpful for rate design. There is no connection to the costs that a class of customers' demands will be expected to add to the utility costs going forward, compared to other customers. By contrast, a marginal cost-based allocation method is a bottom-up approach that does reflect the ongoing, incremental cost impact of customer usage of a given customer class, relative to other customers.

38. Q. IN YOUR OPINION, IF AN ECOS METHOD USES MARGINAL COSTS AS ALLOCATION FACTORS, DOES IT HELP REDUCE DISTORTIONARY EFFECTS FOR CLASS REVENUE ALLOCATION?

A. A hybrid ECOS that uses marginal cost allocators as weighting factors by class is indeed less distortionary compared to traditional embedded cost methods, as it recognizes the energy and demand-related marginal cost relationships in apportioning embedded costs among classes. This recognition of incremental cost in the hybrid ECOS study renders it more likely to provide more equitable results compared to ECOS alternatives that allocate accounting costs purely based on relative class demand or energy allocators without any marginal cost information.[15]

Nevertheless, a hybrid method is not free of limitations compared to a pure MCOS method as it does not reveal the floor level of the charge (marginal costs). It also continues to have the limitations of any ECOS study because FERC distribution plant accounts do not distinguish between voltage level. There is no room for flexibility to allocate lower costs to customers that have similar demand allocator than other classes, but exhibit a higher ability to bypass or relocate, or use less of a

[15] There are traditional ECOS methods such as the Base Intermediate Peak ("BIP") method that attempt to allocate demand-related generation costs to time periods based on the type of plant (peaker, intermediate or baseload). This method is outdated as it does not reflect the characteristics of renewable power, plus the results can be extremely misleading as there is no connection with the true underlying marginal capacity costs and the relationship between energy and capacity marginal costs.

type of asset that is no longer been installed by the Company. The disconnect between price signals and time-varying marginal costs persists to a substantial degree, and therefore it represents a weaker approach as a revenue requirement method compared to the Company's traditional EPMC allocation method.

39. Q. IN EVALUATING THE MANNER IN WHICH ENERGY COSTS ARE TREATED IN THE ECOS STUDY ALLOCATIONS, DO YOU CONSIDER THAT STAFF'S PROPOSAL IN THE SIERRA GENERAL RATE CASE, WHICH ENDORSES REMOVING ENERGY COSTS FROM THE ECOS ALLOCATION OF GENERATION COSTS TO CUSTOMERS IS JUSTIFIED BASED ON BEST PRACTICE AND COST CAUSATION?

A. No. The Company is proposing to include energy revenues/cost in the ECOS study, before adjusting (subtracting) the final class revenue requirement to account for revenue obtained from Base Tariff Energy Rate (BTER) rates. This cost allocation method is superior to the proposed Staff's proposal for revenue apportionment. It is important that the initial cost allocation includes both energy and demand-related costs in the ECOS, to identify each class's cost share of the embedded costs as a first step, according to the respective adopted class energy and demand allocators (ideally using MECs as appropriate time-of-day weighting factors, and LOLP for generation costs), irrespective of how and whether a share of those costs are being recovered outside of standard rates. Energy and demand-related generation embedded cost elements should not be separated as I explained earlier, the Company's plans its generation portfolio as a joint energy and fixed cost - optimization effort. Once the appropriate class's embedded cost allocation has been undertaken using the combined Energy and Generation approach, any revenue collected outside standard rates, including BTER revenues can then be subtracted as a revenue offset. The extent to which BTER revenue does not fully offset the allocated costs, will provide information to the Commission and the Company as to the current distortions or inequities that are built into the flat BTER rate. Those customers with a relatively higher on peak energy usage compared to the average customer in the class, currently underpay through the flat BTER rate. A combined energy and generation cost allocation in the ECOS study, using the appropriate hourly marginal cost allocators, can correct that inequity by partly capturing a share of the attributable BTER costs through the standard rate and this can create stronger alignment of class allocation with time-differentiated marginal costs.

V. RESIDENTIAL RATE DESIGN

40. Q. WHAT ARE THE MAIN CHANGES THAT THE COMPANY PROPOSES IN TERMS OF RATE REBALANCING BY COMPONENT?

A. The Company has proposed to cap the residential classes' revenue increase at the system average increase rate, even though the cost study suggests that the single residential ("RS") class is contributing to a higher share of the revenue requirement, and therefore would warrant a higher revenue target to reduce cross-subsidization from other classes. As part of the moderate class revenue increase, the Company proposes to not allocate the entire kWh component of the rates to the RS class but instead increase the basic service charge ("BSC"), which represents an increase in absolute terms of about $6 per month for all customers. This revenue would otherwise be recovered through the per-kWh charges. The MCOS local facility results make a compelling case to support an increase in the fixed monthly BSC for residential rates from the current levels to the proposed $18.50 per month to support incentives for economically efficient usage and to reduce current cross-subsidies.

41. Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED BSC INCREASE?

A. Yes. Introducing higher fixed charges for residential, or any other class of customers, is consistent with efficient rate design when, after setting all components equal to marginal cost, the rate produces less revenue from the average customer than the amount that would be required to meet the class revenue target as per the Company's revenue requirement. The fixed components of the rate are considered to be the least-price elastic component and suitable to recover sunk costs. Recovery of customer and local facilities cost in the customer charge is justified on the grounds of increasing efficiency in customer usage and reducing intra-cross subsidies. As a floor level, the BSC would reflect the sum of class's customer cost and the Rule 9 per customer facilities costs calculated for the average residential class. Increasing the BSC serves to reduce the increase beyond marginal cost that would otherwise take place in the volumetric component of the rate, further discouraging electricity consumption that would have more value to the customer than the cost to the Company to serve it. The proposed monthly BSC would remain at below cost level since the sum of the monthly marginal customer and facilities costs for the typical residential customer, just before reconciliation to facilities function's revenue requirement, is $33.59 for the RS class. Thus, the Company's proposal is to raise the BSC to only 55 percent of total marginal costs that varies with average customer in the class. This is a step in the right direction. Alternatives which limit fixed charge increases to avoid creating any bill impacts for low-use customers perpetuate the recovery of facilities costs in the kWh charge.

42. Q. ARE DEMAND CHARGES AN APPROPRIATE METHOD TO RECOVER LOCAL FACILITIES?

A. No. It is a common misconception that the costs of facilities will vary with changes in maximum demand. The Rule 9 residential per-customer allowance is associated with a design demand of 10 kVA and today's installed per kW cost of the typical transformer to serve that load. If a home increases demand, the transformer is expected to accommodate up to a certain exceedance of nameplate rating and the cost would not change unless the transformer needed to be replaced. Distribution planners tend to account for potential future, long-term load additions of the customer and therefore the customer class design demand, incorporates built-in near-term excess capacity. Residential customers could be assessed different design demands if a subscription facilities-based charge was in place, by which the customer would commit not to exceed a particular demand threshold. This would in turn be considered by the distribution planner in choosing among standard facilities sizes. In the case of residential customers, the rate only includes two components, a monthly charge and a per-kWh charge.

43. Q. DOES THE COMPANY'S PROPOSED INCREASE TO BSC AFFECT LOW INCOME USERS NEGATIVELY?

A. To the extent that low-income users are largely low-usage customers, any increase to the fixed charge, calibrated to be revenue neutral to the average usage customer, will result in a bill increase to customers with lower-than-average usage, all other things being equal. However, equity is best served if low-income users are separately qualified for a lower BSC, rather than by a continued increase in the kWh charge. In addition, energy usage is not necessarily the right parameter to determine income levels. Many low-income customers are in fact high-usage customers, and low-usage customers may also reflect customers on vacation homes. The BSC charge already differentiates between multi-family and single-family for BSC by effectively separating these two customer types into two different residential rate classes. This separation by unit type helps reduce intra-class cross-subsidies as it recognizes the lower facilities per-customer cost in the more heavily shared facilities installed for multi-family units.

44. Q. IS THERE PRECENDENT IN THE INDUSTRY TO RAISE THE BSC TO RECOVER COSTS BEYOND CUSTOMER-RELATED COSTS?

A. Yes. The Company's proposed increase in the BSC for RS class is well aligned with residential fixed charge increases observed in other states in recent years, where the fixed charge exceeds the Company's estimated cost of meter and service drop and includes a sizeable share of the local facilities cost. Over the last decade, utilities have developed optional rate offerings intended to provide more granular customer choice and help customers with flexible demands to control their bills, by shifting cost recovery to fixed charges. Increasingly, there is a wider recognition of the economic benefits associated with increasing the monthly fixed charges, not just for optional rates but also whole-house rates. The lower kWh charges are helpful to reduce existing intra-class cross-subsidies paid by higher than class average energy users to lower than class average energy users in the legacy rates.

45. Q. GIVEN YOUR RESEARCH ON FIXED CHARGES IMPOSED BY OTHER UTILITIES, HOW DOES THE COMPANY'S BSC STAND AMONG THE SAMPLE?

A. Nevada Power's proposed residential fixed charge of $18.50 per month falls below the mean value of the fixed charges among 24 US surveyed utilities that have increased their residential fixed charges above $15 per month.

Figure Nieto-Direct-1 illustrates a sample of 24 U.S. electric rates that include monthly residential service charges exceeding $15 per month as of May 2023. Some notable examples of higher fixed charges include the following:

- Sacramento Municipal Utility District ("SMUD") uses a "System Infrastructure Fixed Charge" of $23.50 per month, explicitly supported by cost studies.
- The Salt River Project ("SRP") in Arizona increased monthly fixed charges to all residential customers from $17 to $20 in 2015, with the goal to move these charges closer to customer-related costs which includes a definition of facilities costs. At the same time, SRP introduced a separate NEM class under a E-27 rate that included two monthly customer charge components depending on service entrance size ($32.44 per month for homes with < 200 amps of service capacity, and $45.44 per month for the rest).
- In California, utilities adopted in 2021-23 TOU rates that are specifically intended to recover higher costs in the standard monthly fixed charge at around $15 per month for customers, in an effort to lower the volumetric rate to a level that is closer to the underlying marginal cost and not to disincentivize beneficial electrification. Recent legislation has requested the development of income-based fixed charges and the utilities have filed

proposals that would increase the residential fixed charge to about $50 per month for the average residential income tier.[16]

- In late 2022, the Hawaii Public Utility Commission approved the inclusion of a grid access charge that will apply to all customers, to recover the cost of transformers and secondary conductors as a separate monthly fixed charge supplementing existing customer charges, and eventually the intention is to restate it as a non-coincident demand charge.[17]

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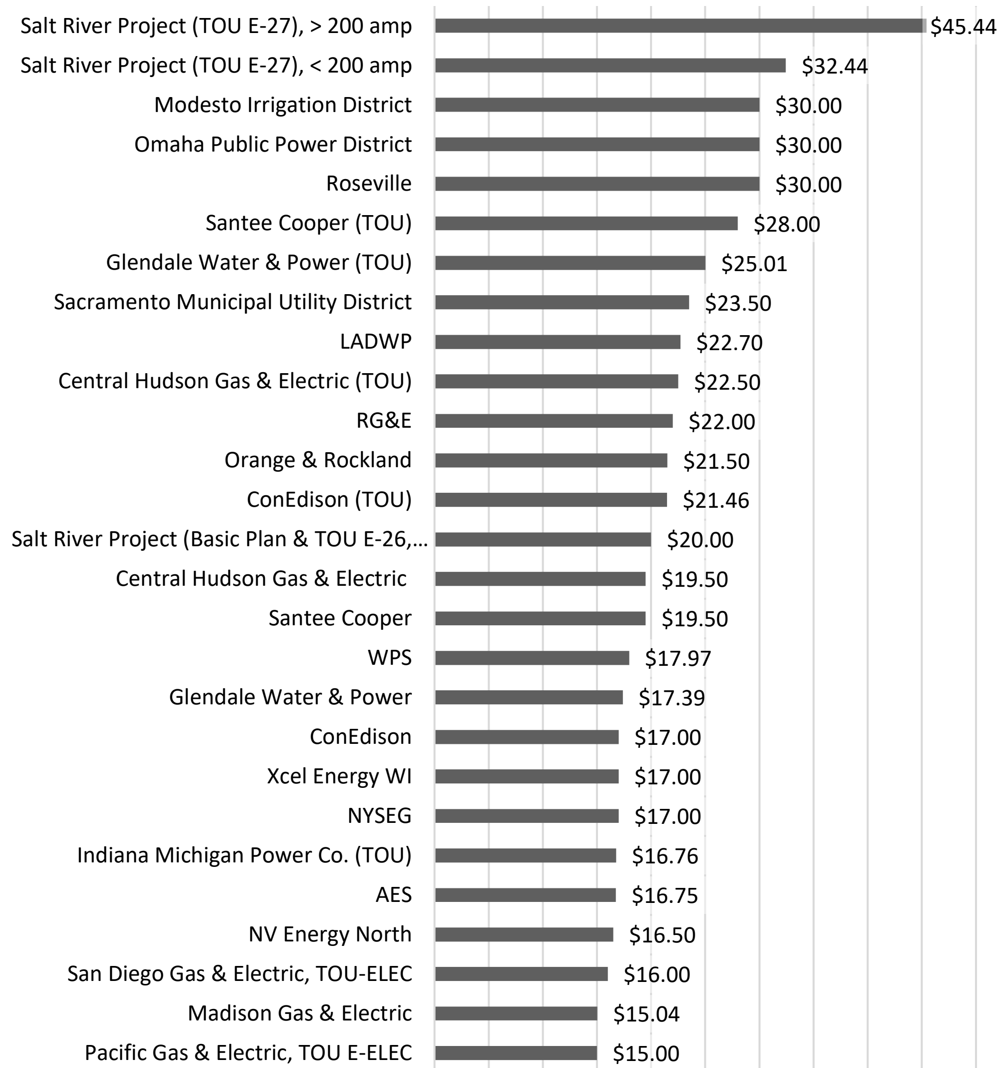
[16] The California Public Utilities Commission is considering proposals submitted by the three California IOUs under the "income-graduated fixed charge" ("IGFG") approach as per Ruling No. (R. 22-07-005). This new rate structure, if ultimately implemented, will distinguish between at least three tiers of income. The most recent IOU proposals include an average tier monthly charge of $49 per month for Southern California Edison ("SCE"), $53 per month for Pacific Gas and Electric ("PG&E"), and $74 per month for San Diego Gas & Electric ("SDG&E"). This approach, if finally accepted, is unique to the current myriad of fixed costs associated to policy programs that are funded by customer payers and the fact that the population with higher usage higher rates in California.

[17] Hawaii Public Utilities Commission, Docket No. 2019-0323, D. 38680. Issued October 31, 2022.

Figure Nieto-Direct-1. Sample of U.S. Residential Monthly Fixed Charges > $15 per month as of May 2023



46. Q. PLEASE SUMMARIZE THE MAIN FINDINGS OF YOUR RESIDENTIAL RATE PROPOSAL REVIEW.

A. The Company's proposed changes to rate design are likely to lead to economic efficiency gains compared to the status quo, by virtue of relying to a great extent on the underlying structure of marginal costs and the different cost drivers. The proposed rates also take into account other important rate design objectives. Rates that strive to set kWh charges that more closely reflect time-differentiated marginal cost-price signals make it easier for the utility to set technology-agnostic rates. Such rates are valid for entire house usage but also appropriate for separately metered flexible loads, such as EV rates, solar generation, battery storage and heat pump loads. Changes in revenue when customers adopt these technologies that either increase or reduce usage during peak periods are likely to track changes in system cost and benefits, thereby limiting the need to continue increasing rates to other customers at the next rate case.

VI. PROPOSED TIME OF USE PERIODS

47. Q. DID YOU REVIEW THE COMPANY'S PROPOSED TOU PERIODS?

A. Yes. The Company is proposing an on-peak period that will start at 3 p.m. and end at 9 p.m., every day of the week during the summer months of June through September. This is a notable update to existing peak period definition. Currently the peak period only exists on weekdays for residential optional TOU classes, while weekends are entirely off-peak. In addition, the existing peak period begins at 1 p.m. and ends at 7 p.m. The Company is not proposing modify the winter TOU period definition, which considers all hours as off-peak, May through October.

48. Q. DO YOU CONSIDER THIS PROPOSAL TO BE APPROPRIATE?

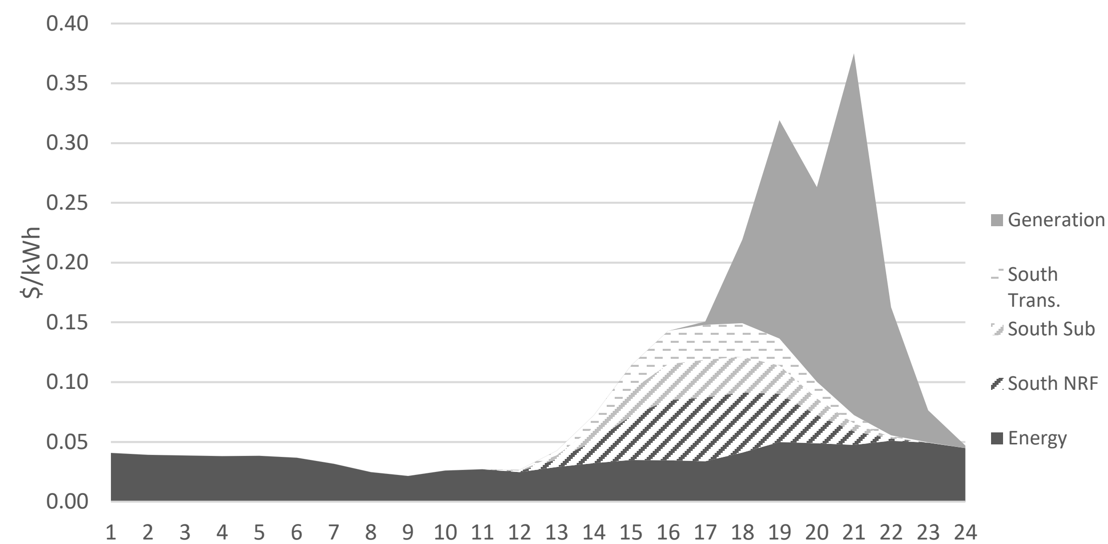
A. Yes. The Company's proposal to revisit TOU periods is based on an approach that analyzes the patterns of hourly marginal costs, after adding generation, transmission and distribution (substation and non-revenue feeder) marginal costs by hour. The proposed on-peak period captures the hours in the year with the relative highest total marginal costs expected during the timeframe the new TOU rates will be in effect. Therefore, the proposal involves more cost-reflective TOU periods for rates, which improves the efficiency property of the rates but it also preserves simplicity to maximize customer understanding and hence the ability of customers to remember them and respond.

49. Q. WHAT ANALYSIS WAS PERFORMED BY THE COMPANY TO DETERMINE THE APPROPRIATE TOU PERIODS?

A. The Company uses a regression analysis that tests if proposed TOU rate periods align well with the expected marginal cost variation, subject to the constraint of keeping existing seasons. High-cost months are combined into a summer season, as the four months with the highest likelihood of having the highest incremental costs. Marginal costs within the summer are the highest from 5 p.m. to 9 p.m. in the months of July and August, due to the abundance of solar generation that is expected to continue to grow in Nevada Power's system. **Figure Nieto-Direct-2** shows the sum of hourly marginal cost for an average summer weekday during the four-month season. **Figure Nieto-Direct-3** shows the respective hourly marginal cost profiles for a summer weekend. It should be noted that these reflect unweighted cost profiles. These charts illustrate how generation capacity marginal cost responsibility has shifted to the evening, even though the gross peak demand continues to occur at 3-5 p.m. The charts also show that an extension of the peak period to 9 p.m. is justified to signal the higher capacity related costs still present in hour 9 p.m. compared to 10 p.m. and later. To be strictly cost reflective, based on the total hourly marginal cost profile, a four-hour peak period (5 p.m. to 9 p.m.) would be more cost-reflective and it would allow using a higher peak price compared to the Company's proposed six-hour period. However, part of the decision of TOU periods is to evaluate the potential customer response to the new peak price, and the degree towards it could potentially incentivize some additional load at 3 pm and 4 pm from customers pre-cooling their homes. Since the Company is not proposing a mid-peak (or shoulder) period for hours 3 p.m. to 5 p.m. and 9 p.m. to 10 p.m. for simplicity and customer understanding, it is reasonable to begin the peak period at to 3:01 pm.

Figure Nieto-Direct-4 illustrates the winter hourly marginal cost profile, which exhibits negligible capacity-related marginal costs and it is mostly reflective of marginal energy costs.

Figure Nieto-2. Hourly Marginal Costs, Weekday, Summer season (Jun-Sep), 2024$



Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Figure Nieto-3. Hourly Marginal Costs, Weekend, Summer season (Jun-Sep), 2024

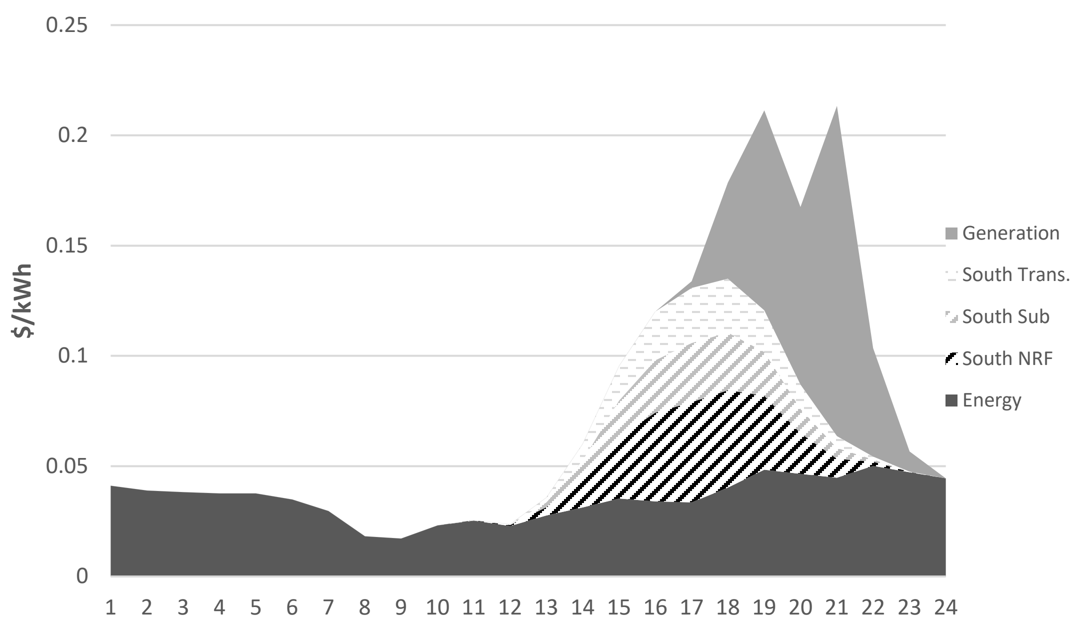
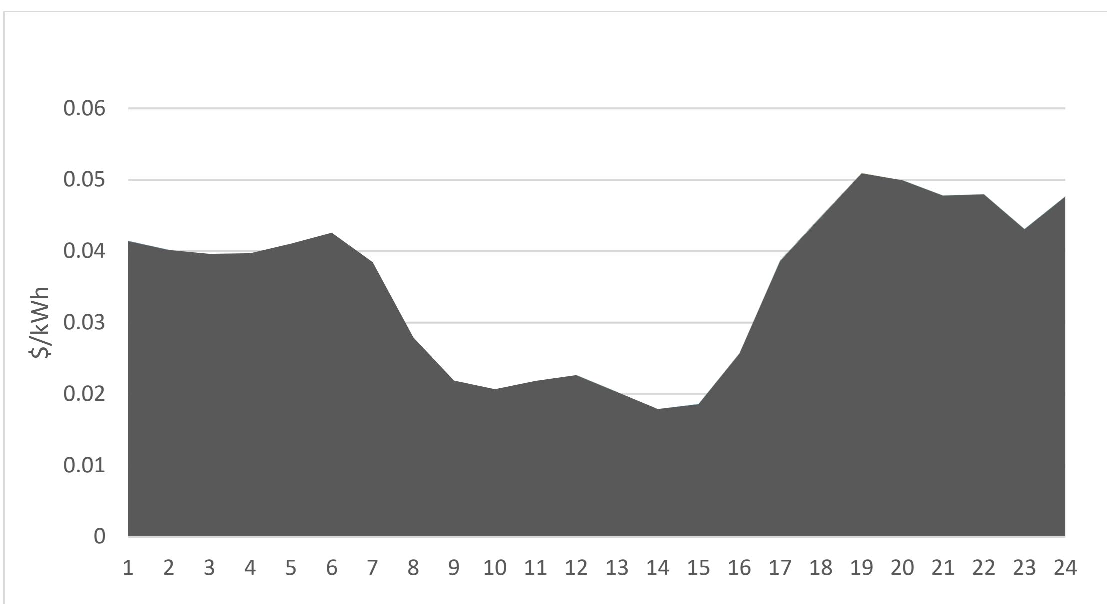


Figure Nieto-4. Hourly Marginal Costs, Weekday, Non-Summer (October-May), 2024$



50. Q. ARE THERE OTHER ALTERNATIVE SEASONAL DEFINITIONS THAT WOULD PRODUCE A HIGHER COST-REFLECTIVENESS IN RATES?

A. Yes, a month-to-month analysis of the marginal cost profile revealed that June and September are assigned lower capacity-related marginal costs compared to July and August due to lower LOLPs but also lower allocation of transmission and distribution costs responsibility. In June and September, the system can accommodate incremental load with a lower likelihood of putting strain on the grid or generation resources and therefore lower probability of triggering expansion, compared to demand increases in July or August. Including a third season comprised of June and September only, would more closely reflect the price differentials in these two months which have lower on-peak marginal costs overall compared to July and August. While this change would produce a small improvement in the TOU price signals, the Company has preferred not to use more than two seasons at this time, from the perspective of simplifying rates and customer acceptance. Introducing a third, shoulder, season of June and September would mean there would be two sets of summer TOU periods to adjust to and this construct would add rate changes (and prorations) that would be displayed on their billing statements, hence adding complexity. In order to avoid this complexity and increase customer acceptance, the Company's proposal seasonality is limited to only two seasons.

51. Q. DID YOU EVALUATE A POTENTIAL USE OF A 'SUPER OFF PEAK' PERIOD TO REFLECT THE HOURS WITH THE LOWEST MARGINAL COSTS?

A. Yes. I did evaluate if a super-off peak period would be warranted, within the currently proposed off peak hours, targeting the lowest marginal costs in the day, which begin at 8 am and end by the afternoon (12 p.m. in summer, and 4 p.m. in the winter). These are hours when solar is particularly abundant relative to loads, and this differentiation with respect to overnight hours is particularly strong in non-summer months which have the lowest system daily loads. The Company has not proposed a morning super off-peak period for its standard TOU rates at this time due to the goal of keeping summer and winter season periods consistent. Instead, it has recommended a low-priced charging period for the Electric Vehicle Rate Rider ("EVRR"), that will incentivize charging in hours 12:01 am to 12:00 pm. These are hours with the lowest marginal costs year-round. Since EV charging is the most likely load to be highly responsive to small TOU price differentials, not introducing time-differentiation in Winter months for standard TOU rates appear as a reasonable decision at this time particularly because underlying cost differentials within the off peak period are still relatively small. However, recognizing the advantages of technology-agnostic TOU periods, I recommend consideration of a super off-peak period for Winter months at the next rate case, after marginal energy cost differentials have continued to increase due to both utility-scale and behind the meter solar generation additions.

VII. CONCLUSION

52. Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW.

A. The overall MCOS methodology used by the Company in this GRC is consistent with the methodology used in numerous prior cases of the Company, as well as with common practice in utility MCOS that employs LRMC-proxy approaches. The Company's proposed method to allocate revenue requirement to customer classes is a sound approach from an economic efficiency standpoint, as it uses the relative differences in class' marginal cost responsibility as the starting point and only deviates in a manner to provide for gradual and not sudden bill impacts. The Company's new TOU periods together with the proposed rate rebalancing between fixed and energy charges in rate designs represent a major efficiency improvement over existing rates. Customers will respond to more economically-efficient price signals as they make decisions regarding beneficial electrification of building/ transportation, charging their EV, or adopting solar power, in a manner that reduces intra-class cross subsidies inherent in existing in rate designs.

53. Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT NIETO-DIRECT-1

AMPARO NIETO

ASSOCIATE PARTNER
PA CONSULTING

Amparo Nieto is an energy economist with over 25 years of advisory and testifying experience in the energy industry. Her extensive knowledge of markets, electricity ratemaking and best-practice regulation allows her to provide economic analysis and independent expert opinion on a broad range of energy regulatory, rates and restructuring policy issues. Ms. Nieto has filed expert reports and extensively testified before state public commissions in the context of rate cases and other proceedings, regarding electricity and natural marginal cost of service studies, multi-year rate plans, optional time-of-use rates; dynamic pricing options; and analysis of energy contracts.

For many years, she has directed a membership-based utility working group that discusses rate innovation and new utility business models, and conducted workshops for utility and Commissions staff. Earlier in her career, Ms. Nieto was advisor to independent system operators and energy regulatory commissions in the US, Canada, Spain, Australia, and Ireland on regulatory policy and market design, including development of rules for effective wholesale and retail competition in restructured markets.

EXPERTISE AREAS

- Rate Design and Regulatory Policy
- Marginal Cost of Service Studies
- Net Energy Metering (NEM)
- Electric Vehicle Rates
- Performance-Based Regulation (PBR)
- Distributed Energy Resources (DER)
- Utility Business Models
- Energy and Capacity Market Design

CLIENTS

- Investor-Owned Utilities
- Municipal Utilities
- Public Utilities Commissions
- Independent energy firms
- Independent System Operators

OVERVIEW OF SELECTED ASSIGNMENTS

ENERGY, RATE DESIGN AND COST OF SERVICE STUDIES

NV Energy, Nevada. Currently conducting and independent review of the Company's electricity marginal cost-of-service study and embedded cost study methods and proposed rate designs, as well as conducting training to the team. Ms. Nieto will submit direct testimony before the Nevada Commission with the findings of her review and discussion of recommendations.

Avangrid, New York. Expert witness for NYSEG and RG&E on their 2022 electric and natural gas rate cases. Conducted marginal cost of service studies for electric and gas, and sponsored testimony on the results of these studies, and on recommended changes in the Company rates supporting the Rates witness in the rate cases. Earlier on, Ms. Nieto supported NYSEG and RG&E as they filed comments before the NY PSC regarding the appropriate approach to establish the distribution value of DERs as part of the Reforming the Energy Vision (REV) proceeding.

Central Maine Power Company, Maine. Advised and served as expert witness during the Company's electric rate case. Conducted a marginal cost of distribution study and supported changes to residential and commercial rates, including a gradual three-year increase to the residential fixed charges. Design of enhanced TOU distribution rate designs, including recommendations on EV rate designs.

California Public Utilities Commission. Net Energy Metering reform, 2020 – 2022. Ms Nieto advised the energy division of the CPUC with regard to the reform of the CA investor-owned utilities' Net Energy Metering (NEM) program (NEM 3.0), affecting compensation to behind the meter solar generation and battery storage. Main author of a white paper that proposed an approach to ensure a viable solar industry while achieving stronger alignment between value of solar generation and customer solar system payback period.

Xcel Energy, MN. Support to Xcel Energy in MN, leading a distribution and customer marginal cost analysis for the utility's rate case filings. The study results guided the minimum fixed charge that allows recovery of the marginal costs of connection to the grid, meter and service costs, consistent with the Company's decoupling efforts.

Otter Tail Power (OTP) Company, MN, ND and SD. On-going advisory and expert witness support during OTP's rate cases in MN, ND and SD. Prepared marginal cost studies of generation, transmission and distribution for revision of existing tariffs and designed optional TOU tariffs. Reviewed and provided recommendations to re-design the hourly pricing methodology currently used for the Company's large general user customers, including Real Time Pricing (RTP) rates.

Eversource Energy, New Hampshire and Connecticut. Designed a proposal for a TOU Electric Vehicle rate design and an enhanced TOU whole-house EV rate design and alternative EV rate design for DC fast charging stations. Conducted a distribution marginal cost analysis and filed testimony as expert witness as part of the utility's 2020-21 Distribution Rate Case.

Sacramento Utility Municipal District, California. Lead team that developed modelling for cost-effective integration of solar generation and battery storage into the utility's service territory. Recommended revisions to electricity rates including improved TOU rates and potential Critical Peak Price (CPP) residential rate as an option to replace traditional net metering.

San Diego Gas & Electric, California. Co-authored a white paper on required changes to the Company's residential rates for more cost-reflective price signals that would foster beneficial electrification while preserving affordability.

Salt River Project, AZ. Support SRP's time of use TOU rate pilot and recommended modifications to TOU periods and rate levels. Earlier on, examined proposed rate changes to NEM and provided expert opinion on the soundness of the proposal to the SRP's Board of Directors. Submitted testimony deposition regarding suitability and cost basis for adoption of demand charges for solar customers.

APS Aggregation Tariff, Arizona. Recommended Aggregator Tariffs for Demand Side Resources, including distributed solar, energy storage, and demand response technologies.

NYSERDA, New York. Modelling of alternative rate options as part of electrification goals.

Nicor Gas, Illinois, US. Conducted a natural gas marginal cost study and supported changes in gas delivery rates.

Manitoba Hydro, Manitoba, Canada. Provided training to the utility staff on methods to estimate marginal costs in the context of rate design. In an earlier assignment, advised Manitoba Hydro on electricity tariff reform to introduce Time-Of-Use rates and inverted- block rates in Manitoba. Analyzed marginal energy costs by time-of-day periods; developed the welfare and cost-benefit models that took into account a range of price elasticity by class and the potential load shifting due to new TOU rate structures and the impact on net welfare. Co-authored the study report for submission to the Manitoba Public Utility Board.

Newfoundland Labrador & Hydro, Newfoundland, Canada. Participated in a study of the marginal cost of generation and transmission for the vertically-integrated utility in Newfoundland, for use in development of Time-of-Use rates.

BC Hydro, Canada. Developed marginal cost estimates of generation, transmission and distribution to support BC Hydro's upcoming rate case and provided recommendations on use of study results to redesign rates, including setting up Time of Use residential and commercial rates.

Newfoundland Power, Newfoundland, Canada. Managed the team developing a generation and transmission marginal cost of service study, which included projections for 2007-2025 for use in Demand-Side-Management efforts.

Commission for Energy Regulatory of Ireland, Ireland. Participated in the drafting of the all-island electricity market rules and recommended changes to the Transmission Use of System (TUoS) charges for the Republic of Ireland.

Tennessee Valley Authority (TVA), TN, US. Conducted a generation and transmission marginal cost of service study for TVA to be used for rates and to evaluate demand response programs.

Southern Company, US. Reviewed the company's proposed approach to undertake loss of load expectation analysis and recommended improvements. Provided guidance to develop capacity cost allocation factors for demand response programs and new customer evaluation.

NB Power, New Brunswick, Canada. Recommended approach to estimate the incremental costs to the utility when customers opt-out of smart metering, taking into account the pace of smart meter deployment plans. Provided rate design recommendations in the light of smart grid investments.

Abu Dhabi, UEA. Advised on the reform of distribution rates and suitable mechanism to undertake cost allocation based on marginal costs. Proposed revision to existing electricity cross-subsidies.

Electricity Regulatory Board (ERB), Kenya, Africa. Co-authored an Electricity Tariff Policy for ERB, aimed at improving the financial health of the sector and promoting the efficient expansion of electricity service. Developed financial models for calculation of utility revenue requirement and provided on-site training to the ERB staff on regulatory analysis and marginal cost studies. Designed the pricing terms of a new sample Power Purchase Agreement between the incumbent generator (KenGen) and the distribution utility (KPLC).

Barbados Federal Trade Commission, Barbados. Directed the team advising the Barbados energy regulatory commission during Barbados Power and Light (BP&L)'s rate application. Assessed the utility's estimated cost of capital, embedded and marginal electricity cost methods used by the utility to allocate costs to customer classes and various proposed rates including time of use rate proposals.

WHOLESALE MARKET, ENERGY RESTRUCTURING, INCENTIVE REGULATION

Commission for Energy Regulatory of Ireland, Ireland: Member of the market design team for the all-island electricity market. Key consultant in the design of options for a Capacity Payment Mechanism on the island of Ireland that would be viable and sensible in the context of the Irish electricity market.

MidAmerican Energy Company, Iowa. Directed the team in charge of reviewing and advising MidAmerican Energy Retail branch's as part of their market strategy and bidding, and load forecasting procedures, as part of their activity in ERCOT, MISO and PJM electricity wholesale market rules. Provided recommendations and training to the team on resource adequacy and transmission open access tariffs.

Australian Energy Market Commission, Australia. Critiqued the proposed revisions to the electricity market rules in Australia regarding firm transmission access and rights. Analyzed the suitability of Financial Transmission Rights, or their equivalent, for the Australian market. Conducted a survey of international transmission planning and cost-allocation methodologies in an earlier assignment.

Alberta Electric System Operator (AESO), Calgary, Alberta. Analyzed AESO's cost study and transmission cost recovery methods and recommended revisions to improve cost allocation.

NYISO, New York, US. Provided recommendations to the New York Independent System Operator for a reform of their Black Start service compensation mechanism as part of the ISO Tariff.

UK Energy Networks Association, UK. Advisor to the Association on evaluating a potential reform of electricity distribution network planning standards to account for new developments, such as the emergence of smart grids.

Grid Australia, Sydney, Australia. Performance-Based Regulation (PBR) methods for electricity network.

Edison Electric Institute (EEI), US. Co-author of report "Making a Business of Energy Efficiency: Sustainable Business Models for Utilities". A report on incentive mechanisms to achieve utility goals for energy efficiency and demand response.

Ministry of Energy, Argentina. Undertook a comprehensive review of the Argentine wholesale electricity market rules and co-authored a report for the government on proposed measures to increase competition.

Iberdrola, Spain Member of the energy practice team advising a large Spanish electric utility regarding its regulatory strategy at the time of the electricity sector in Spain as well as advise in a broad range of regulatory issues involving retail access, stranded cost analysis and open access tariffs. Participated in industry working groups in charge of proposing detailed policy rules.

Commission for energy regulation, Spain. Advised the Commission during the drafting of major energy sector restructuring legislation opening the sector to competition;

Analysis of utility mergers, various utilities, US. Review the competitive impact on electricity markets of a number of proposed utility mergers. Analyzed potential horizontal and vertical market power impacts.

ENERGY SERVICE AND CAPACITY AUCTIONS

PECO Energy Company, Pennsylvania, US. Manager of the Auction team that administered the Default Service Supply auctions on behalf of PECO Energy Company. Co-authored the assessment reports evaluating the competitiveness of the auctions for the Commission's review.

First Energy, Philadelphia, US. Administered Default Service Supply solicitations via a descending-clock auction on behalf of Met-Ed and Penelec utilities in Pennsylvania. Authored the report evaluating the competitiveness of the auction and results for the Commission's review.

Independent System Operator (ISO) of New England, US. Member of the team advising the ISO-NE on revisions to ISO's Forward Capacity Market (FCM), with regard to the *Alternative Capacity Price Rule.*

Ministry of Energy (SENER), Mexico: Advisor to SENER regarding the development of a procurement auction to procure multiple renewable technologies across a variety of time-frames.

Spanish National Energy Commission (CNE), Madrid, Spain. Administered the default service electricity supply ("CESUR") auctions on behalf of the large distribution companies in Spain and Portugal. Assessed the bidders' competitive behavior during the auctions and prepared an assessment report for the Commission.

RENEWABLE ENERGY RESOURCES – INTEGRATION, PROCUREMENT

Various utilities. Provided independent assessment of impact of growth of solar distributed generation on the utility's load, planning and impact on net revenues. Recommended or evaluated revisions to tariff structures to avoid large cost shifting among customers and inequity concerns.

Regulatory Office for Network Industries (RONI), Slovakia. Directed the team that assisted the Slovakian regulatory commission on the design of efficient support mechanisms for renewable energy sources (RES) and a reliable system of issuing guarantees of origin for RES. Trained the commission staff on best practice RES regulation.

Illinois Power Agency (IPA), US. Assessment of parameters and benchmark analysis for Solar Renewable Energy Credits (SRECs) in the context of the auction held by Ameren Illinois Company and Commonwealth Edison to procure RECs from solar distributed generation resources.

Southern California Edison, Los Angeles, California, US. Member of the team that advised the utility's Supply Group on improvements to the mechanism for contracting with renewable generation resources.

RATES AND COST OF SERVICE STUDY EXPERT TESTIMONY

Before the Maine Public Utilities Commission, Rebuttal Testimony: "Central Maine Power Company, "Electricity Marginal Cost Study, Rate Design and Time of Use Periods", February 7, 2023.

Before the Maine Public Utilities Commission, Direct Testimony: "Central Maine Power Company, "Electricity Marginal Cost Study and Efficient Rate Design", August 11, 2022.

Before the New York State Public Service Commission, Direct Testimony: "New York Electric Service and Gas and Rochester Gas & Electric Corporation, Electricity Marginal Cost Study and Rate Designs," May 26, 2022.

Before the New York State Public Service Commission, Direct Testimony: "New York Electric Service and Gas and Rochester Gas & Electric Corporation, Natural Gas Marginal Cost Study," May 26, 2022.

Before the New York State Public Service Commission, Direct Testimony: "New York Electric Service and Gas and Rochester Gas & Electric Corporation, Streetlighting Replacement Cost Study," May 26, 2022.

Before the New Hampshire Public Utilities Commission, filed report on the design of a new EV residential rate, on behalf of the Public Service Company of New Hampshire d/b/a Eversource Energy, May 15, 2021.

Before the New Hampshire Public Utilities Commission, Rebuttal Testimony, "Cost of Service Studies and Rate Design," on behalf of the Public Service Company of New Hampshire d/b/a Eversource Energy, March 3, 2020.

Before the New Hampshire Public Utilities Commission, Direct Testimony, "Marginal Distribution Cost of Service Study and Implications for Rate Design," on behalf of Eversource Energy, May 28, 2019.

Before the New Hampshire Public Utilities Commission, Direct Testimony, "Allocated Cost of Service Study," on behalf of the Public Service Company of New Hampshire d/b/a Eversource Energy, May 28, 2019.

Before the North Dakota Public Service Commission, Marginal Cost of Service Study on behalf of Otter Tail Power Company, June 2018.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony: "Marginal Costs, Revenue Reconciliation and Rate Design for Net Metering Customers," In the Matter of the Application of Sierra Pacific Power Company d/a/a NV Energy for Authority to Reform Rates for Electric Utility Service in 2016 GRC, October 31, 2016.

Before the Public Utilities Commission of the State of Minnesota, Rebuttal Testimony, "Fixed Charges, Marginal Cost Study, and Rate Design" September 12, 2016.

Before the Public Utilities Commission of the State of Minnesota, Direct Testimony: "Fixed Charges and Rate Design Policy," In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, February 16, 2016.

Before the Board of Directors of Salt River Project, testimony regarding analysis of SRP's adoption of a new net metering rate E-27 for solar customers. Nov. 2015.

Before the New York State Public Service Commission, Direct Testimony: "Rochester Gas & Electric Corporation Electricity and Natural Gas Marginal Cost of Service Studies," June 2015.

Before the New York State Public Service Commission, Direct Testimony: "New York State Electric and Gas Electricity and Natural Gas Marginal Cost of Service Studies," June 2015.

Before the Salt River Project Board of Directors, Testimony: "Review of SRP Proposed Residential Customer Generation Price Plan," February 2015.

Before the State of North Carolina Utilities Commission, Testimony: "Review of Alternative Application of the Peaker Method Proposed by EPCOR USA North Carolina LLC with respect to Computation of Avoided Energy and Capacity Costs," July 23, 2010.

Before the New Brunswick Board of Commissioners of Public Utilities, Testimony, with Wayne Olson: "The Role of DSM and Demand Response in Load Forecasting and Integrated Resource Planning," on behalf of the New Brunswick Public Intervener, November 9, 2006.

ENERGY PUBLICATIONS AND PRESENTATIONS

- "Efficient Design of Standby Rates for Cogeneration", presented to the Southern California Public Power Authority Working Group, April 18, 2023.
- "Improved Rate Designs for an Effective Regulatory Construct: Merits of the California NEM Reform for a Cleaner Energy Sector". Western Rutgers University, Regulatory Conference (CRRI), Monterey, CA, 2022.
- "Compensating NWA Providers for their Value to the System", presented at EUCI's annual Non-Wires Alternative (NWA) Conference, on-line webinar, May 18, 2022.
- "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California. Successor Tariff Options Compliant with AB 327". A White Paper prepared for the California Public Utility Commission. January 28, 2021.
- "*Distributed Energy Resource (DER) Rate Mechanisms*", Nieto. Presented at the Advanced Utility Rates Group, December 20, 2020.
- "Rate Design Principles and Options for Vehicle-Grid Integration", a White Paper commissioned by Honda. June 30, 2020
- "Compensatory Framework for Storage and Microgrids for their Value as Capacity and Grid Resources." Presented at 32nd Annual Western Conference (CRRI), Monterey, CA, June 28, 2019.
- "Examining the Key Pricing Policy Elements of New York's Reforming the Energy Vision." Presented at the 31st Annual Western Conference (CRRI), Monterey, CA, June 28, 2018.
- "Estimating the Value of Distributed Energy Resources and Implications for Rates." Presented at the California Municipal Utility Rates Group (CMRG), May 2018.
- "Marginal Cost Methods and Efficient Rate Design," Utility of the Future Rates Group, San Francisco, CA, April 2018.
- "Value-Based Tariff Model for Distributed Energy Resources: Principles and Framework Options." Presented at 30th Annual Western Conference (CRRI), Monterey, CA, June 28, 2017.
- "Incentive Methods for Electricity Distribution". Presented at Rutgers University's 29th Annual Western Conference (CRRI), Monterey, California, June 23, 2016.
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- “Renewable Microgrids: Getting the Pricing Right.” Presented at the Marginal Cost Working Group (MCWG), Washington, D.C., May 5, 2016.
- “Policy Options to Address Cross Subsidies from Self-Generation.” Presented at the 12th Annual National Law Seminars International Conference on Electric Utility Ratemaking, Las Vegas, Nevada, March 14, 2016.
- “Demand Charges and their Role in Net Energy Metering.” Presented at the “Residential Demand Charges Symposium,” EUCI, Calgary, Canada, December 1, 2015.
- “Utility Regulation in the Era of Distributed Renewables: Is There a Need for a New Business Model?” Presented at Rutgers University’s 28th Annual Western Conference (CRRI), Monterey, CA, June 26, 2015.
- “Solar Distributed Generation and Rate Restructuring.” Presented at the California Municipal Rates Group (CMRG), Sacramento, California, May 18, 2015.
- “Integrating Renewable Resources through Capacity Markets: The Case of California.” Presented at Law Seminars International’s Energy in California, San Francisco, California, Sep 16, 2014.
- “Rate Design Options to Deal with Solar Net Metering Concerns.” Presented at the California Municipal Rates Group (CMRG), Sacramento, California, April 25, 2014.
- “Capacity Markets Put to the Test: New Approaches to Meet Evolving Reliability Needs.” Rutgers University’s 27th Annual Western Conference (CRRI), Monterey, California, June 26, 2014.
- “Connecting Wholesale and Retail Pricing: A Look at Required Policy and Market Design Decisions.” Presented at the Harvard Electricity Policy Group, Dana Point, CA, March 7, 2013.
- “Demand Response and its Role within Wholesale Energy and Capacity Markets.” Presented at Rutgers University’s 25th Annual Western Conference (CRRI), Monterey, California, June 2012.
- “Achieving Efficient Demand Response through Dynamic Rates.” Presented at Law Seminars International’s Electric Ratemaking Conference, Las Vegas, Nevada, February 9, 2009.
- “Critical Peak Pricing: A Marginal Cost Approach.” Presented at the Marginal Cost Working Group (MCWG), Phoenix, Arizona, April 2008.
- “Electricity Rate Structure Design: “Rate Design and Cost Studies.” University of PURC’s World Bank International Training Program on Utility Regulation, Florida, January 16, 2007.
- “Demand Bidding Programs in ISO/RTO Environments.” Presented at the Marginal Cost Working Group (MCWG), Austin, Texas, October 12, 2006.

- "Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering." Sponsored by Edison Electric Institute, May 2006.
- "Locational Generation Capacity Payments in New England." Presented at the Marginal Cost Working Group (MCWG), Albuquerque, New Mexico, April 27, 2005.

EDUCATION

Master's Degree in Economics and Public Policy (Honors), Fiscal Studies Institute of Madrid, Spain

Advanced microeconomics, econometrics, public policy, optimal fiscal theory, advanced mathematics.

B.A., Economics, University of Carlos III, Madrid, Spain

Concentrations: microeconomics, macroeconomics, competition policy, industrial economics, international economics, financial analysis, econometrics, mathematics.

PRIOR EMPLOYMENT

Energy and Environmental Economics (E3)

Senior Director 2020 – 2022

Economists Incorporated

Senior Vice President 2018 – 2020

NERA Economic Consulting

Vice President / Senior Consultant / Consultant 1996 – 2017

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, AMPARO NIETO, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Amparo Nieto

Date: June 5, 2023

AMPARO NIETO

MISHA PASCAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06____
2023 General Rate Case

Prepared Direct Testimony of

Misha Pascal

Rate Design

I. INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Misha Pascal. I am a Pricing Specialist for NV Energy, Inc. ("NV Energy"), Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company"), and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). I work primarily out of NV Energy's corporate office located at 6100 Neil Road in Reno, Nevada. I am filing testimony in this proceeding on behalf of Nevada Power.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have two Bachelor of Science degrees, one in Mechanical Engineering and one in Applied Economics and Statistics, with a minor in Business. I have been in my current position since joining the Companies in August of 2018. Prior to joining the Companies, I worked in equipment management for a large North American construction company. A more detailed description of my background and experience is included in **Exhibit Pascal-Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A PRICING SPECIALIST.

A. My responsibilities include conducting the Rule 9 Facilities Study ("Facilities Study"),[1] calculating customer-specific facilities ("CSF") investments, providing contract support for large customers, supplying departmental support for standby customers, calculating and supporting revenue-based allowances, and supporting the Company's line extension Rule 9 projects in a general capacity.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I provided testimony in Sierra's last general rate case ("GRC"), Docket No. 22-06014, and the Companies' Third Amendment to the 2021 Integrated Resource Plan, Docket No. 22-09006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I sponsor the following items:

- The Company's proposed updates to the Rule 9 Line Extension Allowances ("Allowances") and the Facilities Study.
- The development of CSF investment amounts. This includes investment for the Extra-Large General Service (LGS-X) class, the optional High Load Factor (OLGS-3P-HLF) class, as well as investment amounts for the general service transmission-voltage classes (LGS-2T, LGS-3T, LGS-WP2T, and LGW-WP-3T, collectively, the "LGS-T" classes) served under fully-bundled service or Distribution-Only Service ("DOS") rate schedules.

[1] The Facilities Study reviews the costs of facilities installed pursuant to Nevada Power's Rule 9 tariff, which governs line extensions and interconnections with Nevada Power's distribution system.

- Response to Directive 10 from the Commission's order in Docket No. 22-09006 directing the Company to provide an analysis of the impacts of adding electric vehicle charger allowances on the Rule 9 study median cost.[2]

6. Q. PLEASE EXPLAIN HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized into four sections:

I. Introduction;

II. Update to Rule 9 Line Extension Allowances, Facilities Study, and Cost of Service study ("COS") inputs;

III. Non LGS-X CSF Study;

IV. LGS-X CSF Study; and

V. Electric vehicle ("EV") charging cost impacts on allowances.

7. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I sponsor five exhibits to my testimony:

- **Exhibit Pascal Direct-1**, Statement of Qualifications;
- **Exhibit Pascal Direct-2**, Updated Rule 9 Line Extension Allowances and Facilities Study White Paper;
- **Exhibit Pascal Direct-3**, Proposed LGS-T Facilities Investment Amounts;
- **Exhibit Pascal Direct-4**, Proposed HLF Investment Amounts; and
- **Exhibit Pascal Direct-5**, Proposed LGS-X Investment Amounts.

[2] Docket No. 22-09006, March 24, 2023, Order at 157, para. 10.

II. UPDATE TO RULE 9 ALLOWANCES AND FACILITIES STUDY

8. Q. PLEASE DESCRIBE NEVADA POWER'S RULE 9.

A. Nevada Power's line extension process occurs through the construction of various facilities. A line extension is considered as any continuation of, or branch from, the nearest available existing distribution line or facility of the utility. Rule 9 governs both the physical interconnection of new customers to the system and any modifications to the Company's distribution system requested by customers. Rule 9 facilities, located in close proximity to the customer, may include elements such as line extensions, transformers, and service drops. The scope of Rule 9 encompasses the design, construction, inspection, cost allocation, ownership, and taxation of these facilities, and the cost responsibility of each party.

9. Q. WHY IS NEVADA POWER UPDATING ITS RULE 9 FACILITIES COSTS IN THIS PROCEEDING?

A. Section A.30 of the Rule 9 tariff requires that Nevada Power update certain elements of Rule 9 every three years. Typically, Nevada Power performs these triennial updates as part of the GRC proceeding. Section A.30 of the rule specifically addresses the need to update Rule 9 Allowances, Master Planned Community ("MPC") refunds, and Proportionate Share refunds. The currently effective Allowances, MPC refund amounts, and Proportionate Share refunds were approved in Nevada Power's 2020 GRC, Docket No. 20-06003.

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10. Q. WHAT ARE RULE 9 ALLOWANCES AND REFUNDS?

A. The costs of line extension projects are shared by the Company and the applicant pursuant to Rule 9. Projects that are expected to increase demand may qualify for funding from the utility to offset costs of construction and interconnection to the grid, called an "Allowance." The Allowance amount depends on factors such as the type of service, number of units, meters, or new kVA demand expected to be served by the project. Some, or all, of the Allowance may be provided upfront, before construction begins, provided there is a reasonable expectation that the required number of units, meters, and/or kVA demand will materialize within 12 months following the completion of the line extension facilities.

If the project's estimated cost surpasses the pre-construction Allowance, the applicant must cover the difference. There are two types of advances: advances subject to refund and advances not subject to refund. The former refers to amounts the applicant may receive as refunds based on the actual number of units, meters, or new kVA demand served on the project. The latter, known as a Contribution In Aid of Construction ("CIAC"), represents the non-refundable portion of the project that is the customer's responsibility. Rule 9 dictates that certain costs be treated as CIAC, and these costs cannot be offset by allowances. Examples of CIAC cost are alternative routes and requests that exceed minimum requirements.

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11. Q. PLEASE SUMMARIZE THE UPDATES TO LINE EXTENSION ALLOWANCES PURSUANT TO THE FACILITIES STUDY WHITE PAPER SET FORTH IN EXHIBIT PASCAL DIRECT-2.

A. **Exhibit Pascal-Direct-2** is a white paper in compliance with Rule 9 Tariff Section A.30, detailing the methodology employed to update the Facilities Study. This white paper should be reviewed alongside my prepared direct testimony, as it offers a comprehensive overview of the assumptions made and the modeling techniques used to derive the final results presented in this proceeding.

The updated Facilities Study serves two primary objectives. First, it revises the current Rule 9 Allowances, MPC refunds, and Proportionate Share refund amounts, as detailed in **Exhibit Pascal-Direct-2**. Second, the study contributes inputs to the cost of service and rate design models by determining the marginal facilities investment per customer for each class.

12. Q. WHAT IS THE METHODOLOGY USED TO UPDATE THE FACILITIES STUDY?

A. The Facilities Study detailed in **Exhibit Pascal-Direct-2** adheres to the same Commission-approved methodology employed in Nevada Power GRCs dating back over a decade (2012, 2016, 2017, 2020) and recent Sierra GRCs. (2019, 2022). With each iteration of the Facilities Study, the Company has provided a white paper, which outlines the study's fundamental methodology.

Project data for Rule 9 facilities is maintained in the Company's work management system, Maximo. New business project data from 2011 to 2022 was extracted from Maximo, encompassing information such as estimated project costs, the number of meters or kVA per project by customer class, Allowances, rate classes within each project, and construction start and completion dates. A project screening process was applied to exclude projects with incomplete data (e.g., missing construction completion dates, project costs, or expected demand) or those that were canceled or put on hold. Rule 9 facilities may serve multiple rate classes, leading to shared costs for certain projects. For projects with common costs that will be metered under different rate classes, allocation factors were developed based on each class's expected demand, thereby distributing total project costs among the relevant rate classes. As the study period includes January 2011 through December 2022, a project's construction completion date served as the initial inclusion criterion to ensure cost-based Allowances were determined using verified, completed projects. To maintain consistency with the data inputted into the filed cost studies and accommodate the study, project costs were escalated to the first year of the rate-effective period (2024).

Subsequently, the class median per-unit project costs in rate-effective year dollars (2024) were identified from the Rule 9 Maximo data. Next, Allowances were calculated through an iterative analysis, constrained by the requirement that the average utility investment in the rate-effective period must equal the median per-unit project cost from the previous step. Under Rule 9, an Allowance can only be granted up to the amount of the project cost. As a result, projects with costs lower than the potential maximum Allowance receive a reduced Allowance, while projects with costs exceeding the maximum Allowance are capped at the maximum, with the Applicant responsible for covering the remaining project costs.

13. Q. HOW DO THE ALLOWANCE UPDATES COMPARE TO CURRENTLY APPROVED ALLOWANCES?

A. **Table Pascal-Direct-1** offers a comparison between the currently approved Allowances from 2020 in Docket No. 20-06003 and the proposed Allowances in this case. Aside from Large Residential Service ("LRS") staying flat, all classes combined had an overall average increase of 32 percent without any other notable differences among the classes.

Maximo project data encompasses various factors such as material and labor costs, line extension length, design and construction complexity, surrounding area population density, and other elements. Inflationary cost is the main driver of this increase, mainly in material cost increases due to economic and supply chain issues over the last few years.

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TABLE PASCAL-DIRECT 1- ALLOWANCE COMPARISON

Note: Italics indicates insufficient sample size; Allowances are pegged to the most similar class.

Rate Class	Units	Allowances			
		2020	2023	$ Change	% Change
RS	Homes	$3,890	$4,998	$1,108	28%
RM	Homes	$982	$1,377	$395	40%
LRS	kVA	$385	$370	$(15)	-4%
GS	Meter	$2,304	$3,007	$703	30%
LGS-1	Meter	$303	$406	$103	34%
LGS-2S	kVA	$141	$198	$56	40%
LGS-2P	kVA	$140	$186	$46	33%
LGS-3S	kVA	$126	$179	$54	43%
LGS-3P	kVA	$54	$69	$15	28%
LGS-WP-2S	*kVA*	$141	$198	$56	40%
LGS-WP-2P	*kVA*	$140	$186	$46	33%
LGS-WP-3S	*kVA*	$126	$179	$54	43%
LGS-WP-3P	*kVA*	$54	$69	$15	28%

14. Q. DESCRIBE THE UPDATES THAT WERE MADE TO THE HISTORICAL KVA-PER-CUSTOMER INPUT TO THE FACILITIES STUDY.

A. The Facilities Study utilizes historical class average kVA-per-customer for two purposes. This kVA-per-customer value provides the basis for allocating common costs for projects that benefit multiple classes, as well as the investment-per-customer input to the filed cost studies for classes whose Allowance is developed on a per kVA basis. It is important to note that the kVA-per-customer is also a driver of change to the allowance and is described in more detail in the white paper. To illustrate the kVA update, **Table Pascal-Direct-2** provides the current kVA-per-customer along with the historical kVA-per-customer values for the large customer classes. Overall, the class average kVA per customer stayed relatively stable between the 2020 and 2023 Facilities Study, with some exceptions for the water pumping class. This has been an ongoing trend over the last several GRCs, but the number of customers in the class are so low that small changes can adjust the percentage in the other direction such as LGS-WP-2P.

TABLE PASCAL-DIRECT-2: HISTORICAL CLASS AVERAGE KVA PER CUSTOMER

Rate Class	2020 GRC	2023 GRC	% Change
RS	10.6	10.6	0.0%
RM	8.4	8.4	0.2%
LRS	72.0	77.9	8.2%
GS	5.8	5.4	-6.7%
LGS-1	45.8	48.7	6.3%
LGS-2S	549.1	536.5	-2.3%
LGS-2P	640.3	655.9	2.4%
LGS-3S	1,557.9	1,493.3	-4.2%
LGS-3P	3,678.7	3,444.4	-6.4%
LGS-WP-2S	534.7	352.9	-34.0%
LGS-WP-2P	582.6	671.1	15.2%
LGS-WP-3S	1,625.2	1,405.1	-13.5%
LGS-WP-3P	1,968.9	1,615.9	-17.9%

15. Q. DESCRIBE THE GENERAL METHODOLOGY FOR DEVELOPING THE MARGINAL FACILITIES INVESTMENT-PER-CUSTOMER FOR EACH RATE CLASS.

A. The methodology for determining the marginal facilities investment for each customer class remains consistent with previous GRC proceedings. Customers in the LGS-T classes are subject to CSF charges detailed later.

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For all other classes, marginal Rule 9 facilities costs are developed in the filed cost studies. This requires as an input the average Rule 9 facilities investment made on behalf of customers, calculated on a per-customer-by-class basis. The investment in Rule 9 facilities per class is determined using the results of the Facilities Study outlined in **Exhibit Pascal-Direct-2**.

For the residential and small general service classes, the filed cost studies apply the direct result of the average investment per unit (houses and meters). Classes without specific facilities charges see the investment based on per-kVA facilities investment. This is then further converted to a per-customer investment amount using the class average kVA per customer for the filed cost studies.

16. Q. PLEASE DESCRIBE THE METHOD USED TO CONVERT THE FACILITIES INVESTMENT PER KVA TO FACILITIES INVESTMENT PER CUSTOMER FOR INPUT TO THE FILED COST STUDIES.

A. For all classes other than the residential and small GS classes, the Facilities Study produces average investment-per-kVA consistent with Rule 9 Allowances. However, the cost studies require an investment-per-customer, so the investment-per-kVA is converted to an investment-per-customer using the average kVA-per-customer for the entire class. Consistent with prior facilities studies, hourly class load data is used to derive the kVA-per-customer in each customer class. Specifically, the maximum kVA over the test period is identified for each customer in the class (or sample data for the class). The average of these maximum kVA values for the class represents the kVA-per-customer, which is then applied to the average investment-per-kVA to convert the investment into the unit cost required for the cost studies.

17. Q. **PLEASE SUMMARIZE THE MARGINAL INVESTMENT-PER-CUSTOMER UPDATES.**

A. The Company updated both inputs (average utility investment, class average max kVA-per-customer) to calculate the marginal facilities investment. The vector of both inputs drives the change in marginal facilities investment. **Table-Pascal-Direct-3** compares the current marginal investment-per-customer with that used in the 2020 MCS. All classes experienced considerable changes, but reasonably consistent among all the classes with an average increase of 21 percent with one exception in the LGS-WP-2S class that had a decrease mainly impacted by its significant drop in kVA.

TABLE PASCAL DIRECT-3: MARGINAL FACILITIES INVESTMENT-PER-CUSTOMER

Rate Class	2020 GRC	2023 GRC	% Change from 2020 GRC
RS	$3,164	$ 3,941	24.6%
RM	$824	$ 1,044	26.7%
LRS	$19,515	$ 23,689	21.4%
GS	$1,574	$ 1,836	16.6%
LGS1	$9,706	$ 13,087	34.8%
LGS2S	$61,268	$ 76,462	24.8%
LGS2P	$73,739	$ 98,106	33.0%
LGS3S	$134,480	$ 167,438	24.5%
LGS3P	$138,726	$ 168,228	21.3%
LGS-WP-2S	$59,662	$ 50,296	-15.7%
LGS-WP-2P	$67,101	$ 100,384	49.6%
LGS-WP-3S	$140,282	$ 157,550	12.3%
LGS-WP-3P	$74,250	$ 78,920	6.3%

18. Q. ARE THERE ANY UPDATES IN THE METHODOLOGY USED TO CALCULATE THE MPC REFUND AMOUNTS?

A. No, there is no change to the methodology used to calculate refund amounts for MPC projects approved by the Commission in Nevada Power's 2020 GRC. The Company provides MPC refunds to developers who are required to advance 100 percent of the cost for installation of all distribution feeds necessary to serve their developments prior to construction. As loads materialize within the development, the Company refunds the developer its advances subject to refunds for the feeder costs based on the MPC refund amounts.

MPC refunds are calculated using Non-Revenue Feeder ("NRF") Demand Revenues divided by the units in the class as well as having a percent of capital applied to support the investment. The overall decrease in the proposed MPC refunds is a result in decreased demand revenues and an increase in units which lowers the revenue per unit to support the investments as well as the increase in the economic carrying charge directly impacts the final outcome seen in **Table Pascal-Direct-4.**

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TABLE PASCAL DIRECT-4: MPC REFUNDS COMPARISON

Rate Class	Units	2023 MPC Refunds	2020 MPC Refunds	% Change from 2017
RS	Units	$ 991	$ 1,262	-21%
RM	Units	$ 537	$ 639	-16%
GS	Units	$ 391	$ 455	-14%
LRS	Meters	$ 144	$ 174	-17%
LGS-1	kVA	$ 188	$ 223	-16%
LGS-2S	KVA	$ 170	$ 170	-9%
LGS-2P	kVA	$ 184	$ 184	-15%
LGS-3S	KVA	$ 196	$ 196	-12%
LGS-3P	KVA	$ 309	$ 309	-6%

III. NON LGS-X CSF STUDIES

19. Q. WHY ARE CSF STUDIES DEVELOPED FOR ONLY CERTAIN CUSTOMER CLASSES?

A. The objective of developing CSF costs for certain customer classes is to reduce the potential that some customers within the class will bear the facilities costs for other customers that require much greater investment in facilities. For example, transmission level facilities are highly individual in the costs to build, operate and maintain, and vary significantly between customers within the class. The Company's large transmission customers typically have readily identifiable facilities and are fewer in number, allowing for the development of facilities costs for each individual customer in the class. This method eases the computational burden for calculating an individual charge to be assessed to each customer based on the facilities each transmission level or high load factor customer uses. In classes with a greater number of customers, it is impractical to identify and develop individual facilities investment charges. Moreover, in classes with larger and more homogeneous populations, the facilities that serve customers in the class do not vary as widely between customers. As such, determining and utilizing the average facilities investments and charges for customers in these classes is efficient, equitable and reflective of the cost of the individual facilities installed to serve only these customers.

20. Q. HOW WERE THE FACILITIES INVESTMENTS FOR CSF CHARGES FOR TRANSMISSION LEVEL CUSTOMERS DETERMINED?

A. The specific high-voltage distribution facilities that serve each transmission level customer for which the Company contributed facilities investment and ongoing maintenance were identified for purposes of this analysis.[3] As a note, "distribution facilities" includes all distribution plant between the customer-owned equipment and the interface between the Company's distribution and transmission systems. In most cases, these facilities are considered high voltage distribution and consist of 138-kV or 69-kV radial lines extended from a tap on a transmission line to the customer's equipment.

The investment results used in Nevada Power's 2020 GRC were reviewed by Engineering and were escalated to 2024 replacement costs utilizing the Handy Whitman transmission index. These 2024 replacement costs were then converted into annual marginal costs using the same economic carrying charge and appropriate adders used in developing annual facilities marginal costs in the filed cost studies for other classes (with the exception of LGS-X classes).

[3] Standby customers typically pay for their own facilities back to Federal Energy Regulatory Commission transmission and therefore do not pay a CSF.

When calculating the Facilities Charge per dollar of utility investment, the initial non-refundable cost of any customer-contributed plant is excluded, except for any escalation associated with customer-funded plant. To address the operations and maintenance (O&M) costs for the contributed plant, the investment amount is subject to a separate charge, known as the Facilities Charge per dollar of Contributed Investment.

21. Q. WHAT COMPONENTS ARE INCLUDED IN THESE CHARGES?

A. In accordance with the Commission's decisions in the Companies' seven most recent GRCs, the facilities cost for customer-contributed plant is divided into two components:

1. O&M costs related to the original investment in customer-contributed plant: These costs are covered by the Facilities Charge per dollar of Contributed Investment, as mentioned earlier. This ensures that the utility company can maintain and operate the contributed plant effectively.
2. Utility investment for replacing customer-contributed facilities: The difference between the replacement cost of customer-contributed facilities and their original value is considered utility investment. This distinction is important because it represents the company's financial responsibility for replacing those facilities in the future. This portion of the investment cost is treated the same as all other utility-contributed plant, ensuring a consistent approach to calculating the Facilities Charge.

By providing a clear structure for managing customer-contributed plant's costs and utility investment, this approach allows the Company to maintain and replace facilities efficiently while ensuring fair cost allocation.

For each current LGS-T customer, **Exhibit Pascal-Direct-3**, provides (in columns H and I, respectively) Nevada Power's total utility investment (which includes the difference between replacement and original cost on the customer-contributed facilities) and the original customer-contributed investment.

22. Q. PLEASE EXPLAIN FURTHER HOW THE CSF CHARGES ARE CALCULATED FOR LGS-T CUSTOMERS.

A. The CSF investment is applied to a rate that is developed in Statement O, which is then viewed as the monthly customer specific facility charge . Each LGS-T class is used as an input into the filed cost studies and are then annualized. This fully annualized marginal cost associated with this investment, is then developed and becomes an output to Statement O. Here, it is adjusted up or down by the distribution reconciliation factor to derive the CSF rate per dollar of utility and contributed investment that is applied to each CSF for each customer developed in the facility study.

23. Q. HOW HAVE THE LGS-T CSF UTILITY INVESTMENTS CHANGED IN THE PROPOSED CSF STUDY?

A. The replacement cost of the Company's investment in customer-specific facilities for the LGS-T classes has increased since Nevada Power's 2020 GRC. This is a result of escalating the investment values from the last GRC utilizing the Handy Whitman Indices for transmission plant construction. This resulted in an increase of 8.82 percent against all Company investment. Some customers have a total combined investment amount greater than the 8.82 percent increase due to the escalation against their customer contribution as explained above.

24. Q. WHY WAS ESCALATION USED INSTEAD OF RE-ESTIMATING REPLACEMENT COSTS?

A. In review of current facilities, the Company determined that no re-estimates were needed since the facilities utilized today are the same as those included in the 2020 GRC. The Transmission and Civil Engineering Department, which provides the cost estimates, determined that it was an appropriate method to determine current costs.

25. Q. ARE THERE ANY OTHER NON-LGS-X CLASSES THAT HAVE CSF CHARGES?

A. Yes, there is one class, the optional High Load Factor (OLGS-3P-HLF or "HLF") class. The CSF investment amounts for the HLF class are summarized in **Exhibit Pascal-Direct-4**.

26. Q. HOW WERE THE FACILITIES INVESTMENTS FOR CSF CHARGES FOR HLF CUSTOMERS DETERMINED?

A. The HLF CSF investments are developed in a similar manner to the methodology used to develop facilities investment amounts for the non-LGS-X transmission level customers. The only notable difference is that primary voltage HLF facility costs are escalated using distribution cost indices instead of the transmission cost indices used for the transmission level CSFs.

Replacement costs were determined for each customer beginning with the customer's interface to the utility's distribution system and estimating the cost to replace the distribution feeder all the way to the substation. Any portion of the distribution facilities that was only utilized by the specific customer was assigned one hundred percent of the cost. The remaining facilities associated with the distribution feeder were load shared with the other customers sharing the common facilities

27. Q. HOW HAVE THE HLF CSF UTILITY INVESTMENTS CHANGED IN THE PROPOSED STUDY?

A. After reviewing each customer's facilities, the Engineering group determined that replacement estimates can be conducted by applying the Handy Whitman index. The escalation resulted in a 17.1 percent replacement increase across all HLF customers with the exception of one customer that has an increase of 21.5 percent as a result of escalation on customer contribution investments being shifted to utility investments similarly to LGS-T customers explained above.

IV. <u>LGS-X CUSTOMER-SPECIFIC FACILITIES STUDIES</u>

28. Q. PLEASE DESCRIBE THE CHARACTERISTICS OF AN LGS-X CUSTOMER.

A. Pursuant to the Commission's order in Docket No. 06-11022, the LGS-X schedule has been closed to new customers, and new meter locations for existing customers since June 2007. Current LGS-X customers are served on the DOS rate schedules, but still receive the same CSF charges for the facilities serving these customers. An LGS-X customer is one or more individual, but related, accounts that may vary in size and voltage level that are billed under a single basic service charge. The requirements for aggregating a group of accounts into a single LGS-X customer are that the properties must be contiguous, each property must be at least 50 percent owned or controlled by the same entity, and the coincident peak demand of the group must be at least 22 MW.

An LGS-X customer pays a monthly CSF charge based on the actual original costs of the Company's investment in customer-specific facilities that serve the customer's individual accounts. Many of the various accounts of each LGS-X customer are individually metered. The cost of one meter is recovered through the basic service charge for the LGS-X customer, with each additional meter assessed a separate (additional) meter charge. If more than one bill is requested by the LGS-X customer, an extra (or separate) billing charge applies to each additional bill prepared.

29. Q. HOW ARE THE CSF CHARGES FOR THE LGS-X CUSTOMERS DEVELOPED?

A. The LGS-X CSF charges are set based on the "original investment cost" methodology adopted in Docket No. 97-11006 and approved in subsequent cases. Under the original investment cost methodology, the original facility investment is multiplied by the levelized fixed charge rate associated with the plant life and Nevada Power's current marginal weighted cost of capital. As approved in previous cases, where original investment costs are not available, current replacement costs discounted back to the year of installation are used as a proxy for original investment costs. The methodology for calculating LGS-X CSF charges is a departure from the marginal cost logic used throughout the filed cost studies because they are developed by multiplying the levelized fixed charge rate by historical investment costs, rather than by multiplying an economic carrying charge by a replacement cost.

LGS-X CSF charges are based on the actual investments made by the Company on behalf of an LGS-X customer for feeders, substation capacity, and (if the customer owns its own substation) the substation high-side equipment and transmission line tap. Investments in shared facilities are assigned to an LGS-X customer in proportion to its load ratio share of the facilities. If applicable, backup facilities can also be included in these charges. The updated levelized fixed carrying charge rate (including an O&M component) is used to calculate the monthly CSF charge from the assigned investments. For each customer, the CSF charges have been assigned among the secondary, primary and transmission voltage classifications on the same percentage basis as the current allocation. The load ratio share, the fixed charge rate, and the O&M adders are reviewed and updated in each GRC.

Exhibit Pascal-Direct-5 provides both the investment amount and corresponding charges for the facilities that have been directly assigned to each LGS-X customer.

30. Q. HOW WAS THE LGS-X CLASS'S FIXED CHARGE RATE UPDATED?

A. The fixed charge formula calculates the levelized annual cost of owning new utility plant. The fixed charge recovery rates are updated to include the Company's current marginal weighted cost of capital, federal income taxes, property taxes, insurance and depreciation. The levelized fixed charge rate yields an annual charge per dollar of original investment that captures the lifetime regulatory revenue requirements of the plant over its useful life. The proposed fixed charge rates are: 8.96 percent for distribution feeders, 8.84 percent for substation equipment, 8.9 percent for high voltage distribution, and 8.78 percent for substation land.

The annual fixed charge recovery rate (per dollar of investment) and the annual fixed charge recovery amounts (dollars per month) will change from rate case to rate case, as changes occur to the capital structure, interest rates, tax rates, insurance costs and depreciation rates that go into its calculation, and as additional investments are made over time. Also, if changes occur to the load ratio share of existing plant assigned to a customer, the associated CSF charge will change. If original plant wears out and is replaced over time, the charge will reflect the cost of the replacement investment, from that point forward. The fixed charge formula does not include a component for O&M expense. Therefore, the fixed charge rate is increased by current O&M charges as a percent of plant, using accounting data that is incorporated in the filed cost studies. These O&M charges are 0.553 percent for high-voltage plant 1.002 percent for substation plant, and 0.389 percent for distribution feeders. When these values are incorporated into the fixed charge rates stated above, the LGSX customers will see an increase in their monthly CSF charge.

V. ELECTRIC VEHICLE CHARGING INSTALLATION IMPACTS ON ALLOWANCE CALUCLATIONS.

31. Q. PLEASE ADDRESS THE DIRECTIVE FROM DOCKET NO. 22-09006 REGARDING THE EV ALLOWANCE ADDER.

A. The Commission's March 24, 2023, order includes the following directive: "NV Energy must conduct and file an analysis of the impact of adding electric vehicle charger allowances on the Rule 9 study median cost in the respective next general rate case."[4]

The Rule 9 tariff updates implementing the EV Allowance Adder were just recently approved by the Commission with an effective date of May 1, 2023.[5] Therefore, as of the filing of this GRC, there are not yet sufficient data points to conduct a proper analysis.

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[4] Docket No. 22-09006, March 24, 2023, Order, p.157, Directive 10.
[5] Docket No. 22-09006, Approval letter dated May 4 , 2023 for Effective Date May 1, 2023.

32. Q. **PLEASE PROVIDE ANY UPDATES TO THE CURRENT ("EV") ALLOWANCE ADDER FOR NEVADA POWER.**

A. To align the EV Adder with the proposed standard facility allowances for RS and RM in this general rate case, the EV Adder will need to be updated. The EV Adder is based on the standard Allowance and are presented in **Table Pascal-Direct-5** to reflect these updates for both classes. The update resulted in a 28 and 40 percent increase respectively in line with the RS and RM percent increases represented in **Table Pascal -Direct-1** above.

TABLE PASCAL DIRECT-5: UPDATED EV ALLOWANCE ADDER

Rate Class	Current	Proposed	% Change
RS	$1,751	$2,249	28%
RM	$769	$1,078	40%

33. Q. **DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

EXHIBIT PASCAL-DIRECT-1

Misha Pascal
Pricing Specialist
RATES & REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-3571

Mr. Pascal has been an employee of NV Energy since August 2018 and his time at the company has solely been at his current position as a Senior Pricing Analyst and currently as a Pricing Specialist within the Regulatory Pricing & Economic Analysis section of the Rates & Regulatory Affairs department. His current responsibilities are focused upon updating the Allowances and refunds in Rule 9, updating the customer specific facility charges for transmission and non-transmission customers, providing support for projects under development, and providing support for the Company's standby customers.

Prior to joining the Company, Mr. Pascal had experience as a Maintenance Engineer for a North American Contractor Ledcor. There he provided in depth analysis for processing, safety, and maintenance efficiencies. Responsibilities included analysis of several maintenance programs and present them through initiatives, cost justifications, and rate design.

Employment History

NV Energy
August 2018 to Present

Pricing Specialist, Regulatory Pricing & Economic Analysis
August 2018 to Present

- Complete transmission and non-transmission facility studies.
- Updated the Sierra Rule 9 allowances.
- Develop customer facilities charges that involve facilities analysis, cost responsibility, bill corrections, tariff support, and alternative payment arrangement calculations.
- Analysis for cost estimators and rate developments.
- Provide contract support for revenue-based allowances and customer specific facility charges.
- Provide Rule 9 support for gas and electric projects.

Non-Sierra Employment

Ledcor Group
Dec 2013 to June 2018

Maintenance Engineer

- Established planning programs for preventative maintenance and forecast inventory usage of multimillion dollars in stock parts.
- Conducted impacts of regulatory and safety standards and how the outcomes are affected against production and maintenance.
- Managed service contracts and negotiate rates based on margins required for success.
- Provided in depth equipment analysis during contract creation and negotiation and its impacts.

Education

University of Nevada, Reno
Bachelor of Science in Mechanical Engineering, December 2013.

University of Nevada, Reno
Bachelor of Science in Applied Economics and Statistics May 2001.

EXHIBIT PASCAL-DIRECT-2

Nevada Power Company
d/b/a NV Energy

Updated Rule 9 Allowances & Facilities Study White Paper

Allowances,
Master Planned Community Refunds,
Proportionate Share Refund Amounts,
And
Marginal Facilities Investment

1. UPDATING RULE 9 NEW LINE EXTENSION ALLOWANCES

A. Overview and Policy

Nevada Power Company d/b/a NV Energy ("NPC" or the "Utility") invests in line extension projects constructed for Applicants for new service. Most new customers require some form of line extension to obtain service at their homes and businesses. However, since the general body of customers benefits from the addition of load on the utility system, it is equitable for Nevada Power, on behalf of the general body of customers, to invest in a portion of the costs for new line extensions. The Utility's investment in line extensions for each ratepayer class is recovered though customers' utility rates, including the bills of the customers for whom the line extensions are constructed.

The percent of the cost of line extensions in which the Utility should invest requires balancing both efficiency and equity concerns such that the Allowance level results in a level of Utility investment that will fully fund line extensions for projects up to the mid-range of line extension costs, and a portion of costs for higher cost projects. The objective of Rule 9 Allowances is to equitably allocate the cost of line extension facilities required to serve an Applicant's electric load between the Utility and the line extension Applicant.

Section A.30 of Rule 9 of the Tariff requires that the Utility update Rule 9 Allowances, Master Planned Community ("MPC") Refunds and Proportionate Share Refunds every three years. The currently approved method for calculating Allowances, MPC refunds and proportionate share amounts was considered and approved in Docket No. 12-10004. The Commission approved several moderate changes to the existing methodology for Sierra in Docket No. 19-06002. These changes were implemented for purposes of calculating the Allowances presented in this proceeding.

B. Calculating the Updated Allowances

In Docket No. 12-10004, the median per unit project cost was chosen to represent the mid-range of line extension costs that should be fully funded through the allowance. This approach generally mitigates the impact of extreme costs more effectively than using an average, as a few line extensions with notably high costs per premise (or kVA) can substantially increase the average cost beyond reasonable levels. The median cost refers to the line extension cost for the home or small business (or kVA for extensions to larger loads) situated in the middle, meaning the home that separates the lower half of projects from the upper half of projects when ranked by line extension project cost.

C. Study Inputs

The primary inputs for the study consist of individual line extension project costs from Maximo which is NPC's work management system, and the average maximum kVA by customer class, supplied by the Load Research group. The new line extension project data in this proceeding spans from January 2011 to December 2022 for NPC's Updated Rule 9 Line Extension Allowances & Facilities Study ("Facilities Study").

Line extension project costs and the number of units per line extension project (homes, meters, or kVA) were obtained from Maximo. Maximo's information includes, among other details, estimated project costs, the number of meters or kVA per project broken down by class, rate classes within each project, and project completion dates. A project screening process is then employed to remove projects from the dataset if 1) the data was incomplete, 2) service was intended to be temporary, 3) the project status was cancelled or on hold, 4) the estimated project demand was zero, 5) the budget ID codes were unverified, or 6) the project was ineligible to receive an allowance because it was not a new line extension.

Rule 9 facilities can often serve multiple rate classes within a single project. In this NPC Facilities Study, common facilities costs for projects involving multiple rate classes were allocated to the participating classes in proportion to the kVA each class was expected to require from the project. Table 1 below outlines the class average kVA by class, which were updated for the 2023 Facilities Study as depicted in Table 1.

Table 1 – Change in Class Average kVA-per-Customer

Class Average kVA per Customer			
Rate Class	2020 Study	2023 Study	% Change from 2020
RS	10.6	10.6	0.0%
RM	8.4	8.4	0.2%
LRS	72.0	77.9	8.2%
GS	5.8	5.4	-6.7%
LGS-1	45.8	48.7	6.3%
LGS-2S	549.1	536.5	-2.3%
LGS-2P	640.3	655.9	2.4%
LGS-3S	1,557.9	1,493.3	-4.2%
LGS-3P	3,678.7	3,444.4	-6.4%
LGS-WP-2S	534.7	352.9	-34.0%
LGS-WP-2P	582.6	671.1	15.2%
LGS-WP-3S	1,625.2	1,405.1	-13.5%
LGS-WP-3P	1,968.9	1,615.9	-17.9%

The average kVA for all customers combined declined between the 2020 and 2023 notable from water pumping class impacts. These impacts are due to the small number of customers resulting in a sample size bias, but also a continuing general trend of decline of the last several rate cases in this class.

D. Study Methodology

Using 2011-2022 data, Allowances were calculated consistent with the methodology approved by the Commission in Docket No. 12-10004 and methodological revisions approved through several dockets up to Docket No. 20-06002 and are as follows:

1. By rate class, average line extension costs per-units were calculated for each project (total cost for project/units) and ranked lowest cost to highest cost.

    a. Projects with a construction completed year in the range 2011 to 2022 were included in the study.

    b. 12 years of cost data (2011 to 2022) were used to increase the number of projects used in the study to smooth variability in Rule 9 costs and provide a more robust dataset.

    c. To account for the expanded time range of projects included in the study, per-unit project costs were escalated to the first year of the rate effective period.

    d. To control for the impact of atypically large per-unit project costs, projects in top fifth percentile were removed from the calculation of the median per-unit project cost.

    e. The median per-unit project cost was identified for each rate class using the above per-unit project cost (sorted lowest to highest).

2. For customer rate classes with less than 10 projects per class the utility investment per-unit of the otherwise applicable class is used in the calculation of marginal utility investment per-customer.

3. To find the updated Allowance level for each class, an iterative analysis was done by looking at each project and figuring out the resulting utility investment under different Allowance amounts, assuming the investment was made in the first year of the rate effective period (2024). According to Rule 9, the Allowance that can be given is the lowest of either: i) the total project cost, or ii) the possible maximum Allowance based on the number of meters or project kVA. So, projects with costs lower than the potential maximum Allowance get an Allowance below the maximum to prevent a surplus payment to customers. Projects with costs higher than the maximum Allowance are limited to the maximum Allowance, and the Applicant has to cover the remaining project costs. The model stops going through the steps and sets the Allowance when the condition is met, meaning the class average utility investment equals the median project cost from the test period for each class.

E. Allowance Results

The 2023 proposed Allowances are greater for most customer classes than those approved in 2020 as shown in Table 2 below. Consistent with the approved methodology, the LGS-WP-2S, LGS-WP-2P, LGS-WP-3S, and LGS-WP-3P classes have been assigned the same Allowance as their corresponding rate schedule.

Table 2 – Proposed and Current Allowances

Rate Class	Units	2023	2020	$ Change	% Change
RS	Homes	$4,998	$3,890	$1,108	28%
RM	Homes	$1,377	$982	$395	40%
LRS	kVA	$370	$385	$(15)	-4%
GS	Meter	$3,007	$2,304	$703	30%
LGS1	kVA	$406	$303	$103	34%
LGS2S	kVA	$198	$141	$56	40%
LGS2p	kVA	$186	$140	$46	33%
LGS3S	kVA	$179	$126	$54	43%
LGS3P	kVA	$69	$54	$15	28%
LGSwp2S	*kVA*	$198	$141	$56	40%
LGSwp2P	*kVA*	$186	$140	$46	33%
LGSwp3S	*kVA*	$179	$126	$54	43%
LGSwp3P	*kVA*	$69	$54	$15	28%

Note: Italics indicates insufficient sample size; Allowances are pegged to the most similar class.

Allowances are project cost driven; thus it is reasonable to expect that the change in allowance levels of various customer classes will vary due to differences in costs for required materials and labor, length of line extension, complexity of design, construction, population density of surrounding area, and other factors. Inflation across all supply systems is the main driver of project costs and as a result the increase in the proposed Allowances.

2. UPDATING REFUNDS FOR MASTER PLANNED COMMUNITIES

A. Overview and Policy

MPC projects are required to fund 100% of the cost for installation of all distribution feeders required to serve their developments prior to construction. This requirement shields other customers from stranded or under-productive investments should the MPC not realize its forecasted loads.

The MPC developer advances the costs of these feeders to the Utility, and the Utility subsequently designs, constructs, owns, maintains and when necessary, replaces these feeders. Since the feeders are utilized by the Utility to serve load within the MPC, when loads are realized on MPC feeders, it is equitable for the Utility to refund the MPC its Advance Subject to Potential Refund for the feeder costs up to the amount that the Utility would on average spend to install similar feeders. It is a core Utility function to invest in Applicants' line extension projects on behalf of ratepayers, and refunding of MPC feeder costs is consistent with this purpose. The Utility investments in MPC feeders, via refunds to the MPC, are recovered through a portion of the Utility bills of all customers, including those served by the MPC feeders.

B. Results

The methodologies and calculations for computing Master Planned Refunds remains consistent with those approved by the Commission in 2020. The MPC Refunds declined due to growth in the class level units (meters or kW) combined with a decrease in Non-Revenue Feeder Marginal Demand Revenues. There is also an increase in the economic carrying charge which decreases the allowance as well.

C. Table 3 – Nevada Power Proposed Master Planned Community ("MPC") Refunds

Steps	Cost Components and Calculations	RS	RM	GS	LRS	LGS-1	LGS-2S	LGS-2P	LGS-3S	LGS-3P
		Nevada Power Company								
	Rate Classes ==>	RS	RM	GS	LRS	LGS-1	LGS-2S	LGS-2P	LGS-3S	LGS-3P
	Applicable Units ==>	Meter Based			Load Based					
A	NRF Demand Revenues	$49,434,544	$12,804,460	$2,535,078	$210,031	$17,998,698	$9,544,189	$242,935	$2,909,387	$10,849,576
B	Units (Meters or kW)	598,547	285,885	77,740	15,710	1,032,502	605,998	14,278	159,932	378,724
C	Units (Meters or kva) (KW based classes' units converted to kVa	n/a	n/a	n/a	17,455	1,147,225	673,332	15,865	177,702	420,805
D	Demand Revenues for NRF / Meter or kVa	$82.59	$44.79	$32.61	$12.03	$15.69	$14.17	$15.31	$16.37	$25.78
E	Economic Carrying Charge	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
F	Supported Investment / Meter or kW	$1,170	$634	$462	$170	$222	$201	$217	$232	$365
G	Percent of Capital (with O&M Removed)	84.7%	84.7%	84.7%	84.7%	84.7%	84.7%	84.7%	84.7%	84.7%
H	Supported Investment Capital / Meter or kW	$991	$537	$391	$144	$188	$170	$184	$196	$309
I	Reconciliation Factor	100%	100%	100%	100%	100%	100%	100%	100%	100%
J	Reconciled Supported Investment / Meter or kVa	$991	$537	$391	$144	$188	$170	$184	$196	$309

	Summary	RS	RM	GS	LRS	LGS-1	LGS-2S	LGS-2P	LGS-3S	LGS-3P
K	MPC Refund / Meter or kVA	**$ 991**	**$ 537**	**$ 391**	**$ 144**	**$ 188**	**$ 170**	**$ 184**	**$ 196**	**$ 309**
L	2020 MPC - Certification Filing	$ 1,262	$ 639	$ 455	$ 174	$ 223	$ 187	$ 217	$ 224	$ 329
M	Percent Increase 2020-2023	**-21%**	**-16%**	**-14%**	**-17%**	**-16%**	**-9%**	**-15%**	**-12%**	**-6%**

3. UPDATING PROPORTIONATE SHARE ALLOCATION UNIT VALUES

A. Overview and Policy

A Proportionate Share Refund is a mechanism that ensures fairness among applicants who fund secondary, primary, or HVD Line Extension projects and associated transformers. It prevents subsequent applicants from free riding on the investment made by the original applicants (pioneer applicants). Under Section A.16 of Rule 9, the original applicants can receive a refund from subsequent applicants who directly connect to the Line Extension they funded. The utility administers this pass-through mechanism, ensuring that refunds are calculated correctly based on the length or amount of facilities required for the subsequent applicants but initially funded by the original applicants. The utility, however, does not retain any portion of the Proportionate Share Allocation.

The methodology for calculating Proportionate Share Refunds, provided in Advice Letter 538-E Appendix 2, remains unchanged. The calculation involves determining the installed cost of distribution facilities, such as cable or transformers and switches, and unitizing it based on capacity or footage. This results in cost per foot per kVA for cable or cost per kVA for transformers and switches, which are the Proportionate Share Allocations.

B. Results

Factors used in calculating Proportionate Share Allocation unit values are based on the average installed cost and loading capacities (or lengths) of various distribution facilities. Changes in Proportionate Share Refunds per unit reflect changes in the cost of material and labor. A comparison of 2023 and 2020 Proportionate Share Allocations per unit is shown in Table 4.

Table 4 – Proposed Nevada Power 2023 Proportionate Share Refunds

Proportionate Share Costs – 4-12 KV - Proposed								
Phase	Type	Wire	Transformer	Switch	Cost/kVA	Cost/Ft/kVA	2020 Values	% change
1	O/H	2/0				$0.02213	$0.01701	30.09%
3	O/H	2/0				$0.00952	$0.00805	18.28%
3	O/H	954				$0.00637	$0.00505	26.17%
1	U/G	1/0				$0.01834	$0.00829	121.14%
1	U/G	1/0 Res				$0.01656	$0.00714	132.02%
3	U/G	1/0				$0.01145	$0.01193	-4.02%
3	U/G	1/0 Res				$0.00755	$0.00691	9.25%
3	U/G	1000				$0.00510	$0.00222	130.36%
1	O/H		1-50 kVA		$114.72		$94.78000	21.04%
1	O/H		51-167 kVA		$63.14		$40.54413	55.73%
1	U/G		1-50 kVA		$73.82		$79.76000	-7.45%
1	U/G		51-167 kVA		$55.74		$81.08654	-31.26%
3	U/G		1-315 kVA		$96.87		$70.80522	36.81%
3	U/G		316-1000 kVA		$22.92		$19.03206	20.41%
3	U/G		1001-2500 kVA		$29.03		$16.47139	76.22%
3	U/G			600 Amp	$4.70		$1.39310	237.05%
Proportionate Share Costs - 25 KV - Proposed								
Phase	Type	Wire	Transformer	Switch	Cost/kVA	Cost/Ft/kVA	2020 Values	% change
1	O/H	2/0				$0.01068	$0.00798	33.91%
3	O/H	2/0				$0.00476	$0.00382	24.45%
3	O/H	954				$0.00319	$0.00240	32.99%
1	U/G	1/0				$0.00772	$0.00415	86.12%
1	U/G	1/0 Res				$0.00686	$0.00378	81.53%
3	U/G	1/0				$0.00464	$0.00563	-17.68%
3	U/G	1/0 Res				$0.00369	$0.00345	6.80%
3	U/G	1000				$0.00162	$0.00111	45.81%
1	O/H		1-50 kVA		$105.49		$89.85000	17.41%
1	O/H		51-167 kVA		$43.41		$35.05808	23.83%
1	U/G		1-167 kVA		$59.94		$54.28681	10.41%
3	U/G		1-315 kVA		$76.77		$73.86633	3.93%
3	U/G		316-1000 kVA		$17.52		$17.47094	0.28%
3	U/G		1001-2500 kVA		$20.86		$21.03628	-0.84%
3	U/G			600 Amp	$1.07		$0.99260	8.07%

4. COST OF SERVICE STUDY INPUT: MARGINAL FACILITIES INVESTMENT BY CLASS

The secondary purpose of updating the Facilities Study is to provide the marginal facilities investment per customer by class as an input to Nevada Power's cost of service studies. The marginal investment by class was calculated using the average investment results from the Facilities Study stated on a "per meter" basis. For Rule 9 compliance purposes, the calculations performed in the Facilities Study are stated on a per meter basis for the single family residential, multi-family residential and small general service classes with all other class investment per kVA (except those with customer specific facilities charges). Therefore the investment per kVA had to be converted to a per customer investment. This was accomplished using the average max kVA per customer by class provided in Table 1 as a conversion factor.[1] Table 5 provides the marginal facilities investment for the 2023 and 2020 MCS and the percent changes in the marginal facilities between the two MCS.

Table 5 – Marginal Facilities Investment-per-Customer

Rule 9 Marginal Facilities Investment per Customer ($)			
Rate Class	**2023 GRC**	**2020 GRC**	**% Change from 2020 GRC**
RS	$3,941	$3,164	24.6%
RM	$1,044	$824	26.7%
LRS	$23,689	$19,515	21.4%
GS	$1,836	$1,574	16.6%
LGS-1	$13,087	$9,706	34.8%
LGS-2S	$76,807	$61,268	24.8%
LGS-2P	$98,270	$73,739	33.0%
LGS-3S	$168,194	$134,480	24.5%
LGS-3P	$168,509	$138,726	21.3%
LGS-WP-2S	$50,523	$59,662	-15.7%
LGS-WP-2P	$100,551	$67,101	49.6%
LGS-WP-3S	$158,261	$140,282	12.3%
LGS-WP-3P	$79,051	$74,250	6.3%

For the water pumping classes (LGS-WP-2S, LGS-WP-2P, LGS-WP-3S, LGS-WP-3P), the Rule 9 project data has less than 10 projects per class for these classes; so, the utility investment per-unit of the otherwise applicable class is used in the calculation of marginal utility investment per-customer.

[1] The class average max kVA is adjusted for line losses to include the cost of additional facilities upstream of the meter that otherwise would not be captured by rates that have cost determined at the meter.

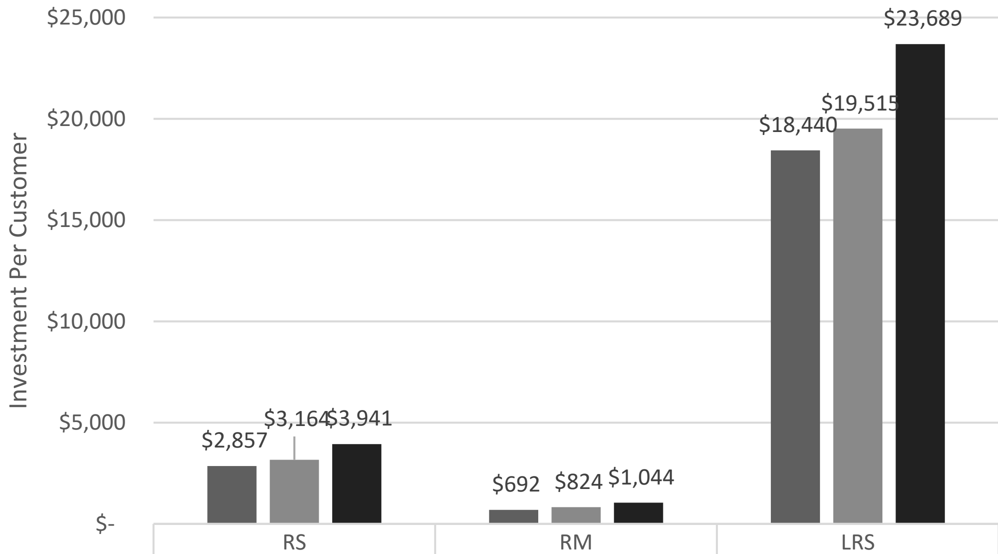
When evaluating changes in marginal facilities investment per customer it is important to remember that the marginal facilities investment is a function of two inputs; utility investment per unit and the class average kVA per customer. Table 6 provides the direction of the change from the 2020 Rule 9 Facilities Study of these two inputs into the marginal utility investment per-customer.

Table 6 – Marginal Facilities Investment Inputs Movement Indicator Table

Rate Class	Utility Investment per Unit	Class Average kVA per Customer	Overall Utility Investment
RS	Increased	Decreased	Increased
RM	Increased	Increased	Increased
LRS	Increased	Increased	Increased
GS	Increased	Decreased	Increased
LGS-1	Increased	Increased	Increased
LGS-2S	Increased	Decreased	Increased
LGS-2P	Increased	Increased	Increased
LGS-3S	Increased	Decreased	Increased
LGS-3P	Increased	Decreased	Increased
LGS-WP-2S	Decreased	Decreased	Decreased
LGS-WP-2P	Increased	Increased	Increased
LGS-WP-3S	Increased	Decreased	Increased
LGS-WP-3P	Increased	Decreased	Increased

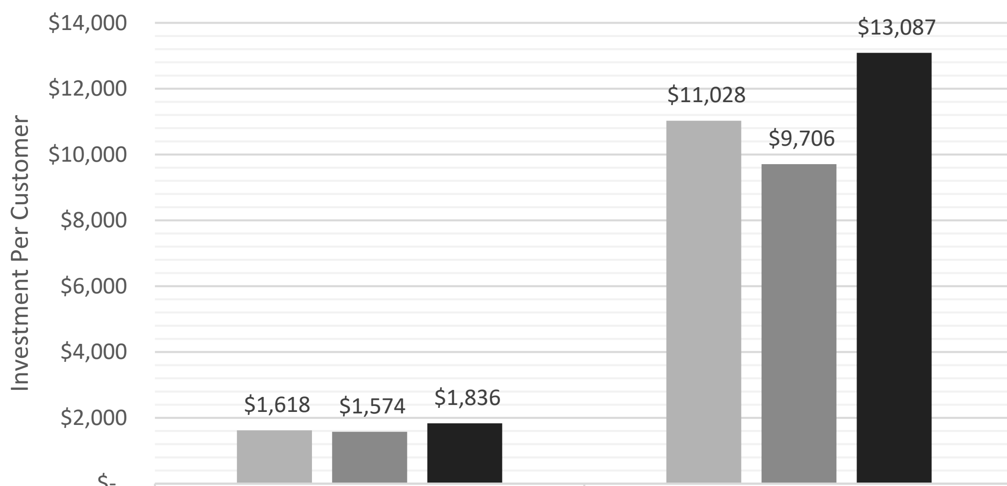
Figures 1, 2, 3 and 4 illustrate the change in marginal utility investments over Nevada Power's last three general rate cases.

Rule 9 Facilities Marginal investment per Customer (Residential Rate Classes)
Figure 1



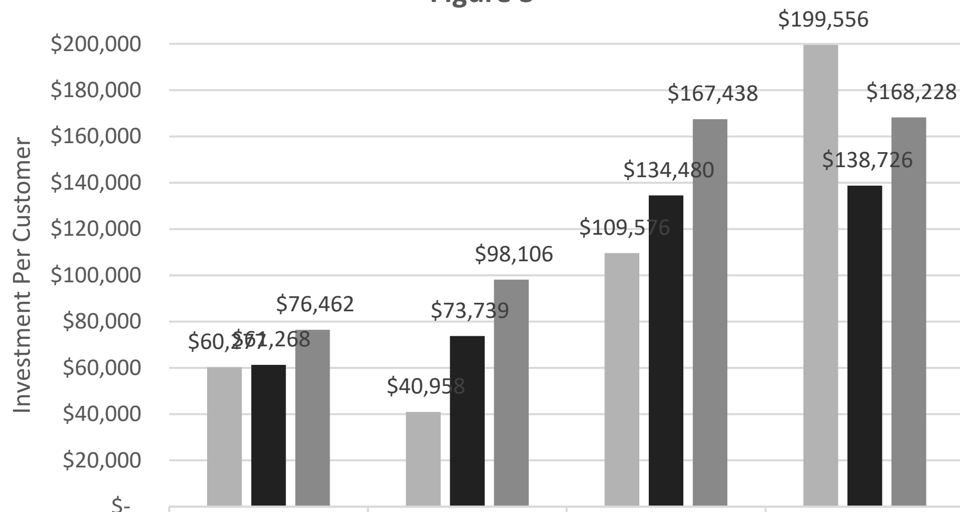
	RS	RM	LRS
2017 GRC	$2,857	$692	$18,440
2020 GRC	$3,164	$824	$19,515
2023 GRC	$3,941	$1,044	$23,689

Rule 9 Facilities Marginal investment per Customer (Small Commerical Rate Classes)
Figure 2



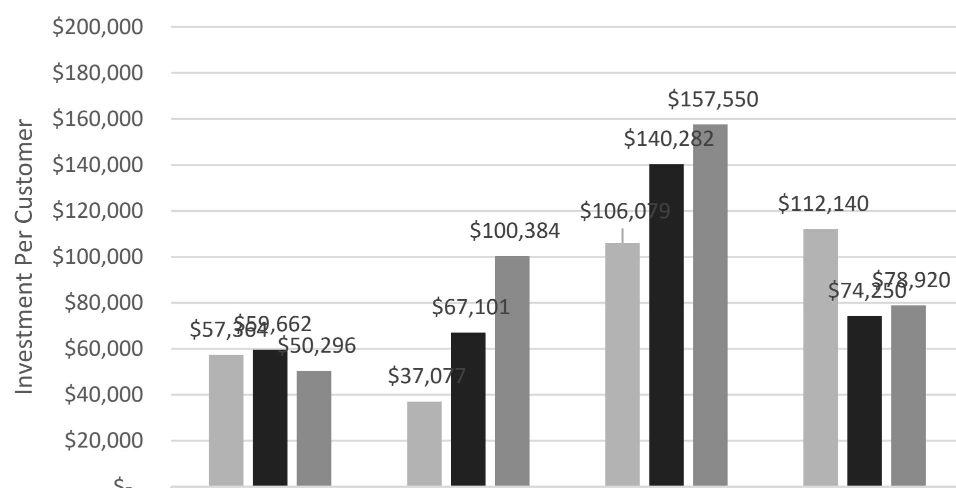
	GS	LGS-1
2017 GRC	$1,618	$11,028
2020 GRC	$1,574	$9,706
2023 GRC	$1,836	$13,087

**Rule 9 Facilities Marginal investment per Customer
(Large Commercial Rate Classes)
Figure 3**



	LGS-2S	LGS-2P	LGS-3S	LGS-3P
2017 GRC	$60,277	$40,958	$109,576	$199,556
2020 GRC	$61,268	$73,739	$134,480	$138,726
2023 GRC	$76,462	$98,106	$167,438	$168,228

**Rule 9 Facilities Marginal investment per Customer
(WP Rate Classes)
Figure 4**



	LGS-WP-2S	LGS-WP-2P	LGS-WP-3S	LGS-WP-3P
2017 GRC	$57,364	$37,077	$106,079	$112,140
2020 GRC	$59,662	$67,101	$140,282	$74,250
2023 GRC	$50,296	$100,384	$157,550	$78,920

EXHIBIT PASCAL-DIRECT-3

NEVADA POWER COMPANY
d/b/a NV ENERGY
LGS-T CUSTOMER-SPECIFIC FACILITIES INVESTMENT - 2024
FOR THE TEST PERIOD ENDED DECEMBER 31, 2022

PROPOSED LGS-T FACILITIES INVESTMENT AMOUNTS

A	B	C	D	E	F	G	H	I	J
Line	Customer	Alternate Name	Rate Class	Bundled or DOS	Current Investment in Facilities by NVE	Escalation on Original Plant Contributed by Customer[3]	Total Plant Contributed NVE[4]	CIAC'd Plant Contributed by Customer	Line
1	LHOIST	LHOIST NORTH AMERICA OF ARIZONA INC	LGS-3T	Bundled	744,110	-	744,110	-	1
2	SA RECYCLING	SILVER DOLLAR RECYCLING	LGS-3T	Bundled	1,366,186	-	1,366,186	-	2
3	VENETIAN	VENETIAN CASINO RESORT	LGS-3T	Bundled	6,606,191	-	6,606,191	-	3
4	HOLDER	HOLDER (Temporary)	LGS-3T	Bundled	1,994,483	140,433	2,134,916	7,223,845	4
5									5
6	**STANDBY CUSTOMERS:** [1]								6
7									7
8									8
9	**TOTAL LGS3T Bundled**				**$ 10,710,970**	**$ 140,433**	**$ 10,851,403**	**$ 7,223,845**	9
10									10
11	SNWA LAMB	SNWA LAMB	LGS-3T	DOS	$ 277,807	$ 8,822	286,629	$ 453,810	11
12	SNWA LAMB	SNWA LAMB	LGS-3T	DOS	277,807	8,822	286,629	453,810	12
13	SNWA SLOAN	SNWA SLOAN	LGS-3T	DOS	681,010	16,069	697,079	826,580	13
14	CITY OF HENDERSON[2]	CITY OF HENDERSON	LGS-3T	DOS	-	621,750	621,750	1,191,000	14
15	CITY OF HENDERSON[2]	CITY OF HENDERSON	LGS-3T	DOS	-	621,750	621,750	1,191,000	15
16	CCWRD[2]	AWT SUBSTATION	LGS-3T	DOS	-	110,577	110,577	374,615	16
17	CCWRD[2]	SURGE POND SUBSTATION	LGS-3T	DOS	-	62,512	62,512	211,779	17
18	CCWRD[2]	ROCHELLE SUBSTATION	LGS-3T	DOS	-	693,361	693,361	2,348,976	18
19	MGM	CITY CENTER	LGS-3T	DOS	22,569,510	-	22,569,510	-	19
20	MGM	MGM GRAND HOTEL INC.	LGS-3T	DOS	$ 1,433,889	$ -	1,433,889	$ -	20
21	CAESAR'S	CAESAR'S PALACE	LGS-3T	DOS	1,025,517	-	1,025,517	-	21
22	AIR LIQUIDE	AIR LIQUIDE	LGS-3T	DOS	-	96,078	96,078	4,942,256	22
23									23
24	**TOTAL LGS3T DOS**				**$ 26,265,540**	**$ 2,239,741**	**$ 28,505,281**	**$ 11,993,826**	24
25									25
26	**TOTAL LGS3T**				**$ 36,976,510**	**$ 2,380,174**	**$ 39,356,684**	**$ 19,217,671**	26
27									27
28	SNWA PP4	SNWA SIR PHILIP	LGS-WP-3T	DOS	$ 30,189	$ -	$ 30,189	$ -	28
29	SNWA PP5	SNWA JUDI LN	LGS-WP-3T	DOS	1,370,240	-	1,370,240	-	29
30	SNWA PP6	SNWA BONANZA	LGS-WP-3T	DOS	672,124	-	672,124	-	30
31	SNWA HACIENDA	SNWA HACIENDA	LGS-WP-3T	DOS	327,087	-	327,087	-	31
32									32
33	**TOTAL LGS-WP-3T**				**$ 2,399,640**	**$ -**	**$ 2,399,640**	**$ -**	33
34									34
35									35
36	SNWA PP3	SNWA HENDERSON	LGS-WP-2T	DOS	**$ 420,825**	**$ -**	**$ 420,825**	**$ -**	36
37									37
38	**TOTAL**				**$ 39,796,975**	**$ 2,380,174**	**$ 42,177,149**	**$ 19,217,671**	38

[1] There are 12 transmission level standby customers (seven LGS-3T & five LGS-2T) not shown on this table, as customer specific facilities charges will not apply to them. These customers have paid for their interconnection facilities back to FERC transmission. Under agreements with the Company, these customers are fully responsible for maintenance and replacement of the facilities; thus, customer specific facilities charges are not applicable.

[2] Customer has paid for its facilities in full.

[3] Escalation of Customer contributed plant to 2024$, less original investment amount (Col. I).

[4] Total of NVE investment and escalation portion of customer contributed investment (Col. F + G).

EXHIBIT PASCAL-DIRECT-4

NEVADA POWER COMPANY
d/b/a NV ENERGY
OLGS-3P-OHLF CUSTOMER-SPECIFIC FACILITIES INVESTMENT - 2024
FOR THE TEST PERIOD ENDED DECEMBER 31, 2022

PROPOSED OHLF INVESTMENT AMOUNTS AND RESULTING FACILITIES' CHARGES

A	B	C	D	E	F	G	H	I	J
Line	Customer	Alternate Name	Rate Class	Bundled or DOS	Current Investment in Facilities by NVE	Escalation on Original Plant Contributed by Customer	Total Plant Contributed NVE	CIAC'd Plant Contributed by Customer	Line
1	**HLF TARIFF:**								1
2									2
3	CLEARWATER PAPER CORPORATION	POTLATCH CORPORATION	LGS-3P HLF	Bundled	$ 1,732,009	$ -	$ 1,732,009	$ -	3
4	NP RED ROCK LLC	RED ROCK STATION CASINO	LGS-3P HLF	Bundled	$ 745,462	$ -	$ 745,462	$ -	4
5	POLY-WEST INC	POLY-AMERICA	LGS-3P HLF	Bundled	$ 247,189	$ 1,006	$ 248,195	$ 51,773	5
6	STATION GVR ACQUISITION LLC	G.V.R. STATION CASINO	LGS-3P HLF	Bundled	$ 338,352	$ -	$ 338,352	$ -	6
7	TRUMP RUFFIN COMMERCIAL LLC	TRUMP INTERNATIONAL HOTEL	LGS-3P HLF	Bundled	$ 1,078,998	$ -	$ 1,078,998	$ -	7
8	SUNSET STATION 1641830	NP SUNSET LLC	LGS-3P HLF	Bundled	$ 466,716	$ -	$ 466,716	$ -	8
9	STRATOSPHERE CORPORATION	VEGAS WORLD	LGS-3P HLF	Bundled	$ 630,870	$ -	$ 630,870	$ -	9
10	STRATOSPHERE CORPORATION	VEGAS WORLD	LGS-3P HLF	Bundled	$ 523,772	$ -	$ 523,772	$ -	10
11	POLY-WEST 2089379	POLY-AMERICA	LGS-3P HLF	Bundled	$ 247,189	$ 1,006	$ 248,195	$ 51,773	11
12									12
13	**TOTAL OLGS-3P-HLF (EXCLUDING 704B PREMISES)**				**$ 6,010,556**	**$ 2,012**	**$ 6,012,568**	**$ 103,546**	13
14									14
15									15
16									16
17									17
18									18
19									19
20									20
21									21
22									22
23									23

EXHIBIT PASCAL-DIRECT-5

NEVADA POWER COMPANY
d/b/a NV ENERGY
LGS-X CUSTOMER SPECIFIC FACILITIES CHARGES - 2024
FOR THE TEST PERIOD ENDED DECEMBER 31, 2022

PROPOSED LGS-X INVESTMENT AMOUNTS AND RESULTING FACILITIES CHARGES

Line	Customer	Bundled or DOS	Current Investment	Current Monthly Charge	Proposed Investment	Proposed Annual Charge	Proposed Monthly Charge	Line
A	B	C	D	E	F	G	H	I
1	Bellagio/Park MGM	DOS	$ 3,841,860	$ 29,105	$ 3,841,860	$ 368,687	$ 30,724	1
2								2
3	Mandalay Bay/Excalibur/Luxor	DOS	4,885,159	35,922	4,885,159	458,049	38,178	3
4								4
5	Paris/Horseshoe	DOS	2,066,291	15,485	2,189,516	208,196	17,351	5
6								6
7	**TOTAL LGS-X DOS:**		$ 10,793,310	$ 80,512	$ 10,916,535	$ 1,034,932	$ 86,253	7
8								8

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MISHA PASCAL, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: June 5, 2023

Misha Pascal

TIMOTHY POLLARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Timothy Pollard

Rate Design

I. INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Tim Pollard. My current position is Director for Load Forecasting, Research and Analytics in the Rates and Regulatory Affairs department for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have worked in the Companies' Rates and Regulatory Affairs department since 2007, and most recently as a Technical Lead within the department where my focus was on regulatory cost of service and rate design issues. In my current position, my primary focus is working with the team on load forecasting and research matters for the Companies.

I was also previously employed by the Companies in 2004 as a Load Forecasting Economist within the Resource Planning department. My statement of qualifications is attached as **Exhibit Pollard-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION.

A. My responsibilities include leading and overseeing the Companies' load forecasts and historical load research activities. This includes all technical aspects of their historical and forecast class load data used for regulatory filings with the Commission. My educational background, previous positions and professional experience are summarized in **Exhibit Pollard-Direct-1**.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have been an expert witness before the Commission regarding load forecasts, cost of service and regulatory pricing issues in support of the Rate & Regulatory Affairs department's responsibilities. Most recently, I provided testimony in the Third Amendment to the 2021 Joint Integrated Resource Plan (Docket No. 22-09006). A full list of cases in which I have provided testimony before the Commission can be found in **Exhibit Pollard-Direct-1**.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support:

1) The development of the hourly class loads used as inputs into the cost-of-service calculations for individual customer classes;

2) Factors used to adjust the historical test period billing determinants in Statement J to account for weather to the approved 20-year trended normal values;

3) Billing determinant adjustments to modify the historical Time-of-Use ("TOU") period information reflecting the Company's proposed new TOU periods;

4) Updates to the diversity factor study used as an input to the Company's proposed rate design; and

5) To provide the Commission with the results of the analysis for wireless device usage, impacts on the Street Lights ("SL") tariff, in response to the analysis agreed to by the Companies in response to a customer complaint in Docket No. 21-10008, and the Company's recommendations to allow for the continued installation of these devices if certain conditions are met by those customers for future installations.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Pollard-Direct-1	Statement of Qualifications
Exhibit Pollard-Direct-2	Weather Normalization
Exhibit Pollard-Direct-3	Wireless Device Analysis

II. <u>HOURLY CLASS LOADS</u>

7. Q. WHAT IS THE PURPOSE OF THE HOURLY CLASS LOAD SHAPES?

A. Class load shapes reflect the way customers in different customer classes use energy across all hours of the year. The hourly loads of the energy delivered to customers are developed for all individual customer classes, in addition to various load shapes for those partial requirements customer classes (e.g. Net-energy metering ("NEM") and energy storage devices ("ESD") customers) to better identify the unique relationships that these customers have with the utility.

These hourly loads for all individual classes are one of the building blocks that Nevada Power uses to develop the cost of providing components of service to individual customer classes that informs rate design in Statement O. Those classes with relatively higher loads during higher use periods typically impose higher costs on the system and are assigned or allocated a larger share of costs in the marginal cost of service studies ("MCSS"), the embedded cost of service studies ("ECSS") and the hybrid cost of service studies ("HCSS"). The effect of these hourly usage patterns and how they are used in the cost-of-service studies and Statement O are described in more detail in the prepared direct testimonies of Jeffrey Bohrman and Samantha Prest.

8. Q. WHAT UPDATES TO CLASS LOAD SHAPES ARE INCLUDED IN THIS FILING?

A. Load shapes for all of Nevada Power's rate classes have been updated using historical recorded load data for the 12 months ending September 2022. The period for class loads is set at 12 months ending September 2022, three months prior to the end of the test period (ending December 31, 2022), to allow for data gathering and processing requirements of 15-minute interval data. At the certification filing, the load shapes will be updated through December 2022 for all customer classes at Nevada Power.

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9. Q. HOW DOES NEVADA POWER UPDATE CLASS LOAD SHAPES?

A. Class load shapes are first updated by identifying the population of customers in each rate class for the 12-month period. Next, class load shapes are developed from individual customer data and expanded to the class customer counts using the population of customers in each given rate class.

Load shapes for these rate classes are the summation of energy use of each customer in the class at each 15-minute interval of the day. This data is then summed to the hour to produce 8,760 hours of energy use for the year. When some of the 15-minute interval data is missing, the hourly data that is available is used to fill in the missing data for these customers. The available hourly data is used as the shape, then applied to the remaining billed sales of those customers with missing information, and both are then summed to the hour for each month across the year. The result is an hourly usage pattern representing the entire rate class for all 8,760 hours of the year for each customer class.

10. Q. PLEASE DESCRIBE ANY CHANGES TO THE METHODOLGY USED TO CREATE CLASS LOAD SHAPES FOR THIS NEVADA POWER GENERAL RATE CASE ("GRC") COMPARED TO THE 2020 GRC.

A. There are three main changes to the way load shapes were created for this GRC. First, load shapes for Nevada Power are no longer based on stratified random sampling methods using customer data to expand to the overall customer class. The saturation, consistency and accuracy of smart meter interval data allowed the Company to process previously sampled classes' class loads (e.g. RS, RS-NEM, RM, ORS, GS, LGS-1, OGS TOU, and LGS-2S) as a census population. This follows the methodology presented and approved in Sierra's 2022 GRC filing, Docket No. 22-06014.

Second, in previous GRCs the residential and small commercial classes were pulled on a per customer basis for development of class loads. Due to the addition of the Big Data Platform ("BDP") and the Company's ability to query larger sets of data more directly for compilation of customer usage for MyAccount on the Companies' web site, 15-minute interval data can now be summarized at the class level.

Third, similar to other NEM classes, the hourly class loads for LGS-1 NEM customers are now developed separately from the larger full-requirements LGS-1 customer class. There are approximately 330 of these customers identified with applicable generation systems installed at Nevada Power during the test period. Due to this large number, and their different service characteristics from fully-bundled customers, these customers were processed as their own class for this GRC.

11. Q. PLEASE FURTHER EXPLAIN THE PROCESS CHANGE FOR CREATING THE SMALL COMMERCIAL AND RESIDENTIAL CLASS LOADS.

A. Beginning in Sierra's 2022 GRC (Docket No. 22-06014), the ability to pull data from BDP allowed the Companies to change from a bottom-up approach to a top-down approach for class loads. Previously, each customer's 15-minute interval data was pulled and then aggregated up to the class load either as a census or by statistically sampling the classes. This bottom-up procedure was labor intensive, time consuming and did not result in any more accurate information than getting interval data on the class level and then drilling down to the customer level, if necessary, for many of the classes with large numbers of customers.

The new method sums all interval data for each customer within a class that was recorded at the meter. The available hourly data is used as the shape and then expanded to the total population for the month in each 15-minute interval to account for any missing data. While there are smaller customer classes that the Company still considers individual customer data in the development of class loads (e.g. current battery customers), this streamlined process has enabled the Company to process all classes on a census basis more efficiently than in past years.

12. Q. WERE THERE ANY CHANGES TO PROCESSING CLASS LOADS FOR THE LARGE COMMERCIAL CLASSES?

A. No, the large commercial classes are processed the same as previous GRCs. Each customer's interval data is collected and then aggregated up the class level to create the class load shape.

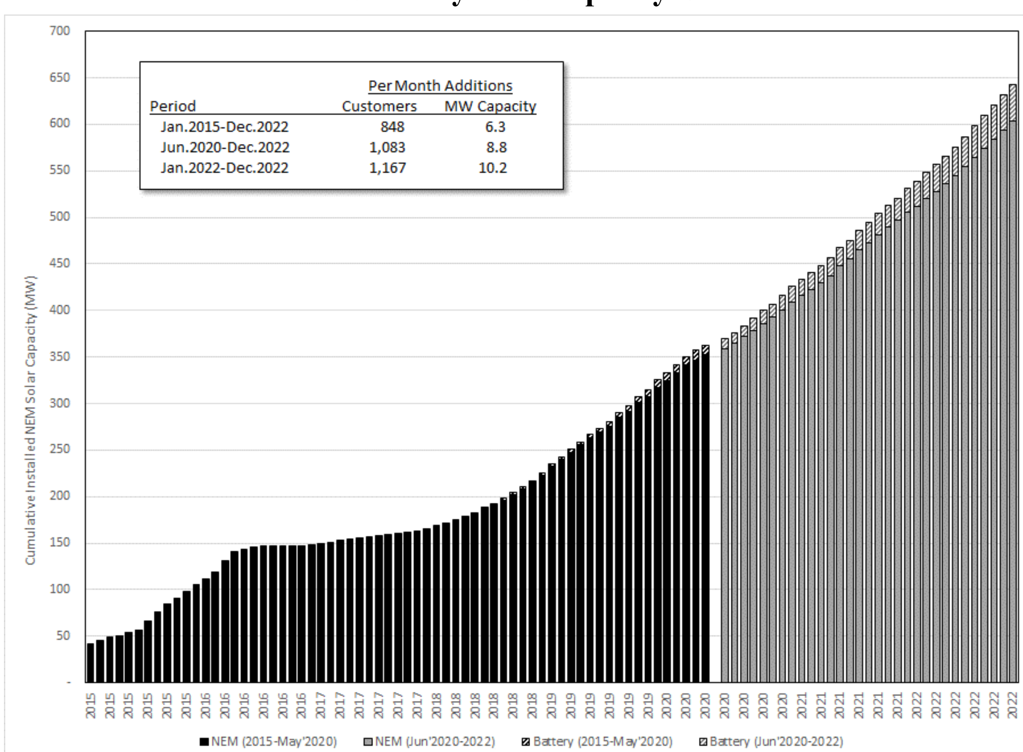
13. Q. ARE THERE ANY NOTABLE CHANGES IN CLASS LOADS FROM THOSE USED IN THE PREVIOUS GRC?

A. Generally, the system-wide hourly load shape has remained consistent with previous years, but there are a few changes to specific classes that I would like to highlight. The first item is a change in the overall level and shape of the hourly loads of the Large General Service-2 Water Pumping schedule ("LGS-2S WP"), which experienced additional customers and more daytime usage than in the 2020 GRC.

The second change is the continued growth of the NEM and battery customer classes over recent years. **Figure Pollard-Direct-1** below presents the growth of the installed capacity of these customer groups since 2015. From 2015 through 2022, nearly 850 customers have moved over to NEM schedules each month at Nevada Power. These customers have installed approximately 6.3 MW of rooftop solar generation each month during this period. In total, nearly 650 MW of rooftop solar generation (600 MW since 2015) has been installed at Nevada Power through the 2022 test period.

Customers choosing to install energy storage devices behind their meter, most commonly with solar generation, have installed roughly 40 MW of capacity since 2015. Most of these customers are existing residential customers, and so they have migrated from the standard single-family residential (RS) customer class to the applicable NEM class.

Figure Pollard Direct-1
NEM/Battery MW Capacity Growth



Finally, as part of the wireless device analysis that I discuss later in my testimony, the Company identified approximately 490 customers who were being inappropriately billed on the SL tariff. Based on discussions with the New Projects department, a system solution is currently underway to automatically limit the SL schedule option to only eligible customers when a request for new lighting service is submitted. The identified premises were removed from the historical SL class loads and billing determinants for this filing and are reflected in the General Service ("GS") schedule. This change accounts for a decrease of approximately five percent of the historical SL class loads, but only 0.89 percent of the GS schedule. This change is also reflected in the movement of the appropriate billing determinants from the SL to GS class in Statement J.

III. BILLING DETERMINANT ADJUSTMENTS

14. Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO WEATHER NORMALIZATION IN THIS GRC.

A. The Company is using the same methodology to adjust test period billing determinants as that supported by Company witness Eric Fox and ultimately approved by the Commission in Sierra's 2022 GRC.[1] The methodology incorporates a 20-year trended normal adjustment for adjustments in Statement J, to account for the impact of weather during the test period.

Exhibit Pollard-Direct-2 summarizes information on the weather normalization calculations for different customer groups. Company witness Matthew Valentic

[1] In the Commission's Order in Nevada Power's 2020 GRC, Directive Paragraph 8 ordered that the weather normalization methodology adopted in Sierra's 2019 GRC (Docket No. 19-06006) should be used in Nevada Power's next GRC. However, in Sierra's 2022 GRC, the Commission approved a trended 20-year methodology for weather normalization that was not opposed by any party. As a result, the Company incorporates the most recently approved methodology in this proceeding.

supports the development, updates, and results of billing determinants in Statement J as part of the revenue requirement phase of this proceeding.

15. Q. WHAT BILLING DETERMINANT ADJUSTMENTS DID THE COMPANY PERFORM TO REFLECT THE PROPOSED NEW TOU PERIODS?

A. As historical TOU-based billing determinants are based on the current TOU periods, it was necessary to adjust these in Statement J to reflect the changes to TOU periods being proposed in this proceeding. Company witness Hank Will supports the proposed changes to the TOU periods. The revised billing determinants will be used in Statement J, each cost-of-service study, and rate design scenario for the affected classes. The result provides percentage adjustments for use in Statement J so that the billing determinants, and ultimately rates, will appropriately reflect the change in TOU periods going forward at the start of the rate effective period.

16. Q. PLEASE SUMMARIZE HOW THESE ADJUSTMENTS WERE CALCULATED.

A. The methodology begins with individual customer 15-minute interval data as the basis to develop class level billing determinants under both the current and new TOU period definitions. The billing determinants under the proposed TOU periods are compared with those under the current definition, developing percentages that are used as an input to Statement J in order to adjust historical billing determinants to the new definitions. The result of this process are TOU billing determinants following the newly proposed definitions for all affected customer classes.

Each billing determinant affected by the change in the TOU period definitions (sum of energy kWh, and maximum kW values) was calculated for each applicable month and TOU period from individual customer interval data. These calculations were run for each premise in the required rate classes, and an expansion factor was applied by month and rate class where necessary to account for missing data, if needed. The energy kWh percentages were summarized from hourly class loads for the large commercial classes to align the billing determinants between the cost-of-service studies and Statement J.

As the standard rate schedule cost of service information is used for optional TOU schedule rate design, these steps were also required for residential and small commercial schedules. Consistent with Sierra's 2022 GRC methodology, a random sample of 500 customers was used for customer classes with large number of customers (e.g. RS, RS-NEM, RM, and GS) to determine the corresponding adjustments.

17. Q. BRIEFLY DESCRIBE THE SAMPLING PROCESS FOR THESE CUSTOMER CLASSES.

A. Customers included in the sample were limited to those billed in the respective rate class for the entire period and those who did not have a month of zero usage. Each rate class population was analyzed based on average monthly usage, or capacity in the case of RS-NEM, and a count of strata by usage or capacity was established. The counts were based on premises that were in the respective rate classes at the end of the period under review (September 2022). The sampled premises were also categorized by strata for their respective rate classes, and an adjustment factor was created expanding results to be representative of the entire rate class. For net metered rate classes, the billing determinants were processed for each channel: delivered, received, generated, and totalized.

For total kWh usage under the proposed time of use, the percentage value was based on what percentage of total kWh consumption fell in the applicable periods by season. The percent total added up to 100 percent for summer and 100 percent for winter (seasons were treated separately) for most classes as this season information is only proposed to change for those customers on the Option B TOU residential schedule. For these customers, the percentages provided were based on the entire year as the proposed periods do not count the same months as summer and winter (all percentages for summer and winter add up to 100 percent together for these rate classes).

Percentages for maximum kW totals under the new time of use were also provided for select rate classes that include kW demand charges. To obtain the percent change for summer on peak, the total maximum kW by rate class was obtained for each rate class's respective current time of use. The same results were obtained for the new time of use, and the calculation provided a percentage adjustment factor based on the following calculation: (new time of use kW total / current time of use kW total) / current time of use kW total + 1. The relevant total used for the final calculation was an aggregation of summer on peak maximum kW values for all premises and all summer months by rate class.

The final result of this process are percentages used in Statement J, adjusting the historical TOU billing determinants to the newly proposed definitions that are used to develop rates designed to collect the revenue requirement approved by the Commission under the new TOU period definitions.

IV. DIVERSITY FACTOR UPDATE

18. Q. PLEASE SUMMARIZE THE PURPOSE OF THE DIVERSITY FACTOR.

A. Following the methodology approved by the Commission, most recently in Sierra's 2022 GRC and Nevada Power's 2020 GRC, the diversity factor is used to split the proposed TOU demand rates of the corresponding full-requirements classes. These demand rates are split between a contract demand charge and a back-up demand charge to reflect the average maximum demand reductions of the on-site generation for these customers while reflecting the demand that the utility stands by to serve in the event their generation stops working.

This diversity factor is used to split the TOU demand rates of the otherwise applicable schedule between a fixed reservation and a variable back-up demand component for standby customers. The (fixed) reservation charge is billed on the backup contract demand of the standby customer. The back-up (variable) demand component only applies when the standby customer requires back-up service and imposes a back-up demand on the Company. Thus, the sum of the reservation and back-up demand charges for each TOU period of the standby classes equal the TOU demand charges of their respective full requirements class. This ensures that these customers will pay no more than they otherwise would have if their generation does not work and will receive any potential demand reductions resulting from their generation when it is working. All supplemental power use beyond the back-up or contract demand requirement is billed at the full demand rates of the full requirements class.

19. Q. HOW IS THE DIVERSITY FACTOR CALCULATED?

A. The method for calculating the diversity factor is consistent with the settlement adopted by the Commission in Docket Nos. 03-0640 and 03-0641, as updated in subsequent Sierra and Nevada Power GRCs. The diversity factor calculation is based on the standby hourly data for the calendar years of 2020, 2021 and 2022. For each hour, the ratio of coincident hourly demand of all non-solar standby customers to their total contract demand is calculated. For each year, the maximum value of this ratio is identified for each TOU period. The three yearly maximum values are then averaged by TOU period, yielding the diversity factors for each TOU period. A single, overall, diversity value is created as a weighted average of the individual TOU period diversity factors, using the transmission and generation marginal demand revenues from the MCS as weights. See page 23 of Workpaper 1 of Statement O for the current calculation of the weighted diversity factor results used for rate design.

20. Q. HOW HAS THE DIVERSITY FACTOR CHANGED FROM THE PREVIOUS GRC RESULTS?

A. **Table Pollard-Direct-1** below summarizes the results from the 2020 Nevada Power GRC.

Table Pollard-Direct-1. Diversity Factor Comparison

	Average Max Percent		
TOU Period	2017-2019 (2020 GRC)	2020-2022 (Current)	Difference
Summer On	25%	23%	-2%
Summer Mid	24%	31%	7%
Summer Off	26%	35%	9%
Winter Off	31%	37%	5%
Total	27%	32%	5%

Generally, the coincidence of standby customers leaning on Nevada Power's system increased from the previous GRC results. There was a slight decrease in the average Summer On-Peak results while there was an increase in all other TOU periods. Company witness Ms. Prest supports the use of these results and final rates developed for standby customers in Statement O.

V. <u>WIRELESS DEVICES</u>

21. Q. WHAT WAS THE IMPETUS FOR THE WIRELESS DEVICE ANALYSIS PROVIDED IN EXHIBIT POLLARD DIRECT-3?

A. On April 26, 2022, the Commission approved temporary modifications to the SL tariff, effective in Docket No. 21-10008 allowing auxiliary devices such as public safety and wireless communications equipment to be temporarily installed and billed up to a limited twenty-five percent of total load per service.

These changes were approved as a temporary measure, with the intent a more permanent solution would be presented in this GRC for Commission consideration as more information became available regarding these installations.

The Company was to provide an analysis regarding the cost responsibility impact of these wireless devices on the SL customer class, which is provided as **Exhibit Pollard Direct-3**.

22. Q. WHAT ARE THE RESULTS OF THE ANALYSIS?

A. Based on the Company's analysis, wireless devices installed on existing street lights within the SL class currently have a minimal impact to the overall class. Roughly only 1.6 percent of the total class usage can be assigned to these wireless devices. Further, the modelled usage attributed to the wireless devices on the 265 meters used in the analysis is estimated to be 22 percent of the total usage on these premises - close to the 25 percent limitation currently defined in the tariff.

Next, calculations of the cost responsibility of these devices are provided in **Table Pollard-Direct-2**, which compares the annual costs for varying groups of street light installations using hourly load data and costs from the Company's proposed marginal cost study and Statement O results.

Table Pollard Direct-2. Wireless Devices Cost Responsibility

Group	Total Estimated Usage (kWh)	Total Estimated Cost	Cost per kWh
Streetlights w/o wireless devices	124,274,320	$ 14,091,807	$ 0.11339
Streetlights w/ wireless devices	9,750,151	$ 1,087,232	$ 0.11151
Wireless devices only	2,222,604	$ 234,779	$ 0.10563
Total Streetlights	134,024,471	$ 15,179,039	$ 0.11326
		Percent difference in total SL cost	-0.12%

Based on the analysis, the impact of installing wireless devices on the identified street light installations are lower than the class average, and have an overall slight positive impact on the SL class cost of service.

23. Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING FUTURE INSTALLATION OF THESE DEVICES?

A. The Commission should approve the Company's proposed SL tariff changes to allow for these devices on metered installations meeting the revised applicability requirements. Supporting the ability of these customers to install these facilities behind the meter on their customer-owned poles will allow for these customers to better provide services to their constituents as they best deem fit. The Company should not try to overly limit the use of these poles for city and county governments that may serve to support the expansion of more efficient lighting, Wi-Fi, and other services that may be viewed largely as services related to public safety/public service considerations.

Therefore, the Company recommends that these installations be allowed going forward, as long as the premise is metered, and the customer will pay for the additional energy usage related to the wireless devices. To effectuate this recommendation, the tariff must be revised. This includes removing the temporary 25 percent threshold implemented in Docket No. 21-10008, as well as eliminating the dusk to dawn usage limitation within the applicability section of the tariff. Finally, the Company recommends adjusting the tariff's applicability section to permit tribal governing bodies to be billed under the SL tariff. This change would ensure that these entities are treated in a manner similar to other local government entities.

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

24. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT POLLARD-DIRECT-1

TIM POLLARD
DIRECTOR, LOAD FORECASTING, RESEARCH & ANALYTICS
RATES & REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4006

Mr. Pollard has been an employee of NV Energy since 2007 and is currently the Director of Load Forecasting and Load Research. His responsibilities are focused upon leading the load research and forecasting teams for regulatory filings and special assignments in support of the Rate & Regulatory Affairs department's responsibilities.

Prior to joining the company in his current position, Mr. Pollard had experience across different industries and was most recently employed at Covance Cardiac Safety Services, a clinical research organization for the pharmaceutical industry, as a Senior Clinical Data Manager.

Employment History
NV Energy

Director, Load Forecasting, Research & Analytics
Technical Lead, Regulatory Policy, Strategy & Analysis
Pricing Specialist, Regulatory Pricing & Economic Analysis
Staff Economist, Regulatory Pricing & Economic Analysis
Senior Economist, Regulatory Pricing & Economic Analysis
January 2007 to Present

- Leads load forecasting and load research teams for required strategy and regulatory activities
- Supports load research and forecasting results as necessary in regulatory filings
- Guides technical aspects of cost of service and rate design filings and special assignments
- Conducts research and prepares studies for internal and external presentation
- Provides technical support and analyzes data necessary to resolve the complex set of pricing, financial, economic, and regulatory issues for filings in Nevada and California, Gas and Electric case filings
- Applies extensive experience and understanding of the principles and theories of cost of service and rate design as well as the technical mechanics and applications necessary to successfully develop pricing of electric and gas service
- Provides direction and technical assistance to less experienced team members
- Develops educational materials and actively instructs other team members on various technical, economic and cost of service related subjects

Economist, Resource Planning & Analysis
June 2004 to December 2004

- Conduct research and prepare studies for internal and external presentation
- Prepare and assist in preparation of load forecasts
- Assist in technical aspects of market analysis projects as requested

Non-Sierra Employment

Covance Cardiac Safety Services
January 2005 to January 2007

Senior Clinical Data Manager (10/06 to 1/07)**; Clinical Data Manager** (2/06 to 10/06)**; Data Analyst** (1/05 to 2/06)**, Data Management & Statistics**

- Technical Lead for all department activities within business unit for the development/validation of new systems and processes
- Acted as primary liaison and escalation contact for clients assigned within team to ensure that data presented met or exceeded the agreed upon expectations for accuracy and timeliness
- Developed and implemented internal and external reports, processes and metrics to add value to company through data analysis, management and quality control activities
- Accountable for all department personnel and activities within Clinical Trial Operations Team

Nevada State Health Division
December 2000 to June 2004

Health Resource Analyst II (7/02 to 6/04)**; Health Resource Analyst I** (12/00 to 7/02)**, Center for Health Data and Research, Bureau of Health Planning & Statistics**

- Development, linkage, management, and analysis of Public Health Data Warehouse (Cancer Registry, HIV/AIDS, Vital Statistics) for program policy and reporting issues relating to public health arena
- Prepared statistical and special topic reports, performed quality assurance measures and evaluated other health related program data
- Management, quality assurance and analysis of Vital Statistics databases for various Division programs, state agencies and requests from the public for health statistics

Education

University of Nevada, Reno
Bachelor of Arts in Economics, August 2000

Certifications

SAS Certified Advanced Programmer
SAS Certified Basic Programmer

Prior Testimony before Public Utilities Commissions

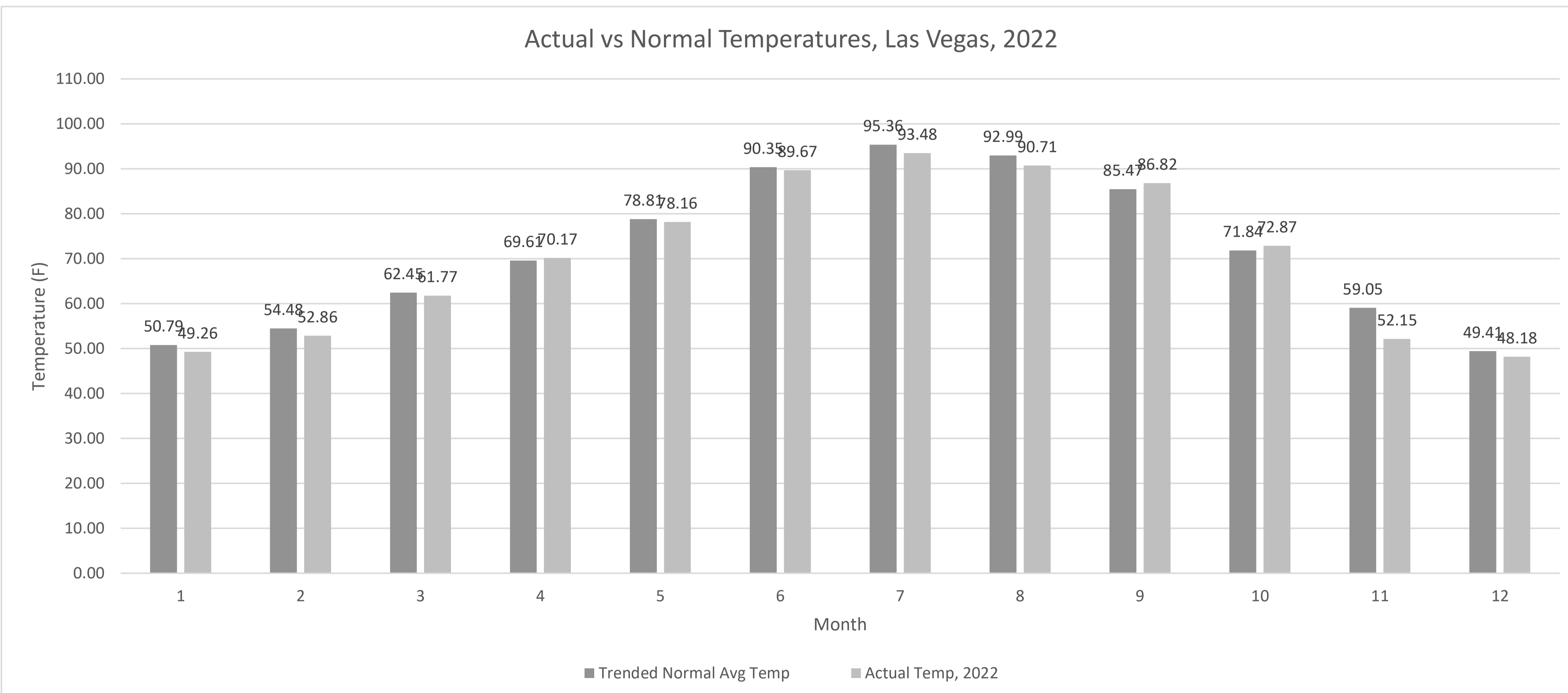
PUCN Dockets: 07-12001, 08-12002, 08-10043, 09-06029, 10-06001, 10-07003, 11-06006, 13-06002, 15-07041, 15-07042, 16-06006, 16-06007, 18-11039, 19-06002, 20-06003, 21-10012, and 22-09006.
CPUC Applications: 08-08-004.

EXHIBIT POLLARD-DIRECT-2

Overview of the weather in 2022

Month	Actual Temp, 2022	Trended Normal Avg Temp	Difference
1	49.26	50.79	-1.53
2	52.86	54.48	-1.62
3	61.77	62.45	-0.68
4	70.17	69.61	0.56
5	78.16	78.81	-0.65
6	89.67	90.35	-0.68
7	93.48	95.36	-1.88
8	90.71	92.99	-2.28
9	86.82	85.47	1.34
10	72.87	71.84	1.03
11	52.15	59.05	-6.90
12	48.18	49.41	-1.23

Overall, the year 2022 was slightly cooler than the normal trended value in Las Vegas. The summer was around 1 degree cooler than normal, and the winter was around 1.5 degrees cooler than normal. September and October were the only months warmer than normal, by around 1 degree on average in 2022. November was significantly cooler than normal, with the largest difference of any month during the year. Since the summer was cooler than normal, we should expect to see an overall positive adjustment for cooling in the summer. Since the winter was also cooler than normal, we should expect to see an overall negative adjustment for heating in the winter. Based on the differences, we expect both of these adjustments to be fairly small for the test period.



Overview of the weather in 2022 (Cont'd.)

Since we will be using heating degree days and cooling degree days to adjust billing data, which is delayed, we rearrange the degree days based on billing cycles to align with historical billing data. In the below table, we show the normal cooling degree days with a cooling threshold of 70, alongside the actual cooling degree days for 2022 with that threshold, and the "cycle-weighted" degree days (rearranged to match billing cycles).

MONTH	Trended Normal CDD-70	Actual CDD-70	Trended Cycle-Weighted Normal	Cycle-Weighted Actual
1	0.00	0.00	0.00	0.00
2	0.02	0.00	0.01	0.00
3	15.41	21.50	6.34	18.24
4	79.66	68.50	52.05	36.20
5	294.18	278.00	183.78	186.76
6	610.41	590.00	450.23	430.43
7	786.15	728.00	706.54	638.04
8	712.73	642.00	750.93	690.14
9	465.21	504.50	583.99	584.68
10	119.50	177.50	290.82	329.58
11	2.87	0.00	60.04	95.95
12	0.00	0.00	1.42	0.00

The way we perform this "cycle-weighting" is by redistributing each day's degrees the same way the average kWh is rearranged for billing. Not all customers are on the same billing cycle. So, the kWh used by one customer on a certain day will be billed to one revenue month, while the kWh used by another customer on the same day may be billed to the next revenue month. So, if a day's kWh's are mostly billed during one revenue month, then that day's cycle-weighted heating and cooling degrees will mostly be found in that month. If a day falls during a part of the billing cycle when roughly half of the kWh's for that day wind up in one revenue month, and the other half wind up in the next revenue month, then in that case the degrees for that day will be split evenly between the two months. In this way, we can adjust the billing data using degree days which match up with the way the kWh's have been distributed in the billing data. You can see why this means if most of a month's hot days are at the end of the month, this results in most of the heating degree days being rearranged into the next revenue month. Similarly, this also means if most of a month's hot days are in the beginning of the month, the cycle-weighted cooling degree days for that revenue month won't look much different from the actual cooling degree days (although they will usually increase due to the cooling degree days from the previous month, if the previous month had hot days near the end of the month).

Weather normalization factors and overall weather impacts for Residential, Single Family

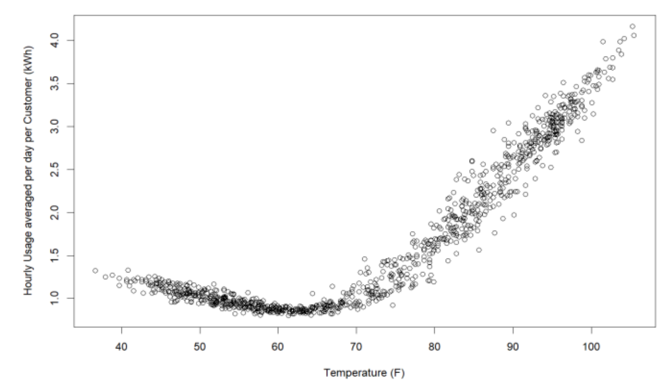
To capture the impact of weather on energy usage, we take a measurement called "cooling degree days" which is, quite simply, 0 for days cooler than a cooling threshold, and for days with an average temperature warmer than this threshold, it's the number of degrees warmer than the threshold. For example, for Residential single family, we set the threshold at 70 degrees that matches where these customers tend to increase their energy usage as temperatures increase. We do something similar for heating, calling it "heating degree days."

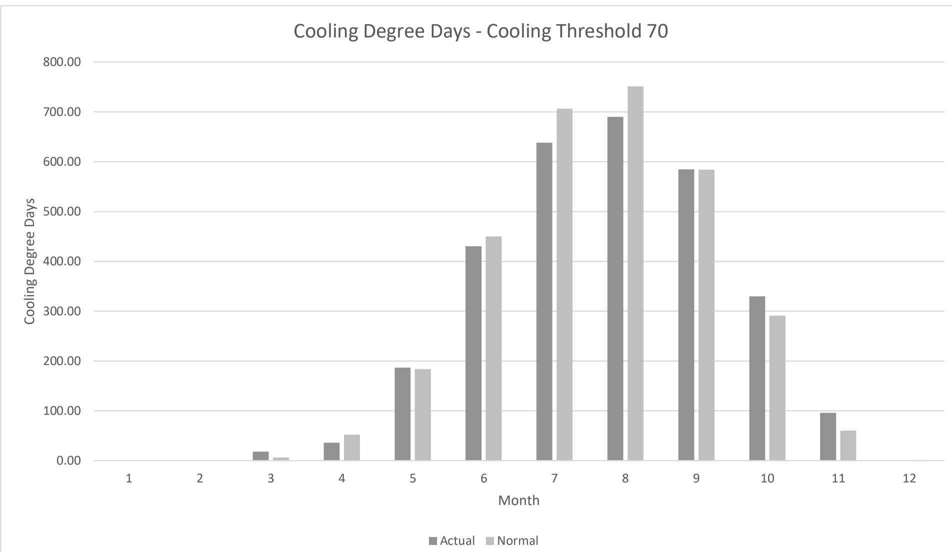
Additionally, calculations are performed to "cycle-weight" the weather adjustments to align with billing cycles, as not all customers are on the same billing cycle. The kWh used by one customer on a certain day will be billed to one revenue month, while the kWh used by another customer on the same day may be billed to the next revenue month. If a day's kWh's are mostly billed during one revenue month, then that day's cycle-weighted heating and cooling degrees will mostly be found in that month. If a day falls during a part of the billing cycle when roughly half of the kWh's for that day wind up in one revenue month, and the other half wind up in the next revenue month, then in that case the degrees for that day will be split evenly between the two months. We adjust the billing data using degree days which match up with the way the kWh's have been distributed in the billing data.

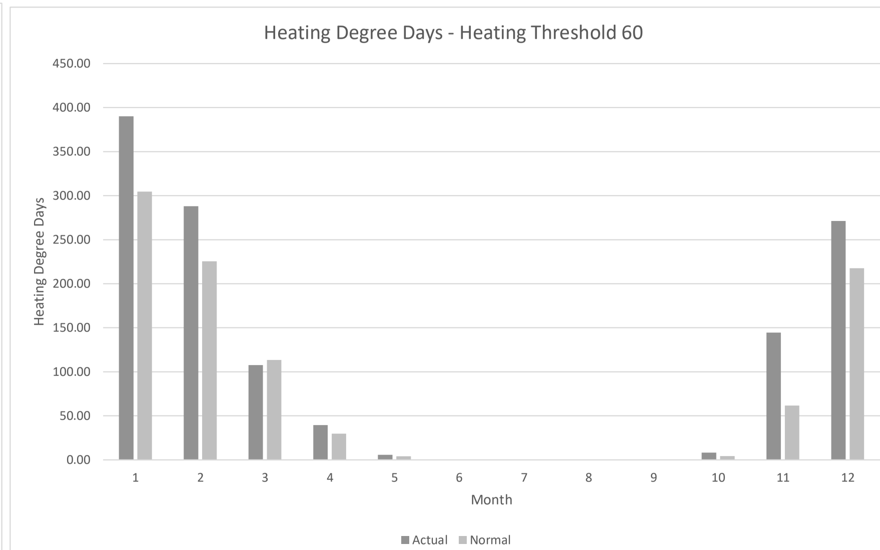
Billed vs. WN Sales (MWH) — **Cycle-weighted weather data**

Impact of Cooling: 2.10649 — Impact of Heating: 1.13439 (kWh/dd)

Residential Single Family					CDD - Base 70			HDD - Base 60		
Year	**Month**	**Billed**	**WN**	**Factor**	**Actual**	**Normal**	**Difference**	**Actual**	**Normal**	**Difference**
2022	1	490,033	432,421	0.8824	0.00	0.00	0.00	390.14	304.64	-85.50
2022	2	408,386	366,358	0.8971	0.00	0.01	0.01	288.03	225.58	-62.44
2022	3	375,113	363,994	0.9704	18.24	6.34	-11.90	107.66	113.39	5.73
2022	4	357,799	371,006	1.0369	36.20	52.05	15.85	39.56	29.69	-9.87
2022	5	425,317	420,495	0.9887	186.76	183.78	-2.99	5.68	4.13	-1.55
2022	6	754,808	779,942	1.0333	430.43	450.23	19.80	0.00	0.10	0.10
2022	7	1,083,738	1,170,269	1.0798	638.04	706.54	68.51	0.00	0.00	0.00
2022	8	1,233,205	1,310,172	1.0624	690.14	750.93	60.80	0.00	0.00	0.00
2022	9	1,233,205	1,232,342	0.9993	584.68	583.99	-0.68	0.00	0.00	0.00
2022	10	803,060	751,274	0.9355	329.58	290.82	-38.75	8.13	4.32	-3.81
2022	11	465,257	362,489	0.7791	95.95	60.04	-35.91	144.60	61.59	-83.01
2022	12	424,227	389,406	0.9179	0.00	1.42	1.42	271.21	217.70	-53.51
Total 2022		**8,054,149**	**7,950,169**	**0.9871**	**3,010**	**3,086**	**76**	**1,255**	**961**	**-294**







Weather normalization factors and overall weather impacts for Residential, Multi-Family

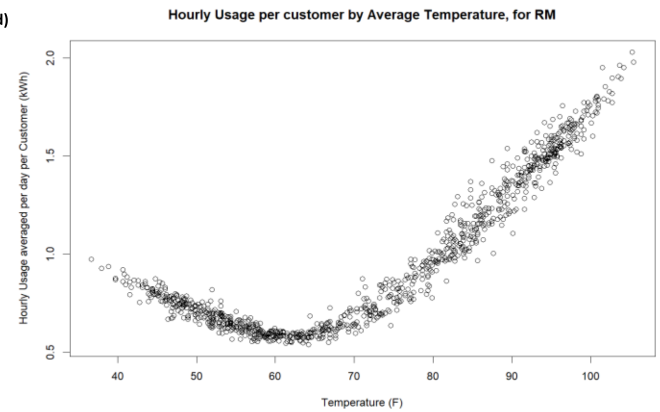
To capture the impact of weather on energy usage, we take a measurement called "cooling degree days" which is, quite simply, 0 for days cooler than a cooling threshold, and for days with an average temperature warmer than this threshold, it's the number of degrees warmer than the threshold. For example, for Residential single family, we set the threshold at 70 degrees that matches where these customers tend to increase their energy usage as temperatures increase. We do something similar for heating, calling it "heating degree days."

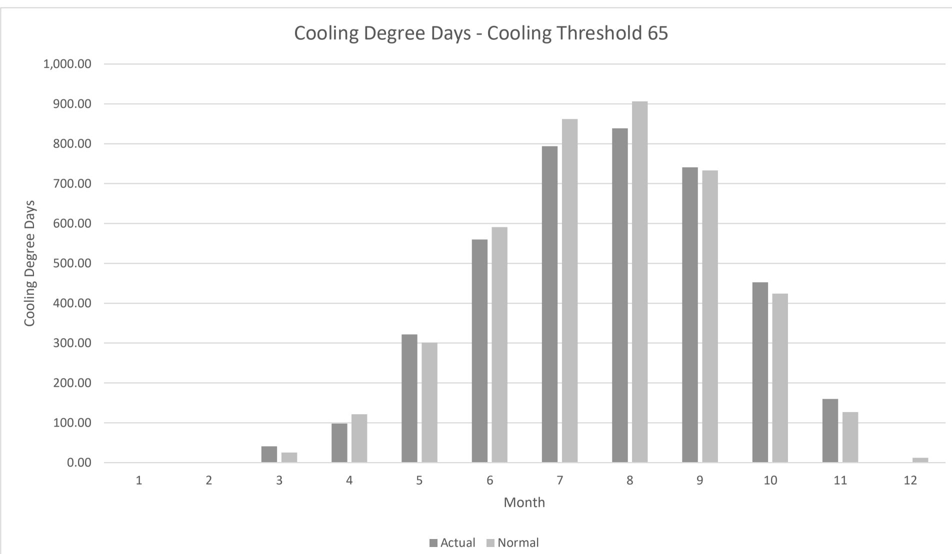
Additionally, calculations are performed to "cycle-weight" the weather adjustments to align with billing cycles, as not all customers are on the same billing cycle. The kWh used by one customer on a certain day will be billed to one revenue month, while the kWh used by another customer on the same day may be billed to the next revenue month. If a day's kWh's are mostly billed during one revenue month, then that day's cycle-weighted heating and cooling degrees will mostly be found in that month. If a day falls during a part of the billing cycle when roughly half of the kWh's for that day wind up in one revenue month, and the other half wind up in the next revenue month, then in that case the degrees for that day will be split evenly between the two months. We adjust the billing data using degree days which match up with the way the kWh's have been distributed in the billing data.

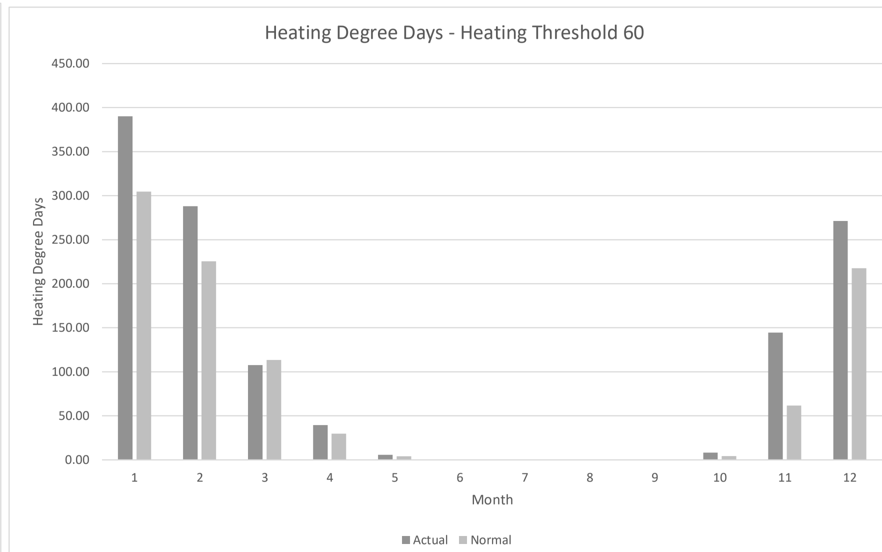
Billed vs. WN Sales (MWH)

Cycle-weighted weather data

Residential Multi-Family					Impact of Cooling: 0.81610 (kWh/dd)			Impact of Heating: 0.84587 (kWh/dd)		
					CDD - Base 65			HDD - Base 60		
Year	**Month**	**Billed**	**WN**	**Factor**	**Actual**	**Normal**	**Norm-Act**	**Actual**	**Normal**	**Norm-Act**
2022	1	165,811	145,226	0.8759	0.00	0.03	0.03	390.14	304.64	-85.50
2022	2	148,850	134,054	0.9006	0.00	0.80	0.80	288.03	225.58	-62.44
2022	3	135,255	132,973	0.9831	41.10	25.40	-15.70	107.66	113.39	5.73
2022	4	128,013	131,024	1.0235	98.04	121.19	23.15	39.56	29.69	-9.87
2022	5	143,107	137,966	0.9641	321.69	301.28	-20.41	5.68	4.13	-1.55
2022	6	211,775	219,134	1.0347	559.93	591.16	31.24	0.00	0.10	0.10
2022	7	279,424	295,338	1.0570	794.16	862.06	67.90	0.00	0.00	0.00
2022	8	320,728	336,678	1.0497	838.64	906.46	67.83	0.00	0.00	0.00
2022	9	320,728	318,879	0.9942	740.93	733.06	-7.86	0.00	0.00	0.00
2022	10	229,531	221,916	0.9668	452.58	423.96	-28.62	8.13	4.32	-3.81
2022	11	155,776	127,876	0.8209	159.60	127.04	-32.56	144.60	61.59	-83.01
2022	12	142,979	132,611	0.9275	0.85	11.93	11.08	271.21	217.70	-53.51
Total 2022		**2,381,977**	**2,333,674**	**0.9797**	**4,008**	**4,104**	**97**	**1,255**	**961**	**-294**







Weather normalization factors and overall weather impacts for Small Industrial/Commercial

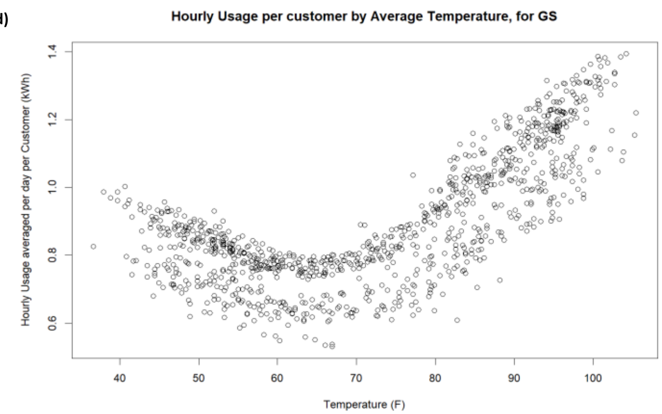
To capture the impact of weather on energy usage, we take a measurement called "cooling degree days" which is, quite simply, 0 for days cooler than a cooling threshold, and for days with an average temperature warmer than this threshold, it's the number of degrees warmer than the threshold. For example, for Residential single family, we set the threshold at 70 degrees that matches where these customers tend to increase their energy usage as temperatures increase. We do something similar for heating, calling it "heating degree days."

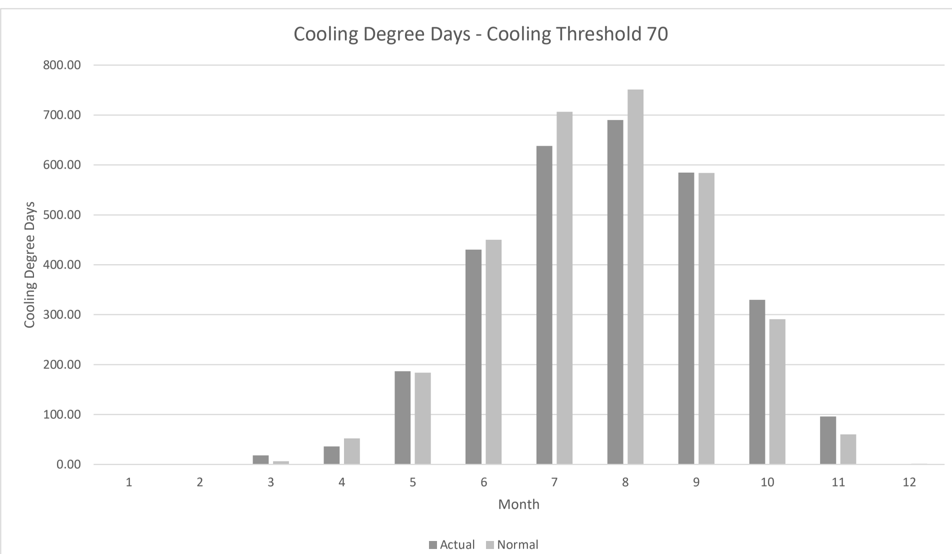
Additionally, calculations are performed to "cycle-weight" the weather adjustments to align with billing cycles, as not all customers are on the same billing cycle. The kWh used by one customer on a certain day will be billed to one revenue month, while the kWh used by another customer on the same day may be billed to the next revenue month. If a day's kWh's are mostly billed during one revenue month, then that day's cycle-weighted heating and cooling degrees will mostly be found in that month. If a day falls during a part of the billing cycle when roughly half of the kWh's for that day wind up in one revenue month, and the other half wind up in the next revenue month, then in that case the degrees for that day will be split evenly between the two months. We adjust the billing data using degree days which match up with the way the kWh's have been distributed in the billing data.

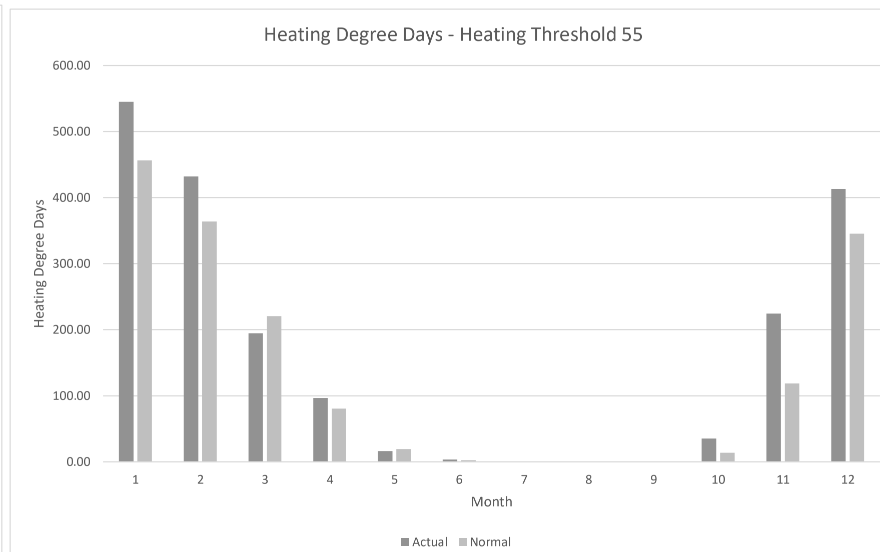
Billed vs. WN Sales (MWH)

Cycle-weighted weather data

	Small Industrial/Commercial				Impact of Cooling: 0.42163 (kWh/dd)			Impact of Heating: 0.25780 (kWh/dd)		
					CDD - Base 70			HDD - Base 65		
Year	Month	Billed	WN	Factor	Actual	Normal	Difference	Actual	Normal	Difference
2022	1	53,225	51,084	0.9598	0.00	0.00	0.00	545.14	456.53	-88.61
2022	2	48,054	45,342	0.9436	0.00	0.01	0.01	432.10	363.77	-68.33
2022	3	46,099	44,780	0.9714	18.24	6.34	-11.90	194.49	220.48	25.99
2022	4	43,362	43,538	1.0041	36.20	52.05	15.85	96.69	80.59	-16.10
2022	5	45,158	48,554	1.0752	186.76	183.78	-2.99	16.23	19.32	3.09
2022	6	54,434	60,420	1.1100	430.43	450.23	19.80	3.43	2.42	-1.00
2022	7	62,680	67,657	1.0794	638.04	706.54	68.51	0.00	0.00	0.00
2022	8	68,214	68,969	1.0111	690.14	750.93	60.80	0.00	0.00	0.00
2022	9	68,214	64,218	0.9414	584.68	583.99	-0.68	0.00	0.00	0.00
2022	10	57,540	50,170	0.8719	329.58	290.82	-38.75	35.38	13.85	-21.53
2022	11	48,393	44,765	0.9250	95.95	60.04	-35.91	224.55	118.72	-105.83
2022	12	48,726	50,171	1.0297	0.00	1.42	1.42	413.01	345.42	-67.60
Total 2022		**644,098**	**639,668**	**0.9931**	**3,010**	**3,086**	**76**	**1,961**	**1,621**	**-340**







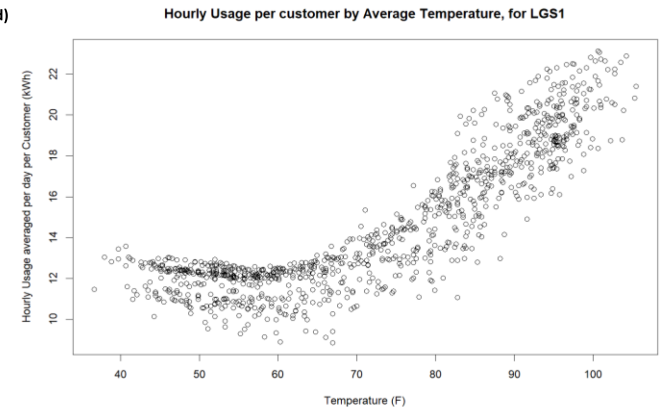
Weather normalization factors and overall weather impacts for Medium Industrial/Commercial

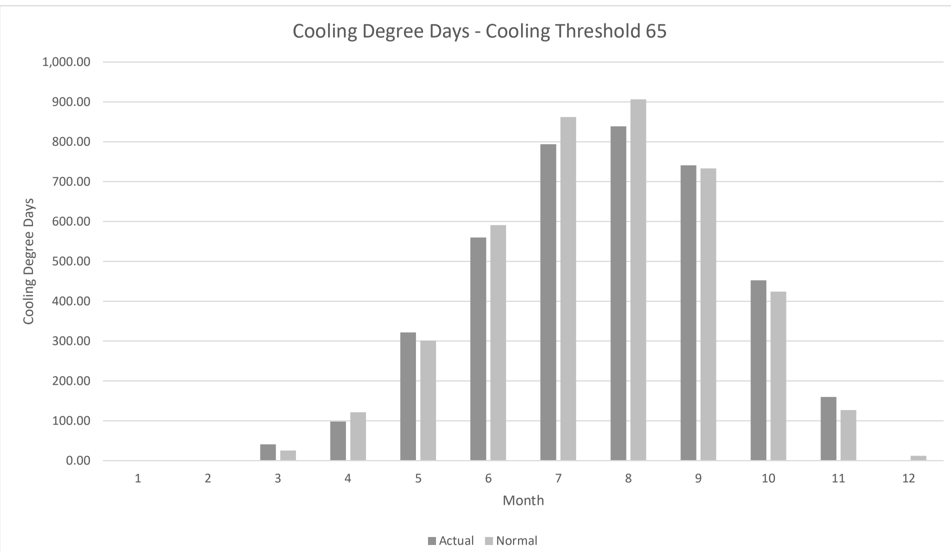
To capture the impact of weather on energy usage, we take a measurement called "cooling degree days" which is, quite simply, 0 for days cooler than a cooling threshold, and for days with an average temperature warmer than this threshold, it's the number of degrees warmer than the threshold. For example, for Residential single family, we set the threshold at 70 degrees that matches where these customers tend to increase their energy usage as temperatures increase. We do something similar for heating, calling it "heating degree days."

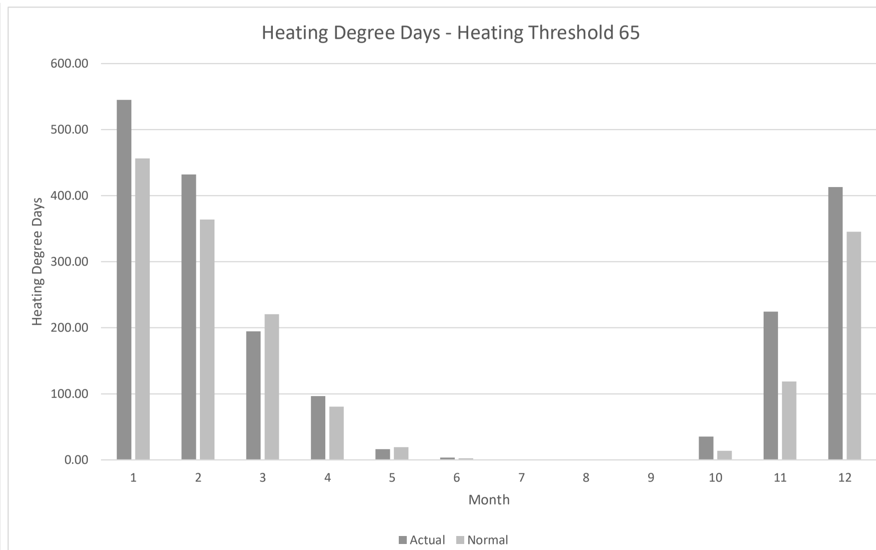
Additionally, calculations are performed to "cycle-weight" the weather adjustments to align with billing cycles, as not all customers are on the same billing cycle. The kWh used by one customer on a certain day will be billed to one revenue month, while the kWh used by another customer on the same day may be billed to the next revenue month. If a day's kWh's are mostly billed during one revenue month, then that day's cycle-weighted heating and cooling degrees will mostly be found in that month. If a day falls during a part of the billing cycle when roughly half of the kWh's for that day wind up in one revenue month, and the other half wind up in the next revenue month, then in that case the degrees for that day will be split evenly between the two months. We adjust the billing data using degree days which match up with the way the kWh's have been distributed in the billing data.

Billed vs. WN Sales (MWH) | **Cycle-weighted weather data**

	Medium Industrial/Commercial				Impact of Cooling: 6.0521 (kWh/dd) CDD - Base 65			Impact of Heating: 1.6903 (kWh/dd) HDD - Base 65		
Year	**Month**	**Billed**	**WN**	**Factor**	**Actual**	**Normal**	**Norm-Act**	**Actual**	**Normal**	**Norm-Act**
2022	1	306,997	301,091	0.9808	0.00	0.03	0.03	545.14	456.53	-88.61
2022	2	281,638	274,538	0.9748	0.00	0.80	0.80	432.10	363.77	-68.33
2022	3	284,342	284,081	0.9991	41.10	25.40	-15.70	194.49	220.48	25.99
2022	4	286,564	297,883	1.0395	98.04	121.19	23.15	96.69	80.59	-16.10
2022	5	307,427	328,827	1.0696	321.69	301.28	-20.41	16.23	19.32	3.09
2022	6	375,491	415,531	1.1066	559.93	591.16	31.24	3.43	2.42	-1.00
2022	7	442,780	472,818	1.0678	794.16	862.06	67.90	0.00	0.00	0.00
2022	8	486,894	492,835	1.0122	838.64	906.46	67.83	0.00	0.00	0.00
2022	9	486,894	461,013	0.9468	740.93	733.06	-7.86	0.00	0.00	0.00
2022	10	400,475	355,465	0.8876	452.58	423.96	-28.62	35.38	13.85	-21.53
2022	11	331,110	302,335	0.9131	159.60	127.04	-32.56	224.55	118.72	-105.83
2022	12	294,871	298,644	1.0128	0.85	11.93	11.08	413.01	345.42	-67.60
Total 2022		**4,285,482**	**4,285,063**	**0.9999**	**4,008**	**4,104**	**97**	**1,961**	**1,621**	**-340**







Weather normalization factors and overall weather impacts for Large Industrial/Commercial

To capture the impact of weather on energy usage, we take a measurement called "cooling degree days" which is, quite simply, 0 for days cooler than a cooling threshold, and for days with an average temperature warmer than this threshold, it's the number of degrees warmer than the threshold. For example, for Residential single family, we set the threshold at 70 degrees that matches where these customers tend to increase their energy usage as temperatures increase. We do something similar for heating, calling it "heating degree days."

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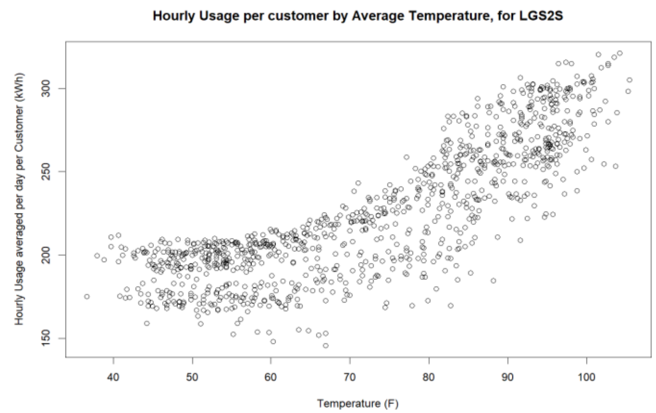
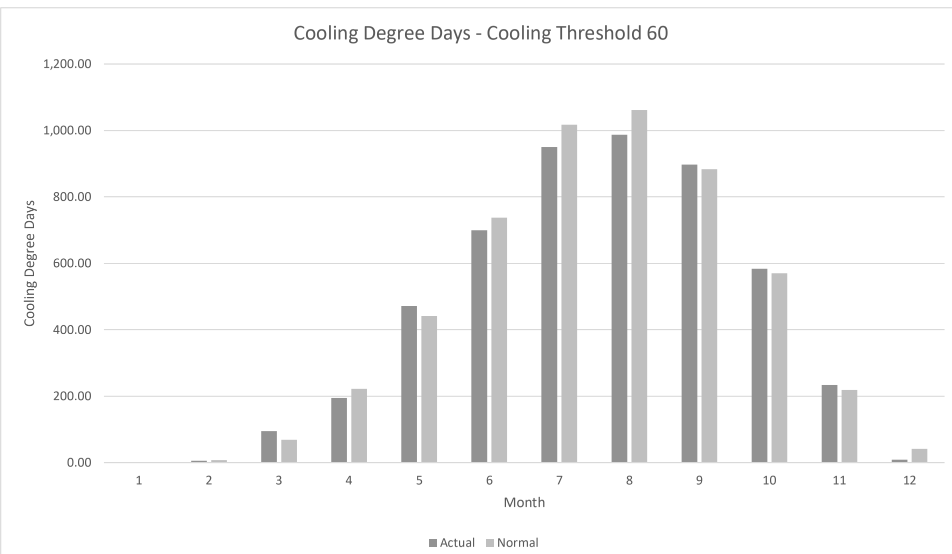
Billed vs. WN Sales (MWH) | **Cycle-weighted weather data**

Impact of Cooling: **4.7844 (kWh/dd)**

	Large Industrial/Commercial				CDD - Base 60		
Year	**Month**	**Billed**	**WN**	**Factor**	**Actual**	**Normal**	**Difference**
2022	1	628,425	628,598	1.0003	0.00	1.08	1.08
2022	2	589,227	589,474	1.0004	5.80	7.36	1.56
2022	3	566,250	562,135	0.9927	94.65	68.67	-25.98
2022	4	583,897	588,268	1.0075	194.79	222.56	27.77
2022	5	625,818	621,072	0.9924	471.14	440.89	-30.25
2022	6	649,212	655,384	1.0095	699.00	737.91	38.91
2022	7	720,687	731,560	1.0151	950.29	1,017.58	67.30
2022	8	805,322	817,410	1.0150	987.14	1,062.00	74.86
2022	9	840,315	838,017	0.9973	897.18	882.94	-14.23
2022	10	817,689	815,428	0.9972	584.08	569.96	-14.12
2022	11	732,861	730,486	0.9968	233.28	218.41	-14.86
2022	12	655,445	660,520	1.0077	9.18	41.31	32.13
Total 2022		**8,215,149**	**8,238,351**	**1.0028**	**5,127**	**5,271**	**144**





(Heating is statistically insignificant in this customer group)

EXHIBIT POLLARD-DIRECT-3

Wireless Device Installations on Street Lighting ("SL") Meters Analysis

Summary:

In 2021, through discussions with Regulatory Operations Staff and several other parties, the company filed Advice Letter 521, Docket No. 21-10008 to provide temporary changes to the Street lighting tariff. On April 26, 2022, the Commission approved modifications to the SL tariff, effective in Docket No. 21-10008 allowing auxiliary devices such as public safety and wireless communications equipment to be installed and billed up to a limited percentage of total load per service. As part of the approval, the Company was to provide additional information in this GRC regarding an analysis of the impact of these wireless device installations on existing SL customers.

The provided analysis by the company works to estimate the impact of these wireless devices by analyzing 265 premises identified as having these devices installed. The ultimate impact of the devices is estimated to be small, in that only 1.6% of the overall class usage can be assigned to these wireless devices.

Based on the analysis, the Company proposes that as long as the premises are metered and incorporated into the overall development of cost of service and rate design steps within future general rate case filings, there should not be an issue with allowing future installations, as they will be treated similarly to all other customers. Further, the company makes the following recommendations:

1) Modify SL tariff to remove 25 percent threshold of annual volumetric usage
2) Remove "dusk to dawn" usage requirement in applicability section of tariff
3) Allow for wireless device installation on these facilities, only if the service is metered and can be appropriately billed for the increase in usage
4) Modify applicability to allow for tribal government bodies to be included in this tariff

Background:

In 2019, Clark County incorporated a new chapter of the Clark County Code, chapter 5.02, which lays out their policies on streetlight pole attachments with fees, necessary licensing and documentation, and classification of the various streetlight poles.

The County has installed "smart poles" in some parts of Las Vegas. These smart poles are tall, hollow streetlight poles equipped with fiberoptic internet connections and multiple communications bays in which telecommunications equipment may be installed within the interior of the pole. The poles are also equipped with antennas that connect to these communications bays, often provided by the telecom using the bays. The following figures supply examples of these installations.

Figures 1 and 2: Installation examples

As these installations are not separately metered services, but installed behind the premise meter, it is difficult to determine the proper estimation of power used by equipment within the bays. The power used by the antennas or radios should not be identified as lighting or traffic control. Because these premises are not sub-metered, it is not possible to accurately identify the 25 percent threshold that was implemented in Docket No. 21-10008. But the Company used statistical techniques on aggregate data from a random sample of multiple meters to decide if the average meter in the sample surpasses the threshold. Unfortunately, such techniques cannot determine whether a particular individual meter is in violation of the threshold. Therefore, the Company recommends that this percent limitation be eliminated, as long as wireless device installations occur on a metered premise.

As of the time of this filing, Clark County and the City of Las Vegas are allowing telecom companies to install wireless devices, either as internal attachments, as with the special smart poles mentioned above, or as external attachments on existing poles. As directed by the FCC and the Court of Appeals, the Clark County code even supplies procedures for telecom companies to replace existing poles at their own expense if the existing poles are for any reason insufficient for the telecom's desired attachments. The Clark County streetlight pole attachments are installed behind the meter and are not sub-metered.

Analysis:

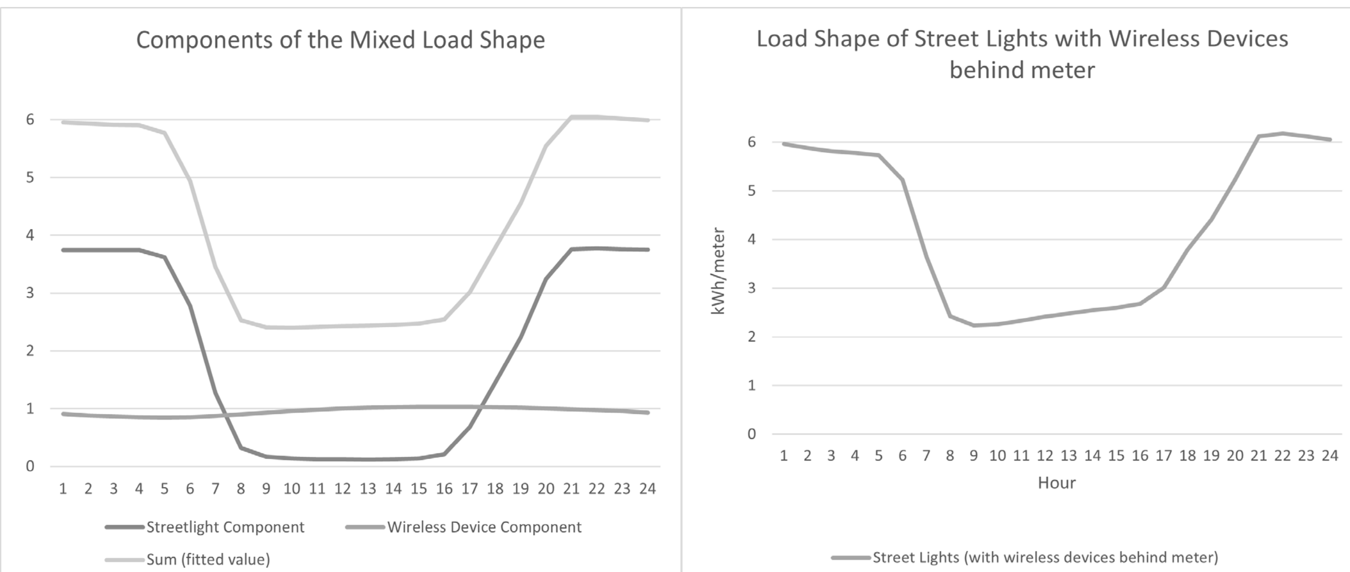
The company used statistical regression techniques to estimate the excess usage due to these devices using data from the premises that have been identified to have these devices installed. A sample of 265 meters that have wireless devices attached behind the meter is a sufficient sample size to estimate the usage caused by wireless devices on the average meter.

Analysis began with the development of a "mixed load shape," and two "pure load shapes" to enable a comparison between the different types of installations. The mixed load shape is the load shape of the meters with both streetlights and wireless devices behind them. The pure streetlight load shape is the load shape of meters with only streetlights and traffic control devices installed. The pure wireless device load shape is the load shape of meters with only wireless devices installed behind them, as these are the locations powering not only the telecommunications equipment but also the antennas and other support equipment. As a result, this shape more accurately reflects the shape of the added usage due to wireless devices. It should be noted that some of the wireless-device-only meters used to make our pure wireless device load shape are not facilities mounted on utility poles or streetlight poles, but are instead larger, ground-based operations, for either 4G or 5G wireless. It is expected that this will show a difference in the *scale* of the usage, but not the *overall shape* of it.

The assumptions regarding the different load shapes analyzed are that the load due to streetlights and traffic control on the mixed meters is shaped the same way as the load behind the streetlight-only meters. Further, the load due to wireless devices on the mixed meters (and any equipment whose purpose is to serve those wireless devices) has the same general shape as the load behind the wireless-device-only meters.

The graph on the lefthand side (Figure 3) presents the different load shape combinations, while the graph on the right (Figure 4) presents the load shape of streetlight meters with wireless device attachments installed behind the meter.

Figures 3 and 4.



These three shapes are used for estimation by a multiple regression (used to estimate the relationship between two or more independent variables and one dependent variable) in which the two separate load shapes were used to estimate the total mixed load shapes. Table 1 below presents the regression results.

Table 1. Regression results

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.996523357
R Square	0.993058801
Adjusted R Square	0.992397735
Standard Error	0.141105444
Observations	24

Estimated wireless device usage (per meter per day)	22.92 (kWh)	22.70%
Estimated lighting usage (per meter per day)	46.78 (kWh)	46.34%
Usage of an unknown cause (per meter per day)	31.26 (kWh)	30.96%

ANOVA

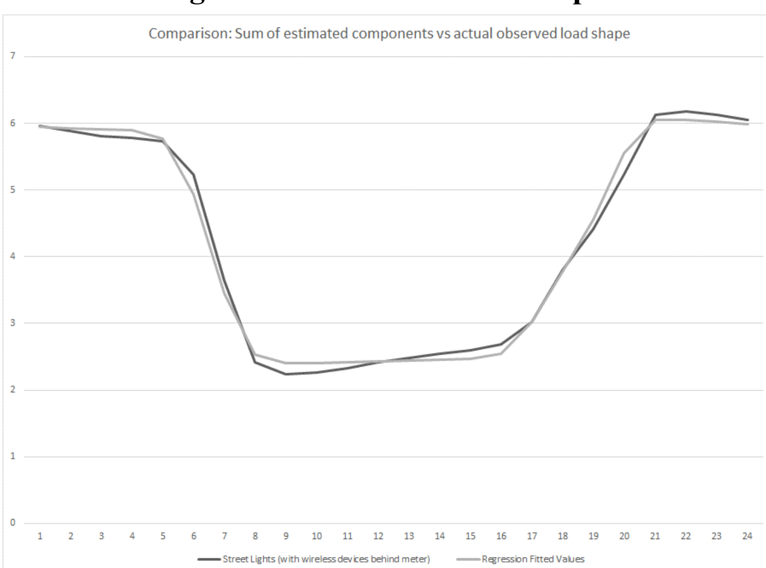
	df	SS	MS	F	Significance F
Regression	2	59.82012462	29.91006231	1502.206986	2.16303E-23
Residual	21	0.418125674	0.019910746		
Total	23	60.23825029			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	1.302419	0.516424	2.521998	0.019812	0.228458	2.376381	0.228458	2.376381
Wireless Devices	0.156920	0.081099	1.934916	0.066584	-0.011735	0.325574	-0.011735	0.325574
Street Lights	1.387769	0.028953	47.931168	0.000000	1.327557	1.447980	1.327557	1.447980

Using the results of the regression, the streetlight component shape is simply the pure streetlight load shape multiplied by the streetlight coefficient. The wireless device component load shape is, similarly, the pure wireless device load shape multiplied by the wireless device coefficient from the regression. The r-squared value of this regression is remarkably high. When the loads are multiplied by their respective coefficients, the resulting shape is essentially the same as that of the mixed meters (see Figure 5).

Figure 4 shows the two components of the mixed load shape, calculated using multiple regression. The lightest-colored load shape is the sum of the other load shapes. Figure 5 shows the actual observed load shape compared with the regression's approximation is shown. To get the estimate of the proportion of the usage in these mixed meters that is attributable to wireless devices, the wireless device component is summed then divided by the overall sum of all components.

Figure 5. Combined Load Shapes



The result of this analysis supports that 22.7% of the usage observed in the mixed meters is caused by the wireless devices, with 46.3% caused by typical streetlight usage. The remaining 31% of the mixed load does not appear typical of either streetlights or of wireless devices. Comparing the load shapes, it is apparent that the streetlight with wireless device usage is above the average streetlight-only meter's usage. It was also discovered that the wireless device component is well below the average for the pure wireless device meters. It appears that the primary purpose of the electrical consumption on these meters is still lighting/traffic control.

The total usage on the mixed meters examined was 9,750 MWh during the test period. Based on our estimated 22.7% usage due to wireless devices, this means that these devices accounted for an estimated 2,213 MWh of usage during the test period.

Table 2 on the next page compares the cost responsibility by function of the different SL customer groups using data from the Company's hourly marginal cost calculations and the Statement O proposed rates. In the first section of the table, which details costs by customer group, one can see that overall, the wireless devices have costs slightly lower than the average of the SL customer class.

By rate component, the different load shapes previously discussed drive higher capacity costs (on a $/kWh effective rate basis) for the wireless devices compared to those streetlights without these devices installed. However, these higher cost components are offset by lower energy costs driven by the higher usage of the wireless devices during lower cost daytime hours. So, the daytime usage, in conflict with the tariff's current "dusk-to-dawn" language, works as an overall benefit to this customer class as more energy is used during low-cost solar generation hours. As the grid continues to accumulate more solar generation capacity, the "dusk-to-dawn" language of this tariff is more of a disadvantage than an advantage in terms of cost.

Streetlights and traffic signals serve an important purpose: to ensure the safety and reliability of public rights-of-way. It makes sense to simply remove the "dusk-to-dawn" language from the tariff entirely and to allow reasonable unrestricted use for any devices the entities who own the poles believe fit to install, provided the purpose is for public safety/public service.

Granted, these devices are being installed behind the meter by both Clark County and by City of Las Vegas, however, it is important to note that this means they *are* metered. So, the County and City are appropriately charged for the added usage. This metered usage will help to inform the cost of service and rate design of the SL class in future filings, like all other customer classes, and so it is not clear that the "dusk-to-dawn" language should still limit the usage of the applicable installations on this tariff. Therefore, the Company recommends that this limitation be removed from the tariff for metered SL installations.

Table 2. SL Group Cost Comparison

Costs

Group	Meters	Per Meter Annual Usage (kWh)	Transmission Demand Cost	Distribution Demand Cost	Generation Capacity Cost	Energy Cost	Transformer Allocation	Facilities Cost	Interclass Rate Rebalancing	Total Cost
Streetlights w/o Wireless Devices	10,438	11,906	$ 6.77	$ 10.74	$ 203.80	$ 970.14	$ 135.80	$ 22.79	---	$ 1,350.05
Streetlights w/ Wireless Devices	265	36,793	$ 74.91	$ 115.89	$ 719.58	$ 2,702.26	$ 419.67	$ 70.44	---	$ 4,102.76
Wireless Devices only	265	8,387	$ 24.15	$ 37.22	$ 157.58	$ 555.28	$ 95.67	$ 16.06	---	$ 885.96
Streetlights as a whole	10,703	12,522	$ 8.46	$ 13.34	$ 216.57	$ 1,013.03	$ 142.83	$ 23.97	---	$ 1,418.20
Streetlights without Wireless Devices (cost per kWh)			$ 0.00057	$ 0.00090	$ 0.01712	$ 0.08148	$ 0.01141	$ 0.00191	---	$ 0.11339
Streetlights with Wireless Devices (cost per kWh)			$ 0.00204	$ 0.00315	$ 0.01956	$ 0.07345	$ 0.01141	$ 0.00191	---	$ 0.11151
Wireless Devices (cost per kWh)			$ 0.00288	$ 0.00444	$ 0.01879	$ 0.06621	$ 0.01141	$ 0.00191	---	$ 0.10563
Streetlights as a whole (cost per kWh)			$ 0.00068	$ 0.00107	$ 0.01729	$ 0.08090	$ 0.01141	$ 0.00191	---	$ 0.11326

Rates

Group	Meters	Per Meter Annual Usage (kWh)	Transmission Demand Cost	Distribution Demand Cost	Generation Capacity Cost	Energy Cost	Transformer Allocation	Facilities Cost	Interclass Rate Rebalancing	Total Cost
Proposed Rates	---	---	$ 0.00097	$ 0.00113	$ 0.02413	$ 0.07960	$ 0.00709	$ 0.00119	$ 0.02225	$ 0.13636
Streetlights w/o Wireless Devices	10,438	11,906	$ 11.55	$ 13.45	$ 287.29	$ 947.71	$ 84.41	$ 14.17	$ 264.91	$ 1,623.50
Streetlights w/ Wireless Devices	265	36,793	$ 35.69	$ 41.58	$ 887.82	$ 2,928.72	$ 260.86	$ 43.78	$ 818.64	$ 5,017.10
Wireless Devices only	265	8,387	$ 8.14	$ 9.48	$ 202.38	$ 667.62	$ 59.47	$ 9.98	$ 186.61	$ 1,143.68
Streetlights as a whole	10,703	12,522	$ 12.15	$ 14.15	$ 302.16	$ 996.76	$ 88.78	$ 14.90	$ 278.62	$ 1,707.52
Streetlights without Wireless Devices (cost per kWh)			$ 0.00097	$ 0.00113	$ 0.02413	$ 0.07960	$ 0.00709	$ 0.00119	$ 0.02225	$ 0.13636
Streetlights with Wireless Devices (cost per kWh)			$ 0.00097	$ 0.00113	$ 0.02413	$ 0.07960	$ 0.00709	$ 0.00119	$ 0.02225	$ 0.13636
Wireless Devices (cost per kWh)			$ 0.00097	$ 0.00113	$ 0.02413	$ 0.07960	$ 0.00709	$ 0.00119	$ 0.02225	$ 0.13636
Streetlights as a whole (cost per kWh)			$ 0.00097	$ 0.00113	$ 0.02413	$ 0.07960	$ 0.00709	$ 0.00119	$ 0.02225	$ 0.13636

Additional changes:

As a result of gathering premise specific data for the Streetlight Class in the process of estimating wireless devices, it was determined that government customers are not the only customers billing in this class, despite the tariff specifically restricting the class to government customers. There were 493 customers (893 lights) that were currently being billed on the SL tariff. This accounts for approximately eight percent of the 10,992 lights that are billed monthly.

As shown in Table 4, most of these ineligible customers are homeowner's associations, commercial parks, and real estate management firms. There was an apparent miscommunication between regulatory limitations and how a customer is placed onto the proper rate schedule when a customer applies for lighting service. Based on discussions with the New Projects department, a system solution is currently underway to automatically limit the SL schedule option to only those eligible customers when a request for new lighting service is submitted. As for these customers, they have all be moved over to the GS class. The median amount by which most of these customers will see their bills increase after being moved into the GS class is estimated at $36.91 per month.

Table 4. Customers on GS Schedule

Group	Customers
HOAs	343
Construction/Real Estate/Mgmt.	66
Commercial Customers	40
Private Individuals	16
Commercial Parks	12
Others	7
Churches and Schools	7
RV Parks	2
Total	**493**

The discovery of these unexpected customers did bring an important topic to light. One of the unexpected customers was identified as a tribal governing body. The language of the tariff does not explicitly include tribal governing bodies as eligible, even though tribal governing bodies are peers to some of the other governing bodies which are explicitly included. So, in this proceeding, the company is also proposing to update the language from specifying "…city, county, or state governing bodies…" to read "…state, county, city or tribal governing bodies…" instead allowing continuous billing under the SL tariff for this customer.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, TIMOTHY POLLARD, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: June 5, 2023

Timothy Pollard

SAMANTHA PREST

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Samantha Prest

Rate Design

I. INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Samantha Prest. I am a Pricing Specialist for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Bachelor of Science degree in Chemical Engineering from the University of Nevada, Reno. I started with the Companies in 2015 as a student intern in the engineering department, joined the Regulatory Pricing department in 2017 as an Associate Pricing Analyst, and was promoted to Pricing Specialist in 2022. More details regarding my professional background and experience are set forth in **Exhibit Prest-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A PRICING SPECIALIST.

A. As a Pricing Specialist, my responsibilities include providing technical support for the Companies' filings, and other rates and regulatory affairs including rate design, coordinating with numerous departments to gather data for marginal cost responsibility factors, embedded cost of service, and other pricing and economic analyses.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. Most recently, I filed testimony with the Commission in Nevada Power and Sierra's annual Deferred Energy Accounting Adjustment filings, Docket Nos. 23-03005 and 23-03006, respectively. I also testified in Sierra's 2022 General Rate Case ("GRC"), Docket No. 22-06014.

5. Q. PLEASE EXPLAIN HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized into four sections:

I. Introduction;
II. Overview of Statement O;
III. Proposed Rate Design; and
IV. Additional Statement O Scenarios.

6. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I sponsor the technical aspects and implementation of rate calculations set forth in the Statement O models and workpapers that support the Company's rate design proposal, sponsored by Company witness Janet Wells. Nevada Power is proposing a $92.7 million increase to revenue requirement from present rate levels, or a 3.3 percent increase, as well as updating the Company's time-of-use ("TOU") period definitions ("Statement O-Proposed ECIC, New TOU") in this proceeding. This revenue requirement represents the Company's requested Expected Change in Circumstance ("ECIC") adjustments to the revenue requirement. I also support a version of Statement O that follows the same rate design methodology as Statement O-Proposed ECIC, New TOU, but implements a revenue requirement increase of $66.7 million ("Statement O-Per NRS, New TOU"). This revenue requirement is what the Company would request without the requested ECIC adjustments. Additionally, I support the same Statement O models described, but using the Company's current TOU period definitions ("Statement O – ECIC, Current TOU" and "Statement O – Per NRS, Current TOU").

I also support 26 additional, full versions of Statement O and corresponding workpapers that do not reflect the Company's recommended rate cap, as discussed in Q&A 20 below and in the testimony of Ms. Wells. These additional Statement O models demonstrate the rate design results through the implementation of various cost of service studies and different modeling assumptions as ordered by the Commission in Nevada Power's 2020 GRC, Docket No. 20-06003 and Sierra's 2022 GRC, Docket No. 22-06014.[1] The different Statement O scenarios also consider both the Company's requested ECIC revenue requirement, and the revenue requirement that the Company would request without the ECIC adjustments. Finally, the different Statement O models show rates using both the current TOU period definitions and the new TOU period definitions that the

[1] Docket No. 20-06003, January 26, 2021, Modified Final Order, pp. 29-30, directives 3-5 and Docket No. 22-06014, February 13, 2023, Modified Final Order, p. 313, directives 8, 11, and 12.

Company is proposing to implement in this case. These additional Statement O models are attached, without workpapers due to the significant volume of material, as **Exhibits Prest Direct-8 through 33** to my testimony.[2] Because these additional 26 versions are presented without any capping proposals, if any one of these methodologies were utilized, a cap or floor recommendation would need to be proposed.

The rate design for all scenarios is based upon inputs supported by the hourly customer class load shapes sponsored by Company witness Timothy Pollard. These are used by Company witness Jeffrey Bohrman in the development of the marginal cost responsibility factors and developing the cost of service for individual classes in the Marginal Cost of Service Study ("MCS"), which he supports in this proceeding. These same hourly class load shapes and marginal cost responsibility factor inputs are used in the development of the Embedded Cost of Service Studies ("ECS"), which Mr. Bohrman also supports in this case. Statement O also relies on Customer Specific Facilities ("CSF") investments for a subset of customer classes, which are supported by Company witness Misha Pascal. Additionally, Company witness Hank Will supports the Company's proposal to implement new TOU period definitions.

The Company's preferred rate design proposal in this proceeding, **Exhibit Prest-Direct-3,** uses information from the preferred MCS[3] sponsored by Mr. Bohrman to prepare the proposed rate design scenario for all classes.

[2] The workpapers for each Statement O are available to the parties in the provided executable files and were provided at the time of the filing.
[3] **Exhibit Bohrman-Direct-2** from the Prepared Direct testimony of Jeffrey Bohrman.

7. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following 33 Exhibits:

- **Exhibit Prest-Direct-1**, Statement of Qualifications;
- **Exhibit Prest-Direct-2**, Rate Design Whitepaper;
- **Exhibit Prest-Direct-3**, Statement O-Proposed – ECIC, New TOU, RS Cap;
- **Exhibit Prest-Direct-4**, Statement O-Per NRS, New TOU, RS Cap;
- **Exhibit Prest-Direct-5**, Statement O-ECIC, Current TOU, RS Cap;
- **Exhibit Prest-Direct-6**, Statement O-Per NRS, Current TOU, RS Cap;
- **Exhibit Prest-Direct-7**, Statement O Scenario Comparison;
- **Exhibit Prest-Direct-8**, Statement O-MCS, ECIC, New TOU;
- **Exhibit Prest-Direct-9**, Statement O-MCS-Per NRS, New TOU;
- **Exhibit Prest-Direct-10**, Statement O-MCS, ECIC, Current TOU;
- **Exhibit Prest-Direct-11**, Statement O-MCS, Per NRS, Current TOU;
- **Exhibit Prest-Direct-12**, Statement O-MCS, ECIC, New TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-13**, Statement O-MCS, Per NRS, New TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-14**, Statement O-MCS, ECIC, Current TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-15**, Statement O-MCS, Per NRS, Current TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-16**, Statement O-MCS, ECIC, New TOU, Joint Dispatch, Generation and Energy (“GE”) Separated;
- **Exhibit Prest-Direct-17**, Statement O-MCS, Per NRS, New TOU, Joint Dispatch, GE Separated;

- **Exhibit Prest-Direct-18**, Statement O-MCS, ECIC, Current TOU, Joint Dispatch, GE Separated;
- **Exhibit Prest-Direct-19**, Statement O-MCS, Per NRS, Current TOU, Joint Dispatch, GE Separated;
- **Exhibit Prest-Direct-20**, Statement O-MCS, ECIC, New TOU, NPC Only Dispatch, GE Separated;
- **Exhibit Prest-Direct-21**, Statement O-MCS, Per NRS, New TOU, NPC Only Dispatch, GE Separated;
- **Exhibit Prest-Direct-22**, Statement O-MCS, ECIC, Current TOU, NPC Only Dispatch, GE Separated;
- **Exhibit Prest-Direct-23**, Statement O-MCS, Per NRS, Current TOU, NPC Only Dispatch, GE Separated;
- **Exhibit Prest-Direct-24**, Statement O-ECS With Energy Removed Using Marginal Allocators (“ECS-E-MA”), ECIC, new TOU;
- **Exhibit Prest-Direct-25**, Statement O-ECS-E-MA, Per NRS, New TOU;
- **Exhibit Prest-Direct-26**, Statement O-ECS-E-MA, ECIC, Current TOU
- **Exhibit Prest-Direct-27**, Statement O-ECS-E-MA, Per NRS, Current TOU
- **Exhibit Prest-Direct-28**, Statement O-ECS-E-MA, ECIC, New TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-29**, Statement O-ECS-E-MA, Per NRS, new TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-30**, Statement O-ECS-E-MA, ECIC, Current TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-31**, Statement O-ECS-E-MA, Per NRS, Current TOU, NPC Only Dispatch;
- **Exhibit Prest-Direct-32**, Statement O-ECS, ECIC, New TOU; and

- **Exhibit Prest-Direct-33**, Statement O-ECS, Per NRS, New TOU

8. Q. PLEASE DESCRIBE THE VARIOUS STATEMENT O SCENARIOS.

A. As discussed above, there are four Statement O versions provided that implement the Company's proposed rate design methodology, including using the Company's preferred MCS (**Exhibit Bohrman-Direct-2)**, and the Company's proposed residential cap. The remaining 26 Statement O scenarios are provided in this filing to compare the different methodological differences in cost studies, the different revenue requirements, or the different TOU period definitions. These Statement O scenarios are developed without a capping mechanism, in order to compare the different iterations more accurately. **Table Prest-Direct-1** below shows the differences in the scenarios and their inputs.

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Table Prest-Direct – 1

Exhibit No.	Scenario	Revenue Requirement	TOU	RS Cap	Cost Study	Cost Study Exhibit No.	Joint Dispatch?	G&E Reconciliation
Proposed Methodology Iterations								
3	**Proposed - ECIC, new TOU**	**ECIC**	**Proposed**	**+0.0%**	**MCS**	**Bohrman - 2**	**Yes**	**Combined**
4	Per NRS, new TOU	Per NRS	Proposed	+0.0%	MCS	Bohrman - 2	Yes	Combined
5	ECIC, Current TOU	ECIC	Current	+0.0%	MCS	Bohrman - 5	Yes	Combined
6	Per NRS, Current TOU	Per NRS	Current	+0.0%	MCS	Bohrman - 5	Yes	Combined
Cost-Based Rate Iterations								
Marginal Cost Study Iterations								
8	MCS, New TOU, ECIC	ECIC	Proposed	n/a	MCS	Bohrman - 2	Yes	Combined
9	MCS, New TOU, Per NRS	Per NRS	Proposed	n/a	MCS	Bohrman - 2	Yes	Combined
10	MCS, Current TOU, ECIC	ECIC	Current	n/a	MCS	Bohrman - 5	Yes	Combined
11	MCS, Current TOU, Per NRS	Per NRS	Current	n/a	MCS	Bohrman - 5	Yes	Combined
12	MCS, New TOU, ECIC, No JD	ECIC	Proposed	n/a	MCS	Bohrman - 4	No	Combined
13	MCS, New TOU, Per NRS, No JD	Per NRS	Proposed	n/a	MCS	Bohrman - 4	No	Combined
14	MCS, Current TOU, ECIC, No JD	ECIC	Current	n/a	MCS	Bohrman - 6	No	Combined
15	MCS, Current TOU, Per NRS, No JD	Per NRS	Current	n/a	MCS	Bohrman - 6	No	Combined
16	MCS, New TOU, ECIC, GE Sep	ECIC	Proposed	n/a	MCS	Bohrman - 2	Yes	Separate
17	MCS, New TOU, Per NRS, GE Sep	Per NRS	Proposed	n/a	MCS	Bohrman - 2	Yes	Separate
18	MCS, Current TOU, ECIC, GE Sep	ECIC	Current	n/a	MCS	Bohrman - 5	Yes	Separate
19	MCS, Current TOU, Per NRS, GE Sep	Per NRS	Current	n/a	MCS	Bohrman - 5	Yes	Separate
20	MCS, New TOU, ECIC, No JD, GE Sep	ECIC	Proposed	n/a	MCS	Bohrman - 4	No	Separate
21	MCS, New TOU, Per NRS, No JD, GE Sep	Per NRS	Proposed	n/a	MCS	Bohrman - 4	No	Separate
22	MCS, Current TOU, ECIC, No JD, GE Sep	ECIC	Current	n/a	MCS	Bohrman - 6	No	Separate
23	MCS, Current TOU, Per NRS, No JD, GE Sep	Per NRS	Current	n/a	MCS	Bohrman - 6	No	Separate
Embedded Cost Study Minus Energy - Marginal Allocators (ECS-E-MA) Iterations								
24	ECS-E-MA, New Tou, ECIC	ECIC	Proposed	n/a	ECS-E-MA	Bohrman - 15	Yes	n/a
25	ECS-E-MA, New Tou, Per NRS	Per NRS	Proposed	n/a	ECS-E-MA	Bohrman - 19	Yes	n/a
26	ECS-E-MA, Current Tou, ECIC	ECIC	Current	n/a	ECS-E-MA	Bohrman - 17	Yes	n/a
27	ECS-E-MA, Current Tou, Per NRS	Per NRS	Current	n/a	ECS-E-MA	Bohrman - 21	Yes	n/a
28	ECS-E-MA, New Tou, ECIC, no JD	ECIC	Proposed	n/a	ECS-E-MA	Bohrman - 16	No	n/a
29	ECS-E-MA, New Tou, Per NRS, no JD	Per NRS	Proposed	n/a	ECS-E-MA	Bohrman - 20	No	n/a
30	ECS-E-MA, Current Tou, ECIC, no JD	ECIC	Current	n/a	ECS-E-MA	Bohrman - 18	No	n/a
31	ECS-E-MA, Current Tou, Per NRS, no JD	Per NRS	Current	n/a	ECS-E-MA	Bohrman - 22	No	n/a
Embedded Cost Study Using Traditional Embedded Allocators (ECS) Iterations								
32	ECS, ECIC, no JD	ECIC	Proposed	n/a	ECS	Bohrman - 24	No	n/a
33	ECS, Per NRS, no JD	Per NRS	Proposed	n/a	ECS	Bohrman - 28	No	n/a

As shown in the table above, there are 16 iterations based on a MCS, eight iterations based on an ECS-E-MA, and two iterations based on an ECS using more generally accepted embedded allocators. Of the 16 Statement O iterations using a MCS, half combine the marginal GE revenue when reconciling to the embedded revenue requirement in Statement O, while the other half reconciles them separately.[4] Each Statement O using hourly cost responsibility factors from the MCS or ECS-E-MA

[4] Docket No. 20-06003 Modified Final Order, January 26, 2021, p. 29, directive 3.

is calculated using either Joint or Nevada Power Stand-alone Dispatch.[5] Each MCS and ECS-E-MA is also shown using both the newly proposed TOU periods and the current TOU periods. Finally, each Statement O iteration is provided using both the Company's proposed ECIC revenue requirement, and the revenue requirement without the ECIC adjustments.

In Nevada Power's 2020 GRC, the Company was ordered to provide an ECS that included the results of the embedded cost allocators agreed upon in a meeting with Regulatory Operations Staff ("Staff"), the Bureau of Consumer Protection ("BCP"), and other interested stakeholders.[6] As discussed by Mr. Bohrman in his direct testimony, while this meeting was held pursuant to the Commission's order, there was no general consensus on which traditional embedded allocators should be used in this filing. Instead, the parties agreed that the Company would provide multiple allocator options that the intervening parties could choose to use in their proposals. While Mr. Bohrman provides several embedded allocator options in his testimony, only one traditional ECS is run through Statement O for comparison purposes. The two Statement O versions using the ECS are provided using ECIC and non-ECIC revenue requirements, respectively.

The Company's preferred Statement O, shown in **Exhibit Prest-Direct-3,** starts with the Company's preferred MCS, which uses joint dispatch hourly cost responsibility factors, provided by Mr. Bohrman in **Exhibit Bohrman-Direct-2**. Additionally, GE revenue is reconciled together to reach the proposed revenue

[5] Docket No. 22-06014 Modified Final Order, February 13, 2023, p. 313, directives 8, 11, and 12.
[6] *Supra* Note 4*,* directive 4.

requirement. It also uses the Company's proposed TOU definitions and the ECIC revenue requirement.

9. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN STATEMENT O RELATED TO CUSTOMER CONTRACT PRICES?

A. Yes. Confidential information has been redacted in all versions of Statement O because it contains commercially sensitive information of costs paid by customers on the Market Price Energy ("MPE") and Large Customer Market Price Energy ("LCMPE") rate schedules.

10. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. The redacted material is customer specific information, and includes information related to prices paid by accounts served under the MPE and LCMPE rate schedules. This material is commercially sensitive and/or discloses the Company's views and expectations of its costs and capabilities to serve both existing and forward sales. This information is not known outside the Company and within the Company its distribution is limited. Releasing this sensitive information would compromise the Company's negotiating position or otherwise impair its ability to achieve favorable pricing, terms, and conditions of forward sales.

11. Q. FOR HOW LONG DOES NEVADA POWER REQUEST CONFIDENTIAL TREATMENT?

A. The requested period for confidential treatment is for no less than five years.

12. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF STAFF OR BCP TO PARTICIPATE IN THIS DOCKET?

A. No, in accordance with the accepted practice in Commission proceedings, the confidential material will be provided to Staff and the BCP under standardized protective agreements with them.

II. <u>OVERVIEW OF STATEMENT O</u>

13. Q. WHAT IS THE PURPOSE OF STATEMENT O?

A. Nevada Administrative Code ("NAC") § 703.2445 sets forth the requirements and purposes of Statement O. Unlike other required statements in the GRC, NAC § 703.2445 requires a narrative supporting the design of the rates proposed in the application. The details of the narrative are also set out in the regulation:

> The statement must describe and justify the objectives of the design of the proposed rate. If the purpose of the design is to reflect costs, the narrative must state how that objective is achieved, and must be accompanied by a summary analyzing cost that would justify the design. If the design is not intended to reflect costs…, a statement must be furnished justifying the departure from rates based on cost.

Consistent with the direction provided in NAC § 703.2445, Nevada Power has set forth and described the development of proposed rates for all classes of customers, including fully-bundled service and Distribution Only Service ("DOS") customers in the remainder of my testimony and the Rate Design Whitepaper attached as **Exhibit Prest-Direct-2**.

14. Q. PLEASE IDENTIFY AND EXPLAIN THE DIRECT INPUTS USED IN STATEMENT O TO DEVELOP BUNDLED AND DOS RETAIL RATES.

A. Four primary studies are used as inputs to the Statement O scenarios presented in this filing: (1) the corresponding cost of service study (the MCS in the Company's proposed Statement O); (2) billing determinants, and recorded and present rate revenue from Statement J; (3) the unbundled Schedule H-2; and (4) the CSF investment study.

The MCS is the foundation of the Company's rate design, and the MCS inputs are used to develop rates that reflect long-run marginal costs. It also serves as the basis for demonstrating differences between proposed rates and the rates at full marginal cost. Mr. Bohrman provides a more detailed discussion of the MCS methodology and those results in his Prepared Direct testimony.

Statement J provides present rate revenue, proposed rate revenue, and billing determinants for customer classes. Company witness Matthew Valentic sponsors the four versions of Statement J prepared for this filing, which correspond to the two revenue requirements and two TOU period definitions being presented in the versions of Statement O outlined previously.

Schedule H-2 provides the results of the revenue requirement unbundling analysis, which is sponsored by Company witness Jeffrey Purtee. Schedule H-2 shows the allocation of Nevada Power's total embedded revenue requirement among the three basic electric utility functions: distribution, transmission and generation. While Nevada Power's rates are based on marginal cost relationships, they must be set to recover the proposed embedded revenue requirement. Because revenue based on marginal costs are unlikely to match the revenue requirement based on embedded costs, the two studies must be reconciled together. The reconciliation process takes the unbundled embedded revenue requirement and assigns the revenue requirement to the individual rate classes on an Equal Percent of Marginal Cost ("EPMC") basis. This reconciliation step is done in Statement O in pages 3 to 6. The resulting class revenue requirement is then used in Statement O to develop proposed rates, subject to other public policy considerations and goals. The reconciliation process is not required in Statement O when an ECS is used in place of the MCS, as the ECS starts with the Company's requested revenue requirement.

The CSF study, sponsored by Company witness Mr. Pascal, provides the derivation of CSF investments used in the cost-of-service studies and Statement O.

15. Q. ARE THERE ANY CHANGES IN METHODOLOGY INCLUDED IN THIS STATEMENT O FROM THOSE PRESENTED IN PREVIOUS GRCS?

A. Yes. While the overall structure of Statement O remains largely the same as that presented in Nevada Power's 2020 GRC, some small changes were made in order to present the information in Statement O more clearly.

First, in the 2020 GRC, the reconciliation process was moved from Statement O to the MCS for ease of comparing the several cost study scenarios required to be performed by the Company. However, that change made it more difficult to follow the MCS results to the reconciled cost-based revenue in Statement O. Therefore, in this proceeding, the reconciliation process was moved back to Statement O, as had been done prior to 2020.

Second, three pages were added in Workpaper 5 that present the unbundled rates for each rate class. This allows reviewers to see which costs are being captured by the individual rates. These pages do not change the methodology in Statement O, and only serve to better present rate design results.

Finally, changes were made to Statement O in order to implement non-bypassable charges agreed upon in the exit orders of several DOS customers related to the decommissioning of Reid Gardner and Navajo Generation plants.[7] This charge for the applicable customer was first presented in Nevada Power's 2017 GRC, Docket No. 17-06003, as a $/kWh charge. However, the recovery of the regulatory asset containing these costs was deferred to a future rate case. In Nevada Power's 2020 GRC, the Company requested Commission guidance on the appropriate way to implement these costs. However, the 2020 GRC was stipulated without addressing this issue. In this filing, the Company is proposing to implement the Commission's orders by charging the applicable revenue for these customers as a monthly flat rate applied to the appropriate customer's largest premise. This calculation can be seen on page 18 of Workpaper 1 in Statement O.

16. Q. PLEASE GENERALLY DESCRIBE HOW STATEMENT O IS STRUCTURED.

A. Statement O consists of 22 pages and summarizes the overall revenue allocation and rate design results including rate impacts by class of each scenario. Five sets of workpapers serve as inputs to each Statement O and are described below. Please refer to the Table of Contents to Statement O for a detailed listing of the documents

[7] Dockets Nos. 15-05006, 15-05017, 16-11034, 18-09015, and 18-12003.

it contains, along with supplemental information relating to revenue allocation and rate design.

- Statement O, page 1: Summarizes the results of present rate revenue, cost-based revenue and proposed rate revenue for those classes included in the revenue reconciliation process. In addition, the revenue impacts for the groups of optional/partial-requirements classes not included in reconciliation are also presented on this page. The optional and/or partial-requirements classes not included in the revenue reconciliation are those that do not have their individual cost of service developed, as their rates are based on the standard Otherwise Applicable Rate Schedule ("OARS").

- Statement O, pages 2-9: These pages present the reconciliation of the marginal costs to the embedded revenue requirement, as well as the class adjustments to the cost-based revenue requirement required to get to the final revenue allocation of each class, and the resulting interclass subsidies.
  - Page 2 shows the Schedule H-2 unbundled revenue requirement, with revenue requirement adjustments for rate design by function.
  - Pages 3-7 show the reconciliation process and allocation of revenue credits. Page 3 presents the unbundled transmission revenue by class. Page 4 shows the distribution revenue, page 5 shows generation revenue, and page 6 presents energy revenue by class. Page 7 summarizes the class revenue by function to be used for rate design.
  - Page 8 takes the class cost-based revenue requirement allocations from page 7 and reallocates the cost based on revenue requirement on the EPMC basis, consistent with the cost-of-service study results, but

applies the caps and floors to the revenue to limit proposed changes from present rates among the customer classes.

- Page 9 shows the calculation of the Interclass Rate Rebalancing ("IRR") charge. The IRR charge is stated on a per kilowatt-hour ("kWh") basis and charged both under bundled and DOS rates. Under bundled rates, the IRR charge is included in the BTGR rate component for all classes, except for non-metered lighting schedules and the non-metered wireless communication schedule, where the IRR charge is included in the total rate. The IRR rate for each class is set to a minimum $0.00001 rate when the rate would be zero. This is consistent with the approved methodology from the 2020 GRC. This minimum value removes potential miscommunication of a zero value within the Company's system of records that store only five digits past the decimal. Including a non-zero value ensures that the system recognizes a valid rate.

- Statement O, pages 10-22: These pages provide various summaries and comparisons of the proposed rate revenue by class and summarize the rate impacts of the rate design on each class.
  - Page 10 summarizes the impact to those classes included in revenue reconciliation for the BTGR and Base Tariff Energy Rate ("BTER") rate components.
  - Page 11 summarizes the revenue impact to all classes, including additional rate components that are charged to customers.
  - Pages 12-13 summarize the proposed bundled rates for standard classes;
  - Page 14 summarizes the proposed rates for Street Lights ("SL").

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- Page 15 summarizes the proposed rates for Residential Private-Area Lighting ("RS-PAL").
- Page 16 summarizes the proposed rates for General Service Private-Area Lighting ("GS-PAL").
- Page 17 summarizes the proposed standby rates (schedules SSR and LSR).
- Page 18 summarizes the proposed DOS rates.
- Page 19 summarizes the proposed rates for the generation capacity rates used in the Incremental Price ("IP") rate schedule.
- Pages 20-21 summarize the development of the CSF charges for non-LGS-X transmission voltage and optional high load factor LGS-3P ("OLGS-3P HLF") classes.
- Page 22 summarizes the development of distribution and CSF charges for the LGS-X customer classes.

17. Q. PLEASE BRIEFLY DESCRIBE THE STATEMENT O WORKPAPERS.

A. Statement O consists of five workpapers used to calculate the different rates for customer classes.

<u>Workpaper 1 – Billing Determinants and Rate Design Revenue Adjustments</u>: These pages provide various summaries and comparisons of the proposed rate revenue by class and summarize the rate impacts of the rate design on each class. This workpaper consists of 18 pages and contains key inputs and calculations used in the rate design and the rate impact calculations, including:

- Pages 1 and 2 include the present rate and revenue at full cost-based levels while pages 3 and 4 include the billing determinants by class.

- Pages 5-11 present the revenue and rate calculations of the Electric Vehicle Recharge Rider ("EVRR") and Electric Vehicle Commercial Charging Rider schedules. These pages present class-level information regarding the billing determinants and ultimate bill impacts of participating customers on these schedules in accordance with item six of the Stipulation in Docket No. 18-09017.[8]
- Page 12 presents the Hoover B benefit calculation.
- Page 13 presents the revenue adjustments for two partial-requirement customers and the OLGS-3P HLF class that are included in the OARS rate design and the proposed class revenue adjustments for proposed rates (pages 5-8).
- Page 14 presents the calculation of the generation credits for the large commercial MPE schedules.
- Page 15 summarizes the revenue received from the OLGS-3P-HLF class.
- Pages 16 and 17 provide summaries of the revenue for the DOS customer classes while page 18 provides the calculation of the Reid Gardner and Navajo decommissioning and remediation costs attributed to a subset of DOS customers, as discussed above.

Due to the large number of optional TOU and TOU EVRR schedules available to residential and small general service customers, the calculations of these individual class revenue have been moved to a workpaper within Statement O that is no longer printed but is available and will be provided in the electronic file. The resulting revenue for these classes is summarized on page 4 of this workpaper in Statement O.

[8] Docket Nos. 18-09017 and 18-09018, Jan. 31, 2019, Order at 3-4, para. 6.

Workpaper 2 – Net Energy Metering (“NEM”): This workpaper contains six pages of information for the NEM customer classes.

- Pages 1-3 summarize the billing determinants of these classes.
- Pages 4 and 5 present the cost-based rate calculations for the NEM schedules.
- Page 6 summarizes the NEM shortfall that is the result of the rates charged to these customer classes relative to cost-based rates.

Workpaper 3 - Standby: This workpaper consists of eight pages related to the standby customer classes (schedules SSR and LSR).

- Page 1 includes the respective billing determinants of these classes.
- Page 2 calculates the diversity factor used in calculating back-up demand rates for standby customers.
- Pages 3 to 8 calculate the class revenue used as revenue credits to the total revenue requirement for rate design.

Workpaper 4 – Rate Design: This workpaper consists of 52 pages and presents the rate design for individual classes. Pages 1-5 present the calculation of distribution rates for both fully-bundled and DOS customer classes. The remaining pages are class-specific and present the rate design for the individual classes.

Workpaper 5 – Present Rates: This workpaper presents 15 pages of supplemental information, primarily providing additional presentations of the proposed fully-bundled and DOS rates, as well as comparisons of present and proposed rates for these classes.

18. Q. HOW DO COSTS FOR INDIVIDUAL CLASSES DIFFER FROM PRESENT RATE REVENUE?

A. Mr. Bohrman details the changes in the MCS results by class in his testimony, which feeds into Statement O. However, in order to see the disparity between cost-based levels and current rates, one needs to also consider the proposed revenue requirement change. While the costs have been updated in every GRC, many policy decisions such as cap/floor mechanisms, combining NEM classes with their OARS, and different cost study methodologies create disparities from cost-based rates.

In order to see the current level of subsidy in present rate revenue, the following comparison is provided. This comparison sets the revenue requirement in Statement O at present rate revenue, applying a zero percent cap so that no class of customer receives an increase from present rates, which provides the result of how the updated cost information from the MCS is reflected in current rates. **Table Prest-Direct-2** below summarizes this information and shows how divergent current rates are from updated costs for individual classes.

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TABLE PREST-DIRECT-2: COST-BASED REVENUE COMPARISON TO PRESENT RATE REVENUE

	Present Rate Revenue			Proposed Rate Revenue		
Class	Present Rate Revenue	Cost-Based Revenue at Present Rates	Existing Difference from Cost	Cost-based Revenue with Proposed RR Increase	Existing Difference from Cost	Percent Change
RS	$ 1,124,472	$ 1,099,064	$ (25,407)	$ 1,138,032	$ 13,561	1.2%
RM	339,331	314,780	(24,551)	325,309	(14,021)	-4.1%
LRS	5,291	4,805	(486)	4,957	(334)	-6.3%
GS	83,497	74,699	(8,799)	77,346	(6,151)	-7.4%
LGS-1	485,467	466,939	(18,528)	481,054	(4,414)	-0.9%
LGS-2S	271,383	258,035	(13,349)	265,248	(6,136)	-2.3%
LGS-2P	7,301	6,858	(443)	7,045	(256)	-3.5%
LGS-2T	-	-	-	-	-	---
LGS-3S	82,792	77,946	(4,846)	80,052	(2,739)	-3.3%
LGS-3P	195,666	181,078	(14,589)	185,935	(9,731)	-5.0%
LGS-3T	59,254	57,698	(1,556)	59,086	(168)	-0.3%
LGS-XS	-	-	-	-	-	---
LGS-XP	-	-	-	-	-	---
LGS-XT	-	-	-	-	-	---
LGS-2S-WP	1,343	1,478	136	1,524	181	13.5%
LGS-2P-WP	1,123	1,013	(110)	1,042	(81)	-7.2%
LGS-2T-WP	-	-	-	-	-	---
LGS-3S-WP	372	444	72	456	84	22.7%
LGS-3P-WP	1,742	1,629	(114)	1,671	(72)	-4.1%
LGS-3T-WP	-	-	-	-	-	---
SL	11,437	14,308	2,871	14,682	3,245	28.4%
RS-Pal	85	92	7	96	10	12.3%
GS-Pal	305	336	31	350	45	14.8%
IAIWP	-	-	-	-	-	---
RS-NEM	80,923	170,148	89,226	176,304	95,382	117.9%
RM-NEM	397	749	352	774	378	95.2%
LRS-NEM	92	111	19	116	23	25.3%
GS-NEM	275	492	217	509	233	84.7%
LGS-1-NEM	9,100	11,274	2,174	11,611	2,511	27.6%

The results show an existing subsidy for the RS-NEM customers of $89.2 million, a combined $0.2 million subsidy for the LGS-2S-WP and LGS-3S-WP classes, and a combined $2.9 million subsidy for the SL and PAL classes when revenue requirement is held static at current levels.

The table also shows that once the proposed $92.7 million revenue increase is applied to the cost-based revenue for customers, the full-requirements RS class shows a slight increase in revenue while all other classes without an existing subsidy remain at a cost-based decrease.

III. PROPOSED RATE DESIGN

19. Q. WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL IN THIS FILING?

A. The Company is proposing three rate design proposals in this case that are incorporated into Statement O, which include:

1. Setting a residential single-family cap of zero percent above the system percent increase of 3.3 percent;
2. Implementing a movement towards cost-based rates in the residential classes (RS, RM, and LRS) Basic Service Charge ("BSC") while maintaining the remaining classes at their current levels; and
3. Implementing the Company's proposed change in TOU period definitions, which includes removing the optional residential schedules that are currently closed to new customers (Option A and Option B).

Ms. Wells discusses and supports these policy decisions in more detail in her testimony. My testimony focuses on the technical aspects of implementing these policy decisions and their corresponding impacts to Statement O.

20. Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSED CAP IN THIS FILING?

A. While the Company recommends implementing the zero percent RS cap, it is ultimately for the Commission to determine the appropriate cap and/or floor. However, **Table Prest-Direct-3** below builds upon the previous table by adding the proposed revenue after implementing the Company's recommended capping mechanism and summarizes the change in class revenue from present rate revenue.

TABLE PREST-DIRECT-3: COMPARISON OF PROPOSED REVENUE CHANGE BY CLASS ($000S)

Class	Present Rate Revenue	Cost-Based Revenue at Present Rates	Existing Difference from Cost	Proposed Rate Revenue			
				Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present
RS	$ 1,124,472	$ 1,099,064	$ (25,407)	$ 1,158,625	$ 20,593	$ 34,154	3.04%
RM	339,331	314,780	(24,551)	343,692	18,383	4,362	1.29%
LRS	5,291	4,805	(486)	5,333	376	42	0.79%
GS	83,497	74,699	(8,799)	83,871	6,525	373	0.45%
LGS-1	485,467	466,939	(18,528)	495,938	14,884	10,471	2.16%
LGS-2S	271,383	258,035	(13,349)	276,033	10,785	4,649	1.71%
LGS-2P	7,301	6,858	(443)	7,404	359	103	1.42%
LGS-2T	-	-	-	-	-	-	na
LGS-3S	82,792	77,946	(4,846)	83,995	3,942	1,203	1.45%
LGS-3P	195,666	181,078	(14,589)	197,708	11,773	2,042	1.04%
LGS-3T	59,254	57,698	(1,556)	60,562	1,476	1,308	2.21%
LGS-XS	-	-	-	-	-	-	na
LGS-XP	-	-	-	-	-	-	na
LGS-XT	-	-	-	-	-	-	na
LGS-2S-WP	1,343	1,478	136	1,693	169	350	26.07%
LGS-2P-WP	1,123	1,013	(110)	1,125	83	2	0.16%
LGS-2T-WP	-	-	-	-	-	-	na
LGS-3S-WP	372	444	72	530	73	158	42.48%
LGS-3P-WP	1,742	1,629	(114)	1,764	94	22	1.26%
LGS-3T-WP	-	-	-	-	-	-	na
SL	11,437	14,308	2,871	17,546	2,864	6,108	53.41%
RS-Pal	85	92	7	106	10	21	24.45%
GS-Pal	305	336	31	393	43	88	28.90%
IAWP	-	-	-	-	-	-	na
RS-NEM	80,923	170,148	89,226	86,504	(89,800)	5,581	6.90%
RM-NEM	397	749	352	403	(371)	6	1.56%
LRS-NEM	92	111	19	98	(18)	5	5.73%
GS-NEM	275	492	217	277	(232)	1	0.53%
LGS-1-NEM	9,100	11,274	2,174	9,388	(2,223)	288	3.17%
Optional/Partial requirements classes not in reconciliation							
Optional TOU	48,258	---	---	49,314	---	1,056	2.19%
Optional TOU EVRR	8,716	---	---	9,172	---	456	5.23%
NEM Optional TOU	1,090	---	---	1,478	---	388	35.59%
NEM EVRR	1,759	---	---	2,329	---	571	32.46%
Standby	15,217	---	---	15,699	---	482	3.17%
EVCCR	1,829	---	---	1,841	---	12	0.65%
DOS	15,394	---	---	31,552	---	16,158	104.96%
Total (Bundled & DOS)	$ 2,805,178	---	---	$ 2,897,836	---	$ 92,658	3.30%

Based on the Company's proposal, the residential multi-family ("RM") and large residential service ("LRS"), and commercial customer classes, excluding Water Pumping ("WP") and lighting schedules, receive an average increase of 1.4 percent from present rates. The bundled WP classes being served at the secondary voltage level, LGS-2S-WP and LGS-3S-WP, as well as the lighting classes (SL, RS-PAL, and GS-PAL) are receiving an average increase of 25.2 percent, due to a significant change in their cost to serve in this case. Mr. Pollard and Mr. Bohrman discuss these changes in their direct testimony.

Other customers billed in optional or partial-requirements categories (Standby, Optional TOU, NEM Optional TOU, and DOS) are presented as separate groups in the table above and show an average increase of 26.5 percent. This increase is mostly due to the Company's proposed increase in the BSC for the residential classes, which causes NEM customers to pay more of their fixed costs that they were previously able to avoid, as well as an increase to the IRR that the DOS customers are required to pay as a direct result of the residential subsidy in this case.

For DOS customers, the percentage shown in **Table Prest-Direct-3** is only the percent increase of their distribution rates included in this filing. When one looks at their entire bill, including Open Access Transmission Tariff and energy rates paid to their energy providers, the overall impact of the GRC is significantly smaller. Individual class impacts for these groups are presented on pages 10 and 11 of Statement O. The differing percentages for these customer classes from their standard fully-bundled counterparts are related to unique usage characteristics of these individual customers (Optional TOU) and due to the limited number of rates paid by these customers that reflect their service and partial-requirements customers (Standby and DOS).

21. Q. HOW DOES THE RS SUBSIDY COMPARE TO HISTORICAL VALUES?

A. As shown above in **Table Prest-Direct-2,** with no movement towards cost-based rates, the RS interclass subsidy is $69.2 million, which is comprised of a subsidy of $89.8 million from RS-NEM that is partially offset by $20.6 million in revenue from the full-requirements RS customers. This amount is allocated to all other customer classes as part of the methodology presented on page 8 of Statement O, which can be seen in **Table Prest-Direct-4.** The table presents the overall subsidy and, for a few select classes, their impact of either contributing to the subsidy or paying for the subsidy. Additionally, the percent of the total subsidy attributable to the RS class is shown.

TABLE PREST DIRECT-4: HISTORICAL SUBSIDY SUMMARY

GRC	Docket	Cost-Based Revenue	Amount of Subsidies	Percent of Total	Select Classes RS	RM	GS	LGS-1	LGS-3P	Percent related to RS Shortfall
2001	01-10001	$1,352,474	$(85,641)	6.3%	$(76,088)	$(7,743)	$(1,811)	$27,051	$ 9,710	88.84%
2003	03-10001	1,414,594	(73,288)	5.2%	(73,124)	9,366	2,378	21,474	6,796	99.78%
2006	06-11022	2,066,844	(59,561)	2.9%	(59,561)	10,410	3,076	17,400	6,366	100.00%
2008	08-12002	2,414,821	(72,026)	3.0%	(72,026)	9,687	4,271	21,714	8,804	100.00%
2011	11-06006	2,108,889	(38,315)	1.8%	(36,817)	7,337	967	10,577	5,609	96.09%
2014	14-05004	2,166,517	(53,181)	2.5%	(52,961)	7,625	429	22,513	6,335	99.59%
2017	17-06003	1,969,462	(63,365)	3.2%	(62,142)	19,546	10,118	24,972	10,569	98.07%
2020	20-06003	1,775,088	(25,028)	1.4%	(21,916)	8,841	6,628	6,938	(123)	87.56%
2023	Proposed	2,833,197	(69,164)	2.4%	(69,164)	18,021	6,369	12,695	11,792	100.00%

The table shows that, under the Company's proposal, the overall deviations from the cost-based revenue of the classes in reconciliation is higher than the 2020 GRC, currently at 2.4 percent of total revenue compared to the 1.4 percent of total reconciled revenue in 2020. The RS subsidy contributes to 100 percent of the difference in cost-based rates, which is re-allocated to other classes, especially the RM, LGS-1, LGS-2S and LGS-3P classes.

22. Q. PLEASE DESCRIBE THE IMPACT OF IMPLEMENTING THE NEW TOU PERIOD DEFINITIONS ON RATES.

A. As discussed in Mr. Will's Prepared Direct Testimony, the Company is proposing to shift the Summer On-peak ("SON") period later in the day from the current peak hours of 1-7 p.m., to 3-9 p.m. Additionally, the Company is proposing to extend the SON peak period to include weekends for the residential classes. For the large commercial classes, the Company is proposing to remove the Summer Mid-peak ("SMID"). The Company is not proposing any change to the Winter period where all hours and all days are considered off peak.

There are two main impacts to Statement O caused by the proposed change to the TOU definitions. The first is the removal of the optional residential TOU schedules, Option A and Option B, which are currently closed to new customers. The second impact is the removal of the SMID peak period rates, and the subsequent shift of costs to the remaining SON peak period and the Summer Off-Peak ("SOFF") periods.

23. Q. HOW DOES THE CHANGE IN TOU PERIODS IMPACT THE OPTIONAL RESIDENTIAL CLASSES?

A. The Company is proposing to remove the Option A and Option B residential classes in this case, and to move all customers currently on those classes to the standard optional TOU schedule. Therefore, in the Statement O iterations that present the proposed TOU periods, those rates are set to the standard optional TOU class rates. In the event that the Company's proposal to remove these schedules is rejected, the rates for these classes are still developed individually in the Statement O iterations using the current TOU period definitions using the same methodology approved in prior GRCs.

24. Q. HOW DOES THE CHANGE IN TOU PERIODS IMPACT THE TOU DEMAND CHARGES FOR LARGE COMMERCIAL CLASSES?

A. As stated above, the Company is requesting to remove the SMID peak period for large commercial classes. Therefore, a change in the TOU demand rates is required in order to recover the same amount of revenue with the demand charges that were previously being recovered through the SMID. By removing the SMID peak, most of the costs that were previously reflected in that TOU period are now reflected in the SON period. The remaining costs are now captured in the SOFF period. In order to reflect the cost-based rates and to collect the same amount of revenue in the demand rates as the current TOU definitions, the Company is proposing to increase the Winter $/kW rates by approximately $1/kW, while the SON peak rates are proposed to increase by about $6/kW for large commercial classes.

IV. ADDITIONAL STATEMENT O SCENARIOS

25. Q. WHY ARE THE VARIOUS STATEMENT O SCENARIOS PRESENTED AT COST-BASED LEVELS, RATHER THAN INCORPORATING THE SAME CAPPING CONSIDERATIONS AS THE COMPANY'S PROPOSAL?

A. Due to the large number of scenarios being presented in this case that are focused on differences between inputs to Statement O (e.g. cost of service studies and system dispatch methodologies), the Company determined that the presentation of cost-based results is necessary in order to provide the Commission the complete impact of the different scenarios. Implementing the proposed policy decisions and limiting the residential class's increase dampens the effect of the differences that would otherwise be driven by the required changes to inputs between scenarios. By presenting cost-based class revenue and rates, the Commission will have the same basis of comparison for the varying inputs to Statement O. The variations each have a theoretical foundation that must be supported, and then the policy decision on how to design rates should be applied to those theoretical supports.

26. Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE COMPANY'S PROPOSED STATEMENT O VERSION AND THE STATEMENT O VERSION PREVIOUSLY APPROVED BY THE COMMISSION.

A. In both Nevada Power's 2020 GRC and Sierra's 2022 GRC, the Commission accepted the rate design based upon the Company's ECS-E-MA using stand-alone dispatch hourly cost responsibility factors and removed energy costs. The corresponding Statement O being presented in this case is shown in **Exhibit Prest-Direct-28. Table Prest-Direct-5** below shows the comparison between the Company's preferred rate design presented in **Exhibit Prest-Direct-3** and the rate design presented in **Exhibit Prest-Direct-28.** As **Exhibit Prest-Direct-3** includes energy costs, and **Exhibit Prest-Direct-28** is required to remove those costs, the table below presents **Exhibit Prest-Direct-28** with and without BTER revenue in order to give a complete comparison.

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TABLE PREST DIRECT-5: STATEMENT O COMPARISON

Class	Exhibit Prest Direct-3			Exhibit Prest Direct-28 -W/O BTER			Exhibit Prest Direct-28 -W/ BTER		
	Cost-based Revenue with Proposed RR Increase	Existing Difference from Cost	Percent Change	Cost-based Revenue with Proposed RR Increase	Existing Difference from Cost	Percent Change	Cost-based Revenue with Proposed RR Increase	Existing Difference from Cost	Percent Change
RS	$ 1,138,032	$ 13,561	1.2%	$ 533,854	$ 20,471	4.0%	$ 1,144,942	$ 20,471	1.8%
RM	325,309	(14,021)	-4.1%	141,845	(4,071)	-2.8%	335,260	(4,071)	-1.2%
LRS	4,957	(334)	-6.3%	1,963	(170)	-8.0%	5,121	(170)	-3.2%
GS	77,346	(6,151)	-7.4%	32,139	(2,640)	-7.6%	80,858	(2,640)	-3.2%
LGS-1	481,054	(4,414)	-0.9%	168,842	7,579	4.7%	493,034	7,567	1.6%
LGS-2S	265,248	(6,136)	-2.3%	83,533	6,118	7.9%	277,502	6,118	2.3%
LGS-2P	7,045	(256)	-3.5%	2,101	339	19.3%	7,640	339	4.6%
LGS-2T	-	-	---	-	-	0.0%	-	-	
LGS-3S	80,052	(2,739)	-3.3%	22,840	1,234	5.7%	84,025	1,234	1.5%
LGS-3P	185,935	(9,731)	-5.0%	54,981	4,718	9.4%	200,384	4,718	2.4%
LGS-3T	59,086	(168)	-0.3%	15,001	5,075	51.1%	64,247	4,993	8.4%
LGS-XS	-	-	---	-	-	0.0%	-	-	
LGS-XP	-	-	---	-	-	0.0%	-	-	
LGS-XT	-	-	---	-	-	0.0%	-	-	
LGS-2S-WP	1,524	181	13.5%	478	319	201.4%	1,662	319	23.8%
LGS-2P-WP	1,042	(81)	-7.2%	301	65	27.7%	1,188	65	5.8%
LGS-2T-WP	-	-	---	-	-		-	-	
LGS-3S-WP	456	84	22.7%	89	68	330.8%	440	68	18.3%
LGS-3P-WP	1,671	(72)	-4.1%	328	98	42.7%	1,840	98	5.6%
LGS-3T-WP	-	-	---	-	-		-	-	
SL	14,682	3,245	28.4%	3,158	1,993	171.2%	13,431	1,993	17.4%
RS-Pal	96	10	12.3%	36	(1)	-1.9%	84	(1)	-0.8%
GS-Pal	350	45	14.8%	126	(2)	-1.9%	302	(2)	-0.8%
IAIWP	-	-	---	-	-	0.0%	-	-	
RS-NEM	176,304	95,382	117.9%	88,568	47,873	117.6%	128,796	47,873	59.2%
RM-NEM	774	378	95.2%	365	187	104.9%	583	187	47.1%
LRS-NEM	116	23	25.3%	55	11	24.8%	103	11	11.9%
GS-NEM	509	233	84.7%	221	138	166.5%	414	138	50.2%
LGS-1-NEM	11,611	2,511	27.6%	4,093	830	25.4%	4,093	(5,007)	-55.0%

As shown in the table above, the largest impact of switching between the cost study models is to the large commercial and NEM classes. The large commercial classes, specifically receive a higher allocation of costs using the ECS-E-MA with stand-alone allocators, while the NEM classes show a significant decrease in their cost-based revenue.

27. Q. DOES USING THE ECS-E-MA WITH STAND-ALONE HOURLY COST RESPONSIBILITY FACTORS AS A BASIS IN STATEMENT O ELIMINATE THE RS SUBSIDY?

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

A. No. The Statement O iteration that uses an ECS-E-MA version is calculated by ignoring the time variant nature of energy costs. As the BTER is calculated using a flat rate applied to all customer classes, that revenue ignores the higher costs to customers who use energy during high-cost hours. In this filing specifically, the Company is seeing a large amount of high energy cost hours occur later in the day, or when the customers with solar systems are no longer able to rely on their solar generation. Therefore, using the ECS-E-MA results does not eliminate a residential or residential NEM subsidy, it simply fails to calculate the subsidy and is ignored.

With that said, while **Table Prest-Direct-5** shows a significant drop in RS-NEM costs in the ECS-E-MA compared to the MCS, it still shows a significant RS-NEM subsidy of $47.8 million present in current rates.

28. Q. PLEASE EXPAND UPON THE PROBLEM WITH RESPECT TO THE SEPARATE GE RECONCILIATION AND THE ECS-E METHODOLOGY.

A. Fuel and purchased power costs, recovered through the BTER, do not reflect the cost-of-service differences between classes as it is required to be simply calculated as a flat non-TOU $/kWh rate.[9] As these costs are litigated separately on a quarterly basis in deferred energy accounting proceedings, it is administratively efficient and reasonable that the BTER/deferred energy filings calculate a simple flat rate for all classes. However, while the simple flat rate appropriately avoids creating unnecessary complexity in the BTER calculations, there is no reflection of the actual cost of providing energy to different classes of customers as it does not provide for variations in the usage patterns of different classes. The only place

[9] NAC § 704.032.

where this occurs is with the hourly loads of individual classes included in a GRC cost of service study and rate design[10].

Therefore, by including the energy revenue through Statement O, the final rates paid by customers reflect the pricing differential across different classes caused by the time-variant nature of energy revenue. With this approach, the Company is able to allocate a larger portion of BTGR revenue to classes with a higher total cost of service and evaluate whether one class is paying more than its allocated embedded cost responsibility. Properly reflecting the total cost of service in rate design provides more accurate price signals to all customers. The final result is one that provides a more appropriate rate in total that works to limit interclass subsidies between classes.

The difference between the flat-rate BTER allocation and the allocated revenue requirement based upon the hourly energy costs of the system in this filing are summarized on page 6 of Statement O. A simplified example, which simply allocates the BTER revenue across classes based upon the energy costs by class from the hourly cost factors is shown below in **Table Prest-Direct-6**. The results show that the RS-NEM class pays less than their cost of service and that this under-recovery is paid for by higher charges for commercial and full-requirements residential customers.

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[10] Additionally, NRS 704.110(12) states that if energy costs are not included in the cost-of-service studies and rate design of a GRC, a cost-of-service study with that information must be calculated in the annual deferred case.

TABLE PREST-DIRECT-6: BTER VERSUS ENERGY COST COMPARISON

Class	BTER Revenue	Percent of Energy Costs by Class	BTER Revenue if allocated by cost	Excess/ Deficiency Present in BTER for Rate Design
RS	$ 611,088	34.6%	$ 587,505	$ 23,583
RM	193,415	11.0%	187,015	6,400
LRS	3,158	0.2%	3,008	150
GS	48,719	2.9%	48,777	(58)
LGS-1	324,204	18.9%	320,053	4,150
LGS-2S	193,969	11.3%	191,069	2,899
LGS-2P	5,539	0.3%	5,380	159
LGS-2T	-	0.0%	-	-
LGS-3S	61,185	3.6%	60,495	690
LGS-3P	145,403	8.3%	140,823	4,580
LGS-3T	49,246	2.8%	48,013	1,234
LGS-XS	-	0.0%	-	-
LGS-XP	-	0.0%	-	-
LGS-XT	-	0.0%	-	-
LGS-2S-WP	1,184	0.1%	1,154	31
LGS-2P-WP	887	0.1%	851	37
LGS-2T-WP	-	0.0%	-	-
LGS-3S-WP	351	0.0%	370	(19)
LGS-3P-WP	1,513	0.1%	1,501	12
LGS-3T-WP	-	0.0%	-	-
SL	10,273	0.7%	12,355	(2,082)
RS-Pal	49	0.0%	57	(8)
GS-Pal	177	0.0%	217	(41)
IAIWP	-	0.0%	-	-
RS-NEM	40,228	4.7%	80,036	(39,808)
RM-NEM	218	0.0%	384	(166)
LRS-NEM	48	0.0%	60	(12)
GS-NEM	192	0.0%	291	(98)
LGS-1-NEM	5,837	0.4%	7,470	(1,633)
TOTAL	$ 1,696,883	100.0%	$ 1,689,412	$ 0

The table shows that a significant amount of this difference is related to NEM customers, who are able to utilize their excess energy mechanism to bank kWh credits and receive a credit equal to the retail amount paid for energy rather than the wholesale market rate for energy.

29. Q. ARE THERE OTHER ISSUES WITH THE ECS-E METHODOLOGY?

A. Yes. The removal of energy costs in the class allocation and rate design will negatively impact very-low-cost classes, LGS-3S WP as an example. These classes get an appropriate allocation of total costs when their full cost of service is considered, including energy. However, their usage patterns dictate that their overall cost to serve is very low when distribution costs are excluded. For some classes, this is actually below the average BTER rate they pay for delivered energy. If energy costs are removed, then this class would no longer receive the benefit of their usage characteristics in which they use energy only during low-cost periods and have an average cost below the annual flat non-TOU BTER rate. In this filing, the impact of this change to the LGS-3S WP class is a 21 percent increase in their BTGR rates.

This issue aside, the Company is providing each respective Statement O following the ordered removal of energy costs as directed by the Commission, and has made necessary changes to Statement O in order to reflect these changes. This rate design is not recommended by the Company, but is intended to comply with the Commission's directives in Nevada Power's 2020 GRC and Sierra's 2022 GRC, that Nevada Power include in this general rate review proceeding rate design results that are based upon the various cost study iterations.

30. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT PREST-DIRECT-1

SAMANTHA PREST
PRICING ANALYST
RATES AND REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137

Ms. Prest has been an employee of NV Energy for eight years and her time at the company has been split between her previous position as an Engineering Student Intern and her current position within the Regulatory Pricing & Economic Analysis section of the Rates & Regulatory Affairs department. Her current responsibilities are focused upon electric cost of service and rate design issues and supplementary studies in support of the Rate & Regulatory Affairs department.

Employment History

NV Energy
June 2015 to Present

Pricing Specialist, Regulatory Pricing & Economic Analysis
Senior Pricing Analyst, Regulatory Pricing & Economic Analysis
Pricing Analyst, Regulatory Pricing & Economic Analysis
Associate Pricing Analyst, Regulatory Pricing & Economic Analysis
August 2017 to Present

- Conduct research and prepare studies for internal and external presentations
- Coordinate with numerous departments to gather data for marginal cost responsibility factors, Embedded Cost of Service, rate design, and other Pricing and Economic Analysis
- Provide technical support for Company filings and other Rate & Regulatory Affairs department responsibilities
- Research and prepare responses to internal and external data requests

Student Intern, Engineering & IT
June 2015 to May 2017
Renewable Energy Programs

- Primarily was responsible for compiling and analyzing NEM customer data for various internal and external data requests
- Supported outreach efforts to educate the community on renewable resource options at NVE.

Vegetation Management

- Coordinated work orders and handled invoices for NVE contractors
- Provided customer solutions regarding safety and reliability concerns as related to vegetation management.

Prior Testimony before Public Utilities Commissions

PUCN Docket Nos.: 21-03005, 21-03006, 22-03001, 22-03002, 22-06014, 23-03005, and 23-03006.

Education

University of Nevada, Reno
Bachelor of Science in Chemical Engineering, May 2017

Continuing Education
Utility Finance and Accounting for Financial Professionals
Economists Inc. Utilities of the Future Rates Group

EXHIBIT PREST DIRECT - 2

Nevada Power Company
2023 General Rate Case
Rate Design

Docket No. 23-06____

Exhibit Prest Direct-2

Nevada Power Company

2023 General Rate Case

Rate Design

Overview

Nevada Power Company d/b/a NV Energy's ("Nevada Power" or the "Company") general rate review application filing updates its Base Tariff General Rates ("BTGR") that recovers, among other costs, capital investments made to provide service to customers. Statement O is one of the schedules that must be included in any utility's general rate review application, as required by Nevada Administrative Code ("NAC") § 703.2445. The proposed general rates for all classes of customers, including bundled service and unbundled Distribution-Only Service ("DOS") customers, are developed in Statement O. Using Statement O, the detailed cost relationships across functions, customer classes, and time-of-use ("TOU") periods are used to set the proposed rates for each class of service. Rates are designed to recover the annual revenue requirement, unbundled by function (Distribution, Generation and Transmission) in Schedule H-2, using the test period billing determinants from Statement J.

In this case, Nevada Power has calculated two different revenue requirements. The first revenue requirement presents the Company's proposed increase of $92.7 million from present rate revenue and incorporates an Expected Change in Circumstance ("ECIC") adjustment that follows guidelines set out in the Nevada Revised Statutes ("NRS"). The second includes adjustments up to the Certification period per NRS requirements, or the revenue requirement that would occur without the ECIC adjustments. This scenario includes an increase of $66.7 million from present rate revenue. Additionally, in this filing the Company is proposing to update the current TOU period definitions in order to more accurately reflect the varying system costs in the TOU period definitions. Both of the calculated revenue requirements are being presented in Statement O using the Company's proposed change in TOU definitions and the current TOU definitions.

Different Statement O models have also been prepared for each scenario using various costing methodologies ordered by the Commission in Nevada Power's 2020 general rate case ("GRC")

(Docket No. 20-06003). Additionally, in Sierra Pacific Power Company d/b/a NV Energy's ("Sierra") 2022 GRC (Docket No. 22-06014), the Commission directed Nevada Power to complete in this GRC a marginal cost of service study ("MCS"), an embedded cost of service study ("ECS"), and a "hybrid" cost of service study using the Regulatory Operations Staff of the Commission's ("Staff") methodology to modify the ECS by removing energy costs and using marginal hourly cost responsibility factors ("ECS-E-MA"). In Sierra's 2022 GRC order, the Commission ordered that both the MCS and the ECS-E-MA filed by the Company must be based on a stand-alone dispatch, but also allowed that the Company could choose to present studies using joint dispatch hourly cost responsibility factors.[1] As the Company still maintains its position that the joint dispatch hourly cost responsibility factors are the appropriate way to allocate costs to customer classes, each cost study and corresponding Statement O is produced using both joint dispatch and stand-alone dispatch hourly cost responsibility factors. Each MCS scenario has been reconciled with Generation and Energy ("G&E") combined and separated, pursuant to the Commission Directives 11 and 12 in Sierra's 2022 GRC Modified Final Order, Docket No. 22-06014, as well as Directive 3 in Nevada Power's 2020 GRC Modified Final Order dated January 26, 2021.

For the ECS studies presented, the Company was directed to file an ECS using allocators agreed upon in a meeting with Staff, the Nevada Bureau of Consumer Protection ("BCP"), and other interested parties.[2] While this meeting was held between the parties, there was not a final consensus on the best allocators to use in the Company's ECS. Instead, the parties agreed that the Company would provide several allocation options that follow more traditional embedded cost allocation methodologies. Therefore, the Company is only presenting two Statement O

[1] Docket No. 22-06014, Modified Final Order February 16, 2023, Directives 8, 11, and 12.
[2] Docket No. 20-06003, Modified Final Order January 26, 2021, Directive 4.

versions using more traditional embedded allocation methodologies in this case, and any interested parties may use any of the allocators provided by the company and/or advocate for any other alternatives in their direct testimony. In order to comply with the different Commission directives discussed, a total of 26 different versions of Statement O are being presented in this case.

To compare the different inputs/decision points and results between the various versions of Statement O, the implementation of the cap and floor mechanism proposed by the Company to mitigate large changes in class revenue is removed in these scenarios. Additionally, four Statement Os are being presented that incorporate the Company's preferred cost of service study with a residential cap implemented in order to show the Company's proposed rate design. The full list of the different versions, along with the Proposed version, is summarized in the following Table 1.

Table 1. Statement O Scenario Summary

Exhibit No.	Scenario	Revenue Requirement	TOU	RS Cap	Cost Study	Cost Study Exhibit No.	Joint Dispatch?	G&E Reconciliation
Proposed Methodology Iterations								
3	**Proposed - ECIC, new TOU**	**ECIC**	**Proposed**	**+0.0%**	**MCS**	**Bohrman - 2**	**Yes**	**Combined**
4	Per NRS, new TOU	Per NRS	Proposed	+0.0%	MCS	Bohrman - 2	Yes	Combined
5	ECIC, Current TOU	ECIC	Current	+0.0%	MCS	Bohrman - 5	Yes	Combined
6	Per NRS, Current TOU	Per NRS	Current	+0.0%	MCS	Bohrman - 5	Yes	Combined
Cost-Based Rate Iterations								
Marginal Cost Study Iterations								
8	MCS, New TOU, ECIC	ECIC	Proposed	n/a	MCS	Bohrman - 2	Yes	Combined
9	MCS, New TOU, Per NRS	Per NRS	Proposed	n/a	MCS	Bohrman - 2	Yes	Combined
10	MCS, Current TOU, ECIC	ECIC	Current	n/a	MCS	Bohrman - 5	Yes	Combined
11	MCS, Current TOU, Per NRS	Per NRS	Current	n/a	MCS	Bohrman - 5	Yes	Combined
12	MCS, New TOU, ECIC, No JD	ECIC	Proposed	n/a	MCS	Bohrman - 4	No	Combined
13	MCS, New TOU, Per NRS, No JD	Per NRS	Proposed	n/a	MCS	Bohrman - 4	No	Combined
14	MCS, Current TOU, ECIC, No JD	ECIC	Current	n/a	MCS	Bohrman - 6	No	Combined
15	MCS, Current TOU, Per NRS, No JD	Per NRS	Current	n/a	MCS	Bohrman - 6	No	Combined
16	MCS, New TOU, ECIC, GE Sep	ECIC	Proposed	n/a	MCS	Bohrman - 2	Yes	Separate
17	MCS, New TOU, Per NRS, GE Sep	Per NRS	Proposed	n/a	MCS	Bohrman - 2	Yes	Separate
18	MCS, Current TOU, ECIC, GE Sep	ECIC	Current	n/a	MCS	Bohrman - 5	Yes	Separate
19	MCS, Current TOU, Per NRS, GE Sep	Per NRS	Current	n/a	MCS	Bohrman - 5	Yes	Separate
20	MCS, New TOU, ECIC, No JD, GE Sep	ECIC	Proposed	n/a	MCS	Bohrman - 4	No	Separate
21	MCS, New TOU, Per NRS, No JD, GE Sep	Per NRS	Proposed	n/a	MCS	Bohrman - 4	No	Separate
22	MCS, Current TOU, ECIC, No JD, GE Sep	ECIC	Current	n/a	MCS	Bohrman - 6	No	Separate
23	MCS, Current TOU, Per NRS, No JD, GE Sep	Per NRS	Current	n/a	MCS	Bohrman - 6	No	Separate
Embedded Cost Study Minus Energy - Marginal Allocators (ECS-E-MA) Iterations								
24	ECS-E-MA, New Tou, ECIC	ECIC	Proposed	n/a	ECS-E-MA	Bohrman - 15	Yes	n/a
25	ECS-E-MA, New Tou, Per NRS	Per NRS	Proposed	n/a	ECS-E-MA	Bohrman - 19	Yes	n/a
26	ECS-E-MA, Current Tou, ECIC	ECIC	Current	n/a	ECS-E-MA	Bohrman - 17	Yes	n/a
27	ECS-E-MA, Current Tou, Per NRS	Per NRS	Current	n/a	ECS-E-MA	Bohrman - 21	Yes	n/a
28	ECS-E-MA, New Tou, ECIC, no JD	ECIC	Proposed	n/a	ECS-E-MA	Bohrman - 16	No	n/a
29	ECS-E-MA, New Tou, Per NRS, no JD	Per NRS	Proposed	n/a	ECS-E-MA	Bohrman - 20	No	n/a
30	ECS-E-MA, Current Tou, ECIC, no JD	ECIC	Current	n/a	ECS-E-MA	Bohrman - 18	No	n/a
31	ECS-E-MA, Current Tou, Per NRS, no JD	Per NRS	Current	n/a	ECS-E-MA	Bohrman - 22	No	n/a
Embedded Cost Study Using Traditional Embedded Allocators (ECS) Iterations								
32	ECS, ECIC, no JD	ECIC	Proposed	n/a	ECS	Bohrman - 24	No	n/a
33	ECS, Per NRS, no JD	Per NRS	Proposed	n/a	ECS	Bohrman - 28	No	n/a

Each Statement O begins with revenue at full cost from the applicable cost of service study. For the MCS versions, revenue reflecting full marginal cost are reconciled to the unbundled embedded revenue requirement from Schedule H-2 in order to set class revenue requirements. This step is unnecessary in the ECS versions as the ECS starts with the embedded revenue requirement from Schedule H-2. I discuss the deviations from, and restrictions imposed on, the adherence to full cost-based revenue imposed by public policy in my testimony.

The Statement O versions that reflect the Company's Proposed scenario, under the two identified revenue requirements and TOU period definitions are:

Exhibit Prest Direct-3:

Company Proposed – **Statement O – ECIC revenue requirement ($92.7 million revenue requirement increase) – Proposed TOU Definitions**. The Company's proposed rates are presented in this Statement O. This proposal bases rates on the total revenue requirement reflecting ECIC adjustments, which includes a $92.7 million (3.3 percent) increase. Rates are proposed to move towards cost-of-service levels, based upon the MCS and include the joint dispatch of the Companies' system and the combined G&E cost reconciliation. Class movements are limited to a zero percent cap for the single-family residential ("RS") class, which at this revenue requirement means an overall 3.3 percent increase for these customers.

Exhibit Prest Direct-4:

Statement O – Per NRS ($66.7 million revenue requirement increase) – Proposed TOU Definitions. This Statement O reflects the Company's proposal without the ECIC adjustments incorporated into rates, but still incorporates the Company's Proposed TOU definitions. This version incorporates the same proposed zero-percent residential cap, with joint dispatch and combined G&E reconciliation as the Proposed version discussed above. This Statement O provides a complete rate design that would be otherwise recommended if the Company's proposal to implement ECIC revenue requirement adjustments was rejected, but the proposed change to TOU definitions was approved.

Exhibit Prest Direct-5:

Company Proposed – **Statement O – ECIC revenue requirement ($92.7 million revenue requirement increase) – Current TOU Definitions**. This Statement O incorporates the Company's proposed ECIC Revenue Requirement of a $92.7

million increase but uses the Company's Current TOU period definitions. This version incorporates the same proposed cap, with joint dispatch, and combined G&E reconciliation as the Proposed version discussed above. This Statement O provides a complete rate design that would be otherwise recommended if the Company's proposal to change the TOU definitions was rejected, but the ECIC revenue requirement was approved.

Exhibit Prest Direct-6:

Statement O – Per NRS ($66.7 million revenue requirement increase) – Current TOU Definitions. This Statement O reflects the Company's proposal without the ECIC adjustments or the Company's proposed TOU definitions incorporated into rates. This version incorporates the same proposed residential cap, with joint dispatch, and combined G&E reconciliation as the Proposed version discussed above. This Statement O provides a complete rate design that would be otherwise recommended if both of the Company's proposals to implement ECIC adjustments and change the TOU definitions were rejected.

The remaining Statement O iterations base their comparison to the Proposed version of Statement O, with the exception of removing the cap limitations so all classes move entirely to cost-based rates. These scenarios will serve as the basis for comparison with the additional iterations presented as complete rate design models. **Exhibit Prest Direct-8** provides a complete rate design that would be otherwise proposed if the Company's proposals to limit the movement of classes towards cost-based rates was rejected but all other decisions were approved.

Filing-Specific Changes

This section details changes made to Statement O in this filing from previous filings. This information is intended to compile the changes so that readers can easily see differences in the methodology and/or presentation being proposed in this filing.

Changes proposed/incorporated in this filing:

1) *Revenue reconciliation presentation changes.* First, in the 2020 GRC, the initial reconciliation of marginal costs to the unbundled revenue requirement from Schedule H-2 (or I-2 at Certification) moved from Statement O to the MCS in order to more easily compare the MCS to the ECS. However, while that change was made with the goal of simplifying the presentation of the cost studies, the end result made the presentation in Statement O more complicated. Therefore, in this filing the reconciliation process for the MCS scenarios is done entirely in Statement O, similar to how it was done prior to the 2020 filing.
2) *Implementation of class revenue cap methodology.* In the 2020 GRC, the allocation of revenue shifted from individual classes that met the cap or floor was modified to allocate the amount of revenue based upon the level of revenue that individual classes were away from cost-based levels, compared to the previously approved methodology that based the allocation on total cost-based class revenue of the applicable classes. In this filing, different classes are showing both required increases and decreases after the proposed cap is implemented, as opposed to the 2020 filing where every class showed a decrease after the cap/floor was implemented. Because of the mix of increases and decreases in revenue requirement for each class, the strict application of the methodology used in 2020 would create non-sensical results. For example, the Street Lighting ("SL") class in this case shows a required cost-based increase of 28.4%. If the methodology utilized in 2020 was applied strictly in the same manner in this case, the SL class would show a 20.3% decrease after the residential cap was applied. Therefore, in this filing the Company is proposing to

allocate the shifted revenue based on an average of each class's revenue away from cost-based levels and the total cost-based revenue for each class. This methodology provides a more reasonable allocation of shifted revenue to all classes as it accounts for the total revenue and how far proposed rate revenue is set from cost-based levels for different classes. The methodology is presented as part of the calculations on page 8 of Statement O.

3) *Implementation of Proposed TOU Definitions.* Two main changes are required in the versions of Statement O that contain the newly defined TOU period definitions in order to implement the Company's proposal. The first change required is to zero out any Summer Mid-peak rates, including the corresponding kWh and kW rates previously required for the larger, mandatory TOU schedules. The second change required to implement the Company's proposal is to eliminate the extraneous optional residential schedules that are currently closed to new customers, Option A and Option B. In the proposed TOU definition versions of O, the rates for these classes are set to their respective currently open standard optional TOU rate.

4) *Market Priced Energy ("MPE") rate schedules.* In the 2020 GRC, additional pages were added and approved in order to implement the newly created MPE and Large Customer Market Priced Energy ("LCMPE") tariffs. This information was deemed confidential and was, therefore, not presented in the public version of Statement O. In this filing, some presentation changes were made to the rate calculations of these customers' generation credits, and therefore that information is no longer marked confidential. These calculations can now be seen on page 14 of Workpaper 1 in Statement O. The MPE calculations that require customer specific information are still deemed confidential and will not be presented in the public version of Statement O.

5) *SB 123 – Reid Gardner and Navajo Decommissioning Costs.* In the exit orders of a subset of DOS customers, beginning as early as 2017, the Commission ordered that these customers were to pay for a portion of the decommissioning costs of the Reid Gardner and

Navajo Generation plants. This charge for the applicable customers was first presented in Nevada Power's 2017 GRC, Docket No. 17-06003 as a $/kWh charge. However, the regulatory asset containing the decommissioning costs was deferred from being included in rate base until future GRC proceedings and this value was set to $0. In Nevada Power's 2020 GRC, the Company requested Commission guidance on the appropriate way to implement these costs. However, the 2020 GRC was stipulated, and this issue was not addressed. In this filing, the Company is proposing to implement the Commission's orders by charging the applicable revenue for these customers as a monthly flat rate to the appropriate customer's largest premise. This calculation can be seen on page 18 of Workpaper 1 in Statement O.

Primary Inputs

There are several primary inputs used in Statement O for rate design, and the process begins with the unbundled embedded revenue requirement from Schedule H-2 and revenue at full marginal cost from the MCS. The marginal cost information is used to allocate the embedded revenue requirement to classes. Rates are designed to recover the annual revenue requirement given the test period billing determinants from Statement J. These inputs provide the necessary information to develop rates that reflect the detailed cost relationships across functions, TOU periods and classes.

As previously stated, in this filing additional cost of service studies are used in different versions of Statement O to allocate the revenue requirement to classes for rate design purposes.

Additional primary inputs include: 1) updated investment amounts for Customer-Specific Facilities ("CSF") charges that are billed to Large General Service ("LGS")-X and other customers who are served at Transmission-level voltages or opt in to the Optional High Load Factor ("HLF") tariff, 2) TOU billing determinants of the residential and small commercial classes to inform the rate design of the optional TOU schedules, and 3) the Component of Tariff ("COT") file that details each individual rate component charged to Nevada Power's customers.

General Model Structure

The structure of Statement O is the same for each version for each scenario presented in this filing. The Statement includes 22 pages followed by five workpapers. Inputs to the model are included in sheets located at the end of the Excel file. The final proposed rates for all Nevada Power customer classes are presented on pages 12-22 of Statement O. The overall structure is:

i. Statement O
   - These pages include overall class revenue summaries, proposed revenue impacts, and proposed rates.

ii. Workpaper 1
   - These pages summarize Present Rate Revenue, class marginal costs by function, billing determinants, and calculation of revenue requirement adjustments for optional schedules.

iii. Workpaper 2
   - These pages summarize net energy metering ("NEM") related billing determinants, revenue and the associated revenue shortfall for these classes.

iv. Workpaper 3
   - These pages summarize billing determinants and class revenue for small and large standby customer classes.

v. Workpaper 4
   - These pages present the rate design calculations by class.

vi. Workpaper 5
   - Workpaper 5 summarizes current rates and rate comparisons.

Class Revenue for Rate Design

Revenue adjustments are made in every general rate review proceeding to modify the revenue used to develop rates for individual classes. These adjustments change the reconciliation results and establish a "target revenue requirement" for each class. The total adjustments by function are shown on page 2 of Statement O, with the allocation to classes reflected on pages 3-6 of Statement O.

None of these adjustments, which I describe below, impact the total amount of sales revenue ultimately collected by the Company.

The adjustments include:

Power Factor Revenue: Power factor revenue ($917,000) recover costs for reactive power (kVARh) use above prescribed levels. Power factor costs and revenue are not specifically identified in marginal costs. Instead, these costs are credited in a manner similar to that described below for Large Standby Service Rider ("LSR") and optional TOU revenue. Power factor revenue are Distribution-related and so they are credited against only the Distribution revenue requirement. At completion of the revenue reconciliation, class-specific power factor costs are added back to their reconciled marginal costs, thereby assigning them to the classes generating them.

Additional Facility and Maintenance ("AF&M") revenue: This revenue is related to special facility-related contracts (e.g., contracts to maintain customer-owned distribution facilities or to charge for certain facilities not covered under a specific tariff) and totaled nearly $71,000 during the test period. For purposes of the revenue reconciliation, AF&M revenue are treated the same way as power factor revenue, with the revenue credited against the Distribution revenue requirement, and then directly assigned to the classes with customers that have the AF&M contracts.

<u>Standby Service (SSR/LSR) and Optional TOU Revenue</u>: With three exceptions, the rates for the standby service classes and all optional TOU schedules (including the optional TOU schedules for the NEM customer classes) have been set using Otherwise Applicable Schedule ("OAS") costs and are excluded from the reconciliation process. The two exceptions are: (1) two partial-requirements LSR customers, (2) the customers billed under the optional LGS-3P High Load Factor ("OLGS-3P HLF"), and (3) the customers billed under the MPE schedules. These sets of customers are included in the OAS schedules for revenue reconciliation and rate design. The revenue generated by the proposed rates for the standby and optional TOU schedules are credited against the revenue requirement in order to avoid collecting more than the sales revenue requirement identified in Statement H-2. The BTGR revenue credit is spread to all non-energy functions in proportion to each function's relative share of the combined revenue requirement and the Base Tariff Energy Rate ("BTER") revenue is credited to the energy function. Customers in all rate schedules benefit from these credited revenue in proportion to their share of total marginal costs within each function as this revenue offsets the amount required through rate design of the standard fully-bundled customer classes.

The inclusion of the two partial requirements customers, OLGS-3P HLF and MPE customers, in the OAS schedules reflects that these classes' rates are based upon the OAS class's rates and is consistent with the approved revenue reconciliation and rate design methodology. These customers are appropriately included in these classes to develop rates that reflect the full nature of providing service to these customers. The difference in revenue collected from the charges under the OAS rates and those billed under the respective standby, OLGS-3P HLF and MPE rates are included as a revenue credit so that the BTGR and BTER revenue match those from Statement H-2. The total combined proposed Standby and Optional TOU revenue, including the adjustments for the partial requirements LSR, OLGS-3P HLF, and MPE schedules, is approximately $33.3 million in this proceeding.

Western Area Power Administration ("WAPA") energy credit: A large customer served under the Large Standby Rider-II ("LSR-II") is eligible for an allocation of low cost WAPA energy. Under the provisions of a special service agreement with this customer, the Company receives scheduled WAPA energy deliveries on behalf of the customer and delivers the WAPA-equivalent energy to the customer. The customer in turn pays the Company the BTGR portion of energy rates for the amount of scheduled WAPA energy delivered, but does not pay for the BTER on those deliveries. On the billing of the customer, the customer pays the full energy rates, but then is credited the BTER, thus the term "WAPA energy credit." The WAPA energy credit, which is equal to the proposed BTER for the class multiplied by the WAPA energy, for the test period was approximately $1,099,000. Since the WAPA credit pertains to the BTER component, the adjustment is made to the reconciliation of the G&E functions. The credit flows through to the class by increasing the combined G&E revenue requirement by the amount of the WAPA credit. After the reconciliation is completed, the WAPA credit amount is subtracted from the reconciled cost of the LGS-3T class.[3]

Hoover B Benefit: The Hoover B benefit adjustment is made consistent with the stipulation reached in Docket No. 99-7035. The assignment of the Hoover B benefit to the residential class is performed similar to the WAPA credit assignment to the LGS-3T class. The overall Hoover B benefit ($14,165,000) is calculated as the total Hoover B benefit

[3] Consistent with the cost and rate design treatment approved by the Commission in prior Nevada Power GRCs, this LSR-II-3T customer is included in the LGS-3T class for marginal cost, revenue allocation and rate development. As such, the WAPA credit is appropriately credited to the LGS-3T class.

determined from Nevada Power's incorporated BTER filing (Docket No. 23-02017), divided by total residential sales from Statement J and is presented on page 12 of Workpaper 1. The sales for the optional TOU and NEM residential schedules are also included in the calculation.

Other Revenue: Since Nevada Power's 2006 GRC (Docket No. 06-11022), "Other Revenue" (e.g. late fee charges, reconnection fees, etc.), which total approximately $5.4 million in the test period, are added to the Distribution revenue requirement for reconciliation. After reconciliation, these revenue are subtracted from each of the respective class's revenue requirement, thereby directly assigning the benefit of payment of these tariff services to the classes that pay them.

DOS Revenue: DOS revenue is treated as a revenue credit in a manner similar to the LSR and optional TOU customer classes' revenue, as these are partial-requirements customers that purchase energy from another provider but require Distribution and Transmission service from the Company. The exception is the portion of DOS revenue associated with the Distribution revenue requirement, as this revenue is already calculated in the marginal cost revenue of their OAS. Since that revenue is already considered in the marginal cost revenue, it does not need to be treated as a revenue credit. The subsidy component of the non-by passable, Interclass Rate Rebalancing ("IRR") charge, DOS revenue is credited to all non-energy functions in proportion to each function's relative share of the combined revenue requirement. The revenue from the R-BTER charges is credited back to the energy function while those revenue from the NRS Chapter 704B impact fees are credited back directly to G&E because these are designed to largely recover generation plant investments and BTER imposed fees/credits. Finally, the DOS revenue received from specific DOS customers for their portion of the decommissioning costs for Reid Gardner and Navajo is credited directly to generation as that revenue is directly related to generation plant. In this proceeding, the total DOS revenue credited back is approximately $17.3 million.

After the adjustments described above are used to modify the total revenue requirement, the resulting functional revenue requirements by class are used to design rates by class. Any related changes to the proposed rates that alter these revenue credits flow back through as modified adjustments to revenue requirement through an iterative process contained on page 2 of Statement O in the working Excel file. This ensures that the proposed rates for all classes are designed to recover the total revenue requirement from Statement H and the cost-based revenue of all classes.

Iterating to a Model Solution

NOTE: THIS STEP IS REQUIRED WHENEVER CHANGES TO THE MODEL AFFECTING CLASS REVENUE ARE MADE.

Since the previously detailed revenue adjustments can be based upon rates being developed for the standard schedules (i.e. rates for the optional schedules are not included in the revenue reconciliation process, but are dependent on class revenue of the standard schedules proposed in Statement O), it is necessary to require additional steps to iterate the Statement O model to a solution so that the proposed rates recover the appropriate revenue requirement. The executable file in this proceeding follows the same methodology that has been used over several GRCs at both Nevada Power and Sierra. The iteration process begins by clicking on the image in cell T5 of the Rev Req sheet. This starts a macro in the VBA editor that simply copies the values from cells P2:P28 and pastes the values into cells Q2:Q28. The macro does this step two times and simplifies the process of updating the hard-coded revenue adjustments each time rates and/or revenue change in Statement O. The model is solved when the functions in all cells in R2:R28 are zero for all revenue requirement adjustments.

The text of the macro is:

```
Sub Iterate_RevReq_for_Solve()
'
' Iterate_RevReq_for_Solve Macro
' Will Copy and Paste Value into cells on RevReq page to iterate to solution
'
    Range("P2:P28").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("Q2").Select
    Selection.PasteSpecial Paste:=xlPasteValues, Operation:=xlNone, SkipBlanks _
        :=False, Transpose:=False
    Range("P2:P28").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("Q2").Select
    Selection.PasteSpecial Paste:=xlPasteValues, Operation:=xlNone, SkipBlanks _
        :=False, Transpose:=False
End Sub
```

Rate Design Methodology

The rate design methodology in this case is primarily the same as the methodology approved by the Commission in past GRCs, with the exception of the modifications previously identified in this whitepaper. The Company's proposed rate design for each customer class is specifically addressed here and in my direct testimony. The discussion of rate design that follows is either generally applicable or specific to the Company's different Statement O versions filed to inform the Commission on cost-based rates under the various ordered scenarios.

Residential and Small General Service ("GS") Classes

Cost to serve, based on cost causation, should be grouped and recovered in three distinct categories: 1) fixed or relatively fixed, 2) demand, and 3) variable consumption. Despite this fact, the residential and small GS classes continue to have a simple two-part rate design, with all costs not recovered in the Basic Service Charge ("BSC") being recovered through variable consumption rates.

Ideally for customers without a demand charge, the BSC would recover 100% of the class's customer and rule 9 facilities costs, as well as a portion of their primary distribution costs. The BSCs for the residential classes (RS, Residential Multi-Family ("RM"), and Large Residential ("LRS") are currently only collecting customer costs and 50% of rule 9 facilities costs. Therefore, the Company is proposing an increase to these classes' BSCs in order to move closer to cost-based rates.

The proposal for the BSCs for every other class, including the GS class, is to be kept constant at their current levels.

The rate design for these four classes is shown on pages 6, 13, 20, and 27 of Workpaper 4 of Statement O.

LGS-1 Service

The Large General Service ("LGS-1") rates are set in the same manner as current rates and continue to include a BSC, a non-TOU energy rate, as well as a separate non-TOU per kW facilities charge and a demand charge. The facilities and demand charges are based upon the maximum demand in the billing period. As previously mentioned, the BSC is kept constant at the current level, while the facilities charge is set to fully recover the customer facilities and distribution demand costs. In the Proposed Statement O, rate design for the LGS-1 class is presented on page 29 of Workpaper 4.

Optional TOU Schedules

The optional TOU rates for all optional TOU classes continue to be developed from the OAS and use the same rate design methodology as in previous GRCs. The optional TOU schedules have been included in Statement O with rates developed in a manner that ensures the rates are revenue neutral to the standard flat-rate schedule. Similar to the rate design used for current rates, the reconciled marginal revenue by function is assigned to the appropriate TOU periods based upon the distribution of these costs from the MCS. The back-bone (or primary) Distribution, Transmission, Generation and Energy marginal revenue is directly accumulated by TOU period as reconciled. The reconciled Distribution costs that are not related to the TOU periods - i.e., the portion of customer service and customer facilities costs not recovered through the BSC - are allocated to the periods in proportion to the kWh sales. The total revenue from each TOU period is divided by the respective TOU kWh sales to derive the cost-based TOU rates.

Generally, the proposed optional TOU rates maintain the relative differences across TOU periods in the proposed rates as those present in the full cost-based rates. However, while the cost-based TOU energy rates are used as targets for rate design, the proposed rates do not fully reflect the cost-based rates for any optional class. As in previous cases, for all optional schedules, the Company continues to maintain or move the proposed rates toward cost-based TOU levels, and also attempts to reasonably reflect the cost-based relationships across the TOU periods. In some cases, the movement toward cost-based TOU relationships was attenuated in order to keep the lowest cost Off-peak/other season BTGR rates from being negative. In other cases, movement toward cost-based rates was limited to prevent excessively large changes in the TOU rates or rate relationships from present rates.

It is the significant differences in rates across the TOU periods that provide existing optional TOU customers the opportunity to save on their average annual electric billings relative to the flat rate schedule. The greater the opportunity for existing flat rate customers to potentially experience significant savings under the optional TOU schedules, the more attractive the optional TOU schedules become. By either maintaining or moving the TOU rates closer to cost-based levels, the Company achieves a comparable separation between the On-peak and Off-peak/other period energy charges. This greater separation allows customers presently benefiting from these optional tariffs on an annual basis to benefit even more, assuming no change in usage patterns, as they will realize more savings during the lower rate Off-peak periods that are significantly greater in number of hours than those periods with higher rates. This also provides greater incentive for customers to shift usage away from the higher-cost On-peak periods. Additionally, it will make these tariffs more attractive to those customers not yet on these schedules, but who would also benefit from their application. While there is more risk, and certain behavioral implications associated with going onto these tariffs may discourage even those that could benefit from opting for them, the "lowest rate guarantee" contained in the optional residential TOU schedules should help overcome concerns that customers may have with trying the TOU rate schedules.

The rate design for the RS, RM, LRS, GS and LGS-1 optional TOU rate schedules is shown on the respective rate design pages in Workpaper 4 of Statement O.

Existing Standard Optional TOU Schedule

As approved in Docket No. 17-07026, the existing Optional TOU schedule, available to residential and small commercial customers, is a two-part TOU rate that provides for higher rates over the standard flat-rate schedule from 1 p.m. to 7 p.m. on weekdays during June through September. The remaining hours included in Off-peak periods are set at lower rates than the standard schedule. This option is slightly different from the closed Option A schedule, which extends the same On-peak hours to include the weekends. The Company is proposing to modify this schedule to shift the Summer On-Peak ("SON") period two hours later to 3 p.m. to 9 p.m., and to extend the On-peak hours to include weekends.

Option B versus Option A Residential TOU Schedules

Similar to Option A, Option B is closed to new customers. Since it was first approved, Option B, under the optional residential TOU schedules, has had a substantially different structure and much higher BSC designed to recover all Rule 9 facilities and primary distribution costs. As a result, despite the shorter summer season and On-peak period, the per kWh energy rate can be much lower. The Option B schedules have an On-peak rate period from 2 p.m. to 7 p.m. in the months of July and August. Due to the July and August months having the highest On-peak costs and the fewer number of On-peak hours under the Option B schedules, the cost basis and proposed On-peak rate for this option is higher than those under other optional TOU schedules. Alternatively, customers on Option B experience a greater number of hours at a lower Off-peak rate, which potentially offsets the higher rate that they pay during the limited On-peak hours. Because the BSC is so much greater under Option B ($34.25 in this case for the ORS-Option B class versus the proposed $18.50 BSC for the standard RS class), customers who benefit under these rates typically have relatively high energy consumption in the Off-peak period. Therefore, they tend to be residential customers with energy use that is greater than the average energy usage of their respective standard schedule.

Due to the Company's proposal to change the current TOU period definitions, while both Option A and Option B TOU schedules are closed to new customers, the Company is proposing to completely remove these schedules and to move the customers currently on these schedules to the standard optional TOU option. Therefore, in the Statement O versions using the Proposed TOU definitions, the rates for Option A and Option B are set to the standard Optional TOU class.

The rate design for the applicable Option B TOU schedules is shown on the respective rate design pages in Workpaper 4 of Statement O.

Daily Demand Pricing ("DDP") Schedules

The DDP schedules provide another optional rate design which incorporates a demand charge component for residential customers. These schedules use the cost of the corresponding full-requirements, flat rate residential class to develop rates that include a BSC, a flat $/kWh rate, a maximum daily kW demand charge, and TOU-based demand charges.

The monthly kW billing determinants are based upon the sum of the customer's daily maximum demand for each day of the billing cycle, and are designed to recover a portion of facilities costs and 100 percent of distribution demand costs, thereby providing a lower BSC relative to the standard non-TOU flat rate schedule. The kW charge has been set to recover 100 percent of primary distribution demand costs and 16 percent of Rule 9 Facilities costs, which represents the unreconciled total customer costs from the Company's MCS.

The TOU demand charges apply to the maximum daily demand placed on the system during the Summer On-peak and Winter TOU periods. These charges are set to recover 100 percent of the seasonal transmission demand costs for the class, which reduces the proposed flat $/kWh rate as compared to the standard flat-rate schedule. Customers with relatively higher load factors and those who minimize the demand that they place on the system will achieve savings.

G&E costs are recovered through a flat $/kWh rate. An adjustment is also made, when applicable, that minimizes any rounding present in the revenue collected from the proposed rates for the class.

Critical Peak Pricing ("CPP") Schedules

The Optional Residential Service CPP TOU schedules provide an additional option for customers to choose a rate structure that provides a price signal encouraging potential savings from shifting usage out of higher cost TOU periods, as well as reducing usage during specific critical events. The CPP TOU schedules are available to full-requirements, single-family, multi-family and large residential customers.

The CPP rate schedules follow the existing open TOU schedules, but include a CPP rate element. The schedule is based in part upon the rates examined and approved by the Commission during the Nevada Dynamic Pricing Trial ("NDPT") in Docket No. 10-05012.

The CPP rate identifies those days on which loads are expected to be higher than average, and on which significant gains for all customers can be achieved, if customers defer their energy usage to other periods. The CPP period isolates 78 high cost hours from the Summer On-peak hours for the RS, RM, and LRS classes: between 12 and 14 total CPP events in the Summer season, each six hours long during the SON peak period on non-holiday weekdays. These CPP events are communicated to the customer on a day-ahead basis and are accompanied by a higher dollar-per-kWh rate. The events are dispatched the day before the occurrence and the customer's CPP rate is fixed across all CPP events. The higher rate during the CPP events results in a correspondingly lower rate in the non-CPP Summer On-peak hours than the existing optional TOU On-peak rate.

The rates for the CPP periods reflect the average of the primary distribution and transmission costs across the entire Summer On-peak period. In addition, rates include the higher generation and energy $/kWh costs present in the hours defined as CPP periods. This results in higher rates during the CPP events reflecting the higher G&E costs of providing service during these times.

An adjustment is also made, when applicable, that minimizes any rounding present in the revenue collected from the proposed rates for the class.

CPP-DDP Schedules

These optional TOU schedules combine the rate structure elements of the optional CPP and DDP schedules to incorporate CPP and demand rate components.

Electric Vehicle Recharge Rider ("EVRR") Schedules

The Company continues to develop the EVRR optional rates using the same method as when these rates were first introduced and since updated. Customers under the EVRR are required to take service under an applicable optional TOU rate schedule. The EVRR rates are set the same as those of the otherwise applicable TOU rate schedule, except that the aggregate BTER and BTGR Off-peak energy rate is discounted by 10 percent. The current discounted Off-peak EVRR rate applies to all of the customer's electric usage during the 10 p.m. to 8 a.m. period, not just the energy used to charge an electric vehicle. The 10 percent discount is subtracted from the Off-peak BTGR rates for each class, and may be large enough to result in a negative BTGR rate component, which is permitted for this rider. As the BTER has changed from the 2020 GRC, the 10 percent discount is recalculated and incorporated in the EVRR rates. As part of the Company's proposed change to the TOU period definitions, the Company is proposing to move the discounted EVRR Off-peak period to range from 12am to 12pm.

The same rate development as described above applies to all of the EVRR rate schedules. These discounted rates are developed and shown on page 5 of Workpaper 1 for residential customers and page 6 for commercial customers.

Electric Vehicle Commercial Charging Rider ("EVCCR") Schedules

Pursuant to paragraph 19 of the Stipulation signed by the parties in Docket No. 18-02002 and approved by the Commission on June 29, 2018, the EVCCR rider supports the development of fast-charging electric vehicle charging station infrastructure in Nevada by providing a discount to the standard GS schedule TOU demand charges during a 10-year transition period. The discount will reduce over the 10-year period and gradually implement cost-based rates for these customers. These reductions in demand charges will encourage the development of electric vehicle charging infrastructure across the State. As operators of electric vehicle fast-charging stations, these customers, who currently have significantly low load factors due to relatively sparse usage, will benefit from paying less in demand charges during this period. Over time, as the adoption of electric vehicles increases and drivers of electric vehicles begin to utilize the facilities more, the overall load factor of the charging stations will increase, thereby reducing the effective rate paid by operators of these facilities. The related savings flow back through as a revenue adjustment to all customers.

As stated earlier, during the transition period, the proposed rates will be based on a rate design developed to be revenue neutral, compared to the existing otherwise applicable rate schedules. The proposed rates include reductions to the TOU demand charges of the OAS, and will be shown on a customer's bill through a separate line item, the "Demand Rate Discount" credit. The Demand Rate Discount is ratcheted down 10 percent annually from a 100 percent discount, starting on April 1, 2019, to a zero percent discount at the end of the 10-year transition period on March 31, 2028. As the rates are designed to be revenue neutral, in order to recover the discounted demand charge revenue of the standard schedule, the proposed rider includes incremental TOU kWh "Transition Rate Adder" charges. This rate component is designed to recover the revenue shortfall caused by the Demand Rate Discount on a volumetric, or per-kWh sold, basis. These TOU Transition Rate Adder charges are also shown as a separate line item on the customer's bill. Customers that opt into the EVCCR will pay all rates of the OAS. In addition to the rates described above, these customers will also receive the additional Electric Vehicle TOU period ("EV Period") discount that provides a 10 percent discount for consumption during the same EVRR Off Peak period as the standard EVRR schedules. The EV Period discount is also a separate line item on the customer's bill, so that customer can clearly see this specific discount on their bill.

Following the Commission's order in Docket No. 22-09006, the EVCCR period has been updated to reflect the shifted EV period to midnight to noon hours from the previously used 10 p.m. to 8 a.m. used in the 2020 GRC.

Bundled LGS TOU Classes

The rate design for the TOU-based LGS rate schedules (excluding the respective curtailable water pumping schedules) is presented in Workpaper 4 of Statement O. The approach to the LGS rate design is generally the same as prior GRCs, with the addition of the proposed changes to TOU demand rates discussed as part of my testimony. Details of the general methodology of rate design for these classes are:

Addition of Partial-Requirements Loads for Cost of Service & Rate Design

The Company includes the full-requirement loads (delivered loads, customer generation, and for one of them, WAPA deliveries) of two large partial-requirement customers in the load shape of the LGS-3P and LGS-3T classes for costs and rate design development purposes, consistent with the methodology most recently approved by the Commission in Nevada Power's 2020 GRC, Docket No. 20-06003. These two large partial-requirements customers are included in the costs and rate design for the respective classes because they use their own generation to only partially serve their respective loads, and would otherwise be served under this rate schedule if not for their solar PV generation. Including these customers in developing the cost of service and rate design of these classes results in rates that are representative of the class, which not only directly apply to the full-requirement customers in the class, but also serve as the basis for charges that apply to these two large standby customers as well as the other standby customers in the class.

Consistent with this treatment, the Company provides the WAPA energy credit applicable to one of these two standby customers through to the LGS-3T class in the revenue reconciliation process. This is appropriate treatment since the LGS-3T rates serve as the basis for the rates all LSR-II-3T customers pay, as all LSR rates are set based on the rates of the OAS. Therefore, even though the LSR-II-3T customer receiving the WAPA benefit does not reside in the LGS-3T class, the benefit of the WAPA energy credit flows through to all customers subject to the LGS-3T rates. There is an additional WAPA credit component related to generation capacity because the Company does not need generation capacity to supply the WAPA energy. Consistent with the approach agreed to between the customer and the Company, and approved by the Commission in Docket No. 06-11022, this portion of the credit is provided to the LGS-3T class in the MCS when the cost to serve is developed.

The development of marginal transmission demand and energy cost revenue for the LGS-3P and LGS-3T classes applies the allocated cost to the kWh sales *including* the hourly generation output of the LSR customers (as if they had no generation). For the development of the LGS-3T marginal generation demand revenue, the WAPA sales are *excluded*, thus providing the WAPA capacity credit to the LGS-3T class, which is consistent with the methodology originally approved by the Commission in Docket No. 06-11022. For the LGS-3P class, the one partial-requirements customer is included in the OAS. The customers currently billed under the OLGS-3P HLF and LGS-3P MPE schedule are also included as the rates for these customers are also based upon the cost of service characteristics and rate design of the LGS-3P class. For this filing, customers billed under the GS MPE, LGS-1 MPE, LGS-2S, LGS-3P MPE and LGS-3T MPE schedules are included in their OAS cost of service and rate design with the difference in revenue incorporated as a revenue adjustment. As discussed earlier, the MPE-specific information has been deemed confidential in this proceeding and is redacted in the public versions of Statement O.

The resulting class marginal cost revenue (reflecting the inclusion of these customers), along with the combined revenue requirement from the revenue allocation in Statement O, are brought into the rate design in the same way as all customer classes. This marginal revenue reflects the class characteristics as if these two partial requirement standby customers were still fully-bundled customers, including the benefit of the generation capacity reduction resulting from WAPA deliveries. In the Statement O file, this information flows to the "LGS-3T" worksheet (page 37) of Workpaper 4 where the LGS-3T rate design (with the one standby customer and the LGS-3T MPE customers included) takes place. In the LGS-3T worksheet, rates are developed using the rate design methodology described for all TOU customer classes. The WAPA energy credit is provided through the revenue reconciliation consistent with previous Commission orders and shows up as a line-item credit on the LGS-3T worksheet.

After the LGS-3T rates are developed, the billing determinants for the standby customers are removed from the LGS-3T class and the LGS-3T revenue of the full-requirement (non-LSR) and LGS-3T customers are derived by applying their LGS-3T determinants to the developed rates. The LSR-3T proposed rate revenue is also derived by applying its determinants to the LGS-3T rates. The revenue of the partial-requirements and MPE customers at LGS-3T rates and billing determinants is compared to how the revenue billed under the standby and MPE schedule are calculated. As discussed earlier, the difference is then used as a revenue credit back to the total revenue requirement to ensure that rates do not recover more than the amount listed in Statement H. The rate design and the treatment of the difference in revenue for the partial requirements customer, the MPE and OLGS-3P HLF customers are treated in a similar manner.

Distribution Charges

Distribution rates for these classes are set to recover the cost-based Distribution costs. Distribution costs include customer costs, the Rule 9 Facilities costs and the primary distribution (feeder and substations) costs. For the non-transmission-level classes without CSF charges, the facilities costs are recovered on a maximum per kW basis, in which the maximum kW is the largest demand of the customer over a rolling 13-month period, including the current month. For Transmission-level customers, all facilities costs are recovered through CSF charges. For the LGS-XS and LGS-XP classes, facilities costs are recovered through both CSF charges and the maximum per kW charges.

CSF Charges for Transmission-Level and OLGS-3P HLF Customers: Utility-Contributed Investment

The monthly CSF charge that Transmission and OLGS-3P HLF customers will pay on customer-specific, utility-contributed investment is dependent on both the facilities investment and CSF charge (stated on a dollar per dollar of utility-contributed investment) to which it applies. The Company proposes to update the investment amounts and increase the current rate by the system revenue requirement increase (3.7%) to develop the charge. The full cost-based charge is developed and shown on page 20 of Statement O. Facilities investment amounts, which are reflective of the replacement cost of the facilities in rate effective year dollars (2024 dollars in this case), are updated to reflect current investment costs.

The CSF charge per dollar of utility-contributed investment is the same for all Transmission-level, LGS-X, and OLGS-3P-HLF customers. The facility investment and development of the CSF charge is detailed by customer on pages 20 to 22 in Statement O.

Lastly, Nevada Power has also developed an alternative, average $/kW of maximum demand charge for transmission-level classes. This charge was developed by taking the reconciled CSF revenue requirement and dividing it by the maximum kW for these Transmission-level customers, and then dividing it by 12 to get the monthly charge. This alternative $/kW rate is intended to apply until the CSF of the customer can be determined. The rate of $0.90 per kW is calculated at the bottom of page 20 of Statement O.

CSF Charges for Transmission-Level and OLGS-3P HLF Customers: Customer-Contributed Investment

The proposed monthly CSF charge for the non-LGS-X Transmission customer-contributed investment is also stated on a dollar per dollar basis. These investments generally represent the facilities that customers pay for upfront through a Contribution In Aid of Construction ("CIAC") payment for a new project. It is developed in Statement O by dividing the annual reconciled revenue requirement for the contributed facilities by the associated customer-contributed investment, and then further dividing by 12 months. The charge continues to be reconciled to the Distribution revenue requirement, as this charge recovers the O&M costs associated with the customer-contributed plant investments. The proposed monthly CSF charge for contributed investments is $0.00059 per dollar of the customer-contributed investment in the proposed Statement O, representing the same increase as the other CSF charge component. The CSF charge for customer-contributed investment, like the CSF charge for investment made by the utility, is the same rate across all the Transmission-level classes. Any changes in revenue resulting from updates to these investments are treated in the same manner as the utility-investment charges.

Transmission and Generation Cost Recovery

Transmission demand costs are recovered through TOU-based demand charges for large commercial and industrial customers. There is a portion of Generation demand costs that is also recovered through the proposed energy rates. This methodology is sometimes referred to as "rate tilt." Given that there is an interrelationship between the G&E functions, even though a disconnect exists between the development of the hourly costs and the imposition of the demand charges that are based on a maximum kW demand across the billing period, it is appropriate to recover a certain portion of demand costs through the energy component. In this filing, the Company is proposing to keep the same rate tilt as utilized in the 2020 filing.

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

Demand Rates for the LGS TOU Classes

The Company is proposing to remove the Summer Mid-Peak in this filing with the proposed changes to the TOU period definitions. Therefore, a change in the TOU demand rates is required in order to recover the same amount of revenue with the demand charges that was previously being recovered through the Summer Mid-Peak demand charge. By removing the Summer Mid Peak, most of those costs that were previously being captured in that TOU period are now reflected in the Summer On-Peak definition. The remaining costs are now captured in the Summer Off-Peak period. Therefore, in order to reflect the cost-based rates and to collect the same amount of revenue in the demand rates as the current TOU definitions, the Winter $/kW rates are being increased by approximately $1/kW, while the Summer On-Peak rates are proposed to increase by about $6/kW for each class.

In the case that the Company's TOU proposal is not accepted by the Commission, the Company is still proposing an increase to the TOU demand rates in order to reflect the proposed revenue requirement increase as well as the increase in T&G marginal costs. These increases result in a general \$0.20/kW increase to the Winter \$/kW rate, around a \$4/kW increase to the Summer On-Peak \$/kW charge, and about a \$1/kW increase to the Summer Mid-Peak \$/kW charges for all affected classes.

Energy Rates for the LGS TOU Classes

The energy TOU rates for these classes are based on the cost-based relationships across the TOU periods. The balance of the Generation demand costs recovered in the energy rates, along with the interclass rate rebalancing (subsidy or shortfall) costs, are then spread to TOU periods in proportion to the TOU marginal energy costs, subject to the constraint that each period's rate must be equal to the BTER rate plus at least one hundredth of a mill (\$0.00001) for the BTGR component. This constraint has been used by the Company in its previous rate designs. Its purpose is to maintain a minimally positive BTGR rate in all TOU periods. The only exception to this approach occurs in three of the curtailable water pumping schedules, in which a negative BTGR is permitted in order to obtain reasonably higher on- and mid-peak energy rates.

OLGS-3P HLF Schedule

The OLGS-3P HLF is an optional schedule approved as part of the stipulation in Nevada Power's 2014 GRC. Eligible customers are LGS-3P customers, with an annual load factor greater than 75 percent and who agree to take service under this optional schedule for three-years. These customers are included in developing costs and rate design of the otherwise applicable LGS-3P schedule because the rates for this optional schedule are based upon the costs of the LGS-3P class, with the exception of the development of individual CSF charges rather than an average $/kW charge. The CSF charge for these customers recovers the customer-related, Rule 9 Facilities costs and non-revenue feeder costs, which decrease the costs for the class. Class rates are also developed in the same manner as other classes. The resulting LGS-3P and OLGS-3P HLF rates are used to determine the proposed revenue that would be charged under each rate schedule. The difference flows back as an adjustment to the total unbundled revenue requirement to modify the target rate design revenue requirement.

The rates for the class are developed on page 36 of Workpaper 4 in Statement O. The CSF charges are developed on pages 20 and 22 of Statement O. Revenue for the customers who have moved to the OLGS-3P HLF schedule, and resulting revenue difference from the OAS rates used as a revenue credit to the total revenue requirement, are presented on page 15 of Workpaper 1.

MPE Rider Schedules

The MPE and LCMPE was approved by the Commission as part of the Stipulation in Docket No. 19-10011 and Docket No. 19-12016, respectively. While the applicability and contracts required for these two tariffs are different, the generation credits developed in rate design that are part of Statement O are the same for both sets of customers. Therefore, these customers are combined and labeled as MPE in Statement O. The development of the generation credit rates for these classes is shown on page 14 of Workpaper 1. The remaining MPE information has been deemed confidential as it contains customer-specific information and is, therefore, redacted in the public version of Statement O. Similar to the OLGS-3P HLF schedule, these customers are included in the standard schedule for cost of service and rate design. The difference in what they would otherwise pay under the standard schedule and the MPE schedule is calculated and flows back as a revenue credit for allocation to all other customers through the revenue credit process.

Curtailable Water Pumping ("WP") Schedules

These rates are developed consistently with the methodology the Commission has approved in past rate cases. The WP customers served under these schedules pay the demand rate only when they continue to have loads during noticed "curtailment periods." There were no such curtailment periods in the test period. Consistent with past practice, the demand rates for the LGS-WP classes are set at the rates of the OAS. Both the On-peak and Mid-peak curtailable demand rates under the LGS-WP tariffs are set at the sum of the On- and Mid-peak rates of the otherwise applicable tariffs under the current TOU definitions. For the proposed TOU definitions, the Summer On-peak demand rates are set to the Summer On-peak rates of their OAS. The other/winter demand rates are also those of the otherwise applicable tariff in that same rating period.

Energy rates are developed as described for the other LGS classes, with the exception that negative BTGR rates are allowed for LGS-WP classes when it is necessary to maintain distribution rates at cost-based levels, and to achieve reasonable TOU energy rates that reasonably reflect cost-based relationships across the TOU periods.

Interruptible Agricultural Irrigation Water Pumping ("IAIWP")

Service under this schedule is limited to water pumping for agricultural irrigation purposes only, and customers must be willing to accept the conditions of interruption or curtailment as provided for in the tariff. This tariff is similar to Sierra's IS-2 rate and exists to provide agricultural irrigation customers with low-cost energy in exchange for their agreement to be interrupted, as required under NRS § 704.225 and NAC § 704.675. Currently no customers take service under the IAIWP class.

Consistent with the rates approved by the Commission in past GRCs, the proposed rates for this class are based upon the OLGS-1 class for the non-irrigation season (November-February) and the legislatively-mandated low-cost irrigation rate ($0.06751) during the irrigation season, which was approved for the 2023 irrigation season in Docket No. 22-10002.

Classes Without Current Customers

LGS-2T class

As with the IAIWP tariff, the Company lacks class-specific cost information for the LGS-2T class. Unlike the IAIWP rate, which is legislatively-mandated, the rates for this class are set within Statement O, and, therefore, the Company must derive rates for this class from information from other classes that have similarities to the LGS-2T class. The LGS-2T cost-based BSC is taken from the MCS, which identifies the customer-related costs of a typical LGS-2T customer, and the proposed rate is obtained from it by applying the distribution reconciliation factor. While a cost-based rate is developed in the MCS, and reconciled to the embedded revenue requirement similar to other classes, the ECS and ECS-E calculations are not able to calculate a cost-based rate for this class and require additional steps. Therefore, in these cost studies, the LGS-2T customer cost for the BSC has been set to the LGS-3T schedule, as the Company assumes that these costs would be similar between the schedules.

This class would also have CSF charges, which would be at the same rate per dollar of investment that is developed for all other classes (e.g., LGS-3T). The LGS-2T demand rates are set equal to the LGS-2P demand rates. New in this filing, the energy rates are set equal to the LGS-3T energy rates. Previously, the rates used the relationship between the LGS-3P and LGS-3T cost-based energy rates to modify the LGS-2P energy rates. For this filing, it was determined that using the proposed LGS-3T rates eliminates the need for the adjustment and provides rates that would more likely apply to any customers being billed on the LGS-2T schedule since the customer would also be eligible for LGS-3T if their energy usage qualified.

Classes Without Bundled Customers (LGS-X, LGS-2T-WP and LGS-3T-WP classes)

Two WP and the three LGS-X classes (LGS-XS, LGS-XP and LGS-XT) presently have no bundled customers. However, the method of setting rates for these classes is essentially the same as described for the LGS-2T class. Because distribution rates are set equal to the combination of bundled and DOS customers, in this filing, these rates are set equal to the appropriate rates based upon the costs of the DOS customers. Customers served under these Transmission voltage-level schedules pay CSF charges and pay the same CSF rate per dollar of investment as developed for any other bundled class with similar charges.

The LGS-2T-WP and LGS-3T-WP demand rates are set equal to the respective LGS-2P-WP and LGS-3P-WP demand rates. Their energy rates are set equal to the respective LGS-2P-WP and LGS-3P-WP energy rates, adjusted downward for losses based on the relationship among the LGS-3P and LGS-3T cost-based energy rates.

The proposed energy rates for the LGS-X schedules have been set to the corresponding LGS-3 schedules since these customers would otherwise be eligible for LGS-3 service if they had not opted in to the LGS-X tariff, which requires a specific contract for service.

Wireless Communication Service ("WCS")

The WCS rates are developed using the same methodology as used in prior GRCs and are consistent with the methodology used when the WCS schedule was first proposed by the Company and approved by the Commission in Advice Letter No. 462-E (revised), filed in Docket No. 06-08010. The WCS is similar to the lighting rates in that the service is unmetered and the kWh energy is approximated for each type of WCS device based on its nameplate rating. Separate cost of service is not developed for WCS as these are unmetered customers who install service for wireless communication towers and/or responders. Instead, the WCS rates are derived directly from the GS rate schedule, which provides a reasonable average of the monthly consumption for these customers. The proposed BTGR for the WCS is the same as the proposed BTGR for the GS class. The BSC for the WCS schedule is also derived from the reconciled cost-based customer component of the GS BSC. Because the WCS service is unmetered, the GS customer charge is reduced to remove the recovery of the meter investment, meter O&M and meter reading. There are currently no customers served on this schedule at Nevada Power.

DOS Schedules

Similar to the methodology approved in Nevada Power's 2020 GRC, the DOS class rates are based upon the combination of both bundled and DOS customers. As the distribution service provided by the utility does not vary based on a customer being fully-bundled or DOS, it is appropriate for rate design and customer rates to reflect this fact.

The distribution rates for DOS classes include the BSC, the Additional Meter Charge ("AMC"), facilities charges and power factor charges. Facilities charges may be charged on a per-kW basis or customer-specific basis, depending on the OAS of the DOS customer. DOS customers also pay the non-bypassable IRR charge, as well as the Universal Energy Charge and all applicable taxes.

The R-BTER ($/kWh) and additional Impact Fee charges are also included as part of the revenue collected from some applicable DOS customers. The revenue requirement associated with these charges are presented on page 4 of Workpaper 1.

Additionally, as part of the exit application for some DOS customers, a subset of customers are required to pay for a portion of the decommissioning costs attributed to retiring the Reid Gardner and Navajo Generation plants. The total amount being recovered by each individual customer is calculated by applying the applicable DOS customer's load share at the time of their departure to the total decommissioning costs requested to be recovered in this filing. That amount is then applied to the largest premise for each of these customers as a flat monthly charge. This calculation is shown on page 18 of Workpaper 1.

The proposed rates for the DOS schedules are presented on page 18 of Statement O. The calculated revenue is summarized on pages 17 and 18 of Workpaper 1.

Standby Service Rider ("SSR") and LSR Schedules

The proposed standby rates are set consistent with prior Commission orders with respect to the SSR and LSR tariffs. The SSR and LSR rates are based upon the OAS that the standby customers would be served under if they did not have self-generation and were not on the standby tariff. For all SSR and LSR service classes, the BSC is set at the otherwise applicable classes' BSC. For all standby classes, other than SSR-I and SSR-II, the generation meter charge is based on the cost of the additional meter. For SSR-I and SSR-II, the meter charge is per customer and reflects the incremental cost-based customer and meter charges. The Rule 9 Facilities charges for SSR-III and LSR classes are set at the reconciled marginal cost-based rates of the OAS or the CSF charges that are otherwise applicable under the OAS. The energy rates for all standby classes, other than SSR-I and SSR-II, are those of the OAS. The SSR-I and SSR-II energy rates are set slightly lower than the costs of the OAS, due to the recovery of a greater portion of facility costs through the monthly per customer charges than is recovered in the OAS.

Standby TOU Demand Charges

As has been the methodology since the SSR and LSR tariffs were approved by the Commission, the reservation and back-up demand charges for the individual standby classes (SSR-III and all LSR classes) are developed from the proposed TOU demand rates of the OAS by applying a diversity factor. The diversity factor is used to split the TOU demand rates of the OAS into two pieces: (1) a fixed reservation, and (2) a variable back-up demand component. Therefore, the sum of the reservation and back-up demand charges, by TOU period, for the standby classes equals the TOU demand charges of their respective OAS. The (fixed) reservation charge is billed on the contract demand of the standby customer. The back-up (variable) demand component only applies when the standby customer requires back-up service and imposes a back-up demand on the Company. All supplemental use beyond the back-up or contract demand requirement is billed at the full demand rates of the OAS.

Diversity Factor

The diversity factor reflects the availability of generation of standby customers by comparing the demands experienced by these customers to their full potential total load based upon the contract demand of their generation that the Company is standing by to serve. The diversity factor calculates the effective reduction in maximum demand placed on the system that is expected from these customers. This reduction, expressed as a percentage, reduces the OAS demand rates to reflect the expected Standby demand so that if the customer experiences the reduction in maximum demand then they will receive a discount on their bill. If their generation does not provide any offset to their maximum demand, then they will pay what they otherwise would have for these charges without their self-generation.

The method of calculating the diversity factor was established in the settlement adopted in the Commission's order in Docket Nos. 03-0640 and 03-0641, and continues to be consistent with that methodology. As approved by the Commission in Nevada Power's 2020 GRC, the diversity factor in this proceeding has been updated using the hourly billing data for all standby customers over a three-year period – in this case the calendar years of 2020, 2021 and 2022 – except for standby customers with solar generation. Standby customers with solar generation almost always use their full back-up capacity and do not receive a significant benefit from the diversity factor as it is applied to the development of the fixed and variable capacity rates in the SSR and LSR schedules. Including solar generators into the calculation tends to inappropriately affect the diversity factor for all other standby customers where the diversity factor does have a meaningful impact.

In each and every hour of this three-year period, the coincident demand of all standby customers relative to the total contract demand of these customers is determined. For each year, the hourly results are collected by TOU period, and the maximum ratio of coincident standby demand to contract demand is identified within each TOU period. The three years of maximum values are then averaged by TOU period to provide the resulting diversity factors for each TOU period. A single diversity value is then developed as a weighted average of the individual diversity factors for the TOU periods, using the TOU transmission and generation marginal demand revenue from the MCS as weights. The updated diversity factor is 26 percent, up from the 25 percent factor in current rates. Due to their usage pattern, the reduction of the contract demand was greater than the reduction in the overall max coincident demands in the calculations; thereby, creating a slight increase in the diversity factor. *See* page 2 of Workpaper 3 of Statement O for the current calculation. Statement O, page 17, also summarizes the proposed rates for the SSR and LSR schedules.

Lighting Schedules

The presentation of the development of rates for the lighting classes - SL, Residential Private Area Lighting ("RS-PAL") and Small General Service Private Area Lighting ("GS-PAL") – is the same as presented and approved in the 2020 GRC. Both the RS-PAL and GS-PAL services are unmetered, with a single flat rate structure stated on a per-lamp basis that recovers the customer, facilities, and demand and energy costs. The energy use of each lamp is derived from its rated wattage and the number of hours of operation. Rates will vary by fixture and by the type of pole on which it is mounted.

SL includes both unmetered and metered service. Unmetered service also exists for both utility-owned and customer-owned facilities. Unmetered street lighting rates are set in the same way the RS-PAL and GS-PAL rates are developed and are similarly stated on the per-lamp basis. Metered SL rates have no customer charge component, with all BTGR revenue recovered on a per kWh basis.

Pages 14 to 16 of Statement O show the proposed rates for the lighting schedules and the detail rate development is provided on pages 49-51 in Workpaper 4.

NEM Schedules

All NEM customers are treated the same for MCS and cost-based rate development. However, Statement O does differentiate between the categories of NEM customers - the grandfathered NMR-G customers (approved in the Docket No. 16-07028 stipulation), customers billed under the cost-based NMR-A and NMR-B billing structures (approved in Docket No. 15-07041), and NMR-405 customers (approved in Docket No. 17-07026) for purposes of appropriately identifying the present and proposed rate revenue for each category. The stipulation approved by the Commission in Docket No. 16-07028 grandfathered the large majority of NEM customers to the NMR-G schedule, with corresponding full-requirements rate schedules and the banking mechanism in the determination of billing determinants. With the implementation of Assembly Bill 405 (2017) through Docket No. 17-07026 that required NEM customers to be included in the rate design of the rates of their OAS counterparts, the allocation of differences in class revenue and cost-based revenue are achieved through the "Passes" tab (page 8 of Statement O). However, the separate cost of service information, which is contained in Workpaper 2 and related to NEM customers and ultimate revenue, provides information on the revenue shortfall incorporated into rates for all customer classes.

In this filing, LGS-1 NEM customers are now being separately identified from the LGS-1 class, similar to the residential and GS NEM customers. This change was made due to the increase in LGS-1 NMR-405 customers from previous cases.

Summary

The Company proposes multiple iterations of Statement O in this filing to comply with the Commission's directives stated in Nevada Power's 2020 and Sierra's 2022 GRC proceedings. The proposed rate design incorporates a $92.7 million revenue increase from present rate revenue with a 0 percent cap for single-family residential. The Company's proposal generally moves rates towards cost-based levels for all classes. Summaries of the proposed rates resulting from each rate design methodology discussed in this whitepaper are presented on pages 12 to 22 of each Statement O model. Percent change comparisons from current rates for each version are presented in Workpaper 5.

EXHIBIT PREST DIRECT - 3

Nevada Power Company

Exhibit Prest Direct-3 (Proposed)

Docket No. 23-06XXX

Statement O

Proposed - ECIC, new TOU, RS Cap

Nevada Power Company
Exhibit Prest Direct-3 (Proposed)
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- The unbundled revenue requirement from Statement H is the starting point for deriving what is known to be the revenue target for rate design.
- The following adjustments are made to the Schedule H revenue requirement on this page:
  1) The proposed revenues for the standby (LSR & SSR), Optional TOU and DOS classes are derived from rates that are developed for the otherwise applicable class; thus, the resulting standby revenues are credited against the Schedule H revenue requirement, and the standby classes are excluded from the revenue reconciliation on page 3 and the capping mechanism (page 8).
  2) Power Factor and Additional Facilities and Maintenance revenues are credited against the distribution revenue requirement, and then in the revenue reconciliation process (page 3) they are assigned to specific classes that impose these costs.

- Reconciles the Marginal Revenue by class to the Adjusted, Unbundled Revenue Requirement for Rate Design using Equal Percent of Marginal Cost (EPMC). The marginal revenue, by function and class, comes directly from the Marginal Cost Study (MCS), and is shown on page 2 of Workpaper 1. The unbundled revenue requirement comes from the Unbundled Schedule H and is summarized on line no. 11, page 1 of Statement O. The adjustments to the revenue requirement are summarized below.
- Reconcile Distribution & Transmission by Function using EPMC: Distribution Marginal Revenue to Distribution Revenue Requirement, and Transmission to Transmission.
- Reconcile Generation and Energy functions combined together on EPMC.

Revenue Adjustments made to the Reconciliation:

Distribution

1) Certain "other revenue" components (miscellaneous revenues (connect/disconnect), returned check, power pedestal, and miscellaneous damage) have been credited to the specific classes in which they are generated, consistent with the Commission's Order in Docket No. 01-10001, which was first implemented in Docket No. 03-10001. They are included in the total DRR that is reconciled, then subtracted from (i.e., credited to) the reconciled distribution revenue requirements of the specific classes that paid them. Thus classes that pay for the services get the benefit through the direct assignment to those classes. These "other revenues" total approximately $4,946.4 million.
2) Revenue from Power Factor services and Additional Facilities and Maintenance (AF&M) services are subtracted (credited to) the DRR on page 7, then get directly assigned to the classes identified with these costs in the reconciliation.

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Generation and Energy

5) The combined generation and energy revenue requirement (G&ERR) is increased by the amount of the credit given to the LGS-3T class on the BTER portion of WAPA energy deliveries associated with one customer included in the class for reconciliation purposes. The credit is then specifically assigned to (or subtracted from) the LGS-3T's reconciled G&E RR. The current WAPA energy credit is $1098.6 thousand.
6) Also, the G&ERR is increased by the amount of the Hoover B Benefit provided to the residential class. The amount of the benefit is then specifically assigned to (or subtracted from) the residential classes' G&ERR based on their relative share of residential kWh sales. The current Hoover B Benefit is $14.2 million.

Standby, Optional Time-of Use, DOS and Other Revenue Credit Adjustments

7) Standby (SSR & LSR) and Optional Time-of-Use (TOU) services have rates that are set off of the otherwise applicable classes marginal costs and/or rates. Accordingly the test period revenues generated by these schedules are treated as credits to proportionately reduce the generation, transmission and distribution revenue requirements on page 4, thereby reducing the revenue requirement and rates for all customers. The total of these revenue credits is approximately -$11.2 million.
8) DOS revenues are treated in a manner analogous to standby and optional TOU service revenues, as DOS distribution rates and non-bypassable charges are set using the otherwise applicable bundled schedule (OAS). The DOS revenues are credited against the revenue requirement, reducing rates for all customers. All DOS revenues, except the non-bypassable interclass rate rebalancing (IRR) revenues, are credited to the DRR. The IRR revenues are credited proportionately to reduce the generation, transmission and distribution revenue requirements on pages 3-7. The current DOS revenue is $31.6 million.

Page 8 **Final Revenue Allocation: Final Class Revenue Requirements Based on Maximum Percent Increase (Capping) and unrestricted floor Mechanism as follows:**

Subject to the caps set forth above:

1) The difference between any capped class revenue and its cost based revenue is re-allocated to other classes using EPMC;
2) Two allocations using the above procedure are required to reach the final revenue requirements that satisfy the imposed capping criteria;
3) The reallocation creates an interclass subsidy, which is the difference between the final revenue requirement shown on this page, and the cost-based revenue requirement resulting from the reconciliation process (page 3-7). If the difference between these two values for any class is negative, then the class is receiving a subsidy from other classes; if the value is positive, then the class is providing a subsidy to other classes.

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Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

Line No	Class	Note	Annualized Bills	Sales (MWh)	Present Rate Revenue: Revenue	Present Rate Revenue: Effective Rate ($/kWh)	Results if Class Revenue Requirements were Set @ Reconciled Cost [1]: Cost-Based Revenue	% Change from Present	Effective Rate ($/kWh)	Class Revenue Requirements Based on Proposed Capping Methodology [2]: Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present	Effective Rate ($/kWh)	Combined AB 405 Proposed Revenue Change: % Change from Present	Effective Rate ($/kWh)	Line No
8																	8
9	Classes in Revenue Reconciliation																9
10	RS		6,219,660	7,262,589	$ 1,124,472	$ 0.15483	$ 1,138,032	1.21%	$ 0.15670	$ 1,158,625	$ 20,593	$ 34,154	3.04%	$ 0.15953	3.30%	$ 0.15372	10
11	RM		3,424,968	2,298,671	339,331	0.14762	325,309	-4.13%	0.14152	343,692	18,383	4,362	1.29%	0.14952	1.29%	0.14946	11
12	LRS		2,484	37,526	5,291	0.14099	4,957	-6.31%	0.13209	5,333	376	42	0.79%	0.14210	0.87%	0.14254	12
13	GS		931,320	612,056	83,497	0.13642	77,346	-7.37%	0.12637	83,871	6,525	373	0.45%	0.13703	0.45%	0.13682	13
14	LGS-1		385,308	4,073,470	485,467	0.11918	481,054	-0.91%	0.11809	495,938	14,884	10,471	2.16%	0.12175	2.18%	0.12166	14
15	LGS-2S		14,676	2,437,061	271,383	0.11136	265,248	-2.26%	0.10884	276,033	10,785	4,649	1.71%	0.11326			15
16	LGS-2P		276	69,583	7,301	0.10492	7,045	-3.50%	0.10125	7,404	359	103	1.42%	0.10640			16
17	LGS-2T	3	-	-	-	---	-	na	---	-	-	-	na	---			17
18	LGS-3S		1,392	768,658	82,792	0.10771	80,052	-3.31%	0.10415	83,995	3,942	1,203	1.45%	0.10927			18
19	LGS-3P	4	1,332	1,826,673	195,666	0.10712	185,935	-4.97%	0.10179	197,708	11,773	2,042	1.04%	0.10823			19
20	LGS-3T	4	48	618,671	59,254	0.09578	59,086	-0.28%	0.09550	60,562	1,476	1,308	2.21%	0.09789			20
21	LGS-XS	5	-	-	-	---	-	na	---	-	-	-	na	---			21
22	LGS-XP	5	-	-	-	---	-	na	---	-	-	-	na	---			22
23	LGS-XT	5	-	-	-	---	-	na	---	-	-	-	na	---			23
24	LGS-2S-WP		276	14,878	1,343	0.09025	1,524	13.48%	0.10242	1,693	169	350	26.07%	0.11378			24
25	LGS-2P-WP		108	11,148	1,123	0.10073	1,042	-7.22%	0.09345	1,125	83	2	0.16%	0.10089			25
26	LGS-2T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			26
27	LGS-3S-WP		24	4,413	372	0.08426	456	22.72%	0.10341	530	73	158	42.48%	0.12005			27
28	LGS-3P-WP		72	19,004	1,742	0.09168	1,671	-4.13%	0.08790	1,764	94	22	1.26%	0.09284			28
29	LGS-3T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			29
30	SL		7,224	129,054	11,437	0.08862	14,682	28.37%	0.11377	17,546	2,864	6,108	53.41%	0.13595			30
31	RS-Pal		-	578	85	0.14730	96	12.33%	0.16545	106	10	21	24.45%	0.18331			31
32	GS-Pal		-	2,217	305	0.13751	350	14.80%	0.15786	393	43	88	28.90%	0.17725			32
33	IAIWP	3	-	-	-	---	-	na	---	-	-	-	na	---			33
34	RS-NEM	6	962,904	837,375	80,923	0.16928	176,304	117.87%	0.21054	86,504	(89,800)	5,581	6.90%	0.18095			34
35	RM-NEM	6	5,652	3,554	397	0.15278	774	95.23%	0.21782	403	(371)	6	1.56%	0.15515			35
36	LRS-NEM	6	204	571	92	0.16155	116	25.28%	0.20270	98	(18)	5	5.73%	0.17081			36
37	GS-NEM	6	1,548	2,985	275	0.11395	509	84.67%	0.17041	277	(232)	1	0.53%	0.11456			37
38	LGS-1 NEM	6	4,248	79,974	9,100	0.12410	11,611	27.59%	0.14518	9,388	(2,223)	288	3.17%	0.12803			38
39																	39
45	Partial Requirements & Optional Schedule Groups not included in Reconciliation																45
46	Optional TOU		66,924	447,300	48,258	0.10789	nc	nc	nc	49,314	nc	1,056	2.19%	0.11025	---	---	46
47	Optional TOU EVRR		38,052	65,465	8,716	0.13314	nc	nc	nc	9,172	nc	456	5.23%	0.14011			47
48	NEM Optional TOU		12,331	7,602	1,090	0.14340	nc	nc	nc	1,478	nc	388	35.59%	0.19445	---	---	48
49	NEM EVRR		15,156	14,179	1,759	0.12403	nc	nc	nc	2,329	nc	571	32.46%	0.16428			49
50	Standby		240	146,311	15,217	0.10400	nc	nc	nc	15,699	nc	482	3.17%	0.10730	---	---	50
51	EVCCR		156	14,835	1,829	0.12331	nc	nc	nc	1,841	nc	12	0.65%	0.12412			51
52	DOS	7	1,980	2,810,428	15,394	0.00548	nc	nc	nc	31,552	nc	16,158	104.96%	0.01123	---	---	52
53																	53
54	Total (Bundled & DOS)		12,094,315	23,793,360	$ 2,805,178	$ 0.11790	$ 2,821,587	na[1]	nc	$ 2,897,836	---	$ 92,658	3.30%	$ 0.12179	3.30%	$ 0.12179	54
55																	55

$	2,897,751	Statement I Revenue Requirement
$	92,658	Change in Revenue Requiremen $ 85
	3.30%	Percent Change

56 nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

57 1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match
58 the value when all revenues are included in the calculations.

59 2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O.
60 Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.

61 3. No Customers in class

62 4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.

63 5. All customers in class are DOS customers; no bundled customers.

64 6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G
65 customers.

66 7. The effective rate for DOS customers is only for distribution rates, and does not consider OATT and energy rates.

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Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
8								8
9	Marginal Cost Revenue		$ 2,099,905	$ 781,213	$ 524,669	$ 113,276	$ 680,747	9
10								10
11	Unbundled Revenue Requirement	1	$ 2,897,751	$ 1,718,820	$ 590,171	$ 152,792	$ 435,968	11
12						Total G, T & D	$ 1,178,931	12
13	Total Revenue Requirement Adjustments for Rate Design							13
14	Revenue Credit to Dist. for Specific Class Assignment							14
15	Power Factor (PF)		(917)				(917)	15
16	Additional Facilities and Maintenance (AF&M)		(71)				(71)	16
17								17
18	Optional TOU Revenue		(34,177)	(21,873)	(6,160)	(1,595)	(4,550)	18
19	Optional TOU NEM revenues		(3,808)	(1,833)	(989)	(256)	(730)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(2,771)	(1,697)	(538)	(139)	(397)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	-				-	21
22	DOS Decommissioning Revenue		(800)		(800)			22
23	DOS Interclass Rate-Rebalancing Revenue		(15,067)		(7,542)	(1,953)	(5,572)	23
24	OLGS-3P HLF & MPE Rate Design Revenue adjustment		576	-	289	75	213	24
25	MPE Revenue Adjustment		6,860	3,972	2,888			25
26	EVCCR Discount Revenue Adjustment		-		-	-		26
27	Total		$ (50,175)	$ (21,430)	$ (12,851)	$ (3,868)	$ (12,025)	27
28								28
29	Class Specific Revenue Requirement Adjustments							29
30	Other Revenue	4	5,368				5,368	30
31	Customer Specific Facilities		(2,816)				(2,816)	31
32	DOS Impact Fee revenue		(1,392)	(511)	(881)			32
33	BTER Energy Credits (WAPA, Hoover B)		(15,264)	(15,264)				33
34	Total Class Specific Adjustments		$ (14,104)	$ (15,775)	$ (881)	$ -	$ 2,552	34
35								35
36	Total Adjustments to Total Revenue Requirement		$ (64,279)	$ (37,205)	$ (13,733)	$ (3,868)	$ (9,473)	36
37								37
38	Target Revenue Requirement for Rate Design		$ 2,833,472	$ 1,359,358	$ 913,878	$ 148,924	$ 423,143	38
39								39

42 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing) 42
43 2. Includes LSR revenues and optional time-of-use revenues. 43
44 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 44
45 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 45
46 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure. 46

					Rate Design Revenue Adjustments										
Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Transmission Cost Based Class Revenue for Rate Design	Line No.
8															8
9	RS	$ 50,251	44.36%	$ 67,781	$ (707)	$ (114)	$ (62)	$ -	$ (866)	$ 33	$ -	$ -	$ -	$ 66,065	9
10	RM	13,031	11.50%	17,577	(183)	(29)	(16)	-	(225)	9	-	-	-	17,132	10
11	LRS	214	0.19%	288	(3)	(0)	(0)	-	(4)	0	-	-	-	281	11
12	GS	2,578	2.28%	3,477	(36)	(6)	(3)	-	(44)	2	-	-	-	3,389	12
13	LGS-1	18,289	16.15%	24,668	(257)	(41)	(22)	-	(315)	12	-	-	-	24,044	13
14	LGS-2S	9,442	8.34%	12,736	(133)	(21)	(12)	-	(163)	6	-	-	-	12,413	14
15	LGS-2P	225	0.20%	303	(3)	(1)	(0)	-	(4)	0	-	-	-	295	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	2,650	2.34%	3,575	(37)	(6)	(3)	-	(46)	2	-	-	-	3,484	17
18	LGS-3P	6,131	5.41%	8,270	(86)	(14)	(8)	-	(106)	4	-	-	-	8,061	18
19	LGS-3T	2,042	1.80%	2,754	(29)	(5)	(3)	-	(35)	1	-	-	-	2,684	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	59	0.05%	80	(1)	(0)	(0)	-	(1)	0	-	-	-	78	23
24	LGS-2P-WP	28	0.02%	38	(0)	(0)	(0)	-	(0)	0	-	-	-	37	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	14	0.01%	19	(0)	(0)	(0)	-	(0)	0	-	-	-	19	26
27	LGS-3P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	94	0.08%	127	(1)	(0)	(0)	-	(2)	0	-	-	-	124	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	-	-	-	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	-	-	-	1	31
32	IAIWP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	7,640	6.74%	10,305	(108)	(17)	(9)	-	(132)	5	-	-	-	10,044	33
34	RM-NEM	36	0.03%	48	(1)	(0)	(0)	-	(1)	0	-	-	-	47	34
35	LRS-NEM	4	0.00%	5	(0)	(0)	(0)	-	(0)	0	-	-	-	5	35
36	GS-NEM	20	0.02%	27	(0)	(0)	(0)	-	(0)	0	-	-	-	27	36
37	LGS-1-NEM	500	0.44%	674	(7)	(1)	(1)	-	(9)	0	-	-	-	657	37
38															38
39	TOTAL	$ 113,276	100.00%	$ 152,792	$ (1,595)	$ (256)	$ (139)	$ -	$ (1,953)	$ 75	$ -	$ -	$ -	$ 148,924	39
40				from Sch. H-2											40
41															41
42															42
43															43
44	Summation of NEM customers into Standard Schedule for Rate Design														44
45	RS	$ 57,891	51.11%	$ 78,086	$ (815)	$ (131)	$ (71)	$ -	$ (998)	$ 38	$ -	$ -	$ -	$ 76,109	45
46	RM	13,067	11.54%	17,625	(184)	(30)	(16)	-	(225)	9	-	-	-	17,179	46
47	LRS	217	0.19%	293	(3)	(0)	(0)	-	(4)	0	-	-	-	286	47
48	GS	2,598	2.29%	3,505	(37)	(6)	(3)	-	(45)	2	-	-	-	3,416	48
49	LGS-1	18,788	16.59%	25,343	(265)	(42)	(23)	-	(324)	12	-	-	-	24,701	49
50															50

Nevada Power Company

Statement O

Distribution Revenue by Class for Rate Design

				Class Specific Adjustments			Rate Design Revenue Adjustments												
Line No.	Class	Unreconciled Cost-Based Distribution Revenue	Percent of Total	Other Revenue Adjustment	Adjustment for Class Cust Spec. Facilities	Reconciled Distribution Revenue Requirement	Power Factor Revenue	Additional Facilities & Maintenance Revenue	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Decommissioning Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	MPE Revenue Adjustment	EVCCR Discount Revenue Adjustment	Distribution Cost Based Class Revenue for Rate Design	Line No.
8																			8
9	RS	$ 340,083	50.16%	$ (2,192)		$ 217,791	$ (460)	$ (36)	$ (2,283)	$ (366)	$ (199)	$ -	$ (401)	$ (2,795)	$ 107	$ -	$ -	$ 211,358	9
10	RM	81,994	12.09%	(2,237)		50,801	(111)	(9)	(550)	(88)	(48)	-	(97)	(674)	26	-		49,250	10
11	LRS	995	0.15%	(0)		643	(1)	(0)	(7)	(1)	(1)	-	(1)	(8)	0	-		625	11
12	GS	25,019	3.69%	(235)		15,949	(34)	(3)	(168)	(27)	(15)	-	(30)	(206)	8	-		15,475	12
13	LGS-1	87,165	12.86%	(77)		56,306	(118)	(9)	(585)	(94)	(51)	-	(103)	(716)	27	-		54,657	13
14	LGS-2S	34,624	5.11%	(2)		22,395	(47)	(4)	(232)	(37)	(20)	-	(41)	(285)	11	-		21,740	14
15	LGS-2P	856	0.13%	(0)		554	(1)	(0)	(6)	(1)	(1)	-	(1)	(7)	0	-		537	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-		-	16
17	LGS-3S	9,639	1.42%	(0)		6,235	(13)	(1)	(65)	(10)	(6)	-	(11)	(79)	3	-		6,052	17
18	LGS-3P	30,314	4.47%	(0)	-	19,609	(41)	(3)	(203)	(33)	(18)	-	(36)	(249)	10	-		19,035	18
19	LGS-3T	1,660	0.24%	(0)	1,671	2,745	(2)	(0)	(11)	(2)	(1)	-	(2)	(14)	1	-		2,713	19
20	LGS-XS	61	0.01%	-	22	61	(0)	(0)	(0)	(0)	(0)	-	(0)	(1)	0	-		60	20
21	LGS-XP	2,581	0.38%	-	645	2,314	(3)	(0)	(17)	(3)	(2)	-	(3)	(21)	1	-		2,266	21
22	LGS-XT	29	0.00%	-	369	387	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		387	22
23	LGS-2S-WP	337	0.05%	-		218	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		211	23
24	LGS-2P-WP	171	0.03%	-		110	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		107	24
25	LGS-2T-WP	20	0.00%	-	16	30	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		29	25
26	LGS-3S-WP	353	0.05%	-		228	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		222	26
27	LGS-3P-WP	654	0.10%	-		423	(1)	(0)	(4)	(1)	(0)	-	(1)	(5)	0	-		411	27
28	LGS-3T-WP	112	0.02%	-	94	166	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		164	28
29	SL	2,021	0.30%	(20)		1,287	(3)	(0)	(14)	(2)	(1)	-	(2)	(17)	1	-		1,249	29
30	RS-Pal	55	0.01%	(0)		36	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		35	30
31	GS-Pal	184	0.03%	(0)		119	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		115	31
32	IAWP	-	0.00%			-	-	-	-	-	-	-	-	-	-	-		-	32
33	RS-NEM	56,769	8.37%	(595)		36,126	(77)	(6)	(381)	(61)	(33)	-	(67)	(467)	18	-		35,052	33
34	RM-NEM	193	0.03%	(9)		116	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		112	34
35	LRS-NEM	48	0.01%	(0)		31	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		30	35
36	GS-NEM	127	0.02%	(0)		82	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		80	36
37	LGS-1-NEM	1,866	0.28%	(0)		1,206	(3)	(0)	(13)	(2)	(1)	-	(2)	(15)	1	-		1,171	37
38						not a sum													38
39	TOTAL	$ 677,931	100.00%	$ (5,368)	$ 2,816	$ 435,968	$ (917)	$ (71)	$ (4,550)	$ (730)	$ (397)	$ -	$ (800)	$ (5,572)	$ 213	$ -	$ -	$ 423,143	39
40						from Sch. H-2													40
41				exc. Specific Class adjustments		$ 438,520													41
42																			42
43						$ -													43
44	Summation of NEM customers into Standard Schedule for Rate Design																		44
45	RS	$ 396,852	58.54%	$ (2,786)	$ -	$ 253,918	$ (537)	$ (42)	$ (2,664)	$ (427)	$ (233)	$ -		$ (3,262)	$ 125	$ -	$ -	$ 246,410	45
46	RM	82,187	12.12%	(2,247)	-	50,916	(111)	(9)	(552)	(89)	(48)	-		(675)	26	-	-	49,361	46
47	LRS	1,043	0.15%	(0)	-	674	(1)	(0)	(7)	(1)	(1)	-		(9)	0	-	-	654	47
48	GS	25,146	3.71%	(235)	-	16,031	(34)	(3)	(169)	(27)	(15)	-		(207)	8	-	-	15,555	48
49	LGS-1	89,031	13.13%	(77)	-	57,512	(120)	(9)	(598)	(96)	(52)	-		(732)	28	-	-	55,828	49
50																			50

						Rate Design Revenue Adjustments											
Line No.	Class	Unreconciled Cost-Based Generation Revenue	Percent of Total	DOS R-BTER and BTER Impact Fee Revenue	Reconciled Generation Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS BTGR Impact Fee Revenue	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Generation Cost Based Class Revenue for Rate Design	Line No.
8																	8
9	RS	$ 226,699	43.21%	$ -	$ 400,457	$ (2,661)	$ (427)	$ (232)		$ (3,259)	$ 125	$ (381)		$ 1,248	$ -	$ 394,869	9
10	RM	63,525	12.11%	-	112,215	(746)	(120)	(65)		(913)	35	(107)		350	-	110,649	10
11	LRS	957	0.18%	-	1,691	(11)	(2)	(1)		(14)	1	(2)		5	-	1,668	11
12	GS	10,890	2.08%	-	19,236	(128)	(21)	(11)		(157)	6	(18)		60	-	18,968	12
13	LGS-1	82,110	15.65%	-	145,045	(964)	(155)	(84)		(1,180)	45	(138)		452	-	143,021	13
14	LGS-2S	43,951	8.38%	-	77,638	(516)	(83)	(45)		(632)	24	(74)		242	-	76,555	14
15	LGS-2P	1,075	0.20%	-	1,900	(13)	(2)	(1)		(15)	1	(2)		6	-	1,873	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	16
17	LGS-3S	12,675	2.42%	-	22,390	(149)	(24)	(13)		(182)	7	(21)		70	-	22,077	17
18	LGS-3P	29,567	5.64%	-	52,229	(347)	(56)	(30)		(425)	16	(50)		163	-	51,500	18
19	LGS-3T	9,820	1.87%	-	17,347	(115)	(19)	(10)		(141)	5	(16)		54	-	17,105	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	22
23	LGS-2S-WP	186	0.04%	-	329	(2)	(0)	(0)		(3)	0	(0)		1	-	325	23
24	LGS-2P-WP	119	0.02%	-	210	(1)	(0)	(0)		(2)	0	(0)		1	-	207	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	25
26	LGS-3S-WP	50	0.01%	-	89	(1)	(0)	(0)		(1)	0	(0)		0	-	88	26
27	LGS-3P-WP	167	0.03%	-	294	(2)	(0)	(0)		(2)	0	(0)		1	-	290	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	28
29	SL	1,895	0.36%	-	3,347	(22)	(4)	(2)		(27)	1	(3)		10	-	3,301	29
30	RS-Pal	9	0.00%	-	15	(0)	(0)	(0)		(0)	0	(0)		0	-	15	30
31	GS-Pal	33	0.01%	-	59	(0)	(0)	(0)		(0)	0	(0)		0	-	58	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	32
33	RS-NEM	38,507	7.34%	-	68,021	(452)	(73)	(39)		(554)	21	(65)		212	-	67,072	33
34	RM-NEM	177	0.03%	-	312	(2)	(0)	(0)		(3)	0	(0)		1	-	308	34
35	LRS-NEM	19	0.00%	-	33	(0)	(0)	(0)		(0)	0	(0)		0	-	33	35
36	GS-NEM	96	0.02%	-	169	(1)	(0)	(0)		(1)	0	(0)		1	-	167	36
37	LGS-1-NEM	2,142	0.41%	-	3,784	(25)	(4)	(2)		(31)	1	(4)		12	-	3,731	37
38					not a sum												38
39	TOTAL	$ 524,669	100.00%	$ -	$ 590,171	$ (6,160)	$ (989)	$ (538)		$ (7,542)	$ 289	$ (881)	$ -	$ 2,888	$ -	$ 913,878	39
40					from Sch. H-2												40
41			Generation Revenue for Rate Design $		524,669	$ (1,003,109)											41
42			w/ Specific Class adjustments $		926,810	Combined											42
43																	43
44																	44
45																	45
46	Summation of NEM customers into Standard Schedule for Rate Design																46
47	RS	$ 265,206	50.55%	$ -	$ 468,478	$ (3,114)	$ (500)	$ (272)	$ -	$ (3,812)	$ 146	$ (445)	$ -	$ 1,460	$ -	$ 461,941	47
48	RM	63,702	12.14%	-	112,527	(748)	(120)	(65)	-	(916)	35	(107)	-	351	-	110,956	48
49	LRS	976	0.19%	-	1,725	(11)	(2)	(1)	-	(14)	1	(2)	-	5	-	1,701	49
50	GS	10,986	2.09%	-	19,406	(129)	(21)	(11)	-	(158)	6	(18)	-	60	-	19,135	50
51	LGS-1	84,252	16.06%	-	148,829	(989)	(159)	(86)	-	(1,211)	46	(141)	-	464	-	146,752	51
52																	52

Nevada Power Company

Statement O

Energy Revenue by Class for Rate Design

Line No.	Class	BTER Revenue	Unreconciled Cost-Based Energy Revenue	Percent of Total	Class Specific Adjustments: Hoover B, EDRR, MPE and WAPA Credits	Class Specific Adjustments: Reconciled Energy Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Rate Design Revenue Adjustments: Optional TOU NEM revenues	Rate Design Revenue Adjustments: Standby Customer Revenue	Rate Design Revenue Adjustments: DOS Interclass Rate-Rebalancing Revenue	Rate Design Revenue Adjustments: OLGS-3P HLF Rate Design Revenue adjustment	Rate Design Revenue Adjustments: DOS R-BTER and BTER Impact Fee Revenue	Rate Design Revenue Adjustments: MPE Revenue Adjustment	Rate Design Revenue Adjustments: EVCCR Revenue Adjustment	Energy Cost Based Class Revenue for Rate Design	Excess/ Deficiency Present in BTER for Rate Design	Line No.
8																	8
9	RS	$ 611,088	$ 270,477	34.62%	$ (10,189)	$ 473,337	$ (7,573)	$ (635)	$ (588)	$ -	$ -	$ (177)	$ 1,375	$ -	$ 465,741	$ (145,347)	9
10	RM	193,415	86,098	11.02%	(3,219)	150,697	(2,411)	(202)	(187)	-	-	(56)	438	-	148,279	(45,136)	10
11	LRS	3,158	1,385	0.18%	(53)	2,423	(39)	(3)	(3)	-	-	(1)	7	-	2,384	(774)	11
12	GS	48,719	22,456	2.87%	-	40,145	(629)	(53)	(49)	-	-	(15)	114	-	39,514	(9,205)	12
13	LGS-1	324,204	147,347	18.86%	-	263,409	(4,125)	(346)	(320)	-	-	(96)	749	-	259,271	(64,933)	13
14	LGS-2S	193,969	87,965	11.26%	-	157,253	(2,463)	(206)	(191)	-	-	(58)	447	-	154,783	(39,186)	14
15	LGS-2P	5,539	2,477	0.32%	-	4,428	(69)	(6)	(5)	-	-	(2)	13	-	4,358	(1,180)	15
16	LGS-2T	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	61,185	27,851	3.57%	-	49,788	(780)	(65)	(60)	-	-	(18)	142	-	49,006	(12,179)	17
18	LGS-3P	145,403	64,832	8.30%	-	115,900	(1,815)	(152)	(141)	-	-	(42)	330	-	114,079	(31,324)	18
19	LGS-3T	49,246	22,104	2.83%	(1,099)	38,417	(619)	(52)	(48)	-	-	(14)	112	-	37,796	(11,450)	19
20	LGS-XS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	1,184	531	0.07%	-	949	(15)	(1)	(1)	-	-	(0)	3	-	935	(250)	23
24	LGS-2P-WP	887	392	0.05%	-	700	(11)	(1)	(1)	-	-	(0)	2	-	689	(198)	24
25	LGS-2T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	351	170	0.02%	-	304	(5)	(0)	(0)	-	-	(0)	1	-	300	(52)	26
27	LGS-3P-WP	1,513	691	0.09%	-	1,235	(19)	(2)	(2)	-	-	(0)	4	-	1,216	(297)	27
28	LGS-3T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	10,273	5,688	0.73%	-	10,168	(159)	(13)	(12)	-	-	(4)	29	-	10,009	(264)	29
30	RS-Pal	49	26	0.00%	-	47	(1)	(0)	(0)	-	-	(0)	0	-	46	(3)	30
31	GS-Pal	177	100	0.01%	-	179	(3)	(0)	(0)	-	-	(0)	1	-	176	(1)	31
32	IAIWP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	40,228	36,847	4.72%	(700)	65,171	(1,032)	(86)	(80)	-	-	(24)	187	-	64,136	23,908	33
34	RM-NEM	218	177	0.02%	(4)	312	(5)	(0)	(0)	-	-	(0)	1	-	307	89	34
35	LRS-NEM	48	28	0.00%	(1)	48	(1)	(0)	(0)	-	-	(0)	0	-	48	(0)	35
36	GS-NEM	192	134	0.02%		239	(4)	(0)	(0)	-	-	(0)	1	-	235	43	36
37	LGS-1-NEM	5,837	3,439	0.44%		6,148	(96)	(8)	(7)	-	-	(2)	17	-	6,052	215	37
38						not a sum											38
39	TOTAL	$ 1,696,883	$ 781,213	100.00%	$ (15,264)	$ 1,718,820	$ (21,873)	$ (1,833)	$ (1,697)	$ -	$ -	$ (511)	$ 3,972	$ -	$ 1,359,358	$ (337,525)	39
40						from Sch. H-2											40
41					Energy Revenue for Rate Design	781,225	$(1,003,109)										41
42					w/ Specific Class adjustments $	1,396,563											42
43																	43
44																	44
45	Summation of NEM customers into Standard Schedule for Rate Design																45
46	RS	$ 651,316	$ 307,323	39.34%	$ (10,889)	$ 538,508	$ (8,605)	$ (721)	$ (668)	$ -	$ -	$ (201)	$ 1,563	$ -	$ 529,877	$ (121,439)	46
47	RM	193,633	86,275	11.04%	(3,222)	151,010	(2,416)	(202)	(187)	-	-	(56)	439	-	148,587	(45,047)	47
48	LRS	3,206	1,412	0.18%	(53)	2,471	(40)	(3)	(3)	-	-	(1)	7	-	2,432	(774)	48
49	GS	48,912	22,590	2.89%	-	40,384	(632)	(53)	(49)	-	-	(15)	115	-	39,749	(9,162)	49
50	LGS-1	330,041	150,786	19.30%	-	269,558	(4,222)	(354)	(328)	-	-	(99)	767	-	265,322	(64,718)	50
51																	51

Nevada Power Company
Statement O

Class Revenue Results Summary

			Cost Based Class Revenue by Function															
Line No.	Class	Sales (MWh)	Distribution	Transmission	Generation	Energy/ variable	Subtotal	Power Factor Revenue	Additional Facilities & Maintenance Revenue	Exc. DOS Cost Revenue	Sum of Functional Cost Based Class Revenue for Rate Design	Interclass Rate Rebalancing Revenue	Capped Class Revenue Requirement	Revenue Proof	Percent of Total	Difference from Capped Revenue Requirement (Rounding)	Overall Effective Rate	Line No.
8																		8
9	RS	7,262,589	$ 211,358	$ 66,065	$ 394,869	$ 465,741	$ 1,138,032	$ -	$ -		$ 1,138,032	$ (64,928)	$ 1,158,668	$ 1,158,625	40.9%	$ (7)	$ 0.15954	9
10	RM	2,298,671	49,250	17,132	110,649	148,279	325,309	-	-		325,309	17,999	343,702	343,692	12.1%	(7)	0.14952	10
11	LRS	37,526	625	281	1,668	2,384	4,957	-	-		4,957	351	5,332	5,333	0.2%	0	0.14208	11
12	GS	612,056	15,475	3,389	18,968	39,514	77,347	-	-	1	77,346	6,347	83,947	83,871	3.0%	1	0.13716	12
13	LGS-1	4,073,470	54,657	24,044	143,021	259,271	480,993	133	1	74	481,054	12,464	495,971	495,942	17.5%	(29)	0.12176	13
14	LGS-2S	2,437,061	21,740	12,413	76,555	154,783	265,491	349	-	592	265,248	10,796	276,053	276,033	9.7%	(20)	0.11327	14
15	LGS-2P	69,583	537	295	1,873	4,358	7,064	6	-	26	7,045	359	7,404	7,404	0.3%	(0)	0.10640	15
16	LGS-2T	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	16
17	LGS-3S	768,658	6,052	3,484	22,077	49,006	80,620	88	-	656	80,052	3,950	84,003	83,995	3.0%	(8)	0.10928	17
18	LGS-3P	1,826,673	19,035	8,061	51,500	114,079	192,675	226	70	7,035	185,935	11,792	197,727	197,693	7.0%	(34)	0.10824	18
19	LGS-3T	618,671	2,713	2,684	17,105	37,796	60,298	20	-	1,233	59,086	1,476	60,562	60,562	2.1%	0	0.09789	19
20	LGS-XS	-	60	-	-	-	60	2	-	63	-	-	-	-	0.0%	-	---	20
21	LGS-XP	-	2,266	-	-	-	2,266	65	-	2,331	-	-	-	-	0.0%	-	---	21
22	LGS-XT	-	387	-	-	-	387	2	-	389	-	-	-	-	0.0%	-	---	22
23	LGS-2S-WP	14,878	211	78	325	935	1,548	4	-	28	1,524	175	1,699	1,693	0.1%	(6)	0.11420	23
24	LGS-2P-WP	11,148	107	37	207	689	1,040	2	-	-	1,042	87	1,129	1,125	0.0%	(4)	0.10123	24
25	LGS-2T-WP	-	29	-	-	-	29	-	-	29	-	-	-	-	0.0%	-	---	25
26	LGS-3S-WP	4,413	222	19	88	300	628	6	-	178	456	76	532	530	0.0%	(3)	0.12063	26
27	LGS-3P-WP	19,004	411	36	290	1,216	1,953	12	-	295	1,671	94	1,764	1,764	0.1%	0	0.09284	27
28	LGS-3T-WP	-	164	-	-	-	164	0	-	164	-	-	-	-	0.0%	-	---	28
29	SL	129,054	1,249	124	3,301	10,009	14,682	-	-		14,682	2,854	17,536	17,546	0.6%	9	0.13588	29
30	RS-Pal	578	35	0	15	46	96	-	-		96	10	106	106	0.0%	(0)	0.18332	30
31	GS-Pal	2,217	115	1	58	176	350	-	-		350	43	393	393	0.0%	(0)	0.17727	31
32	IAIWP	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	32
33	RS-NEM	478,046	35,052	10,044	67,072	64,136	176,304	-	-		176,304	(4,274)	86,504	86,504	3.1%	---	0.18095	33
34	RM-NEM	2,596	112	47	308	307	774	-	-		774	20	403	403	0.0%	---	0.15515	34
35	LRS-NEM	571	30	5	33	48	116	-	-		116	5	98	98	0.0%	---	0.17081	35
36	GS-NEM	2,417	80	27	167	235	509	-	-		509	25	277	277	0.0%	---	0.11456	36
37	LGS-1-NEM	73,329	1,171	657	3,731	6,052	11,611	-	-		11,611	224	9,388	9,388	0.3%	---	0.12803	37
38																		38
39	TOTAL	20,743,210	$ 423,143	$ 148,924	$ 913,878	$ 1,359,358		$ 917	$ 71	$ 13,094	$ 2,833,197	$ (53)	$ 2,833,197	$ 2,832,975	100.0%	$ (106)	$ 0.13658	39
40																		40
41																		41
42																		42
43																		43
44	Summation of NEM customers into Standard Schedule for Rate Design																	44
45	RS	7,740,635	$ 246,410	$ 76,109	$ 461,941	$ 529,877	$ 1,314,337	$ -	$ -	$ -	$ 1,314,337	$ (69,201)	$ 1,245,172	$ 1,245,129	44.0%	$ (7)	$ 0.16086	45
46	RM	2,301,267	49,361	17,179	110,956	148,587	326,084	-	-	-	326,084	18,019	344,105	344,095	12.1%	(7)	0.14953	46
47	LRS	38,097	654	286	1,701	2,432	5,072	-	-	-	5,072	357	5,429	5,430	0.2%	0	0.14251	47
48	GS	614,473	15,555	3,416	19,135	39,749	77,855	-	-	1	77,855	6,372	84,224	84,148	3.0%	1	0.13707	48
49	LGS-1	4,146,799	55,828	24,701	146,752	265,322	492,604	133	1	74	492,664	12,688	505,360	505,330	17.8%	(29)	0.12187	49

Nevada Power Company
Statement O

Class Revenue Adjustments Due to Cap & Floor Criteria (1)

Exhibit Prest Direct-3 (Proposed)
Docket No. 23-06XXX
Proposed - ECIC, new TOU, RS Cap
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Line No.	Class	Present Rate Revenue	AB 405 Present Rate Revenue	Total Class Revenue Requirement: Sum of Functional Cost Based Class Revenue	Percent of Total	AB 405 Cost Based Class Revenue	Percent of Total	% change over Present Rate Revenue	AB405 Cost-Based Pct change over Present Rate Revenue	First Allocation - Cap: Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.
9	RS	$ 1,124,472	$ 1,205,394	$ 1,138,032	40.17%	$ 1,314,337	46.39%	1.21%	9.04%	Capped	3.30%	$ 1,245,172	$ 69,164	$ -	$ -	0.00%	$ -	1,245,172	3.30%	9
10	RM	339,331	339,727	325,309	11.48%	326,084	11.51%	-4.13%	-4.02%	-	-4.02%	326,084	-	326,084	(13,643)	26.06%	18,021	344,105	1.29%	10
11	LRS	5,291	5,383	4,957	0.17%	5,072	0.18%	-6.31%	-5.77%	-	-5.77%	5,072	-	5,072	(311)	0.52%	357	5,429	0.86%	11
12	GS	83,497	83,773	77,346	2.73%	77,855	2.75%	-7.37%	-7.06%	-	-7.06%	77,855	-	77,855	(5,918)	9.21%	6,369	84,224	0.54%	12
13	LGS-1	485,467	494,567	481,054	16.98%	492,664	17.39%	-0.91%	-0.38%	-	-0.38%	492,664	-	492,664	(1,903)	18.36%	12,695	505,360	2.18%	13
14	LGS-2S	271,383	271,383	265,248	9.36%	265,248	9.36%	-2.26%	-2.26%	-	-2.26%	265,248	-	265,248	(6,136)	15.62%	10,805	276,053	1.72%	14
15	LGS-2P	7,301	7,301	7,045	0.25%	7,045	0.25%	-3.50%	-3.50%	-	-3.50%	7,045	-	7,045	(256)	0.52%	359	7,404	1.42%	15
16	LGS-2T				0.00%		0.00%						-			0.00%	-			16
17	LGS-3S	82,792	82,792	80,052	2.83%	80,052	2.83%	-3.31%	-3.31%	-	-3.31%	80,052	-	80,052	(2,739)	5.71%	3,950	84,003	1.46%	17
18	LGS-3P	195,666	195,666	185,935	6.56%	185,935	6.56%	-4.97%	-4.97%	-	-4.97%	185,935	-	185,935	(9,731)	17.05%	11,792	197,727	1.05%	18
19	LGS-3T	59,254	59,254	59,086	2.09%	59,086	2.09%	-0.28%	-0.28%	-	-0.28%	59,086	-	59,086	(168)	2.13%	1,476	60,562	2.21%	19
20	LGS-XS				0.00%		0.00%									0.00%				20
21	LGS-XP				0.00%		0.00%									0.00%				21
22	LGS-XT				0.00%		0.00%									0.00%				22
23	LGS-2S-WP	1,343	1,343	1,524	0.05%	1,524	0.05%	13.48%	13.48%	-	13.48%	1,524	-	1,524	181	0.25%	175	1,699	26.53%	23
24	LGS-2P-WP	1,123	1,123	1,042	0.04%	1,042	0.04%	-7.22%	-7.22%	-	-7.22%	1,042	-	1,042	(81)	0.13%	87	1,129	0.50%	24
25	LGS-2T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			25
26	LGS-3S-WP	372	372	456	0.02%	456	0.02%	22.72%	22.72%	-	22.72%	456	-	456	84	0.11%	76	532	43.16%	26
27	LGS-3P-WP	1,742	1,742	1,671	0.06%	1,671	0.06%	-4.13%	-4.13%	-	-4.13%	1,671	-	1,671	(72)	0.14%	94	1,764	1.26%	27
28	LGS-3T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			28
29	SL	11,437	11,437	14,682	0.52%	14,682	0.52%	28.37%	28.37%	-	28.37%	14,682	-	14,682	3,245	4.13%	2,854	17,536	53.33%	29
30	RS-Pal	85	85	96	0.00%	96	0.00%	12.33%	12.33%	-	12.33%	96	-	96	10	0.01%	10	106	24.46%	30
31	GS-Pal	305	305	350	0.01%	350	0.01%	14.80%	14.80%	-	14.80%	350	-	350	45	0.06%	43	393	28.91%	31
32	IAIWP			-																32
33	RS-NEM	80,923	inc in Full Req Class	176,304	6.22%	inc in Full Req Class		117.87%	inc in Full Req Class											33
34	RM-NEM	397	inc in Full Req Class	774	0.03%	inc in Full Req Class		95.23%	inc in Full Req Class											34
35	LRS-NEM	92	inc in Full Req Class	116	0.00%	inc in Full Req Class		25.28%	inc in Full Req Class											35
36	GS-NEM	275	inc in Full Req Class	509	0.02%	inc in Full Req Class		84.67%	inc in Full Req Class											36
37	LGS-1-NEM	9,100	inc in Full Req Class	11,611	0.41%	inc in Full Req Class		27.59%	inc in Full Req Class											37
38		Not a Sum:		Not a sum:				Overall Increase:												38
39	Total	$ 2,805,178		$ 2,897,751	100.00%	$ 2,897,751	100.00%	3.30%				$ 2,764,033	$ 69,164	$ 1,518,861	$ 44,524	100%	$ 69,164			39
40		$ 2,761,648		$ 2,833,197	=sum=	$ 2,833,197		$ 92,572												40
41			$ 64,553	<Rev Credits: Revenue Credits exc. PF and AF&M revenues																41
42																				42

/--Second Allocation--/

Line No.	Class	Class Revenue Requirement, after 1st Allocation	Pct Change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement	% change over Present Rate Revenue	Final Class Revenue Allocation: Capped Class Revenue Requirement	% change over Present Rate Revenue	Difference from Cost	Line No.
50	RS	$ 1,245,172	3.30%	Capped	3.30%	$ 1,245,172	$ -	$ 1,245,172	$ -	0.00%	$ -	$ 1,245,172	3.30%	$ 1,245,172	3.30%	$ (69,164)	50
51	RM	344,105	1.29%	-	1.29%	$ 344,105	$ -	$ 344,105	$ 4,378	13.78%	0	$ 344,105	1.29%	344,105	1.29%	18,021	51
52	LRS	5,429	0.86%	-	0.86%	$ 5,429	$ -	$ 5,429	$ 46	0.15%	0	$ 5,429	0.86%	5,429	0.86%	357	52
53	GS	84,224	0.54%	-	0.54%	$ 84,224	$ 0	$ -	$ 451	1.42%	0	$ 84,224	0.54%	84,224	0.54%	6,369	53
54	LGS-1	505,360	2.18%	-	2.18%	$ 505,360	$ -	$ 505,360	$ 10,792	33.97%	0	$ 505,360	2.18%	505,360	2.18%	12,695	54
55	LGS-2S	276,053	1.72%	-	1.72%	$ 276,053	$ -	$ 276,053	$ 4,669	14.70%	0	$ 276,053	1.72%	276,053	1.72%	10,805	55
56	LGS-2P	7,404	1.42%	-	1.42%	$ 7,404	$ (0)	$ -	$ 103	0.33%	0	$ 7,404	1.42%	7,404	1.42%	359	56
57	LGS-2T									0.00%	-	$ -		-		-	57
58	LGS-3S	84,003	1.46%	-	1.46%	$ 84,003	$ -	$ 84,003	$ 1,211	3.81%	0	$ 84,003	1.46%	84,003	1.46%	3,950	58
59	LGS-3P	197,727	1.05%	-	1.05%	$ 197,727	$ (0)	$ -	$ 2,061	6.49%	0	$ 197,727	1.05%	197,727	1.05%	11,792	59
60	LGS-3T	60,562	2.21%	-	2.21%	$ 60,562	$ -	$ 60,562	$ 1,308	4.12%	0	$ 60,562	2.21%	60,562	2.21%	1,476	60
61	LGS-XS									0.00%	-			-		-	61
62	LGS-XP									0.00%	-			-		-	62
63	LGS-XT									0.00%	-			-		-	63
64	LGS-2S-WP	1,699	26.53%	-	26.53%	$ 1,699	$ -	$ 1,699	$ 356	1.12%	0	$ 1,699	26.53%	1,699	26.53%	175	64
65	LGS-2P-WP	1,129	0.50%	-	0.50%	$ 1,129	$ -	$ 1,129	$ 6	0.02%	0	$ 1,129	0.50%	1,129	0.50%	87	65
66	LGS-2T-WP							$ -	$ -	0.00%	-			-		-	66
67	LGS-3S-WP	532	43.16%	-	43.16%	$ 532	$ -	$ 532	$ 160	0.51%	0	$ 532	43.16%	532	43.16%	76	67
68	LGS-3P-WP	1,764	1.26%	-	1.26%	$ 1,764	$ -	$ 1,764	$ 22	0.07%	0	$ 1,764	1.26%	1,764	1.26%	94	68
69	LGS-3T-WP							$ -	$ -	0.00%	-			-		-	69
70	SL	17,536	53.33%	-	53.33%	$ 17,536	$ -	$ 17,536	$ 6,099	19.20%	0	$ 17,536	53.33%	17,536	53.33%	2,854	70
71	RS-Pal	106	24.46%	-	24.46%	$ 106	$ -	$ 106	$ 21	0.07%	0	$ 106	24.46%	106	24.46%	10	71
72	GS-Pal	393	28.91%	-	28.91%	$ 393	$ -	$ 393	$ 88	0.28%	0	$ 393	28.91%	393	28.91%	43	72
73	IAIWP													-		-	73
74	RS-NEM	inc in Full Req Class															74
75	RM-NEM	inc in Full Req Class															75
76	LRS-NEM	inc in Full Req Class															76
77	GS-NEM	inc in Full Req Class															77
78	LGS-1-NEM	inc in Full Req Class															78
79																	79
80	Total						$ 0	$ 2,543,843	$ 31,772	100.0%	$ 0	$ 2,833,197		$ 2,833,197			80
81														$ -			81

81 (1) Increases in rates cannot exceed the total average percentage increase in rates. For example, a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates,
82 may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.
83 (2) NEM classes include all customers under NMR-G and NMR-A rate schedules.

Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

Line No.	Classes[1]	Bundled kWh Sales	DOS kWh Sales	Total kWh Sales	Sum of Functional Cost Based Class Revenue	Capped Class Revenue Requirement	Interclass Subsidy (difference)	Subsidy Component per kWh	Rounding	Note	Line No.
8	RS	7,262,588,952		7,740,635,272	$ 1,314,337	$ 1,245,172	$ (69,164)	$ (0.00894)	$ (37)		8
9	RM	2,298,671,171		2,301,266,943	326,084	344,105	18,021	0.00783	(2)		9
10	LRS	37,525,901		38,097,297	5,072	5,429	357	0.00936	(0)		10
11	GS	612,055,594		614,472,857	77,855	84,224	6,369	0.01037	3		11
12	LGS-1	4,073,469,942		4,146,798,580	492,664	505,360	12,695	0.00306	(6)		12
13	LGS-2S	2,437,060,885		2,437,060,885	265,248	276,053	10,805	0.00443	(9)		13
14	LGS-2P	69,583,297		69,583,297	7,045	7,404	359	0.00516	0		14
15	LGS-2T	-		-	-	-	-	0.00306	-	<<Set equal to LGS-1>>	15
16	LGS-3S	768,658,032		768,658,032	80,052	84,003	3,950	0.00514	1		16
17	LGS-3P	1,826,672,960		1,826,672,959.93	185,935	197,727	11,792	0.00646	9		17
18	LGS-3T	618,671,150		618,671,150	59,086	60,562	1,476	0.00239	2		18
19	LGS-XS	-		-	-	-	-	0.00514	-	<<Set equal to LGS-XS DOS>>	19
20	LGS-XP	-		-	-	-	-	0.00646	-	<<Set equal to LGS-XP DOS>>	20
21	LGS-XT	-		-	-	-	-	0.00239	-	<<Set equal to LGS-XT DOS>>	21
22	LGS-2S-WP	14,877,558		14,877,558	1,524	1,699	175	0.01178	0		22
23	LGS-2P-WP	11,147,772		11,147,772	1,042	1,129	87	0.00778	0		23
24	LGS-2T-WP	-		-	-	-	-	0.00873	-	<<Set equal to LGS-2T WP DOS>>	24
25	LGS-3S-WP	4,412,814		4,412,814	456	532	76	0.01722	(0)		25
26	LGS-3P-WP	19,004,483		19,004,483	1,671	1,764	94	0.00494	(0)		26
27	LGS-3T-WP	-		-	-	-	-	0.00873	-	<<Set equal to LGS-3T WP DOS>>	27
28	SL	129,054,441		129,054,441	14,682	17,536	2,854	0.02212	0		28
29	RS-Pal	578,040		578,040	96	106	10	0.01787	(0)		29
30	GS-Pal	2,217,456		2,217,456	350	393	43	0.01940	(0)		30
31	IAIWP	-		na	-	-	-	na	---		31
32	RS-NEM	478,046,320		inc in Full Req Class							32
33	RM-NEM	2,595,772		inc in Full Req Class							33
34	LRS-NEM	571,396		inc in Full Req Class							34
35	GS-NEM	2,417,263		inc in Full Req Class							35
36	LGS-1 -NEM	73,328,638		inc in Full Req Class							36
37											37
38	Bundled TOTAL	20,743,209,837		20,743,209,837	$ 2,833,197	$ 2,833,197	$ 0			<< Subsidy amount prior to RevReq adjustment when maintaining current rates.	38
39											39
40	**DISTRIBUTION ONLY SERVICE CLASSES -- SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)[2]**										40
41	DOS: GS		51,413	na	na	na	na	$ 0.01037		<<Set equal to GS>>	41
42	DOS: LGS-1		7,843,178	na	na	na	na	0.00306		<<Set equal to LGS-1>>	42
43	DOS: LGS-2S		82,487,915	na	na	na	na	0.00443		<<Set equal to LGS-2S>>	43
44	DOS: LGS-2P		4,487,342	na	na	na	na	0.00516		<<Set equal to LGS-2P>>	44
45	DOS: LGS-2T		-	na	na	na	na	0.00306		<<Set equal to LGS-2T>>	45
46	DOS: LGS-3S		85,826,485	na	na	na	na	0.00514		<<Set equal to LGS-3S>>	46
47	DOS: LGS-3P		1,414,522,800	na	na	na	na	0.00646		<<Set equal to LGS-3P>>	47
48	DOS: LGS-3T		591,977,970	na	na	na	na	0.00239		<<Set equal to LGS-3T>>	48
49	DOS: LGS-XS		7,153,043	na	na	na	na	0.00514		<<Set to 0.00001 or Current x 94%>>	49
50	DOS: LGS-XP		287,352,976	na	na	na	na	0.00646		<<Set to 0.00001 or Current x 94%>>	50
51	DOS: LGS-XT		165,618,096	na	na	na	na	0.00239		<<Set to 0.00001 or Current x 94%>>	51
52	DOS: LGS-2S-WP		4,841,057	na	na	na	na	0.01178		<<Set equal to LGS-2S-WP>>	52
53	DOS: LGS-2P-WP		-	na	na	na	na	0.00778		<<Set equal to LGS-2P-WP>>	53
54	DOS: LGS-2T-WP		1,889,274	na	na	na	na	0.00873		<<Set to 0.00001 or Current x 94%>>	54
55	DOS: LGS-3S-WP		25,647,446	na	na	na	na	0.01722		<<Set equal to LGS-3S-WP>>	55
56	DOS: LGS-3P-WP		75,371,524	na	na	na	na	0.00494		<<Set equal to LGS-3P-WP>>	56
57	DOS: LGS-3T-WP		55,357,230	na	na	na	na	0.00873		<<Set to 0.00001 or Current x 94%>>	57
58											58

59 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2). 59

60 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes. 60

Line No	Class	Sales (kWh)	BTGR Revenue Present	BTGR Revenue Proposed	Percent Change	BTGR & BTER[1] Revenue Present	BTGR & BTER[1] Revenue Proposed	Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed	Percent Change	Line No
8	RS	7,262,588,952	$ 513,383,508	$ 547,537,018	6.65%	$ 1,124,471,607	$ 1,158,625,117	3.04%	$ 1,284,192,975	$ 1,318,346,485	2.66%	8
9	RM	2,298,671,171	145,915,631	150,277,397	2.99%	339,330,523	343,692,289	1.29%	389,356,065	393,717,832	1.12%	9
10	LRS	37,525,901	2,132,970	2,174,752	1.96%	5,290,775	5,332,557	0.79%	6,096,455	6,138,237	0.69%	10
11	GS	612,055,143	34,777,894	35,151,288	1.07%	83,497,092	83,870,486	0.45%	94,978,182	95,351,576	0.39%	11
12	LGS-1	4,073,133,716	161,250,916	171,720,817	6.49%	485,427,795	495,897,696	2.16%	562,024,412	572,494,313	1.86%	12
13	LGS-2S	2,429,180,261	77,189,770	81,806,072	5.98%	270,531,139	275,147,441	1.71%	315,956,810	320,573,111	1.46%	13
14	LGS-2P	69,583,297	1,761,763	1,865,086	5.86%	7,300,593	7,403,916	1.42%	8,588,581	8,691,904	1.20%	14
15	LGS-2T	-	-	-	na	-	-	na	-	-	na	15
16	LGS-3S	768,658,032	21,606,500	22,809,454	5.57%	82,791,679	83,994,633	1.45%	97,127,152	98,330,106	1.24%	16
17	LGS-3P	1,393,295,183	39,586,638	40,912,754	3.35%	150,492,935	151,819,051	0.88%	176,700,817	178,026,934	0.75%	17
18	LGS-3T	247,665,929	4,377,192	4,764,425	8.85%	24,091,400	24,478,633	1.61%	28,658,360	29,045,593	1.35%	18
19	LGS-XS	-	-	-	na	-	-	na	-	-	na	19
20	LGS-XP	-	-	-	na	-	-	na	-	-	na	20
21	LGS-XT	-	-	-	na	-	-	na	-	-	na	21
22	LGS-2S-WP	14,877,558	158,497	508,556	220.86%	1,342,751	1,692,810	26.07%	1,623,788	1,973,847	21.56%	22
23	LGS-2P-WP	11,147,772	235,565	237,334	0.75%	1,122,928	1,124,697	0.16%	1,327,601	1,329,370	0.13%	23
24	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	24
25	LGS-3S-WP	4,412,814	20,575	178,520	767.65%	371,835	529,780	42.48%	451,353	609,298	34.99%	25
26	LGS-3P-WP	19,004,483	229,669	251,652	9.57%	1,742,426	1,764,409	1.26%	2,087,357	2,109,340	1.05%	26
27	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	27
28	SL	129,054,441	1,164,568	7,272,792	524.51%	11,437,302	17,545,526	53.41%	13,840,296	19,948,520	44.13%	28
29	RS-Pal	578,040	36,501	57,319	57.03%	85,143	105,961	24.45%	97,306	118,123	21.39%	29
30	GS-Pal	2,217,456	128,415	216,539	68.62%	304,924	393,048	28.90%	345,791	433,915	25.48%	30
31	IAIWP	-	-	-	na	-	-	na	-	-	na	31
32	**Optional Time of Use**											32
33	ORS-TOU	9,396,344	478,100	596,972	24.86%	1,268,289	1,387,161	9.37%	1,473,445	1,592,317	8.07%	33
34	ORS-TOU OPT A	21,030,431	1,250,839	1,453,471	16.20%	3,020,046	3,222,678	6.71%	3,481,412	3,684,045	5.82%	34
35	ORS-TOU OPT B	4,239,586	173,888	234,774	35.01%	530,649	591,535	11.47%	624,004	684,890	9.76%	35
39	ORM-TOU	873,422	49,455	55,269	11.76%	122,872	128,686	4.73%	141,630	147,444	4.11%	39
40	ORM-TOU OPT A	718,287	45,450	48,919	7.63%	105,894	109,363	3.28%	121,546	125,015	2.85%	40
41	ORM-TOU OPT B	70,254	4,084	4,426	8.37%	9,996	10,338	3.42%	11,526	11,868	2.97%	41
42	ORM-TOU DDP	9,561	414	404	-2.37%	1,170	1,160	-0.84%	1,211	1,201	-0.81%	42
51	OGS-TOU	27,565,080	1,261,147	1,275,867	1.17%	3,455,327	3,470,047	0.43%	3,972,448	3,987,168	0.37%	51
52	OLGS-1 TOU	124,787,383	3,997,063	4,310,005	7.83%	13,930,139	14,243,081	2.25%	16,277,390	16,590,332	1.92%	52
53	OLGS-3P-HLF	258,609,361	5,228,244	5,564,601	6.43%	25,813,549	26,149,906	1.30%	30,677,991	31,014,348	1.10%	53
54	**Optional Time of Use EVRR**											54
55	ORS-TOU EVRR	52,516,143	2,615,103	2,982,251	14.04%	7,033,504	7,400,652	5.22%	8,187,065	8,554,213	4.48%	55
56	ORS-TOU Opt A EVRR	6,627,577	342,755	375,546	9.57%	900,466	933,257	3.64%	1,046,406	1,079,197	3.13%	56
57	ORS-TOU Opt B EVRR	4,621,440	160,839	211,595	31.56%	549,733	600,489	9.23%	651,497	702,253	7.79%	57
60	ORM-TOU EVRR	1,289,179	67,312	72,277	7.38%	175,686	180,651	2.83%	203,405	208,370	2.44%	60
61	ORM-TOU OPT A EVRR	60,410	3,580	3,498	-2.29%	8,664	8,582	-0.95%	9,980	9,898	-0.82%	61
62	ORM-TOU OPT B EVRR	29,643	1,740	1,840	5.76%	4,234	4,334	2.37%	4,881	4,981	2.05%	62
65	OLRS-TOU EVRR	299,866	14,816	15,238	2.85%	40,050	40,472	1.05%	46,488	46,910	0.91%	65
70	OGS-TOU EVRR	20,511	1,899	1,905	0.33%	3,532	3,538	0.18%	3,917	3,923	0.16%	70
71	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	71
72	**Net Metering:**											72
73	RS-NEM	478,046,320	40,695,177	46,276,602	13.72%	80,922,775	86,504,200	6.90%	91,449,355	97,030,780	6.10%	73
74	RM-NEM	2,595,772	178,138	184,312	3.47%	396,572	402,746	1.56%	453,135	459,309	1.36%	74
75	LRS-NEM	571,396	44,227	49,516	11.96%	92,310	97,599	5.73%	104,579	109,868	5.06%	75
76	GS-NEM	2,417,263	83,034	84,507	1.77%	275,449	276,922	0.53%	320,798	322,270	0.46%	76
77	LGS-1 NEM	73,328,638	3,263,161	3,551,195	8.83%	9,100,120	9,388,154	3.17%	10,479,431	10,767,465	2.75%	77
78	ORS-NEM	3,324,908	177,128	352,762	99.16%	456,919	632,553	38.44%	530,133	705,767	33.13%	78
79	ORS-NEM OPT A	4,057,523	260,478	464,202	78.21%	601,919	805,643	33.85%	691,267	894,991	29.47%	79
80	ORS-NEM OPT B	218,046	12,617	21,295	68.78%	30,965	39,643	28.02%	35,766	44,444	24.26%	80
84	ORM-NEM	1,460	220	203	-7.62%	343	326	-4.89%	374	357	-4.48%	84
97	**NEM EVRR**											97
98	ORS-NEM EVRR	11,862,176	478,864	963,755	101.26%	1,477,066	1,961,957	32.83%	1,738,271	2,223,162	27.90%	98
99	ORS-NEM OPT A EVRR	1,879,925	67,276	143,153	112.78%	225,472	301,349	33.65%	266,867	342,744	28.43%	99
100	ORS-NEM OPT B EVRR	411,121	18,066	27,785	53.80%	52,661	62,380	18.46%	61,715	71,434	15.75%	100
103	ORM-NEM EVRR	25,756	1,240	1,539	24.14%	3,407	3,706	8.78%	3,968	4,267	7.54%	103
114	**Standby**											114
116	SSR - GS	-	-	-	na	-	-	na	-	-	na	116
117	SSR - LGS-1	1,130,064	54,212	60,057	10.78%	144,165	150,010	4.05%	165,421	171,265	3.53%	117
118	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	118
119	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	119
120	LSR - LGS-2T	9,583,450	159,003	296,677	86.59%	921,846	1,059,520	14.93%	1,099,236	1,236,910	12.52%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	26,274,564	868,679	937,704	7.95%	2,960,134	3,029,159	2.33%	3,454,358	3,523,383	2.00%	122
123	LSR - LGS-3T	109,322,768	2,488,706	2,757,809	10.81%	11,190,798	11,459,901	2.40%	13,206,710	13,475,814	2.04%	123
133	**EVCCR**											133
134	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	134
135	LGS-2S EVCCR	14,835,492	648,508	660,475	1.85%	1,829,413	1,841,380	0.65%	2,106,836	2,118,803	0.57%	135
136	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	136
137	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	137
138	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	138
139	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	139
140	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	140
147												147
148	**TOTAL Bundled**	21,055,299,880	$ 1,071,470,793	$ 1,147,970,728	7.14%	$ 2,789,783,845	$ 2,866,283,780	2.74%	$ 3,210,501,292	$ 3,287,001,228	2.38%	148
149	Residential	10,204,140,610	$ 708,610,416	$ 754,588,089	6.49%	$ 1,567,209,710	$ 1,613,187,383	2.93%	$ 1,791,082,729	$ 1,837,060,402	2.57%	149
150	Non-Residential	10,851,159,270	$ 362,860,377	$ 393,382,639	8.41%	$ 1,222,574,135	$ 1,253,096,397	2.50%	$ 1,419,418,564	$ 1,449,940,826	2.15%	150
151												151
152	**DISTRIBUTION ONLY SERVICE (DOS)[3]**											152
153	GS-DOS	51,413	$ 3,947	$ 3,899	-1.21%	$ 3,947	$ 3,899	-1.21%	$ 4,020	$ 3,972	-1.19%	153
154	LGS-1-DOS	7,843,178	85,196	104,898	23.13%	86,342	106,045	22.82%	98,389	118,092	20.03%	154
155	LGS-2S-DOS	82,487,915	734,814	1,034,167	40.74%	788,210	1,087,563	37.98%	947,993	1,247,346	31.58%	155
156	LGS-2P-DOS	4,487,342	58,866	85,954	46.02%	55,082	82,170	49.18%	66,599	93,687	40.67%	156
157	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	157
158	LGS-3S-DOS	85,826,485	813,709	1,182,296	45.30%	866,433	1,235,021	42.54%	1,029,961	1,398,548	35.79%	158
159	LGS-3P-DOS	1,414,522,800	8,148,886	17,036,169	109.06%	8,313,358	17,200,641	106.90%	10,485,712	19,372,996	84.76%	159
160	LGS-3T-DOS	591,977,970	1,323,566	3,468,559	162.06%	1,454,782	3,599,775	147.44%	2,399,837	4,544,830	89.38%	160
161	LGS-XS-DOS	7,153,043	55,175	128,986	133.78%	62,113	135,924	118.83%	77,765	151,576	94.91%	161
162	LGS-XP-DOS	287,352,976	2,541,281	5,101,132	100.73%	2,646,507	5,206,358	96.73%	3,138,262	5,698,113	81.57%	162
163	LGS-XT-DOS	165,618,096	598,410	861,930	44.04%	598,410	861,930	44.04%	833,588	1,097,107	31.61%	163
164	LGS-2S-WP-DOS	4,841,057	24,486	88,584	261.77%	24,486	88,584	261.77%	31,360	95,458	204.39%	164
165	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	165
166	LGS-2T-WP-DOS	1,889,274	17,854	34,936	95.68%	17,854	34,936	95.68%	20,537	37,619	83.18%	166
167	LGS-3S-WP-DOS	25,647,446	79,367	631,014	695.06%	79,367	631,014	695.06%	115,786	667,434	476.44%	167
168	LGS-3P-WP-DOS	75,371,524	297,544	692,102	132.60%	297,544	692,102	132.60%	404,572	799,129	97.52%	168
169	LGS-3T-WP-DOS	55,357,230	100,063	586,241	485.87%	100,063	586,241	485.87%	178,670	664,848	272.11%	169
170												170
171	DOS TOTAL	2,810,427,749	$ 14,883,164	$ 31,040,867	108.56%	$ 15,394,498	$ 31,552,202	104.96%	$ 19,833,051	$ 35,990,756	81.47%	171
172												172
173	TOTAL (Inc. DOS)	23,865,727,629	$ 1,086,353,957	$ 1,179,011,596	8.53%	$ 2,805,178,343	$ 2,897,835,983	3.30%	$ 3,230,334,344	$ 3,322,991,983	2.87%	173
174												174

175 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. 175

176 1. Present BTER and DEAA revenues are based on April 1, 2023 rates. 176

177 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 177

178 3. DOS schedules only reflect a percentage change to their distribution rates, not the OATT and energy rates paid through other mechanisms. 178

Line No.	Class	Sales	BTER Revenue Present	BTER Revenue Proposed	BTER Percent Change	DEAA Revenue Present	DEAA Revenue Proposed	DEAA Percent Change	EE Revenue Present	EE Revenue Proposed	EE Percent Change
9		Residential Rate	$ 0.08415	$ 0.08415		$ 0.01750	$ 0.01750		Rates vary by Class		
10		Non-Residential Rate	$ 0.07960	$ 0.07960		$ 0.01500	$ 0.01500				
11											
12	RS	7,262,588,952	$ 611,088,099	$ 611,088,099	0.0%	$ 126,894,467	$ 126,894,467	0.0%	$ 16,921,832	$ 16,921,832	0.0%
13	RM	2,298,671,171	193,414,892	193,414,892	0.0%	40,164,242	40,164,242	0.0%	4,827,210	4,827,210	0.0%
14	LRS	37,525,901	3,157,805	3,157,805	0.0%	656,703	656,703	0.0%	66,795	66,795	0.0%
15	GS	612,055,143	48,719,198	48,719,198	0.0%	9,179,762	9,179,762	0.0%	960,927	960,927	0.0%
16	LGS-1	4,073,133,716	324,176,879	324,176,879	0.0%	61,077,978	61,077,978	0.0%	6,598,476	6,598,476	0.0%
17	LGS-2S	2,429,180,261	193,341,369	193,341,369	0.0%	36,437,704	36,437,704	0.0%	3,668,062	3,668,062	0.0%
18	LGS-2P	69,583,297	5,538,830	5,538,830	0.0%	1,043,749	1,043,749	0.0%	91,851	91,851	0.0%
19	LGS-2T	-	-	-	na	-	-	na	-	-	na
20	LGS-3S	768,658,032	61,185,179	61,185,179	0.0%	11,529,870	11,529,870	0.0%	1,122,241	1,122,241	0.0%
21	LGS-3P	1,393,295,183	110,906,297	110,906,297	0.0%	20,899,428	20,899,428	0.0%	2,257,138	2,257,138	0.0%
22	LGS-3T	247,665,929	19,714,208	19,714,208	0.0%	3,714,989	3,714,989	0.0%	309,583	309,583	0.0%
23	LGS-XS	-	-	-	na	-	-	na	-	-	na
24	LGS-XP	-	-	-	na	-	-	na	-	-	na
25	LGS-XT	-	-	-	na	-	-	na	-	-	na
26	LGS-2S-WP	14,877,558	1,184,254	1,184,254	0.0%	223,163	223,163	0.0%	25,292	25,292	0.0%
27	LGS-2P-WP	11,147,772	887,363	887,363	0.0%	167,217	167,217	0.0%	13,043	13,043	0.0%
28	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na
29	LGS-3S-WP	4,412,814	351,260	351,260	0.0%	66,192	66,192	0.0%	3,662	3,662	0.0%
30	LGS-3P-WP	19,004,483	1,512,757	1,512,757	0.0%	285,067	285,067	0.0%	18,244	18,244	0.0%
31	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na
32	SL	129,054,441	10,272,734	10,272,734	0.0%	1,935,817	1,935,817	0.0%	184,548	184,548	0.0%
33	RS-Pal	578,040	48,642	48,642	0.0%	10,116	10,116	0.0%	781	781	0.0%
34	GS-Pal	2,217,456	176,509	176,509	0.0%	33,262	33,262	0.0%	2,749	2,749	0.0%
35	IAIWP	-	-	-	na	-	-	na	-	-	na
36	**Optional Time of Use**										
37	ORS-TOU	9,396,344	790,189	790,189	0.0%	162,684	162,684	0.0%	21,894	21,894	0.0%
38	ORS-TOU OPT A	21,030,431	1,769,207	1,769,207	0.0%	366,309	366,309	0.0%	49,001	49,001	0.0%
39	ORS-TOU OPT B	4,239,586	356,761	356,761	0.0%	74,193	74,193	0.0%	9,878	9,878	0.0%
43	ORM-TOU	873,422	73,417	73,417	0.0%	15,010	15,010	0.0%	1,835	1,835	0.0%
44	ORM-TOU OPT A	718,287	60,444	60,444	0.0%	12,570	12,570	0.0%	1,509	1,509	0.0%
45	ORM-TOU OPT B	70,254	5,912	5,912	0.0%	1,229	1,229	0.0%	147	147	0.0%
46	ORM-TOU DDP	9,561	756	756	0.0%	0	0	0.0%	20	20	0.0%
55	OGS-TOU	27,565,080	2,194,180	2,194,180	0.0%	413,476	413,476	0.0%	43,277	43,277	0.0%
56	OLGS-1 TOU	124,787,383	9,933,076	9,933,076	0.0%	1,871,811	1,871,811	0.0%	202,156	202,156	0.0%
57	OLGS-3P-HLF	258,609,361	20,585,305	20,585,305	0.0%	3,879,140	3,879,140	0.0%	418,947	418,947	0.0%
58	**Optional Time of Use EVRR**										
59	ORS-TOU EVRR	52,516,143	4,418,401	4,418,401	0.0%	916,188	916,188	0.0%	122,363	122,363	0.0%
60	ORS-TOU Opt A EVRR	6,627,577	557,711	557,711	0.0%	115,983	115,983	0.0%	15,443	15,443	0.0%
61	ORS-TOU Opt B EVRR	4,621,440	388,894	388,894	0.0%	80,875	80,875	0.0%	10,768	10,768	0.0%
64	ORM-TOU EVRR	1,289,179	108,374	108,374	0.0%	22,188	22,188	0.0%	2,708	2,708	0.0%
65	ORM-TOU OPT A EVRR	60,410	5,084	5,084	0.0%	1,057	1,057	0.0%	127	127	0.0%
66	ORM-TOU OPT B EVRR	29,643	2,494	2,494	0.0%	519	519	0.0%	63	63	0.0%
69	OLRS-TOU EVRR	299,866	25,234	25,234	0.0%	5,248	5,248	0.0%	534	534	0.0%
74	OGS-TOU EVRR	20,511	1,633	1,633	0.0%	308	308	0.0%	32	32	0.0%
75	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na
76	**Net Metering:**										
77	RS-NEM	478,046,320	40,227,598	40,227,598	0.0%	8,365,811	8,365,811	0.0%	1,113,848	1,113,848	0.0%
78	RM-NEM	2,595,772	218,434	218,434	0.0%	45,426	45,426	0.0%	5,452	5,452	0.0%
79	LRS-NEM	571,396	48,083	48,083	0.0%	9,999	9,999	0.0%	1,018	1,018	0.0%
80	GS-NEM	2,417,263	192,415	192,415	0.0%	36,259	36,259	0.0%	3,796	3,796	0.0%
81	LGS-1 NEM	73,328,638	5,836,959	5,836,959	0.0%	1,099,930	1,099,930	0.0%	118,792	118,792	0.0%
82	ORS-NEM	3,324,908	279,791	279,791	0.0%	58,186	58,186	0.0%	7,747	7,747	0.0%
83	ORS-NEM OPT A	4,057,523	341,441	341,441	0.0%	71,007	71,007	0.0%	9,455	9,455	0.0%
84	ORS-NEM OPT B	218,046	18,348	18,348	0.0%	3,816	3,816	0.0%	508	508	0.0%
88	ORM-NEM	1,460	123	123	0.0%	26	26	0.0%	2	2	0.0%
101	**NEM EVRR**					-	-				
102	ORS-NEM EVRR	11,862,176	998,202	998,202	0.0%	207,588	207,588	0.0%	27,639	27,639	0.0%
103	ORS-NEM OPT A EVRR	1,879,925	158,196	158,196	0.0%	32,899	32,899	0.0%	4,379	4,379	0.0%
104	ORS-NEM OPT B EVRR	411,121	34,595	34,595	0.0%	7,195	7,195	0.0%	959	959	0.0%
107	ORM-NEM EVRR	25,756	2,167	2,167	0.0%	451	451	0.0%	54	54	0.0%
118	**Standby**										
120	SSR - GS	-	-	-	na	-	-	na	-	-	na
121	SSR - LGS-1	1,130,064	89,953	89,953	0.0%	16,951	16,951	0.0%	1,830	1,830	0.0%
122	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na
123	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na
124	LSR - LGS-2T	9,583,450	762,843	762,843	0.0%	143,752	143,752	0.0%	12,650	12,650	0.0%
125	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na
126	LSR - LGS-3P	26,274,564	2,091,455	2,091,455	0.0%	394,118	394,118	0.0%	42,564	42,564	0.0%
127	LSR - LGS-3T	109,322,768	8,702,092	8,702,092	0.0%	1,639,842	1,639,842	0.0%	136,654	136,654	0.0%
137	**EVCCR**					-	-				
138	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na
139	LGS-2S EVCCR	14,835,492	1,180,905	1,180,905	0.0%	222,532	222,532	0.0%	22,401	22,401	0.0%
140	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na
141	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na
142	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na
143	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na
144	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na
151											
152	**TOTAL Bundled**	21,055,299,880	$ 1,718,313,052	$ 1,718,313,052	0.0%	334,614,299	334,614,299	0.0%	40,019,026	40,019,026	0.0%
153	Residential	10,204,140,610	858,599,294	858,599,294	0.0%	178,301,982	178,301,982	0.0%	23,223,969	23,223,969	0.0%
154	Non-Residential	10,851,159,270	859,713,758	859,713,758	0.0%	156,312,317	156,312,317	0.0%	16,795,057	16,795,057	0.0%
155											
156	**DISTRIBUTION ONLY SERVICE (DOS)**		R-BTER & BTER Impact Fee DOS Revenue								
157	GS-DOS	51,413	-	-	na	-	-	na	-	-	na
158	LGS-1-DOS	7,843,178	1,146	1,146	0.0%	27	27	0.0%	51	51	0.0%
159	LGS-2S-DOS	82,487,915	53,396	53,396	0.0%	897	897	0.0%	1,701	1,701	0.0%
160	LGS-2P-DOS	4,487,342	(3,784)	(3,784)	0.0%	103	103	0.0%	1,587	1,587	0.0%
161	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na
162	LGS-3S-DOS	85,826,485	52,724	52,724	0.0%	1,543	1,543	0.0%	2,925	2,925	0.0%
163	LGS-3P-DOS	1,414,522,800	164,473	164,472	0.0%	3,361	3,361	0.0%	15,074	15,074	0.0%
164	LGS-3T-DOS	591,977,970	131,216	131,216	0.0%	2,722	2,722	0.0%	5,162	5,162	0.0%
165	LGS-XS-DOS	7,153,043	6,938	6,938	0.0%	182	182	0.0%	345	345	0.0%
166	LGS-XP-DOS	287,352,976	105,226	105,226	0.0%	2,248	2,248	0.0%	4,263	4,263	0.0%
167	LGS-XT-DOS	165,618,096	-	-	na	-	-	na	-	-	na
168	LGS-2S-WP-DOS	4,841,057	-	-	na	-	-	na	-	-	na
169	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na
170	LGS-2T-WP-DOS	1,889,274	-	-	na	-	-	na	-	-	na
171	LGS-3S-WP-DOS	25,647,446	-	-	na	-	-	na	-	-	na
172	LGS-3P-WP-DOS	75,371,524	-	-	na	-	-	na	-	-	na
173	LGS-3T-WP-DOS	55,357,230	-	-	na	-	-	na	-	-	na
174											
175	DOS TOTAL	$ 2,810,427,749	$ 511,335	$ 511,334	0.0%	$ 11,083	$ 11,083	0.0%	$ 31,108	$ 31,108	0.0%
176											
177	TOTAL	68,786,755,138	$ 1,718,824,387	$ 1,718,824,386	0.0%	$ 334,625,382	$ 334,625,382	0.0%	$ 40,050,134	$ 40,050,134	0.0%
178				$ (1)			$ -			$ -	
179											

Line No.	Class	REPR Revenue Present	REPR Revenue Proposed	REPR Percent Change	NDPP Present	NDPP Proposed	NDPP Percent Change	ESAP Present	ESAP Proposed	ESAP Percent Change
9	Residential Rate	$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002	
10	Non-Residential Rate	$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002	
11										
12	RS	$ 5,592,193	$ 5,592,193	0.0%	$ 10,312,876	$ 10,312,876	0.0%	$ 145,252	$ 145,252	0.0%
13	RM	1,769,977	1,769,977	0.0%	3,264,113	3,264,113	0.0%	45,973	45,973	0.0%
14	LRS	28,895	28,895	0.0%	53,287	53,287	0.0%	751	751	0.0%
15	GS	471,282	471,282	0.0%	869,118	869,118	0.0%	12,241	12,241	0.0%
16	LGS-1	3,136,313	3,136,313	0.0%	5,783,850	5,783,850	0.0%	81,463	81,463	0.0%
17	LGS-2S	1,870,469	1,870,469	0.0%	3,449,436	3,449,436	0.0%	48,584	48,584	0.0%
18	LGS-2P	53,579	53,579	0.0%	98,808	98,808	0.0%	1,392	1,392	0.0%
19	LGS-2T	-	-	na	-	-	na	-	-	na
20	LGS-3S	591,867	591,867	0.0%	1,091,494	1,091,494	0.0%	15,373	15,373	0.0%
21	LGS-3P	1,072,837	1,072,837	0.0%	1,978,479	1,978,479	0.0%	27,866	27,866	0.0%
22	LGS-3T	190,703	190,703	0.0%	351,686	351,686	0.0%	4,953	4,953	0.0%
23	LGS-XS	-	-	na	-	-	na	-	-	na
24	LGS-XP	-	-	na	-	-	na	-	-	na
25	LGS-XT	-	-	na	-	-	na	-	-	na
26	LGS-2S-WP	11,456	11,456	0.0%	21,126	21,126	0.0%	298	298	0.0%
27	LGS-2P-WP	8,584	8,584	0.0%	15,830	15,830	0.0%	223	223	0.0%
28	LGS-2T-WP	-	-	na	-	-	na	-	-	na
29	LGS-3S-WP	3,398	3,398	0.0%	6,266	6,266	0.0%	88	88	0.0%
30	LGS-3P-WP	14,633	14,633	0.0%	26,986	26,986	0.0%	380	380	0.0%
31	LGS-3T-WP	-	-	na	-	-	na	-	-	na
32	SL	99,372	99,372	0.0%	183,257	183,257	0.0%	2,581	2,581	0.0%
33	RS-Pal	445	445	0.0%	821	821	0.0%	12	12	0.0%
34	GS-Pal	1,707	1,707	0.0%	3,149	3,149	0.0%	44	44	0.0%
35	IAIWP	-	-	na	-	-	na	-	-	na
36	**Optional Time of Use**									
37	ORS-TOU	7,235	7,235	0.0%	13,343	13,343	0.0%	188	188	0.0%
38	ORS-TOU OPT A	16,193	16,193	0.0%	29,863	29,863	0.0%	421	421	0.0%
39	ORS-TOU OPT B	3,264	3,264	0.0%	6,020	6,020	0.0%	85	85	0.0%
43	ORM-TOU	673	673	0.0%	1,240	1,240	0.0%	17	17	0.0%
44	ORM-TOU OPT A	553	553	0.0%	1,020	1,020	0.0%	14	14	0.0%
45	ORM-TOU OPT B	54	54	0.0%	100	100	0.0%	1	1	0.0%
46	ORM-TOU DDP	7	7	0.0%	14	14	0.0%	0	0	0.0%
55	OGS-TOU	21,225	21,225	0.0%	39,142	39,142	0.0%	551	551	0.0%
56	OLGS-1 TOU	96,086	96,086	0.0%	177,198	177,198	0.0%	2,496	2,496	0.0%
57	OLGS-3P-HLF	199,129	199,129	0.0%	367,225	367,225	0.0%	5,172	5,172	0.0%
58	**Optional Time of Use EVRR**									
59	ORS-TOU EVRR	40,437	40,437	0.0%	74,573	74,573	0.0%	1,050	1,050	0.0%
60	ORS-TOU Opt A EVRR	5,103	5,103	0.0%	9,411	9,411	0.0%	133	133	0.0%
61	ORS-TOU Opt B EVRR	3,559	3,559	0.0%	6,562	6,562	0.0%	92	92	0.0%
64	ORM-TOU EVRR	993	993	0.0%	1,831	1,831	0.0%	26	26	0.0%
65	ORM-TOU OPT A EVRR	47	47	0.0%	86	86	0.0%	1	1	0.0%
66	ORM-TOU OPT B EVRR	23	23	0.0%	42	42	0.0%	1	1	0.0%
69	OLRS-TOU EVRR	231	231	0.0%	426	426	0.0%	6	6	0.0%
74	OGS-TOU EVRR	16	16	0.0%	29	29	0.0%	0	0	0.0%
75	OLGS-1-TOU EVRR	-	-	na	-	-	na	-	-	na
76	**Net Metering:**									
77	RS-NEM	368,096	368,096	0.0%	678,826	678,826	0.0%	9,561	9,561	0.0%
78	RM-NEM	1,999	1,999	0.0%	3,686	3,686	0.0%	52	52	0.0%
79	LRS-NEM	440	440	0.0%	811	811	0.0%	11	11	0.0%
80	GS-NEM	1,861	1,861	0.0%	3,433	3,433	0.0%	48	48	0.0%
81	LGS-1 NEM	56,463	56,463	0.0%	104,127	104,127	0.0%	1,467	1,467	0.0%
82	ORS-NEM	2,560	2,560	0.0%	4,721	4,721	0.0%	66	66	0.0%
83	ORS-NEM OPT A	3,124	3,124	0.0%	5,762	5,762	0.0%	81	81	0.0%
84	ORS-NEM OPT B	168	168	0.0%	310	310	0.0%	4	4	0.0%
88	ORM-NEM	1	1	0.0%	2	2	0.0%	0	0	0.0%
101	**NEM EVRR**									
102	ORS-NEM EVRR	9,134	9,134	0.0%	16,844	16,844	0.0%	237	237	0.0%
103	ORS-NEM OPT A EVRR	1,448	1,448	0.0%	2,669	2,669	0.0%	38	38	0.0%
104	ORS-NEM OPT B EVRR	317	317	0.0%	584	584	0.0%	8	8	0.0%
107	ORM-NEM EVRR	20	20	0.0%	37	37	0.0%	1	1	0.0%
118	**Standby**									
120	SSR - GS	-	-	na	-	-	na	-	-	na
121	SSR - LGS-1	870	870	0.0%	1,605	1,605	0.0%	23	23	0.0%
122	LSR - LGS-2S	-	-	na	-	-	na	-	-	na
123	LSR - LGS-2P	-	-	na	-	-	na	-	-	na
124	LSR - LGS-2T	7,379	7,379	0.0%	13,608	13,608	0.0%	192	192	0.0%
125	LSR - LGS-3S	-	-	na	-	-	na	-	-	na
126	LSR - LGS-3P	20,231	20,231	0.0%	37,310	37,310	0.0%	525	525	0.0%
127	LSR - LGS-3T	84,179	84,179	0.0%	155,238	155,238	0.0%	2,186	2,186	0.0%
137	**EVCCR**									
138	OLGS-1 EVCCR	-	-	na	-	-	na	-	-	na
139	LGS-2S EVCCR	11,423	11,423	0.0%	21,066	21,066	0.0%	297	297	0.0%
140	LGS-2P EVCCR	-	-	na	-	-	na	-	-	na
141	LGS-2T EVCCR	-	-	na	-	-	na	-	-	na
142	LGS-3S EVCCR	-	-	na	-	-	na	-	-	na
143	LGS-3P EVCCR	-	-	na	-	-	na	-	-	na
144	LGS-3T EVCCR	-	-	na	-	-	na	-	-	na
151										
152	**TOTAL Bundled**	16,185,597	16,185,597	0.0%	29,898,526	29,898,526	0.0%	421,106	421,106	0.0%
153	Residential	7,857,188	7,857,188	0.0%	14,489,880	14,489,880	0.0%	204,083	204,083	0.0%
154	Non-Residential	8,328,409	8,328,409	0.0%	15,408,646	15,408,646	0.0%	217,023	217,023	0.0%
155										
156	**DISTRIBUTION ONLY SERVICE (DOS)**									
157	GS-DOS	-	-	na	73	73	0.0%	1	1	0.0%
158	LGS-1-DOS	832	832	0.0%	11,137	11,137	0.0%	157	157	0.0%
159	LGS-2S-DOS	40,052	40,052	0.0%	117,133	117,133	0.0%	1,650	1,650	0.0%
160	LGS-2P-DOS	3,455	3,455	0.0%	6,372	6,372	0.0%	90	90	0.0%
161	LGS-2T-DOS	-	-	na	-	-	na	-	-	na
162	LGS-3S-DOS	37,186	37,186	0.0%	121,874	121,874	0.0%	1,717	1,717	0.0%
163	LGS-3P-DOS	145,297	145,297	0.0%	2,008,622	2,008,622	0.0%	28,290	28,290	0.0%
164	LGS-3T-DOS	96,562	96,562	0.0%	840,609	840,609	0.0%	11,840	11,840	0.0%
165	LGS-XS-DOS	4,968	4,968	0.0%	10,157	10,157	0.0%	143	143	0.0%
166	LGS-XP-DOS	77,203	77,203	0.0%	408,041	408,041	0.0%	5,747	5,747	0.0%
167	LGS-XT-DOS	-	-	na	235,178	235,178	0.0%	3,312	3,312	0.0%
168	LGS-2S-WP-DOS	-	-	na	6,874	6,874	0.0%	97	97	0.0%
169	LGS-2P-WP-DOS	-	-	na	-	-	na	-	-	na
170	LGS-2T-WP-DOS	-	-	na	2,683	2,683	0.0%	38	38	0.0%
171	LGS-3S-WP-DOS	-	-	na	36,419	36,419	0.0%	513	513	0.0%
172	LGS-3P-WP-DOS	-	-	na	107,028	107,028	0.0%	1,507	1,507	0.0%
173	LGS-3T-WP-DOS	-	-	na	78,607	78,607	0.0%	1,107	1,107	0.0%
174										
175	DOS TOTAL	$ 405,555	$ 405,555	0.0%	$ 3,990,807	$ 3,990,807	0.0%	$ 56,209	$ 56,209	0.0%
176										
177	TOTAL	$ 16,591,152	$ 16,591,152	0.0%	$ 33,889,333	$ 33,889,333	0.0%	$ 477,315	$ 477,315	0.0%
178			$ -			$ -			$ -	
179										

Summary of Proposed Rates -- Bundled

Line No.	Class	Note	Distribution Charges: Charge, per Cust:	Distribution Charges: Meter Charge:	Distribution Charges: Facilities Charge, per kW (1)	T and G Demand Charges, metered kW: Summer On Peak	T and G Demand Charges, metered kW: Summer Mid Peak	T and G Demand Charges, metered kW: Winter -OR - All Periods	BTGR Energy, per kWh (includes IRR): Critical Peak	BTGR: Summer On Peak	BTGR: Summer Mid Peak	BTGR: Summer Off Peak	BTGR: Winter -OR - All Periods	BTGR: Summer EVRR	BTGR: Winter EVRR	BTER Energy, per kWh	Line No.
9	RS		$ 18.50										0.05954			$ 0.08415	9
10	RM		8.20										0.05315			0.08415	10
11	LRS		98.70										0.05142			0.08415	11
12	GS		25.50	$ 2.00									0.01863			0.07960	12
13	LGS-1		15.80	5.75	$ 4.25			$ 5.35					0.01212			0.07960	13
14	LGS-2S		122.40	12.25	2.80	$ 18.56	$ -	1.60		0.03473	-	0.00267	0.00325			0.07960	14
15	LGS-2P		207.70	54.25	2.80	16.29	-	1.60		0.02108	-	0.00088	0.00511			0.07960	15
16	LGS-2T		182.00	88.25	0.90	17.01	-	1.50		0.03128	-	0.00023	0.00199			0.07960	16
17	LGS-3S		122.00	14.75	2.75	18.92	-	2.00		0.02479	-	0.00196	0.00550			0.07960	17
18	LGS-3P		214.10	67.75	2.60	16.72	-	2.25		0.02196	-	0.00476	0.00582			0.07960	18
19	LGS-3T		182.00	88.25	0.90	17.01	-	1.50		0.03128	-	0.00023	0.00199			0.07960	19
20	LGS-XS		4,743.00	16.70	2.25	18.92	-	2.00		0.02479	-	0.00196	0.00550			0.07960	20
21	LGS-XP		4,743.00	53.80	3.05	16.72	-	2.25		0.02196	-	0.00476	0.00582			0.07960	21
22	LGS-XT		4,743.00	91.80	na	17.01	-	1.50		0.03128	-	0.00023	0.00199			0.07960	22
23	LGS-2S-WP		128.70	12.25	1.10	18.56	-	1.60		0.04493	-	0.01898	0.01899			0.07960	23
24	LGS-2P-WP		208.60	54.25	1.55	16.29	-	1.60		0.04568	-	0.00786	0.00787			0.07960	24
25	LGS-2T-WP		169.10	92.00	0.90	17.01	-	1.50		0.03965	-	0.00781	0.00642			0.07960	25
26	LGS-3S-WP		149.90	14.75	1.25	18.92	-	2.00		0.12358	-	0.02370	0.02371			0.07960	26
27	LGS-3P-WP		234.20	67.75	1.00	16.72	-	2.25		0.05724	-	0.00335	0.00336			0.07960	27
28	LGS-3T-WP		189.10	88.25	0.90	18.15	-	2.25		0.05065	-	0.00330	0.00198			0.07960	28
29	IAIWP															0.06751	29
30																	30
31	ORS-TOU		18.50							0.28899		0.00059	0.00802	(0.00788)	(0.00120)	0.08415	31
32	ORS-TOU Opt A		18.50							0.28899		0.00059	0.00802	(0.00788)	(0.00120)	0.08415	32
33	ORS-TOU Opt B		18.50							0.28899		0.00059	0.00802	(0.00788)	(0.00120)	0.08415	33
34	ORS-TOU DDP		7.00		0.23	0.14		0.05					0.03444			0.08415	34
35	ORS-TOU CPP		18.50						0.62673	0.23476		0.00521	0.00802	(0.00373)	(0.00120)	0.08415	35
36	ORS-TOU CPP DDP		18.50			0.14		0.05	0.62673	0.19188		0.00521	0.00215	(0.00373)	(0.00648)	0.08415	36
37	ORM-TOU		8.20							0.22997		0.03125	0.01041	0.01971	0.00095	0.08415	37
38	ORM-TOU Opt A		8.20							0.22997		0.03125	0.01041	0.01971	0.00095	0.08415	38
39	ORM-TOU Opt B		8.20							0.22997		0.03125	0.01041	0.01971	0.00095	0.08415	39
40	ORM-TOU DDP		4.75		0.09	0.06		0.05					0.03636			0.08415	40
41	ORM-TOU CPP		8.20						0.38501	0.19934		0.02857	0.01514	0.01730	0.00521	0.08415	41
42	ORM-TOU CPP DDP		8.20			0.06		0.05	0.38501	0.17764		0.02857	0.00650	0.01730	(0.00257)	0.08415	42
43	OLRS-TOU		98.70							0.26004		0.01398	0.01214	0.00417	0.00251	0.08415	43
44	OLRS-TOU Opt A		98.70							0.26004		0.01398	0.01214	0.00417	0.00251	0.08415	44
45	OLRS-TOU Opt B		98.70							0.26004		0.01398	0.01214	0.00417	0.00251	0.08415	45
46	OLRS-TOU DDP		25.75		0.22	0.18		0.05					0.03379			0.08415	46
47	OLRS-TOU CPP		98.70						0.30142	0.22656		0.01348	0.01977	0.00372	0.00938	0.08415	47
48	OLRS-TOU CPP DDP		98.70			0.18		0.05	0.30142	0.18436		0.01348	0.01648	0.00372	0.00642	0.08415	48
49	OGS-TOU		25.50	2.00						0.07487		0.01335	0.01031	0.00405	0.00132	0.07960	49
50	OLGS-1-TOU		15.80	5.75	4.25	8.28	<- Summer Winter->	0.50		0.09639		0.00684	0.00794	(0.00180)	(0.00081)	0.07960	50
51	OLGS-3P-HLF		214.10	67.75	1.40	23.59	-	1.90		0.01674	-	0.00041	0.00141			0.07960	51
52																	52
53	Incremental MPE						Generation $/kW Credit				Generation $/kWh Credit						53
54	GS MPE												(0.01623)				54
55	LGS-1 MPE							(3.60)					(0.00905)				55
56	LGS-2S MPE					(13.70)	-	(1.18)		(0.01129)	-	(0.00087)	(0.00106)				56
57	LGS-3P MPE					(11.77)	-	(1.58)		(0.00221)	-	(0.00048)	(0.00058)				57
58	LGS-3T MPE					(6.80)	-	(0.60)		(0.01497)	-	(0.00011)	(0.00095)				58
59																	59
60	Incremental EVCCR						EVCCR Demand Reduction Rates				EVCCR Transition kWh Adder Rates						60
61	OLGS-1 EVCCR					(4.97)		(0.30)		0.04015			0.00105	(0.00778)	(0.00788)		61
62	LGS-2S EVCCR					(11.14)	-	(0.96)		0.08473	-	-	0.00229	(0.00823)	(0.00829)		62
63	LGS-2P EVCCR					(9.77)	-	(0.96)		0.06979	-	-	0.00193	(0.00805)	(0.00847)		63
64	LGS-2T EVCCR					(10.21)	-	(0.90)		0.06653	-	-	0.04895	(0.00798)	(0.00816)		64
65	LGS-3S EVCCR					(11.35)	-	(1.20)		0.08038	-	-	0.00250	(0.00816)	(0.00851)		65
66	LGS-3P EVCCR					(10.03)	-	(1.35)		0.06955	-	-	0.00270	(0.00844)	(0.00854)		66
67	LGS-3T EVCCR					(10.21)	-	(0.90)		0.06082	-	-	0.00171	(0.00798)	(0.00816)		67
68																	68
69																	69

70 Additional Charges: 70

71 Separate Billing 71

72 LGS-X & LGS-WP-X: $ 12.00 Per additional bill 72

73 DOS LGS-X & LGS-WP-X: $ 12.00 Per additional bill 73

74 Power Factor Charges ($/kVarh): 74

75 Summer: $ 0.00200 $/kVarh 75

76 Winter: $ 0.00100 $/kVarh 76

Customer Specific Facilities Charges	Charge per $ of: Utility	Charge per $ of: Customer Contributed
Transmission non-X customers	$ 0.00325	$ 0.00059
DOS Transmission non-X customers	$ 0.00325	$ 0.00059
OLGS-3P HLF customers	$ 0.00325	$ 0.00059

77 Notes: 77

78 (1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge recovers 78
79 both the Rule 9 and primary distibution facility costs. For LGSX customers the per kW facility charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facility charge (CSFC). 79

80 (2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M 80
81 recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of 81
82 service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical. 82

83 (3) The per kW facility charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer 83
84 facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer. 84

Nevada Power Company
Statement O

Summary of Proposed Rates -- Bundled (continued)

		BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy)							Additional Charges on per kWH Basis						Total Energy, per kWh (BTGR & BTER + EE + DEAA)							
Line No.	Class	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	REPR	TRED	DEAA	EE	NDPP	ESAP	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	Line No.
8																						8
9	RS					$ 0.14369			$ 0.00077	$ 0.00070	$ 0.01750	$ 0.00206	$ 0.00142	$ 0.00002					$ 0.16472			9
10	RM					0.13730			0.00077	0.00070	0.01750	0.00186	0.00142	0.00002					0.15813			10
11	LRS					0.13557			0.00077	0.00070	0.01750	0.00156	0.00142	0.00002					0.15610			11
12	GS					0.09823			0.00077	0.00057	0.01500	0.00139	0.00142	0.00002					0.11596			12
13	LGS-1					0.09172			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002					0.10951			13
14	LGS-2S		$ 0.11433	$ -	$ 0.08227	0.08285			0.00077	0.00057	0.01500	0.00135	0.00142	0.00002		$ 0.13202	$ -	$ 0.09996	0.10054			14
15	LGS-2P		0.10068	-	0.08048	0.08471			0.00077	0.00057	0.01500	0.00117	0.00142	0.00002		0.11819	-	0.09799	0.10222			15
16	LGS-2T		0.11088	-	0.07983	0.08159			0.00077	0.00057	0.01500	0.00101	0.00142	0.00002		0.12823	-	0.09718	0.09894			16
17	LGS-3S		0.10439	-	0.08156	0.08510			0.00077	0.00057	0.01500	0.00130	0.00142	0.00002		0.12203	-	0.09920	0.10274			17
18	LGS-3P		0.10156	-	0.08436	0.08542			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11935	-	0.10215	0.10321			18
19	LGS-3T		0.11088	-	0.07983	0.08159			0.00077	0.00057	0.01500	0.00107	0.00142	0.00002		0.12829	-	0.09724	0.09900			19
20	LGS-XS		0.10439	-	0.08156	0.08510			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.12218	-	0.09935	0.10289			20
21	LGS-XP		0.10156	-	0.08436	0.08542			0.00077	0.00057	0.01500	0.00161	0.00142	0.00002		0.11951	-	0.10231	0.10337			21
22	LGS-XT		0.11088	-	0.07983	0.08159			0.00077	0.00057	0.01500	0.00124	0.00142	0.00002		0.12846	-	0.09741	0.09917			22
23	LGS-2S-WP		0.12453	-	0.09858	0.09859			0.00077	0.00057	0.01500	0.00141	0.00142	0.00002		0.14228	-	0.11633	0.11634			23
24	LGS-2P-WP		0.12528	-	0.08746	0.08747			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.14265	-	0.10483	0.10484			24
25	LGS-2T-WP		0.11925	-	0.08741	0.08602			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.13662	-	0.10478	0.10339			25
26	LGS-3S-WP		0.20318	-	0.10330	0.10331			0.00077	0.00057	0.01500	0.00068	0.00142	0.00002		0.22020	-	0.12032	0.12033			26
27	LGS-3P-WP		0.13684	-	0.08295	0.08296			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.15403	-	0.10014	0.10015			27
28	LGS-3T-WP		0.13025	-	0.08290	0.08158			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.14744	-	0.10009	0.09877			28
29	IAIWP					0.06751			-	-	-								0.06751			29
30																						30
31	ORS-TOU		0.37314		0.08474	0.09217	$ 0.07627	$ 0.08295	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39167		0.10327	0.11070	$ 0.09480	$ 0.10148	31
32	ORS-TOU Opt A		0.37314		0.08474	0.09217	0.07627	0.08295	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39167		0.10327	0.11070	0.09480	0.10148	32
33	ORS-TOU Opt B		0.37314		0.08474	0.09217	0.07627	0.08295	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39167		0.10327	0.11070	0.09480	0.10148	33
34	ORS-TOU DDP					0.11859			0.00077	0.00070	0.01500	0.00206	0.00142	0.00002					0.13712			34
35	ORS-TOU CPP	0.62553	0.31891		0.08936	0.09217	0.08042	0.08295	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.64406	0.33744		0.10789	0.11070	0.09895	0.10148	35
36	ORS-TOU CPP DDP	0.62025	0.27603		0.08936	0.08630	0.08042	0.07767	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.63878	0.29456		0.10789	0.10483	0.09895	0.09620	36
37	ORM-TOU		0.31412		0.11540	0.09456	0.10386	0.08510	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.33245		0.13373	0.11289	0.12219	0.10343	37
38	ORM-TOU Opt A		0.31412		0.11540	0.09456	0.10386	0.08510	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.33245		0.13373	0.11289	0.12219	0.10343	38
39	ORM-TOU Opt B		0.31412		0.11540	0.09456	0.10386	0.08510	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.33245		0.13373	0.11289	0.12219	0.10343	39
40	ORM-TOU DDP					0.12051			0.00077	0.00070	0.01500	0.00186	0.00142	0.00002					0.13884			40
41	ORM-TOU CPP	0.39022	0.28349		0.11272	0.09929	0.10145	0.08936	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.40855	0.30182		0.13105	0.11762	0.11978	0.10769	41
42	ORM-TOU CPP DDP	0.38244	0.26179		0.11272	0.09065	0.10145	0.08158	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.40077	0.28012		0.13105	0.10898	0.11978	0.09991	42
43	OLRS-TOU		0.34419		0.09813	0.09629	0.08832	0.08666	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.36222		0.11616	0.11432	0.10635	0.10469	43
44	OLRS-TOU Opt A		0.34419		0.09813	0.09629	0.08832	0.08666	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.36222		0.11616	0.11432	0.10635	0.10469	44
45	OLRS-TOU Opt B		0.34419		0.09813	0.09629	0.08832	0.08666	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.36222		0.11616	0.11432	0.10635	0.10469	45
46	OLRS-TOU DDP					0.11794			0.00077	0.00070	0.01500	0.00156	0.00142	0.00002					0.13597			46
47	OLRS-TOU CPP	0.31080	0.31071		0.09763	0.10392	0.08787	0.09353	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.32883	0.32874		0.11566	0.12195	0.10590	0.11156	47
48	OLRS-TOU CPP DDP	0.30784	0.26851		0.09763	0.10063	0.08787	0.09057	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.32587	0.28654		0.11566	0.11866	0.10590	0.10860	48
49	OGS-TOU		0.15447		0.09295	0.08991	0.08365	0.08092	0.00077	0.00057	0.01500	0.00139	0.00142	0.00002		0.17220		0.11068	0.10764	0.10138	0.09865	49
50	OLGS-1-TOU		0.17599		0.08644	0.08754	0.07780	0.07879	0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.19378		0.10423	0.10533	0.09559	0.09658	50
51	OLGS-3P-HLF		0.09634	-	0.08001	0.08101			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11413		0.09780	0.09880	0.01779	0.01779	51
52																						52
53	(1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O.																					53

Proposed Street Lighting (SL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00132	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	Street Lights - Non-metered																	12
13	Mercury Vapor	Non-Metered	100W	CLS 20		73	$ 3.18	$ 5.81	**$ 8.99**	$ 1.10	$ 0.04	$ 0.10	$ 0.06	$ 0.10	$ -	---	$ 10.39	13
14	Mercury Vapor	Non-Metered	100W	CLS 20		73	3.18	5.81	**8.99**	1.10	0.04	0.10	0.06	0.10	-	---	10.39	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.16	8.20	**9.36**	1.55	0.06	0.14	0.08	0.15	-	---	11.34	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.16	8.20	**9.36**	1.55	0.06	0.14	0.08	0.15	-	---	11.34	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.10**	2.48	0.09	0.22	0.13	0.23	-	---	13.25	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.10**	2.48	0.09	0.22	0.13	0.23	-	---	13.25	18
19	High Pressure	Non-Metered	100W	CLS 23		42	5.29	3.34	**8.63**	0.63	0.02	0.06	0.03	0.06	-	---	9.43	19
20	High Pressure	Non-Metered	200W	CLS 24		83	2.50	6.61	**9.11**	1.25	0.05	0.11	0.06	0.12	-	---	10.70	20
21	Municipal Street Lights - Public																	21
22	Incandescent	n/a	100W	CLS 30		73	3.15	5.81	**8.96**	1.10	0.04	0.10	0.06	0.10	-	---	10.36	22
23	Incandescent	n/a	200W	CLS 31		120	0.01	9.55	**9.51**	1.80	0.07	0.16	0.09	0.17	-	---	11.80	23
24	Incandescent	n/a	200W	CLS 32		167	0.01	13.29	**10.07**	2.51	0.10	0.22	0.13	0.24	-	---	13.27	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	3.16	5.81	**8.97**	1.10	0.04	0.10	0.06	0.10	-	---	10.37	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	1.12	8.20	**9.32**	1.55	0.06	0.14	0.08	0.15	-	---	11.30	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	0.01	13.13	**10.04**	2.48	0.09	0.22	0.13	0.23	-	---	13.19	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	3.16	5.81	**8.97**	1.10	0.04	0.10	0.06	0.10	-	---	10.37	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	1.12	8.20	**9.32**	1.55	0.06	0.14	0.08	0.15	-	---	11.30	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	0.01	13.13	**10.04**	2.48	0.09	0.22	0.13	0.23	-	---	13.19	30
31	Sodium Vapor	n/a	100W	CLS 89		42	5.26	3.34	**8.60**	0.63	0.02	0.06	0.03	0.06	-	---	9.40	31
32	Sodium Vapor	n/a	200W	CLS 90		83	2.47	6.61	**9.08**	1.25	0.05	0.11	0.06	0.12	-	---	10.67	32
33	Municipal Street Lights - Customer Owned																	33
34	Incandescent	n/a	200W	CLS 51		120	0.01	9.55	**3.87**	1.80	0.07	0.16	0.09	0.17	-	0.05	6.21	34
35	Mercury Vapor	n/a	200W	CLS 53		73	0.01	5.81	**3.33**	1.10	0.04	0.10	0.06	0.10	-	0.03	4.76	35
36	Mercury Vapor	n/a	200W	CLS 54		103	0.01	8.20	**3.68**	1.55	0.06	0.14	0.08	0.15	-	0.04	5.70	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.01	13.13	**4.40**	2.48	0.09	0.22	0.13	0.23	-	0.06	7.61	37
38	Street Lights - LED																	38
39	LED	Non-Metered	100W	CLS 20		70	3.16	5.57	**8.73**	1.05	0.04	0.09	0.05	0.10	-	---	10.06	39
40	LED	Non-Metered	200W	CLS 21		35	3.16	5.57	**8.73**	0.53	0.02	0.05	0.03	0.05	-	---	9.41	40
41	LED	Non-Metered	200W	CLS 22		70	1.11	5.57	**6.68**	1.05	0.04	0.09	0.05	0.10	-	---	8.01	41
42	LED	Non-Metered	200W	CLS 24		70	1.11	5.57	**6.68**	1.05	0.04	0.09	0.05	0.10	-	---	8.01	42
43	Municipal Street Lights - LED																	43
44	LED	n/a	100W	CLS 30		35	3.00	2.79	**5.79**	0.53	0.02	0.05	0.03	0.05	-	---	6.47	44
45	LED	n/a	200W	CLS 31		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	45
46	LED	n/a	200W	CLS 32		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	46
47	LED	Wood Pole	200W	CLS 33		70	3.00	2.79	**5.79**	1.05	0.04	0.09	0.05	0.10	-	---	7.12	47
48	LED	Wood Pole	200W	CLS 34		70	1.02	2.79	**3.81**	1.05	0.04	0.09	0.05	0.10	-	---	5.14	48
49																		49
50	Metered	Metered	Metered	Metered		Mtrd	0.05676	0.07960	**0.13636**	0.01500	0.00057	0.00132	0.00077	0.00142	0.00002	0.00039	0.15585	50
51																		51
52	Note: Municipal and Public Street Lights do not pay UEC charges.																	52

Proposed Residential Private Area Lighting (RS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01750	$ 0.00070	$ 0.00124	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	RS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.55	$ 6.14	**$ 13.69**	$ 1.28	$ 0.05	$ 0.09	$ 0.06	$ 0.10	$ -	0.03	$ 15.30	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.55	6.14	**13.69**	1.28	0.05	0.09	0.06	0.10	-	0.03	15.30	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.22	13.88	**25.10**	2.89	0.12	0.20	0.13	0.23	-	0.06	28.73	15
16	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.30	3.53	**9.83**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.76	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.30	3.53	**9.83**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.76	17
18	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.94	6.98	**14.92**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.74	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.94	6.98	**14.92**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.74	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	11.22	13.88	**25.10**	2.89	0.12	0.20	0.13	0.23	-	0.06	28.73	20
21	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.23	6.14	**19.37**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.98	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.23	6.14	**19.37**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.98	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.90	13.88	**30.78**	2.89	0.12	0.20	0.13	0.23	-	0.06	34.41	23
24	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.98	3.53	**15.51**	0.74	0.03	0.05	0.03	0.06	-	0.02	16.44	24
25	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	7.94	6.98	**14.92**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.74	25
26	LED	RATE A (Existing pole)	200W	CLS 10		70	7.34	5.89	**13.23**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.78	26
27	LED	RATE A (Existing pole)	200W	CLS 12		70	5.95	5.89	**11.84**	1.23	0.05	0.09	0.05	0.10	-	0.03	13.39	27
28	LED	RATE A (Existing pole)	100W	CLS 14		35	5.75	2.95	**8.70**	0.61	0.02	0.04	0.03	0.05	-	0.01	9.46	28
29	LED	RATE A (Existing pole)	200W	CLS 15		70	7.08	5.89	**12.97**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.52	29
30	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.97	5.89	**18.86**	1.23	0.05	0.09	0.05	0.10	-	0.03	20.41	30
31	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.43	5.89	**16.32**	1.23	0.05	0.09	0.05	0.10	-	0.03	17.87	31
32	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.32	2.95	**14.27**	0.61	0.02	0.04	0.03	0.05	-	0.01	15.03	32
33																		33
34																		34

Proposed General Service Private Area Lighting (GS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00113	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	GS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.75	$ 5.81	**$ 13.56**	$ 1.10	$ 0.04	$ 0.08	$ 0.06	$ 0.10	$ -	0.03	$ 14.97	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.75	5.81	**13.56**	1.10	0.04	0.08	0.06	0.10	-	0.03	14.97	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.99	13.13	**25.12**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.30	15
16	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.99	13.13	**25.12**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.30	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.29	3.34	**9.63**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.44	17
18	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.29	3.34	**9.63**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.44	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	8.20	6.61	**14.81**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.41	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	8.20	6.61	**14.81**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.41	20
21	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	11.99	13.13	**25.12**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.30	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.45	5.81	**19.26**	1.10	0.04	0.08	0.06	0.10	-	0.03	20.67	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	17.69	13.13	**30.82**	2.48	0.09	0.19	0.13	0.23	-	0.06	34.00	23
24	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	17.69	13.13	**30.82**	2.48	0.09	0.19	0.13	0.23	-	0.06	34.00	24
25	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.99	3.34	**15.33**	0.63	0.02	0.05	0.03	0.06	-	0.02	16.14	25
26	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.90	6.61	**20.51**	1.25	0.05	0.09	0.06	0.12	-	0.03	22.11	26
27	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.90	6.61	**20.51**	1.25	0.05	0.09	0.06	0.12	-	0.03	22.11	27
28	LED	RATE A (Existing pole)	200W	CLS 10		70	7.53	5.57	**13.10**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.45	28
29	LED	RATE A (Existing pole)	200W	CLS 12		70	6.29	5.57	**11.86**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.21	29
30	LED	RATE A (Existing pole)	100W	CLS 14		35	5.72	2.79	**8.51**	0.53	0.02	0.04	0.03	0.05	-	0.01	9.19	30
31	LED	RATE A (Existing pole)	200W	CLS 15		70	7.29	5.57	**12.86**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.21	31
32	LED	RATE A (Existing pole)	200W	CLS 88		70	6.29	5.57	**11.86**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.21	32
33	LED	RATE B (30 Foot pole)	200W	CLS 11		70	13.18	5.57	**18.75**	1.05	0.04	0.08	0.05	0.10	-	0.03	20.10	33
34	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.83	5.57	**16.40**	1.05	0.04	0.08	0.05	0.10	-	0.03	17.75	34
35	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.31	2.79	**14.10**	0.53	0.02	0.04	0.03	0.05	-	0.01	14.78	35
36	LED	RATE B (30 Foot pole)	200W	CLS 17		70	12.79	5.57	**18.36**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.71	36
37																		37
38																		38

Line No.		Class	Distribution Charges: Distribution Charge, per Cust:	Additional Meter/ Generation Meter Charge[8]	Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3]	Facilities Charge, per kW[2,3]	Contract Demand Charges, contract kW[4]: Sum On Peak:	Sum Mid Peak:	Other:	Backup Service Variable T&G Demand Charges, metered kW: Sum On Peak:	Sum Mid Peak:	Other:	BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]: Sum On Peak:	Sum Mid Peak:	Sum Off Peak:	Other:	Maintenance Back-up Service[7]: Set @ 50% of Summer On-peak Variable T&G Demand Charges	BTER Energy, per kWh	Line No.
9	SSR II	SS-II GS	25.50	2.00	7.68											0.00697		0.07960	9
10	SSR III	LGS-1	15.80	5.75	4.25	$ 4.25			$ 1.39			$ 3.96				0.01212	$ 1.98	0.07960	10
11	LSR I	LGS-2S	122.40	12.25	2.80	2.80	$ 4.83	$ -	0.42	$ 13.73	$ -	1.18	$ 0.03473	$ -	$ 0.00267	0.00325	6.87	0.07960	11
12	LSR I	LGS-2P	207.70	54.25	2.80	2.80	4.24	-	0.42	12.05	-	1.18	0.02108	-	0.00088	0.00511	6.03	0.07960	12
13	LSR I	LGS-2T	182.00	88.25	CSF	0.90	4.42	-	0.39	12.59	-	1.11	0.03128	-	0.00023	0.00199	6.30	0.07960	13
14	LSR II	LGS-3S	122.00	14.75	2.75	2.75	4.92	-	0.52	14.00	-	1.48	0.02479	-	0.00196	0.00550	7.00	0.07960	14
15	LSR II	LGS-3P	214.10	67.75	2.60	2.60	4.35	-	0.59	12.37	-	1.66	0.02196	-	0.00476	0.00582	6.19	0.07960	15
16	LSR II[2]	LGS-3T	182.00	88.25	CSF	0.90	4.42	-	0.39	12.59	-	1.11	0.03128	-	0.00023	0.00199	6.30	0.07960	16
17	LSR III[9]	LGS-XS	4,743.00	16.70	2.25	2.25	4.92	-	0.52	14.00	-	1.48	0.02479	-	0.00196	0.00550	7.00	0.07960	17
18	LSR III[9]	LGS-XP	4,743.00	53.80	3.05	3.05	4.35	-	0.59	12.37	-	1.66	0.02196	-	0.00476	0.00582	6.19	0.07960	18
19	LSR III[1,9]	LGS-XT	4,743.00	91.80	CSF	na	4.42	-	0.39	12.59	-	1.11	0.03128	-	0.00023	0.00199	6.30	0.07960	19
20	LSR I WP	LGS-2-WPS	128.70	12.25	1.10	1.10	4.83	-	0.42	13.73	-	1.18	0.04493	-	0.01898	0.01899	6.87	0.07960	20
21	LSR I WP	LGS-2-WPP	208.60	54.25	1.55	1.55	4.24	-	0.42	12.05	-	1.18	0.04568	-	0.00786	0.00787	6.03	0.07960	21
22	LSR I WP	LGS-2-WPT	169.10	92.00	CSF	0.90	4.42	-	0.39	12.59	-	1.11	0.03965	-	0.00781	0.00642	6.30	0.07960	22
23	LSR II WP	LGS-3-WPS	149.90	14.75	1.25	1.25	4.92	-	0.52	14.00	-	1.48	0.12358	-	0.02370	0.02371	7.00	0.07960	23
24	LSR II WP	LGS-3-WPP	234.20	67.75	1.00	1.00	4.35	-	0.59	12.37	-	1.66	0.05724	-	0.00335	0.00336	6.19	0.07960	24
25	LSR II WP	LGS-3-WPT	189.10	88.25	CSF	0.90	4.72	-	0.59	13.43	-	1.66	0.05065	-	0.00330	0.00198	6.72	0.07960	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF cha (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are customer spe
3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
4. The contract demand charge is set at 26% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.
5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See note
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated costs
9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charges

Proposed Distribution Only Service (DOS) Rates

Line No.	Class	Note	Distribution Charge, per Customer	Total Facilities Charge, per kW (1)	Additional Meter Charge, per Meter	LGSX CSF Charges (monthly dollar charge for entire class)	NDPP	ESAP	Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR)	Line No.
8	GS	1	$ 25.50		$ 2.00		$ 0.00142	$ 0.00002	$ 0.01037	8
9	LGS-1	1	15.80	$ 4.25	5.75		0.00142	0.00002	0.00306	9
10	LGS-2S		122.40	2.80	12.25		0.00142	0.00002	0.00443	10
11	LGS-2P		207.70	2.80	54.25		0.00142	0.00002	0.00516	11
12	LGS-2T	2	182.00	0.90	88.25		0.00142	0.00002	0.00306	12
13	LGS-3S		122.00	2.75	14.75		0.00142	0.00002	0.00514	13
14	LGS-3P		214.10	2.60	67.75		0.00142	0.00002	0.00646	14
15	LGS-3T	2	182.00	0.90	88.25		0.00142	0.00002	0.00239	15
16	LGS-XS	3	4,743.00	2.25	16.70	$ 1,802.00	0.00142	0.00002	0.00514	16
17	LGS-XP	3	4,743.00	3.05	53.80	$ 53,727.00	0.00142	0.00002	0.00646	17
18	LGS-XT	3	4,743.00	na	91.80	$ 30,724.00	0.00142	0.00002	0.00239	18
19	LGS-2S-WP		128.70	1.10	12.25		0.00142	0.00002	0.01178	19
20	LGS-2P-WP		208.60	1.55	54.25		0.00142	0.00002	0.00778	20
21	LGS-2T-WP	2	169.10	0.90	92.00		0.00142	0.00002	0.00873	21
22	LGS-3S-WP		149.90	1.25	14.75		0.00142	0.00002	0.01722	22
23	LGS-3P-WP		234.20	1.00	67.75		0.00142	0.00002	0.00494	23
24	LGS-3T-WP	2	189.10	0.90	88.25		0.00142	0.00002	0.00873	24
25	SL	4					0.00142	0.00002		25
26	GS-Pal	4					0.00142	0.00002		26

Line No.	Additional Charges			Line No.
27				27
28	Additional Charges:			28
29	Separate Billing			29
30	DOS LGS-X & LGS-WP-X:	$ 12.00	Per additional bill	30
31	Power Factor Charges ($/kVarh)[5]:			31
32	Summer:	$ 0.00200	$/kVarh	32
33	Winter:	0.00100	$/kVarh	33
34	Non-X class Customer Specific Facilities:	0.00325	Per $ of Utility Investment	34
35		0.00059	$ per Customer Contributed Investment	35
36	R-BTER - 2016 charge ($/kWh)[6]:	0.00139		36
37	R-BTER - 2017 charge ($/kWh)[6]:	0.00095		37
38	DECOM REV			38

(1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

(2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

(3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

(4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

(5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

Nevada Power Company

Statement O

Summary of Incremental Price (IP) Generation Capacity Rates

Line No.	Class[1]	Sales (kWh)	Marginal Generation Revenue	Reconciled Generation Cost per kWh[2]
8	**Bundled Service**			
9	GS	612,055,143	$ 12,249,323	$ 0.02001
10	LGS-1	4,073,133,716	92,361,475	0.02268
11	LGS-2S	2,429,180,261	49,438,288	0.02035
12	LGS-2P	69,583,297	1,209,653	0.01738
13	LGS-2T	no customers	(set @ LGS-3T)	0.04460
14	LGS-3S	768,658,032	14,257,152	0.01855
15	LGS-3P	1,393,295,183	33,257,945	0.02387
16	LGS-3T	247,665,929	11,045,998	0.04460
17	LGS-XS	0	(set @ LGS-3S)	0.01855
18	LGS-XP	0	(set @ LGS-3P)	0.02387
19	LGS-XT	0	(set @ LGS-3T)	0.04460
20	LGS-2S-WP	14,877,558	209,774	0.01410
21	LGS-2P-WP	11,147,772	133,430	0.01197
22	LGS-2T-WP	no customers	(set @ LGS-3T)	0.04460
23	LGS-3S-WP	4,412,814	56,696	0.01285
24	LGS-3P-WP	19,004,483	187,500	0.00987
25	LGS-3T-WP	no customers	(set @ LGS-3T)	0.04460
26	SL	129,054,441	2,131,470	0.01652
27	GS-Pal	2,217,456	37,305	0.01682
28	IAIWP	no customers	(set @ LGS-3S)	0.02268
29				
30	**Current LSR & Optional/Trial TOU Classes with Customers:**			
31	LSR-1: LGS-2S		(set @ LGS-2S)	0.02035
32	LSR-1: LGS-2P		(set @ LGS-2P)	0.01738
33	LSR-1: LGS-2T		(set @ LGS-2T)	0.04460
34	LSR-2: LGS-3P		(set @ LGS-3P)	0.01855
35	LSR-2: LGS-3T		(set @ LGS-3T)	0.04460
36	LSR-2: LGS-3S-WP		(set @ LGS-3S-WP)	0.01285
37	LSR-2: LGS-3P-WP		(set @ LGS-3P)	0.00987
38	LSR-2: LGS-2S-WP		(set @ LGS-2S)	0.01410
39	OGS-TOU		(set @ GS)	0.02001
40	OLGS-1-TOU		(set @ LGS-1)	0.02268
41				
42	**DOS Classes:**			
43	DOS: GS		(set @ GS)	0.02001
44	DOS: LGS-1		(set @ LGS-1)	0.02268
45	DOS: LGS-2S		(set @ LGS-2S)	0.02035
46	DOS: LGS-3S		(set @ LGS-3S)	0.01855
47	DOS: LGS-3P		(set @ LGS-3P)	0.02387
48	DOS: LGS-3T		(set @ LGS-3T)	0.04460
49	DOS: LGS-2S-WP		(set @ LGS-2S-WP)	0.01410
50	DOS: LGS-2T-WP		(set @ LGS-2T-WP)	0.04460
51	DOS: LGS-3S-WP		(set @ LGS-3S-WP)	0.01285
52	DOS: LGS-3P-WP		(set @ LGS-3P-WP)	0.00987
53	DOS: LGS-3T-WP		(set @ LGS-3T-WP)	0.04460

1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions. For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table.
2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class.

Reconciliation factor is: 112.5%

Calculation of Customer Specific Facilities Charges

Line No.		Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer / Total	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
	Customer Specific Facility Investment & Revenue Requirement					Total			
7	Investment Cost for all Transmission level customers					$ 42,182,585			7
8	Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment					$ 3,293,268			8
9	Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7)					$ 0.07807			9
10	Distribution Reconciliation Factor					62.3%			10
11	Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10)					$ 0.03896			11
12									12
13	**CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above**								13
16	Individual CSFC	Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	16
17	LHOIST	LGS-3T	Bundled	$ 744,171	$ 0.03896	$ 29,023	$ 0.00325	$ 2,418.56	17
18	SA RECYCLING	LGS-3T	Bundled	1,366,297	0.03896	53,286	0.00325	4,440.47	18
19	VENETIAN	LGS-3T	Bundled	6,606,728	0.03896	257,662	0.00325	21,471.87	19
20	HOLDER	LGS-3T	Bundled	2,136,118	0.03896	83,309	0.00325	6,942.38	20
21	SNWA LAMB	LGS-3T	DOS	286,690	0.03896	11,181	0.00325	931.74	21
22	SNWA LAMB	LGS-3T	DOS	286,690	0.03896	11,181	0.00325	931.74	22
23	SNWA SLOAN	LGS-3T	DOS	697,203	0.03896	27,191	0.00325	2,265.91	23
24	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03896	24,254	0.00325	2,021.17	24
25	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03896	24,254	0.00325	2,021.17	25
26	CCWRD2	LGS-3T	DOS	110,617	0.03896	4,314	0.00325	359.50	26
27	CCWRD2	LGS-3T	DOS	62,534	0.03896	2,439	0.00325	203.24	27
28	CCWRD2	LGS-3T	DOS	693,608	0.03896	27,051	0.00325	2,254.23	28
29	MGM	LGS-3T	DOS	22,571,345	0.03896	880,282	0.00325	73,356.87	29
30	MGM	LGS-3T	DOS	1,434,005	0.03896	55,926	0.00325	4,660.52	30
31	CAESAR'S	LGS-3T	DOS	1,025,601	0.03896	39,998	0.00325	3,333.20	31
32	AIR LIQUIDE	LGS-3T	DOS	96,488	0.03896	3,763	0.00325	313.59	32
33	SNWA PP4	LGS-3T-WP	DOS	30,192	0.03896	1,177	0.00325	98.12	33
34	SNWA PP5	LGS-3T-WP	DOS	1,370,352	0.03896	53,444	0.00325	4,453.64	34
35	SNWA PP6	LGS-3T-WP	DOS	672,178	0.03896	26,215	0.00325	2,184.58	35
36	SNWA HACIENDA	LGS-3T-WP	DOS	327,114	0.03896	12,757	0.00325	1,063.12	36
37	SNWA PP3	LGS-2T-WP	DOS	420,860	0.03896	16,414	0.00325	1,367.80	37
38	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	1,891,817	0.03896	73,781	0.00325	6,148.41	38
39	NP RED ROCK LLC	OLGS-3P HLF	Bundled	814,244	0.03896	31,756	0.00325	2,646.29	39
40	POLY-WEST INC	OLGS-3P HLF	Bundled	275,872	0.03896	10,759	0.00325	896.58	40
41	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	376,661	0.03896	14,690	0.00325	1,224.15	41
42	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	951,162	0.03896	37,095	0.00325	3,091.28	42
43	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	488,832	0.03896	19,064	0.00325	1,588.70	43
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	628,800	0.03896	24,523	0.00325	2,043.60	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	623,669	0.03896	24,323	0.00325	2,026.92	45
46	POLY-WEST 2089379	OLGS-3P HLF	Bundled	275,872	0.03896	10,759	0.00325	896.58	46
47									47
48									48
49									49
50									50
51	Subtotals by Class and Service								51
52	LGS-3T - Bundled	LGS-3T	Bundled	$ 10,853,314	0.03896	423,279	0.00325	35,273	52
53	LGS-3T - DOS	LGS-3T	DOS	28,508,575	0.03896	1,111,834	0.00325	92,653	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	0.03896	-	0.00325	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	420,860	0.03896	16,414	0.00325	1,368	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	0.03896	-	0.00325	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	2,399,836	0.03896	93,594	0.00325	7,799	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	6,326,928	0.03896	246,750	0.00325	20,563	58
59					avg.		avg.		59
60	Total			$ 48,509,514	0.03900	$ 1,891,871	0.00325	$ 157,656	60
61					rounding>>	$ 0		$ 0	61
62	**Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)**						^^^^^^^^^^^^^		62
63							Proposed		63
64	Investment Cost for Transmission level customers:					$ 42,182,585	Tariff Recovery		64
65	Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 64 * line 11):					$ 3,293,268	Rate per Dollar		65
66	Distribution Reconciliation Factor (line 11):					62.3%	of Facility		66
67	Reconciled Investment Cost (line 66 * line 65):					$ 2,050,918	Investment		67
68	Annual facility kW determinants					2,270,623			68
69	Per kW facilty rate (line 67 / Line 68)					$ 0.90			69

Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Line No.	**Development of Annual & Monthly Per Dollar of Investment Recovery Rate**	(a)	(b)			(c)	Line No.
7							7
8	Annual: Dist Reconciliation Factor	X	Dollar O&M/A&G Recovery Per Dollar of Contributed Investment				8
9	62.3%	X	$0.01062	=	$	0.00661	9
10	Monthly: (annual rate divided by 12)			=	$	0.00059	10
11							11
12							12

Line No.	Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	Dollar Per Dollar of Investment $ (cost based -- before reconciliation) [(b) / (a)]	Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment	Line No.
13							Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer				13
15	**CIAC Investment & O&M and A&G Revenue Requirement**										15
17											17
18	LHOIST	LGS-3T	Bundled	-	$ -	$0.01062	$ -	$ 0.00059	$ -	$ -	18
19	SA RECYCLING	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	19
20	VENETIAN	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	20
21	HOLDER	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	21
22	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	22
23	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	23
24	SNWA SLOAN	LGS-3T	DOS	826,580	8,780	$0.01062	826,580	0.00059	487.68	5,852.16	24
25	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	25
26	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	26
27	CCWRD2	LGS-3T	DOS	374,615	3,979	$0.01062	374,615	0.00059	221.02	2,652.24	27
28	CCWRD2	LGS-3T	DOS	211,779	2,249	$0.01062	211,779	0.00059	124.95	1,499.40	28
29	CCWRD2	LGS-3T	DOS	2,348,976	24,950	$0.01062	2,348,976	0.00059	1,385.90	16,630.80	29
30	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	30
31	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	31
32	CAESAR'S	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	32
33	AIR LIQUIDE	LGS-3T	DOS	4,942,256	52,495	$0.01062	4,942,256	0.00059	2,915.93	34,991.16	33
34	SNWA PP4	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	34
35	SNWA PP5	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	35
36	SNWA PP6	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	36
37	SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	37
38	SNWA PP3	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	38
39	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	39
40	NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	40
41	POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	41
42	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	42
43	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	43
44	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	45
46	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	46
47	POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	47
48											48
49											49
50											50
51	Subtotals by Class and Service										51
52	LGS-3T - Bundled	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	52
53	LGS-3T - DOS	LGS-3T	DOS	11,993,826	127,395	$0.01062	11,993,826	0.00059	7,076.36	84,916.32	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,100	$0.01062	103,546	0.00059	61.09	733.08	58
59											59
60	Total			$ 19,321,217	$ 205,224	$0.01062	$ 38,642,434		$ 11,399.52	$ 136,794.24	60
61						Marginal O&M from MCS					61
62						$205,224					62

Nevada Power Company
Statement O

Calculation of LGS-X Specific Charges

Line No.		Basic Service Charge: Billing Units	Basic Service Charge: Cost-Based Revenue	Basic Service Charge: Rate	Additional Meter Charge: Billing Units	Additional Meter Charge: Cost-Based Revenue	Additional Meter Charge: Rate	Separate Bill: Billing Units	Separate Bill: Cost-Based Revenue	Separate Bill: Rate	Line No.
7	**Basic Service, Additional Meter and Separate Billing Charges**										7
8			D Reconc.	62%							8
11	LGS-XS	-	$ -		60	$ 1,004.70	$ 16.70	-	$ -		11
12	LGS-XP	24	$ 29,085.61	$ 1,211.90	156	$ 8,399.57	$ 53.80	24	$ 271.36	$11.31	12
13	LGS-XT	12	$ 14,542.81	$ 1,211.90	36	$ 3,305.67	$ 91.80	12	$ 135.68	$11.31	13
14	Total	36	$ 43,628.42	**$4,743.00**	252	$ 12,709.94	**$50.40**	36	$ 407.03	**$12.00**	14
15			Present DOS Rate:	$4,743.00					Present Rate:	$93.50	15
16			Percent Change:	0.0%					Percent Change:	-87.2%	16

LGS-X Customer Specific Facilities

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment	Line No.
22	Horseshoe	1231089	LGS-XP DOS	$ 3,740	$ 44,880		$ 4,191	$ 50,292		22
23	Horseshoe	1231091	LGS-XS DOS	1,608	19,296		1,802	21,624		23
24	Paris	1735149	LGS-XP DOS	5,068	60,816		5,679	68,148		24
25	Paris	1735152	LGS-XP DOS	5,068	60,816		5,679	68,148		25
26				$ 15,484	$ 185,808	$ 2,066,291	$ 17,351	$ 208,212	$ 2,189,516	26
34	New Castle Corp (Excalibur)	1396169	LGS-XP DOS	$ 4,710	$ 56,520		$ 5,006	$ 60,072		34
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	4,687	56,244		4,981	59,772		35
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-		36
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-		37
38	Luxor	1500684	LGS-XP DOS	5,640	67,680		5,994	71,928		38
39	Luxor	1500685	LGS-XP DOS	7,006	84,072		7,446	89,352		39
40	Luxor	1511139	LGS-XS DOS	-	-		-	-		40
41	Luxor	1652129	LGS-XP DOS	1,698	20,376		1,805	21,660		41
42	Mandalay Bay	1714502	LGS-XP DOS	6,090	73,080		6,473	77,676		42
43	Mandalay Bay	1714503	LGS-XP DOS	6,090	73,080		6,473	77,676		43
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-		44
45				$ 35,921	$ 431,052	$ 4,885,159	$ 38,178	$ 458,136	$ 4,885,159	45
47	Park MGM	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -		47
48	Park MGM	1607750	LGS-XT DOS	9,790	117,480		10,335	124,020		48
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-		49
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-		50
51	Bellagio	1693991	LGS-XT DOS	19,315	231,780		20,389	244,668		51
52	Park MGM	1782548	LGS-XP DOS	-	-		-	-		52
53				$ 29,105	$ 349,260	$ 3,841,860	$ 30,724	$ 368,688	$ 3,841,860	53
55	Subtotals by Class and Service		LGS-XS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	55
56			LGS-XP	-	-	-	-	-	-	56
57			LGS-XT	-	-	-	-	-	-	57
58			LGS-XS DOS	**1,608**	**19,296**	-	**1,802**	**21,624**	-	58
59			LGS-XP DOS	**49,797**	**597,564**	-	**53,727**	**644,724**	-	59
60			LGS-XT DOS	**29,105**	**349,260**	-	**30,724**	**368,688**	-	60
61			Total for Class	**$ 80,510**	**$ 966,120**	$ -	**$ 86,253**	**$ 1,035,036**	$ -	61

63 Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying Investment has remained the same), and allocating the Primary Charges in proportion to the 63
64 current Primary charges. 64

EXHIBIT PREST DIRECT - 4

Nevada Power Company

Exhibit Prest Direct-4

Docket No. 23-06XXX

Statement O

MCS, per NRS, new TOU, Joint Dispatch, RS Cap

Nevada Power Company
Exhibit Prest Direct-4
Statement O

Table of Contents

- The unbundled revenue requirement from Statement H is the starting point for deriving what is known to be the revenue target for rate design.
- The following adjustments are made to the Schedule H revenue requirement on this page:
    1) The proposed revenues for the standby (LSR & SSR), Optional TOU and DOS classes are derived from rates that are developed for the otherwise applicable class; thus, the resulting standby revenues are credited against the Schedule H revenue requirement, and the standby classes are excluded from the revenue reconciliation on page 3 and the capping mechanism (page 8).
    2) Power Factor and Additional Facilities and Maintenance revenues are credited against the distribution revenue requirement, and then in the revenue reconciliation process (page 3) they are assigned to specific classes that impose these costs.

- Reconciles the Marginal Revenue by class to the Adjusted, Unbundled Revenue Requirement for Rate Design using Equal Percent of Marginal Cost (EPMC). The marginal revenue, by function and class, comes directly from the Marginal Cost Study (MCS), and is shown on page 2 of Workpaper 1. The unbundled revenue requirement comes from the Unbundled Schedule H and is summarized on line no. 11, page 1 of Statement O. The adjustments to the revenue requirement are summarized below.
- Reconcile Distribution & Transmission by Function using EPMC: Distribution Marginal Revenue to Distribution Revenue Requirement, and Transmission to Transmission.
- Reconcile Generation and Energy functions combined together on EPMC.

Revenue Adjustments made to the Reconciliation:

Distribution

1) Certain "other revenue" components (miscellaneous revenues (connect/disconnect), returned check, power pedestal, and miscellaneous damage) have been credited to the specific classes in which they are generated, consistent with the Commission's Order in Docket No. 01-10001, which was first implemented in Docket No. 03-10001. They are included in the total DRR that is reconciled, then subtracted from (i.e., credited to) the reconciled distribution revenue requirements of the specific classes that paid them. Thus classes that pay for the services get the benefit through the direct assignment to those classes. These "other revenues" total approximately $4,946.4 million.
2) Revenue from Power Factor services and Additional Facilities and Maintenance (AF&M) services are subtracted (credited to) the DRR on page 7, then get directly assigned to the classes identified with these costs in the reconciliation.

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Generation and Energy

5) The combined generation and energy revenue requirement (G&ERR) is increased by the amount of the credit given to the LGS-3T class on the BTER portion of WAPA energy deliveries associated with one customer included in the class for reconciliation purposes. The credit is then specifically assigned to (or subtracted from) the LGS-3T's reconciled G&E RR. The current WAPA energy credit is $1098.6 thousand.
6) Also, the G&ERR is increased by the amount of the Hoover B Benefit provided to the residential class. The amount of the benefit is then specifically assigned to (or subtracted from) the residential classes' G&ERR based on their relative share of residential kWh sales. The current Hoover B Benefit is $14.2 million.

Standby, Optional Time-of Use, DOS and Other Revenue Credit Adjustments

7) Standby (SSR & LSR) and Optional Time-of-Use (TOU) services have rates that are set off of the otherwise applicable classes marginal costs and/or rates. Accordingly the test period revenues generated by these schedules are treated as credits to proportionately reduce the generation, transmission and distribution revenue requirements on page 4, thereby reducing the revenue requirement and rates for all customers. The total of these revenue credits is approximately -$11.3 million.
8) DOS revenues are treated in a manner analogous to standby and optional TOU service revenues, as DOS distribution rates and non-bypassable charges are set using the otherwise applicable bundled schedule (OAS). The DOS revenues are credited against the revenue requirement, reducing rates for all customers. All DOS revenues, except the non-bypassable interclass rate rebalancing (IRR) revenues, are credited to the DRR. The IRR revenues are credited proportionately to reduce the generation, transmission and distribution revenue requirements on pages 3-7. The current DOS revenue is $31.2 million.

Page 8 **Final Revenue Allocation: Final Class Revenue Requirements Based on Maximum Percent Increase (Capping) and unrestricted floor Mechanism as follows:**

Subject to the caps set forth above:

1) The difference between any capped class revenue and its cost based revenue is re-allocated to other classes using EPMC;
2) Two allocations using the above procedure are required to reach the final revenue requirements that satisfy the imposed capping criteria;
3) The reallocation creates an interclass subsidy, which is the difference between the final revenue requirement shown on this page, and the cost-based revenue requirement resulting from the reconciliation process (page 3-7). If the difference between these two values for any class is negative, then the class is receiving a subsidy from other classes; if the value is positive, then the class is providing a subsidy to other classes.

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Workpapers

Workpaper 1

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Nevada Power Company
Statement O

Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

Line No	Class	Note	Annualized Bills	Sales (MWh)	Present Rate Revenue: Revenue	Present Rate Revenue: Effective Rate ($/kWh)	Results if Class Revenue Requirements were Set @ Reconciled Cost [1]: Cost-Based Revenue	% Change from Present	Effective Rate ($/kWh)	Class Revenue Requirements Based on Proposed Capping Methodology [2]: Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present	Effective Rate ($/kWh)	Combined AB 405 Proposed Revenue Change: % Change from Present	Effective Rate ($/kWh)	Line No
8																	8
9	Classes in Revenue Reconciliation																9
10	RS		6,219,660	7,262,589	$ 1,124,472	$ 0.15483	$ 1,128,591	0.37%	$ 0.15540	$ 1,148,240	$ 19,649	$ 23,768	2.11%	$ 0.15810	2.38%	$ 0.15235	10
11	RM		3,424,968	2,298,671	339,331	0.14762	322,392	-4.99%	0.14025	339,966	17,574	636	0.19%	0.14790	0.19%	0.14784	11
12	LRS		2,484	37,526	5,291	0.14099	4,909	-7.21%	0.13083	5,255	345	(36)	-0.68%	0.14003	-0.59%	0.14047	12
13	GS		931,320	612,056	83,497	0.13642	76,735	-8.10%	0.12537	82,512	5,777	(985)	-1.18%	0.13481	-1.18%	0.13460	13
14	LGS-1		385,308	4,073,470	485,467	0.11918	476,394	-1.87%	0.11695	493,680	17,286	8,213	1.69%	0.12119	1.71%	0.12111	14
15	LGS-2S		14,676	2,437,061	271,383	0.11136	262,498	-3.27%	0.10771	273,770	11,273	2,387	0.88%	0.11234			15
16	LGS-2P		276	69,583	7,301	0.10492	6,971	-4.52%	0.10018	7,326	355	25	0.34%	0.10528			16
17	LGS-2T	3	-	-	-	---	-	na	---	-	-	-	na	---			17
18	LGS-3S		1,392	768,658	82,792	0.10771	79,202	-4.34%	0.10304	83,129	3,927	338	0.41%	0.10815			18
19	LGS-3P	4	1,332	1,826,673	195,666	0.10712	183,950	-5.99%	0.10070	195,065	11,115	(602)	-0.31%	0.10679			19
20	LGS-3T	4	48	618,671	59,254	0.09578	58,394	-1.45%	0.09439	60,248	1,854	994	1.68%	0.09738			20
21	LGS-XS	5	-	-	-	---	-	na	---	-	-	-	na	---			21
22	LGS-XP	5	-	-	-	---	-	na	---	-	-	-	na	---			22
23	LGS-XT	5	-	-	-	---	-	na	---	-	-	-	na	---			23
24	LGS-2S-WP		276	14,878	1,343	0.09025	1,509	12.39%	0.10144	1,636	127	293	21.85%	0.10998			24
25	LGS-2P-WP		108	11,148	1,123	0.10073	1,032	-8.14%	0.09253	1,105	74	(18)	-1.56%	0.09916			25
26	LGS-2T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			26
27	LGS-3S-WP		24	4,413	372	0.08426	452	21.50%	0.10238	507	55	135	36.34%	0.11488			27
28	LGS-3P-WP		72	19,004	1,742	0.09168	1,653	-5.13%	0.08698	1,744	91	1	0.07%	0.09175			28
29	LGS-3T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			29
30	SL		7,224	129,054	11,437	0.08862	14,531	27.05%	0.11260	16,692	2,161	5,255	45.95%	0.12934			30
31	RS-Pal		-	578	85	0.14730	95	11.81%	0.16469	103	8	18	21.28%	0.17864			31
32	GS-Pal		-	2,217	305	0.13751	348	14.20%	0.15703	382	33	77	25.15%	0.17210			32
33	IAIWP	3	-	-	-	---	-	na	---	-	-	-	na	---			33
34	RS-NEM	6	962,904	837,375	80,923	0.16928	174,903	116.14%	0.20887	85,821	(89,082)	4,898	6.05%	0.17952			34
35	RM-NEM	6	5,652	3,554	397	0.15278	767	93.48%	0.21586	399	(369)	2	0.54%	0.15360			35
36	LRS-NEM	6	204	571	92	0.16155	115	24.43%	0.20132	97	(18)	4	4.56%	0.16891			36
37	GS-NEM	6	1,548	2,985	275	0.11395	504	83.04%	0.16891	272	(233)	(4)	-1.41%	0.11234			37
38	LGS-1 NEM	6	4,248	79,974	9,100	0.12410	11,495	26.32%	0.14374	9,339	(2,157)	239	2.62%	0.12735			38
39																	39
45	Partial Requirements & Optional Schedule Groups not included in Reconciliation																45
46	Optional TOU		66,924	447,300	48,258	0.10789	nc	nc	nc	48,803	nc	545	1.13%	0.10911	---	---	46
47	Optional TOU EVRR		38,052	65,465	8,716	0.13314	nc	nc	nc	9,066	nc	350	4.02%	0.13849			47
48	NEM Optional TOU		12,331	7,602	1,090	0.14340	nc	nc	nc	1,471	nc	381	34.93%	0.19350	---	---	48
49	NEM EVRR		15,156	14,179	1,759	0.12403	nc	nc	nc	2,310	nc	552	31.37%	0.16294			49
50	Standby		240	146,311	15,217	0.10400	nc	nc	nc	15,503	nc	286	1.88%	0.10596	---	---	50
51	EVCCR		156	14,835	1,829	0.12331	nc	nc	nc	1,817	nc	(12)	-0.66%	0.12250			51
52	DOS	7	1,980	2,810,428	15,394	0.00548	nc	nc	nc	31,203	nc	15,809	102.69%	0.01110	---	---	52
53																	53
54	Total (Bundled & DOS)		12,094,315	23,793,360	$ 2,805,178	$ 0.11790	$ 2,795,946	na[1]	nc	$ 2,871,860	---	$ 66,682	2.38%	$ 0.12070	2.38%	$ 0.12070	54
55																	55

$	2,871,796	Statement I Revenue Requirement
$	66,682	Change in Revenue Requiremen $ 65
	2.38%	Percent Change

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.
2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.
3. No Customers in class
4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.
5. All customers in class are DOS customers; no bundled customers.
6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G customers.
7. The effective rate for DOS customers is only for distribution rates, and does not consider OATT and energy rates.

Nevada Power Company

Statement O

Exhibit Prest Direct-4

Docket No. 23-06XXX

MCS, per NRS, new TOU, Joint Dispatch, RS Cap

Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
8								8
9	Marginal Cost Revenue		$ 2,099,905	$ 781,213	$ 524,669	$ 113,276	$ 680,747	9
10								10
11	Unbundled Revenue Requirement	1	$ 2,871,796	$ 1,718,820	$ 562,479	$ 150,868	$ 439,629	11
12						Total G, T & D	$ 1,152,976	12
13	Total Revenue Requirement Adjustments for Rate Design							13
14	Revenue Credit to Dist. for Specific Class Assignment							14
15	Power Factor (PF)		(917)				(917)	15
16	Additional Facilities and Maintenance (AF&M)		(71)				(71)	16
17								17
18	Optional TOU Revenue		(33,869)	(21,873)	(5,852)	(1,570)	(4,574)	18
19	Optional TOU NEM revenues		(3,781)	(1,833)	(951)	(255)	(743)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(2,716)	(1,697)	(497)	(133)	(388)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	-				-	21
22	DOS Decommissioning Revenue		(800)		(800)			22
23	DOS Interclass Rate-Rebalancing Revenue		(14,717)		(7,180)	(1,926)	(5,611)	23
24	OLGS-3P HLF & MPE Rate Design Revenue adjustment		545	-	266	71	208	24
25	MPE Revenue Adjustment		6,430	3,972	2,458			25
26	EVCCR Discount Revenue Adjustment		-		-	-		26
27	Total		$ (49,897)	$ (21,430)	$ (12,556)	$ (3,812)	$ (12,098)	27
28								28
29	Class Specific Revenue Requirement Adjustments							29
30	Other Revenue	4	5,368				5,368	30
31	Customer Specific Facilities		(2,801)				(2,801)	31
32	DOS Impact Fee revenue		(1,392)	(511)	(881)			32
33	BTER Energy Credits (WAPA, Hoover B)		(15,264)	(15,264)				33
34	Total Class Specific Adjustments		$ (14,089)	$ (15,775)	$ (881)	$ -	$ 2,567	34
35								35
36	Total Adjustments to Total Revenue Requirement		$ (63,986)	$ (37,205)	$ (13,437)	$ (3,812)	$ (9,531)	36
37								37
38	Target Revenue Requirement for Rate Design		$ 2,807,810	$ 1,342,792	$ 903,047	$ 147,056	$ 426,731	38
39								39

42 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing) 42

43 2. Includes LSR revenues and optional time-of-use revenues. 43

44 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 44

45 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 45

46 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure. 46

Nevada Power Company

Statement O

Transmission Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Transmission Cost Based Class Revenue for Rate Design	Line No.
8															8
9	RS	$ 50,251	44.36%	$ 66,928	$ (696)	$ (113)	$ (59)	$ -	$ (854)	$ 32	$ -	$ -	$ -	$ 65,236	9
10	RM	13,031	11.50%	17,356	(181)	(29)	(15)	-	(222)	8	-	-	-	16,917	10
11	LRS	214	0.19%	284	(3)	(0)	(0)	-	(4)	0	-	-	-	277	11
12	GS	2,578	2.28%	3,434	(36)	(6)	(3)	-	(44)	2	-	-	-	3,347	12
13	LGS-1	18,289	16.15%	24,358	(253)	(41)	(22)	-	(311)	12	-	-	-	23,742	13
14	LGS-2S	9,442	8.34%	12,576	(131)	(21)	(11)	-	(161)	6	-	-	-	12,258	14
15	LGS-2P	225	0.20%	299	(3)	(1)	(0)	-	(4)	0	-	-	-	292	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	2,650	2.34%	3,530	(37)	(6)	(3)	-	(45)	2	-	-	-	3,440	17
18	LGS-3P	6,131	5.41%	8,166	(85)	(14)	(7)	-	(104)	4	-	-	-	7,960	18
19	LGS-3T	2,042	1.80%	2,719	(28)	(5)	(2)	-	(35)	1	-	-	-	2,650	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	59	0.05%	79	(1)	(0)	(0)	-	(1)	0	-	-	-	77	23
24	LGS-2P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	14	0.01%	19	(0)	(0)	(0)	-	(0)	0	-	-	-	19	26
27	LGS-3P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	94	0.08%	125	(1)	(0)	(0)	-	(2)	0	-	-	-	122	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	-	-	-	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	-	-	-	1	31
32	IAIWP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	7,640	6.74%	10,175	(106)	(17)	(9)	-	(130)	5	-	-	-	9,918	33
34	RM-NEM	36	0.03%	48	(0)	(0)	(0)	-	(1)	0	-	-	-	47	34
35	LRS-NEM	4	0.00%	5	(0)	(0)	(0)	-	(0)	0	-	-	-	5	35
36	GS-NEM	20	0.02%	27	(0)	(0)	(0)	-	(0)	0	-	-	-	26	36
37	LGS-1-NEM	500	0.44%	666	(7)	(1)	(1)	-	(8)	0	-	-	-	649	37
38															38
39	TOTAL	$ 113,276	100.00%	$ 150,868	$ (1,570)	$ (255)	$ (133)	$ -	$ (1,926)	$ 71	$ -	$ -	$ -	$ 147,056	39
40				from Sch. H-2											40
41															41
42															42
43															43
44	Summation of NEM customers into Standard Schedule for Rate Design														44
45	RS	$ 57,891	51.11%	$ 77,103	$ (802)	$ (130)	$ (68)	$ -	$ (984)	$ 36	$ -	$ -	$ -	$ 75,154	45
46	RM	13,067	11.54%	17,403	(181)	(29)	(15)	-	(222)	8	-	-	-	16,964	46
47	LRS	217	0.19%	289	(3)	(0)	(0)	-	(4)	0	-	-	-	282	47
48	GS	2,598	2.29%	3,461	(36)	(6)	(3)	-	(44)	2	-	-	-	3,373	48
49	LGS-1	18,788	16.59%	25,024	(260)	(42)	(22)	-	(319)	12	-	-	-	24,391	49
50															50

Nevada Power Company

Statement O

Distribution Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Distribution Revenue	Percent of Total	Class Specific Adjustments: Other Revenue Adjustment	Class Specific Adjustments: Adjustment for Class Cust Spec. Facilities	Reconciled Distribution Revenue Requirement	Rate Design Revenue Adjustments: Power Factor Revenue	Additional Facilities & Maintenance Revenue	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Decommissioning Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	MPE Revenue Adjustment	EVCCR Discount Revenue Adjustment	Distribution Cost Based Class Revenue for Rate Design	Line No.
8																			8
9	RS	$ 340,083	50.16%	$ (2,192)		$ 219,630	$ (460)	$ (36)	$ (2,295)	$ (373)	$ (195)	$ -	$ (401)	$ (2,815)	$ 104	$ -	$ -	$ 213,160	9
10	RM	81,994	12.09%	(2,237)		51,244	(111)	(9)	(553)	(90)	(47)	-	(97)	(679)	25	-		49,684	10
11	LRS	995	0.15%	(0)		649	(1)	(0)	(7)	(1)	(1)	-	(1)	(8)	0	-		630	11
12	GS	25,019	3.69%	(235)		16,084	(34)	(3)	(169)	(27)	(14)	-	(30)	(207)	8	-		15,608	12
13	LGS-1	87,165	12.86%	(77)		56,777	(118)	(9)	(588)	(96)	(50)	-	(103)	(721)	27	-		55,119	13
14	LGS-2S	34,624	5.11%	(2)		22,582	(47)	(4)	(234)	(38)	(20)	-	(41)	(287)	11	-		21,923	14
15	LGS-2P	856	0.13%	(0)		558	(1)	(0)	(6)	(1)	(0)	-	(1)	(7)	0	-		542	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-		-	16
17	LGS-3S	9,639	1.42%	(0)		6,287	(13)	(1)	(65)	(11)	(6)	-	(11)	(80)	3	-		6,103	17
18	LGS-3P	30,314	4.47%	(0)	-	19,773	(41)	(3)	(205)	(33)	(17)	-	(36)	(251)	9	-		19,196	18
19	LGS-3T	1,674	0.25%	(0)	1,657	2,749	(2)	(0)	(11)	(2)	(1)	-	(2)	(14)	1	-		2,717	19
20	LGS-XS	61	0.01%	-	22	62	(0)	(0)	(0)	(0)	(0)	-	(0)	(1)	0	-		61	20
21	LGS-XP	2,581	0.38%	-	645	2,328	(3)	(0)	(17)	(3)	(1)	-	(3)	(21)	1	-		2,279	21
22	LGS-XT	29	0.00%	-	369	388	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		387	22
23	LGS-2S-WP	337	0.05%	-		220	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		213	23
24	LGS-2P-WP	171	0.03%	-		111	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		108	24
25	LGS-2T-WP	21	0.00%	-	16	30	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		29	25
26	LGS-3S-WP	353	0.05%	-		230	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		224	26
27	LGS-3P-WP	654	0.10%	-		427	(1)	(0)	(4)	(1)	(0)	-	(1)	(5)	0	-		414	27
28	LGS-3T-WP	113	0.02%	-	93	166	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		164	28
29	SL	2,021	0.30%	(20)		1,298	(3)	(0)	(14)	(2)	(1)	-	(2)	(17)	1	-		1,260	29
30	RS-Pal	55	0.01%	(0)		36	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		35	30
31	GS-Pal	184	0.03%	(0)		120	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		116	31
32	IAIWP	-	0.00%			-	-	-	-	-	-	-	-	-	-	-		-	32
33	RS-NEM	56,769	8.37%	(595)		36,433	(77)	(6)	(383)	(62)	(33)	-	(67)	(470)	17	-		35,353	33
34	RM-NEM	193	0.03%	(9)		117	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		113	34
35	LRS-NEM	48	0.01%	(0)		31	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		30	35
36	GS-NEM	127	0.02%	(0)		83	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		80	36
37	LGS-1-NEM	1,866	0.28%	(0)		1,217	(3)	(0)	(13)	(2)	(1)	-	(2)	(15)	1	-		1,181	37
38						not a sum													38
39	TOTAL	$ 677,946	100.00%	$ (5,368)	$ 2,801	$ 439,629	$ (917)	$ (71)	$ (4,574)	$ (743)	$ (388)	$ -	$ (800)	$ (5,611)	$ 208	$ -	$ -	$ 426,731	39
40						from Sch. H-2													40
41					exc. Specific Class adjustments $	442,196													41
42																			42
43						$ -													43
44	Summation of NEM customers into Standard Schedule for Rate Design																		44
45	RS	$ 396,852	58.54%	$ (2,786)	$ -	$ 256,064	$ (537)	$ (42)	$ (2,678)	$ (435)	$ (227)	$ -		$ (3,285)	$ 122	$ -	$ -	$ 248,514	45
46	RM	82,187	12.12%	(2,247)	-	51,361	(111)	(9)	(555)	(90)	(47)	-		(680)	25	-	-	49,797	46
47	LRS	1,043	0.15%	(0)	-	680	(1)	(0)	(7)	(1)	(1)	-		(9)	0	-	-	660	47
48	GS	25,146	3.71%	(235)	-	16,167	(34)	(3)	(170)	(28)	(14)	-		(208)	8	-	-	15,688	48
49	LGS-1	89,031	13.13%	(77)	-	57,994	(120)	(9)	(601)	(98)	(51)	-		(737)	27	-	-	56,300	49
50																			50

Rate Design Revenue Adjustments

Line No.	Class	Unreconciled Cost-Based Generation Revenue	Percent of Total	DOS R-BTER and BTER Impact Fee Revenue	Reconciled Generation Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS BTGR Impact Fee Revenue	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Generation Cost Based Class Revenue for Rate Design	Line No.
8																	8
9	RS	$ 226,699	43.21%	$ -	$ 395,649	$ (2,529)	$ (411)	$ (215)		$ (3,102)	$ 115	$ (381)		$ 1,062	$ -	$ 390,189	9
10	RM	63,525	12.11%	-	110,867	(709)	(115)	(60)		(869)	32	(107)		298	-	109,337	10
11	LRS	957	0.18%	-	1,671	(11)	(2)	(1)		(13)	0	(2)		4	-	1,648	11
12	GS	10,890	2.08%	-	19,006	(121)	(20)	(10)		(149)	6	(18)		51	-	18,743	12
13	LGS-1	82,110	15.65%	-	143,304	(916)	(149)	(78)		(1,124)	42	(138)		385	-	141,326	13
14	LGS-2S	43,951	8.38%	-	76,706	(490)	(80)	(42)		(601)	22	(74)		206	-	75,648	14
15	LGS-2P	1,075	0.20%	-	1,877	(12)	(2)	(1)		(15)	1	(2)		5	-	1,851	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	16
17	LGS-3S	12,675	2.42%	-	22,121	(141)	(23)	(12)		(173)	6	(21)		59	-	21,816	17
18	LGS-3P	29,567	5.64%	-	51,602	(330)	(54)	(28)		(405)	15	(50)		139	-	50,889	18
19	LGS-3T	9,820	1.87%	-	17,139	(110)	(18)	(9)		(134)	5	(16)		46	-	16,902	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	22
23	LGS-2S-WP	186	0.04%	-	325	(2)	(0)	(0)		(3)	0	(0)		1	-	321	23
24	LGS-2P-WP	119	0.02%	-	207	(1)	(0)	(0)		(2)	0	(0)		1	-	204	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	25
26	LGS-3S-WP	50	0.01%	-	88	(1)	(0)	(0)		(1)	0	(0)		0	-	87	26
27	LGS-3P-WP	167	0.03%	-	291	(2)	(0)	(0)		(2)	0	(0)		1	-	287	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	28
29	SL	1,895	0.36%	-	3,307	(21)	(3)	(2)		(26)	1	(3)		9	-	3,261	29
30	RS-Pal	9	0.00%	-	15	(0)	(0)	(0)		(0)	0	(0)		0	-	15	30
31	GS-Pal	33	0.01%	-	58	(0)	(0)	(0)		(0)	0	(0)		0	-	57	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	32
33	RS-NEM	38,507	7.34%	-	67,204	(430)	(70)	(36)		(527)	19	(65)		180	-	66,277	33
34	RM-NEM	177	0.03%	-	308	(2)	(0)	(0)		(2)	0	(0)		1	-	304	34
35	LRS-NEM	19	0.00%	-	33	(0)	(0)	(0)		(0)	0	(0)		0	-	33	35
36	GS-NEM	96	0.02%	-	167	(1)	(0)	(0)		(1)	0	(0)		0	-	165	36
37	LGS-1-NEM	2,142	0.41%	-	3,738	(24)	(4)	(2)		(29)	1	(4)		10	-	3,687	37
38					not a sum												38
39	TOTAL	$ 524,669	100.00%	$ -	$ 562,479	$ (5,852)	$ (951)	$ (497)		$ (7,180)	$ 266	$ (881)	$ -	$ 2,458	$ -	$ 903,047	39
40					from Sch. H-2												40
41			Generation Revenue for Rate Design	$	524,669	$ (975,417)											41
42			w/ Specific Class adjustments	$	915,684	Combined											42
43																	43
44																	44
45																	45
46	Summation of NEM customers into Standard Schedule for Rate Design																46
47	RS	$ 265,206	50.55%	$ -	$ 462,854	$ (2,958)	$ (480)	$ (251)	$ -	$ (3,629)	$ 134	$ (445)	$ -	$ 1,242	$ -	$ 456,466	47
48	RM	63,702	12.14%	-	111,176	(711)	(115)	(60)	-	(872)	32	(107)	-	298	-	109,642	48
49	LRS	976	0.19%	-	1,704	(11)	(2)	(1)	-	(13)	0	(2)	-	5	-	1,681	49
50	GS	10,986	2.09%	-	19,173	(123)	(20)	(10)	-	(150)	6	(18)	-	51	-	18,908	50
51	LGS-1	84,252	16.06%	-	147,043	(940)	(153)	(80)	-	(1,153)	43	(141)	-	395	-	145,013	51
52																	52

Nevada Power Company

Statement O

Energy Revenue by Class for Rate Design

					Class Specific Adjustments		Rate Design Revenue Adjustments										
Line No.	Class	BTER Revenue	Unreconciled Cost-Based Energy Revenue	Percent of Total	Hoover B, EDRR, MPE and WAPA Credits	Reconciled Energy Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS R-BTER and BTER Impact Fee Revenue	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Energy Cost Based Class Revenue for Rate Design	Excess/ Deficiency Present in BTER for Rate Design	Line No.
8																	8
9	RS	$ 611,088	$ 270,477	34.62%	$ (10,189)	$ 467,602	$ (7,573)	$ (635)	$ (588)	$ -	$ -	$ (177)	$ 1,375	$ -	$ 460,005	$ (151,083)	9
10	RM	193,415	86,098	11.02%	(3,219)	148,872	(2,411)	(202)	(187)	-	-	(56)	438	-	146,453	(46,961)	10
11	LRS	3,158	1,385	0.18%	(53)	2,393	(39)	(3)	(3)	-	-	(1)	7	-	2,354	(803)	11
12	GS	48,719	22,456	2.87%	-	39,668	(629)	(53)	(49)	-	-	(15)	114	-	39,038	(9,682)	12
13	LGS-1	324,204	147,347	18.86%	-	260,285	(4,125)	(346)	(320)	-	-	(96)	749	-	256,146	(68,057)	13
14	LGS-2S	193,969	87,965	11.26%	-	155,388	(2,463)	(206)	(191)	-	-	(58)	447	-	152,917	(41,051)	14
15	LGS-2P	5,539	2,477	0.32%	-	4,375	(69)	(6)	(5)	-	-	(2)	13	-	4,306	(1,233)	15
16	LGS-2T	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	61,185	27,851	3.57%	-	49,198	(780)	(65)	(60)	-	-	(18)	142	-	48,416	(12,770)	17
18	LGS-3P	145,403	64,832	8.30%	-	114,525	(1,815)	(152)	(141)	-	-	(42)	330	-	112,704	(32,699)	18
19	LGS-3T	49,246	22,104	2.83%	(1,099)	37,948	(619)	(52)	(48)	-	-	(14)	112	-	37,327	(11,919)	19
20	LGS-XS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	1,184	531	0.07%	-	938	(15)	(1)	(1)	-	-	(0)	3	-	923	(261)	23
24	LGS-2P-WP	887	392	0.05%	-	692	(11)	(1)	(1)	-	-	(0)	2	-	681	(206)	24
25	LGS-2T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	351	170	0.02%	-	301	(5)	(0)	(0)	-	-	(0)	1	-	296	(55)	26
27	LGS-3P-WP	1,513	691	0.09%	-	1,220	(19)	(2)	(2)	-	-	(0)	4	-	1,201	(312)	27
28	LGS-3T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	10,273	5,688	0.73%	-	10,048	(159)	(13)	(12)	-	-	(4)	29	-	9,888	(385)	29
30	RS-Pal	49	26	0.00%	-	46	(1)	(0)	(0)	-	-	(0)	0	-	45	(3)	30
31	GS-Pal	177	100	0.01%	-	177	(3)	(0)	(0)	-	-	(0)	1	-	174	(3)	31
32	IAIWP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	40,228	36,847	4.72%	(700)	64,390	(1,032)	(86)	(80)	-	-	(24)	187	-	63,355	23,127	33
34	RM-NEM	218	177	0.02%	(4)	309	(5)	(0)	(0)	-	-	(0)	1	-	304	85	34
35	LRS-NEM	48	28	0.00%	(1)	48	(1)	(0)	(0)	-	-	(0)	0	-	47	(1)	35
36	GS-NEM	192	134	0.02%		236	(4)	(0)	(0)	-	-	(0)	1	-	233	40	36
37	LGS-1-NEM	5,837	3,439	0.44%		6,075	(96)	(8)	(7)	-	-	(2)	17	-	5,979	142	37
38						not a sum											38
39	TOTAL	$ 1,696,883	$ 781,213	100.00%	$ (15,264)	$ 1,718,820	$ (21,873)	$ (1,833)	$ (1,697)	$ -	$ -	$ (511)	$ 3,972	$ -	$ 1,342,792	$ (354,091)	39
40						from Sch. H-2											40
41				Energy Revenue for Rate Design		781,225	$ (975,417)										41
42				w/ Specific Class adjustments	$	1,379,997											42
43																	43
44																	44
45	Summation of NEM customers into Standard Schedule for Rate Design																45
46	RS	$ 651,316	$ 307,323	39.34%	$ (10,889)	$ 531,991	$ (8,605)	$ (721)	$ (668)	$ -	$ -	$ (201)	$ 1,563	$ -	$ 523,360	$ (127,956)	46
47	RM	193,633	86,275	11.04%	(3,222)	149,180	(2,416)	(202)	(187)	-	-	(56)	439	-	146,757	(46,876)	47
48	LRS	3,206	1,412	0.18%	(53)	2,441	(40)	(3)	(3)	-	-	(1)	7	-	2,402	(804)	48
49	GS	48,912	22,590	2.89%	-	39,905	(632)	(53)	(49)	-	-	(15)	115	-	39,270	(9,641)	49
50	LGS-1	330,041	150,786	19.30%	-	266,360	(4,222)	(354)	(328)	-	-	(99)	767	-	262,125	(67,916)	50
51																	51

Line No.	Class	Sales (MWh)	Cost Based Class Revenue by Function: Distribution	Transmission	Generation	Energy/ variable	Subtotal	Power Factor Revenue	Additional Facilities & Maintenance Revenue	Exc. DOS Cost Revenue	Sum of Functional Cost Based Class Revenue for Rate Design	Interclass Rate Rebalancing Revenue	Capped Class Revenue Requirement	Revenue Proof	Percent of Total	Difference from Capped Revenue Requirement (Rounding)	Overall Effective Rate	Line No.
8																		8
9	RS	7,262,589	$ 213,160	$ 65,236	$ 390,189	$ 460,005	$ 1,128,591	$ -	$ -		$ 1,128,591	$ (65,145)	$ 1,148,202	$ 1,148,240	40.9%	$ (1)	$ 0.15810	9
10	RM	2,298,671	49,684	16,917	109,337	146,453	322,392	-	-		322,392	17,194	339,963	339,966	12.1%	(8)	0.14790	10
11	LRS	37,526	630	277	1,648	2,354	4,909	-	-		4,909	322	5,255	5,255	0.2%	1	0.14003	11
12	GS	612,056	15,608	3,347	18,743	39,038	76,736	-	-	1	76,735	5,600	82,592	82,512	2.9%	3	0.13494	12
13	LGS-1	4,073,470	55,119	23,742	141,326	256,146	476,334	133	1	74	476,394	14,908	493,744	493,685	17.6%	(60)	0.12121	13
14	LGS-2S	2,437,061	21,923	12,258	75,648	152,917	262,746	349	-	597	262,498	11,284	273,784	273,770	9.8%	(13)	0.11234	14
15	LGS-2P	69,583	542	292	1,851	4,306	6,990	6	-	26	6,971	355	7,326	7,326	0.3%	0	0.10528	15
16	LGS-2T	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	16
17	LGS-3S	768,658	6,103	3,440	21,816	48,416	79,775	88	-	661	79,202	3,939	83,141	83,129	3.0%	(12)	0.10816	17
18	LGS-3P	1,826,673	19,196	7,960	50,889	112,704	190,749	226	70	7,095	183,950	11,135	195,086	195,050	6.9%	(36)	0.10680	18
19	LGS-3T	618,671	2,717	2,650	16,902	37,327	59,596	20	-	1,223	58,394	1,854	60,248	60,248	2.1%	0	0.09738	19
20	LGS-XS	-	61	-	-	-	61	2	-	63	-	-	-	-	0.0%	-	---	20
21	LGS-XP	-	2,279	-	-	-	2,279	65	-	2,345	-	-	-	-	0.0%	-	---	21
22	LGS-XT	-	387	-	-	-	387	2	-	389	-	-	-	-	0.0%	-	---	22
23	LGS-2S-WP	14,878	213	77	321	923	1,534	4	-	29	1,509	133	1,642	1,636	0.1%	(6)	0.11036	23
24	LGS-2P-WP	11,148	108	36	204	681	1,029	2	-	-	1,032	78	1,109	1,105	0.0%	(4)	0.09949	24
25	LGS-2T-WP	-	29	-	-	-	29	-	-	29	-	-	-	-	0.0%	-	---	25
26	LGS-3S-WP	4,413	224	19	87	296	625	6	-	180	452	57	509	507	0.0%	(2)	0.11540	26
27	LGS-3P-WP	19,004	414	36	287	1,201	1,938	12	-	298	1,653	91	1,744	1,744	0.1%	0	0.09175	27
28	LGS-3T-WP	-	164	-	-	-	164	0	-	165	-	-	-	-	0.0%	-	---	28
29	SL	129,054	1,260	122	3,261	9,888	14,531	-	-		14,531	2,154	16,686	16,692	0.6%	7	0.12929	29
30	RS-Pal	578	35	0	15	45	95	-	-		95	8	103	103	0.0%	(0)	0.17872	30
31	GS-Pal	2,217	116	1	57	174	348	-	-		348	33	382	382	0.0%	(0)	0.17213	31
32	IAIWP	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	32
33	RS-NEM	478,046	35,353	9,918	66,277	63,355	174,903	-	-		174,903	(4,288)	85,821	85,821	3.1%	---	0.17952	33
34	RM-NEM	2,596	113	47	304	304	767	-	-		767	19	399	399	0.0%	---	0.15360	34
35	LRS-NEM	571	30	5	33	47	115	-	-		115	5	97	97	0.0%	---	0.16891	35
36	GS-NEM	2,417	80	26	165	233	504	-	-		504	22	272	272	0.0%	---	0.11234	36
37	LGS-1-NEM	73,329	1,181	649	3,687	5,979	11,495	-	-		11,495	268	9,339	9,339	0.3%	---	0.12735	37
38																		38
39	TOTAL	20,743,210	$ 426,731	$ 147,056	$ 903,047	$ 1,342,792		$ 917	$ 71	$ 13,173	$ 2,807,441	$ 27	$ 2,807,441	$ 2,807,277	100.0%	$ (130)	$ 0.13534	39
40																		40
41																		41
42																		42
43																		43
44	Summation of NEM customers into Standard Schedule for Rate Design																	44
45	RS	7,740,635	$ 248,514	$ 75,154	$ 456,466	$ 523,360	$ 1,303,494	$ -	$ -	$ -	$ 1,303,494	$ (69,433)	$ 1,234,022	$ 1,234,060	44.0%	$ (1)	$ 0.15942	45
46	RM	2,301,267	49,797	16,964	109,642	146,757	323,159	-	-	-	323,159	17,213	340,362	340,365	12.1%	(8)	0.14790	46
47	LRS	38,097	660	282	1,681	2,402	5,024	-	-	-	5,024	327	5,351	5,351	0.2%	1	0.14046	47
48	GS	614,473	15,688	3,373	18,908	39,270	77,240	-	-	1	77,239	5,622	82,864	82,784	2.9%	3	0.13485	48
49	LGS-1	4,146,799	56,300	24,391	145,013	262,125	487,829	133	1	74	487,889	15,176	503,083	503,023	17.9%	(60)	0.12132	49

Nevada Power Company
Statement O

Class Revenue Adjustments Due to Cap & Floor Criteria (1)

Exhibit Prest Direct-4
Docket No. 23-06XXX
MCS, per NRS, new TOU, Joint Dispatch, RS Cap

				Total Class Revenue Requirement					First Allocation - Cap											
Line No.	Class	Present Rate Revenue	AB 405 Present Rate Revenue	Sum of Functional Cost Based Class Revenue	Percent of Total	AB 405 Cost Based Class Revenue	Percent of Total	% change over Present Rate Revenue	AB405 Cost-Based Pct change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.
9	RS	$ 1,124,472	$ 1,205,394	$ 1,128,591	40.20%	$ 1,303,494	46.43%	0.37%	8.14%	Capped	2.38%	$ 1,234,022	$ 69,471	$ -	$ -	0.00%	$ -	1,234,022	2.38%	9
10	RM	339,331	339,727	322,392	11.48%	323,159	11.51%	-4.99%	-4.88%	-	-4.88%	323,159	-	323,159	(16,568)	24.76%	17,202	340,362	0.19%	10
11	LRS	5,291	5,383	4,909	0.17%	5,024	0.18%	-7.21%	-6.67%	-	-6.67%	5,024	-	5,024	(359)	0.47%	327	5,351	-0.59%	11
12	GS	83,497	83,773	76,735	2.73%	77,239	2.75%	-8.10%	-7.80%	-	-7.80%	77,239	-	77,239	(6,533)	8.10%	5,624	82,864	-1.09%	12
13	LGS-1	485,467	494,567	476,394	16.97%	487,889	17.38%	-1.87%	-1.35%	-	-1.35%	487,889	-	487,889	(6,678)	21.87%	15,194	503,083	1.72%	13
14	LGS-2S	271,383	271,383	262,498	9.35%	262,498	9.35%	-3.27%	-3.27%	-	-3.27%	262,498	-	262,498	(8,886)	16.25%	11,286	273,784	0.88%	14
15	LGS-2P	7,301	7,301	6,971	0.25%	6,971	0.25%	-4.52%	-4.52%	-	-4.52%	6,971	-	6,971	(330)	0.51%	355	7,326	0.34%	15
16	LGS-2T				0.00%		0.00%						-			0.00%	-			16
17	LGS-3S	82,792	82,792	79,202	2.82%	79,202	2.82%	-4.34%	-4.34%	-	-4.34%	79,202	-	79,202	(3,590)	5.67%	3,939	83,141	0.42%	17
18	LGS-3P	195,666	195,666	183,950	6.55%	183,950	6.55%	-5.99%	-5.99%	-	-5.99%	183,950	-	183,950	(11,716)	16.03%	11,135	195,086	-0.30%	18
19	LGS-3T	59,254	59,254	58,394	2.08%	58,394	2.08%	-1.45%	-1.45%	-	-1.45%	58,394	-	58,394	(860)	2.67%	1,854	60,248	1.68%	19
20	LGS-XS				0.00%		0.00%									0.00%				20
21	LGS-XP				0.00%		0.00%									0.00%				21
22	LGS-XT				0.00%		0.00%									0.00%				22
23	LGS-2S-WP	1,343	1,343	1,509	0.05%	1,509	0.05%	12.39%	12.39%	-	12.39%	1,509	-	1,509	166	0.19%	133	1,642	22.27%	23
24	LGS-2P-WP	1,123	1,123	1,032	0.04%	1,032	0.04%	-8.14%	-8.14%	-	-8.14%	1,032	-	1,032	(91)	0.11%	78	1,109	-1.23%	24
25	LGS-2T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			25
26	LGS-3S-WP	372	372	452	0.02%	452	0.02%	21.50%	21.50%	-	21.50%	452	-	452	80	0.08%	57	509	36.95%	26
27	LGS-3P-WP	1,742	1,742	1,653	0.06%	1,653	0.06%	-5.13%	-5.13%	-	-5.13%	1,653	-	1,653	(89)	0.13%	91	1,744	0.07%	27
28	LGS-3T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			28
29	SL	11,437	11,437	14,531	0.52%	14,531	0.52%	27.05%	27.05%	-	27.05%	14,531	-	14,531	3,094	3.10%	2,154	16,686	45.89%	29
30	RS-Pal	85	85	95	0.00%	95	0.00%	11.81%	11.81%	-	11.81%	95	-	95	10	0.01%	8	103	21.34%	30
31	GS-Pal	305	305	348	0.01%	348	0.01%	14.20%	14.20%	-	14.20%	348	-	348	43	0.05%	33	382	25.18%	31
32	IAIWP			-																32
33	RS-NEM	80,923	inc in Full Req Class	174,903	6.23%	inc in Full Req Class		116.14%	inc in Full Req Class											33
34	RM-NEM	397	inc in Full Req Class	767	0.03%	inc in Full Req Class		93.48%	inc in Full Req Class											34
35	LRS-NEM	92	inc in Full Req Class	115	0.00%	inc in Full Req Class		24.43%	inc in Full Req Class											35
36	GS-NEM	275	inc in Full Req Class	504	0.02%	inc in Full Req Class		83.04%	inc in Full Req Class											36
37	LGS-1-NEM	9,100	inc in Full Req Class	11,495	0.41%	inc in Full Req Class		26.32%	inc in Full Req Class											37
38		Not a Sum:		Not a sum:				Overall Increase:												38
39	Total	$ 2,805,178		$ 2,871,796	100.00%	$ 2,871,796	100.00%	2.38%				$ 2,737,970	$ 69,471	$ 1,503,947	$ 59,094	100%	$ 69,471			39
40		$ 2,761,648		$ 2,807,441	=sum=	$ 2,807,441		$ 66,618												40
41			$ 64,355	<Rev Credits: Revenue Credits exc. PF and AF&M revenues																41

		Second Allocation												Final Class Revenue Allocation			
Line No.	Class	Class Revenue Requirement, after 1st Allocation	Pct Change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement	% change over Present Rate Revenue	Capped Class Revenue Requirement	% change over Present Rate Revenue	Difference from Cost	Line No.
50	RS	$ 1,234,022	2.38%	Capped	2.38%	$ 1,234,022	$ -	$ 1,234,022	$ -	0.00%	$ -	$ 1,234,022	2.38%	$ 1,234,022	2.38%	$ (69,471)	50
51	RM	340,362	0.19%	-	0.19%	$ 340,362	$ -	$ 340,362	$ 635	3.70%	0	$ 340,362	0.19%	340,362	0.19%	17,202	51
52	LRS	5,351	-0.59%	-	-0.59%	$ 5,351	$ -	$ 5,351	$ (32)	-0.19%	(0)	$ 5,351	-0.59%	5,351	-0.59%	327	52
53	GS	82,864	-1.09%	-	-1.09%	$ 82,864	$ -	$ 82,864	$ (909)	-5.30%	(0)	$ 82,864	-1.09%	82,864	-1.09%	5,624	53
54	LGS-1	503,083	1.72%	-	1.72%	$ 503,083	$ -	$ 503,083	$ 8,516	49.61%	0	$ 503,083	1.72%	503,083	1.72%	15,194	54
55	LGS-2S	273,784	0.88%	-	0.88%	$ 273,784	$ -	$ 273,784	$ 2,400	13.98%	0	$ 273,784	0.88%	273,784	0.88%	11,286	55
56	LGS-2P	7,326	0.34%	-	0.34%	$ 7,326	$ (0)	$ -	$ 25	0.15%	0	$ 7,326	0.34%	7,326	0.34%	355	56
57	LGS-2T									0.00%	-	$ -		-		-	57
58	LGS-3S	83,141	0.42%	-	0.42%	$ 83,141	$ -	$ 83,141	$ 350	2.04%	0	$ 83,141	0.42%	83,141	0.42%	3,939	58
59	LGS-3P	195,086	-0.30%	-	-0.30%	$ 195,086	$ -	$ 195,086	$ (581)	-3.38%	(0)	$ 195,086	-0.30%	195,086	-0.30%	11,135	59
60	LGS-3T	60,248	1.68%	-	1.68%	$ 60,248	$ -	$ 60,248	$ 994	5.79%	0	$ 60,248	1.68%	60,248	1.68%	1,854	60
61	LGS-XS									0.00%	-			-		-	61
62	LGS-XP									0.00%	-			-		-	62
63	LGS-XT									0.00%	-			-		-	63
64	LGS-2S-WP	1,642	22.27%	-	22.27%	$ 1,642	$ -	$ 1,642	$ 299	1.74%	0	$ 1,642	22.27%	1,642	22.27%	133	64
65	LGS-2P-WP	1,109	-1.23%	-	-1.23%	$ 1,109	$ -	$ 1,109	$ (14)	-0.08%	(0)	$ 1,109	-1.23%	1,109	-1.23%	78	65
66	LGS-2T-WP							$ -	$ -	0.00%	-			-		-	66
67	LGS-3S-WP	509	36.95%	-	36.95%	$ 509	$ -	$ 509	$ 137	0.80%	0	$ 509	36.95%	509	36.95%	57	67
68	LGS-3P-WP	1,744	0.07%	-	0.07%	$ 1,744	$ 0	$ -	$ 1	0.01%	0	$ 1,744	0.07%	1,744	0.07%	91	68
69	LGS-3T-WP							$ -	$ -	0.00%	-			-		-	69
70	SL	16,686	45.89%	-	45.89%	$ 16,686	$ -	$ 16,686	$ 5,248	30.58%	0	$ 16,686	45.89%	16,686	45.89%	2,154	70
71	RS-Pal	103	21.34%	-	21.34%	$ 103	$ (0)	$ -	$ 18	0.11%	0	$ 103	21.34%	103	21.34%	8	71
72	GS-Pal	382	25.18%	-	25.18%	$ 382	$ -	$ 382	$ 77	0.45%	0	$ 382	25.18%	382	25.18%	33	72
73	IAIWP													-		-	73
74	RS-NEM	inc in Full Req Class															74
75	RM-NEM	inc in Full Req Class															75
76	LRS-NEM	inc in Full Req Class															76
77	GS-NEM	inc in Full Req Class															77
78	LGS-1-NEM	inc in Full Req Class															78
80	Total						$ 0	$ 2,798,268	$ 17,165	100.0%	$ 0	$ 2,807,441		$ 2,807,441			80
81														$ -			81

(1) Increases in rates cannot exceed the total average percentage increase in rates. For example, a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.

(2) NEM classes include all customers under NMR-G and NMR-A rate schedules.

Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

Line No.	Classes[1]	Bundled kWh Sales	DOS kWh Sales	Total kWh Sales	Sum of Functional Cost Based Class Revenue	Capped Class Revenue Requirement	Interclass Subsidy (difference)	Subsidy Component per kWh	Rounding	Note	Line No.
8	RS	7,262,588,952		7,740,635,272	$ 1,303,494	$ 1,234,022	$ (69,471)	$ (0.00897)	$ 38		8
9	RM	2,298,671,171		2,301,266,943	323,159	340,362	17,202	0.00748	11		9
10	LRS	37,525,901		38,097,297	5,024	5,351	327	0.00858	(0)		10
11	GS	612,055,594		614,472,857	77,239	82,864	5,624	0.00915	(2)		11
12	LGS-1	4,073,469,942		4,146,798,580	487,889	503,083	15,194	0.00366	(17)		12
13	LGS-2S	2,437,060,885		2,437,060,885	262,498	273,784	11,286	0.00463	(2)		13
14	LGS-2P	69,583,297		69,583,297	6,971	7,326	355	0.00510	0		14
15	LGS-2T	-		-	-	-	-	0.00366	-	<<Set equal to LGS-1>>	15
16	LGS-3S	768,658,032		768,658,032	79,202	83,141	3,939	0.00512	(4)		16
17	LGS-3P	1,826,672,960		1,826,672,959.93	183,950	195,086	11,135	0.00610	7		17
18	LGS-3T	618,671,150		618,671,150	58,394	60,248	1,854	0.00300	2		18
19	LGS-XS	-		-	-	-	-	0.00512	-	<<Set equal to LGS-XS DOS>>	19
20	LGS-XP	-		-	-	-	-	0.00610	-	<<Set equal to LGS-XP DOS>>	20
21	LGS-XT	-		-	-	-	-	0.00300	-	<<Set equal to LGS-XT DOS>>	21
22	LGS-2S-WP	14,877,558		14,877,558	1,509	1,642	133	0.00892	0		22
23	LGS-2P-WP	11,147,772		11,147,772	1,032	1,109	78	0.00696	0		23
24	LGS-2T-WP	-		-	-	-	-	0.00725	-	<<Set equal to LGS-2T WP DOS>>	24
25	LGS-3S-WP	4,412,814		4,412,814	452	509	57	0.01302	0		25
26	LGS-3P-WP	19,004,483		19,004,483	1,653	1,744	91	0.00478	0		26
27	LGS-3T-WP	-		-	-	-	-	0.00725	-	<<Set equal to LGS-3T WP DOS>>	27
28	SL	129,054,441		129,054,441	14,531	16,686	2,154	0.01669	(0)		28
29	RS-Pal	578,040		578,040	95	103	8	0.01403	0		29
30	GS-Pal	2,217,456		2,217,456	348	382	33	0.01510	(0)		30
31	IAIWP	-		na	-	-	-	na	---		31
32	RS-NEM	478,046,320		inc in Full Req Class							32
33	RM-NEM	2,595,772		inc in Full Req Class							33
34	LRS-NEM	571,396		inc in Full Req Class							34
35	GS-NEM	2,417,263		inc in Full Req Class							35
36	LGS-1 -NEM	73,328,638		inc in Full Req Class							36
37											37
38	Bundled TOTAL	20,743,209,837		20,743,209,837	$ 2,807,441	$ 2,807,441	$ 0	<< Subsidy amount prior to RevReq adjustment when maintaining current rates.			38
39											39
40	**DISTRIBUTION ONLY SERVICE CLASSES -- SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)[2]**										40
41	DOS: GS		51,413	na	na	na	na	$ 0.00915		<<Set equal to GS>>	41
42	DOS: LGS-1		7,843,178	na	na	na	na	0.00366		<<Set equal to LGS-1>>	42
43	DOS: LGS-2S		82,487,915	na	na	na	na	0.00463		<<Set equal to LGS-2S>>	43
44	DOS: LGS-2P		4,487,342	na	na	na	na	0.00510		<<Set equal to LGS-2P>>	44
45	DOS: LGS-2T		-	na	na	na	na	0.00366		<<Set equal to LGS-2T>>	45
46	DOS: LGS-3S		85,826,485	na	na	na	na	0.00512		<<Set equal to LGS-3S>>	46
47	DOS: LGS-3P		1,414,522,800	na	na	na	na	0.00610		<<Set equal to LGS-3P>>	47
48	DOS: LGS-3T		591,977,970	na	na	na	na	0.00300		<<Set equal to LGS-3T>>	48
49	DOS: LGS-XS		7,153,043	na	na	na	na	0.00512		<<Set to 0.00001 or Current x 94%>>	49
50	DOS: LGS-XP		287,352,976	na	na	na	na	0.00610		<<Set to 0.00001 or Current x 94%>>	50
51	DOS: LGS-XT		165,618,096	na	na	na	na	0.00300		<<Set to 0.00001 or Current x 94%>>	51
52	DOS: LGS-2S-WP		4,841,057	na	na	na	na	0.00892		<<Set equal to LGS-2S-WP>>	52
53	DOS: LGS-2P-WP		-	na	na	na	na	0.00696		<<Set equal to LGS-2P-WP>>	53
54	DOS: LGS-2T-WP		1,889,274	na	na	na	na	0.00725		<<Set to 0.00001 or Current x 94%>>	54
55	DOS: LGS-3S-WP		25,647,446	na	na	na	na	0.01302		<<Set equal to LGS-3S-WP>>	55
56	DOS: LGS-3P-WP		75,371,524	na	na	na	na	0.00478		<<Set equal to LGS-3P-WP>>	56
57	DOS: LGS-3T-WP		55,357,230	na	na	na	na	0.00725		<<Set to 0.00001 or Current x 94%>>	57
58											58

59 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2). 59

60 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes. 60

Line No	Class	Sales (kWh)	BTGR Revenue Present	BTGR Revenue Proposed	Percent Change	BTGR & BTER[1] Revenue Present	BTGR & BTER[1] Revenue Proposed	Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed	Percent Change	Line No
8	RS	7,262,588,952	$ 513,383,508	$ 537,151,515	4.63%	$ 1,124,471,607	$ 1,148,239,614	2.11%	$ 1,284,192,975	$ 1,307,960,983	1.85%	8
9	RM	2,298,671,171	145,915,631	146,551,246	0.44%	339,330,523	339,966,138	0.19%	389,356,065	389,991,681	0.16%	9
10	LRS	37,525,901	2,132,970	2,097,063	-1.68%	5,290,775	5,254,868	-0.68%	6,096,455	6,060,548	-0.59%	10
11	GS	612,055,143	34,777,894	33,792,527	-2.83%	83,497,092	82,511,725	-1.18%	94,978,182	93,992,815	-1.04%	11
12	LGS-1	4,073,133,716	161,250,916	169,463,348	5.09%	485,427,795	493,640,227	1.69%	562,024,412	570,236,844	1.46%	12
13	LGS-2S	2,429,180,261	77,189,770	79,548,343	3.06%	270,531,139	272,889,712	0.87%	315,956,810	318,315,383	0.75%	13
14	LGS-2P	69,583,297	1,761,763	1,786,885	1.43%	7,300,593	7,325,715	0.34%	8,588,581	8,613,703	0.29%	14
15	LGS-2T	-	-	-	na	-	-	na	-	-	na	15
16	LGS-3S	768,658,032	21,606,500	21,944,074	1.56%	82,791,679	83,129,253	0.41%	97,127,152	97,464,725	0.35%	16
17	LGS-3P	1,393,295,183	39,586,638	38,888,501	-1.76%	150,492,935	149,794,798	-0.46%	176,700,817	176,002,681	-0.40%	17
18	LGS-3T	247,665,929	4,377,192	4,614,606	5.42%	24,091,400	24,328,814	0.99%	28,658,360	28,895,774	0.83%	18
19	LGS-XS	-	-	-	na	-	-	na	-	-	na	19
20	LGS-XP	-	-	-	na	-	-	na	-	-	na	20
21	LGS-XT	-	-	-	na	-	-	na	-	-	na	21
22	LGS-2S-WP	14,877,558	158,497	451,945	185.14%	1,342,751	1,636,199	21.85%	1,623,788	1,917,236	18.07%	22
23	LGS-2P-WP	11,147,772	235,565	217,999	-7.46%	1,122,928	1,105,362	-1.56%	1,327,601	1,310,035	-1.32%	23
24	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	24
25	LGS-3S-WP	4,412,814	20,575	155,694	656.72%	371,835	506,954	36.34%	451,353	586,473	29.94%	25
26	LGS-3P-WP	19,004,483	229,669	230,968	0.57%	1,742,426	1,743,725	0.07%	2,087,357	2,088,656	0.06%	26
27	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	27
28	SL	129,054,441	1,164,568	6,419,591	451.24%	11,437,302	16,692,325	45.95%	13,840,296	19,095,319	37.97%	28
29	RS-Pal	578,040	36,501	54,617	49.63%	85,143	103,259	21.28%	97,306	115,421	18.62%	29
30	GS-Pal	2,217,456	128,415	205,105	59.72%	304,924	381,614	25.15%	345,791	422,481	22.18%	30
31	IAIWP	-	-	-	na	-	-	na	-	-	na	31
32	**Optional Time of Use**											32
33	ORS-TOU	9,396,344	478,100	581,132	21.55%	1,268,289	1,371,321	8.12%	1,473,445	1,576,477	6.99%	33
34	ORS-TOU OPT A	21,030,431	1,250,839	1,419,530	13.49%	3,020,046	3,188,737	5.59%	3,481,412	3,650,104	4.85%	34
35	ORS-TOU OPT B	4,239,586	173,888	226,643	30.34%	530,649	583,404	9.94%	624,004	676,759	8.45%	35
39	ORM-TOU	873,422	49,455	53,880	8.95%	122,872	127,297	3.60%	141,630	146,055	3.12%	39
40	ORM-TOU OPT A	718,287	45,450	47,778	5.12%	105,894	108,222	2.20%	121,546	123,874	1.92%	40
41	ORM-TOU OPT B	70,254	4,084	4,314	5.64%	9,996	10,226	2.30%	11,526	11,757	2.00%	41
42	ORM-TOU DDP	9,561	414	389	-6.11%	1,170	1,145	-2.16%	1,211	1,186	-2.09%	42
51	OGS-TOU	27,565,080	1,261,147	1,215,035	-3.66%	3,455,327	3,409,215	-1.33%	3,972,448	3,926,335	-1.16%	51
52	OLGS-1 TOU	124,787,383	3,997,063	4,252,998	6.40%	13,930,139	14,186,074	1.84%	16,277,390	16,533,325	1.57%	52
53	OLGS-3P-HLF	258,609,361	5,228,244	5,232,183	0.08%	25,813,549	25,817,488	0.02%	30,677,991	30,681,930	0.01%	53
54	**Optional Time of Use EVRR**											54
55	ORS-TOU EVRR	52,516,143	2,615,103	2,898,318	10.83%	7,033,504	7,316,719	4.03%	8,187,065	8,470,279	3.46%	55
56	ORS-TOU Opt A EVRR	6,627,577	342,755	365,054	6.51%	900,466	922,765	2.48%	1,046,406	1,068,705	2.13%	56
57	ORS-TOU Opt B EVRR	4,621,440	160,839	202,878	26.14%	549,733	591,772	7.65%	651,497	693,536	6.45%	57
60	ORM-TOU EVRR	1,289,179	67,312	70,245	4.36%	175,686	178,619	1.67%	203,405	206,338	1.44%	60
61	ORM-TOU OPT A EVRR	60,410	3,580	3,398	-5.10%	8,664	8,482	-2.11%	9,980	9,798	-1.83%	61
62	ORM-TOU OPT B EVRR	29,643	1,740	1,794	3.12%	4,234	4,288	1.28%	4,881	4,935	1.11%	62
65	OLRS-TOU EVRR	299,866	14,816	14,663	-1.04%	40,050	39,897	-0.38%	46,488	46,335	-0.33%	65
70	OGS-TOU EVRR	20,511	1,899	1,861	-2.00%	3,532	3,494	-1.07%	3,917	3,879	-0.97%	70
71	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	71
72	**Net Metering:**											72
73	RS-NEM	478,046,320	40,695,177	45,592,995	12.04%	80,922,775	85,820,593	6.05%	91,449,355	96,347,174	5.36%	73
74	RM-NEM	2,595,772	178,138	180,283	1.20%	396,572	398,717	0.54%	453,135	455,279	0.47%	74
75	LRS-NEM	571,396	44,227	48,433	9.51%	92,310	96,516	4.56%	104,579	108,784	4.02%	75
76	GS-NEM	2,417,263	83,034	79,140	-4.69%	275,449	271,555	-1.41%	320,798	316,904	-1.21%	76
77	LGS-1 NEM	73,328,638	3,263,161	3,501,689	7.31%	9,100,120	9,338,648	2.62%	10,479,431	10,717,959	2.28%	77
78	ORS-NEM	3,324,908	177,128	349,493	97.31%	456,919	629,284	37.72%	530,133	702,499	32.51%	78
79	ORS-NEM OPT A	4,057,523	260,478	460,436	76.77%	601,919	801,877	33.22%	691,267	891,225	28.93%	79
80	ORS-NEM OPT B	218,046	12,617	21,135	67.51%	30,965	39,483	27.51%	35,766	44,284	23.82%	80
84	ORM-NEM	1,460	220	201	-8.82%	343	324	-5.66%	374	354	-5.19%	84
97	**NEM EVRR**											97
98	ORS-NEM EVRR	11,862,176	478,864	948,063	97.98%	1,477,066	1,946,265	31.77%	1,738,271	2,207,470	26.99%	98
99	ORS-NEM OPT A EVRR	1,879,925	67,276	140,511	108.86%	225,472	298,707	32.48%	266,867	340,102	27.44%	99
100	ORS-NEM OPT B EVRR	411,121	18,066	27,128	50.16%	52,661	61,723	17.21%	61,715	70,777	14.68%	100
103	ORM-NEM EVRR	25,756	1,240	1,499	20.89%	3,407	3,666	7.60%	3,968	4,227	6.53%	103
114	**Standby**											114
116	SSR - GS	-	-	-	na	-	-	na	-	-	na	116
117	SSR - LGS-1	1,130,064	54,212	59,150	9.11%	144,165	149,103	3.43%	165,421	170,359	2.98%	117
118	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	118
119	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	119
120	LSR - LGS-2T	9,583,450	159,003	274,518	72.65%	921,846	1,037,361	12.53%	1,099,236	1,214,750	10.51%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	26,274,564	868,679	898,533	3.44%	2,960,134	2,989,988	1.01%	3,454,358	3,484,212	0.86%	122
123	LSR - LGS-3T	109,322,768	2,488,706	2,624,348	5.45%	11,190,798	11,326,440	1.21%	13,206,710	13,342,353	1.03%	123
133	**EVCCR**											133
134	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	134
135	LGS-2S EVCCR	14,835,492	648,508	636,476	-1.86%	1,829,413	1,817,381	-0.66%	2,106,836	2,094,805	-0.57%	135
136	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	136
137	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	137
138	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	138
139	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	139
140	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	140
147												147
148	**TOTAL Bundled**	21,055,299,880	$ 1,071,470,793	$ 1,122,344,000	4.75%	$ 2,789,783,845	$ 2,840,657,052	1.82%	$ 3,210,501,292	$ 3,261,374,500	1.58%	148
149	Residential	10,204,140,610	$ 708,610,416	$ 739,514,633	4.36%	$ 1,567,209,710	$ 1,598,113,927	1.97%	$ 1,791,082,729	$ 1,821,986,946	1.73%	149
150	Non-Residential	10,851,159,270	$ 362,860,377	$ 382,829,367	5.50%	$ 1,222,574,135	$ 1,242,543,125	1.63%	$ 1,419,418,564	$ 1,439,387,554	1.41%	150
151												151
152	**DISTRIBUTION ONLY SERVICE (DOS)[3]**											152
153	GS-DOS	51,413	$ 3,947	$ 3,836	-2.80%	$ 3,947	$ 3,836	-2.80%	$ 4,020	$ 3,909	-2.75%	153
154	LGS-1-DOS	7,843,178	85,196	109,604	28.65%	86,342	110,751	28.27%	98,389	122,798	24.81%	154
155	LGS-2S-DOS	82,487,915	734,814	1,050,664	42.98%	788,210	1,104,061	40.07%	947,993	1,263,843	33.32%	155
156	LGS-2P-DOS	4,487,342	58,866	86,117	46.29%	55,082	82,333	49.47%	66,599	93,850	40.92%	156
157	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	157
158	LGS-3S-DOS	85,826,485	813,709	1,192,259	46.52%	866,433	1,244,983	43.69%	1,029,961	1,408,511	36.75%	158
159	LGS-3P-DOS	1,414,522,800	8,148,886	16,526,977	102.81%	8,313,358	16,691,449	100.78%	10,485,712	18,863,803	79.90%	159
160	LGS-3T-DOS	591,977,970	1,323,566	3,819,448	188.57%	1,454,782	3,950,664	171.56%	2,399,837	4,895,718	104.00%	160
161	LGS-XS-DOS	7,153,043	55,175	128,855	133.54%	62,113	135,793	118.62%	77,765	151,445	94.75%	161
162	LGS-XP-DOS	287,352,976	2,541,281	4,997,763	96.66%	2,646,507	5,102,989	92.82%	3,138,262	5,594,744	78.28%	162
163	LGS-XT-DOS	165,618,096	598,410	962,986	60.92%	598,410	962,986	60.92%	833,588	1,198,163	43.74%	163
164	LGS-2S-WP-DOS	4,841,057	24,486	74,738	205.23%	24,486	74,738	205.23%	31,360	81,613	160.24%	164
165	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	165
166	LGS-2T-WP-DOS	1,889,274	17,854	31,988	79.17%	17,854	31,988	79.17%	20,537	34,671	68.83%	166
167	LGS-3S-WP-DOS	25,647,446	79,367	523,295	559.34%	79,367	523,295	559.34%	115,786	559,714	383.40%	167
168	LGS-3P-WP-DOS	75,371,524	297,544	680,048	128.55%	297,544	680,048	128.55%	404,572	787,076	94.55%	168
169	LGS-3T-WP-DOS	55,357,230	100,063	503,448	403.13%	100,063	503,448	403.13%	178,670	582,055	225.77%	169
170												170
171	DOS TOTAL	2,810,427,749	$ 14,883,164	$ 30,692,028	106.22%	$ 15,394,498	$ 31,203,362	102.69%	$ 19,833,051	$ 35,641,916	79.71%	171
172												172
173	TOTAL (Inc. DOS)	23,865,727,629	$ 1,086,353,957	$ 1,153,036,028	6.14%	$ 2,805,178,343	$ 2,871,860,415	2.38%	$ 3,230,334,344	$ 3,297,016,415	2.06%	173
174												174

175 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. 175

176 1. Present BTER and DEAA revenues are based on April 1, 2023 rates. 176

177 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 177

178 3. DOS schedules only reflect a percentage change to their distribution rates, not the OATT and energy rates paid through other mechanisms. 178

Line No.	Class	Sales	BTER Revenue Present	BTER Revenue Proposed	Percent Change	DEAA Revenue Present	DEAA Revenue Proposed	Percent Change	EE Revenue Present	EE Revenue Proposed	Percent Change	REPR Revenue Present	REPR Revenue Proposed	Percent Change	NDPP Present	NDPP Proposed	Percent Change	ESAP Present	ESAP Proposed	Percent Change	Line No.
9		Residential Rate	$ 0.08415	$ 0.08415		$ 0.01750	$ 0.01750		Rates vary by Class			$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		9
10		Non-Residential Rate	$ 0.07960	$ 0.07960		$ 0.01500	$ 0.01500					$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		10
11																					11
12	RS	7,262,588,952	$ 611,088,099	$ 611,088,099	0.0%	$ 126,894,467	$ 126,894,467	0.0%	$ 16,921,832	$ 16,921,832	0.0%	$ 5,592,193	$ 5,592,193	0.0%	$ 10,312,876	$ 10,312,876	0.0%	$ 145,252	$ 145,252	0.0%	12
13	RM	2,298,671,171	193,414,892	193,414,892	0.0%	40,164,242	40,164,242	0.0%	4,827,210	4,827,210	0.0%	1,769,977	1,769,977	0.0%	3,264,113	3,264,113	0.0%	45,973	45,973	0.0%	13
14	LRS	37,525,901	3,157,805	3,157,805	0.0%	656,703	656,703	0.0%	66,795	66,795	0.0%	28,895	28,895	0.0%	53,287	53,287	0.0%	751	751	0.0%	14
15	GS	612,055,143	48,719,198	48,719,198	0.0%	9,179,762	9,179,762	0.0%	960,927	960,927	0.0%	471,282	471,282	0.0%	869,118	869,118	0.0%	12,241	12,241	0.0%	15
16	LGS-1	4,073,133,716	324,176,879	324,176,879	0.0%	61,077,978	61,077,978	0.0%	6,598,476	6,598,476	0.0%	3,136,313	3,136,313	0.0%	5,783,850	5,783,850	0.0%	81,463	81,463	0.0%	16
17	LGS-2S	2,429,180,261	193,341,369	193,341,369	0.0%	36,437,704	36,437,704	0.0%	3,668,062	3,668,062	0.0%	1,870,469	1,870,469	0.0%	3,449,436	3,449,436	0.0%	48,584	48,584	0.0%	17
18	LGS-2P	69,583,297	5,538,830	5,538,830	0.0%	1,043,749	1,043,749	0.0%	91,851	91,851	0.0%	53,579	53,579	0.0%	98,808	98,808	0.0%	1,392	1,392	0.0%	18
19	LGS-2T	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	19
20	LGS-3S	768,658,032	61,185,179	61,185,179	0.0%	11,529,870	11,529,870	0.0%	1,122,241	1,122,241	0.0%	591,867	591,867	0.0%	1,091,494	1,091,494	0.0%	15,373	15,373	0.0%	20
21	LGS-3P	1,393,295,183	110,906,297	110,906,297	0.0%	20,899,428	20,899,428	0.0%	2,257,138	2,257,138	0.0%	1,072,837	1,072,837	0.0%	1,978,479	1,978,479	0.0%	27,866	27,866	0.0%	21
22	LGS-3T	247,665,929	19,714,208	19,714,208	0.0%	3,714,989	3,714,989	0.0%	309,583	309,583	0.0%	190,703	190,703	0.0%	351,686	351,686	0.0%	4,953	4,953	0.0%	22
23	LGS-XS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	23
24	LGS-XP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	24
25	LGS-XT	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	25
26	LGS-2S-WP	14,877,558	1,184,254	1,184,254	0.0%	223,163	223,163	0.0%	25,292	25,292	0.0%	11,456	11,456	0.0%	21,126	21,126	0.0%	298	298	0.0%	26
27	LGS-2P-WP	11,147,772	887,363	887,363	0.0%	167,217	167,217	0.0%	13,043	13,043	0.0%	8,584	8,584	0.0%	15,830	15,830	0.0%	223	223	0.0%	27
28	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	28
29	LGS-3S-WP	4,412,814	351,260	351,260	0.0%	66,192	66,192	0.0%	3,662	3,662	0.0%	3,398	3,398	0.0%	6,266	6,266	0.0%	88	88	0.0%	29
30	LGS-3P-WP	19,004,483	1,512,757	1,512,757	0.0%	285,067	285,067	0.0%	18,244	18,244	0.0%	14,633	14,633	0.0%	26,986	26,986	0.0%	380	380	0.0%	30
31	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	31
32	SL	129,054,441	10,272,734	10,272,734	0.0%	1,935,817	1,935,817	0.0%	184,548	184,548	0.0%	99,372	99,372	0.0%	183,257	183,257	0.0%	2,581	2,581	0.0%	32
33	RS-Pal	578,040	48,642	48,642	0.0%	10,116	10,116	0.0%	781	781	0.0%	445	445	0.0%	821	821	0.0%	12	12	0.0%	33
34	GS-Pal	2,217,456	176,509	176,509	0.0%	33,262	33,262	0.0%	2,749	2,749	0.0%	1,707	1,707	0.0%	3,149	3,149	0.0%	44	44	0.0%	34
35	IAIWP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	35
36	**Optional Time of Use**																				36
37	ORS-TOU	9,396,344	790,189	790,189	0.0%	162,684	162,684	0.0%	21,894	21,894	0.0%	7,235	7,235	0.0%	13,343	13,343	0.0%	188	188	0.0%	37
38	ORS-TOU OPT A	21,030,431	1,769,207	1,769,207	0.0%	366,309	366,309	0.0%	49,001	49,001	0.0%	16,193	16,193	0.0%	29,863	29,863	0.0%	421	421	0.0%	38
39	ORS-TOU OPT B	4,239,586	356,761	356,761	0.0%	74,193	74,193	0.0%	9,878	9,878	0.0%	3,264	3,264	0.0%	6,020	6,020	0.0%	85	85	0.0%	39
43	ORM-TOU	873,422	73,417	73,417	0.0%	15,010	15,010	0.0%	1,835	1,835	0.0%	673	673	0.0%	1,240	1,240	0.0%	17	17	0.0%	43
44	ORM-TOU OPT A	718,287	60,444	60,444	0.0%	12,570	12,570	0.0%	1,509	1,509	0.0%	553	553	0.0%	1,020	1,020	0.0%	14	14	0.0%	44
45	ORM-TOU OPT B	70,254	5,912	5,912	0.0%	1,229	1,229	0.0%	147	147	0.0%	54	54	0.0%	100	100	0.0%	1	1	0.0%	45
46	ORM-TOU DDP	9,561	756	756	0.0%	0	0	0.0%	20	20	0.0%	7	7	0.0%	14	14	0.0%	0	0	0.0%	46
55	OGS-TOU	27,565,080	2,194,180	2,194,180	0.0%	413,476	413,476	0.0%	43,277	43,277	0.0%	21,225	21,225	0.0%	39,142	39,142	0.0%	551	551	0.0%	55
56	OLGS-1 TOU	124,787,383	9,933,076	9,933,076	0.0%	1,871,811	1,871,811	0.0%	202,156	202,156	0.0%	96,086	96,086	0.0%	177,198	177,198	0.0%	2,496	2,496	0.0%	56
57	OLGS-3P-HLF	258,609,361	20,585,305	20,585,305	0.0%	3,879,140	3,879,140	0.0%	418,947	418,947	0.0%	199,129	199,129	0.0%	367,225	367,225	0.0%	5,172	5,172	0.0%	57
58	**Optional Time of Use EVRR**																				58
59	ORS-TOU EVRR	52,516,143	4,418,401	4,418,401	0.0%	916,188	916,188	0.0%	122,363	122,363	0.0%	40,437	40,437	0.0%	74,573	74,573	0.0%	1,050	1,050	0.0%	59
60	ORS-TOU Opt A EVRR	6,627,577	557,711	557,711	0.0%	115,983	115,983	0.0%	15,443	15,443	0.0%	5,103	5,103	0.0%	9,411	9,411	0.0%	133	133	0.0%	60
61	ORS-TOU Opt B EVRR	4,621,440	388,894	388,894	0.0%	80,875	80,875	0.0%	10,768	10,768	0.0%	3,559	3,559	0.0%	6,562	6,562	0.0%	92	92	0.0%	61
64	ORM-TOU EVRR	1,289,179	108,374	108,374	0.0%	22,188	22,188	0.0%	2,708	2,708	0.0%	993	993	0.0%	1,831	1,831	0.0%	26	26	0.0%	64
65	ORM-TOU OPT A EVRR	60,410	5,084	5,084	0.0%	1,057	1,057	0.0%	127	127	0.0%	47	47	0.0%	86	86	0.0%	1	1	0.0%	65
66	ORM-TOU OPT B EVRR	29,643	2,494	2,494	0.0%	519	519	0.0%	63	63	0.0%	23	23	0.0%	42	42	0.0%	1	1	0.0%	66
69	OLRS-TOU EVRR	299,866	25,234	25,234	0.0%	5,248	5,248	0.0%	534	534	0.0%	231	231	0.0%	426	426	0.0%	6	6	0.0%	69
74	OGS-TOU EVRR	20,511	1,633	1,633	0.0%	308	308	0.0%	32	32	0.0%	16	16	0.0%	29	29	0.0%	0	0	0.0%	74
75	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	75
76	**Net Metering:**																				76
77	RS-NEM	478,046,320	40,227,598	40,227,598	0.0%	8,365,811	8,365,811	0.0%	1,113,848	1,113,848	0.0%	368,096	368,096	0.0%	678,826	678,826	0.0%	9,561	9,561	0.0%	77
78	RM-NEM	2,595,772	218,434	218,434	0.0%	45,426	45,426	0.0%	5,452	5,452	0.0%	1,999	1,999	0.0%	3,686	3,686	0.0%	52	52	0.0%	78
79	LRS-NEM	571,396	48,083	48,083	0.0%	9,999	9,999	0.0%	1,018	1,018	0.0%	440	440	0.0%	811	811	0.0%	11	11	0.0%	79
80	GS-NEM	2,417,263	192,415	192,415	0.0%	36,259	36,259	0.0%	3,796	3,796	0.0%	1,861	1,861	0.0%	3,433	3,433	0.0%	48	48	0.0%	80
81	LGS-1 NEM	73,328,638	5,836,959	5,836,959	0.0%	1,099,930	1,099,930	0.0%	118,792	118,792	0.0%	56,463	56,463	0.0%	104,127	104,127	0.0%	1,467	1,467	0.0%	81
82	ORS-NEM	3,324,908	279,791	279,791	0.0%	58,186	58,186	0.0%	7,747	7,747	0.0%	2,560	2,560	0.0%	4,721	4,721	0.0%	66	66	0.0%	82
83	ORS-NEM OPT A	4,057,523	341,441	341,441	0.0%	71,007	71,007	0.0%	9,455	9,455	0.0%	3,124	3,124	0.0%	5,762	5,762	0.0%	81	81	0.0%	83
84	ORS-NEM OPT B	218,046	18,348	18,348	0.0%	3,816	3,816	0.0%	508	508	0.0%	168	168	0.0%	310	310	0.0%	4	4	0.0%	84
88	ORM-NEM	1,460	123	123	0.0%	26	26	0.0%	2	2	0.0%	1	1	0.0%	2	2	0.0%	0	0	0.0%	88
101	**NEM EVRR**					-	-														101
102	ORS-NEM EVRR	11,862,176	998,202	998,202	0.0%	207,588	207,588	0.0%	27,639	27,639	0.0%	9,134	9,134	0.0%	16,844	16,844	0.0%	237	237	0.0%	102
103	ORS-NEM OPT A EVRR	1,879,925	158,196	158,196	0.0%	32,899	32,899	0.0%	4,379	4,379	0.0%	1,448	1,448	0.0%	2,669	2,669	0.0%	38	38	0.0%	103
104	ORS-NEM OPT B EVRR	411,121	34,595	34,595	0.0%	7,195	7,195	0.0%	959	959	0.0%	317	317	0.0%	584	584	0.0%	8	8	0.0%	104
107	ORM-NEM EVRR	25,756	2,167	2,167	0.0%	451	451	0.0%	54	54	0.0%	20	20	0.0%	37	37	0.0%	1	1	0.0%	107
118	**Standby**																				118
120	SSR - GS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	120
121	SSR - LGS-1	1,130,064	89,953	89,953	0.0%	16,951	16,951	0.0%	1,830	1,830	0.0%	870	870	0.0%	1,605	1,605	0.0%	23	23	0.0%	121
122	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	122
123	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	123
124	LSR - LGS-2T	9,583,450	762,843	762,843	0.0%	143,752	143,752	0.0%	12,650	12,650	0.0%	7,379	7,379	0.0%	13,608	13,608	0.0%	192	192	0.0%	124
125	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	125
126	LSR - LGS-3P	26,274,564	2,091,455	2,091,455	0.0%	394,118	394,118	0.0%	42,564	42,564	0.0%	20,231	20,231	0.0%	37,310	37,310	0.0%	525	525	0.0%	126
127	LSR - LGS-3T	109,322,768	8,702,092	8,702,092	0.0%	1,639,842	1,639,842	0.0%	136,654	136,654	0.0%	84,179	84,179	0.0%	155,238	155,238	0.0%	2,186	2,186	0.0%	127
137	**EVCCR**					-	-														137
138	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	138
139	LGS-2S EVCCR	14,835,492	1,180,905	1,180,905	0.0%	222,532	222,532	0.0%	22,401	22,401	0.0%	11,423	11,423	0.0%	21,066	21,066	0.0%	297	297	0.0%	139
140	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	140
141	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	141
142	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	142
143	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	143
144	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	144
151																					151
152	**TOTAL Bundled**	21,055,299,880	$ 1,718,313,052	$ 1,718,313,052	0.0%	334,614,299	334,614,299	0.0%	40,019,026	40,019,026	0.0%	16,185,597	16,185,597	0.0%	29,898,526	29,898,526	0.0%	421,106	421,106	0.0%	152
153	Residential	10,204,140,610	858,599,294	858,599,294	0.0%	178,301,982	178,301,982	0.0%	23,223,969	23,223,969	0.0%	7,857,188	7,857,188	0.0%	14,489,880	14,489,880	0.0%	204,083	204,083	0.0%	153
154	Non-Residential	10,851,159,270	859,713,758	859,713,758	0.0%	156,312,317	156,312,317	0.0%	16,795,057	16,795,057	0.0%	8,328,409	8,328,409	0.0%	15,408,646	15,408,646	0.0%	217,023	217,023	0.0%	154
155																					155
156	**DISTRIBUTION ONLY SERVICE (DOS)**		R-BTER & BTER Impact Fee DOS Revenue																		156
157	GS-DOS	51,413	-	-	na	-	-	na	-	-	na	-	-	na	73	73	0.0%	1	1	0.0%	157
158	LGS-1-DOS	7,843,178	1,146	1,146	0.0%	27	27	0.0%	51	51	0.0%	832	832	0.0%	11,137	11,137	0.0%	157	157	0.0%	158
159	LGS-2S-DOS	82,487,915	53,396	53,396	0.0%	897	897	0.0%	1,701	1,701	0.0%	40,052	40,052	0.0%	117,133	117,133	0.0%	1,650	1,650	0.0%	159
160	LGS-2P-DOS	4,487,342	(3,784)	(3,784)	0.0%	103	103	0.0%	1,587	1,587	0.0%	3,455	3,455	0.0%	6,372	6,372	0.0%	90	90	0.0%	160
161	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	161
162	LGS-3S-DOS	85,826,485	52,724	52,724	0.0%	1,543	1,543	0.0%	2,925	2,925	0.0%	37,186	37,186	0.0%	121,874	121,874	0.0%	1,717	1,717	0.0%	162
163	LGS-3P-DOS	1,414,522,800	164,473	164,472	0.0%	3,361	3,361	0.0%	15,074	15,074	0.0%	145,297	145,297	0.0%	2,008,622	2,008,622	0.0%	28,290	28,290	0.0%	163
164	LGS-3T-DOS	591,977,970	131,216	131,216	0.0%	2,722	2,722	0.0%	5,162	5,162	0.0%	96,562	96,562	0.0%	840,609	840,609	0.0%	11,840	11,840	0.0%	164
165	LGS-XS-DOS	7,153,043	6,938	6,938	0.0%	182	182	0.0%	345	345	0.0%	4,968	4,968	0.0%	10,157	10,157	0.0%	143	143	0.0%	165
166	LGS-XP-DOS	287,352,976	105,226	105,226	0.0%	2,248	2,248	0.0%	4,263	4,263	0.0%	77,203	77,203	0.0%	408,041	408,041	0.0%	5,747	5,747	0.0%	166
167	LGS-XT-DOS	165,618,096	-	-	na	-	-	na	-	-	na	-	-	na	235,178	235,178	0.0%	3,312	3,312	0.0%	167
168	LGS-2S-WP-DOS	4,841,057	-	-	na	-	-	na	-	-	na	-	-	na	6,874	6,874	0.0%	97	97	0.0%	168
169	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	169
170	LGS-2T-WP-DOS	1,889,274	-	-	na	-	-	na	-	-	na	-	-	na	2,683	2,683	0.0%	38	38	0.0%	170
171	LGS-3S-WP-DOS	25,647,446	-	-	na	-	-	na	-	-	na	-	-	na	36,419	36,419	0.0%	513	513	0.0%	171
172	LGS-3P-WP-DOS	75,371,524	-	-	na	-	-	na	-	-	na	-	-	na	107,028	107,028	0.0%	1,507	1,507	0.0%	172
173	LGS-3T-WP-DOS	55,357,230	-	-	na	-	-	na	-	-	na	-	-	na	78,607	78,607	0.0%	1,107	1,107	0.0%	173
174																					174
175	DOS TOTAL	$ 2,810,427,749	$ 511,335	$ 511,334	0.0%	$ 11,083	$ 11,083	0.0%	$ 31,108	$ 31,108	0.0%	$ 405,555	$ 405,555	0.0%	$ 3,990,807	$ 3,990,807	0.0%	$ 56,209	$ 56,209	0.0%	175
176																					176
177	TOTAL	68,786,755,138	$ 1,718,824,387	$ 1,718,824,386	0.0%	$ 334,625,382	$ 334,625,382	0.0%	$ 40,050,134	$ 40,050,134	0.0%	$ 16,591,152	$ 16,591,152	0.0%	$ 33,889,333	$ 33,889,333	0.0%	$ 477,315	$ 477,315	0.0%	177
178				$ (1)			$ -			$ -			$ -			$ -			$ -		178
179																					179

Summary of Proposed Rates -- Bundled

			Distribution Charges			T and G Demand Charges, metered kW			BTGR Energy, per kWh (includes IRR)								
Line No.	Class	Note	Charge, per Cust:	Meter Charge:	Facilities Charge, per kW (1)	Summer On Peak	Summer Mid Peak	Winter -OR - All Periods	Critical Peak	Summer On Peak	Summer Mid Peak	Summer Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	BTER Energy, per kWh	Line No.
9	RS		$ 18.50										0.05811			$ 0.08415	9
10	RM		8.30										0.05138			0.08415	10
11	LRS		99.30										0.04931			0.08415	11
12	GS		25.50	$ 2.00									0.01641			0.07960	12
13	LGS-1		15.80	5.75	$ 4.25			$ 5.18					0.01207			0.07960	13
14	LGS-2S		122.40	12.25	2.80	$ 15.78	$ -	1.60		0.02495	-	0.00585	0.00586			0.07960	14
15	LGS-2P		207.70	54.75	2.85	13.53	-	1.60		0.02186	-	0.00155	0.00580			0.07960	15
16	LGS-2T		182.00	89.00	0.91	14.33	-	1.50		0.03242	-	0.00144	0.00320			0.07960	16
17	LGS-3S		122.00	15.00	2.80	15.78	-	2.00		0.02601	-	0.00292	0.00646			0.07960	17
18	LGS-3P		214.10	68.25	2.60	16.48	-	2.25		0.02049	-	0.00352	0.00456			0.07960	18
19	LGS-3T		182.00	89.00	0.91	14.33	-	1.50		0.03242	-	0.00144	0.00320			0.07960	19
20	LGS-XS		4,743.00	16.90	2.25	15.78	-	2.00		0.02601	-	0.00292	0.00646			0.07960	20
21	LGS-XP		4,743.00	54.30	3.05	16.48	-	2.25		0.02049	-	0.00352	0.00456			0.07960	21
22	LGS-XT		4,743.00	92.60	na	14.33	-	1.50		0.03242	-	0.00144	0.00320			0.07960	22
23	LGS-2S-WP		128.70	12.25	1.10	15.78	-	1.60		0.04167	-	0.01514	0.01515			0.07960	23
24	LGS-2P-WP		208.60	54.75	1.55	13.53	-	1.60		0.04375	-	0.00614	0.00615			0.07960	24
25	LGS-2T-WP		169.10	92.75	0.91	14.33	-	1.50		0.03781	-	0.00609	0.00473			0.07960	25
26	LGS-3S-WP		149.90	15.00	1.25	15.78	-	2.00		0.11619	-	0.01867	0.01868			0.07960	26
27	LGS-3P-WP		234.20	68.25	1.00	16.48	-	2.25		0.05551	-	0.00230	0.00231			0.07960	27
28	LGS-3T-WP		189.10	89.00	0.91	17.89	-	2.25		0.04900	-	0.00225	0.00095			0.07960	28
29	IAIWP															0.06751	29
30																	30
31	ORS-TOU		18.50							0.29188		0.00007	0.00402	(0.00835)	(0.00480)	0.08415	31
32	ORS-TOU Opt A		18.50							0.29188		0.00007	0.00402	(0.00835)	(0.00480)	0.08415	32
33	ORS-TOU Opt B		18.50							0.29188		0.00007	0.00402	(0.00835)	(0.00480)	0.08415	33
34	ORS-TOU DDP		7.00		0.23	0.14		0.05					0.03301			0.08415	34
35	ORS-TOU CPP		18.50						0.61265	0.24117		0.00408	0.00402	(0.00474)	(0.00480)	0.08415	35
36	ORS-TOU CPP DDP		18.50			0.14		0.05	0.61265	0.18663		0.00222	0.00402	(0.00642)	(0.00480)	0.08415	36
37	ORM-TOU		8.30							0.22623		0.02972	0.00912	0.01833	(0.00021)	0.08415	37
38	ORM-TOU Opt A		8.30							0.22623		0.02972	0.00912	0.01833	(0.00021)	0.08415	38
39	ORM-TOU Opt B		8.30							0.22623		0.02972	0.00912	0.01833	(0.00021)	0.08415	39
40	ORM-TOU DDP		4.75		0.09	0.06		0.05					0.03474			0.08415	40
41	ORM-TOU CPP		8.30						0.37972	0.19594		0.02707	0.01378	0.01595	0.00399	0.08415	41
42	ORM-TOU CPP DDP		8.30			0.06		0.05	0.37972	0.17428		0.02707	0.00514	0.01595	(0.00379)	0.08415	42
43	OLRS-TOU		99.30							0.25579		0.01228	0.01046	0.00264	0.00100	0.08415	43
44	OLRS-TOU Opt A		99.30							0.25579		0.01228	0.01046	0.00264	0.00100	0.08415	44
45	OLRS-TOU Opt B		99.30							0.25579		0.01228	0.01046	0.00264	0.00100	0.08415	45
46	OLRS-TOU DDP		25.50		0.22	0.18		0.05					0.03176			0.08415	46
47	OLRS-TOU CPP		99.30						0.29689	0.22265		0.01179	0.01801	0.00220	0.00779	0.08415	47
48	OLRS-TOU CPP DDP		99.30			0.18		0.05	0.29689	0.18044		0.01179	0.01472	0.00220	0.00483	0.08415	48
49	OGS-TOU		25.50	2.00						0.07226		0.01118	0.00814	0.00210	(0.00063)	0.07960	49
50	OLGS-1-TOU		15.80	5.75	4.25	7.95	<- Summer Winter->	0.50		0.09592		0.00665	0.00777	(0.00198)	(0.00097)	0.07960	50
51	OLGS-3P-HLF		214.10	68.25	1.41	22.23	-	1.90		0.01606	-	0.00001	0.00085			0.07960	51
52																	52
53	Incremental MPE						Generation $/kW Credit				Generation $/kWh Credit						53
54	GS MPE												(0.01508)				54
55	LGS-1 MPE							(3.41)					(0.00842)				55
56	LGS-2S MPE					(11.02)	-	(1.12)		(0.01044)	-	(0.00245)	(0.00245)				56
57	LGS-3P MPE					(10.71)	-	(1.46)		(0.00186)	-	(0.00032)	(0.00042)				57
58	LGS-3T MPE					(5.73)	-	(0.60)		(0.01015)	-	(0.00045)	(0.00100)				58
59																	59
60	Incremental EVCCR						EVCCR Demand Reduction Rates				EVCCR Transition kWh Adder Rates						60
61	OLGS-1 EVCCR					(4.77)		(0.30)		0.03854			0.00105	(0.00776)	(0.00786)		61
62	LGS-2S EVCCR					(9.47)	-	(0.96)		0.07203	-	-	0.00229	(0.00855)	(0.00855)		62
63	LGS-2P EVCCR					(8.12)	-	(0.96)		0.05800	-	-	0.00193	(0.00812)	(0.00854)		63
64	LGS-2T EVCCR					(8.60)	-	(0.90)		0.06721	-	-	0.04968	(0.00810)	(0.00828)		64
65	LGS-3S EVCCR					(9.47)	-	(1.20)		0.06706	-	-	0.00250	(0.00825)	(0.00861)		65
66	LGS-3P EVCCR					(9.89)	-	(1.35)		0.06858	-	-	0.00270	(0.00831)	(0.00842)		66
67	LGS-3T EVCCR					(8.60)	-	(0.90)		0.05123	-	-	0.00171	(0.00810)	(0.00828)		67
68																	68
69																	69

Line No.				Line No.
70	Additional Charges:			70
71	Separate Billing			71
72	LGS-X & LGS-WP-X:	$	12.00 Per additional bill	72
73	DOS LGS-X & LGS-WP-X:	$	12.00 Per additional bill	73
74	Power Factor Charges ($/kVarh):			74
75	Summer:	$	0.00200 $/kVarh	75
76	Winter:	$	0.00100 $/kVarh	76

	Charge per $ of: Utility	Charge per $ of: Customer Contributed
Customer Specific Facilities Charges	Utility	Customer Contributed
Transmission non-X customers	$ 0.00322	$ 0.00059
DOS Transmission non-X customers	$ 0.00322	$ 0.00059
OLGS-3P HLF customers	$ 0.00322	$ 0.00059

77 Notes:

78 (1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge recovers both the Rule 9 and primary distibution facility costs. For LGSX customers the per kW facility charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facility charge (CSFC).

80 (2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical.

83 (3) The per kW facility charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

Nevada Power Company
Statement O

Summary of Proposed Rates -- Bundled (continued)

Line No.	Class	BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy) Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	Additional Charges on per kWH Basis REPR	TRED	DEAA	EE	NDPP	ESAP	Total Energy, per kWh (BTGR & BTER + EE + DEAA) Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR
8																					
9	RS					$ 0.14226			$ 0.00077	$ 0.00070	$ 0.01750	$ 0.00206	$ 0.00142	$ 0.00002					$ 0.16329		
10	RM					0.13553			0.00077	0.00070	0.01750	0.00186	0.00142	0.00002					0.15636		
11	LRS					0.13346			0.00077	0.00070	0.01750	0.00156	0.00142	0.00002					0.15399		
12	GS					0.09601			0.00077	0.00057	0.01500	0.00139	0.00142	0.00002					0.11374		
13	LGS-1					0.09167			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002					0.10946		
14	LGS-2S		$ 0.10455	$ -	$ 0.08545	0.08546			0.00077	0.00057	0.01500	0.00135	0.00142	0.00002		$ 0.12224	$ -	$ 0.10314	0.10315		
15	LGS-2P		0.10146	-	0.08115	0.08540			0.00077	0.00057	0.01500	0.00117	0.00142	0.00002		0.11897	-	0.09866	0.10291		
16	LGS-2T		0.11202	-	0.08104	0.08280			0.00077	0.00057	0.01500	0.00101	0.00142	0.00002		0.12937	-	0.09839	0.10015		
17	LGS-3S		0.10561	-	0.08252	0.08606			0.00077	0.00057	0.01500	0.00130	0.00142	0.00002		0.12325	-	0.10016	0.10370		
18	LGS-3P		0.10009	-	0.08312	0.08416			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11788	-	0.10091	0.10195		
19	LGS-3T		0.11202	-	0.08104	0.08280			0.00077	0.00057	0.01500	0.00107	0.00142	0.00002		0.12943	-	0.09845	0.10021		
20	LGS-XS		0.10561	-	0.08252	0.08606			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.12340	-	0.10031	0.10385		
21	LGS-XP		0.10009	-	0.08312	0.08416			0.00077	0.00057	0.01500	0.00161	0.00142	0.00002		0.11804	-	0.10107	0.10211		
22	LGS-XT		0.11202	-	0.08104	0.08280			0.00077	0.00057	0.01500	0.00124	0.00142	0.00002		0.12960	-	0.09862	0.10038		
23	LGS-2S-WP		0.12127	-	0.09474	0.09475			0.00077	0.00057	0.01500	0.00141	0.00142	0.00002		0.13902	-	0.11249	0.11250		
24	LGS-2P-WP		0.12335	-	0.08574	0.08575			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.14072	-	0.10311	0.10312		
25	LGS-2T-WP		0.11741	-	0.08569	0.08433			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.13478	-	0.10306	0.10170		
26	LGS-3S-WP		0.19579	-	0.09827	0.09828			0.00077	0.00057	0.01500	0.00068	0.00142	0.00002		0.21281	-	0.11529	0.11530		
27	LGS-3P-WP		0.13511	-	0.08190	0.08191			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.15230	-	0.09909	0.09910		
28	LGS-3T-WP		0.12860	-	0.08185	0.08055			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.14579	-	0.09904	0.09774		
29	IAIWP					0.06751			-	-	-								0.06751		
30																					
31	ORS-TOU		0.37603		0.08422	0.08817	$ 0.07580	$ 0.07935	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39456		0.10275	0.10670	$ 0.09433	$ 0.09788
32	ORS-TOU Opt A		0.37603		0.08422	0.08817	0.07580	0.07935	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39456		0.10275	0.10670	0.09433	0.09788
33	ORS-TOU Opt B		0.37603		0.08422	0.08817	0.07580	0.07935	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.39456		0.10275	0.10670	0.09433	0.09788
34	ORS-TOU DDP					0.11716			0.00077	0.00070	0.01500	0.00206	0.00142	0.00002					0.13569		
35	ORS-TOU CPP	0.60785	0.32532		0.08823	0.08817	0.07941	0.07935	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.62638	0.34385		0.10676	0.10670	0.09794	0.09788
36	ORS-TOU CPP DDP	0.60785	0.27078		0.08637	0.08817	0.07773	0.07935	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.62638	0.28931		0.10490	0.10670	0.09626	0.09788
37	ORM-TOU		0.31038		0.11387	0.09327	0.10248	0.08394	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.32871		0.13220	0.11160	0.12081	0.10227
38	ORM-TOU Opt A		0.31038		0.11387	0.09327	0.10248	0.08394	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.32871		0.13220	0.11160	0.12081	0.10227
39	ORM-TOU Opt B		0.31038		0.11387	0.09327	0.10248	0.08394	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.32871		0.13220	0.11160	0.12081	0.10227
40	ORM-TOU DDP					0.11889			0.00077	0.00070	0.01500	0.00186	0.00142	0.00002					0.13722		
41	ORM-TOU CPP	0.38371	0.28009		0.11122	0.09793	0.10010	0.08814	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.40204	0.29842		0.12955	0.11626	0.11843	0.10647
42	ORM-TOU CPP DDP	0.37593	0.25843		0.11122	0.08929	0.10010	0.08036	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.39426	0.27676		0.12955	0.10762	0.11843	0.09869
43	OLRS-TOU		0.33994		0.09643	0.09461	0.08679	0.08515	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.35797		0.11446	0.11264	0.10482	0.10318
44	OLRS-TOU Opt A		0.33994		0.09643	0.09461	0.08679	0.08515	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.35797		0.11446	0.11264	0.10482	0.10318
45	OLRS-TOU Opt B		0.33994		0.09643	0.09461	0.08679	0.08515	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.35797		0.11446	0.11264	0.10482	0.10318
46	OLRS-TOU DDP					0.11591			0.00077	0.00070	0.01500	0.00156	0.00142	0.00002					0.13394		
47	OLRS-TOU CPP	0.30468	0.30680		0.09594	0.10216	0.08635	0.09194	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.32271	0.32483		0.11397	0.12019	0.10438	0.10997
48	OLRS-TOU CPP DDP	0.30172	0.26459		0.09594	0.09887	0.08635	0.08898	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.31975	0.28262		0.11397	0.11690	0.10438	0.10701
49	OGS-TOU		0.15186		0.09078	0.08774	0.08170	0.07897	0.00077	0.00057	0.01500	0.00139	0.00142	0.00002		0.16959		0.10851	0.10547	0.09943	0.09670
50	OLGS-1-TOU		0.17552		0.08625	0.08737	0.07762	0.07863	0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.19331		0.10404	0.10516	0.09541	0.09642
51	OLGS-3P-HLF		0.09566	-	0.07961	0.08045			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11345		0.09740	0.09824	0.01779	0.01779
52																					

53 (1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O.

Nevada Power Company
Statement O

Proposed Street Lighting (SL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00132	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	Street Lights - Non-metered																	12
13	Mercury Vapor	Non-Metered	100W	CLS 20		73	$ 3.21	$ 5.81	**$ 9.02**	$ 1.10	$ 0.04	$ 0.10	$ 0.06	$ 0.10	$ -	---	$ 10.42	13
14	Mercury Vapor	Non-Metered	100W	CLS 20		73	3.21	5.81	**9.02**	1.10	0.04	0.10	0.06	0.10	-	---	10.42	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.18	8.20	**9.38**	1.55	0.06	0.14	0.08	0.15	-	---	11.36	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.18	8.20	**9.38**	1.55	0.06	0.14	0.08	0.15	-	---	11.36	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.08**	2.48	0.09	0.22	0.13	0.23	-	---	13.23	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.08**	2.48	0.09	0.22	0.13	0.23	-	---	13.23	18
19	High Pressure	Non-Metered	100W	CLS 23		42	5.34	3.34	**8.68**	0.63	0.02	0.06	0.03	0.06	-	---	9.48	19
20	High Pressure	Non-Metered	200W	CLS 24		83	2.53	6.61	**9.14**	1.25	0.05	0.11	0.06	0.12	-	---	10.73	20
21	Municipal Street Lights - Public																	21
22	Incandescent	n/a	100W	CLS 30		73	3.18	5.81	**8.99**	1.10	0.04	0.10	0.06	0.10	-	---	10.39	22
23	Incandescent	n/a	200W	CLS 31		120	0.01	9.55	**9.53**	1.80	0.07	0.16	0.09	0.17	-	---	11.82	23
24	Incandescent	n/a	200W	CLS 32		167	0.01	13.29	**10.04**	2.51	0.10	0.22	0.13	0.24	-	---	13.24	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	3.19	5.81	**9.00**	1.10	0.04	0.10	0.06	0.10	-	---	10.40	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	1.14	8.20	**9.34**	1.55	0.06	0.14	0.08	0.15	-	---	11.32	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	0.01	13.13	**10.02**	2.48	0.09	0.22	0.13	0.23	-	---	13.17	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	3.19	5.81	**9.00**	1.10	0.04	0.10	0.06	0.10	-	---	10.40	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	1.14	8.20	**9.34**	1.55	0.06	0.14	0.08	0.15	-	---	11.32	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	0.01	13.13	**10.02**	2.48	0.09	0.22	0.13	0.23	-	---	13.17	30
31	Sodium Vapor	n/a	100W	CLS 89		42	5.31	3.34	**8.65**	0.63	0.02	0.06	0.03	0.06	-	---	9.45	31
32	Sodium Vapor	n/a	200W	CLS 90		83	2.50	6.61	**9.11**	1.25	0.05	0.11	0.06	0.12	-	---	10.70	32
33	Municipal Street Lights - Customer Owned																	33
34	Incandescent	n/a	200W	CLS 51		120	0.01	9.55	**3.84**	1.80	0.07	0.16	0.09	0.17	-	0.05	6.18	34
35	Mercury Vapor	n/a	200W	CLS 53		73	0.01	5.81	**3.31**	1.10	0.04	0.10	0.06	0.10	-	0.03	4.74	35
36	Mercury Vapor	n/a	200W	CLS 54		103	0.01	8.20	**3.65**	1.55	0.06	0.14	0.08	0.15	-	0.04	5.67	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.01	13.13	**4.33**	2.48	0.09	0.22	0.13	0.23	-	0.06	7.54	37
38	Street Lights - LED																	38
39	LED	Non-Metered	100W	CLS 20		70	3.19	5.57	**8.76**	1.05	0.04	0.09	0.05	0.10	-	---	10.09	39
40	LED	Non-Metered	200W	CLS 21		35	3.19	5.57	**8.76**	0.53	0.02	0.05	0.03	0.05	-	---	9.44	40
41	LED	Non-Metered	200W	CLS 22		70	1.13	5.57	**6.70**	1.05	0.04	0.09	0.05	0.10	-	---	8.03	41
42	LED	Non-Metered	200W	CLS 24		70	1.13	5.57	**6.70**	1.05	0.04	0.09	0.05	0.10	-	---	8.03	42
43	Municipal Street Lights - LED																	43
44	LED	n/a	100W	CLS 30		35	3.03	2.79	**5.82**	0.53	0.02	0.05	0.03	0.05	-	---	6.50	44
45	LED	n/a	200W	CLS 31		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	45
46	LED	n/a	200W	CLS 32		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	46
47	LED	Wood Pole	200W	CLS 33		70	3.04	2.79	**5.83**	1.05	0.04	0.09	0.05	0.10	-	---	7.16	47
48	LED	Wood Pole	200W	CLS 34		70	1.05	2.79	**3.84**	1.05	0.04	0.09	0.05	0.10	-	---	5.17	48
49																		49
50	Metered	Metered	Metered	Metered		Mtrd	0.05011	0.07960	**0.12971**	0.01500	0.00057	0.00132	0.00077	0.00142	0.00002	0.00039	0.14920	50
51																		51
52	Note: Municipal and Public Street Lights do not pay UEC charges.																	52

Proposed Residential Private Area Lighting (RS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	Proposed BTGR & BTER Rate	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01750	$ 0.00070	$ 0.00124	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	RS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.21	$ 6.14	**$ 13.35**	$ 1.28	$ 0.05	$ 0.09	$ 0.06	$ 0.10	$ -	0.03	$ 14.96	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.21	6.14	**13.35**	1.28	0.05	0.09	0.06	0.10	-	0.03	14.96	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	10.41	13.88	**24.29**	2.89	0.12	0.20	0.13	0.23	-	0.06	27.92	15
16	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.12	3.53	**9.65**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.58	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.12	3.53	**9.65**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.58	17
18	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.55	6.98	**14.53**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.35	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.55	6.98	**14.53**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.35	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	10.41	13.88	**24.29**	2.89	0.12	0.20	0.13	0.23	-	0.06	27.92	20
21	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.94	6.14	**19.08**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.69	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.94	6.14	**19.08**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.69	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.14	13.88	**30.02**	2.89	0.12	0.20	0.13	0.23	-	0.06	33.65	23
24	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.85	3.53	**15.38**	0.74	0.03	0.05	0.03	0.06	-	0.02	16.31	24
25	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	7.55	6.98	**14.53**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.35	25
26	LED	RATE A (Existing pole)	200W	CLS 10		70	7.02	5.89	**12.91**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.46	26
27	LED	RATE A (Existing pole)	200W	CLS 12		70	5.57	5.89	**11.46**	1.23	0.05	0.09	0.05	0.10	-	0.03	13.01	27
28	LED	RATE A (Existing pole)	100W	CLS 14		35	5.60	2.95	**8.55**	0.61	0.02	0.04	0.03	0.05	-	0.01	9.31	28
29	LED	RATE A (Existing pole)	200W	CLS 15		70	6.75	5.89	**12.64**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.19	29
30	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.70	5.89	**18.59**	1.23	0.05	0.09	0.05	0.10	-	0.03	20.14	30
31	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.06	5.89	**15.95**	1.23	0.05	0.09	0.05	0.10	-	0.03	17.50	31
32	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.22	2.95	**14.17**	0.61	0.02	0.04	0.03	0.05	-	0.01	14.93	32
33																		33
34																		34

Proposed General Service Private Area Lighting (GS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00113	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	GS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.37	$ 5.81	**$ 13.18**	$ 1.10	$ 0.04	$ 0.08	$ 0.06	$ 0.10	$ -	0.03	$ 14.59	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.37	5.81	**13.18**	1.10	0.04	0.08	0.06	0.10	-	0.03	14.59	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.12	13.13	**24.25**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.43	15
16	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.12	13.13	**24.25**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.43	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.09	3.34	**9.43**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.24	17
18	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.09	3.34	**9.43**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.24	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.77	6.61	**14.38**	1.25	0.05	0.09	0.06	0.12	-	0.03	15.98	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.77	6.61	**14.38**	1.25	0.05	0.09	0.06	0.12	-	0.03	15.98	20
21	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	11.12	13.13	**24.25**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.43	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.11	5.81	**18.92**	1.10	0.04	0.08	0.06	0.10	-	0.03	20.33	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.86	13.13	**29.99**	2.48	0.09	0.19	0.13	0.23	-	0.06	33.17	23
24	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.86	13.13	**29.99**	2.48	0.09	0.19	0.13	0.23	-	0.06	33.17	24
25	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.84	3.34	**15.18**	0.63	0.02	0.05	0.03	0.06	-	0.02	15.99	25
26	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.51	6.61	**20.12**	1.25	0.05	0.09	0.06	0.12	-	0.03	21.72	26
27	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.51	6.61	**20.12**	1.25	0.05	0.09	0.06	0.12	-	0.03	21.72	27
28	LED	RATE A (Existing pole)	200W	CLS 10		70	7.17	5.57	**12.74**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.09	28
29	LED	RATE A (Existing pole)	200W	CLS 12		70	5.88	5.57	**11.45**	1.05	0.04	0.08	0.05	0.10	-	0.03	12.80	29
30	LED	RATE A (Existing pole)	100W	CLS 14		35	5.56	2.79	**8.35**	0.53	0.02	0.04	0.03	0.05	-	0.01	9.03	30
31	LED	RATE A (Existing pole)	200W	CLS 15		70	6.93	5.57	**12.50**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.85	31
32	LED	RATE A (Existing pole)	200W	CLS 88		70	5.88	5.57	**11.45**	1.05	0.04	0.08	0.05	0.10	-	0.03	12.80	32
33	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.86	5.57	**18.43**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.78	33
34	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.44	5.57	**16.01**	1.05	0.04	0.08	0.05	0.10	-	0.03	17.36	34
35	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.20	2.79	**13.99**	0.53	0.02	0.04	0.03	0.05	-	0.01	14.67	35
36	LED	RATE B (30 Foot pole)	200W	CLS 17		70	12.46	5.57	**18.03**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.38	36
37																		37
38																		38

Nevada Power Company

Statement O

Proposed Standby Rates

Line No.	Class		Distribution Charges				Contract Demand Charges, contract kW[4]			Backup Service Variable T&G Demand Charges, metered kW			BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]				Maintenance Back-up Service[7]		Line No.
			Distribution Charge, per Cust:	Additional Meter/ Generation Meter Charge[8]	Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3]	Facilities Charge, per kW[2,3]	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Sum Off Peak:	Other:	Set @ 50% of Summer On-peak Variable T&G Demand Charges	BTER Energy, per kWh	
9	SSR II	SS-II GS	25.50	2.00	7.74											0.00465		0.07960	9
10	SSR III	LGS-1	15.80	5.75	4.25	$ 4.25			$ 1.35			$ 3.83				0.01207	$ 1.92	0.07960	10
11	LSR I	LGS-2S	122.40	12.25	2.80	2.80	$ 4.10	$ -	0.42	$ 11.68	$ -	1.18	$ 0.02495	$ -	$ 0.00585	0.00586	5.84	0.07960	11
12	LSR I	LGS-2P	207.70	54.75	2.85	2.85	3.52	-	0.42	10.01	-	1.18	0.02186	-	0.00155	0.00580	5.01	0.07960	12
13	LSR I	LGS-2T	182.00	89.00	CSF	0.91	3.73	-	0.39	10.60	-	1.11	0.03242	-	0.00144	0.00320	5.30	0.07960	13
14	LSR II	LGS-3S	122.00	15.00	2.80	2.80	4.10	-	0.52	11.68	-	1.48	0.02601	-	0.00292	0.00646	5.84	0.07960	14
15	LSR II	LGS-3P	214.10	68.25	2.60	2.60	4.28	-	0.59	12.20	-	1.66	0.02049	-	0.00352	0.00456	6.10	0.07960	15
16	LSR II[2]	LGS-3T	182.00	89.00	CSF	0.91	3.73	-	0.39	10.60	-	1.11	0.03242	-	0.00144	0.00320	5.30	0.07960	16
17	LSR III[9]	LGS-XS	4,743.00	16.90	2.25	2.25	4.10	-	0.52	11.68	-	1.48	0.02601	-	0.00292	0.00646	5.84	0.07960	17
18	LSR III[9]	LGS-XP	4,743.00	54.30	3.05	3.05	4.28	-	0.59	12.20	-	1.66	0.02049	-	0.00352	0.00456	6.10	0.07960	18
19	LSR III[1,9]	LGS-XT	4,743.00	92.60	CSF	na	3.73	-	0.39	10.60	-	1.11	0.03242	-	0.00144	0.00320	5.30	0.07960	19
20	LSR I WP	LGS-2-WPS	128.70	12.25	1.10	1.10	4.10	-	0.42	11.68	-	1.18	0.04167	-	0.01514	0.01515	5.84	0.07960	20
21	LSR I WP	LGS-2-WPP	208.60	54.75	1.55	1.55	3.52	-	0.42	10.01	-	1.18	0.04375	-	0.00614	0.00615	5.01	0.07960	21
22	LSR I WP	LGS-2-WPT	169.10	92.75	CSF	0.91	3.73	-	0.39	10.60	-	1.11	0.03781	-	0.00609	0.00473	5.30	0.07960	22
23	LSR II WP	LGS-3-WPS	149.90	15.00	1.25	1.25	4.10	-	0.52	11.68	-	1.48	0.11619	-	0.01867	0.01868	5.84	0.07960	23
24	LSR II WP	LGS-3-WPP	234.20	68.25	1.00	1.00	4.28	-	0.59	12.20	-	1.66	0.05551	-	0.00230	0.00231	6.10	0.07960	24
25	LSR II WP	LGS-3-WPT	189.10	89.00	CSF	0.91	4.65	-	0.59	13.24	-	1.66	0.04900	-	0.00225	0.00095	6.62	0.07960	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF cha (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are customer spe
3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
4. The contract demand charge is set at 26% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.
5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See note
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated costs
9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charges

Proposed Distribution Only Service (DOS) Rates

Line No.	Class	Note	Distribution Charge, per Customer	Total Facilities Charge, per kW (1)	Additional Meter Charge, per Meter	LGSX CSF Charges (monthly dollar charge for entire class)	NDPP	ESAP	Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR)	Line No.
8	GS	1	$ 25.50		$ 2.00		$ 0.00142	$ 0.00002	$ 0.00915	8
9	LGS-1	1	15.80	$ 4.25	5.75		0.00142	0.00002	0.00366	9
10	LGS-2S		122.40	2.80	12.25		0.00142	0.00002	0.00463	10
11	LGS-2P		207.70	2.85	54.75		0.00142	0.00002	0.00510	11
12	LGS-2T	2	182.00	0.91	89.00		0.00142	0.00002	0.00366	12
13	LGS-3S		122.00	2.80	15.00		0.00142	0.00002	0.00512	13
14	LGS-3P		214.10	2.60	68.25		0.00142	0.00002	0.00610	14
15	LGS-3T	2	182.00	0.91	89.00		0.00142	0.00002	0.00300	15
16	LGS-XS	3	4,743.00	2.25	16.90	$ 1,802.00	0.00142	0.00002	0.00512	16
17	LGS-XP	3	4,743.00	3.05	54.30	$ 53,727.00	0.00142	0.00002	0.00610	17
18	LGS-XT	3	4,743.00	na	92.60	$ 30,724.00	0.00142	0.00002	0.00300	18
19	LGS-2S-WP		128.70	1.10	12.25		0.00142	0.00002	0.00892	19
20	LGS-2P-WP		208.60	1.55	54.75		0.00142	0.00002	0.00696	20
21	LGS-2T-WP	2	169.10	0.91	92.75		0.00142	0.00002	0.00725	21
22	LGS-3S-WP		149.90	1.25	15.00		0.00142	0.00002	0.01302	22
23	LGS-3P-WP		234.20	1.00	68.25		0.00142	0.00002	0.00478	23
24	LGS-3T-WP	2	189.10	0.91	89.00		0.00142	0.00002	0.00725	24
25	SL	4					0.00142	0.00002		25
26	GS-Pal	4					0.00142	0.00002		26

Line No.					Line No.
28	Additional Charges:				28
29	Separate Billing				29
30	DOS LGS-X & LGS-WP-X:	$	12.00	Per additional bill	30
31	Power Factor Charges ($/kVarh)[5]:				31
32	Summer:	$	0.00200	$/kVarh	32
33	Winter:		0.00100	$/kVarh	33
34	Non-X class Customer Specific Facilities:		0.00322	Per $ of Utility Investment	34
35			0.00059	$ per Customer Contributed Investment	35
36	R-BTER - 2016 charge ($/kWh)[6]:		0.00139		36
37	R-BTER - 2017 charge ($/kWh)[6]:		0.00095		37
38	DECOM REV				38

(1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

(2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

(3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

(4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

(5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

Line No.	Class[1]	Sales (kWh)	Marginal Generation Revenue	Reconciled Generation Cost per kWh[2]	Line No.
8	**Bundled Service**				8
9	GS	612,055,143	$ 11,674,557	$ 0.01907	9
10	LGS-1	4,073,133,716	88,027,660	0.02161	10
11	LGS-2S	2,429,180,261	47,118,528	0.01940	11
12	LGS-2P	69,583,297	1,152,893	0.01657	12
13	LGS-2T	no customers	(set @ LGS-3T)	0.04251	13
14	LGS-3S	768,658,032	13,588,173	0.01768	14
15	LGS-3P	1,393,295,183	31,697,405	0.02275	15
16	LGS-3T	247,665,929	10,527,694	0.04251	16
17	LGS-XS	0	(set @ LGS-3S)	0.01768	17
18	LGS-XP	0	(set @ LGS-3P)	0.02275	18
19	LGS-XT	0	(set @ LGS-3T)	0.04251	19
20	LGS-2S-WP	14,877,558	199,931	0.01344	20
21	LGS-2P-WP	11,147,772	127,169	0.01141	21
22	LGS-2T-WP	no customers	(set @ LGS-3T)	0.04251	22
23	LGS-3S-WP	4,412,814	54,036	0.01225	23
24	LGS-3P-WP	19,004,483	178,702	0.00940	24
25	LGS-3T-WP	no customers	(set @ LGS-3T)	0.04251	25
26	SL	129,054,441	2,031,457	0.01574	26
27	GS-Pal	2,217,456	35,555	0.01603	27
28	IAIWP	no customers	(set @ LGS-3S)	0.02161	28
29					29
30	**Current LSR & Optional/Trial TOU Classes with Customers:**				30
31	LSR-1: LGS-2S		(set @ LGS-2S)	0.01940	31
32	LSR-1: LGS-2P		(set @ LGS-2P)	0.01657	32
33	LSR-1: LGS-2T		(set @ LGS-2T)	0.04251	33
34	LSR-2: LGS-3P		(set @ LGS-3P)	0.01768	34
35	LSR-2: LGS-3T		(set @ LGS-3T)	0.04251	35
36	LSR-2: LGS-3S-WP		(set @ LGS-3S-WP)	0.01225	36
37	LSR-2: LGS-3P-WP		(set @ LGS-3P)	0.00940	37
38	LSR-2: LGS-2S-WP		(set @ LGS-2S)	0.01344	38
39	OGS-TOU		(set @ GS)	0.01907	39
40	OLGS-1-TOU		(set @ LGS-1)	0.02161	40
41					41
42	**DOS Classes:**				42
43	DOS: GS		(set @ GS)	0.01907	43
44	DOS: LGS-1		(set @ LGS-1)	0.02161	44
45	DOS: LGS-2S		(set @ LGS-2S)	0.01940	45
46	DOS: LGS-3S		(set @ LGS-3S)	0.01768	46
47	DOS: LGS-3P		(set @ LGS-3P)	0.02275	47
48	DOS: LGS-3T		(set @ LGS-3T)	0.04251	48
49	DOS: LGS-2S-WP		(set @ LGS-2S-WP)	0.01344	49
50	DOS: LGS-2T-WP		(set @ LGS-2T-WP)	0.04251	50
51	DOS: LGS-3S-WP		(set @ LGS-3S-WP)	0.01225	51
52	DOS: LGS-3P-WP		(set @ LGS-3P-WP)	0.00940	52
53	DOS: LGS-3T-WP		(set @ LGS-3T-WP)	0.04251	53

55 1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions. 55
56 For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise 56
57 applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table. 57
58 2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class. 58
59 Reconciliation factor is: 107.2% 59

Calculation of Customer Specific Facilities Charges

Line No.		Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
	Customer Specific Facility Investment & Revenue Requirement					Total			
7	Investment Cost for all Transmission level customers					$ 42,182,585			7
8	Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment					$ 3,293,268			8
9	Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7)					$ 0.07807			9
10	Distribution Reconciliation Factor					62.8%			10
11	Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10)					$ 0.03861			11
12									12
13	**CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above**								13
16	Individual CSFC								16
17	LHOIST	LGS-3T	Bundled	$ 744,171	$ 0.03861	$ 28,755	$ 0.00322	$ 2,396.23	17
18	SA RECYCLING	LGS-3T	Bundled	1,366,297	0.03861	52,794	0.00322	4,399.48	18
19	VENETIAN	LGS-3T	Bundled	6,606,728	0.03861	255,284	0.00322	21,273.66	19
20	HOLDER	LGS-3T	Bundled	2,136,118	0.03861	82,540	0.00322	6,878.30	20
21	SNWA LAMB	LGS-3T	DOS	286,690	0.03861	11,078	0.00322	923.14	21
22	SNWA LAMB	LGS-3T	DOS	286,690	0.03861	11,078	0.00322	923.14	22
23	SNWA SLOAN	LGS-3T	DOS	697,203	0.03861	26,940	0.00322	2,244.99	23
24	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03861	24,030	0.00322	2,002.51	24
25	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03861	24,030	0.00322	2,002.51	25
26	CCWRD2	LGS-3T	DOS	110,617	0.03861	4,274	0.00322	356.19	26
27	CCWRD2	LGS-3T	DOS	62,534	0.03861	2,416	0.00322	201.36	27
28	CCWRD2	LGS-3T	DOS	693,608	0.03861	26,801	0.00322	2,233.42	28
29	MGM	LGS-3T	DOS	22,571,345	0.03861	872,157	0.00322	72,679.73	29
30	MGM	LGS-3T	DOS	1,434,005	0.03861	55,410	0.00322	4,617.50	30
31	CAESAR'S	LGS-3T	DOS	1,025,601	0.03861	39,629	0.00322	3,302.44	31
32	AIR LIQUIDE	LGS-3T	DOS	96,488	0.03861	3,728	0.00322	310.69	32
33	SNWA PP4	LGS-3T-WP	DOS	30,192	0.03861	1,167	0.00322	97.22	33
34	SNWA PP5	LGS-3T-WP	DOS	1,370,352	0.03861	52,950	0.00322	4,412.53	34
35	SNWA PP6	LGS-3T-WP	DOS	672,178	0.03861	25,973	0.00322	2,164.41	35
36	SNWA HACIENDA	LGS-3T-WP	DOS	327,114	0.03861	12,640	0.00322	1,053.31	36
37	SNWA PP3	LGS-2T-WP	DOS	420,860	0.03861	16,262	0.00322	1,355.17	37
38	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	1,891,817	0.03861	73,100	0.00322	6,091.65	38
39	NP RED ROCK LLC	OLGS-3P HLF	Bundled	814,244	0.03861	31,462	0.00322	2,621.87	39
40	POLY-WEST INC	OLGS-3P HLF	Bundled	275,872	0.03861	10,660	0.00322	888.31	40
41	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	376,661	0.03861	14,554	0.00322	1,212.85	41
42	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	951,162	0.03861	36,753	0.00322	3,062.74	42
43	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	488,832	0.03861	18,888	0.00322	1,574.04	43
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	628,800	0.03861	24,297	0.00322	2,024.73	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	623,669	0.03861	24,099	0.00322	2,008.21	45
46	POLY-WEST 2089379	OLGS-3P HLF	Bundled	275,872	0.03861	10,660	0.00322	888.31	46
47									47
48									48
49									49
50									50
51	Subtotals by Class and Service								51
52	LGS-3T - Bundled	LGS-3T	Bundled	$ 10,853,314	0.03861	419,372	0.00322	34,948	52
53	LGS-3T - DOS	LGS-3T	DOS	28,508,575	0.03861	1,101,571	0.00322	91,798	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	0.03861	-	0.00322	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	420,860	0.03861	16,262	0.00322	1,355	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	0.03861	-	0.00322	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	2,399,836	0.03861	92,730	0.00322	7,727	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	6,326,928	0.03861	244,473	0.00322	20,373	58
59					avg.		avg.		59
60	Total			$ 48,509,514	0.03864	$ 1,874,408	0.00322	$ 156,201	60
61					rounding>>	$ 0		$ (0)	61
62	**Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)**						^^^^^^^^^^^^^		62
63							Proposed		63
64	Investment Cost for Transmission level customers:					$ 42,182,585	Tariff Recovery		64
65	Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 64 * line 11):					$ 3,293,268	Rate per Dollar		65
66	Distribution Reconciliation Factor (line 11):					62.8%	of Facility		66
67	Reconciled Investment Cost (line 66 * line 65):					$ 2,068,275	Investment		67
68	Annual facility kW determinants					2,270,623			68
69	Per kW facilty rate (line 67 / Line 68)					$ 0.91			69

Nevada Power Company
Statement O

Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Development of Annual & Monthly Per Dollar of Investment Recovery Rate

Line No.		(a)	(b)		(c)
7		(a)	(b)		(c)
8	Annual: Dist Reconciliation Factor	X	Dollar O&M/A&G Recovery Per Dollar of Contributed Investment		
9	62.8%	X	$0.01062	=	$ 0.00667
10	Monthly: (annual rate divided by 12)			=	$ 0.00059

CIAC Investment & O&M and A&G Revenue Requirement

Line No.	Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	Dollar Per Dollar of Investment $ (cost based -- before reconciliation) [(b) / (a)]	Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment
13-16							Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer			
17										
18	LHOIST	LGS-3T	Bundled	-	$ -	$0.01062	$ -	$ 0.00059	$ -	$ -
19	SA RECYCLING	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-
20	VENETIAN	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-
21	HOLDER	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84
22	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00
23	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00
24	SNWA SLOAN	LGS-3T	DOS	826,580	8,780	$0.01062	826,580	0.00059	487.68	5,852.16
25	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28
26	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28
27	CCWRD2	LGS-3T	DOS	374,615	3,979	$0.01062	374,615	0.00059	221.02	2,652.24
28	CCWRD2	LGS-3T	DOS	211,779	2,249	$0.01062	211,779	0.00059	124.95	1,499.40
29	CCWRD2	LGS-3T	DOS	2,348,976	24,950	$0.01062	2,348,976	0.00059	1,385.90	16,630.80
30	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-
31	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-
32	CAESAR'S	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-
33	AIR LIQUIDE	LGS-3T	DOS	4,942,256	52,495	$0.01062	4,942,256	0.00059	2,915.93	34,991.16
34	SNWA PP4	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
35	SNWA PP5	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
36	SNWA PP6	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
37	SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
38	SNWA PP3	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
39	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
40	NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
41	POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60
42	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
43	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
44	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
46	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-
47	POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60
48										
49										
50										
51	Subtotals by Class and Service									
52	LGS-3T - Bundled	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84
53	LGS-3T - DOS	LGS-3T	DOS	11,993,826	127,395	$0.01062	11,993,826	0.00059	7,076.36	84,916.32
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,100	$0.01062	103,546	0.00059	61.09	733.08
59										
60	Total			$ 19,321,217	$ 205,224	$0.01062	$ 38,642,434		$ 11,399.52	$ 136,794.24
61						Marginal O&M from MCS				
62						$205,224				

Nevada Power Company
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Calculation of LGS-X Specific Charges

Line No.		Basic Service Charge: Billing Units	Basic Service Charge: Cost-Based Revenue	Basic Service Charge: Rate	Additional Meter Charge: Billing Units	Additional Meter Charge: Cost-Based Revenue	Additional Meter Charge: Rate	Separate Bill: Billing Units	Separate Bill: Cost-Based Revenue	Separate Bill: Rate
7	**Basic Service, Additional Meter and Separate Billing Charges**									
8			D Reconc.	63%						
11	LGS-XS	-	$ -		60	$ 1,013.20	$ 16.90	-	$ -	
12	LGS-XP	24	$ 29,331.77	$ 1,222.16	156	$ 8,470.66	$ 54.30	24	$ 273.65	$11.40
13	LGS-XT	12	$ 14,665.89	$ 1,222.16	36	$ 3,333.64	$ 92.60	12	$ 136.83	$11.40
14	Total	36	$ 43,997.66	**$4,743.00**	252	$ 12,817.51	**$50.90**	36	$ 410.48	**$12.00**
15			Present DOS Rate:	$4,743.00					Present Rate:	$93.50
16			Percent Change:	0.0%					Percent Change:	-87.2%

LGS-X Customer Specific Facilities (line 18)

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment
22	Horseshoe	1231089	LGS-XP DOS	$ 3,740	$ 44,880		$ 4,191	$ 50,292	
23	Horseshoe	1231091	LGS-XS DOS	1,608	19,296		1,802	21,624	
24	Paris	1735149	LGS-XP DOS	5,068	60,816		5,679	68,148	
25	Paris	1735152	LGS-XP DOS	5,068	60,816		5,679	68,148	
26				$ 15,484	$ 185,808	$ 2,066,291	$ 17,351	$ 208,212	$ 2,189,516
34	New Castle Corp (Excalibur)	1396169	LGS-XP DOS	$ 4,710	$ 56,520		$ 5,006	$ 60,072	
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	4,687	56,244		4,981	59,772	
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-	
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-	
38	Luxor	1500684	LGS-XP DOS	5,640	67,680		5,994	71,928	
39	Luxor	1500685	LGS-XP DOS	7,006	84,072		7,446	89,352	
40	Luxor	1511139	LGS-XS DOS	-	-		-	-	
41	Luxor	1652129	LGS-XP DOS	1,698	20,376		1,805	21,660	
42	Mandalay Bay	1714502	LGS-XP DOS	6,090	73,080		6,473	77,676	
43	Mandalay Bay	1714503	LGS-XP DOS	6,090	73,080		6,473	77,676	
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-	
45				$ 35,921	$ 431,052	$ 4,885,159	$ 38,178	$ 458,136	$ 4,885,159
47	Park MGM	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -	
48	Park MGM	1607750	LGS-XT DOS	9,790	117,480		10,335	124,020	
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-	
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-	
51	Bellagio	1693991	LGS-XT DOS	19,315	231,780		20,389	244,668	
52	Park MGM	1782548	LGS-XP DOS	-	-		-	-	
53				$ 29,105	$ 349,260	$ 3,841,860	$ 30,724	$ 368,688	$ 3,841,860
55	Subtotals by Class and Service		LGS-XS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
56			LGS-XP	-	-	-	-	-	-
57			LGS-XT	-	-	-	-	-	-
58			LGS-XS DOS	**1,608**	**19,296**	-	**1,802**	**21,624**	-
59			LGS-XP DOS	**49,797**	**597,564**	-	**53,727**	**644,724**	-
60			LGS-XT DOS	**29,105**	**349,260**	-	**30,724**	**368,688**	-
61			Total for Class	**$ 80,510**	**$ 966,120**	$ -	**$ 86,253**	**$ 1,035,036**	$ -

Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying Investment has remained the same), and allocating the Primary Charges in proportion to the current Primary charges.

EXHIBIT PREST DIRECT - 5

Nevada Power Company

Exhibit Prest Direct-5

Docket No. 23-06XXX

Statement O

MCS, ECIC, Current TOU, Joint Dispatch, RS Cap

Nevada Power Company
Exhibit Prest Direct-5
Statement O

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Page 1 **Comparison of Present, Cost-Based and Proposed Rate Class Revenue**

Page 2 **Revenue Requirement from Schedule H-2, Unbundled Cost of Service Study**

- The unbundled revenue requirement from Statement H is the starting point for deriving what is known to be the revenue target for rate design.
- The following adjustments are made to the Schedule H revenue requirement on this page:
  1) The proposed revenues for the standby (LSR & SSR), Optional TOU and DOS classes are derived from rates that are developed for the otherwise applicable class; thus, the resulting standby revenues are credited against the Schedule H revenue requirement, and the standby classes are excluded from the revenue reconciliation on page 3 and the capping mechanism (page 8).
  2) Power Factor and Additional Facilities and Maintenance revenues are credited against the distribution revenue requiremen and then in the revenue reconciliation process (page 3) they are assigned to specific classes that impose these costs.

Pages 3-7 **Revenue Reconciliation and Revenue Adjustments for Rate Design**

- Reconciles the Marginal Revenue by class to the Adjusted, Unbundled Revenue Requirement for Rate Design using Equal Percent of Marginal Cost (EPMC). The marginal revenue, by function and class, comes directly from the Marginal Cost Study (MCS), and is shown on page 2 of Workpaper 1. The unbundled revenue requirement comes from the Unbundled Schedule H and is summarized on line no. 11, page 1 of Statement O. The adjustments to the revenue requirement are summarized below.
- Reconcile Distribution & Transmission by Function using EPMC: Distribution Marginal Revenue to Distribution Revenue Requirement, and Transmission to Transmission.
- Reconcile Generation and Energy functions combined together on EPMC.

Revenue Adjustments made to the Reconciliation:

Distribution

1) Certain “other revenue” components (miscellaneous revenues (connect/disconnect), returned check, power pedestal and miscellaneous damage) have been credited to the specific classes in which they are generated, consistent with the Commission’s Order in Docket No. 01-10001, which was first implemented in Docket No. 03-10001. They are included in the total DRR that is reconciled, then subtracted from (i.e., credited to) the reconciled distribution revenue requirements of the specific classes that paid them. Thus classes that pay for the services get the benefit through the direct assignment to those classes. These “other revenues” total approximately $4,946.4 million.
2) Revenue from Power Factor services and Additional Facilities and Maintenance (AF&M) services are subtracted (credited to) the DRR on page 7, then get directly assigned to the classes identified with these costs in the reconciliation.

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Generation and Energy

5) The combined generation and energy revenue requirement (G&ERR) is increased by the amount of the credit given to the LGS-3T class on the BTER portion of WAPA energy deliveries associated with one customer included in the class for reconciliation purposes. The credit is then specifically assigned to (or subtracted from) the LGS-3T's reconciled G&E RR. The current WAPA energy credit is $1098.6 thousand.
6) Also, the G&ERR is increased by the amount of the Hoover B Benefit provided to the residential class. The amount of the benefit is then specifically assigned to (or subtracted from) the residential classes' G&ERR based on their relative share of residential kWh sales. The current Hoover B Benefit is $14.2 million.

Standby, Optional Time-of Use, DOS and Other Revenue Credit Adjustments

7) Standby (SSR & LSR) and Optional Time-of-Use (TOU) services have rates that are set off of the otherwise applicable classes marginal costs and/or rates. Accordingly the test period revenues generated by these schedules are treated as credits to proportionately reduce the generation, transmission and distribution revenue requirements on page 4, thereby reducing the revenue requirement and rates for all customers. The total of these revenue credits is approximately -$12.2 million.
8) DOS revenues are treated in a manner analogous to standby and optional TOU service revenues, as DOS distribution rates and non-bypassable charges are set using the otherwise applicable bundled schedule (OAS). The DOS revenues are credited against the revenue requirement, reducing rates for all customers. All DOS revenues, except the non-bypassable interclass rate rebalancing (IRR) revenues, are credited to the DRR. The IRR revenues are credited proportionately to reduce the generation, transmission and distribution revenue requirements on pages 3-7. The current DOS revenue is $31.9 million.

Page 8 **Final Revenue Allocation: Final Class Revenue Requirements Based on Maximum Percent Increase (Capping) and unrestricted floor Mechanism as follows:**

Subject to the caps set forth above:

1) The difference between any capped class revenue and its cost based revenue is re-allocated to other classes using EPMC
2) Two allocations using the above procedure are required to reach the final revenue requirements that satisfy the imposed capping criteria;
3) The reallocation creates an interclass subsidy, which is the difference between the final revenue requirement shown on this page, and the cost-based revenue requirement resulting from the reconciliation process (page 3-7). If the difference between these two values for any class is negative, then the class is receiving a subsidy from other classes; if the value is positive, then the class is providing a subsidy to other classes.

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Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

Line No	Class	Note	Annualized Bills	Sales (MWh)	Present Rate Revenue: Revenue	Present Rate Revenue: Effective Rate ($/kWh)	Results if Class Revenue Requirements were Set @ Reconciled Cost [1]: Cost-Based Revenue	% Change from Present	Effective Rate ($/kWh)	Class Revenue Requirements Based on Proposed Capping Methodology [2]: Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present	Effective Rate ($/kWh)	Combined AB 405 Proposed Revenue Change: % Change from Present	Effective Rate ($/kWh)	Line No
8																	8
9	Classes in Revenue Reconciliation																9
10	RS		6,219,660	7,262,589	$ 1,124,472	$ 0.15483	$ 1,138,729	1.27%	$ 0.15679	$ 1,158,698	$ 19,969	$ 34,226	3.04%	$ 0.15954	3.30%	$ 0.15373	10
11	RM		3,424,968	2,298,671	339,331	0.14762	325,497	-4.08%	0.14160	343,899	18,402	4,569	1.35%	0.14961	1.35%	0.14955	11
12	LRS		2,484	37,526	5,291	0.14099	4,960	-6.26%	0.13216	5,335	376	44	0.84%	0.14217	0.92%	0.14261	12
13	GS		931,320	612,056	83,497	0.13642	77,384	-7.32%	0.12643	83,920	6,536	422	0.51%	0.13711	0.51%	0.13690	13
14	LGS-1		385,308	4,073,470	485,467	0.11918	481,293	-0.86%	0.11815	496,101	14,808	10,634	2.19%	0.12179	2.21%	0.12170	14
15	LGS-2S		14,676	2,437,061	271,383	0.11136	265,012	-2.35%	0.10874	276,088	11,076	4,704	1.73%	0.11329			15
16	LGS-2P		276	69,583	7,301	0.10492	7,048	-3.46%	0.10129	7,408	359	107	1.47%	0.10646			16
17	LGS-2T	3	-	-	-	---	-	na	---	-	-	-	na	---			17
18	LGS-3S		1,392	768,658	82,792	0.10771	79,925	-3.46%	0.10398	83,998	4,073	1,206	1.46%	0.10928			18
19	LGS-3P	4	1,332	1,826,673	195,666	0.10712	186,098	-4.89%	0.10188	197,816	11,718	2,150	1.10%	0.10829			19
20	LGS-3T	4	48	618,671	59,254	0.09578	58,748	-0.85%	0.09496	60,496	1,748	1,242	2.10%	0.09778			20
21	LGS-XS		-	-	-	---	-	na	---	-	-	-	na	---			21
22	LGS-XP		-	-	-	---	-	na	---	-	-	-	na	---			22
23	LGS-XT		-	-	-	---	-	na	---	-	-	-	na	---			23
24	LGS-2S-WP		276	14,878	1,343	0.09025	1,592	18.54%	0.10699	1,820	228	477	35.56%	0.12234			24
25	LGS-2P-WP		108	11,148	1,123	0.10073	1,040	-7.35%	0.09333	1,127	87	4	0.39%	0.10113			25
26	LGS-2T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			26
27	LGS-3S-WP		24	4,413	372	0.08426	409	9.97%	0.09266	447	38	75	20.24%	0.10132			27
28	LGS-3P-WP		72	19,004	1,742	0.09168	1,601	-8.11%	0.08425	1,751	150	8	0.48%	0.09212			28
29	LGS-3T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			29
30	SL		7,224	129,054	11,437	0.08862	14,687	28.41%	0.11380	17,570	2,883	6,133	53.62%	0.13614			30
31	RS-Pal		-	578	85	0.14730	96	12.37%	0.16552	106	10	21	24.61%	0.18355			31
32	GS-Pal		-	2,217	305	0.13751	350	14.85%	0.15793	394	43	89	29.05%	0.17746			32
33	IAIWP	3	-	-	-	---	-	na	---	-	-	-	na	---			33
34	RS-NEM	6	962,904	837,375	80,923	0.16928	176,419	118.01%	0.21068	86,509	(89,910)	5,586	6.90%	0.18096			34
35	RM-NEM	6	5,652	3,554	397	0.15278	775	95.35%	0.21795	403	(372)	6	1.62%	0.15524			35
36	LRS-NEM	6	204	571	92	0.16155	116	25.35%	0.20282	98	(18)	5	5.77%	0.17088			36
37	GS-NEM	6	1,548	2,985	275	0.11395	509	84.77%	0.17051	277	(232)	2	0.60%	0.11464			37
38	LGS-1 NEM	6	4,248	79,974	9,100	0.12410	11,456	25.89%	0.14324	9,391	(2,065)	291	3.20%	0.12807			38
39																	39
45	Partial Requirements & Optional Schedule Groups not included in Reconciliation																45
46	Optional TOU		66,924	447,300	48,258	0.10789	nc	nc	nc	48,866	nc	608	1.26%	0.10925	---	---	46
47	Optional TOU EVRR		38,052	65,465	8,716	0.13314	nc	nc	nc	8,841	nc	125	1.44%	0.13505			47
48	NEM Optional TOU		12,331	7,602	1,090	0.14340	nc	nc	nc	1,169	nc	79	7.25%	0.15380	---	---	48
49	NEM EVRR		15,156	14,179	1,759	0.12403	nc	nc	nc	1,798	nc	40	2.25%	0.12682			49
50	Standby		240	146,311	15,217	0.10400	nc	nc	nc	15,850	nc	633	4.16%	0.10833	---	---	50
51	EVCCR		156	14,835	1,829	0.12331	nc	nc	nc	1,835	nc	5	0.28%	0.12366			51
52	DOS	7	1,980	2,810,428	15,394	0.00548	nc	nc	nc	31,945	nc	16,551	107.51%	0.01137	---	---	52
53																	53
54	Total (Bundled & DOS)		12,094,315	23,793,360	$ 2,805,178	$ 0.11790	$ 2,822,287	na[1]	nc	$ 2,897,938	---	$ 92,760	3.31%	$ 0.12180	3.31%	$ 0.12180	54
55																	55

$ 2,897,751	Statement I Revenue Requirement
$ 92,760	Change in Revenue Requiremen $ 187
3.31%	Percent Change

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.
2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.
3. No Customers in class
4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.
5. All customers in class are DOS customers; no bundled customers.
6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G customers.
7. The effective rate for DOS customers is only for distribution rates, and does not consider OATT and energy rates.

Nevada Power Company

Statement O

Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

Exhibit Prest Direct-5

Docket No. 23-06XXX

MCS, ECIC, Current TOU, Joint Dispatch, RS Cap

Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
8								8
9	Marginal Cost Revenue		$ 2,099,805	$ 781,113	$ 524,669	$ 113,276	$ 680,747	9
10								10
11	Unbundled Revenue Requirement	1	$ 2,897,751	$ 1,718,820	$ 590,171	$ 152,792	$ 435,968	11
12						Total G, T & D	$ 1,178,931	12
13	Total Revenue Requirement Adjustments for Rate Design							13
14	Revenue Credit to Dist. for Specific Class Assignment							14
15	Power Factor (PF)		(913)				(913)	15
16	Additional Facilities and Maintenance (AF&M)		(71)				(71)	16
17								17
18	Optional TOU Revenue		(33,513)	(21,873)	(5,827)	(1,509)	(4,305)	18
19	Optional TOU NEM revenues		(2,967)	(1,833)	(568)	(147)	(420)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(3,308)	(1,697)	(807)	(209)	(596)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	-				-	21
22	DOS SB123 Revenue		(800)		(800)			22
23	DOS Interclass Rate-Rebalancing Revenue		(15,470)		(7,744)	(2,005)	(5,721)	23
24	OLGS-3P HLF & MPE Rate Design Revenue adjustment		680	-	340	88	251	24
25	MPE Revenue Adjustment		6,744	3,972	2,772			25
26	EVCCR Discount Revenue Adjustment		-		-	-		26
27	Total		$ (49,618)	$ (21,430)	$ (12,633)	$ (3,781)	$ (11,774)	27
28								28
29	Class Specific Revenue Requirement Adjustments							29
30	Other Revenue	4	5,368				5,368	30
31	Customer Specific Facilities		(2,816)				(2,816)	31
32	DOS Impact Fee revenue		(1,392)	(511)	(881)			32
33	BTER Energy Credits (WAPA, Hoover B)		(15,258)	(15,258)				33
34	Total Class Specific Adjustments		$ (14,098)	$ (15,769)	$ (881)	$ -	$ 2,552	34
35								35
36	Total Adjustments to Total Revenue Requirement		$ (63,716)	$ (37,199)	$ (13,514)	$ (3,781)	$ (9,221)	36
37								37
38	Target Revenue Requirement for Rate Design		$ 2,834,035	$ 1,359,287	$ 914,167	$ 149,011	$ 423,394	38
39								39

42 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing) 42

43 2. Includes LSR revenues and optional time-of-use revenues. 43

44 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 44

45 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 45

46 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure. 46

Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Transmission Cost Based Class Revenue for Rate Design	Line No.
8															8
9	RS	$ 50,290	44.40%	$ 67,834	$ (670)	$ (65)	$ (93)	$ -	$ (890)	$ 39	$ -	$ -	$ -	$ 66,155	9
10	RM	13,041	11.51%	17,591	(174)	(17)	(24)	-	(231)	10	-	-	-	17,155	10
11	LRS	214	0.19%	288	(3)	(0)	(0)	-	(4)	0	-	-	-	281	11
12	GS	2,580	2.28%	3,480	(34)	(3)	(5)	-	(46)	2	-	-	-	3,394	12
13	LGS-1	18,303	16.16%	24,688	(244)	(24)	(34)	-	(324)	14	-	-	-	24,077	13
14	LGS-2S	9,411	8.31%	12,695	(125)	(12)	(17)	-	(167)	7	-	-	-	12,380	14
15	LGS-2P	225	0.20%	303	(3)	(0)	(0)	-	(4)	0	-	-	-	296	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	2,634	2.33%	3,553	(35)	(3)	(5)	-	(47)	2	-	-	-	3,465	17
18	LGS-3P	6,138	5.42%	8,280	(82)	(8)	(11)	-	(109)	5	-	-	-	8,075	18
19	LGS-3T	2,009	1.77%	2,710	(27)	(3)	(4)	-	(36)	2	-	-	-	2,643	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	59	0.05%	80	(1)	(0)	(0)	-	(1)	0	-	-	-	78	23
24	LGS-2P-WP	28	0.02%	38	(0)	(0)	(0)	-	(0)	0	-	-	-	37	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	14	0.01%	19	(0)	(0)	(0)	-	(0)	0	-	-	-	19	26
27	LGS-3P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	94	0.08%	127	(1)	(0)	(0)	-	(2)	0	-	-	-	124	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	-	-	-	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	-	-	-	1	31
32	IAIWP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	7,646	6.75%	10,313	(102)	(10)	(14)	-	(135)	6	-	-	-	10,058	33
34	RM-NEM	36	0.03%	48	(0)	(0)	(0)	-	(1)	0	-	-	-	47	34
35	LRS-NEM	4	0.00%	5	(0)	(0)	(0)	-	(0)	0	-	-	-	5	35
36	GS-NEM	20	0.02%	27	(0)	(0)	(0)	-	(0)	0	-	-	-	27	36
37	LGS-1-NEM	500	0.44%	675	(7)	(1)	(1)	-	(9)	0	-	-	-	658	37
38															38
39	TOTAL	$ 113,276	100.00%	$ 152,792	$ (1,509)	$ (147)	$ (209)	$ -	$ (2,005)	$ 88	$ -	$ -	$ -	$ 149,011	39
40				from Sch. H-2											40
41															41
42															42
43															43
44	Summation of NEM customers into Standard Schedule for Rate Design														44
45	RS	$ 57,936	51.15%	$ 78,147	$ (772)	$ (75)	$ (107)	$ -	$ (1,025)	$ 45	$ -	$ -	$ -	$ 76,213	45
46	RM	13,077	11.54%	17,639	(174)	(17)	(24)	-	(231)	10	-	-	-	17,202	46
47	LRS	218	0.19%	293	(3)	(0)	(0)	-	(4)	0	-	-	-	286	47
48	GS	2,600	2.30%	3,508	(35)	(3)	(5)	-	(46)	2	-	-	-	3,421	48
49	LGS-1	18,803	16.60%	25,362	(250)	(24)	(35)	-	(333)	15	-	-	-	24,735	49
50															50

Nevada Power Company
Statement O

Distribution Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Distribution Revenue	Percent of Total	Class Specific Adjustments: Other Revenue Adjustment	Class Specific Adjustments: Adjustment for Class Cust Spec. Facilities	Reconciled Distribution Revenue Requirement	Rate Design Revenue Adjustments: Power Factor Revenue	Additional Facilities & Maintenance Revenue	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Decommissionin g Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	MPE Revenue Adjustment	EVCCR Discount Revenue Adjustment	Distribution Cost Based Class Revenue for Rate Design	Line No.
8																			8
9	RS	$ 340,143	50.17%	$ (2,192)		$ 217,830	$ (458)	$ (36)	$ (2,160)	$ (210)	$ (299)	$ -	$ (401)	$ (2,870)	$ 126	$ -	$ -	$ 211,521	9
10	RM	82,009	12.10%	(2,237)		50,811	(110)	(9)	(521)	(51)	(72)	-	(97)	(692)	30	-		49,290	10
11	LRS	995	0.15%	(0)		644	(1)	(0)	(6)	(1)	(1)	-	(1)	(8)	0	-		625	11
12	GS	25,022	3.69%	(235)		15,951	(34)	(3)	(159)	(15)	(22)	-	(30)	(211)	9	-		15,487	12
13	LGS-1	87,187	12.86%	(77)		56,320	(117)	(9)	(554)	(54)	(77)	-	(103)	(736)	32	-		54,703	13
14	LGS-2S	34,537	5.09%	(2)		22,338	(47)	(4)	(219)	(21)	(30)	-	(41)	(291)	13	-		21,698	14
15	LGS-2P	856	0.13%	(0)		554	(1)	(0)	(5)	(1)	(1)	-	(1)	(7)	0	-		538	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-		-	16
17	LGS-3S	9,596	1.42%	(0)		6,207	(13)	(1)	(61)	(6)	(8)	-	(11)	(81)	4	-		6,029	17
18	LGS-3P	30,333	4.47%	(0)	-	19,621	(41)	(3)	(193)	(19)	(27)	-	(36)	(256)	11	-		19,058	18
19	LGS-3T	1,660	0.24%	(0)	1,671	2,745	(2)	(0)	(11)	(1)	(1)	-	(2)	(14)	1	-		2,714	19
20	LGS-XS	61	0.01%	-	22	61	(0)	(0)	(0)	(0)	(0)	-	(0)	(1)	0	-		60	20
21	LGS-XP	2,582	0.38%	-	645	2,315	(3)	(0)	(16)	(2)	(2)	-	(3)	(22)	1	-		2,267	21
22	LGS-XT	29	0.00%	-	369	387	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		387	22
23	LGS-2S-WP	336	0.05%	-		217	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		211	23
24	LGS-2P-WP	171	0.03%	-		110	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		107	24
25	LGS-2T-WP	20	0.00%	-	16	30	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		29	25
26	LGS-3S-WP	352	0.05%	-		228	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		221	26
27	LGS-3P-WP	655	0.10%	-		424	(1)	(0)	(4)	(0)	(1)	-	(1)	(6)	0	-		411	27
28	LGS-3T-WP	112	0.02%	-	94	166	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		164	28
29	SL	2,021	0.30%	(20)		1,287	(3)	(0)	(13)	(1)	(2)	-	(2)	(17)	1	-		1,250	29
30	RS-Pal	55	0.01%	(0)		36	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		35	30
31	GS-Pal	184	0.03%	(0)		119	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		115	31
32	IAIWP	-	0.00%			-	-	-	-	-	-	-	-	-	-	-		-	32
33	RS-NEM	56,780	8.38%	(595)		36,133	(76)	(6)	(361)	(35)	(50)	-	(67)	(479)	21	-		35,080	33
34	RM-NEM	193	0.03%	(9)		116	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		112	34
35	LRS-NEM	48	0.01%	(0)		31	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		30	35
36	GS-NEM	127	0.02%	(0)		82	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		80	36
37	LGS-1-NEM	1,866	0.28%	(0)		1,207	(3)	(0)	(12)	(1)	(2)	-	(2)	(16)	1	-		1,172	37
38						not a sum													38
39	TOTAL	$ 677,931	100.00%	$ (5,368)	$ 2,816	$ 435,968	$ (913)	$ (71)	$ (4,305)	$ (420)	$ (596)	$ -	$ (800)	$ (5,721)	$ 251	$ -	$ -	$ 423,394	39
40						from Sch. H-2													40
41					exc. Specific Class adjustments $	438,520													41
42																			42
43						$ -													43
44	Summation of NEM customers into Standard Schedule for Rate Design																		44
45	RS	$ 396,923	58.55%	$ (2,786)	$ -	$ 253,963	$ (535)	$ (42)	$ (2,520)	$ (246)	$ (349)	$ -		$ (3,349)	$ 147	$ -	$ -	$ 246,602	45
46	RM	82,203	12.13%	(2,247)	-	50,926	(111)	(9)	(522)	(51)	(72)	-		(694)	30	-	-	49,402	46
47	LRS	1,043	0.15%	(0)	-	674	(1)	(0)	(7)	(1)	(1)	-		(9)	0	-	-	655	47
48	GS	25,149	3.71%	(235)	-	16,033	(34)	(3)	(160)	(16)	(22)	-		(212)	9	-	-	15,566	48
49	LGS-1	89,053	13.14%	(77)	-	57,527	(120)	(9)	(565)	(55)	(78)	-		(751)	33	-	-	55,875	49
50																			50

Nevada Power Company
Statement O

Generation Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Generation Revenue	Percent of Total	DOS R-BTER and BTER Impact Fee Revenue	Reconciled Generation Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS BTGR Impact Fee Revenue	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Generation Cost Based Class Revenue for Rate Design	Line No.
8																	8
9	RS	$ 226,859	43.24%	$ -	$ 400,769	$ (2,520)	$ (246)	$ (349)		$ (3,348)	$ 147	$ (381)		$ 1,199	$ -	$ 395,272	9
10	RM	63,570	12.12%	-	112,302	(706)	(69)	(98)		(938)	41	(107)		336	-	110,762	10
11	LRS	958	0.18%	-	1,693	(11)	(1)	(1)		(14)	1	(2)		5	-	1,669	11
12	GS	10,897	2.08%	-	19,251	(121)	(12)	(17)		(161)	7	(18)		58	-	18,987	12
13	LGS-1	82,168	15.66%	-	145,159	(913)	(89)	(126)		(1,213)	53	(138)		434	-	143,167	13
14	LGS-2S	43,843	8.36%	-	77,454	(487)	(47)	(67)		(647)	28	(74)		232	-	76,391	14
15	LGS-2P	1,076	0.21%	-	1,902	(12)	(1)	(2)		(16)	1	(2)		6	-	1,876	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	16
17	LGS-3S	12,620	2.41%	-	22,295	(140)	(14)	(19)		(186)	8	(21)		67	-	21,989	17
18	LGS-3P	29,627	5.65%	-	52,339	(329)	(32)	(46)		(437)	19	(50)		157	-	51,621	18
19	LGS-3T	9,648	1.84%	-	17,044	(107)	(10)	(15)		(142)	6	(16)		51	-	16,810	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	22
23	LGS-2S-WP	224	0.04%	-	395	(2)	(0)	(0)		(3)	0	(0)		1	-	390	23
24	LGS-2P-WP	118	0.02%	-	208	(1)	(0)	(0)		(2)	0	(0)		1	-	205	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	25
26	LGS-3S-WP	24	0.00%	-	43	(0)	(0)	(0)		(0)	0	(0)		0	-	43	26
27	LGS-3P-WP	129	0.02%	-	227	(1)	(0)	(0)		(2)	0	(0)		1	-	224	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	28
29	SL	1,896	0.36%	-	3,350	(21)	(2)	(3)		(28)	1	(3)		10	-	3,304	29
30	RS-Pal	9	0.00%	-	15	(0)	(0)	(0)		(0)	0	(0)		0	-	15	30
31	GS-Pal	33	0.01%	-	59	(0)	(0)	(0)		(0)	0	(0)		0	-	58	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	32
33	RS-NEM	38,534	7.34%	-	68,074	(428)	(42)	(59)		(569)	25	(65)		204	-	67,140	33
34	RM-NEM	177	0.03%	-	312	(2)	(0)	(0)		(3)	0	(0)		1	-	308	34
35	LRS-NEM	19	0.00%	-	33	(0)	(0)	(0)		(0)	0	(0)		0	-	33	35
36	GS-NEM	96	0.02%	-	169	(1)	(0)	(0)		(1)	0	(0)		1	-	167	36
37	LGS-1-NEM	2,144	0.41%	-	3,787	(24)	(2)	(3)		(32)	1	(4)		11	-	3,735	37
38					not a sum												38
39	TOTAL	$ 524,669	100.00%	$ -	$ 590,171	$ (5,827)	$ (568)	$ (807)		$ (7,744)	$ 340	$ (881)	$ -	$ 2,772	$ -	$ 914,167	39
40					from Sch. H-2												40
41			Generation Revenue for Rate Design $		524,669	$ (1,003,209)											41
42			w/ Specific Class adjustments $		926,881	Combined											42
43																	43
44																	44
45																	45
46	Summation of NEM customers into Standard Schedule for Rate Design																46
47	RS	$ 265,393	50.58%	$ -	$ 468,844	$ (2,948)	$ (287)	$ (408)	$ -	$ (3,917)	$ 172	$ (446)	$ -	$ 1,402	$ -	$ 462,412	47
48	RM	63,746	12.15%	-	112,615	(708)	(69)	(98)	-	(941)	41	(107)	-	337	-	111,070	48
49	LRS	977	0.19%	-	1,726	(11)	(1)	(2)	-	(14)	1	(2)	-	5	-	1,702	49
50	GS	10,993	2.10%	-	19,421	(122)	(12)	(17)	-	(162)	7	(18)	-	58	-	19,154	50
51	LGS-1	84,312	16.07%	-	148,945	(936)	(91)	(130)	-	(1,244)	55	(142)	-	445	-	146,902	51
52																	52

Nevada Power Company
Statement O

Energy Revenue by Class for Rate Design

Line No.	Class	BTER Revenue	Unreconciled Cost-Based Energy Revenue	Percent of Total	Class Specific Adjustments: Hoover B, EDRR, MPE and WAPA Credits	Class Specific Adjustments: Reconciled Energy Revenue Requirement	**Rate Design Revenue Adjustments**: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS R-BTER and BTER Impact Fee Revenue	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Energy Cost Based Class Revenue for Rate Design	Excess/ Deficiency Present in BTER for Rate Design	Line No.
8																	8
9	RS	$ 611,088	$ 270,477	34.63%	$ (10,184)	$ 473,378	$ (7,574)	$ (635)	$ (588)	$ -	$ -	$ (177)	$ 1,375	$ -	$ 465,781	$ (145,307)	9
10	RM	193,415	86,098	11.02%	(3,219)	150,709	(2,411)	(202)	(187)	-	-	(56)	438	-	148,290	(45,125)	10
11	LRS	3,158	1,385	0.18%	(53)	2,423	(39)	(3)	(3)	-	-	(1)	7	-	2,384	(774)	11
12	GS	48,719	22,456	2.87%	-	40,148	(629)	(53)	(49)	-	-	(15)	114	-	39,517	(9,202)	12
13	LGS-1	324,204	147,347	18.86%	-	263,428	(4,126)	(346)	(320)	-	-	(96)	749	-	259,289	(64,914)	13
14	LGS-2S	193,969	87,960	11.26%	-	157,256	(2,463)	(206)	(191)	-	-	(58)	447	-	154,785	(39,184)	14
15	LGS-2P	5,539	2,477	0.32%	-	4,428	(69)	(6)	(5)	-	-	(2)	13	-	4,359	(1,180)	15
16	LGS-2T	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	61,185	27,849	3.57%	-	49,788	(780)	(65)	(61)	-	-	(18)	142	-	49,006	(12,179)	17
18	LGS-3P	145,403	64,835	8.30%	-	115,913	(1,816)	(152)	(141)	-	-	(42)	330	-	114,092	(31,311)	18
19	LGS-3T	49,246	22,101	2.83%	(1,099)	38,414	(619)	(52)	(48)	-	-	(14)	112	-	37,793	(11,453)	19
20	LGS-XS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	1,184	533	0.07%	-	953	(15)	(1)	(1)	-	-	(0)	3	-	938	(246)	23
24	LGS-2P-WP	887	392	0.05%	-	700	(11)	(1)	(1)	-	-	(0)	2	-	689	(198)	24
25	LGS-2T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	351	169	0.02%	-	302	(5)	(0)	(0)	-	-	(0)	1	-	298	(54)	26
27	LGS-3P-WP	1,513	689	0.09%	-	1,232	(19)	(2)	(1)	-	-	(0)	4	-	1,212	(300)	27
28	LGS-3T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	10,273	5,688	0.73%	-	10,169	(159)	(13)	(12)	-	-	(4)	29	-	10,009	(263)	29
30	RS-Pal	49	26	0.00%	-	47	(1)	(0)	(0)	-	-	(0)	0	-	46	(3)	30
31	GS-Pal	177	100	0.01%	-	179	(3)	(0)	(0)	-	-	(0)	1	-	176	(1)	31
32	IAIWP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	40,228	36,847	4.72%	(700)	65,176	(1,032)	(86)	(80)	-	-	(24)	187	-	64,141	23,913	33
34	RM-NEM	218	177	0.02%	(4)	312	(5)	(0)	(0)	-	-	(0)	1	-	307	89	34
35	LRS-NEM	48	28	0.00%	(1)	48	(1)	(0)	(0)	-	-	(0)	0	-	48	(0)	35
36	GS-NEM	192	134	0.02%		239	(4)	(0)	(0)	-	-	(0)	1	-	236	43	36
37	LGS-1-NEM	5,837	3,348	0.43%		5,985	(94)	(8)	(7)	-	-	(2)	17	-	5,891	54	37
38						not a sum											38
39	TOTAL	$ 1,696,883	$ 781,113	100.00%	$ (15,258)	$ 1,718,820	$ (21,873)	$ (1,833)	$ (1,697)	$ -	$ -	$ (511)	$ 3,972	$ -	$ 1,359,287	$ (337,596)	39
40						from Sch. H-2											40
41					Energy Revenue for Rate Design	781,126	$(1,003,209)										41
42					w/ Specific Class adjustments $	1,396,486											42
43																	43
44																	44
45	Summation of NEM customers into Standard Schedule for Rate Design																45
46	RS	$ 651,316	$ 307,323	39.34%	$ (10,883)	$ 538,554	$ (8,606)	$ (721)	$ (668)	$ -	$ -	$ (201)	$ 1,563	$ -	$ 529,921	$ (121,394)	46
47	RM	193,633	86,275	11.05%	(3,222)	151,021	(2,416)	(202)	(187)	-	-	(56)	439	-	148,598	(45,036)	47
48	LRS	3,206	1,412	0.18%	(53)	2,471	(40)	(3)	(3)	-	-	(1)	7	-	2,432	(774)	48
49	GS	48,912	22,590	2.89%	-	40,387	(633)	(53)	(49)	-	-	(15)	115	-	39,752	(9,159)	49
50	LGS-1	330,041	150,694	19.29%	-	269,413	(4,220)	(354)	(327)	-	-	(99)	766	-	265,180	(64,860)	50
51																	51

Line No.	Class	Sales (MWh)	Cost Based Class Revenue by Function: Distribution	Transmission	Generation	Energy/ variable	Subtotal	Power Factor Revenue (exc. DOS)	Additional Facilities & Maintenance Revenue	Exc. DOS Cost Revenue	Sum of Functional Cost Based Class Revenue for Rate Design	Interclass Rate Rebalancing Revenue	Capped Class Revenue Requirement	Revenue Proof	Percent of Total	Difference from Capped Revenue Requirement (Rounding)	Overall Effective Rate	Line No.
8																		8
9	RS	7,262,589	$ 211,521	$ 66,155	$ 395,272	$ 465,781	$ 1,138,729	$ -	$ -		$ 1,138,729	$ (65,654)	$ 1,158,663	$ 1,158,698	40.9%	$ 33	$ 0.15954	9
10	RM	2,298,671	49,290	17,155	110,762	148,290	325,497	-	-		325,497	17,999	343,884	343,899	12.1%	12	0.14960	10
11	LRS	37,526	625	281	1,669	2,384	4,960	-	-		4,960	352	5,335	5,335	0.2%	1	0.14216	11
12	GS	612,056	15,487	3,394	18,987	39,517	77,385	-	-	1	77,384	6,359	83,998	83,920	3.0%	0	0.13724	12
13	LGS-1	4,073,470	54,703	24,077	143,167	259,289	481,236	129	1	74	481,293	12,545	496,129	496,105	17.5%	(24)	0.12180	13
14	LGS-2S	2,437,061	21,698	12,380	76,391	154,785	265,254	349	-	591	265,012	11,089	276,089	276,088	9.7%	(1)	0.11329	14
15	LGS-2P	69,583	538	296	1,876	4,359	7,068	6	-	26	7,048	359	7,408	7,408	0.3%	0	0.10646	15
16	LGS-2T	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	16
17	LGS-3S	768,658	6,029	3,465	21,989	49,006	80,490	88	-	653	79,925	4,078	84,003	83,998	3.0%	(6)	0.10929	17
18	LGS-3P	1,826,673	19,058	8,075	51,621	114,092	192,846	226	70	7,044	186,098	11,753	197,851	197,801	7.0%	(50)	0.10831	18
19	LGS-3T	618,671	2,714	2,643	16,810	37,793	59,961	20	-	1,233	58,748	1,748	60,496	60,496	2.1%	(0)	0.09778	19
20	LGS-XS	-	60	-	-	-	60	2	-	63	-	-	-	-	0.0%	-	---	20
21	LGS-XP	-	2,267	-	-	-	2,267	65	-	2,333	-	-	-	-	0.0%	-	---	21
22	LGS-XT	-	387	-	-	-	387	2	-	389	-	-	-	-	0.0%	-	---	22
23	LGS-2S-WP	14,878	211	78	390	938	1,616	4	-	28	1,592	231	1,823	1,820	0.1%	(3)	0.12252	23
24	LGS-2P-WP	11,148	107	37	205	689	1,038	2	-	-	1,040	88	1,129	1,127	0.0%	(1)	0.10126	24
25	LGS-2T-WP	-	29	-	-	-	29	-	-	29	-	-	-	-	0.0%	-	---	25
26	LGS-3S-WP	4,413	221	19	43	298	580	6	-	178	409	38	447	447	0.0%	(0)	0.10135	26
27	LGS-3P-WP	19,004	411	36	224	1,212	1,884	12	-	295	1,601	147	1,748	1,751	0.1%	2	0.09199	27
28	LGS-3T-WP	-	164	-	-	-	164	0	-	164	-	-	-	-	0.0%	-	---	28
29	SL	129,054	1,250	124	3,304	10,009	14,687	-	-		14,687	2,874	17,561	17,570	0.6%	9	0.13607	29
30	RS-Pal	578	35	0	15	46	96	-	-		96	10	106	106	0.0%	(0)	0.18356	30
31	GS-Pal	2,217	115	1	58	176	350	-	-		350	43	394	394	0.0%	(0)	0.17750	31
32	IAIWP	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	32
33	RS-NEM	478,046	35,080	10,058	67,140	64,141	176,419	-	-		176,419	(4,322)	86,509	86,509	3.1%	---	0.18096	33
34	RM-NEM	2,596	112	47	308	307	775	-	-		775	20	403	403	0.0%	---	0.15524	34
35	LRS-NEM	571	30	5	33	48	116	-	-		116	5	98	98	0.0%	---	0.17088	35
36	GS-NEM	2,417	80	27	167	236	509	-	-		509	25	277	277	0.0%	---	0.11464	36
37	LGS-1-NEM	73,329	1,172	658	3,735	5,891	11,456	-	-		11,456	226	9,391	9,391	0.3%	---	0.12807	37
38																		38
39	TOTAL	20,743,210	$ 423,394	$ 149,011	$ 914,167	$ 1,359,287		$ 913	$ 71	$ 13,100	$ 2,833,743	$ 16	$ 2,833,743	$ 2,833,640	100.0%	$ (29)	$ 0.13661	39
40																		40
41																		41
42																		42
43																		43
44	Summation of NEM customers into Standard Schedule for Rate Design																	44
45	RS	7,740,635	$ 246,602	$ 76,213	$ 462,412	$ 529,921	$ 1,315,148	$ -	$ -	$ -	$ 1,315,148	$ (69,975)	$ 1,245,172	$ 1,245,207	43.9%	$ 33	$ 0.16086	45
46	RM	2,301,267	49,402	17,202	111,070	148,598	326,272	-	-	-	326,272	18,019	344,287	344,302	12.2%	12	0.14961	46
47	LRS	38,097	655	286	1,702	2,432	5,075	-	-	-	5,075	357	5,432	5,433	0.2%	1	0.14259	47
48	GS	614,473	15,566	3,421	19,154	39,752	77,894	-	-	1	77,893	6,384	84,275	84,197	3.0%	0	0.13715	48
49	LGS-1	4,146,799	55,875	24,735	146,902	265,180	492,692	129	1	74	492,748	12,771	505,520	505,496	17.8%	(24)	0.12191	49

Nevada Power Company

Statement O

Class Revenue Adjustments Due to Cap & Floor Criteria (1)

Exhibit Prest Direct-5

Docket No. 23-06XXX

MCS, ECIC, Current TOU, Joint Dispatch, RS Cap

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Line No.	Class	Present Rate Revenue	AB 405 Present Rate Revenue	Total Class Revenue Requirement: Sum of Functional Cost Based Class Revenue	Percent of Total	AB 405 Cost Based Class Revenue	Percent of Total	% change over Present Rate Revenue	AB405 Cost-Based Pct change over Present Rate Revenue	First Allocation - Cap: Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.
9	RS	$ 1,124,472	$ 1,205,394	$ 1,138,729	40.18%	$ 1,315,148	46.41%	1.27%	9.11%	Capped	3.30%	$ 1,245,172	$ 69,975	$ -	$ -	0.00%	$ -	1,245,172	3.30%	9
10	RM	339,331	339,727	325,497	11.49%	326,272	11.51%	-4.08%	-3.96%	-	-3.96%	326,272	-	326,272	(13,455)	25.75%	18,016	344,287	1.34%	10
11	LRS	5,291	5,383	4,960	0.18%	5,075	0.18%	-6.26%	-5.72%	-	-5.72%	5,075	-	5,075	(308)	0.51%	357	5,432	0.92%	11
12	GS	83,497	83,773	77,384	2.73%	77,893	2.75%	-7.32%	-7.02%	-	-7.02%	77,893	-	77,893	(5,880)	9.12%	6,382	84,275	0.60%	12
13	LGS-1	485,467	494,567	481,293	16.98%	492,748	17.39%	-0.86%	-0.37%	-	-0.37%	492,748	-	492,748	(1,819)	18.25%	12,772	505,520	2.21%	13
14	LGS-2S	271,383	271,383	265,012	9.35%	265,012	9.35%	-2.35%	-2.35%	-	-2.35%	265,012	-	265,012	(6,371)	15.83%	11,077	276,089	1.73%	14
15	LGS-2P	7,301	7,301	7,048	0.25%	7,048	0.25%	-3.46%	-3.46%	-	-3.46%	7,048	-	7,048	(252)	0.51%	359	7,408	1.46%	15
16	LGS-2T				0.00%		0.00%						-			0.00%	-			16
17	LGS-3S	82,792	82,792	79,925	2.82%	79,925	2.82%	-3.46%	-3.46%	-	-3.46%	79,925	-	79,925	(2,867)	5.83%	4,078	84,003	1.46%	17
18	LGS-3P	195,666	195,666	186,098	6.57%	186,098	6.57%	-4.89%	-4.89%	-	-4.89%	186,098	-	186,098	(9,568)	16.80%	11,753	197,851	1.12%	18
19	LGS-3T	59,254	59,254	58,748	2.07%	58,748	2.07%	-0.85%	-0.85%	-	-0.85%	58,748	-	58,748	(506)	2.50%	1,748	60,496	2.10%	19
20	LGS-XS				0.00%		0.00%									0.00%				20
21	LGS-XP				0.00%		0.00%									0.00%				21
22	LGS-XT				0.00%		0.00%									0.00%				22
23	LGS-2S-WP	1,343	1,343	1,592	0.06%	1,592	0.06%	18.54%	18.54%	-	18.54%	1,592	-	1,592	249	0.33%	231	1,823	35.75%	23
24	LGS-2P-WP	1,123	1,123	1,040	0.04%	1,040	0.04%	-7.35%	-7.35%	-	-7.35%	1,040	-	1,040	(82)	0.13%	88	1,129	0.52%	24
25	LGS-2T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			25
26	LGS-3S-WP	372	372	409	0.01%	409	0.01%	9.97%	9.97%	-	9.97%	409	-	409	37	0.05%	38	447	20.27%	26
27	LGS-3P-WP	1,742	1,742	1,601	0.06%	1,601	0.06%	-8.11%	-8.11%	-	-8.11%	1,601	-	1,601	(141)	0.21%	147	1,748	0.33%	27
28	LGS-3T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-			28
29	SL	11,437	11,437	14,687	0.52%	14,687	0.52%	28.41%	28.41%	-	28.41%	14,687	-	14,687	3,250	4.11%	2,874	17,561	53.54%	29
30	RS-Pal	85	85	96	0.00%	96	0.00%	12.37%	12.37%	-	12.37%	96	-	96	11	0.01%	10	106	24.62%	30
31	GS-Pal	305	305	350	0.01%	350	0.01%	14.85%	14.85%	-	14.85%	350	-	350	45	0.06%	43	394	29.08%	31
32	IAIWP			-																32
33	RS-NEM	80,923	inc in Full Req Class	176,419	6.23%	inc in Full Req Class		118.01%												33
34	RM-NEM	397	inc in Full Req Class	775	0.03%	inc in Full Req Class		95.35%												34
35	LRS-NEM	92	inc in Full Req Class	116	0.00%	inc in Full Req Class		25.35%												35
36	GS-NEM	275	inc in Full Req Class	509	0.02%	inc in Full Req Class		84.77%												36
37	LGS-1-NEM	9,100	inc in Full Req Class	11,456	0.40%	inc in Full Req Class		25.89%												37
38		Not a Sum:		Not a sum:				Overall Increase:												38
39	Total	$ 2,805,178		$ 2,897,751	100.00%	$ 2,897,751	100.00%	3.30%				$ 2,763,768	$ 69,975	$ 1,518,595	$ 44,841	100%	$ 69,975			39
40		$ 2,761,648		$ 2,833,743	=sum=	$ 2,833,743		$ 92,572												40
41		$ 64,008	<Rev Credits: Revenue Credits exc. PF and AF&M revenues																	41
42																				42

/------------Second Allocation------------/

Line No.	Class	Class Revenue Requirement, after 1st Allocation	Pct Change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement	% change over Present Rate Revenue	Final Class Revenue Allocation: Capped Class Revenue Requirement	% change over Present Rate Revenue	Difference from Cost	Line No.
50	RS	$ 1,245,172	3.30%	Capped	3.30%	$ 1,245,172	$ -	$ 1,245,172	$ -	0.00%	$ -	$ 1,245,172	3.30%	$ 1,245,172	3.30%	$ (69,975)	50
51	RM	344,287	1.34%	-	1.34%	$ 344,287	$ -	$ 344,287	$ 4,560	14.11%	(0)	$ 344,287	1.34%	344,287	1.34%	18,016	51
52	LRS	5,432	0.92%	-	0.92%	$ 5,432	$ -	$ 5,432	$ 49	0.15%	(0)	$ 5,432	0.92%	5,432	0.92%	357	52
53	GS	84,275	0.60%	-	0.60%	$ 84,275	$ 0	$ -	$ 503	1.56%	(0)	$ 84,275	0.60%	84,275	0.60%	6,382	53
54	LGS-1	505,520	2.21%	-	2.21%	$ 505,520	$ 0	$ -	$ 10,953	33.89%	(0)	$ 505,520	2.21%	505,520	2.21%	12,772	54
55	LGS-2S	276,089	1.73%	-	1.73%	$ 276,089	$ -	$ 276,089	$ 4,706	14.56%	(0)	$ 276,089	1.73%	276,089	1.73%	11,077	55
56	LGS-2P	7,408	1.46%	-	1.46%	$ 7,408	$ -	$ 7,408	$ 107	0.33%	(0)	$ 7,408	1.46%	7,408	1.46%	359	56
57	LGS-2T									0.00%	-	$ -		-		-	57
58	LGS-3S	84,003	1.46%	-	1.46%	$ 84,003	$ (0)	$ -	$ 1,211	3.75%	(0)	$ 84,003	1.46%	84,003	1.46%	4,078	58
59	LGS-3P	197,851	1.12%	-	1.12%	$ 197,851	$ -	$ 197,851	$ 2,185	6.76%	(0)	$ 197,851	1.12%	197,851	1.12%	11,753	59
60	LGS-3T	60,496	2.10%	-	2.10%	$ 60,496	$ 0	$ -	$ 1,242	3.84%	(0)	$ 60,496	2.10%	60,496	2.10%	1,748	60
61	LGS-XS									0.00%	-			-		-	61
62	LGS-XP									0.00%	-			-		-	62
63	LGS-XT									0.00%	-			-		-	63
64	LGS-2S-WP	1,823	35.75%	-	35.75%	$ 1,823	$ -	$ 1,823	$ 480	1.49%	(0)	$ 1,823	35.75%	1,823	35.75%	231	64
65	LGS-2P-WP	1,129	0.52%	-	0.52%	$ 1,129	$ -	$ 1,129	$ 6	0.02%	(0)	$ 1,129	0.52%	1,129	0.52%	88	65
66	LGS-2T-WP							$ -	$ -	0.00%	-			-		-	66
67	LGS-3S-WP	447	20.27%	-	20.27%	$ 447	$ -	$ 447	$ 75	0.23%	(0)	$ 447	20.27%	447	20.27%	38	67
68	LGS-3P-WP	1,748	0.33%	-	0.33%	$ 1,748	$ -	$ 1,748	$ 6	0.02%	(0)	$ 1,748	0.33%	1,748	0.33%	147	68
69	LGS-3T-WP							$ -	$ -	0.00%	-			-		-	69
70	SL	17,561	53.54%	-	53.54%	$ 17,561	$ -	$ 17,561	$ 6,124	18.95%	(0)	$ 17,561	53.54%	17,561	53.54%	2,874	70
71	RS-Pal	106	24.62%	-	24.62%	$ 106	$ -	$ 106	$ 21	0.06%	(0)	$ 106	24.62%	106	24.62%	10	71
72	GS-Pal	394	29.08%	-	29.08%	$ 394	$ -	$ 394	$ 89	0.27%	(0)	$ 394	29.08%	394	29.08%	43	72
73	IAIWP													-		-	73
74	RS-NEM	inc in Full Req Class															74
75	RM-NEM	inc in Full Req Class															75
76	LRS-NEM	inc in Full Req Class															76
77	GS-NEM	inc in Full Req Class															77
78	LGS-1-NEM	inc in Full Req Class															78
79																	79
80	Total						$ (0)	$ 2,099,448	$ 32,317	100.0%	$ (0)	$ 2,833,743		$ 2,833,743			80
81														$ 0			81

(1) Increases in rates cannot exceed the total average percentage increase in rates. For example, a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.

(2) NEM classes include all customers under NMR-G and NMR-A rate schedules.

Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

Line No.	Classes[1]	Bundled kWh Sales	DOS kWh Sales	Total kWh Sales	Sum of Functional Cost Based Class Revenue	Capped Class Revenue Requirement	Interclass Subsidy (difference)	Subsidy Component per kWh	Rounding	Note	Line No.
8	RS	7,262,588,952		7,740,635,272	$ 1,315,148	$ 1,245,172	$ (69,975)	$ (0.00904)	$ 0		8
9	RM	2,298,671,171		2,301,266,943	326,272	344,287	18,016	0.00783	3		9
10	LRS	37,525,901		38,097,297	5,075	5,432	357	0.00937	(0)		10
11	GS	612,055,594		614,472,857	77,893	84,275	6,382	0.01039	2		11
12	LGS-1	4,073,469,942		4,146,798,580	492,748	505,520	12,772	0.00308	0		12
13	LGS-2S	2,437,060,885		2,437,060,885	265,012	276,089	11,077	0.00455	12		13
14	LGS-2P	69,583,297		69,583,297	7,048	7,408	359	0.00516	(0)		14
15	LGS-2T	-		-	-	-	-	0.00308	-	<<Set equal to LGS-1>>	15
16	LGS-3S	768,658,032		768,658,032	79,925	84,003	4,078	0.00531	3		16
17	LGS-3P	1,826,672,960		1,826,672,959.93	186,098	197,851	11,753	0.00643	(7)		17
18	LGS-3T	618,671,150		618,671,150	58,748	60,496	1,748	0.00283	3		18
19	LGS-XS	-		-	-	-	-	0.00531	-	<<Set equal to LGS-XS DOS>>	19
20	LGS-XP	-		-	-	-	-	0.00643	-	<<Set equal to LGS-XP DOS>>	20
21	LGS-XT	-		-	-	-	-	0.00283	-	<<Set equal to LGS-XT DOS>>	21
22	LGS-2S-WP	14,877,558		14,877,558	1,592	1,823	231	0.01552	(0)		22
23	LGS-2P-WP	11,147,772		11,147,772	1,040	1,129	88	0.00792	(0)		23
24	LGS-2T-WP	-		-	-	-	-	0.01021	-	<<Set equal to LGS-2T WP DOS>>	24
25	LGS-3S-WP	4,412,814		4,412,814	409	447	38	0.00869	0		25
26	LGS-3P-WP	19,004,483		19,004,483	1,601	1,748	147	0.00774	(0)		26
27	LGS-3T-WP	-		-	-	-	-	0.01021	-	<<Set equal to LGS-3T WP DOS>>	27
28	SL	129,054,441		129,054,441	14,687	17,561	2,874	0.02227	0		28
29	RS-Pal	578,040		578,040	96	106	10	0.01803	(0)		29
30	GS-Pal	2,217,456		2,217,456	350	394	43	0.01957	0		30
31	IAIWP	-		na	-	-	-	na	---		31
32	RS-NEM	478,046,320		inc in Full Req Class							32
33	RM-NEM	2,595,772		inc in Full Req Class							33
34	LRS-NEM	571,396		inc in Full Req Class							34
35	GS-NEM	2,417,263		inc in Full Req Class							35
36	LGS-1 -NEM	73,328,638		inc in Full Req Class							36
37											37
38	Bundled TOTAL	20,743,209,837		20,743,209,837	$ 2,833,743	$ 2,833,743	$ 0	<< Subsidy amount prior to RevReq adjustment when maintaining current rates.			38
39											39
40	**DISTRIBUTION ONLY SERVICE CLASSES -- SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)[2]**										40
41	DOS: GS		51,413	na	na	na	na	$ 0.01039		<<Set equal to GS>>	41
42	DOS: LGS-1		7,843,178	na	na	na	na	0.00308		<<Set equal to LGS-1>>	42
43	DOS: LGS-2S		82,487,915	na	na	na	na	0.00455		<<Set equal to LGS-2S>>	43
44	DOS: LGS-2P		4,487,342	na	na	na	na	0.00516		<<Set equal to LGS-2P>>	44
45	DOS: LGS-2T		-	na	na	na	na	0.00308		<<Set equal to LGS-2T>>	45
46	DOS: LGS-3S		85,826,485	na	na	na	na	0.00531		<<Set equal to LGS-3S>>	46
47	DOS: LGS-3P		1,414,522,800	na	na	na	na	0.00643		<<Set equal to LGS-3P>>	47
48	DOS: LGS-3T		591,977,970	na	na	na	na	0.00283		<<Set equal to LGS-3T>>	48
49	DOS: LGS-XS		7,153,043	na	na	na	na	0.00531		<<Set to 0.00001 or Current x 94%>>	49
50	DOS: LGS-XP		287,352,976	na	na	na	na	0.00643		<<Set to 0.00001 or Current x 94%>>	50
51	DOS: LGS-XT		165,618,096	na	na	na	na	0.00283		<<Set to 0.00001 or Current x 94%>>	51
52	DOS: LGS-2S-WP		4,841,057	na	na	na	na	0.01552		<<Set equal to LGS-2S-WP>>	52
53	DOS: LGS-2P-WP		-	na	na	na	na	0.00792		<<Set equal to LGS-2P-WP>>	53
54	DOS: LGS-2T-WP		1,889,274	na	na	na	na	0.01021		<<Set to 0.00001 or Current x 94%>>	54
55	DOS: LGS-3S-WP		25,647,446	na	na	na	na	0.00869		<<Set equal to LGS-3S-WP>>	55
56	DOS: LGS-3P-WP		75,371,524	na	na	na	na	0.00774		<<Set equal to LGS-3P-WP>>	56
57	DOS: LGS-3T-WP		55,357,230	na	na	na	na	0.01021		<<Set to 0.00001 or Current x 94%>>	57

58 58

59 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2). 59

60 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes. 60

Comparison of Present and Proposed Rate Revenue

Line No	Class	Sales (kWh)	BTGR Revenue Present	BTGR Revenue Proposed	Percent Change	BTGR & BTER[1] Revenue Present	BTGR & BTER[1] Revenue Proposed	Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed	Percent Change	Line No
8	RS	7,262,588,952	$ 513,383,508	$ 547,609,643	6.67%	$ 1,124,471,607	$ 1,158,697,742	3.04%	$ 1,284,192,975	$ 1,318,419,111	2.67%	8
9	RM	2,298,671,171	145,915,631	150,484,278	3.13%	339,330,523	343,899,170	1.35%	389,356,065	393,924,712	1.17%	9
10	LRS	37,525,901	2,132,970	2,177,379	2.08%	5,290,775	5,335,184	0.84%	6,096,455	6,140,864	0.73%	10
11	GS	612,055,143	34,777,894	35,200,253	1.21%	83,497,092	83,919,451	0.51%	94,978,182	95,400,541	0.44%	11
12	LGS-1	4,073,133,716	161,250,916	171,883,743	6.59%	485,427,795	496,060,622	2.19%	562,024,412	572,657,238	1.89%	12
13	LGS-2S	2,429,180,261	77,189,770	81,861,084	6.05%	270,531,139	275,202,453	1.73%	315,956,810	320,628,124	1.48%	13
14	LGS-2P	69,583,297	1,761,763	1,868,729	6.07%	7,300,593	7,407,559	1.47%	8,588,581	8,695,547	1.25%	14
15	LGS-2T	-	-	-	na	-	-	na	-	-	na	15
16	LGS-3S	768,658,032	21,606,500	22,812,395	5.58%	82,791,679	83,997,574	1.46%	97,127,152	98,333,046	1.24%	16
17	LGS-3P	1,393,295,183	39,586,638	41,172,436	4.01%	150,492,935	152,078,733	1.05%	176,700,817	178,286,616	0.90%	17
18	LGS-3T	247,665,929	4,377,192	4,933,771	12.72%	24,091,400	24,647,979	2.31%	28,658,360	29,214,939	1.94%	18
19	LGS-XS	-	-	-	na	-	-	na	-	-	na	19
20	LGS-XP	-	-	-	na	-	-	na	-	-	na	20
21	LGS-XT	-	-	-	na	-	-	na	-	-	na	21
22	LGS-2S-WP	14,877,558	158,497	635,928	301.22%	1,342,751	1,820,182	35.56%	1,623,788	2,101,219	29.40%	22
23	LGS-2P-WP	11,147,772	235,565	239,980	1.87%	1,122,928	1,127,343	0.39%	1,327,601	1,332,017	0.33%	23
24	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	24
25	LGS-3S-WP	4,412,814	20,575	95,829	365.76%	371,835	447,089	20.24%	451,353	526,608	16.67%	25
26	LGS-3P-WP	19,004,483	229,669	237,955	3.61%	1,742,426	1,750,712	0.48%	2,087,357	2,095,643	0.40%	26
27	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	27
28	SL	129,054,441	1,164,568	7,297,216	526.60%	11,437,302	17,569,950	53.62%	13,840,296	19,972,943	44.31%	28
29	RS-Pal	578,040	36,501	57,457	57.41%	85,143	106,099	24.61%	97,306	118,261	21.54%	29
30	GS-Pal	2,217,456	128,415	216,995	68.98%	304,924	393,504	29.05%	345,791	434,372	25.62%	30
31	IAIWP	-	-	-	na	-	-	na	-	-	na	31
32	**Optional Time of Use**											32
33	ORS-TOU	9,396,344	478,100	513,830	7.47%	1,268,289	1,304,019	2.82%	1,473,445	1,509,175	2.42%	33
34	ORS-TOU OPT A	21,030,431	1,250,839	1,402,900	12.16%	3,020,046	3,172,107	5.04%	3,481,412	3,633,474	4.37%	34
35	ORS-TOU OPT B	4,239,586	173,888	204,726	17.73%	530,649	561,487	5.81%	624,004	654,842	4.94%	35
39	ORM-TOU	873,422	49,455	51,731	4.60%	122,872	125,148	1.85%	141,630	143,905	1.61%	39
40	ORM-TOU OPT A	718,287	45,450	47,539	4.60%	105,894	107,983	1.97%	121,546	123,635	1.72%	40
41	ORM-TOU OPT B	70,254	4,084	4,435	8.58%	9,996	10,347	3.51%	11,526	11,877	3.04%	41
42	ORM-TOU DDP	9,561	414	405	-2.18%	1,170	1,161	-0.77%	1,211	1,202	-0.75%	42
51	OGS-TOU	27,565,080	1,261,147	1,266,150	0.40%	3,455,327	3,460,330	0.14%	3,972,448	3,977,450	0.13%	51
52	OLGS-1 TOU	124,787,383	3,997,063	4,161,495	4.11%	13,930,139	14,094,571	1.18%	16,277,390	16,441,822	1.01%	52
53	OLGS-3P-HLF	258,609,361	5,228,244	5,443,074	4.11%	25,813,549	26,028,379	0.83%	30,677,991	30,892,821	0.70%	53
54	**Optional Time of Use EVRR**											54
55	ORS-TOU EVRR	52,516,143	2,615,103	2,695,805	3.09%	7,033,504	7,114,206	1.15%	8,187,065	8,267,766	0.99%	55
56	ORS-TOU Opt A EVRR	6,627,577	342,755	367,015	7.08%	900,466	924,726	2.69%	1,046,406	1,070,666	2.32%	56
57	ORS-TOU Opt B EVRR	4,621,440	160,839	180,628	12.30%	549,733	569,522	3.60%	651,497	671,286	3.04%	57
60	ORM-TOU EVRR	1,289,179	67,312	67,958	0.96%	175,686	176,332	0.37%	203,405	204,051	0.32%	60
61	ORM-TOU OPT A EVRR	60,410	3,580	3,613	0.91%	8,664	8,697	0.38%	9,980	10,013	0.33%	61
62	ORM-TOU OPT B EVRR	29,643	1,740	1,843	5.93%	4,234	4,337	2.44%	4,881	4,984	2.12%	62
65	OLRS-TOU EVRR	299,866	14,816	14,608	-1.40%	40,050	39,842	-0.52%	46,488	46,280	-0.45%	65
70	OGS-TOU EVRR	20,511	1,899	1,899	-0.01%	3,532	3,532	0.00%	3,917	3,916	0.00%	70
71	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	71
72	**Net Metering:**											72
73	RS-NEM	478,046,320	40,695,177	46,281,382	13.73%	80,922,775	86,508,980	6.90%	91,449,355	97,035,560	6.11%	73
74	RM-NEM	2,595,772	178,138	184,546	3.60%	396,572	402,980	1.62%	453,135	459,542	1.41%	74
75	LRS-NEM	571,396	44,227	49,556	12.05%	92,310	97,639	5.77%	104,579	109,908	5.10%	75
76	GS-NEM	2,417,263	83,034	84,700	2.01%	275,449	277,115	0.60%	320,798	322,464	0.52%	76
77	LGS-1 NEM	73,328,638	3,263,161	3,554,128	8.92%	9,100,120	9,391,087	3.20%	10,479,431	10,770,398	2.78%	77
78	ORS-NEM	3,324,908	177,128	205,848	16.21%	456,919	485,639	6.29%	530,133	558,854	5.42%	78
79	ORS-NEM OPT A	4,057,523	260,478	308,692	18.51%	601,919	650,133	8.01%	691,267	739,481	6.97%	79
80	ORS-NEM OPT B	218,046	12,617	14,723	16.69%	30,965	33,071	6.80%	35,766	37,873	5.89%	80
84	ORM-NEM	1,460	220	224	1.65%	343	347	1.06%	374	377	0.97%	84
97	**NEM EVRR**											97
98	ORS-NEM EVRR	11,862,176	478,864	507,045	5.89%	1,477,066	1,505,247	1.91%	1,738,271	1,766,453	1.62%	98
99	ORS-NEM OPT A EVRR	1,879,925	67,276	76,433	13.61%	225,472	234,629	4.06%	266,867	276,024	3.43%	99
100	ORS-NEM OPT B EVRR	411,121	18,066	20,267	12.18%	52,661	54,862	4.18%	61,715	63,916	3.57%	100
103	ORM-NEM EVRR	25,756	1,240	1,241	0.11%	3,407	3,408	0.04%	3,968	3,970	0.04%	103
114	**Standby**											114
116	SSR - GS	-	-	-	na	-	-	na	-	-	na	116
117	SSR - LGS-1	1,130,064	54,212	60,556	11.70%	144,165	150,509	4.40%	165,421	171,765	3.83%	117
118	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	118
119	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	119
120	LSR - LGS-2T	9,583,450	159,003	214,330	34.80%	921,846	977,173	6.00%	1,099,236	1,154,563	5.03%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	26,274,564	868,679	927,851	6.81%	2,960,134	3,019,306	2.00%	3,454,358	3,513,529	1.71%	122
123	LSR - LGS-3T	109,322,768	2,488,706	3,000,981	20.58%	11,190,798	11,703,073	4.58%	13,206,710	13,718,986	3.88%	123
133	**EVCCR**											133
134	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	134
135	LGS-2S EVCCR	14,835,492	648,508	653,650	0.79%	1,829,413	1,834,555	0.28%	2,106,836	2,111,978	0.24%	135
136	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	136
137	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	137
138	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	138
139	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	139
140	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	140
147												147
148	**TOTAL Bundled**	21,055,299,880	$ 1,071,470,793	$ 1,147,680,021	7.11%	$ 2,789,783,845	$ 2,865,993,073	2.73%	$ 3,210,501,292	$ 3,286,710,521	2.37%	148
149	Residential	10,204,140,610	$ 708,610,416	$ 753,535,750	6.34%	$ 1,567,209,710	$ 1,612,135,044	2.87%	$ 1,791,082,729	$ 1,836,008,062	2.51%	149
150	Non-Residential	10,851,159,270	$ 362,860,377	$ 394,144,272	8.62%	$ 1,222,574,135	$ 1,253,858,030	2.56%	$ 1,419,418,564	$ 1,450,702,459	2.20%	150
151												151
152	**DISTRIBUTION ONLY SERVICE (DOS)[3]**											152
153	GS-DOS	51,413	$ 3,947	$ 3,900	-1.19%	$ 3,947	$ 3,900	-1.19%	$ 4,020	$ 3,973	-1.16%	153
154	LGS-1-DOS	7,843,178	85,196	105,055	23.31%	86,342	106,202	23.00%	98,389	118,249	20.18%	154
155	LGS-2S-DOS	82,487,915	734,814	1,033,787	40.69%	788,210	1,087,183	37.93%	947,993	1,246,966	31.54%	155
156	LGS-2P-DOS	4,487,342	58,866	85,954	46.02%	55,082	82,170	49.18%	66,599	93,687	40.67%	156
157	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	157
158	LGS-3S-DOS	85,826,485	813,709	1,196,896	47.09%	866,433	1,249,620	44.23%	1,029,961	1,413,148	37.20%	158
159	LGS-3P-DOS	1,414,522,800	8,148,886	16,993,733	108.54%	8,313,358	17,158,206	106.39%	10,485,712	19,330,560	84.35%	159
160	LGS-3T-DOS	591,977,970	1,323,566	3,729,045	181.74%	1,454,782	3,860,260	165.35%	2,399,837	4,805,315	100.24%	160
161	LGS-XS-DOS	7,153,043	55,175	130,208	135.99%	62,113	137,146	120.80%	77,765	152,798	96.49%	161
162	LGS-XP-DOS	287,352,976	2,541,281	5,092,527	100.39%	2,646,507	5,197,753	96.40%	3,138,262	5,689,508	81.29%	162
163	LGS-XT-DOS	165,618,096	598,410	934,805	56.21%	598,410	934,805	56.21%	833,588	1,169,983	40.36%	163
164	LGS-2S-WP-DOS	4,841,057	24,486	106,689	335.72%	24,486	106,689	335.72%	31,360	113,564	262.13%	164
165	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	165
166	LGS-2T-WP-DOS	1,889,274	17,854	37,732	111.34%	17,854	37,732	111.34%	20,537	40,415	96.79%	166
167	LGS-3S-WP-DOS	25,647,446	79,367	412,242	419.41%	79,367	412,242	419.41%	115,786	448,661	287.49%	167
168	LGS-3P-WP-DOS	75,371,524	297,544	903,142	203.53%	297,544	903,142	203.53%	404,572	1,010,169	149.69%	168
169	LGS-3T-WP-DOS	55,357,230	100,063	668,170	567.75%	100,063	668,170	567.75%	178,670	746,777	317.96%	169
170												170
171	DOS TOTAL	2,810,427,749	$ 14,883,164	$ 31,433,885	111.20%	$ 15,394,498	$ 31,945,220	107.51%	$ 19,833,051	$ 36,383,773	83.45%	171
172												172
173	TOTAL (Inc. DOS)	23,865,727,629	$ 1,086,353,957	$ 1,179,113,906	8.54%	$ 2,805,178,343	$ 2,897,938,293	3.31%	$ 3,230,334,344	$ 3,323,094,294	2.87%	173
174												174

175 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. 175

176 1. Present BTER and DEAA revenues are based on April 1, 2023 rates. 176

177 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 177

178 3. DOS schedules only reflect a percentage change to their distribution rates, not the OATT and energy rates paid through other mechanisms. 178

Line No.	Class	Sales	BTER Revenue Present	BTER Revenue Proposed	BTER Percent Change	DEAA Revenue Present	DEAA Revenue Proposed	DEAA Percent Change	EE Revenue Present	EE Revenue Proposed	EE Percent Change
9		Residential Rate	$ 0.08415	$ 0.08415		$ 0.01750	$ 0.01750		Rates vary by Class		
10		Non-Residential Rate	$ 0.07960	$ 0.07960		$ 0.01500	$ 0.01500				
11											
12	RS	7,262,588,952	$ 611,088,099	$ 611,088,099	0.0%	$ 126,894,467	$ 126,894,467	0.0%	$ 16,921,832	$ 16,921,832	0.0%
13	RM	2,298,671,171	193,414,892	193,414,892	0.0%	40,164,242	40,164,242	0.0%	4,827,210	4,827,210	0.0%
14	LRS	37,525,901	3,157,805	3,157,805	0.0%	656,703	656,703	0.0%	66,795	66,795	0.0%
15	GS	612,055,143	48,719,198	48,719,198	0.0%	9,179,762	9,179,762	0.0%	960,927	960,927	0.0%
16	LGS-1	4,073,133,716	324,176,879	324,176,879	0.0%	61,077,978	61,077,978	0.0%	6,598,476	6,598,476	0.0%
17	LGS-2S	2,429,180,261	193,341,369	193,341,369	0.0%	36,437,704	36,437,704	0.0%	3,668,062	3,668,062	0.0%
18	LGS-2P	69,583,297	5,538,830	5,538,830	0.0%	1,043,749	1,043,749	0.0%	91,851	91,851	0.0%
19	LGS-2T	-	-	-	na	-	-	na	-	-	na
20	LGS-3S	768,658,032	61,185,179	61,185,179	0.0%	11,529,870	11,529,870	0.0%	1,122,241	1,122,241	0.0%
21	LGS-3P	1,393,295,183	110,906,297	110,906,297	0.0%	20,899,428	20,899,428	0.0%	2,257,138	2,257,138	0.0%
22	LGS-3T	247,665,929	19,714,208	19,714,208	0.0%	3,714,989	3,714,989	0.0%	309,583	309,583	0.0%
23	LGS-XS	-	-	-	na	-	-	na	-	-	na
24	LGS-XP	-	-	-	na	-	-	na	-	-	na
25	LGS-XT	-	-	-	na	-	-	na	-	-	na
26	LGS-2S-WP	14,877,558	1,184,254	1,184,254	0.0%	223,163	223,163	0.0%	25,292	25,292	0.0%
27	LGS-2P-WP	11,147,772	887,363	887,363	0.0%	167,217	167,217	0.0%	13,043	13,043	0.0%
28	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na
29	LGS-3S-WP	4,412,814	351,260	351,260	0.0%	66,192	66,192	0.0%	3,662	3,662	0.0%
30	LGS-3P-WP	19,004,483	1,512,757	1,512,757	0.0%	285,067	285,067	0.0%	18,244	18,244	0.0%
31	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na
32	SL	129,054,441	10,272,734	10,272,734	0.0%	1,935,817	1,935,817	0.0%	184,548	184,548	0.0%
33	RS-Pal	578,040	48,642	48,642	0.0%	10,116	10,116	0.0%	781	781	0.0%
34	GS-Pal	2,217,456	176,509	176,509	0.0%	33,262	33,262	0.0%	2,749	2,749	0.0%
35	IAIWP	-	-	-	na	-	-	na	-	-	na
36	**Optional Time of Use**										
37	ORS-TOU	9,396,344	790,189	790,189	0.0%	162,684	162,684	0.0%	21,894	21,894	0.0%
38	ORS-TOU OPT A	21,030,431	1,769,207	1,769,207	0.0%	366,309	366,309	0.0%	49,001	49,001	0.0%
39	ORS-TOU OPT B	4,239,586	356,761	356,761	0.0%	74,193	74,193	0.0%	9,878	9,878	0.0%
43	ORM-TOU	873,422	73,417	73,417	0.0%	15,010	15,010	0.0%	1,835	1,835	0.0%
44	ORM-TOU OPT A	718,287	60,444	60,444	0.0%	12,570	12,570	0.0%	1,509	1,509	0.0%
45	ORM-TOU OPT B	70,254	5,912	5,912	0.0%	1,229	1,229	0.0%	147	147	0.0%
46	ORM-TOU DDP	9,561	756	756	0.0%	0	0	0.0%	20	20	0.0%
55	OGS-TOU	27,565,080	2,194,180	2,194,180	0.0%	413,476	413,476	0.0%	43,277	43,277	0.0%
56	OLGS-1 TOU	124,787,383	9,933,076	9,933,076	0.0%	1,871,811	1,871,811	0.0%	202,156	202,156	0.0%
57	OLGS-3P-HLF	258,609,361	20,585,305	20,585,305	0.0%	3,879,140	3,879,140	0.0%	418,947	418,947	0.0%
58	**Optional Time of Use EVRR**										
59	ORS-TOU EVRR	52,516,143	4,418,401	4,418,401	0.0%	916,188	916,188	0.0%	122,363	122,363	0.0%
60	ORS-TOU Opt A EVRR	6,627,577	557,711	557,711	0.0%	115,983	115,983	0.0%	15,443	15,443	0.0%
61	ORS-TOU Opt B EVRR	4,621,440	388,894	388,894	0.0%	80,875	80,875	0.0%	10,768	10,768	0.0%
64	ORM-TOU EVRR	1,289,179	108,374	108,374	0.0%	22,188	22,188	0.0%	2,708	2,708	0.0%
65	ORM-TOU OPT A EVRR	60,410	5,084	5,084	0.0%	1,057	1,057	0.0%	127	127	0.0%
66	ORM-TOU OPT B EVRR	29,643	2,494	2,494	0.0%	519	519	0.0%	63	63	0.0%
69	OLRS-TOU EVRR	299,866	25,234	25,234	0.0%	5,248	5,248	0.0%	534	534	0.0%
74	OGS-TOU EVRR	20,511	1,633	1,633	0.0%	308	308	0.0%	32	32	0.0%
75	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na
76	**Net Metering:**										
77	RS-NEM	478,046,320	40,227,598	40,227,598	0.0%	8,365,811	8,365,811	0.0%	1,113,848	1,113,848	0.0%
78	RM-NEM	2,595,772	218,434	218,434	0.0%	45,426	45,426	0.0%	5,452	5,452	0.0%
79	LRS-NEM	571,396	48,083	48,083	0.0%	9,999	9,999	0.0%	1,018	1,018	0.0%
80	GS-NEM	2,417,263	192,415	192,415	0.0%	36,259	36,259	0.0%	3,796	3,796	0.0%
81	LGS-1 NEM	73,328,638	5,836,959	5,836,959	0.0%	1,099,930	1,099,930	0.0%	118,792	118,792	0.0%
82	ORS-NEM	3,324,908	279,791	279,791	0.0%	58,186	58,186	0.0%	7,747	7,747	0.0%
83	ORS-NEM OPT A	4,057,523	341,441	341,441	0.0%	71,007	71,007	0.0%	9,455	9,455	0.0%
84	ORS-NEM OPT B	218,046	18,348	18,348	0.0%	3,816	3,816	0.0%	508	508	0.0%
88	ORM-NEM	1,460	123	123	0.0%	26	26	0.0%	2	2	0.0%
101	**NEM EVRR**					-	-				
102	ORS-NEM EVRR	11,862,176	998,202	998,202	0.0%	207,588	207,588	0.0%	27,639	27,639	0.0%
103	ORS-NEM OPT A EVRR	1,879,925	158,196	158,196	0.0%	32,899	32,899	0.0%	4,379	4,379	0.0%
104	ORS-NEM OPT B EVRR	411,121	34,595	34,595	0.0%	7,195	7,195	0.0%	959	959	0.0%
107	ORM-NEM EVRR	25,756	2,167	2,167	0.0%	451	451	0.0%	54	54	0.0%
118	**Standby**										
120	SSR - GS	-	-	-	na	-	-	na	-	-	na
121	SSR - LGS-1	1,130,064	89,953	89,953	0.0%	16,951	16,951	0.0%	1,830	1,830	0.0%
122	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na
123	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na
124	LSR - LGS-2T	9,583,450	762,843	762,843	0.0%	143,752	143,752	0.0%	12,650	12,650	0.0%
125	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na
126	LSR - LGS-3P	26,274,564	2,091,455	2,091,455	0.0%	394,118	394,118	0.0%	42,564	42,564	0.0%
127	LSR - LGS-3T	109,322,768	8,702,092	8,702,092	0.0%	1,639,842	1,639,842	0.0%	136,654	136,654	0.0%
137	**EVCCR**					-	-				
138	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na
139	LGS-2S EVCCR	14,835,492	1,180,905	1,180,905	0.0%	222,532	222,532	0.0%	22,401	22,401	0.0%
140	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na
141	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na
142	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na
143	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na
144	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na
151											
152	**TOTAL Bundled**	21,055,299,880	$ 1,718,313,052	$ 1,718,313,052	0.0%	334,614,299	334,614,299	0.0%	40,019,026	40,019,026	0.0%
153	Residential	10,204,140,610	858,599,294	858,599,294	0.0%	178,301,982	178,301,982	0.0%	23,223,969	23,223,969	0.0%
154	Non-Residential	10,851,159,270	859,713,758	859,713,758	0.0%	156,312,317	156,312,317	0.0%	16,795,057	16,795,057	0.0%
155											
156	**DISTRIBUTION ONLY SERVICE (DOS)**		R-BTER & BTER Impact Fee DOS Revenue								
157	GS-DOS	51,413	-	-	na	-	-	na	-	-	na
158	LGS-1-DOS	7,843,178	1,146	1,146	0.0%	27	27	0.0%	51	51	0.0%
159	LGS-2S-DOS	82,487,915	53,396	53,396	0.0%	897	897	0.0%	1,701	1,701	0.0%
160	LGS-2P-DOS	4,487,342	(3,784)	(3,784)	0.0%	103	103	0.0%	1,587	1,587	0.0%
161	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na
162	LGS-3S-DOS	85,826,485	52,724	52,724	0.0%	1,543	1,543	0.0%	2,925	2,925	0.0%
163	LGS-3P-DOS	1,414,522,800	164,473	164,472	0.0%	3,361	3,361	0.0%	15,074	15,074	0.0%
164	LGS-3T-DOS	591,977,970	131,216	131,216	0.0%	2,722	2,722	0.0%	5,162	5,162	0.0%
165	LGS-XS-DOS	7,153,043	6,938	6,938	0.0%	182	182	0.0%	345	345	0.0%
166	LGS-XP-DOS	287,352,976	105,226	105,226	0.0%	2,248	2,248	0.0%	4,263	4,263	0.0%
167	LGS-XT-DOS	165,618,096	-	-	na	-	-	na	-	-	na
168	LGS-2S-WP-DOS	4,841,057	-	-	na	-	-	na	-	-	na
169	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na
170	LGS-2T-WP-DOS	1,889,274	-	-	na	-	-	na	-	-	na
171	LGS-3S-WP-DOS	25,647,446	-	-	na	-	-	na	-	-	na
172	LGS-3P-WP-DOS	75,371,524	-	-	na	-	-	na	-	-	na
173	LGS-3T-WP-DOS	55,357,230	-	-	na	-	-	na	-	-	na
174											
175	DOS TOTAL	$ 2,810,427,749	$ 511,335	$ 511,334	0.0%	$ 11,083	$ 11,083	0.0%	$ 31,108	$ 31,108	0.0%
176											
177	TOTAL	68,786,755,138	$ 1,718,824,387	$ 1,718,824,386	0.0%	$ 334,625,382	$ 334,625,382	0.0%	$ 40,050,134	$ 40,050,134	0.0%
178				$ (1)			$ -			$ -	
179											

Line No.	Class	REPR Revenue Present	REPR Revenue Proposed	REPR Percent Change	NDPP Present	NDPP Proposed	NDPP Percent Change	ESAP Present	ESAP Proposed	ESAP Percent Change	Line No.
9	Residential Rate	$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		9
10	Non-Residential Rate	$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		10
11											11
12	RS	$ 5,592,193	$ 5,592,193	0.0%	$ 10,312,876	$ 10,312,876	0.0%	$ 145,252	$ 145,252	0.0%	12
13	RM	1,769,977	1,769,977	0.0%	3,264,113	3,264,113	0.0%	45,973	45,973	0.0%	13
14	LRS	28,895	28,895	0.0%	53,287	53,287	0.0%	751	751	0.0%	14
15	GS	471,282	471,282	0.0%	869,118	869,118	0.0%	12,241	12,241	0.0%	15
16	LGS-1	3,136,313	3,136,313	0.0%	5,783,850	5,783,850	0.0%	81,463	81,463	0.0%	16
17	LGS-2S	1,870,469	1,870,469	0.0%	3,449,436	3,449,436	0.0%	48,584	48,584	0.0%	17
18	LGS-2P	53,579	53,579	0.0%	98,808	98,808	0.0%	1,392	1,392	0.0%	18
19	LGS-2T	-	-	na	-	-	na	-	-	na	19
20	LGS-3S	591,867	591,867	0.0%	1,091,494	1,091,494	0.0%	15,373	15,373	0.0%	20
21	LGS-3P	1,072,837	1,072,837	0.0%	1,978,479	1,978,479	0.0%	27,866	27,866	0.0%	21
22	LGS-3T	190,703	190,703	0.0%	351,686	351,686	0.0%	4,953	4,953	0.0%	22
23	LGS-XS	-	-	na	-	-	na	-	-	na	23
24	LGS-XP	-	-	na	-	-	na	-	-	na	24
25	LGS-XT	-	-	na	-	-	na	-	-	na	25
26	LGS-2S-WP	11,456	11,456	0.0%	21,126	21,126	0.0%	298	298	0.0%	26
27	LGS-2P-WP	8,584	8,584	0.0%	15,830	15,830	0.0%	223	223	0.0%	27
28	LGS-2T-WP	-	-	na	-	-	na	-	-	na	28
29	LGS-3S-WP	3,398	3,398	0.0%	6,266	6,266	0.0%	88	88	0.0%	29
30	LGS-3P-WP	14,633	14,633	0.0%	26,986	26,986	0.0%	380	380	0.0%	30
31	LGS-3T-WP	-	-	na	-	-	na	-	-	na	31
32	SL	99,372	99,372	0.0%	183,257	183,257	0.0%	2,581	2,581	0.0%	32
33	RS-Pal	445	445	0.0%	821	821	0.0%	12	12	0.0%	33
34	GS-Pal	1,707	1,707	0.0%	3,149	3,149	0.0%	44	44	0.0%	34
35	IAIWP	-	-	na	-	-	na	-	-	na	35
36	**Optional Time of Use**										36
37	ORS-TOU	7,235	7,235	0.0%	13,343	13,343	0.0%	188	188	0.0%	37
38	ORS-TOU OPT A	16,193	16,193	0.0%	29,863	29,863	0.0%	421	421	0.0%	38
39	ORS-TOU OPT B	3,264	3,264	0.0%	6,020	6,020	0.0%	85	85	0.0%	39
43	ORM-TOU	673	673	0.0%	1,240	1,240	0.0%	17	17	0.0%	43
44	ORM-TOU OPT A	553	553	0.0%	1,020	1,020	0.0%	14	14	0.0%	44
45	ORM-TOU OPT B	54	54	0.0%	100	100	0.0%	1	1	0.0%	45
46	ORM-TOU DDP	7	7	0.0%	14	14	0.0%	0	0	0.0%	46
55	OGS-TOU	21,225	21,225	0.0%	39,142	39,142	0.0%	551	551	0.0%	55
56	OLGS-1 TOU	96,086	96,086	0.0%	177,198	177,198	0.0%	2,496	2,496	0.0%	56
57	OLGS-3P-HLF	199,129	199,129	0.0%	367,225	367,225	0.0%	5,172	5,172	0.0%	57
58	**Optional Time of Use EVRR**										58
59	ORS-TOU EVRR	40,437	40,437	0.0%	74,573	74,573	0.0%	1,050	1,050	0.0%	59
60	ORS-TOU Opt A EVRR	5,103	5,103	0.0%	9,411	9,411	0.0%	133	133	0.0%	60
61	ORS-TOU Opt B EVRR	3,559	3,559	0.0%	6,562	6,562	0.0%	92	92	0.0%	61
64	ORM-TOU EVRR	993	993	0.0%	1,831	1,831	0.0%	26	26	0.0%	64
65	ORM-TOU OPT A EVRR	47	47	0.0%	86	86	0.0%	1	1	0.0%	65
66	ORM-TOU OPT B EVRR	23	23	0.0%	42	42	0.0%	1	1	0.0%	66
69	OLRS-TOU EVRR	231	231	0.0%	426	426	0.0%	6	6	0.0%	69
74	OGS-TOU EVRR	16	16	0.0%	29	29	0.0%	0	0	0.0%	74
75	OLGS-1-TOU EVRR	-	-	na	-	-	na	-	-	na	75
76	**Net Metering:**										76
77	RS-NEM	368,096	368,096	0.0%	678,826	678,826	0.0%	9,561	9,561	0.0%	77
78	RM-NEM	1,999	1,999	0.0%	3,686	3,686	0.0%	52	52	0.0%	78
79	LRS-NEM	440	440	0.0%	811	811	0.0%	11	11	0.0%	79
80	GS-NEM	1,861	1,861	0.0%	3,433	3,433	0.0%	48	48	0.0%	80
81	LGS-1 NEM	56,463	56,463	0.0%	104,127	104,127	0.0%	1,467	1,467	0.0%	81
82	ORS-NEM	2,560	2,560	0.0%	4,721	4,721	0.0%	66	66	0.0%	82
83	ORS-NEM OPT A	3,124	3,124	0.0%	5,762	5,762	0.0%	81	81	0.0%	83
84	ORS-NEM OPT B	168	168	0.0%	310	310	0.0%	4	4	0.0%	84
88	ORM-NEM	1	1	0.0%	2	2	0.0%	0	0	0.0%	88
101	**NEM EVRR**										101
102	ORS-NEM EVRR	9,134	9,134	0.0%	16,844	16,844	0.0%	237	237	0.0%	102
103	ORS-NEM OPT A EVRR	1,448	1,448	0.0%	2,669	2,669	0.0%	38	38	0.0%	103
104	ORS-NEM OPT B EVRR	317	317	0.0%	584	584	0.0%	8	8	0.0%	104
107	ORM-NEM EVRR	20	20	0.0%	37	37	0.0%	1	1	0.0%	107
118	**Standby**										118
120	SSR - GS	-	-	na	-	-	na	-	-	na	120
121	SSR - LGS-1	870	870	0.0%	1,605	1,605	0.0%	23	23	0.0%	121
122	LSR - LGS-2S	-	-	na	-	-	na	-	-	na	122
123	LSR - LGS-2P	-	-	na	-	-	na	-	-	na	123
124	LSR - LGS-2T	7,379	7,379	0.0%	13,608	13,608	0.0%	192	192	0.0%	124
125	LSR - LGS-3S	-	-	na	-	-	na	-	-	na	125
126	LSR - LGS-3P	20,231	20,231	0.0%	37,310	37,310	0.0%	525	525	0.0%	126
127	LSR - LGS-3T	84,179	84,179	0.0%	155,238	155,238	0.0%	2,186	2,186	0.0%	127
137	**EVCCR**										137
138	OLGS-1 EVCCR	-	-	na	-	-	na	-	-	na	138
139	LGS-2S EVCCR	11,423	11,423	0.0%	21,066	21,066	0.0%	297	297	0.0%	139
140	LGS-2P EVCCR	-	-	na	-	-	na	-	-	na	140
141	LGS-2T EVCCR	-	-	na	-	-	na	-	-	na	141
142	LGS-3S EVCCR	-	-	na	-	-	na	-	-	na	142
143	LGS-3P EVCCR	-	-	na	-	-	na	-	-	na	143
144	LGS-3T EVCCR	-	-	na	-	-	na	-	-	na	144
151											151
152	**TOTAL Bundled**	16,185,597	16,185,597	0.0%	29,898,526	29,898,526	0.0%	421,106	421,106	0.0%	152
153	Residential	7,857,188	7,857,188	0.0%	14,489,880	14,489,880	0.0%	204,083	204,083	0.0%	153
154	Non-Residential	8,328,409	8,328,409	0.0%	15,408,646	15,408,646	0.0%	217,023	217,023	0.0%	154
155											155
156	**DISTRIBUTION ONLY SERVICE (DOS)**										156
157	GS-DOS	-	-	na	73	73	0.0%	1	1	0.0%	157
158	LGS-1-DOS	832	832	0.0%	11,137	11,137	0.0%	157	157	0.0%	158
159	LGS-2S-DOS	40,052	40,052	0.0%	117,133	117,133	0.0%	1,650	1,650	0.0%	159
160	LGS-2P-DOS	3,455	3,455	0.0%	6,372	6,372	0.0%	90	90	0.0%	160
161	LGS-2T-DOS	-	-	na	-	-	na	-	-	na	161
162	LGS-3S-DOS	37,186	37,186	0.0%	121,874	121,874	0.0%	1,717	1,717	0.0%	162
163	LGS-3P-DOS	145,297	145,297	0.0%	2,008,622	2,008,622	0.0%	28,290	28,290	0.0%	163
164	LGS-3T-DOS	96,562	96,562	0.0%	840,609	840,609	0.0%	11,840	11,840	0.0%	164
165	LGS-XS-DOS	4,968	4,968	0.0%	10,157	10,157	0.0%	143	143	0.0%	165
166	LGS-XP-DOS	77,203	77,203	0.0%	408,041	408,041	0.0%	5,747	5,747	0.0%	166
167	LGS-XT-DOS	-	-	na	235,178	235,178	0.0%	3,312	3,312	0.0%	167
168	LGS-2S-WP-DOS	-	-	na	6,874	6,874	0.0%	97	97	0.0%	168
169	LGS-2P-WP-DOS	-	-	na	-	-	na	-	-	na	169
170	LGS-2T-WP-DOS	-	-	na	2,683	2,683	0.0%	38	38	0.0%	170
171	LGS-3S-WP-DOS	-	-	na	36,419	36,419	0.0%	513	513	0.0%	171
172	LGS-3P-WP-DOS	-	-	na	107,028	107,028	0.0%	1,507	1,507	0.0%	172
173	LGS-3T-WP-DOS	-	-	na	78,607	78,607	0.0%	1,107	1,107	0.0%	173
174											174
175	DOS TOTAL	$ 405,555	$ 405,555	0.0%	$ 3,990,807	$ 3,990,807	0.0%	$ 56,209	$ 56,209	0.0%	175
176											176
177	TOTAL	$ 16,591,152	$ 16,591,152	0.0%	$ 33,889,333	$ 33,889,333	0.0%	$ 477,315	$ 477,315	0.0%	177
178			$ -			$ -			$ -		178
179											179

Summary of Proposed Rates -- Bundled

Line No.	Class	Note	Distribution Charges: Charge, per Cust:	Distribution Charges: Meter Charge:	Distribution Charges: Facilities Charge, per kW (1)	T and G Demand Charges, metered kW: Summer On Peak	T and G Demand Charges, metered kW: Summer Mid Peak	T and G Demand Charges, metered kW: Winter -OR - All Periods	BTGR Energy, per kWh (includes IRR): Critical Peak	BTGR Energy: Summer On Peak	BTGR Energy: Summer Mid Peak	BTGR Energy: Summer Off Peak	BTGR Energy: Winter -OR - All Periods	BTGR Energy: Summer EVRR	BTGR Energy: Winter EVRR	BTER Energy, per kWh	Line No.
9	RS		$ 18.50										0.05955			$ 0.08415	9
10	RM		8.20										0.05324			0.08415	10
11	LRS		98.70										0.05149			0.08415	11
12	GS		25.50	$ 2.00									0.01871			0.07960	12
13	LGS-1		15.80	5.75	$ 4.25			$ 5.35					0.01216			0.07960	13
14	LGS-2S		122.40	12.25	2.75	$ 16.26	$ 3.60	0.80		0.01707	0.00856	0.00469	0.00480			0.07960	14
15	LGS-2P		207.70	54.25	2.80	14.39	3.36	0.80		0.01355	0.00612	0.00327	0.00472			0.07960	15
16	LGS-2T		182.00	88.50	0.90	15.57	3.15	1.00		0.02648	0.01041	0.00083	0.00111			0.07960	16
17	LGS-3S		122.00	15.00	2.75	16.35	4.35	1.00		0.01670	0.00819	0.00467	0.00469			0.07960	17
18	LGS-3P		214.10	67.75	2.60	14.73	3.96	1.10		0.01410	0.01031	0.00524	0.00611			0.07960	18
19	LGS-3T		182.00	88.50	0.90	15.57	3.15	1.00		0.02648	0.01041	0.00083	0.00111			0.07960	19
20	LGS-XS		4,743.00	16.80	2.25	16.35	4.35	1.00		0.01670	0.00819	0.00467	0.00469			0.07960	20
21	LGS-XP		4,743.00	53.90	3.05	14.73	3.96	1.10		0.01410	0.01031	0.00524	0.00611			0.07960	21
22	LGS-XT		4,743.00	91.90	na	15.57	3.15	1.00		0.02648	0.01041	0.00083	0.00111			0.07960	22
23	LGS-2S-WP		128.70	12.25	1.10	19.86	19.86	0.80		0.04090	0.02288	0.02879	0.02880			0.07960	23
24	LGS-2P-WP		208.60	54.25	1.55	17.75	17.75	0.80		0.02249	0.00748	0.00995	0.00996			0.07960	24
25	LGS-2T-WP		169.10	92.00	0.90	18.72	18.72	1.00		0.01672	0.02528	0.00305	0.00847			0.07960	25
26	LGS-3S-WP		149.90	15.00	1.25	20.70	20.70	1.00		0.10589	0.09118	0.00727	0.00728			0.07960	26
27	LGS-3P-WP		234.20	67.75	1.00	18.69	18.69	1.10		0.02001	0.00145	0.00517	0.00518			0.07960	27
28	LGS-3T-WP		189.10	88.50	0.90	19.57	19.57	1.10		0.01438	0.01802	(0.00136)	0.00377			0.07960	28
29	IAIWP															0.06751	29
30																	30
31	ORS-TOU		18.50							0.32604		0.01038	0.01087	0.00093	0.00137	0.08415	31
32	ORS-TOU Opt A		18.50							0.26985		0.00520	0.01087	(0.00374)	0.00137	0.08415	32
33	ORS-TOU Opt B		34.25							0.40590		0.00241	0.01087	(0.00625)	0.00137	0.08415	33
34	ORS-TOU DDP		7.00		0.23	0.14		0.05					0.03445			0.08415	34
35	ORS-TOU CPP		18.50						0.65083	0.28412		0.01227	0.00474	0.00263	(0.00415)	0.08415	35
36	ORS-TOU CPP DDP		18.50			0.14		0.05	0.65083	0.19777		0.00888	0.01087	(0.00042)	0.00137	0.08415	36
37	ORM-TOU		8.20							0.25256		0.04065	0.01294	0.02817	0.00323	0.08415	37
38	ORM-TOU Opt A		8.20							0.24100		0.03074	0.00792	0.01925	(0.00129)	0.08415	38
39	ORM-TOU Opt B		14.40							0.25330		0.06930	0.01626	0.05395	0.00622	0.08415	39
40	ORM-TOU DDP		4.75		0.09	0.06		0.05					0.03644			0.08415	40
41	ORM-TOU CPP		8.20						0.40734	0.21967		0.03444	0.01868	0.02258	0.00840	0.08415	41
42	ORM-TOU CPP DDP		8.20			0.06		0.05	0.40734	0.19040		0.03444	0.01004	0.02258	0.00062	0.08415	42
43	OLRS-TOU		98.70							0.27926		0.01908	0.01714	0.00876	0.00701	0.08415	43
44	OLRS-TOU Opt A		98.70							0.26091		0.01428	0.00849	0.00444	(0.00077)	0.08415	44
45	OLRS-TOU Opt B		243.70							0.27046		0.07105	0.01090	0.05553	0.00139	0.08415	45
46	OLRS-TOU DDP		25.75		0.22	0.18		0.05					0.03387			0.08415	46
47	OLRS-TOU CPP		98.70						0.31156	0.24386		0.01607	0.02533	0.00605	0.01438	0.08415	47
48	OLRS-TOU CPP DDP		98.70			0.18		0.05	0.31156	0.19072		0.01607	0.02204	0.00605	0.01142	0.08415	48
49	OGS-TOU		25.50	2.00						0.06383		0.02005	0.01021	0.01008	0.00123	0.07960	49
50	OLGS-1-TOU		15.80	5.75	4.25	8.28	<- Summer Winter->	0.50		0.10835		0.00607	0.00506	(0.00250)	(0.00341)	0.07960	50
51	OLGS-3P-HLF		214.10	67.75	1.40	22.66	5.63	1.00		0.00576	(0.00156)	0.00001	0.00002			0.07960	51
52																	52
53	Incremental MPE						Generation $/kW Credit				Generation $/kWh Credit						53
54	GS MPE												(0.01627)				54
55	LGS-1 MPE							$ (3.59)					(0.00908)				55
56	LGS-2S MPE					(11.93)	(2.64)	(0.59)		(0.00527)	(0.00265)	(0.00145)	(0.00148)				56
57	LGS-3P MPE					(10.36)	(2.79)	(0.77)		(0.00152)	(0.00111)	(0.00056)	(0.00066)				57
58	LGS-3T MPE					(6.23)	(1.26)	(0.40)		(0.01018)	(0.00400)	(0.00032)	(0.00043)				58
59																	59
60	Incremental EVCCR						EVCCR Demand Reduction Rates				EVCCR Transition kWh Adder Rates						60
61	OLGS-1 EVCCR					(4.97)		(0.30)		0.03668			0.00107	(0.00771)	(0.00762)		61
62	LGS-2S EVCCR					(9.76)	(2.16)	(0.48)		0.07267	0.01706	-	0.00115	(0.00843)	(0.00844)		62
63	LGS-2P EVCCR					(8.63)	(2.02)	(0.48)		0.06077	0.01462	-	0.00096	(0.00829)	(0.00843)		63
64	LGS-2T EVCCR					(9.34)	(1.89)	(0.60)		0.06365	0.05401	-	0.04843	(0.00804)	(0.00807)		64
65	LGS-3S EVCCR					(9.81)	(2.61)	(0.60)		0.06946	0.01914	-	0.00125	(0.00843)	(0.00843)		65
66	LGS-3P EVCCR					(8.84)	(2.38)	(0.66)		0.06078	0.01692	-	0.00132	(0.00848)	(0.00857)		66
67	LGS-3T EVCCR					(9.34)	(1.89)	(0.60)		0.05662	0.01171	-	0.00114	(0.00804)	(0.00807)		67

Additional Charges:

Separate Billing

LGS-X & LGS-WP-X:	$ 12.00	Per additional bill
DOS LGS-X & LGS-WP-X:	$ 12.00	Per additional bill

Power Factor Charges ($/kVarh):

Summer:	$ 0.00200	$/kVarh
Winter:	$ 0.00100	$/kVarh

Customer Specific Facilities Charges	Charge per $ of: Utility	Charge per $ of: Customer Contributed
Transmission non-X customers	$ 0.00325	$ 0.00059
DOS Transmission non-X customers	$ 0.00325	$ 0.00059
OLGS-3P HLF customers	$ 0.00325	$ 0.00059

Notes:

(1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge recovers both the Rule 9 and primary distibution facility costs. For LGSX customers the per kW facility charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facility charge (CSFC).

(2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical.

(3) The per kW facility charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

Nevada Power Company
Statement O

Summary of Proposed Rates -- Bundled (continued)

		BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy)							Additional Charges on per kWH Basis						Total Energy, per kWh (BTGR & BTER + EE + DEAA)							
Line No.	Class	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	REPR	TRED	DEAA	EE	NDPP	ESAP	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	Line No.
8																						8
9	RS					$ 0.14370			$ 0.00077	$ 0.00070	$ 0.01750	$ 0.00206	$ 0.00142	$ 0.00002					$ 0.16473			9
10	RM					0.13739			0.00077	0.00070	0.01750	0.00186	0.00142	0.00002					0.15822			10
11	LRS					0.13564			0.00077	0.00070	0.01750	0.00156	0.00142	0.00002					0.15617			11
12	GS					0.09831			0.00077	0.00057	0.01500	0.00139	0.00142	0.00002					0.11604			12
13	LGS-1					0.09176			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002					0.10955			13
14	LGS-2S		$ 0.09667	$ 0.08816	$ 0.08429	0.08440			0.00077	0.00057	0.01500	0.00135	0.00142	0.00002		$ 0.11436	$ 0.10585	$ 0.10198	0.10209			14
15	LGS-2P		0.09315	0.08572	0.08287	0.08432			0.00077	0.00057	0.01500	0.00117	0.00142	0.00002		0.11066	0.10323	0.10038	0.10183			15
16	LGS-2T		0.10608	0.09001	0.08043	0.08071			0.00077	0.00057	0.01500	0.00101	0.00142	0.00002		0.12343	0.10736	0.09778	0.09806			16
17	LGS-3S		0.09630	0.08779	0.08427	0.08429			0.00077	0.00057	0.01500	0.00130	0.00142	0.00002		0.11394	0.10543	0.10191	0.10193			17
18	LGS-3P		0.09370	0.08991	0.08484	0.08571			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11149	0.10770	0.10263	0.10350			18
19	LGS-3T		0.10608	0.09001	0.08043	0.08071			0.00077	0.00057	0.01500	0.00107	0.00142	0.00002		0.12349	0.10742	0.09784	0.09812			19
20	LGS-XS		0.09630	0.08779	0.08427	0.08429			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11409	0.10558	0.10206	0.10208			20
21	LGS-XP		0.09370	0.08991	0.08484	0.08571			0.00077	0.00057	0.01500	0.00161	0.00142	0.00002		0.11165	0.10786	0.10279	0.10366			21
22	LGS-XT		0.10608	0.09001	0.08043	0.08071			0.00077	0.00057	0.01500	0.00124	0.00142	0.00002		0.12366	0.10759	0.09801	0.09829			22
23	LGS-2S-WP		0.12050	0.10248	0.10839	0.10840			0.00077	0.00057	0.01500	0.00141	0.00142	0.00002		0.13825	0.12023	0.12614	0.12615			23
24	LGS-2P-WP		0.10209	0.08708	0.08955	0.08956			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.11946	0.10445	0.10692	0.10693			24
25	LGS-2T-WP		0.09632	0.10488	0.08265	0.08807			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.11369	0.12225	0.10002	0.10544			25
26	LGS-3S-WP		0.18549	0.17078	0.08687	0.08688			0.00077	0.00057	0.01500	0.00068	0.00142	0.00002		0.20251	0.18780	0.10389	0.10390			26
27	LGS-3P-WP		0.09961	0.08105	0.08477	0.08478			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.11680	0.09824	0.10196	0.10197			27
28	LGS-3T-WP		0.09398	0.09762	0.07824	0.08337			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.11117	0.11481	0.09543	0.10056			28
29	IAIWP					0.06751			-	-	-								0.06751			29
30																						30
31	ORS-TOU		0.41019		0.09453	0.09502	$ 0.08508	$ 0.08552	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.42872		0.11306	0.11355	$ 0.10361	$ 0.10405	31
32	ORS-TOU Opt A		0.35400		0.08935	0.09502	0.08041	0.08552	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.37253		0.10788	0.11355	0.09894	0.10405	32
33	ORS-TOU Opt B		0.49005		0.08656	0.09502	0.07790	0.08552	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.50858		0.10509	0.11355	0.09643	0.10405	33
34	ORS-TOU DDP					0.11860			0.00077	0.00070	0.01500	0.00206	0.00142	0.00002					0.13713			34
35	ORS-TOU CPP	0.64668	0.36827		0.09642	0.08889	0.08678	0.08000	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.66521	0.38680		0.11495	0.10742	0.10531	0.09853	35
36	ORS-TOU CPP DDP	0.65220	0.28192		0.09303	0.09502	0.08373	0.08552	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.67073	0.30045		0.11156	0.11355	0.10226	0.10405	36
37	ORM-TOU		0.33671		0.12480	0.09709	0.11232	0.08738	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.35504		0.14313	0.11542	0.13065	0.10571	37
38	ORM-TOU Opt A		0.32515		0.11489	0.09207	0.10340	0.08286	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.34348		0.13322	0.11040	0.12173	0.10119	38
39	ORM-TOU Opt B		0.33745		0.15345	0.10041	0.13810	0.09037	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.35578		0.17178	0.11874	0.15643	0.10870	39
40	ORM-TOU DDP					0.12059			0.00077	0.00070	0.01500	0.00186	0.00142	0.00002					0.13892			40
41	ORM-TOU CPP	0.41574	0.30382		0.11859	0.10283	0.10673	0.09255	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.43407	0.32215		0.13692	0.12116	0.12506	0.11088	41
42	ORM-TOU CPP DDP	0.40796	0.27455		0.11859	0.09419	0.10673	0.08477	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.42629	0.29288		0.13692	0.11252	0.12506	0.10310	42
43	OLRS-TOU		0.36341		0.10323	0.10129	0.09291	0.09116	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.38144		0.12126	0.11932	0.11094	0.10919	43
44	OLRS-TOU Opt A		0.34506		0.09843	0.09264	0.08859	0.08338	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.36309		0.11646	0.11067	0.10662	0.10141	44
45	OLRS-TOU Opt B		0.35461		0.15520	0.09505	0.13968	0.08554	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.37264		0.17323	0.11308	0.15771	0.10357	45
46	OLRS-TOU DDP					0.11802			0.00077	0.00070	0.01500	0.00156	0.00142	0.00002					0.13605			46
47	OLRS-TOU CPP	0.32594	0.32801		0.10022	0.10948	0.09020	0.09853	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.34397	0.34604		0.11825	0.12751	0.10823	0.11656	47
48	OLRS-TOU CPP DDP	0.32298	0.27487		0.10022	0.10619	0.09020	0.09557	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.34101	0.29290		0.11825	0.12422	0.10823	0.11360	48
49	OGS-TOU		0.14343		0.09965	0.08981	0.08968	0.08083	0.00077	0.00057	0.01500	0.00139	0.00142	0.00002		0.16116		0.11738	0.10754	0.10741	0.09856	49
50	OLGS-1-TOU		0.18795		0.08567	0.08466	0.07710	0.07619	0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.20574		0.10346	0.10245	0.09489	0.09398	50
51	OLGS-3P-HLF		0.08536	(0.00156)	0.07961	0.07962			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.10315		0.09740	0.09741	0.01779	0.01779	51
52																						52
53	(1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O.																					53

Proposed Street Lighting (SL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00132	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	Street Lights - Non-metered																	12
13	Mercury Vapor	Non-Metered	100W	CLS 20		73	$ 3.18	$ 5.81	**$ 8.99**	$ 1.10	$ 0.04	$ 0.10	$ 0.06	$ 0.10	$ -	---	$ 10.39	13
14	Mercury Vapor	Non-Metered	100W	CLS 20		73	3.18	5.81	**8.99**	1.10	0.04	0.10	0.06	0.10	-	---	10.39	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.17	8.20	**9.37**	1.55	0.06	0.14	0.08	0.15	-	---	11.35	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.17	8.20	**9.37**	1.55	0.06	0.14	0.08	0.15	-	---	11.35	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.11**	2.48	0.09	0.22	0.13	0.23	-	---	13.26	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.11**	2.48	0.09	0.22	0.13	0.23	-	---	13.26	18
19	High Pressure	Non-Metered	100W	CLS 23		42	5.29	3.34	**8.63**	0.63	0.02	0.06	0.03	0.06	-	---	9.43	19
20	High Pressure	Non-Metered	200W	CLS 24		83	2.51	6.61	**9.12**	1.25	0.05	0.11	0.06	0.12	-	---	10.71	20
21	Municipal Street Lights - Public																	21
22	Incandescent	n/a	100W	CLS 30		73	3.16	5.81	**8.97**	1.10	0.04	0.10	0.06	0.10	-	---	10.37	22
23	Incandescent	n/a	200W	CLS 31		120	0.01	9.55	**9.52**	1.80	0.07	0.16	0.09	0.17	-	---	11.81	23
24	Incandescent	n/a	200W	CLS 32		167	0.01	13.29	**10.08**	2.51	0.10	0.22	0.13	0.24	-	---	13.28	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	3.17	5.81	**8.98**	1.10	0.04	0.10	0.06	0.10	-	---	10.38	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	1.14	8.20	**9.34**	1.55	0.06	0.14	0.08	0.15	-	---	11.32	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	0.01	13.13	**10.05**	2.48	0.09	0.22	0.13	0.23	-	---	13.20	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	3.17	5.81	**8.98**	1.10	0.04	0.10	0.06	0.10	-	---	10.38	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	1.14	8.20	**9.34**	1.55	0.06	0.14	0.08	0.15	-	---	11.32	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	0.01	13.13	**10.05**	2.48	0.09	0.22	0.13	0.23	-	---	13.20	30
31	Sodium Vapor	n/a	100W	CLS 89		42	5.27	3.34	**8.61**	0.63	0.02	0.06	0.03	0.06	-	---	9.41	31
32	Sodium Vapor	n/a	200W	CLS 90		83	2.48	6.61	**9.09**	1.25	0.05	0.11	0.06	0.12	-	---	10.68	32
33	Municipal Street Lights - Customer Owned																	33
34	Incandescent	n/a	200W	CLS 51		120	0.01	9.55	**3.87**	1.80	0.07	0.16	0.09	0.17	-	0.05	6.21	34
35	Mercury Vapor	n/a	200W	CLS 53		73	0.01	5.81	**3.33**	1.10	0.04	0.10	0.06	0.10	-	0.03	4.76	35
36	Mercury Vapor	n/a	200W	CLS 54		103	0.01	8.20	**3.69**	1.55	0.06	0.14	0.08	0.15	-	0.04	5.71	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.01	13.13	**4.40**	2.48	0.09	0.22	0.13	0.23	-	0.06	7.61	37
38	Street Lights - LED																	38
39	LED	Non-Metered	100W	CLS 20		70	3.16	5.57	**8.73**	1.05	0.04	0.09	0.05	0.10	-	---	10.06	39
40	LED	Non-Metered	200W	CLS 21		35	3.17	5.57	**8.74**	0.53	0.02	0.05	0.03	0.05	-	---	9.42	40
41	LED	Non-Metered	200W	CLS 22		70	1.12	5.57	**6.69**	1.05	0.04	0.09	0.05	0.10	-	---	8.02	41
42	LED	Non-Metered	200W	CLS 24		70	1.12	5.57	**6.69**	1.05	0.04	0.09	0.05	0.10	-	---	8.02	42
43	Municipal Street Lights - LED																	43
44	LED	n/a	100W	CLS 30		35	3.00	2.79	**5.79**	0.53	0.02	0.05	0.03	0.05	-	---	6.47	44
45	LED	n/a	200W	CLS 31		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	45
46	LED	n/a	200W	CLS 32		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	46
47	LED	Wood Pole	200W	CLS 33		70	3.01	2.79	**5.80**	1.05	0.04	0.09	0.05	0.10	-	---	7.13	47
48	LED	Wood Pole	200W	CLS 34		70	1.04	2.79	**3.83**	1.05	0.04	0.09	0.05	0.10	-	---	5.16	48
49																		49
50	Metered	Metered	Metered	Metered		Mtrd	0.05695	0.07960	**0.13655**	0.01500	0.00057	0.00132	0.00077	0.00142	0.00002	0.00039	0.15604	50
51																		51
52	Note: Municipal and Public Street Lights do not pay UEC charges.																	52

Proposed Residential Private Area Lighting (RS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01750	$ 0.00070	$ 0.00124	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	RS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.57	$ 6.14	**$ 13.71**	$ 1.28	$ 0.05	$ 0.09	$ 0.06	$ 0.10	$ -	0.03	$ 15.32	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.57	6.14	**13.71**	1.28	0.05	0.09	0.06	0.10	-	0.03	15.32	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.24	13.88	**25.12**	2.89	0.12	0.20	0.13	0.23	-	0.06	28.75	15
16	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.31	3.53	**9.84**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.77	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.31	3.53	**9.84**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.77	17
18	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.96	6.98	**14.94**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.76	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.96	6.98	**14.94**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.76	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	11.24	13.88	**25.12**	2.89	0.12	0.20	0.13	0.23	-	0.06	28.75	20
21	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.25	6.14	**19.39**	1.28	0.05	0.09	0.06	0.10	-	0.03	21.00	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.25	6.14	**19.39**	1.28	0.05	0.09	0.06	0.10	-	0.03	21.00	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.92	13.88	**30.80**	2.89	0.12	0.20	0.13	0.23	-	0.06	34.43	23
24	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	12.00	3.53	**15.53**	0.74	0.03	0.05	0.03	0.06	-	0.02	16.46	24
25	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	7.96	6.98	**14.94**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.76	25
26	LED	RATE A (Existing pole)	200W	CLS 10		70	7.35	5.89	**13.24**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.79	26
27	LED	RATE A (Existing pole)	200W	CLS 12		70	5.96	5.89	**11.85**	1.23	0.05	0.09	0.05	0.10	-	0.03	13.40	27
28	LED	RATE A (Existing pole)	100W	CLS 14		35	5.75	2.95	**8.70**	0.61	0.02	0.04	0.03	0.05	-	0.01	9.46	28
29	LED	RATE A (Existing pole)	200W	CLS 15		70	7.10	5.89	**12.99**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.54	29
30	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.98	5.89	**18.87**	1.23	0.05	0.09	0.05	0.10	-	0.03	20.42	30
31	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.44	5.89	**16.33**	1.23	0.05	0.09	0.05	0.10	-	0.03	17.88	31
32	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.33	2.95	**14.28**	0.61	0.02	0.04	0.03	0.05	-	0.01	15.04	32
33																		33
34																		34

Proposed General Service Private Area Lighting (GS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00113	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	GS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.76	$ 5.81	**$ 13.57**	$ 1.10	$ 0.04	$ 0.08	$ 0.06	$ 0.10	$ -	0.03	$ 14.98	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.76	5.81	**13.57**	1.10	0.04	0.08	0.06	0.10	-	0.03	14.98	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	12.03	13.13	**25.16**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.34	15
16	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	12.03	13.13	**25.16**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.34	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.31	3.34	**9.65**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.46	17
18	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.31	3.34	**9.65**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.46	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	8.21	6.61	**14.82**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.42	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	8.21	6.61	**14.82**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.42	20
21	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	12.03	13.13	**25.16**	2.48	0.09	0.19	0.13	0.23	-	0.06	28.34	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.47	5.81	**19.28**	1.10	0.04	0.08	0.06	0.10	-	0.03	20.69	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	17.74	13.13	**30.87**	2.48	0.09	0.19	0.13	0.23	-	0.06	34.05	23
24	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	17.74	13.13	**30.87**	2.48	0.09	0.19	0.13	0.23	-	0.06	34.05	24
25	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	12.01	3.34	**15.35**	0.63	0.02	0.05	0.03	0.06	-	0.02	16.16	25
26	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.92	6.61	**20.53**	1.25	0.05	0.09	0.06	0.12	-	0.03	22.13	26
27	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.92	6.61	**20.53**	1.25	0.05	0.09	0.06	0.12	-	0.03	22.13	27
28	LED	RATE A (Existing pole)	200W	CLS 10		70	7.54	5.57	**13.11**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.46	28
29	LED	RATE A (Existing pole)	200W	CLS 12		70	6.30	5.57	**11.87**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.22	29
30	LED	RATE A (Existing pole)	100W	CLS 14		35	5.73	2.79	**8.52**	0.53	0.02	0.04	0.03	0.05	-	0.01	9.20	30
31	LED	RATE A (Existing pole)	200W	CLS 15		70	7.30	5.57	**12.87**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.22	31
32	LED	RATE A (Existing pole)	200W	CLS 88		70	6.30	5.57	**11.87**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.22	32
33	LED	RATE B (30 Foot pole)	200W	CLS 11		70	13.20	5.57	**18.77**	1.05	0.04	0.08	0.05	0.10	-	0.03	20.12	33
34	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.85	5.57	**16.42**	1.05	0.04	0.08	0.05	0.10	-	0.03	17.77	34
35	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.32	2.79	**14.11**	0.53	0.02	0.04	0.03	0.05	-	0.01	14.79	35
36	LED	RATE B (30 Foot pole)	200W	CLS 17		70	12.81	5.57	**18.38**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.73	36
37																		37
38																		38

Line No.		Class	Distribution Charges: Distribution Charge, per Cust:	Distribution Charges: Additional Meter/ Generation Meter Charge[8]	Distribution Charges: Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3]	Distribution Charges: Facilities Charge, per kW[2,3]	Contract Demand Charges, contract kW[4]: Sum On Peak:	Contract Demand Charges: Sum Mid Peak:	Contract Demand Charges: Other:	Backup Service Variable T&G Demand Charges, metered kW: Sum On Peak:	Backup Service: Sum Mid Peak:	Backup Service: Other:	BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]: Sum On Peak:	BTGR: Sum Mid Peak:	BTGR: Sum Off Peak:	BTGR: Other:	Maintenance Back-up Service[7]: Set @ 50% of Summer On-peak Variable T&G Demand Charges	BTER Energy, per kWh	Line No.
9	SSR II	SS-II GS	25.50	2.00	7.68											0.00705		0.07960	9
10	SSR III	LGS-1	15.80	5.75	4.25	$ 4.25			$ 1.61			$ 3.74				0.01216	$ 1.87	0.07960	10
11	LSR I	LGS-2S	122.40	12.25	2.75	2.75	$ 4.88	$ 1.08	0.24	$ 11.38	$ 2.52	0.56	$ 0.01707	$ 0.00856	$ 0.00469	0.00480	5.69	0.07960	11
12	LSR I	LGS-2P	207.70	54.25	2.80	2.80	4.32	1.01	0.24	10.07	2.35	0.56	0.01355	0.00612	0.00327	0.00472	5.04	0.07960	12
13	LSR I	LGS-2T	182.00	88.50	CSF	0.90	4.67	0.95	0.30	10.90	2.20	0.70	0.02648	0.01041	0.00083	0.00111	5.45	0.07960	13
14	LSR II	LGS-3S	122.00	15.00	2.75	2.75	4.91	1.31	0.30	11.44	3.04	0.70	0.01670	0.00819	0.00467	0.00469	5.72	0.07960	14
15	LSR II	LGS-3P	214.10	67.75	2.60	2.60	4.42	1.19	0.33	10.31	2.77	0.77	0.01410	0.01031	0.00524	0.00611	5.16	0.07960	15
16	LSR II[2]	LGS-3T	182.00	88.50	CSF	0.90	4.67	0.95	0.30	10.90	2.20	0.70	0.02648	0.01041	0.00083	0.00111	5.45	0.07960	16
17	LSR III[9]	LGS-XS	4,743.00	16.80	2.25	2.25	4.91	1.31	0.30	11.44	3.04	0.70	0.01670	0.00819	0.00467	0.00469	5.72	0.07960	17
18	LSR III[9]	LGS-XP	4,743.00	53.90	3.05	3.05	4.42	1.19	0.33	10.31	2.77	0.77	0.01410	0.01031	0.00524	0.00611	5.16	0.07960	18
19	LSR III[1,9]	LGS-XT	4,743.00	91.90	CSF	na	4.67	0.95	0.30	10.90	2.20	0.70	0.02648	0.01041	0.00083	0.00111	5.45	0.07960	19
20	LSR I WP	LGS-2-WPS	128.70	12.25	1.10	1.10	5.96	5.96	0.24	13.90	13.90	0.56	0.04090	0.02288	0.02879	0.02880	6.95	0.07960	20
21	LSR I WP	LGS-2-WPP	208.60	54.25	1.55	1.55	5.33	5.33	0.24	12.42	12.42	0.56	0.02249	0.00748	0.00995	0.00996	6.21	0.07960	21
22	LSR I WP	LGS-2-WPT	169.10	92.00	CSF	0.90	5.62	5.62	0.30	13.10	13.10	0.70	0.01672	0.02528	0.00305	0.00847	6.55	0.07960	22
23	LSR II WP	LGS-3-WPS	149.90	15.00	1.25	1.25	6.21	6.21	0.30	14.49	14.49	0.70	0.10589	0.09118	0.00727	0.00728	7.25	0.07960	23
24	LSR II WP	LGS-3-WPP	234.20	67.75	1.00	1.00	5.61	5.61	0.33	13.08	13.08	0.77	0.02001	0.00145	0.00517	0.00518	6.54	0.07960	24
25	LSR II WP	LGS-3-WPT	189.10	88.50	CSF	0.90	5.87	5.87	0.33	13.70	13.70	0.77	0.01438	0.01802	(0.00136)	0.00377	6.85	0.07960	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF ch (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are customer sp
3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
4. The contract demand charge is set at 30% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.
5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See not
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated cos
9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charg

Proposed Distribution Only Service (DOS) Rates

Line No.	Class	Note	Distribution Charge, per Customer	Total Facilities Charge, per kW (1)	Additional Meter Charge, per Meter	LGSX CSF Charges (monthly dollar charge for entire class)	NDPP	ESAP	Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR)	Line No.
8	GS	1	$ 25.50		$ 2.00		$ 0.00142	$ 0.00002	$ 0.01039	8
9	LGS-1	1	15.80	$ 4.25	5.75		0.00142	0.00002	0.00308	9
10	LGS-2S		122.40	2.75	12.25		0.00142	0.00002	0.00455	10
11	LGS-2P		207.70	2.80	54.25		0.00142	0.00002	0.00516	11
12	LGS-2T	2	182.00	0.90	88.50		0.00142	0.00002	0.00308	12
13	LGS-3S		122.00	2.75	15.00		0.00142	0.00002	0.00531	13
14	LGS-3P		214.10	2.60	67.75		0.00142	0.00002	0.00643	14
15	LGS-3T	2	182.00	0.90	88.50		0.00142	0.00002	0.00283	15
16	LGS-XS	3	4,743.00	2.25	16.80	$ 1,802.00	0.00142	0.00002	0.00531	16
17	LGS-XP	3	4,743.00	3.05	53.90	$ 53,727.00	0.00142	0.00002	0.00643	17
18	LGS-XT	3	4,743.00	na	91.90	$ 30,724.00	0.00142	0.00002	0.00283	18
19	LGS-2S-WP		128.70	1.10	12.25		0.00142	0.00002	0.01552	19
20	LGS-2P-WP		208.60	1.55	54.25		0.00142	0.00002	0.00792	20
21	LGS-2T-WP	2	169.10	0.90	92.00		0.00142	0.00002	0.01021	21
22	LGS-3S-WP		149.90	1.25	15.00		0.00142	0.00002	0.00869	22
23	LGS-3P-WP		234.20	1.00	67.75		0.00142	0.00002	0.00774	23
24	LGS-3T-WP	2	189.10	0.90	88.50		0.00142	0.00002	0.01021	24
25	SL	4					0.00142	0.00002		25
26	GS-Pal	4					0.00142	0.00002		26

Line No.	Item		Rate	Unit	Line No.
27					27
28	Additional Charges:				28
29	Separate Billing				29
30	DOS LGS-X & LGS-WP-X:	$	12.00	Per additional bill	30
31	Power Factor Charges ($/kVarh)[5]:				31
32	Summer:	$	0.00200	$/kVarh	32
33	Winter:		0.00100	$/kVarh	33
34	Non-X class Customer Specific Facilities:		0.00325	Per $ of Utility Investment	34
35			0.00059	$ per Customer Contributed Investment	35
36	R-BTER - 2016 charge ($/kWh)[6]:		0.00139		36
37	R-BTER - 2017 charge ($/kWh)[6]:		0.00095		37
38	DECOM REV				38

(1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

(2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

(3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

(4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

(5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

Nevada Power Company
Statement O

Summary of Incremental Price (IP) Generation Capacity Rates

Line No.	Class[1]	Sales (kWh)	Marginal Generation Revenue	Reconciled Generation Cost per kWh[2]	Line No.
8	**Bundled Service**				8
9	GS	612,055,143	$ 12,257,947	$ 0.02003	9
10	LGS-1	4,073,133,716	92,426,501	0.02269	10
11	LGS-2S	2,429,180,261	49,316,886	0.02030	11
12	LGS-2P	69,583,297	1,210,853	0.01740	12
13	LGS-2T	no customers	(set @ LGS-3T)	0.04382	13
14	LGS-3S	768,658,032	14,196,032	0.01847	14
15	LGS-3P	1,393,295,183	33,325,718	0.02392	15
16	LGS-3T	247,665,929	10,852,498	0.04382	16
17	LGS-XS	0	(set @ LGS-3S)	0.01847	17
18	LGS-XP	0	(set @ LGS-3P)	0.02392	18
19	LGS-XT	0	(set @ LGS-3T)	0.04382	19
20	LGS-2S-WP	14,877,558	251,747	0.01692	20
21	LGS-2P-WP	11,147,772	132,430	0.01188	21
22	LGS-2T-WP	no customers	(set @ LGS-3T)	0.04382	22
23	LGS-3S-WP	4,412,814	27,462	0.00622	23
24	LGS-3P-WP	19,004,483	144,607	0.00761	24
25	LGS-3T-WP	no customers	(set @ LGS-3T)	0.04382	25
26	SL	129,054,441	2,132,971	0.01653	26
27	GS-Pal	2,217,456	37,332	0.01684	27
28	IAIWP	no customers	(set @ LGS-3S)	0.02269	28
29					29
30	**Current LSR & Optional/Trial TOU Classes with Customers:**				30
31	LSR-1: LGS-2S		(set @ LGS-2S)	0.02030	31
32	LSR-1: LGS-2P		(set @ LGS-2P)	0.01740	32
33	LSR-1: LGS-2T		(set @ LGS-2T)	0.04382	33
34	LSR-2: LGS-3P		(set @ LGS-3P)	0.01847	34
35	LSR-2: LGS-3T		(set @ LGS-3T)	0.04382	35
36	LSR-2: LGS-3S-WP		(set @ LGS-3S-WP)	0.00622	36
37	LSR-2: LGS-3P-WP		(set @ LGS-3P)	0.00761	37
38	LSR-2: LGS-2S-WP		(set @ LGS-2S)	0.01692	38
39	OGS-TOU		(set @ GS)	0.02003	39
40	OLGS-1-TOU		(set @ LGS-1)	0.02269	40
41					41
42	**DOS Classes:**				42
43	DOS: GS		(set @ GS)	0.02003	43
44	DOS: LGS-1		(set @ LGS-1)	0.02269	44
45	DOS: LGS-2S		(set @ LGS-2S)	0.02030	45
46	DOS: LGS-3S		(set @ LGS-3S)	0.01847	46
47	DOS: LGS-3P		(set @ LGS-3P)	0.02392	47
48	DOS: LGS-3T		(set @ LGS-3T)	0.04382	48
49	DOS: LGS-2S-WP		(set @ LGS-2S-WP)	0.01692	49
50	DOS: LGS-2T-WP		(set @ LGS-2T-WP)	0.04382	50
51	DOS: LGS-3S-WP		(set @ LGS-3S-WP)	0.00622	51
52	DOS: LGS-3P-WP		(set @ LGS-3P-WP)	0.00761	52
53	DOS: LGS-3T-WP		(set @ LGS-3T-WP)	0.04382	53

1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions.
   For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table.
2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class.

Reconciliation factor is: 112.5%

Line No.		Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
	Customer Specific Facility Investment & Revenue Requirement					Total			
7	Investment Cost for all Transmission level customers					$ 42,182,585			7
8	Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment					$ 3,293,268			8
9	Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7)					$ 0.07807			9
10	Distribution Reconciliation Factor					62.3%			10
11	Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10)					$ 0.03896			11
12									12
13	**CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above**								13
16	Individual CSFC	Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	16
17	LHOIST	LGS-3T	Bundled	$ 744,171	$ 0.03896	$ 29,023	$ 0.00325	$ 2,418.56	17
18	SA RECYCLING	LGS-3T	Bundled	1,366,297	0.03896	53,286	0.00325	4,440.47	18
19	VENETIAN	LGS-3T	Bundled	6,606,728	0.03896	257,662	0.00325	21,471.87	19
20	HOLDER	LGS-3T	Bundled	2,136,118	0.03896	83,309	0.00325	6,942.38	20
21	SNWA LAMB	LGS-3T	DOS	286,690	0.03896	11,181	0.00325	931.74	21
22	SNWA LAMB	LGS-3T	DOS	286,690	0.03896	11,181	0.00325	931.74	22
23	SNWA SLOAN	LGS-3T	DOS	697,203	0.03896	27,191	0.00325	2,265.91	23
24	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03896	24,254	0.00325	2,021.17	24
25	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03896	24,254	0.00325	2,021.17	25
26	CCWRD2	LGS-3T	DOS	110,617	0.03896	4,314	0.00325	359.50	26
27	CCWRD2	LGS-3T	DOS	62,534	0.03896	2,439	0.00325	203.24	27
28	CCWRD2	LGS-3T	DOS	693,608	0.03896	27,051	0.00325	2,254.23	28
29	MGM	LGS-3T	DOS	22,571,345	0.03896	880,282	0.00325	73,356.87	29
30	MGM	LGS-3T	DOS	1,434,005	0.03896	55,926	0.00325	4,660.52	30
31	CAESAR'S	LGS-3T	DOS	1,025,601	0.03896	39,998	0.00325	3,333.20	31
32	AIR LIQUIDE	LGS-3T	DOS	96,488	0.03896	3,763	0.00325	313.59	32
33	SNWA PP4	LGS-3T-WP	DOS	30,192	0.03896	1,177	0.00325	98.12	33
34	SNWA PP5	LGS-3T-WP	DOS	1,370,352	0.03896	53,444	0.00325	4,453.64	34
35	SNWA PP6	LGS-3T-WP	DOS	672,178	0.03896	26,215	0.00325	2,184.58	35
36	SNWA HACIENDA	LGS-3T-WP	DOS	327,114	0.03896	12,757	0.00325	1,063.12	36
37	SNWA PP3	LGS-2T-WP	DOS	420,860	0.03896	16,414	0.00325	1,367.80	37
38	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	1,891,817	0.03896	73,781	0.00325	6,148.41	38
39	NP RED ROCK LLC	OLGS-3P HLF	Bundled	814,244	0.03896	31,756	0.00325	2,646.29	39
40	POLY-WEST INC	OLGS-3P HLF	Bundled	275,872	0.03896	10,759	0.00325	896.58	40
41	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	376,661	0.03896	14,690	0.00325	1,224.15	41
42	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	951,162	0.03896	37,095	0.00325	3,091.28	42
43	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	488,832	0.03896	19,064	0.00325	1,588.70	43
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	628,800	0.03896	24,523	0.00325	2,043.60	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	623,669	0.03896	24,323	0.00325	2,026.92	45
46	POLY-WEST 2089379	OLGS-3P HLF	Bundled	275,872	0.03896	10,759	0.00325	896.58	46
47									47
48									48
49									49
50									50
51	Subtotals by Class and Service								51
52	LGS-3T - Bundled	LGS-3T	Bundled	$ 10,853,314	0.03896	423,279	0.00325	35,273	52
53	LGS-3T - DOS	LGS-3T	DOS	28,508,575	0.03896	1,111,834	0.00325	92,653	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	0.03896	-	0.00325	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	420,860	0.03896	16,414	0.00325	1,368	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	0.03896	-	0.00325	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	2,399,836	0.03896	93,594	0.00325	7,799	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	6,326,928	0.03896	246,750	0.00325	20,563	58
59					avg.		avg.		59
60	Total			$ 48,509,514	0.03900	$ 1,891,871	0.00325	$ 157,656	60
61					rounding>>	$ 0		$ 0	61
62	**Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)**						^^^^^^^^^^^^^		62
63							Proposed		63
64	Investment Cost for Transmission level customers:					$ 42,182,585	Tariff Recovery		64
65	Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 64 * line 11):					$ 3,293,268	Rate per Dollar		65
66	Distribution Reconciliation Factor (line 11):					62.3%	of Facility		66
67	Reconciled Investment Cost (line 66 * line 65):					$ 2,052,134	Investment		67
68	Annual facility kW determinants					2,270,623			68
69	Per kW facilty rate (line 67 / Line 68)					$ 0.90			69

Nevada Power Company

Statement O

Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Line No.	Development of Annual & Monthly Per Dollar of Investment Recovery Rate						Line No.
7		(a)	(b)		(c)		7
8	Annual: Dist Reconciliation Factor	x	Dollar O&M/A&G Recovery Per Dollar of Contributed Investment				8
9	62.3%	x	$0.01062	=	$	0.00662	9
10	Monthly: (annual rate divided by 12)			=	$	0.00059	10
11							11
12							12

Line No.	CIAC Investment & O&M and A&G Revenue Requirement					Dollar Per Dollar of Investment $ (cost based -- before reconciliation)	Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer				Line No.
16	Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	[(b) / (a)]	Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment	16
17											17
18	LHOIST	LGS-3T	Bundled	-	$ -	$0.01062	$ -	$ 0.00059	$ -	$ -	18
19	SA RECYCLING	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	19
20	VENETIAN	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	20
21	HOLDER	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	21
22	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	22
23	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	23
24	SNWA SLOAN	LGS-3T	DOS	826,580	8,780	$0.01062	826,580	0.00059	487.68	5,852.16	24
25	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	25
26	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	26
27	CCWRD2	LGS-3T	DOS	374,615	3,979	$0.01062	374,615	0.00059	221.02	2,652.24	27
28	CCWRD2	LGS-3T	DOS	211,779	2,249	$0.01062	211,779	0.00059	124.95	1,499.40	28
29	CCWRD2	LGS-3T	DOS	2,348,976	24,950	$0.01062	2,348,976	0.00059	1,385.90	16,630.80	29
30	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	30
31	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	31
32	CAESAR'S	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	32
33	AIR LIQUIDE	LGS-3T	DOS	4,942,256	52,495	$0.01062	4,942,256	0.00059	2,915.93	34,991.16	33
34	SNWA PP4	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	34
35	SNWA PP5	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	35
36	SNWA PP6	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	36
37	SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	37
38	SNWA PP3	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	38
39	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	39
40	NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	40
41	POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	41
42	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	42
43	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	43
44	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	45
46	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	46
47	POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	47
48											48
49											49
50											50
51	Subtotals by Class and Service										51
52	LGS-3T - Bundled	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	52
53	LGS-3T - DOS	LGS-3T	DOS	11,993,826	127,395	$0.01062	11,993,826	0.00059	7,076.36	84,916.32	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,100	$0.01062	103,546	0.00059	61.09	733.08	58
59											59
60	Total			$ 19,321,217	$ 205,224	$0.01062	$ 38,642,434		$ 11,399.52	$ 136,794.24	60
61						Marginal O&M from MCS					61
62						$205,224					62

Calculation of LGS-X Specific Charges

Line No.		Basic Service Charge: Billing Units	Basic Service Charge: Cost-Based Revenue	Basic Service Charge: Rate	Additional Meter Charge: Billing Units	Additional Meter Charge: Cost-Based Revenue	Additional Meter Charge: Rate	Separate Bill: Billing Units	Separate Bill: Cost-Based Revenue	Separate Bill: Rate	Line No.
7	**Basic Service, Additional Meter and Separate Billing Charges**										7
8			Dist Recon.	62%							8
11	LGS-XS	-	$ -		60	$ 1,005.30	$ 16.80	-	$ -		11
12	LGS-XP	24	$ 29,102.86	$ 1,212.62	156	$ 8,404.55	$ 53.90	24	$ 271.52	$11.31	12
13	LGS-XT	12	$ 14,551.43	$ 1,212.62	36	$ 3,307.63	$ 91.90	12	$ 135.76	$11.31	13
14	Total	36	$ 43,654.29	**$4,743.00**	252	$ 12,717.48	**$50.50**	36	$ 407.28	**$12.00**	14
15			Present DOS Rate:	$4,743.00					Present Rate:	$93.50	15
16			Percent Change:	0.0%					Percent Change:	-87.2%	16

18 **LGS-X Customer Specific Facilities**

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment	Line No.
22	Horseshoe	1231089	LGS-XP DOS	$ 3,740	$ 44,880		$ 4,191	$ 50,292		22
23	Horseshoe	1231091	LGS-XS DOS	1,608	19,296		1,802	21,624		23
24	Paris	1735149	LGS-XP DOS	5,068	60,816		5,679	68,148		24
25	Paris	1735152	LGS-XP DOS	5,068	60,816		5,679	68,148		25
26				$ 15,484	$ 185,808	$ 2,066,291	$ 17,351	$ 208,212	$ 2,189,516	26
34	New Castle Corp (Excalibur)	1396169	LGS-XP DOS	$ 4,710	$ 56,520		$ 5,006	$ 60,072		34
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	4,687	56,244		4,981	59,772		35
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-		36
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-		37
38	Luxor	1500684	LGS-XP DOS	5,640	67,680		5,994	71,928		38
39	Luxor	1500685	LGS-XP DOS	7,006	84,072		7,446	89,352		39
40	Luxor	1511139	LGS-XS DOS	-	-		-	-		40
41	Luxor	1652129	LGS-XP DOS	1,698	20,376		1,805	21,660		41
42	Mandalay Bay	1714502	LGS-XP DOS	6,090	73,080		6,473	77,676		42
43	Mandalay Bay	1714503	LGS-XP DOS	6,090	73,080		6,473	77,676		43
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-		44
45				$ 35,921	$ 431,052	$ 4,885,159	$ 38,178	$ 458,136	$ 4,885,159	45
47	Park MGM	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -		47
48	Park MGM	1607750	LGS-XT DOS	9,790	117,480		10,335	124,020		48
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-		49
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-		50
51	Bellagio	1693991	LGS-XT DOS	19,315	231,780		20,389	244,668		51
52	Park MGM	1782548	LGS-XP DOS	-	-		-	-		52
53				$ 29,105	$ 349,260	$ 3,841,860	$ 30,724	$ 368,688	$ 3,841,860	53
55		Subtotals by Class and Service	LGS-XS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	55
56			LGS-XP	-	-	-	-	-	-	56
57			LGS-XT	-	-	-	-	-	-	57
58			LGS-XS DOS	**1,608**	**19,296**	-	**1,802**	**21,624**	-	58
59			LGS-XP DOS	**49,797**	**597,564**	-	**53,727**	**644,724**	-	59
60			LGS-XT DOS	**29,105**	**349,260**	-	**30,724**	**368,688**	-	60
61			Total for Class	**$ 80,510**	**$ 966,120**	**$ -**	**$ 86,253**	**$ 1,035,036**	**$ -**	61

63 Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying Investment has remained the same), and allocating the Primary Charges in proportion to the current Primary charges.

EXHIBIT PREST DIRECT - 6

Nevada Power Company

Exhibit Prest Direct-6

Docket No. 23-06XXX

Statement O

MCS, per NRS, Current TOU, Joint Dispatch, RS Cap

Nevada Power Company
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Page 1 **Comparison of Present, Cost-Based and Proposed Rate Class Revenue**

Page 2 **Revenue Requirement from Schedule H-2, Unbundled Cost of Service Study**

- The unbundled revenue requirement from Statement H is the starting point for deriving what is known to be the revenue target for rate design.
- The following adjustments are made to the Schedule H revenue requirement on this page:
  1) The proposed revenues for the standby (LSR & SSR), Optional TOU and DOS classes are derived from rates that are developed for the otherwise applicable class; thus, the resulting standby revenues are credited against the Schedule H revenue requirement, and the standby classes are excluded from the revenue reconciliation on page 3 and the capping mechanism (page 8).
  2) Power Factor and Additional Facilities and Maintenance revenues are credited against the distribution revenue requirement, and then in the revenue reconciliation process (page 3) they are assigned to specific classes that impose these costs.

Pages 3-7 **Revenue Reconciliation and Revenue Adjustments for Rate Design**

- Reconciles the Marginal Revenue by class to the Adjusted, Unbundled Revenue Requirement for Rate Design using Equal Percent of Marginal Cost (EPMC). The marginal revenue, by function and class, comes directly from the Marginal Cost Study (MCS), and is shown on page 2 of Workpaper 1. The unbundled revenue requirement comes from the Unbundled Schedule H and is summarized on line no. 11, page 1 of Statement O. The adjustments to the revenue requirement are summarized below.
- Reconcile Distribution & Transmission by Function using EPMC: Distribution Marginal Revenue to Distribution Revenue Requirement, and Transmission to Transmission.
- Reconcile Generation and Energy functions combined together on EPMC.

Revenue Adjustments made to the Reconciliation:

<u>Distribution</u>

1) Certain “other revenue” components (miscellaneous revenues (connect/disconnect), returned check, power pedestal, and miscellaneous damage) have been credited to the specific classes in which they are generated, consistent with the Commission’s Order in Docket No. 01-10001, which was first implemented in Docket No. 03-10001. They are included in the total DRR that is reconciled, then subtracted from (i.e., credited to) the reconciled distribution revenue requirements of the specific classes that paid them. Thus classes that pay for the services get the benefit through the direct assignment to those classes. These “other revenues” total approximately $4,946.4 million.
2) Revenue from Power Factor services and Additional Facilities and Maintenance (AF&M) services are subtracted (credited to) the DRR on page 7, then get directly assigned to the classes identified with these costs in the reconciliation.

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Generation and Energy

5) The combined generation and energy revenue requirement (G&ERR) is increased by the amount of the credit given to the LGS-3T class on the BTER portion of WAPA energy deliveries associated with one customer included in the class for reconciliation purposes. The credit is then specifically assigned to (or subtracted from) the LGS-3T's reconciled G&E RR. The current WAPA energy credit is $1098.6 thousand.
6) Also, the G&ERR is increased by the amount of the Hoover B Benefit provided to the residential class. The amount of the benefit is then specifically assigned to (or subtracted from) the residential classes' G&ERR based on their relative share of residential kWh sales. The current Hoover B Benefit is $14.2 million.

Standby, Optional Time-of Use, DOS and Other Revenue Credit Adjustments

7) Standby (SSR & LSR) and Optional Time-of-Use (TOU) services have rates that are set off of the otherwise applicable classes marginal costs and/or rates. Accordingly the test period revenues generated by these schedules are treated as credits to proportionately reduce the generation, transmission and distribution revenue requirements on page 4, thereby reducing the revenue requirement and rates for all customers. The total of these revenue credits is approximately -$12.1 million.
8) DOS revenues are treated in a manner analogous to standby and optional TOU service revenues, as DOS distribution rates and non-bypassable charges are set using the otherwise applicable bundled schedule (OAS). The DOS revenues are credited against the revenue requirement, reducing rates for all customers. All DOS revenues, except the non-bypassable interclass rate rebalancing (IRR) revenues, are credited to the DRR. The IRR revenues are credited proportionately to reduce the generation, transmission and distribution revenue requirements on pages 3-7. The current DOS revenue is $31.7 million.

Page 8 **Final Revenue Allocation: Final Class Revenue Requirements Based on Maximum Percent Increase (Capping) and unrestricted floor Mechanism as follows:**

Subject to the caps set forth above:

1) The difference between any capped class revenue and its cost based revenue is re-allocated to other classes using EPMC;
2) Two allocations using the above procedure are required to reach the final revenue requirements that satisfy the imposed capping criteria;
3) The reallocation creates an interclass subsidy, which is the difference between the final revenue requirement shown on this page, and the cost-based revenue requirement resulting from the reconciliation process (page 3-7). If the difference between these two values for any class is negative, then the class is receiving a subsidy from other classes; if the value is positive, then the class is providing a subsidy to other classes.

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Comparison of Present, Cost-based and Proposed Rate Revenue ($000s)

Line No	Class	Note	Annualized Bills	Sales (MWh)	Present Rate Revenue: Revenue	Present Rate Revenue: Effective Rate ($/kWh)	Results if Class Revenue Requirements were Set @ Reconciled Cost [1]: Cost-Based Revenue	% Change from Present	Effective Rate ($/kWh)	Class Revenue Requirements Based on Proposed Capping Methodology [2]: Proposed Rate Revenue	Difference from Cost	Change from Present Rate Revenue	% Change from Present	Effective Rate ($/kWh)	Combined AB 405 Proposed Revenue Change: % Change from Present	Effective Rate ($/kWh)	Line No
8																	8
9	Classes in Revenue Reconciliation																9
10	RS		6,219,660	7,262,589	$ 1,124,472	$ 0.15483	$ 1,129,319	0.43%	$ 0.15550	$ 1,148,240	$ 18,921	$ 23,768	2.11%	$ 0.15810	2.38%	$ 0.15235	10
11	RM		3,424,968	2,298,671	339,331	0.14762	322,587	-4.93%	0.14034	340,219	17,631	888	0.26%	0.14801	0.26%	0.14795	11
12	LRS		2,484	37,526	5,291	0.14099	4,912	-7.15%	0.13091	5,260	347	(31)	-0.59%	0.14016	-0.50%	0.14060	12
13	GS		931,320	612,056	83,497	0.13642	76,775	-8.05%	0.12544	82,579	5,804	(918)	-1.10%	0.13492	-1.10%	0.13471	13
14	LGS-1		385,308	4,073,470	485,467	0.11918	476,646	-1.82%	0.11701	493,884	17,238	8,417	1.73%	0.12124	1.75%	0.12116	14
15	LGS-2S		14,676	2,437,061	271,383	0.11136	262,269	-3.36%	0.10762	273,785	11,515	2,401	0.88%	0.11234			15
16	LGS-2P		276	69,583	7,301	0.10492	6,974	-4.47%	0.10023	7,331	356	30	0.41%	0.10535			16
17	LGS-2T	3	-	-	-	---	-	na	---	-	-	-	na	---			17
18	LGS-3S		1,392	768,658	82,792	0.10771	79,077	-4.49%	0.10288	83,119	4,043	328	0.40%	0.10814			18
19	LGS-3P	4	1,332	1,826,673	195,666	0.10712	184,115	-5.90%	0.10079	195,229	11,114	(437)	-0.22%	0.10688			19
20	LGS-3T	4	48	618,671	59,254	0.09578	58,062	-2.01%	0.09385	60,125	2,063	871	1.47%	0.09718			20
21	LGS-XS		-	-	-	---	-	na	---	-	-	-	na	---			21
22	LGS-XP		-	-	-	---	-	na	---	-	-	-	na	---			22
23	LGS-XT		-	-	-	---	-	na	---	-	-	-	na	---			23
24	LGS-2S-WP		276	14,878	1,343	0.09025	1,576	17.40%	0.10596	1,750	173	407	30.30%	0.11760			24
25	LGS-2P-WP		108	11,148	1,123	0.10073	1,030	-8.26%	0.09241	1,108	78	(15)	-1.34%	0.09938			25
26	LGS-2T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			26
27	LGS-3S-WP		24	4,413	372	0.08426	405	8.90%	0.09176	434	29	62	16.69%	0.09833			27
28	LGS-3P-WP		72	19,004	1,742	0.09168	1,584	-9.07%	0.08337	1,715	131	(27)	-1.57%	0.09024			28
29	LGS-3T-WP	5	-	-	-	---	-	na	---	-	-	-	na	---			29
30	SL		7,224	129,054	11,437	0.08862	14,537	27.10%	0.11264	16,719	2,183	5,282	46.18%	0.12955			30
31	RS-Pal		-	578	85	0.14730	95	11.86%	0.16477	103	8	18	21.52%	0.17899			31
32	GS-Pal		-	2,217	305	0.13751	348	14.25%	0.15710	382	34	77	25.37%	0.17240			32
33	IAIWP	3	-	-	-	---	-	na	---	-	-	-	na	---			33
34	RS-NEM	6	962,904	837,375	80,923	0.16928	175,023	116.28%	0.20901	85,821	(89,202)	4,898	6.05%	0.17952			34
35	RM-NEM	6	5,652	3,554	397	0.15278	768	93.60%	0.21600	399	(369)	2	0.61%	0.15371			35
36	LRS-NEM	6	204	571	92	0.16155	115	24.50%	0.20145	97	(18)	4	4.65%	0.16907			36
37	GS-NEM	6	1,548	2,985	275	0.11395	504	83.15%	0.16901	272	(233)	(4)	-1.32%	0.11245			37
38	LGS-1 NEM	6	4,248	79,974	9,100	0.12410	11,343	24.64%	0.14183	9,342	(2,000)	242	2.66%	0.12740			38
39																	39
45	Partial Requirements & Optional Schedule Groups not included in Reconciliation																45
46	Optional TOU		66,924	447,300	48,258	0.10789	nc	nc	nc	48,419	nc	161	0.33%	0.10825	---	---	46
47	Optional TOU EVRR		38,052	65,465	8,716	0.13314	nc	nc	nc	8,758	nc	42	0.48%	0.13377			47
48	NEM Optional TOU		12,331	7,602	1,090	0.14340	nc	nc	nc	1,160	nc	70	6.38%	0.15255	---	---	48
49	NEM EVRR		15,156	14,179	1,759	0.12403	nc	nc	nc	1,783	nc	24	1.36%	0.12572			49
50	Standby		240	146,311	15,217	0.10400	nc	nc	nc	15,634	nc	417	2.74%	0.10686	---	---	50
51	EVCCR		156	14,835	1,829	0.12331	nc	nc	nc	1,815	nc	(14)	-0.78%	0.12235			51
52	DOS	7	1,980	2,810,428	15,394	0.00548	nc	nc	nc	31,688	nc	16,293	105.84%	0.01128	---	---	52
53																	53
54	Total (Bundled & DOS)		12,094,315	23,793,360	$ 2,805,178	$ 0.11790	$ 2,796,724	na[1]	nc	$ 2,871,987	---	$ 66,808	2.38%	$ 0.12071	2.38%	$ 0.12071	54

$ 2,871,796	Statement I Revenue Requirement	
$ 66,808	Change in Revenue Requiremen	$ 191
2.38%	Percent Change	

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.
2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 7 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.
3. No Customers in class
4. Cost-based revenue requirement for LGS-3P includes OLGS-3P HLF customers billed under the OAS. Additionally, one partial requirements LSR-2 LGS-3P and LSR-2 LGS-3T customer are included as explained in rate design testimony. The results shown here include these customers.
5. All customers in class are DOS customers; no bundled customers.
6. Class level information presented here includes all customers under NMR-G and NMR-A rate schedules. NEM class effective rates for cost-based revenue are based on delivered loads. Present rate and proposed rate revenue are calculated using delivered kWh sales for NMR-A customers and net-billed kWh sales for NMR-G customers.
7. The effective rate for DOS customers is only for distribution rates, and does not consider OATT and energy rates.

Nevada Power Company

Statement O

Exhibit Prest Direct-6

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MCS, per NRS, Current TOU, Joint Dispatch, RS Cap

Unbundled Revenue Requirement and Rate Design Adjustments ($000's)

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Line No.		Note	Total	Energy	Generation	Transmission	Distribution	Line No.
8								8
9	Marginal Cost Revenue		$ 2,099,805	$ 781,113	$ 524,669	$ 113,276	$ 680,747	9
10								10
11	Unbundled Revenue Requirement	1	$ 2,871,796	$ 1,718,820	$ 562,479	$ 150,868	$ 439,629	11
12						Total G, T & D	$ 1,152,976	12
13	Total Revenue Requirement Adjustments for Rate Design							13
14	Revenue Credit to Dist. for Specific Class Assignment							14
15	Power Factor (PF)		(917)				(917)	15
16	Additional Facilities and Maintenance (AF&M)		(71)				(71)	16
17								17
18	Optional TOU Revenue		(33,245)	(21,873)	(5,548)	(1,488)	(4,336)	18
19	Optional TOU NEM revenues		(2,942)	(1,833)	(541)	(145)	(423)	19
20	Standby Customer Revenue (Inc. Part Req. Customers)	2	(3,207)	(1,697)	(737)	(198)	(576)	20
21	DOS BTGR Revenue (exc. IRR and Impact Fees)	3	-				-	21
22	DOS SB123 Revenue		(800)		(800)			22
23	DOS Interclass Rate-Rebalancing Revenue		(15,067)		(7,351)	(1,972)	(5,745)	23
24	OLGS-3P HLF & MPE Rate Design Revenue adjustment		686	-	335	90	262	24
25	MPE Revenue Adjustment		6,301	3,972	2,328			25
26	EVCCR Discount Revenue Adjustment		-		-	-		26
27	Total		$ (49,264)	$ (21,430)	$ (12,313)	$ (3,713)	$ (11,808)	27
28								28
29	Class Specific Revenue Requirement Adjustments							29
30	Other Revenue	4	5,368				5,368	30
31	Customer Specific Facilities		(2,801)				(2,801)	31
32	DOS Impact Fee revenue		(1,392)	(511)	(881)			32
33	BTER Energy Credits (WAPA, Hoover B)		(15,258)	(15,258)				33
34	Total Class Specific Adjustments		$ (14,082)	$ (15,769)	$ (881)	$ -	$ 2,567	34
35								35
36	Total Adjustments to Total Revenue Requirement		$ (63,346)	$ (37,199)	$ (13,194)	$ (3,713)	$ (9,240)	36
37								37
38	Target Revenue Requirement for Rate Design		$ 2,808,449	$ 1,342,722	$ 903,360	$ 147,156	$ 427,021	38
39								39

42 1. Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing) 42

43 2. Includes LSR revenues and optional time-of-use revenues. 43

44 3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues. 44

45 4. Other Revenue include misc. revenues, returned check, power pedestal, and misc. damage revenues. 45

46 5. Revenue are based on reconciled cost-based revenues used for rate design and include standard flat-rate NEM customers using NMR-A rate structure. 46

Nevada Power Company

Statement O

Transmission Revenue by Class for Rate Design

Line No.	Class	Unreconciled Cost-Based Transmission Revenue	Percent of Total	Reconciled Transmission Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Transmission Cost Based Class Revenue for Rate Design	Line No.
8															8
9	RS	$ 50,290	44.40%	$ 66,979	$ (661)	$ (64)	$ (88)	$ -	$ (875)	$ 40	$ -	$ -	$ -	$ 65,331	9
10	RM	13,041	11.51%	17,369	(171)	(17)	(23)	-	(227)	10	-	-	-	16,942	10
11	LRS	214	0.19%	285	(3)	(0)	(0)	-	(4)	0	-	-	-	278	11
12	GS	2,580	2.28%	3,436	(34)	(3)	(5)	-	(45)	2	-	-	-	3,352	12
13	LGS-1	18,303	16.16%	24,377	(240)	(23)	(32)	-	(319)	15	-	-	-	23,777	13
14	LGS-2S	9,411	8.31%	12,535	(124)	(12)	(16)	-	(164)	7	-	-	-	12,226	14
15	LGS-2P	225	0.20%	299	(3)	(0)	(0)	-	(4)	0	-	-	-	292	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	2,634	2.33%	3,509	(35)	(3)	(5)	-	(46)	2	-	-	-	3,422	17
18	LGS-3P	6,138	5.42%	8,175	(81)	(8)	(11)	-	(107)	5	-	-	-	7,974	18
19	LGS-3T	2,009	1.77%	2,676	(26)	(3)	(4)	-	(35)	2	-	-	-	2,610	19
20	LGS-XS	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	59	0.05%	79	(1)	(0)	(0)	-	(1)	0	-	-	-	77	23
24	LGS-2P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	14	0.01%	19	(0)	(0)	(0)	-	(0)	0	-	-	-	19	26
27	LGS-3P-WP	28	0.02%	37	(0)	(0)	(0)	-	(0)	0	-	-	-	36	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	94	0.08%	126	(1)	(0)	(0)	-	(2)	0	-	-	-	122	29
30	RS-Pal	0	0.00%	0	(0)	(0)	(0)	-	(0)	0	-	-	-	0	30
31	GS-Pal	1	0.00%	1	(0)	(0)	(0)	-	(0)	0	-	-	-	1	31
32	IAIWP	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	7,646	6.75%	10,183	(100)	(10)	(13)	-	(133)	6	-	-	-	9,933	33
34	RM-NEM	36	0.03%	48	(0)	(0)	(0)	-	(1)	0	-	-	-	47	34
35	LRS-NEM	4	0.00%	5	(0)	(0)	(0)	-	(0)	0	-	-	-	5	35
36	GS-NEM	20	0.02%	27	(0)	(0)	(0)	-	(0)	0	-	-	-	26	36
37	LGS-1-NEM	500	0.44%	666	(7)	(1)	(1)	-	(9)	0	-	-	-	650	37
38															38
39	TOTAL	$ 113,276	100.00%	$ 150,868	$ (1,488)	$ (145)	$ (198)	$ -	$ (1,972)	$ 90	$ -	$ -	$ -	$ 147,156	39
40				from Sch. H-2											40
41															41
42															42
43															43
44	Summation of NEM customers into Standard Schedule for Rate Design														44
45	RS	$ 57,936	51.15%	$ 77,163	$ (761)	$ (74)	$ (101)	$ -	$ (1,008)	$ 46	$ -	$ -	$ -	$ 75,264	45
46	RM	13,077	11.54%	17,417	(172)	(17)	(23)	-	(228)	10	-	-	-	16,988	46
47	LRS	218	0.19%	290	(3)	(0)	(0)	-	(4)	0	-	-	-	283	47
48	GS	2,600	2.30%	3,463	(34)	(3)	(5)	-	(45)	2	-	-	-	3,378	48
49	LGS-1	18,803	16.60%	25,043	(247)	(24)	(33)	-	(327)	15	-	-	-	24,427	49
50															50

Line No.	Class	Unreconciled Cost-Based Distribution Revenue	Percent of Total	Class Specific Adjustments: Other Revenue Adjustment	Class Specific Adjustments: Adjustment for Class Cust Spec. Facilities	Reconciled Distribution Revenue Requirement	Rate Design Revenue Adjustments: Power Factor Revenue	Additional Facilities & Maintenance Revenue	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Decommissioning Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	MPE Revenue Adjustment	EVCCR Discount Revenue Adjustment	Distribution Cost Based Class Revenue for Rate Design	Line No.
8																			8
9	RS	$ 340,143	50.17%	$ (2,192)		$ 219,670	$ (460)	$ (36)	$ (2,176)	$ (212)	$ (289)	$ -	$ (401)	$ (2,883)	$ 131	$ -	$ -	$ 213,344	9
10	RM	82,009	12.10%	(2,237)		51,254	(111)	(9)	(525)	(51)	(70)	-	(97)	(695)	32	-		49,729	10
11	LRS	995	0.15%	(0)		649	(1)	(0)	(6)	(1)	(1)	-	(1)	(8)	0	-		630	11
12	GS	25,022	3.69%	(235)		16,086	(34)	(3)	(160)	(16)	(21)	-	(30)	(212)	10	-		15,621	12
13	LGS-1	87,187	12.86%	(77)		56,791	(118)	(9)	(558)	(54)	(74)	-	(103)	(739)	34	-		55,170	13
14	LGS-2S	34,537	5.09%	(2)		22,525	(47)	(4)	(221)	(22)	(29)	-	(41)	(293)	13	-		21,883	14
15	LGS-2P	856	0.13%	(0)		558	(1)	(0)	(5)	(1)	(1)	-	(1)	(7)	0	-		542	15
16	LGS-2T	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-		-	16
17	LGS-3S	9,596	1.42%	(0)		6,259	(13)	(1)	(61)	(6)	(8)	-	(11)	(81)	4	-		6,080	17
18	LGS-3P	30,333	4.47%	(0)	-	19,785	(41)	(3)	(194)	(19)	(26)	-	(36)	(257)	12	-		19,221	18
19	LGS-3T	1,674	0.25%	(0)	1,657	2,749	(2)	(0)	(11)	(1)	(1)	-	(2)	(14)	1	-		2,718	19
20	LGS-XS	61	0.01%	-	22	62	(0)	(0)	(0)	(0)	(0)	-	(0)	(1)	0	-		61	20
21	LGS-XP	2,582	0.38%	-	645	2,329	(3)	(0)	(17)	(2)	(2)	-	(3)	(22)	1	-		2,281	21
22	LGS-XT	29	0.00%	-	369	388	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		387	22
23	LGS-2S-WP	336	0.05%	-		219	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		213	23
24	LGS-2P-WP	171	0.03%	-		111	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		108	24
25	LGS-2T-WP	21	0.00%	-	16	30	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		29	25
26	LGS-3S-WP	352	0.05%	-		230	(0)	(0)	(2)	(0)	(0)	-	(0)	(3)	0	-		223	26
27	LGS-3P-WP	655	0.10%	-		427	(1)	(0)	(4)	(0)	(1)	-	(1)	(6)	0	-		415	27
28	LGS-3T-WP	113	0.02%	-	93	166	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		164	28
29	SL	2,021	0.30%	(20)		1,298	(3)	(0)	(13)	(1)	(2)	-	(2)	(17)	1	-		1,261	29
30	RS-Pal	55	0.01%	(0)		36	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		35	30
31	GS-Pal	184	0.03%	(0)		120	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		116	31
32	IAIWP	-	0.00%			-	-	-	-	-	-	-	-	-	-	-		-	32
33	RS-NEM	56,780	8.38%	(595)		36,440	(77)	(6)	(363)	(35)	(48)	-	(67)	(481)	22	-		35,385	33
34	RM-NEM	193	0.03%	(9)		117	(0)	(0)	(1)	(0)	(0)	-	(0)	(2)	0	-		113	34
35	LRS-NEM	48	0.01%	(0)		31	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	0	-		30	35
36	GS-NEM	127	0.02%	(0)		83	(0)	(0)	(1)	(0)	(0)	-	(0)	(1)	0	-		80	36
37	LGS-1-NEM	1,866	0.28%	(0)		1,217	(3)	(0)	(12)	(1)	(2)	-	(2)	(16)	1	-		1,182	37
38						not a sum													38
39	TOTAL	$ 677,946	100.00%	$ (5,368)	$ 2,801	$ 439,629	$ (917)	$ (71)	$ (4,336)	$ (423)	$ (576)	$ -	$ (800)	$ (5,745)	$ 262	$ -	$ -	$ 427,021	39
40						from Sch. H-2													40
41				exc. Specific Class adjustments	$	442,196													41
42																			42
43						$ -													43
44	Summation of NEM customers into Standard Schedule for Rate Design																		44
45	RS	$ 396,923	58.55%	$ (2,786)	$ -	$ 256,110	$ (537)	$ (42)	$ (2,539)	$ (248)	$ (337)	$ -		$ (3,364)	$ 153	$ -	$ -	$ 248,729	45
46	RM	82,203	12.13%	(2,247)	-	51,371	(111)	(9)	(526)	(51)	(70)	-		(697)	32	-	-	49,842	46
47	LRS	1,043	0.15%	(0)	-	680	(1)	(0)	(7)	(1)	(1)	-		(9)	0	-	-	661	47
48	GS	25,149	3.71%	(235)	-	16,169	(34)	(3)	(161)	(16)	(21)	-		(213)	10	-	-	15,701	48
49	LGS-1	89,053	13.14%	(77)	-	58,008	(121)	(9)	(570)	(56)	(76)	-		(755)	34	-	-	56,352	49
50																			50

Line No.	Class	Unreconciled Cost-Based Generation Revenue	Percent of Total	DOS R-BTER and BTER Impact Fee Revenue	Reconciled Generation Revenue Requirement	Rate Design Revenue Adjustments: Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS BTGR Revenue (exc. IRR and Impact Fees)	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS BTGR Impact Fee Revenue	BTER Energy Credits (WAPA, Hoover B, EDRR)	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Generation Cost Based Class Revenue for Rate Design	Line No.
8																	8
9	RS	$ 226,859	43.24%	$ -	$ 395,958	$ (2,399)	$ (234)	$ (319)		$ (3,178)	$ 145	$ (381)		$ 1,007	$ -	$ 390,599	9
10	RM	63,570	12.12%	-	110,954	(672)	(66)	(89)		(891)	41	(107)		282	-	109,452	10
11	LRS	958	0.18%	-	1,672	(10)	(1)	(1)		(13)	1	(2)		4	-	1,650	11
12	GS	10,897	2.08%	-	19,020	(115)	(11)	(15)		(153)	7	(18)		48	-	18,763	12
13	LGS-1	82,168	15.66%	-	143,416	(869)	(85)	(115)		(1,151)	52	(138)		365	-	141,475	13
14	LGS-2S	43,843	8.36%	-	76,524	(464)	(45)	(62)		(614)	28	(74)		195	-	75,488	14
15	LGS-2P	1,076	0.21%	-	1,879	(11)	(1)	(2)		(15)	1	(2)		5	-	1,853	15
16	LGS-2T	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	16
17	LGS-3S	12,620	2.41%	-	22,028	(133)	(13)	(18)		(177)	8	(21)		56	-	21,730	17
18	LGS-3P	29,627	5.65%	-	51,711	(313)	(31)	(42)		(415)	19	(50)		131	-	51,011	18
19	LGS-3T	9,648	1.84%	-	16,840	(102)	(10)	(14)		(135)	6	(16)		43	-	16,612	19
20	LGS-XS	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	20
21	LGS-XP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	21
22	LGS-XT	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	22
23	LGS-2S-WP	224	0.04%	-	391	(2)	(0)	(0)		(3)	0	(0)		1	-	385	23
24	LGS-2P-WP	118	0.02%	-	205	(1)	(0)	(0)		(2)	0	(0)		1	-	203	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	25
26	LGS-3S-WP	24	0.00%	-	43	(0)	(0)	(0)		(0)	0	(0)		0	-	42	26
27	LGS-3P-WP	129	0.02%	-	224	(1)	(0)	(0)		(2)	0	(0)		1	-	221	27
28	LGS-3T-WP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	28
29	SL	1,896	0.36%	-	3,310	(20)	(2)	(3)		(27)	1	(3)		8	-	3,265	29
30	RS-Pal	9	0.00%	-	15	(0)	(0)	(0)		(0)	0	(0)		0	-	15	30
31	GS-Pal	33	0.01%	-	58	(0)	(0)	(0)		(0)	0	(0)		0	-	57	31
32	IAIWP	-	0.00%	-	-	-	-	-		-	-	-		-	-	-	32
33	RS-NEM	38,534	7.34%	-	67,257	(407)	(40)	(54)		(540)	25	(65)		171	-	66,347	33
34	RM-NEM	177	0.03%	-	309	(2)	(0)	(0)		(2)	0	(0)		1	-	304	34
35	LRS-NEM	19	0.00%	-	33	(0)	(0)	(0)		(0)	0	(0)		0	-	33	35
36	GS-NEM	96	0.02%	-	167	(1)	(0)	(0)		(1)	0	(0)		0	-	165	36
37	LGS-1-NEM	2,144	0.41%	-	3,741	(23)	(2)	(3)		(30)	1	(4)		10	-	3,691	37
38					not a sum												38
39	TOTAL	$ 524,669	100.00%	$ -	$ 562,479	$ (5,548)	$ (541)	$ (737)		$ (7,351)	$ 335	$ (881)	$ -	$ 2,328	$ -	$ 903,360	39
40					from Sch. H-2												40
41			Generation Revenue for Rate Design	$	524,669	$ (975,517)											41
42			w/ Specific Class adjustments	$	915,755	Combined											42
43																	43
44																	44
45																	45
46	Summation of NEM customers into Standard Schedule for Rate Design																46
47	RS	$ 265,393	50.58%	$ -	$ 463,215	$ (2,806)	$ (274)	$ (373)	$ -	$ (3,718)	$ 169	$ (446)	$ -	$ 1,178	$ -	$ 456,946	47
48	RM	63,746	12.15%	-	111,263	(674)	(66)	(90)	-	(893)	41	(107)	-	283	-	109,757	48
49	LRS	977	0.19%	-	1,705	(10)	(1)	(1)	-	(14)	1	(2)	-	4	-	1,682	49
50	GS	10,993	2.10%	-	19,188	(116)	(11)	(15)	-	(154)	7	(18)	-	49	-	18,928	50
51	LGS-1	84,312	16.07%	-	147,157	(892)	(87)	(118)	-	(1,181)	54	(142)	-	374	-	145,166	51
52																	52

Nevada Power Company

Statement O

Energy Revenue by Class for Rate Design

					Class Specific Adjustments		**Rate Design Revenue Adjustments**										
Line No.	Class	BTER Revenue	Unreconciled Cost-Based Energy Revenue	Percent of Total	Hoover B, EDRR, MPE and WAPA Credits	Reconciled Energy Revenue Requirement	Optional TOU Revenue	Optional TOU NEM revenues	Standby Customer Revenue	DOS Interclass Rate-Rebalancing Revenue	OLGS-3P HLF Rate Design Revenue adjustment	DOS R-BTER and BTER Impact Fee Revenue	MPE Revenue Adjustment	EVCCR Revenue Adjustment	Energy Cost Based Class Revenue for Rate Design	Excess/ Deficiency Present in BTER for Rate Design	Line No.
8																	8
9	RS	$ 611,088	$ 270,477	34.63%	$ (10,184)	$ 467,642	$ (7,574)	$ (635)	$ (588)	$ -	$ -	$ (177)	$ 1,375	$ -	$ 460,045	$ (151,043)	9
10	RM	193,415	86,098	11.02%	(3,219)	148,883	(2,411)	(202)	(187)	-	-	(56)	438	-	146,464	(46,951)	10
11	LRS	3,158	1,385	0.18%	(53)	2,394	(39)	(3)	(3)	-	-	(1)	7	-	2,355	(803)	11
12	GS	48,719	22,456	2.87%	-	39,671	(629)	(53)	(49)	-	-	(15)	114	-	39,041	(9,679)	12
13	LGS-1	324,204	147,347	18.86%	-	260,304	(4,126)	(346)	(320)	-	-	(96)	749	-	256,165	(68,039)	13
14	LGS-2S	193,969	87,960	11.26%	-	155,390	(2,463)	(206)	(191)	-	-	(58)	447	-	152,920	(41,049)	14
15	LGS-2P	5,539	2,477	0.32%	-	4,376	(69)	(6)	(5)	-	-	(2)	13	-	4,306	(1,233)	15
16	LGS-2T	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	16
17	LGS-3S	61,185	27,849	3.57%	-	49,198	(780)	(65)	(61)	-	-	(18)	142	-	48,415	(12,770)	17
18	LGS-3P	145,403	64,835	8.30%	-	114,538	(1,816)	(152)	(141)	-	-	(42)	330	-	112,717	(32,686)	18
19	LGS-3T	49,246	22,101	2.83%	(1,099)	37,946	(619)	(52)	(48)	-	-	(14)	112	-	37,325	(11,922)	19
20	LGS-XS	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	20
21	LGS-XP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	21
22	LGS-XT	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	22
23	LGS-2S-WP	1,184	533	0.07%	-	942	(15)	(1)	(1)	-	-	(0)	3	-	927	(258)	23
24	LGS-2P-WP	887	392	0.05%	-	692	(11)	(1)	(1)	-	-	(0)	2	-	681	(206)	24
25	LGS-2T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	25
26	LGS-3S-WP	351	169	0.02%	-	299	(5)	(0)	(0)	-	-	(0)	1	-	294	(57)	26
27	LGS-3P-WP	1,513	689	0.09%	-	1,217	(19)	(2)	(1)	-	-	(0)	4	-	1,198	(315)	27
28	LGS-3T-WP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	28
29	SL	10,273	5,688	0.73%	-	10,048	(159)	(13)	(12)	-	-	(4)	29	-	9,889	(384)	29
30	RS-Pal	49	26	0.00%	-	46	(1)	(0)	(0)	-	-	(0)	0	-	45	(3)	30
31	GS-Pal	177	100	0.01%	-	177	(3)	(0)	(0)	-	-	(0)	1	-	174	(3)	31
32	IAIWP	-	-	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	32
33	RS-NEM	40,228	36,847	4.72%	(700)	64,394	(1,032)	(86)	(80)	-	-	(24)	187	-	63,359	23,132	33
34	RM-NEM	218	177	0.02%	(4)	309	(5)	(0)	(0)	-	-	(0)	1	-	304	85	34
35	LRS-NEM	48	28	0.00%	(1)	48	(1)	(0)	(0)	-	-	(0)	0	-	47	(1)	35
36	GS-NEM	192	134	0.02%		236	(4)	(0)	(0)	-	-	(0)	1	-	233	40	36
37	LGS-1-NEM	5,837	3,348	0.43%		5,914	(94)	(8)	(7)	-	-	(2)	17	-	5,820	(17)	37
38						not a sum											38
39	TOTAL	$ 1,696,883	$ 781,113	100.00%	$ (15,258)	$ 1,718,820	$ (21,873)	$ (1,833)	$ (1,697)	$ -	$ -	$ (511)	$ 3,972	$ -	$ 1,342,722	$ (354,161)	39
40						from Sch. H-2											40
41					Energy Revenue for Rate Design	781,126	$ (975,517)										41
42					w/ Specific Class adjustments $	1,379,921											42
43																	43
44																	44
45	Summation of NEM customers into Standard Schedule for Rate Design																45
46	RS	$ 651,316	$ 307,323	39.34%	$ (10,883)	$ 532,037	$ (8,606)	$ (721)	$ (668)	$ -	$ -	$ (201)	$ 1,563	$ -	$ 523,404	$ (127,912)	46
47	RM	193,633	86,275	11.05%	(3,222)	149,192	(2,416)	(202)	(187)	-	-	(56)	439	-	146,768	(46,865)	47
48	LRS	3,206	1,412	0.18%	(53)	2,441	(40)	(3)	(3)	-	-	(1)	7	-	2,402	(804)	48
49	GS	48,912	22,590	2.89%	-	39,908	(633)	(53)	(49)	-	-	(15)	115	-	39,273	(9,638)	49
50	LGS-1	330,041	150,694	19.29%	-	266,218	(4,220)	(354)	(327)	-	-	(99)	766	-	261,984	(68,056)	50
51																	51

Nevada Power Company

Statement O

Class Revenue Results Summary

Line No.	Class	Sales (MWh)	Cost Based Class Revenue by Function: Distribution	Transmission	Generation	Energy/ variable	Subtotal	Power Factor Revenue	Additional Facilities & Maintenance Revenue	Exc. DOS Cost Revenue	Sum of Functional Cost Based Class Revenue for Rate Design	Interclass Rate Rebalancing Revenue	Capped Class Revenue Requirement	Revenue Proof	Percent of Total	Difference from Capped Revenue Requirement (Rounding)	Overall Effective Rate	Line No.
8																		8
9	RS	7,262,589	$ 213,344	$ 65,331	$ 390,599	$ 460,045	$ 1,129,319	$ -	$ -		$ 1,129,319	$ (65,944)	$ 1,148,202	$ 1,148,240	40.9%	$ 2	$ 0.15810	9
10	RM	2,298,671	49,729	16,942	109,452	146,464	322,587	-	-		322,587	17,240	340,213	340,219	12.1%	3	0.14800	10
11	LRS	37,526	630	278	1,650	2,355	4,912	-	-		4,912	323	5,259	5,260	0.2%	1	0.14014	11
12	GS	612,056	15,621	3,352	18,763	39,041	76,776	-	-	1	76,775	5,631	82,660	82,579	2.9%	(0)	0.13505	12
13	LGS-1	4,073,470	55,170	23,777	141,475	256,165	476,586	133	1	75	476,646	15,030	493,952	493,888	17.6%	(64)	0.12126	13
14	LGS-2S	2,437,061	21,883	12,226	75,488	152,920	262,516	349	-	596	262,269	11,527	273,799	273,785	9.8%	(15)	0.11235	14
15	LGS-2P	69,583	542	292	1,853	4,306	6,994	6	-	26	6,974	356	7,331	7,331	0.3%	(0)	0.10535	15
16	LGS-2T	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	16
17	LGS-3S	768,658	6,080	3,422	21,730	48,415	79,647	88	-	659	79,077	4,049	83,126	83,119	3.0%	(6)	0.10814	17
18	LGS-3P	1,826,673	19,221	7,974	51,011	112,717	190,923	226	70	7,104	184,115	11,146	195,261	195,214	7.0%	(47)	0.10689	18
19	LGS-3T	618,671	2,718	2,610	16,612	37,325	59,264	20	-	1,223	58,062	2,064	60,126	60,125	2.1%	(0)	0.09718	19
20	LGS-XS	-	61	-	-	-	61	2	-	63	-	-	-	-	0.0%	-	---	20
21	LGS-XP	-	2,281	-	-	-	2,281	65	-	2,346	-	-	-	-	0.0%	-	---	21
22	LGS-XT	-	387	-	-	-	387	2	-	389	-	-	-	-	0.0%	-	---	22
23	LGS-2S-WP	14,878	213	77	385	927	1,601	4	-	29	1,576	175	1,752	1,750	0.1%	(2)	0.11774	23
24	LGS-2P-WP	11,148	108	36	203	681	1,028	2	-	-	1,030	79	1,109	1,108	0.0%	(1)	0.09950	24
25	LGS-2T-WP	-	29	-	-	-	29	-	-	29	-	-	-	-	0.0%	-	---	25
26	LGS-3S-WP	4,413	223	19	42	294	578	6	-	179	405	29	434	434	0.0%	(0)	0.09835	26
27	LGS-3P-WP	19,004	415	36	221	1,198	1,870	12	-	298	1,584	131	1,715	1,715	0.1%	0	0.09024	27
28	LGS-3T-WP	-	164	-	-	-	164	0	-	165	-	-	-	-	0.0%	-	---	28
29	SL	129,054	1,261	122	3,265	9,889	14,537	-	-		14,537	2,175	16,712	16,719	0.6%	7	0.12950	29
30	RS-Pal	578	35	0	15	45	95	-	-		95	8	103	103	0.0%	0	0.17897	30
31	GS-Pal	2,217	116	1	57	174	348	-	-		348	34	382	382	0.0%	0	0.17237	31
32	IAIWP	-	-	-	-	-	-	-	-		-	-	-	-	0.0%	-	---	32
33	RS-NEM	478,046	35,385	9,933	66,347	63,359	175,023	-	-		175,023	(4,341)	85,821	85,821	3.1%	---	0.17952	33
34	RM-NEM	2,596	113	47	304	304	768	-	-		768	19	399	399	0.0%	---	0.15371	34
35	LRS-NEM	571	30	5	33	47	115	-	-		115	5	97	97	0.0%	---	0.16907	35
36	GS-NEM	2,417	80	26	165	233	504	-	-		504	22	272	272	0.0%	---	0.11245	36
37	LGS-1-NEM	73,329	1,182	650	3,691	5,820	11,343	-	-		11,343	271	9,342	9,342	0.3%	---	0.12740	37
38																		38
39	TOTAL	20,743,210	$ 427,021	$ 147,156	$ 903,360	$ 1,342,722		$ 917	$ 71	$ 13,181	$ 2,808,067	$ 30	$ 2,808,067	$ 2,807,902	100.0%	$ (122)	$ 0.13537	39
40																		40
41																		41
42																		42
43																		43
44	Summation of NEM customers into Standard Schedule for Rate Design																	44
45	RS	7,740,635	$ 248,729	$ 75,264	$ 456,946	$ 523,404	$ 1,304,342	$ -	$ -	$ -	$ 1,304,342	$ (70,285)	$ 1,234,022	$ 1,234,060	43.9%	$ 2	$ 0.15942	45
46	RM	2,301,267	49,842	16,988	109,757	146,768	323,355	-	-	-	323,355	17,260	340,612	340,618	12.1%	3	0.14801	46
47	LRS	38,097	661	283	1,682	2,402	5,027	-	-	-	5,027	328	5,356	5,356	0.2%	1	0.14058	47
48	GS	614,473	15,701	3,378	18,928	39,273	77,280	-	-	1	77,280	5,653	82,932	82,851	3.0%	(0)	0.13496	48
49	LGS-1	4,146,799	56,352	24,427	145,166	261,984	487,929	133	1	75	487,989	15,300	503,295	503,231	17.9%	(64)	0.12137	49

Nevada Power Company
Statement O

Class Revenue Adjustments Due to Cap & Floor Criteria (1)

Exhibit Prest Direct-6
Docket No. 23-06XXX
MCS, per NRS, Current TOU, Joint Dispatch, RS Cap
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Line No.	Class	Present Rate Revenue	AB 405 Present Rate Revenue	Total Class Revenue Requirement: Sum of Functional Cost Based Class Revenue	Total Class Revenue Requirement: Percent of Total	Total Class Revenue Requirement: AB 405 Cost Based Class Revenue	Total Class Revenue Requirement: Percent of Total	% change over Present Rate Revenue	AB405 Cost-Based Pct change over Present Rate Revenue	First Allocation - Cap: Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue
9	RS	$ 1,124,472	$ 1,205,394	$ 1,129,319	40.22%	$ 1,304,342	46.45%	0.43%	8.21%	Capped	2.38%	$ 1,234,022	$ 70,319	$ -	$ -	0.00%	$ -	1,234,022	2.38%
10	RM	339,331	339,727	322,587	11.49%	323,355	11.52%	-4.93%	-4.82%	-	-4.82%	323,355	-	323,355	(16,372)	24.54%	17,257	340,612	0.26%
11	LRS	5,291	5,383	4,912	0.17%	5,027	0.18%	-7.15%	-6.61%	-	-6.61%	5,027	-	5,027	(356)	0.47%	328	5,356	-0.51%
12	GS	83,497	83,773	76,775	2.73%	77,280	2.75%	-8.05%	-7.75%	-	-7.75%	77,280	-	77,280	(6,493)	8.04%	5,652	82,932	-1.00%
13	LGS-1	485,467	494,567	476,646	16.97%	487,989	17.38%	-1.82%	-1.33%	-	-1.33%	487,989	-	487,989	(6,578)	21.77%	15,306	503,295	1.76%
14	LGS-2S	271,383	271,383	262,269	9.34%	262,269	9.34%	-3.36%	-3.36%	-	-3.36%	262,269	-	262,269	(9,114)	16.40%	11,530	273,799	0.89%
15	LGS-2P	7,301	7,301	6,974	0.25%	6,974	0.25%	-4.47%	-4.47%	-	-4.47%	6,974	-	6,974	(326)	0.51%	356	7,331	0.41%
16	LGS-2T				0.00%		0.00%						-			0.00%	-		
17	LGS-3S	82,792	82,792	79,077	2.82%	79,077	2.82%	-4.49%	-4.49%	-	-4.49%	79,077	-	79,077	(3,715)	5.76%	4,049	83,126	0.40%
18	LGS-3P	195,666	195,666	184,115	6.56%	184,115	6.56%	-5.90%	-5.90%	-	-5.90%	184,115	-	184,115	(11,551)	15.85%	11,146	195,261	-0.21%
19	LGS-3T	59,254	59,254	58,062	2.07%	58,062	2.07%	-2.01%	-2.01%	-	-2.01%	58,062	-	58,062	(1,192)	2.93%	2,064	60,126	1.47%
20	LGS-XS				0.00%		0.00%									0.00%			
21	LGS-XP				0.00%		0.00%									0.00%			
22	LGS-XT				0.00%		0.00%									0.00%			
23	LGS-2S-WP	1,343	1,343	1,576	0.06%	1,576	0.06%	17.40%	17.40%	-	17.40%	1,576	-	1,576	234	0.25%	175	1,752	30.46%
24	LGS-2P-WP	1,123	1,123	1,030	0.04%	1,030	0.04%	-8.26%	-8.26%	-	-8.26%	1,030	-	1,030	(93)	0.11%	79	1,109	-1.22%
25	LGS-2T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-		
26	LGS-3S-WP	372	372	405	0.01%	405	0.01%	8.90%	8.90%	-	8.90%	405	-	405	33	0.04%	29	434	16.72%
27	LGS-3P-WP	1,742	1,742	1,584	0.06%	1,584	0.06%	-9.07%	-9.07%	-	-9.07%	1,584	-	1,584	(158)	0.19%	131	1,715	-1.57%
28	LGS-3T-WP	-	-	-	0.00%	-	0.00%							-	-	0.00%	-		
29	SL	11,437	11,437	14,537	0.52%	14,537	0.52%	27.10%	27.10%	-	27.10%	14,537	-	14,537	3,099	3.09%	2,175	16,712	46.12%
30	RS-Pal	85	85	95	0.00%	95	0.00%	11.86%	11.86%	-	11.86%	95	-	95	10	0.01%	8	103	21.50%
31	GS-Pal	305	305	348	0.01%	348	0.01%	14.25%	14.25%	-	14.25%	348	-	348	43	0.05%	34	382	25.35%
32	IAIWP			-															
33	RS-NEM	80,923	inc in Full Req Class	175,023	6.23%	inc in Full Req Class		116.28%											
34	RM-NEM	397	inc in Full Req Class	768	0.03%	inc in Full Req Class		93.60%											
35	LRS-NEM	92	inc in Full Req Class	115	0.00%	inc in Full Req Class		24.50%											
36	GS-NEM	275	inc in Full Req Class	504	0.02%	inc in Full Req Class		83.15%											
37	LGS-1-NEM	9,100	inc in Full Req Class	11,343	0.40%	inc in Full Req Class		24.64%											
38		Not a Sum:		Not a sum:				Overall Increase:											
39	Total	$ 2,805,178		$ 2,871,796	100.00%	$ 2,871,796	100.00%	2.38%				$ 2,737,747	$ 70,319	$ 1,503,725	$ 59,368	100%	$ 70,319		
40		$ 2,761,648		$ 2,808,067	=sum=	$ 2,808,067		$ 66,618											
41		$ 63,729	<Rev Credits: Revenue Credits exc. PF and AF&M revenues																
42																			

/--------------------Second Allocation--------------------/

Line No.	Class	Class Revenue Requirement, after 1st Allocation	Pct Change over Present Rate Revenue	Result of Capping/Floor Proposal	Revenue Cap at Proposed	Re-set Revenue for classes subject to Cap Criteria	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Difference from Cost Based/Floor revenue of Uncapped Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement	% change over Present Rate Revenue	Final Class Revenue Allocation: Capped Class Revenue Requirement	Final Class Revenue Allocation: % change over Present Rate Revenue	Difference from Cost
50	RS	$ 1,234,022	2.38%	Capped	2.38%	$ 1,234,022	$ -	$ 1,234,022	$ -	0.00%	$ -	$ 1,234,022	2.38%	$ 1,234,022	2.38%	$ (70,319)
51	RM	340,612	0.26%	-	0.26%	$ 340,612	$ -	$ 340,612	$ 885	4.97%	0	$ 340,612	0.26%	340,612	0.26%	17,257
52	LRS	5,356	-0.51%	-	-0.51%	$ 5,356	$ -	$ 5,356	$ (28)	-0.15%	(0)	$ 5,356	-0.51%	5,356	-0.51%	328
53	GS	82,932	-1.00%	-	-1.00%	$ 82,932	$ -	$ 82,932	$ (841)	-4.73%	(0)	$ 82,932	-1.00%	82,932	-1.00%	5,652
54	LGS-1	503,295	1.76%	-	1.76%	$ 503,295	$ -	$ 503,295	$ 8,728	49.06%	0	$ 503,295	1.76%	503,295	1.76%	15,306
55	LGS-2S	273,799	0.89%	-	0.89%	$ 273,799	$ -	$ 273,799	$ 2,416	13.58%	0	$ 273,799	0.89%	273,799	0.89%	11,530
56	LGS-2P	7,331	0.41%	-	0.41%	$ 7,331	$ -	$ 7,331	$ 30	0.17%	0	$ 7,331	0.41%	7,331	0.41%	356
57	LGS-2T									0.00%	-	$ -		-		-
58	LGS-3S	83,126	0.40%	-	0.40%	$ 83,126	$ (0)	$ -	$ 334	1.88%	0	$ 83,126	0.40%	83,126	0.40%	4,049
59	LGS-3P	195,261	-0.21%	-	-0.21%	$ 195,261	$ -	$ 195,261	$ (405)	-2.28%	(0)	$ 195,261	-0.21%	195,261	-0.21%	11,146
60	LGS-3T	60,126	1.47%	-	1.47%	$ 60,126	$ -	$ 60,126	$ 872	4.90%	0	$ 60,126	1.47%	60,126	1.47%	2,064
61	LGS-XS									0.00%	-			-		-
62	LGS-XP									0.00%	-			-		-
63	LGS-XT									0.00%	-			-		-
64	LGS-2S-WP	1,752	30.46%	-	30.46%	$ 1,752	$ -	$ 1,752	$ 409	2.30%	0	$ 1,752	30.46%	1,752	30.46%	175
65	LGS-2P-WP	1,109	-1.22%	-	-1.22%	$ 1,109	$ -	$ 1,109	$ (14)	-0.08%	(0)	$ 1,109	-1.22%	1,109	-1.22%	79
66	LGS-2T-WP							$ -	$ -	0.00%	-			-		-
67	LGS-3S-WP	434	16.72%	-	16.72%	$ 434	$ -	$ 434	$ 62	0.35%	0	$ 434	16.72%	434	16.72%	29
68	LGS-3P-WP	1,715	-1.57%	-	-1.57%	$ 1,715	$ -	$ 1,715	$ (27)	-0.15%	(0)	$ 1,715	-1.57%	1,715	-1.57%	131
69	LGS-3T-WP							$ -	$ -	0.00%	-			-		-
70	SL	16,712	46.12%	-	46.12%	$ 16,712	$ -	$ 16,712	$ 5,275	29.65%	0	$ 16,712	46.12%	16,712	46.12%	2,175
71	RS-Pal	103	21.50%	-	21.50%	$ 103	$ -	$ 103	$ 18	0.10%	0	$ 103	21.50%	103	21.50%	8
72	GS-Pal	382	25.35%	-	25.35%	$ 382	$ -	$ 382	$ 77	0.43%	0	$ 382	25.35%	382	25.35%	34
73	IAIWP													-		-
74	RS-NEM	inc in Full Req Class														
75	RM-NEM	inc in Full Req Class														
76	LRS-NEM	inc in Full Req Class														
77	GS-NEM	inc in Full Req Class														
78	LGS-1-NEM	inc in Full Req Class														
79																
80	Total						$ 0	$ 2,724,941	$ 17,791	100.0%	$ 0	$ 2,808,067		$ 2,808,067		
81														$ (0)		

(1) Increases in rates cannot exceed the total average percentage increase in rates. For example, a 3% cap on an average increase of 10% will result in a rate increase of 13%. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. No class will receive a decrease in rates if a 0% floor is implemented.

(2) NEM classes include all customers under NMR-G and NMR-A rate schedules.

Nevada Power Company
Statement O

Non-Bypassable kWh Charges: Interclass Rate Rebalancing (IRR)

Line No.	Classes[1]	Bundled kWh Sales	DOS kWh Sales	Total kWh Sales	Sum of Functional Cost Based Class Revenue	Capped Class Revenue Requirement	Interclass Subsidy (difference)	Subsidy Component per kWh	Rounding	Note	Line No.
8	RS	7,262,588,952		7,740,635,272	$ 1,304,342	$ 1,234,022	$ (70,319)	$ (0.00908)	$ 34		8
9	RM	2,298,671,171		2,301,266,943	323,355	340,612	17,257	0.00750	3		9
10	LRS	37,525,901		38,097,297	5,027	5,356	328	0.00862	0		10
11	GS	612,055,594		614,472,857	77,280	82,932	5,652	0.00920	1		11
12	LGS-1	4,073,469,942		4,146,798,580	487,989	503,295	15,306	0.00369	(4)		12
13	LGS-2S	2,437,060,885		2,437,060,885	262,269	273,799	11,530	0.00473	(3)		13
14	LGS-2P	69,583,297		69,583,297	6,974	7,331	356	0.00512	(0)		14
15	LGS-2T	-		-	-	-	-	0.00369	-	<<Set equal to LGS-1>>	15
16	LGS-3S	768,658,032		768,658,032	79,077	83,126	4,049	0.00527	2		16
17	LGS-3P	1,826,672,960		1,826,672,959.93	184,115	195,261	11,146	0.00610	(3)		17
18	LGS-3T	618,671,150		618,671,150	58,062	60,126	2,064	0.00334	3		18
19	LGS-XS	-		-	-	-	-	0.00527	-	<<Set equal to LGS-XS DOS>>	19
20	LGS-XP	-		-	-	-	-	0.00610	-	<<Set equal to LGS-XP DOS>>	20
21	LGS-XT	-		-	-	-	-	0.00334	-	<<Set equal to LGS-XT DOS>>	21
22	LGS-2S-WP	14,877,558		14,877,558	1,576	1,752	175	0.01178	(0)		22
23	LGS-2P-WP	11,147,772		11,147,772	1,030	1,109	79	0.00709	0		23
24	LGS-2T-WP	-		-	-	-	-	0.00837	-	<<Set equal to LGS-2T WP DOS>>	24
25	LGS-3S-WP	4,412,814		4,412,814	405	434	29	0.00659	0		25
26	LGS-3P-WP	19,004,483		19,004,483	1,584	1,715	131	0.00687	(0)		26
27	LGS-3T-WP	-		-	-	-	-	0.00837	-	<<Set equal to LGS-3T WP DOS>>	27
28	SL	129,054,441		129,054,441	14,537	16,712	2,175	0.01686	0		28
29	RS-Pal	578,040		578,040	95	103	8	0.01420	0		29
30	GS-Pal	2,217,456		2,217,456	348	382	34	0.01527	(0)		30
31	IAIWP	-		na	-	-	-	na	---		31
32	RS-NEM	478,046,320		inc in Full Req Class							32
33	RM-NEM	2,595,772		inc in Full Req Class							33
34	LRS-NEM	571,396		inc in Full Req Class							34
35	GS-NEM	2,417,263		inc in Full Req Class							35
36	LGS-1 -NEM	73,328,638		inc in Full Req Class							36
37											37
38	Bundled TOTAL	20,743,209,837		20,743,209,837	$ 2,808,067	$ 2,808,067	$ (0)	<< Subsidy amount prior to RevReq adjustment when maintaining current rates.			38
39											39
40	**DISTRIBUTION ONLY SERVICE CLASSES -- SET @ OTHERWISE APPLICABLE CLASS AS IDENTIFIED (If <0, then set to zero)**[2]										40
41	DOS: GS		51,413	na	na	na	na	$ 0.00920		<<Set equal to GS>>	41
42	DOS: LGS-1		7,843,178	na	na	na	na	0.00369		<<Set equal to LGS-1>>	42
43	DOS: LGS-2S		82,487,915	na	na	na	na	0.00473		<<Set equal to LGS-2S>>	43
44	DOS: LGS-2P		4,487,342	na	na	na	na	0.00512		<<Set equal to LGS-2P>>	44
45	DOS: LGS-2T		-	na	na	na	na	0.00369		<<Set equal to LGS-2T>>	45
46	DOS: LGS-3S		85,826,485	na	na	na	na	0.00527		<<Set equal to LGS-3S>>	46
47	DOS: LGS-3P		1,414,522,800	na	na	na	na	0.00610		<<Set equal to LGS-3P>>	47
48	DOS: LGS-3T		591,977,970	na	na	na	na	0.00334		<<Set equal to LGS-3T>>	48
49	DOS: LGS-XS		7,153,043	na	na	na	na	0.00527		<<Set to 0.00001 or Current x 94%>>	49
50	DOS: LGS-XP		287,352,976	na	na	na	na	0.00610		<<Set to 0.00001 or Current x 94%>>	50
51	DOS: LGS-XT		165,618,096	na	na	na	na	0.00334		<<Set to 0.00001 or Current x 94%>>	51
52	DOS: LGS-2S-WP		4,841,057	na	na	na	na	0.01178		<<Set equal to LGS-2S-WP>>	52
53	DOS: LGS-2P-WP		-	na	na	na	na	0.00709		<<Set equal to LGS-2P-WP>>	53
54	DOS: LGS-2T-WP		1,889,274	na	na	na	na	0.00837		<<Set to 0.00001 or Current x 94%>>	54
55	DOS: LGS-3S-WP		25,647,446	na	na	na	na	0.00659		<<Set equal to LGS-3S-WP>>	55
56	DOS: LGS-3P-WP		75,371,524	na	na	na	na	0.00687		<<Set equal to LGS-3P-WP>>	56
57	DOS: LGS-3T-WP		55,357,230	na	na	na	na	0.00837		<<Set to 0.00001 or Current x 94%>>	57
58											58

59 1. Optional TOU classes are not shown in this table, but have IRR rates equal to their otherwise applicable schedules. Any revenues collected from these classes are revenue credited (See page 2). 59

60 2. The DOS classes identified here are only those that presently have DOS customers in them. However, for other classes that are eligible for DOS, the IRR will be set similarly for all eligible classes. 60

Nevada Power Company
Statement O

Comparison of Present and Proposed Rate Revenue

Exhibit Prest Direct-6
Docket No. 23-06XXX
MCS, per NRS, Current TOU, Joint Dispatch, RS Cap

Line No	Class	Sales (kWh)	BTGR Revenue Present	BTGR Revenue Proposed	Percent Change	BTGR & BTER[1] Revenue Present	BTGR & BTER[1] Revenue Proposed	Percent Change	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Present	Total Revenue: BTGR & BTER Revenue Plus Other Rate Components[1] Proposed	Percent Change	Line No
8	RS	7,262,588,952	$ 513,383,508	$ 537,151,515	4.63%	$ 1,124,471,607	$ 1,148,239,614	2.11%	$ 1,284,192,975	$ 1,307,960,983	1.85%	8
9	RM	2,298,671,171	145,915,631	146,804,100	0.61%	339,330,523	340,218,992	0.26%	389,356,065	390,244,534	0.23%	9
10	LRS	37,525,901	2,132,970	2,101,814	-1.46%	5,290,775	5,259,619	-0.59%	6,096,455	6,065,299	-0.51%	10
11	GS	612,055,143	34,777,894	33,859,853	-2.64%	83,497,092	82,579,051	-1.10%	94,978,182	94,060,141	-0.97%	11
12	LGS-1	4,073,133,716	161,250,916	169,667,005	5.22%	485,427,795	493,843,884	1.73%	562,024,412	570,440,501	1.50%	12
13	LGS-2S	2,429,180,261	77,189,770	79,564,109	3.08%	270,531,139	272,905,478	0.88%	315,956,810	318,331,149	0.75%	13
14	LGS-2P	69,583,297	1,761,763	1,791,747	1.70%	7,300,593	7,330,577	0.41%	8,588,581	8,618,564	0.35%	14
15	LGS-2T	-	-	-	na	-	-	na	-	-	na	15
16	LGS-3S	768,658,032	21,606,500	21,934,199	1.52%	82,791,679	83,119,378	0.40%	97,127,152	97,454,851	0.34%	16
17	LGS-3P	1,393,295,183	39,586,638	39,111,759	-1.20%	150,492,935	150,018,056	-0.32%	176,700,817	176,225,938	-0.27%	17
18	LGS-3T	247,665,929	4,377,192	4,758,615	8.71%	24,091,400	24,472,823	1.58%	28,658,360	29,039,784	1.33%	18
19	LGS-XS	-	-	-	na	-	-	na	-	-	na	19
20	LGS-XP	-	-	-	na	-	-	na	-	-	na	20
21	LGS-XT	-	-	-	na	-	-	na	-	-	na	21
22	LGS-2S-WP	14,877,558	158,497	565,382	256.71%	1,342,751	1,749,636	30.30%	1,623,788	2,030,673	25.06%	22
23	LGS-2P-WP	11,147,772	235,565	220,488	-6.40%	1,122,928	1,107,851	-1.34%	1,327,601	1,312,524	-1.14%	23
24	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	24
25	LGS-3S-WP	4,412,814	20,575	82,634	301.62%	371,835	433,894	16.69%	451,353	513,412	13.75%	25
26	LGS-3P-WP	19,004,483	229,669	202,266	-11.93%	1,742,426	1,715,023	-1.57%	2,087,357	2,059,954	-1.31%	26
27	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	27
28	SL	129,054,441	1,164,568	6,446,596	453.56%	11,437,302	16,719,330	46.18%	13,840,296	19,122,324	38.16%	28
29	RS-Pal	578,040	36,501	54,822	50.19%	85,143	103,464	21.52%	97,306	115,627	18.83%	29
30	GS-Pal	2,217,456	128,415	205,776	60.24%	304,924	382,285	25.37%	345,791	423,153	22.37%	30
31	IAIWP	-	-	-	na	-	-	na	-	-	na	31
32	**Optional Time of Use**											32
33	ORS-TOU	9,396,344	478,100	501,816	4.96%	1,268,289	1,292,005	1.87%	1,473,445	1,497,161	1.61%	33
34	ORS-TOU OPT A	21,030,431	1,250,839	1,374,330	9.87%	3,020,046	3,143,537	4.09%	3,481,412	3,604,903	3.55%	34
35	ORS-TOU OPT B	4,239,586	173,888	199,274	14.60%	530,649	556,035	4.78%	624,004	649,391	4.07%	35
39	ORM-TOU	873,422	49,455	50,399	1.91%	122,872	123,816	0.77%	141,630	142,574	0.67%	39
40	ORM-TOU OPT A	718,287	45,450	46,430	2.16%	105,894	106,874	0.93%	121,546	122,526	0.81%	40
41	ORM-TOU OPT B	70,254	4,084	4,326	5.91%	9,996	10,238	2.42%	11,526	11,768	2.10%	41
42	ORM-TOU DDP	9,561	414	390	-5.88%	1,170	1,146	-2.08%	1,211	1,187	-2.01%	42
51	OGS-TOU	27,565,080	1,261,147	1,206,245	-4.35%	3,455,327	3,400,425	-1.59%	3,972,448	3,917,546	-1.38%	51
52	OLGS-1 TOU	124,787,383	3,997,063	4,105,499	2.71%	13,930,139	14,038,575	0.78%	16,277,390	16,385,826	0.67%	52
53	OLGS-3P-HLF	258,609,361	5,228,244	5,160,824	-1.29%	25,813,549	25,746,129	-0.26%	30,677,991	30,610,571	-0.22%	53
54	**Optional Time of Use EVRR**											54
55	ORS-TOU EVRR	52,516,143	2,615,103	2,629,415	0.55%	7,033,504	7,047,816	0.20%	8,187,065	8,201,377	0.17%	55
56	ORS-TOU Opt A EVRR	6,627,577	342,755	358,387	4.56%	900,466	916,098	1.74%	1,046,406	1,062,038	1.49%	56
57	ORS-TOU Opt B EVRR	4,621,440	160,839	174,693	8.61%	549,733	563,587	2.52%	651,497	665,351	2.13%	57
60	ORM-TOU EVRR	1,289,179	67,312	66,001	-1.95%	175,686	174,375	-0.75%	203,405	202,094	-0.64%	60
61	ORM-TOU OPT A EVRR	60,410	3,580	3,512	-1.89%	8,664	8,596	-0.78%	9,980	9,913	-0.68%	61
62	ORM-TOU OPT B EVRR	29,643	1,740	1,798	3.36%	4,234	4,292	1.38%	4,881	4,939	1.20%	62
65	OLRS-TOU EVRR	299,866	14,816	14,049	-5.18%	40,050	39,283	-1.92%	46,488	45,721	-1.65%	65
70	OGS-TOU EVRR	20,511	1,899	1,855	-2.31%	3,532	3,488	-1.24%	3,917	3,873	-1.12%	70
71	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	71
72	**Net Metering:**											72
73	RS-NEM	478,046,320	40,695,177	45,592,995	12.04%	80,922,775	85,820,593	6.05%	91,449,355	96,347,174	5.36%	73
74	RM-NEM	2,595,772	178,138	180,568	1.36%	396,572	399,002	0.61%	453,135	455,565	0.54%	74
75	LRS-NEM	571,396	44,227	48,522	9.71%	92,310	96,605	4.65%	104,579	108,873	4.11%	75
76	GS-NEM	2,417,263	83,034	79,406	-4.37%	275,449	271,821	-1.32%	320,798	317,170	-1.13%	76
77	LGS-1 NEM	73,328,638	3,263,161	3,505,355	7.42%	9,100,120	9,342,314	2.66%	10,479,431	10,721,626	2.31%	77
78	ORS-NEM	3,324,908	177,128	201,825	13.94%	456,919	481,616	5.41%	530,133	554,830	4.66%	78
79	ORS-NEM OPT A	4,057,523	260,478	303,454	16.50%	601,919	644,895	7.14%	691,267	734,243	6.22%	79
80	ORS-NEM OPT B	218,046	12,617	14,447	14.51%	30,965	32,795	5.91%	35,766	37,596	5.12%	80
84	ORM-NEM	1,460	220	221	0.38%	343	344	0.24%	374	375	0.22%	84
97	**NEM EVRR**											97
98	ORS-NEM EVRR	11,862,176	478,864	494,002	3.16%	1,477,066	1,492,204	1.02%	1,738,271	1,753,409	0.87%	98
99	ORS-NEM OPT A EVRR	1,879,925	67,276	74,415	10.61%	225,472	232,611	3.17%	266,867	274,006	2.68%	99
100	ORS-NEM OPT B EVRR	411,121	18,066	19,775	9.46%	52,661	54,370	3.25%	61,715	63,424	2.77%	100
103	ORM-NEM EVRR	25,756	1,240	1,205	-2.81%	3,407	3,372	-1.02%	3,968	3,933	-0.88%	103
114	**Standby**											114
116	SSR - GS	-	-	-	na	-	-	na	-	-	na	116
117	SSR - LGS-1	1,130,064	54,212	59,619	9.97%	144,165	149,572	3.75%	165,421	170,828	3.27%	117
118	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	118
119	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	119
120	LSR - LGS-2T	9,583,450	159,003	204,159	28.40%	921,846	967,002	4.90%	1,099,236	1,144,392	4.11%	120
121	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	121
122	LSR - LGS-3P	26,274,564	868,679	880,198	1.33%	2,960,134	2,971,653	0.39%	3,454,358	3,465,877	0.33%	122
123	LSR - LGS-3T	109,322,768	2,488,706	2,844,069	14.28%	11,190,798	11,546,161	3.18%	13,206,710	13,562,073	2.69%	123
133	**EVCCR**											133
134	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	134
135	LGS-2S EVCCR	14,835,492	648,508	634,245	-2.20%	1,829,413	1,815,150	-0.78%	2,106,836	2,092,574	-0.68%	135
136	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	136
137	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	137
138	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	138
139	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	139
140	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	140
147												147
148	**TOTAL Bundled**	21,055,299,880	$ 1,071,470,793	$ 1,121,985,770	4.71%	$ 2,789,783,845	$ 2,840,298,822	1.81%	$ 3,210,501,292	$ 3,261,016,269	1.57%	148
149	Residential	10,204,140,610	$ 708,610,416	$ 738,468,501	4.21%	$ 1,567,209,710	$ 1,597,067,795	1.91%	$ 1,791,082,729	$ 1,820,940,814	1.67%	149
150	Non-Residential	10,851,159,270	$ 362,860,377	$ 383,517,269	5.69%	$ 1,222,574,135	$ 1,243,231,027	1.69%	$ 1,419,418,564	$ 1,440,075,455	1.46%	150
151												151
152	**DISTRIBUTION ONLY SERVICE (DOS)[3]**											152
153	GS-DOS	51,413	$ 3,947	$ 3,839	-2.74%	$ 3,947	$ 3,839	-2.74%	$ 4,020	$ 3,912	-2.69%	153
154	LGS-1-DOS	7,843,178	85,196	109,840	28.93%	86,342	110,986	28.54%	98,389	123,033	25.05%	154
155	LGS-2S-DOS	82,487,915	734,814	1,058,913	44.11%	788,210	1,112,309	41.12%	947,993	1,272,092	34.19%	155
156	LGS-2P-DOS	4,487,342	58,866	86,207	46.45%	55,082	82,423	49.64%	66,599	93,940	41.05%	156
157	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	157
158	LGS-3S-DOS	85,826,485	813,709	1,205,133	48.10%	866,433	1,257,857	45.18%	1,029,961	1,421,385	38.00%	158
159	LGS-3P-DOS	1,414,522,800	8,148,886	16,660,601	104.45%	8,313,358	16,825,074	102.39%	10,485,712	18,997,428	81.17%	159
160	LGS-3T-DOS	591,977,970	1,323,566	4,020,735	203.78%	1,454,782	4,151,951	185.40%	2,399,837	5,097,006	112.39%	160
161	LGS-XS-DOS	7,153,043	55,175	129,928	135.48%	62,113	136,866	120.35%	77,765	152,518	96.13%	161
162	LGS-XP-DOS	287,352,976	2,541,281	4,997,763	96.66%	2,646,507	5,102,989	92.82%	3,138,262	5,594,744	78.28%	162
163	LGS-XT-DOS	165,618,096	598,410	1,019,299	70.33%	598,410	1,019,299	70.33%	833,588	1,254,477	50.49%	163
164	LGS-2S-WP-DOS	4,841,057	24,486	88,584	261.77%	24,486	88,584	261.77%	31,360	95,458	204.39%	164
165	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	165
166	LGS-2T-WP-DOS	1,889,274	17,854	34,104	91.02%	17,854	34,104	91.02%	20,537	36,787	79.13%	166
167	LGS-3S-WP-DOS	25,647,446	79,367	358,382	351.55%	79,367	358,382	351.55%	115,786	394,801	240.97%	167
168	LGS-3P-WP-DOS	75,371,524	297,544	837,575	181.50%	297,544	837,575	181.50%	404,572	944,602	133.48%	168
169	LGS-3T-WP-DOS	55,357,230	100,063	565,448	465.09%	100,063	565,448	465.09%	178,670	644,056	260.47%	169
170												170
171	DOS TOTAL	2,810,427,749	$ 14,883,164	$ 31,176,352	109.47%	$ 15,394,498	$ 31,687,687	105.84%	$ 19,833,051	$ 36,126,240	82.15%	171
172												172
173	TOTAL (Inc. DOS)	23,865,727,629	$ 1,086,353,957	$ 1,153,162,122	6.15%	$ 2,805,178,343	$ 2,871,986,509	2.38%	$ 3,230,334,344	$ 3,297,142,510	2.07%	173
174												174

175 Note: Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. 175

176 1. Present BTER and DEAA revenues are based on April 1, 2023 rates. 176

177 2. Partial requirements customers included in LGS-3P and LGS-3T for rate design purposes are presented in their respective standby schedules. 177

178 3. DOS schedules only reflect a percentage change to their distribution rates, not the OATT and energy rates paid through other mechanisms. 178

Nevada Power Company
Statement O

Verification of Present Rate Components & Comparison to Proposed Revenue

			BTER Revenue			DEAA Revenue			EE Revenue			REPR Revenue			NDPP			ESAP			
Line No.	Class	Sales	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Line No.
9		Residential Rate	$ 0.08415	$ 0.08415		$ 0.01750	$ 0.01750		Rates vary by Class			$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		9
10		Non-Residential Rate	$ 0.07960	$ 0.07960		$ 0.01500	$ 0.01500					$ 0.00077	$ 0.00077		$ 0.00142	$ 0.00142		$ 0.00002	$ 0.00002		10
11																					11
12	RS	7,262,588,952	$ 611,088,099	$ 611,088,099	0.0%	$ 126,894,467	$ 126,894,467	0.0%	$ 16,921,832	$ 16,921,832	0.0%	$ 5,592,193	$ 5,592,193	0.0%	$ 10,312,876	$ 10,312,876	0.0%	$ 145,252	$ 145,252	0.0%	12
13	RM	2,298,671,171	193,414,892	193,414,892	0.0%	40,164,242	40,164,242	0.0%	4,827,210	4,827,210	0.0%	1,769,977	1,769,977	0.0%	3,264,113	3,264,113	0.0%	45,973	45,973	0.0%	13
14	LRS	37,525,901	3,157,805	3,157,805	0.0%	656,703	656,703	0.0%	66,795	66,795	0.0%	28,895	28,895	0.0%	53,287	53,287	0.0%	751	751	0.0%	14
15	GS	612,055,143	48,719,198	48,719,198	0.0%	9,179,762	9,179,762	0.0%	960,927	960,927	0.0%	471,282	471,282	0.0%	869,118	869,118	0.0%	12,241	12,241	0.0%	15
16	LGS-1	4,073,133,716	324,176,879	324,176,879	0.0%	61,077,978	61,077,978	0.0%	6,598,476	6,598,476	0.0%	3,136,313	3,136,313	0.0%	5,783,850	5,783,850	0.0%	81,463	81,463	0.0%	16
17	LGS-2S	2,429,180,261	193,341,369	193,341,369	0.0%	36,437,704	36,437,704	0.0%	3,668,062	3,668,062	0.0%	1,870,469	1,870,469	0.0%	3,449,436	3,449,436	0.0%	48,584	48,584	0.0%	17
18	LGS-2P	69,583,297	5,538,830	5,538,830	0.0%	1,043,749	1,043,749	0.0%	91,851	91,851	0.0%	53,579	53,579	0.0%	98,808	98,808	0.0%	1,392	1,392	0.0%	18
19	LGS-2T	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	19
20	LGS-3S	768,658,032	61,185,179	61,185,179	0.0%	11,529,870	11,529,870	0.0%	1,122,241	1,122,241	0.0%	591,867	591,867	0.0%	1,091,494	1,091,494	0.0%	15,373	15,373	0.0%	20
21	LGS-3P	1,393,295,183	110,906,297	110,906,297	0.0%	20,899,428	20,899,428	0.0%	2,257,138	2,257,138	0.0%	1,072,837	1,072,837	0.0%	1,978,479	1,978,479	0.0%	27,866	27,866	0.0%	21
22	LGS-3T	247,665,929	19,714,208	19,714,208	0.0%	3,714,989	3,714,989	0.0%	309,583	309,583	0.0%	190,703	190,703	0.0%	351,686	351,686	0.0%	4,953	4,953	0.0%	22
23	LGS-XS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	23
24	LGS-XP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	24
25	LGS-XT	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	25
26	LGS-2S-WP	14,877,558	1,184,254	1,184,254	0.0%	223,163	223,163	0.0%	25,292	25,292	0.0%	11,456	11,456	0.0%	21,126	21,126	0.0%	298	298	0.0%	26
27	LGS-2P-WP	11,147,772	887,363	887,363	0.0%	167,217	167,217	0.0%	13,043	13,043	0.0%	8,584	8,584	0.0%	15,830	15,830	0.0%	223	223	0.0%	27
28	LGS-2T-WP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	28
29	LGS-3S-WP	4,412,814	351,260	351,260	0.0%	66,192	66,192	0.0%	3,662	3,662	0.0%	3,398	3,398	0.0%	6,266	6,266	0.0%	88	88	0.0%	29
30	LGS-3P-WP	19,004,483	1,512,757	1,512,757	0.0%	285,067	285,067	0.0%	18,244	18,244	0.0%	14,633	14,633	0.0%	26,986	26,986	0.0%	380	380	0.0%	30
31	LGS-3T-WP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	31
32	SL	129,054,441	10,272,734	10,272,734	0.0%	1,935,817	1,935,817	0.0%	184,548	184,548	0.0%	99,372	99,372	0.0%	183,257	183,257	0.0%	2,581	2,581	0.0%	32
33	RS-Pal	578,040	48,642	48,642	0.0%	10,116	10,116	0.0%	781	781	0.0%	445	445	0.0%	821	821	0.0%	12	12	0.0%	33
34	GS-Pal	2,217,456	176,509	176,509	0.0%	33,262	33,262	0.0%	2,749	2,749	0.0%	1,707	1,707	0.0%	3,149	3,149	0.0%	44	44	0.0%	34
35	IAIWP	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	35
36	**Optional Time of Use**																				36
37	ORS-TOU	9,396,344	790,189	790,189	0.0%	162,684	162,684	0.0%	21,894	21,894	0.0%	7,235	7,235	0.0%	13,343	13,343	0.0%	188	188	0.0%	37
38	ORS-TOU OPT A	21,030,431	1,769,207	1,769,207	0.0%	366,309	366,309	0.0%	49,001	49,001	0.0%	16,193	16,193	0.0%	29,863	29,863	0.0%	421	421	0.0%	38
39	ORS-TOU OPT B	4,239,586	356,761	356,761	0.0%	74,193	74,193	0.0%	9,878	9,878	0.0%	3,264	3,264	0.0%	6,020	6,020	0.0%	85	85	0.0%	39
43	ORM-TOU	873,422	73,417	73,417	0.0%	15,010	15,010	0.0%	1,835	1,835	0.0%	673	673	0.0%	1,240	1,240	0.0%	17	17	0.0%	43
44	ORM-TOU OPT A	718,287	60,444	60,444	0.0%	12,570	12,570	0.0%	1,509	1,509	0.0%	553	553	0.0%	1,020	1,020	0.0%	14	14	0.0%	44
45	ORM-TOU OPT B	70,254	5,912	5,912	0.0%	1,229	1,229	0.0%	147	147	0.0%	54	54	0.0%	100	100	0.0%	1	1	0.0%	45
46	ORM-TOU DDP	9,561	756	756	0.0%	0	0	0.0%	20	20	0.0%	7	7	0.0%	14	14	0.0%	0	0	0.0%	46
55	OGS-TOU	27,565,080	2,194,180	2,194,180	0.0%	413,476	413,476	0.0%	43,277	43,277	0.0%	21,225	21,225	0.0%	39,142	39,142	0.0%	551	551	0.0%	55
56	OLGS-1 TOU	124,787,383	9,933,076	9,933,076	0.0%	1,871,811	1,871,811	0.0%	202,156	202,156	0.0%	96,086	96,086	0.0%	177,198	177,198	0.0%	2,496	2,496	0.0%	56
57	OLGS-3P-HLF	258,609,361	20,585,305	20,585,305	0.0%	3,879,140	3,879,140	0.0%	418,947	418,947	0.0%	199,129	199,129	0.0%	367,225	367,225	0.0%	5,172	5,172	0.0%	57
58	**Optional Time of Use EVRR**																				58
59	ORS-TOU EVRR	52,516,143	4,418,401	4,418,401	0.0%	916,188	916,188	0.0%	122,363	122,363	0.0%	40,437	40,437	0.0%	74,573	74,573	0.0%	1,050	1,050	0.0%	59
60	ORS-TOU Opt A EVRR	6,627,577	557,711	557,711	0.0%	115,983	115,983	0.0%	15,443	15,443	0.0%	5,103	5,103	0.0%	9,411	9,411	0.0%	133	133	0.0%	60
61	ORS-TOU Opt B EVRR	4,621,440	388,894	388,894	0.0%	80,875	80,875	0.0%	10,768	10,768	0.0%	3,559	3,559	0.0%	6,562	6,562	0.0%	92	92	0.0%	61
64	ORM-TOU EVRR	1,289,179	108,374	108,374	0.0%	22,188	22,188	0.0%	2,708	2,708	0.0%	993	993	0.0%	1,831	1,831	0.0%	26	26	0.0%	64
65	ORM-TOU OPT A EVRR	60,410	5,084	5,084	0.0%	1,057	1,057	0.0%	127	127	0.0%	47	47	0.0%	86	86	0.0%	1	1	0.0%	65
66	ORM-TOU OPT B EVRR	29,643	2,494	2,494	0.0%	519	519	0.0%	63	63	0.0%	23	23	0.0%	42	42	0.0%	1	1	0.0%	66
69	OLRS-TOU EVRR	299,866	25,234	25,234	0.0%	5,248	5,248	0.0%	534	534	0.0%	231	231	0.0%	426	426	0.0%	6	6	0.0%	69
74	OGS-TOU EVRR	20,511	1,633	1,633	0.0%	308	308	0.0%	32	32	0.0%	16	16	0.0%	29	29	0.0%	0	0	0.0%	74
75	OLGS-1-TOU EVRR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	75
76	**Net Metering:**																				76
77	RS-NEM	478,046,320	40,227,598	40,227,598	0.0%	8,365,811	8,365,811	0.0%	1,113,848	1,113,848	0.0%	368,096	368,096	0.0%	678,826	678,826	0.0%	9,561	9,561	0.0%	77
78	RM-NEM	2,595,772	218,434	218,434	0.0%	45,426	45,426	0.0%	5,452	5,452	0.0%	1,999	1,999	0.0%	3,686	3,686	0.0%	52	52	0.0%	78
79	LRS-NEM	571,396	48,083	48,083	0.0%	9,999	9,999	0.0%	1,018	1,018	0.0%	440	440	0.0%	811	811	0.0%	11	11	0.0%	79
80	GS-NEM	2,417,263	192,415	192,415	0.0%	36,259	36,259	0.0%	3,796	3,796	0.0%	1,861	1,861	0.0%	3,433	3,433	0.0%	48	48	0.0%	80
81	LGS-1 NEM	73,328,638	5,836,959	5,836,959	0.0%	1,099,930	1,099,930	0.0%	118,792	118,792	0.0%	56,463	56,463	0.0%	104,127	104,127	0.0%	1,467	1,467	0.0%	81
82	ORS-NEM	3,324,908	279,791	279,791	0.0%	58,186	58,186	0.0%	7,747	7,747	0.0%	2,560	2,560	0.0%	4,721	4,721	0.0%	66	66	0.0%	82
83	ORS-NEM OPT A	4,057,523	341,441	341,441	0.0%	71,007	71,007	0.0%	9,455	9,455	0.0%	3,124	3,124	0.0%	5,762	5,762	0.0%	81	81	0.0%	83
84	ORS-NEM OPT B	218,046	18,348	18,348	0.0%	3,816	3,816	0.0%	508	508	0.0%	168	168	0.0%	310	310	0.0%	4	4	0.0%	84
88	ORM-NEM	1,460	123	123	0.0%	26	26	0.0%	2	2	0.0%	1	1	0.0%	2	2	0.0%	0	0	0.0%	88
101	**NEM EVRR**					-	-														101
102	ORS-NEM EVRR	11,862,176	998,202	998,202	0.0%	207,588	207,588	0.0%	27,639	27,639	0.0%	9,134	9,134	0.0%	16,844	16,844	0.0%	237	237	0.0%	102
103	ORS-NEM OPT A EVRR	1,879,925	158,196	158,196	0.0%	32,899	32,899	0.0%	4,379	4,379	0.0%	1,448	1,448	0.0%	2,669	2,669	0.0%	38	38	0.0%	103
104	ORS-NEM OPT B EVRR	411,121	34,595	34,595	0.0%	7,195	7,195	0.0%	959	959	0.0%	317	317	0.0%	584	584	0.0%	8	8	0.0%	104
107	ORM-NEM EVRR	25,756	2,167	2,167	0.0%	451	451	0.0%	54	54	0.0%	20	20	0.0%	37	37	0.0%	1	1	0.0%	107
118	**Standby**																				118
120	SSR - GS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	120
121	SSR - LGS-1	1,130,064	89,953	89,953	0.0%	16,951	16,951	0.0%	1,830	1,830	0.0%	870	870	0.0%	1,605	1,605	0.0%	23	23	0.0%	121
122	LSR - LGS-2S	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	122
123	LSR - LGS-2P	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	123
124	LSR - LGS-2T	9,583,450	762,843	762,843	0.0%	143,752	143,752	0.0%	12,650	12,650	0.0%	7,379	7,379	0.0%	13,608	13,608	0.0%	192	192	0.0%	124
125	LSR - LGS-3S	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	125
126	LSR - LGS-3P	26,274,564	2,091,455	2,091,455	0.0%	394,118	394,118	0.0%	42,564	42,564	0.0%	20,231	20,231	0.0%	37,310	37,310	0.0%	525	525	0.0%	126
127	LSR - LGS-3T	109,322,768	8,702,092	8,702,092	0.0%	1,639,842	1,639,842	0.0%	136,654	136,654	0.0%	84,179	84,179	0.0%	155,238	155,238	0.0%	2,186	2,186	0.0%	127
137	**EVCCR**					-	-														137
138	OLGS-1 EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	138
139	LGS-2S EVCCR	14,835,492	1,180,905	1,180,905	0.0%	222,532	222,532	0.0%	22,401	22,401	0.0%	11,423	11,423	0.0%	21,066	21,066	0.0%	297	297	0.0%	139
140	LGS-2P EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	140
141	LGS-2T EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	141
142	LGS-3S EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	142
143	LGS-3P EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	143
144	LGS-3T EVCCR	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	144
151																					151
152	**TOTAL Bundled**	21,055,299,880	$ 1,718,313,052	$ 1,718,313,052	0.0%	334,614,299	334,614,299	0.0%	40,019,026	40,019,026	0.0%	16,185,597	16,185,597	0.0%	29,898,526	29,898,526	0.0%	421,106	421,106	0.0%	152
153	Residential	10,204,140,610	858,599,294	858,599,294	0.0%	178,301,982	178,301,982	0.0%	23,223,969	23,223,969	0.0%	7,857,188	7,857,188	0.0%	14,489,880	14,489,880	0.0%	204,083	204,083	0.0%	153
154	Non-Residential	10,851,159,270	859,713,758	859,713,758	0.0%	156,312,317	156,312,317	0.0%	16,795,057	16,795,057	0.0%	8,328,409	8,328,409	0.0%	15,408,646	15,408,646	0.0%	217,023	217,023	0.0%	154
155																					155
156	**DISTRIBUTION ONLY SERVICE (DOS)**		R-BTER & BTER Impact Fee DOS Revenue																		156
157	GS-DOS	51,413	-	-	na	-	-	na	-	-	na	-	-	na	73	73	0.0%	1	1	0.0%	157
158	LGS-1-DOS	7,843,178	1,146	1,146	0.0%	27	27	0.0%	51	51	0.0%	832	832	0.0%	11,137	11,137	0.0%	157	157	0.0%	158
159	LGS-2S-DOS	82,487,915	53,396	53,396	0.0%	897	897	0.0%	1,701	1,701	0.0%	40,052	40,052	0.0%	117,133	117,133	0.0%	1,650	1,650	0.0%	159
160	LGS-2P-DOS	4,487,342	(3,784)	(3,784)	0.0%	103	103	0.0%	1,587	1,587	0.0%	3,455	3,455	0.0%	6,372	6,372	0.0%	90	90	0.0%	160
161	LGS-2T-DOS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	161
162	LGS-3S-DOS	85,826,485	52,724	52,724	0.0%	1,543	1,543	0.0%	2,925	2,925	0.0%	37,186	37,186	0.0%	121,874	121,874	0.0%	1,717	1,717	0.0%	162
163	LGS-3P-DOS	1,414,522,800	164,473	164,472	0.0%	3,361	3,361	0.0%	15,074	15,074	0.0%	145,297	145,297	0.0%	2,008,622	2,008,622	0.0%	28,290	28,290	0.0%	163
164	LGS-3T-DOS	591,977,970	131,216	131,216	0.0%	2,722	2,722	0.0%	5,162	5,162	0.0%	96,562	96,562	0.0%	840,609	840,609	0.0%	11,840	11,840	0.0%	164
165	LGS-XS-DOS	7,153,043	6,938	6,938	0.0%	182	182	0.0%	345	345	0.0%	4,968	4,968	0.0%	10,157	10,157	0.0%	143	143	0.0%	165
166	LGS-XP-DOS	287,352,976	105,226	105,226	0.0%	2,248	2,248	0.0%	4,263	4,263	0.0%	77,203	77,203	0.0%	408,041	408,041	0.0%	5,747	5,747	0.0%	166
167	LGS-XT-DOS	165,618,096	-	-	na	-	-	na	-	-	na	-	-	na	235,178	235,178	0.0%	3,312	3,312	0.0%	167
168	LGS-2S-WP-DOS	4,841,057	-	-	na	-	-	na	-	-	na	-	-	na	6,874	6,874	0.0%	97	97	0.0%	168
169	LGS-2P-WP-DOS	-	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	-	-	na	169
170	LGS-2T-WP-DOS	1,889,274	-	-	na	-	-	na	-	-	na	-	-	na	2,683	2,683	0.0%	38	38	0.0%	170
171	LGS-3S-WP-DOS	25,647,446	-	-	na	-	-	na	-	-	na	-	-	na	36,419	36,419	0.0%	513	513	0.0%	171
172	LGS-3P-WP-DOS	75,371,524	-	-	na	-	-	na	-	-	na	-	-	na	107,028	107,028	0.0%	1,507	1,507	0.0%	172
173	LGS-3T-WP-DOS	55,357,230	-	-	na	-	-	na	-	-	na	-	-	na	78,607	78,607	0.0%	1,107	1,107	0.0%	173
174																					174
175	DOS TOTAL	$ 2,810,427,749	$ 511,335	$ 511,334	0.0%	$ 11,083	$ 11,083	0.0%	$ 31,108	$ 31,108	0.0%	$ 405,555	$ 405,555	0.0%	$ 3,990,807	$ 3,990,807	0.0%	$ 56,209	$ 56,209	0.0%	175
176																					176
177	TOTAL	68,786,755,138	$ 1,718,824,387	$ 1,718,824,386	0.0%	$ 334,625,382	$ 334,625,382	0.0%	$ 40,050,134	$ 40,050,134	0.0%	$ 16,591,152	$ 16,591,152	0.0%	$ 33,889,333	$ 33,889,333	0.0%	$ 477,315	$ 477,315	0.0%	177
178				$ (1)			$ -			$ -			$ -			$ -			$ -		178
179																					179

		Distribution Charges			T and G Demand Charges, metered kW			BTGR Energy, per kWh (includes IRR)							
Class	Note	Charge, per Cust:	Meter Charge:	Facilities Charge, per kW (1)	Summer On Peak	Summer Mid Peak	Winter -OR - All Periods	Critical Peak	Summer On Peak	Summer Mid Peak	Summer Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	BTER Energy, per kWh
RS		$ 18.50										0.05811			$ 0.08415
RM		8.30										0.05149			0.08415
LRS		99.40										0.04943			0.08415
GS		25.50	$ 2.00									0.01652			0.07960
LGS-1		15.80	5.75	$ 4.25			$ 5.18					0.01212			0.07960
LGS-2S		122.40	12.25	2.80	$ 14.59	$ 3.14	0.80		0.01786	0.00934	0.00541	0.00549			0.07960
LGS-2P		207.70	54.75	2.85	12.55	2.93	0.80		0.00944	0.00637	0.00535	0.00536			0.07960
LGS-2T		182.00	89.25	0.91	13.58	2.92	1.00		0.02728	0.01132	0.00157	0.00190			0.07960
LGS-3S		122.00	15.00	2.80	14.46	3.69	1.00		0.01732	0.00880	0.00525	0.00525			0.07960
LGS-3P		214.10	68.25	2.65	12.76	3.43	1.10		0.01436	0.01058	0.00549	0.00635			0.07960
LGS-3T		182.00	89.25	0.91	13.58	2.92	1.00		0.02728	0.01132	0.00157	0.00190			0.07960
LGS-XS		4,743.00	16.90	2.25	14.46	3.69	1.00		0.01732	0.00880	0.00525	0.00525			0.07960
LGS-XP		4,743.00	54.30	3.05	12.76	3.43	1.10		0.01436	0.01058	0.00549	0.00635			0.07960
LGS-XT		4,743.00	92.70	na	13.58	2.92	1.00		0.02728	0.01132	0.00157	0.00190			0.07960
LGS-2S-WP		128.70	12.25	1.10	17.73	17.73	0.80		0.03680	0.01838	0.02396	0.02397			0.07960
LGS-2P-WP		208.60	54.75	1.55	15.48	15.48	0.80		0.02090	0.00582	0.00818	0.00819			0.07960
LGS-2T-WP		169.10	93.00	0.91	16.50	16.50	1.00		0.01522	0.02328	0.00142	0.00673			0.07960
LGS-3S-WP		149.90	15.00	1.25	18.15	18.15	1.00		0.10120	0.08565	0.00437	0.00438			0.07960
LGS-3P-WP		234.20	68.25	1.00	16.19	16.19	1.10		0.02334	0.01915	0.00202	0.00203			0.07960
LGS-3T-WP		189.10	89.25	0.91	16.95	16.95	1.10		0.01752	0.03933	(0.00427)	0.00067			0.07960
IAIWP															0.06751
ORS-TOU		18.50							0.32219		0.00939	0.00986	0.00004	0.00046	0.08415
ORS-TOU Opt A		18.50							0.26652		0.00427	0.00986	(0.00457)	0.00046	0.08415
ORS-TOU Opt B		34.50							0.39891		0.00086	0.00986	(0.00764)	0.00046	0.08415
ORS-TOU DDP		7.00		0.23	0.14		0.05					0.03301			0.08415
ORS-TOU CPP		18.50						0.64408	0.28065		0.01126	0.00380	0.00172	(0.00500)	0.08415
ORS-TOU CPP DDP		18.50			0.14		0.05	0.64408	0.19449		0.00788	0.00986	(0.00132)	0.00046	0.08415
ORM-TOU		8.30							0.24866		0.03905	0.01162	0.02673	0.00204	0.08415
ORM-TOU Opt A		8.30							0.23723		0.02925	0.00665	0.01791	(0.00243)	0.08415
ORM-TOU Opt B		14.50							0.24917		0.06729	0.01483	0.05215	0.00493	0.08415
ORM-TOU DDP		4.75		0.09	0.06		0.05					0.03484			0.08415
ORM-TOU CPP		8.30						0.40171	0.21613		0.03290	0.01731	0.02119	0.00716	0.08415
ORM-TOU CPP DDP		8.30			0.06		0.05	0.40171	0.18684		0.03290	0.00867	0.02119	(0.00061)	0.08415
OLRS-TOU		99.40							0.27484		0.01736	0.01544	0.00721	0.00548	0.08415
OLRS-TOU Opt A		99.40							0.25675		0.01263	0.00684	0.00295	(0.00226)	0.08415
OLRS-TOU Opt B		245.80							0.26601		0.06872	0.00901	0.05343	(0.00031)	0.08415
OLRS-TOU DDP		25.50		0.22	0.18		0.05					0.03188			0.08415
OLRS-TOU CPP		99.40						0.30680	0.23980		0.01437	0.02354	0.00452	0.01277	0.08415
OLRS-TOU CPP DDP		99.40			0.18		0.05	0.30680	0.18669		0.01437	0.02025	0.00452	0.00981	0.08415
OGS-TOU		25.50	2.00						0.06125		0.01791	0.00806	0.00816	(0.00071)	0.07960
OLGS-1-TOU		15.80	5.75	4.25	7.95	<- Summer Winter->	0.50		0.10793		0.00588	0.00488	(0.00267)	(0.00357)	0.07960
OLGS-3P-HLF		214.10	68.25	1.41	19.83	5.63	1.00		0.00841	0.00126	0.00001	0.00002			0.07960
Incremental MPE					Generation $/kW Credit				Generation $/kWh Credit						
GS MPE												(0.01512)			
LGS-1 MPE							$ (3.41)					(0.00843)			
LGS-2S MPE					(10.40)	(2.24)	(0.57)		(0.00628)	(0.00328)	(0.00190)	(0.00193)			
LGS-3P MPE					(8.58)	(2.31)	(0.74)		(0.00259)	(0.00191)	(0.00099)	(0.00114)			
LGS-3T MPE					(5.43)	(1.17)	(0.40)		(0.00626)	(0.00260)	(0.00036)	(0.00044)			
Incremental EVCCR					EVCCR Demand Reduction Rates				EVCCR Transition kWh Adder Rates						
OLGS-1 EVCCR					(4.77)		(0.30)		0.03521			0.00107	(0.00769)	(0.00760)	
LGS-2S EVCCR					(8.75)	(1.88)	(0.48)		0.06514	0.01486	-	0.00114	(0.00850)	(0.00851)	
LGS-2P EVCCR					(7.53)	(1.76)	(0.48)		0.05301	0.01275	-	0.00096	(0.00850)	(0.00850)	
LGS-2T EVCCR					(8.15)	(1.75)	(0.60)		0.06413	0.05455	-	0.04890	(0.00812)	(0.00815)	
LGS-3S EVCCR					(8.68)	(2.21)	(0.60)		0.06143	0.01623	-	0.00125	(0.00849)	(0.00849)	
LGS-3P EVCCR					(7.66)	(2.06)	(0.66)		0.05266	0.01466	-	0.00132	(0.00851)	(0.00860)	
LGS-3T EVCCR					(8.15)	(1.75)	(0.60)		0.04939	0.01086	-	0.00114	(0.00812)	(0.00815)	

Additional Charges:

Separate Billing

LGS-X & LGS-WP-X:	$ 12.00	Per additional bill
DOS LGS-X & LGS-WP-X:	$ 12.00	Per additional bill
Power Factor Charges ($/kVarh):		
Summer:	$ 0.00200	$/kVarh
Winter:	$ 0.00100	$/kVarh

	Charge per $ of:	
Customer Specific Facilities Charges	Utility	Customer Contributed
Transmission non-X customers	$ 0.00322	$ 0.00059
DOS Transmission non-X customers	$ 0.00322	$ 0.00059
OLGS-3P HLF customers	$ 0.00322	$ 0.00059

Notes:

(1) The facilities charge is per kWh for Residential and GS, per metered demand for LGS-1 and per the highest measured demand for the billing period and the prior twelve billing periods for all other. For non-transmission level customers, and non-X customers, the facilities charge recovers both the Rule 9 and primary distibution facility costs. For LGSX customers the per kW facility charge recovers only the primary distribution costs, with other facilities recovered in a customer specific facility charge (CSFC).

(2) The non-LGS-X transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. The $/kW charge for transmission level classes is a placeholder until a CSFC is implemented. All new, permanent customers served under these tariffs will be placed on a CSF charge as soon as reasonably practical.

(3) The per kW facility charge applies only to the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the customer facilities identified to serve them. See page 22 in Statement O for the CSFCs by LGS-X customer.

		BTGR & BTER Energy, per kWh (the BTGR includes IRR Subsidy)							Additional Charges on per kWH Basis						Total Energy, per kWh (BTGR & BTER + EE + DEAA)							
Line No.	Class	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	REPR	TRED	DEAA	EE	NDPP	ESAP	Critical Peak	On Peak	Mid Peak	Off Peak	Winter -OR - All Periods	Summer EVRR	Winter EVRR	Line No.
8																						8
9	RS					$ 0.14226			$ 0.00077	$ 0.00070	$ 0.01750	$ 0.00206	$ 0.00142	$ 0.00002					$ 0.16329			9
10	RM					0.13564			0.00077	0.00070	0.01750	0.00186	0.00142	0.00002					0.15647			10
11	LRS					0.13358			0.00077	0.00070	0.01750	0.00156	0.00142	0.00002					0.15411			11
12	GS					0.09612			0.00077	0.00057	0.01500	0.00139	0.00142	0.00002					0.11385			12
13	LGS-1					0.09172			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002					0.10951			13
14	LGS-2S		$ 0.09746	$ 0.08894	$ 0.08501	0.08509			0.00077	0.00057	0.01500	0.00135	0.00142	0.00002		$ 0.11515	$ 0.10663	$ 0.10270	0.10278			14
15	LGS-2P		0.08904	0.08597	0.08495	0.08496			0.00077	0.00057	0.01500	0.00117	0.00142	0.00002		0.10655	0.10348	0.10246	0.10247			15
16	LGS-2T		0.10688	0.09092	0.08117	0.08150			0.00077	0.00057	0.01500	0.00101	0.00142	0.00002		0.12423	0.10827	0.09852	0.09885			16
17	LGS-3S		0.09692	0.08840	0.08485	0.08485			0.00077	0.00057	0.01500	0.00130	0.00142	0.00002		0.11456	0.10604	0.10249	0.10249			17
18	LGS-3P		0.09396	0.09018	0.08509	0.08595			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11175	0.10797	0.10288	0.10374			18
19	LGS-3T		0.10688	0.09092	0.08117	0.08150			0.00077	0.00057	0.01500	0.00107	0.00142	0.00002		0.12429	0.10833	0.09858	0.09891			19
20	LGS-XS		0.09692	0.08840	0.08485	0.08485			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.11471	0.10619	0.10264	0.10264			20
21	LGS-XP		0.09396	0.09018	0.08509	0.08595			0.00077	0.00057	0.01500	0.00161	0.00142	0.00002		0.11191	0.10813	0.10304	0.10390			21
22	LGS-XT		0.10688	0.09092	0.08117	0.08150			0.00077	0.00057	0.01500	0.00124	0.00142	0.00002		0.12446	0.10850	0.09875	0.09908			22
23	LGS-2S-WP		0.11640	0.09798	0.10356	0.10357			0.00077	0.00057	0.01500	0.00141	0.00142	0.00002		0.13415	0.11573	0.12131	0.12132			23
24	LGS-2P-WP		0.10050	0.08542	0.08778	0.08779			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.11787	0.10279	0.10515	0.10516			24
25	LGS-2T-WP		0.09482	0.10288	0.08102	0.08633			0.00077	0.00057	0.01500	0.00103	0.00142	0.00002		0.11219	0.12025	0.09839	0.10370			25
26	LGS-3S-WP		0.18080	0.16525	0.08397	0.08398			0.00077	0.00057	0.01500	0.00068	0.00142	0.00002		0.19782	0.18227	0.10099	0.10100			26
27	LGS-3P-WP		0.10294	0.09875	0.08162	0.08163			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.12013	0.11594	0.09881	0.09882			27
28	LGS-3T-WP		0.09712	0.11893	0.07533	0.08027			0.00077	0.00057	0.01500	0.00085	0.00142	0.00002		0.11431	0.13612	0.09252	0.09746			28
29	IAIWP					0.06751			-	-	-								0.06751			29
30																						30
31	ORS-TOU		0.40634		0.09354	0.09401	$ 0.08419	$ 0.08461	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.42487		0.11207	0.11254	$ 0.10272	$ 0.10314	31
32	ORS-TOU Opt A		0.35067		0.08842	0.09401	0.07958	0.08461	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.36920		0.10695	0.11254	0.09811	0.10314	32
33	ORS-TOU Opt B		0.48306		0.08501	0.09401	0.07651	0.08461	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002		0.50159		0.10354	0.11254	0.09504	0.10314	33
34	ORS-TOU DDP					0.11716			0.00077	0.00070	0.01500	0.00206	0.00142	0.00002					0.13569			34
35	ORS-TOU CPP	0.63908	0.36480		0.09541	0.08795	0.08587	0.07915	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.65761	0.38333		0.11394	0.10648	0.10440	0.09768	35
36	ORS-TOU CPP DDP	0.64454	0.27864		0.09203	0.09401	0.08283	0.08461	0.00077	0.00070	0.01500	0.00206	0.00142	0.00002	0.66307	0.29717		0.11056	0.11254	0.10136	0.10314	36
37	ORM-TOU		0.33281		0.12320	0.09577	0.11088	0.08619	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.35114		0.14153	0.11410	0.12921	0.10452	37
38	ORM-TOU Opt A		0.32138		0.11340	0.09080	0.10206	0.08172	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.33971		0.13173	0.10913	0.12039	0.10005	38
39	ORM-TOU Opt B		0.33332		0.15144	0.09898	0.13630	0.08908	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002		0.35165		0.16977	0.11731	0.15463	0.10741	39
40	ORM-TOU DDP					0.11899			0.00077	0.00070	0.01500	0.00186	0.00142	0.00002					0.13732			40
41	ORM-TOU CPP	0.40887	0.30028		0.11705	0.10146	0.10534	0.09131	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.42720	0.31861		0.13538	0.11979	0.12367	0.10964	41
42	ORM-TOU CPP DDP	0.40110	0.27099		0.11705	0.09282	0.10534	0.08354	0.00077	0.00070	0.01500	0.00186	0.00142	0.00002	0.41943	0.28932		0.13538	0.11115	0.12367	0.10187	42
43	OLRS-TOU		0.35899		0.10151	0.09959	0.09136	0.08963	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.37702		0.11954	0.11762	0.10939	0.10766	43
44	OLRS-TOU Opt A		0.34090		0.09678	0.09099	0.08710	0.08189	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.35893		0.11481	0.10902	0.10513	0.09992	44
45	OLRS-TOU Opt B		0.35016		0.15287	0.09316	0.13758	0.08384	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002		0.36819		0.17090	0.11119	0.15561	0.10187	45
46	OLRS-TOU DDP					0.11603			0.00077	0.00070	0.01500	0.00156	0.00142	0.00002					0.13406			46
47	OLRS-TOU CPP	0.31957	0.32395		0.09852	0.10769	0.08867	0.09692	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.33760	0.34198		0.11655	0.12572	0.10670	0.11495	47
48	OLRS-TOU CPP DDP	0.31661	0.27084		0.09852	0.10440	0.08867	0.09396	0.00077	0.00070	0.01500	0.00156	0.00142	0.00002	0.33464	0.28887		0.11655	0.12243	0.10670	0.11199	48
49	OGS-TOU		0.14085		0.09751	0.08766	0.08776	0.07889	0.00077	0.00057	0.01500	0.00139	0.00142	0.00002		0.15858		0.11524	0.10539	0.10549	0.09662	49
50	OLGS-1-TOU		0.18753		0.08548	0.08448	0.07693	0.07603	0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.20532		0.10327	0.10227	0.09472	0.09382	50
51	OLGS-3P-HLF		0.08801	0.00126	0.07961	0.07962			0.00077	0.00057	0.01500	0.00145	0.00142	0.00002		0.10580		0.09740	0.09741	0.01779	0.01779	51
52																						52

53 (1) The bundled proposed rates for Streetlights and PAL are shown on pages 14-16 of Statement O. 53

Nevada Power Company
Statement O

Exhibit Prest Direct-6
Docket No. 23-06XXX
MCS, per NRS, Current TOU, Joint Dispatch, RS Cap

Proposed Street Lighting (SL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00132	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	Street Lights - Non-metered																	12
13	Mercury Vapor	Non-Metered	100W	CLS 20		73	$ 3.21	$ 5.81	**$ 9.02**	$ 1.10	$ 0.04	$ 0.10	$ 0.06	$ 0.10	$ -	---	$ 10.42	13
14	Mercury Vapor	Non-Metered	100W	CLS 20		73	3.21	5.81	**9.02**	1.10	0.04	0.10	0.06	0.10	-	---	10.42	14
15	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.18	8.20	**9.38**	1.55	0.06	0.14	0.08	0.15	-	---	11.36	15
16	Mercury Vapor	Non-Metered	200W	CLS 21		103	1.18	8.20	**9.38**	1.55	0.06	0.14	0.08	0.15	-	---	11.36	16
17	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.10**	2.48	0.09	0.22	0.13	0.23	-	---	13.25	17
18	Mercury Vapor	Non-Metered	200W	CLS 22		165	0.01	13.13	**10.10**	2.48	0.09	0.22	0.13	0.23	-	---	13.25	18
19	High Pressure	Non-Metered	100W	CLS 23		42	5.34	3.34	**8.68**	0.63	0.02	0.06	0.03	0.06	-	---	9.48	19
20	High Pressure	Non-Metered	200W	CLS 24		83	2.54	6.61	**9.15**	1.25	0.05	0.11	0.06	0.12	-	---	10.74	20
21	Municipal Street Lights - Public																	21
22	Incandescent	n/a	100W	CLS 30		73	3.19	5.81	**9.00**	1.10	0.04	0.10	0.06	0.10	-	---	10.40	22
23	Incandescent	n/a	200W	CLS 31		120	0.01	9.55	**9.54**	1.80	0.07	0.16	0.09	0.17	-	---	11.83	23
24	Incandescent	n/a	200W	CLS 32		167	0.01	13.29	**10.06**	2.51	0.10	0.22	0.13	0.24	-	---	13.26	24
25	Mercury Vapor	Wood Pole	200W	CLS 33		73	3.20	5.81	**9.01**	1.10	0.04	0.10	0.06	0.10	-	---	10.41	25
26	Mercury Vapor	Wood Pole	200W	CLS 34		103	1.15	8.20	**9.35**	1.55	0.06	0.14	0.08	0.15	-	---	11.33	26
27	Mercury Vapor	Wood Pole	200W	CLS 35		165	0.01	13.13	**10.04**	2.48	0.09	0.22	0.13	0.23	-	---	13.19	27
28	Mercury Vapor	Steel Pole	200W	CLS 43		73	3.20	5.81	**9.01**	1.10	0.04	0.10	0.06	0.10	-	---	10.41	28
29	Mercury Vapor	Steel Pole	200W	CLS 44		103	1.15	8.20	**9.35**	1.55	0.06	0.14	0.08	0.15	-	---	11.33	29
30	Mercury Vapor	Steel Pole	200W	CLS 45		165	0.01	13.13	**10.04**	2.48	0.09	0.22	0.13	0.23	-	---	13.19	30
31	Sodium Vapor	n/a	100W	CLS 89		42	5.32	3.34	**8.66**	0.63	0.02	0.06	0.03	0.06	-	---	9.46	31
32	Sodium Vapor	n/a	200W	CLS 90		83	2.51	6.61	**9.12**	1.25	0.05	0.11	0.06	0.12	-	---	10.71	32
33	Municipal Street Lights - Customer Owned																	33
34	Incandescent	n/a	200W	CLS 51		120	0.01	9.55	**3.84**	1.80	0.07	0.16	0.09	0.17	-	0.05	6.18	34
35	Mercury Vapor	n/a	200W	CLS 53		73	0.01	5.81	**3.31**	1.10	0.04	0.10	0.06	0.10	-	0.03	4.74	35
36	Mercury Vapor	n/a	200W	CLS 54		103	0.01	8.20	**3.65**	1.55	0.06	0.14	0.08	0.15	-	0.04	5.67	36
37	Mercury Vapor	n/a	200W	CLS 55		165	0.01	13.13	**4.34**	2.48	0.09	0.22	0.13	0.23	-	0.06	7.55	37
38	Street Lights - LED																	38
39	LED	Non-Metered	100W	CLS 20		70	3.19	5.57	**8.76**	1.05	0.04	0.09	0.05	0.10	-	---	10.09	39
40	LED	Non-Metered	200W	CLS 21		35	3.20	5.57	**8.77**	0.53	0.02	0.05	0.03	0.05	-	---	9.45	40
41	LED	Non-Metered	200W	CLS 22		70	1.13	5.57	**6.70**	1.05	0.04	0.09	0.05	0.10	-	---	8.03	41
42	LED	Non-Metered	200W	CLS 24		70	1.13	5.57	**6.70**	1.05	0.04	0.09	0.05	0.10	-	---	8.03	42
43	Municipal Street Lights - LED																	43
44	LED	n/a	100W	CLS 30		35	3.04	2.79	**5.83**	0.53	0.02	0.05	0.03	0.05	-	---	6.51	44
45	LED	n/a	200W	CLS 31		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	45
46	LED	n/a	200W	CLS 32		70	0.01	2.79	**2.80**	1.05	0.04	0.09	0.05	0.10	-	---	4.13	46
47	LED	Wood Pole	200W	CLS 33		70	3.05	2.79	**5.84**	1.05	0.04	0.09	0.05	0.10	-	---	7.17	47
48	LED	Wood Pole	200W	CLS 34		70	1.06	2.79	**3.85**	1.05	0.04	0.09	0.05	0.10	-	---	5.18	48
49																		49
50	Metered	Metered	Metered	Metered		Mtrd	0.05032	0.07960	**0.12992**	0.01500	0.00057	0.00132	0.00077	0.00142	0.00002	0.00039	0.14941	50
51																		51
52	Note: Municipal and Public Street Lights do not pay UEC charges.																	52

Nevada Power Company
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Proposed Residential Private Area Lighting (RS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01750	$ 0.00070	$ 0.00124	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	RS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.24	$ 6.14	**$ 13.38**	$ 1.28	$ 0.05	$ 0.09	$ 0.06	$ 0.10	$ -	0.03	$ 14.99	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.24	6.14	**13.38**	1.28	0.05	0.09	0.06	0.10	-	0.03	14.99	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	10.45	13.88	**24.33**	2.89	0.12	0.20	0.13	0.23	-	0.06	27.96	15
16	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.13	3.53	**9.66**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.59	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.13	3.53	**9.66**	0.74	0.03	0.05	0.03	0.06	-	0.02	10.59	17
18	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.58	6.98	**14.56**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.38	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.58	6.98	**14.56**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.38	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	10.45	13.88	**24.33**	2.89	0.12	0.20	0.13	0.23	-	0.06	27.96	20
21	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.97	6.14	**19.11**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.72	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	12.97	6.14	**19.11**	1.28	0.05	0.09	0.06	0.10	-	0.03	20.72	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.18	13.88	**30.06**	2.89	0.12	0.20	0.13	0.23	-	0.06	33.69	23
24	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.86	3.53	**15.39**	0.74	0.03	0.05	0.03	0.06	-	0.02	16.32	24
25	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	7.58	6.98	**14.56**	1.45	0.06	0.10	0.06	0.12	-	0.03	16.38	25
26	LED	RATE A (Existing pole)	200W	CLS 10		70	7.03	5.89	**12.92**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.47	26
27	LED	RATE A (Existing pole)	200W	CLS 12		70	5.58	5.89	**11.47**	1.23	0.05	0.09	0.05	0.10	-	0.03	13.02	27
28	LED	RATE A (Existing pole)	100W	CLS 14		35	5.61	2.95	**8.56**	0.61	0.02	0.04	0.03	0.05	-	0.01	9.32	28
29	LED	RATE A (Existing pole)	200W	CLS 15		70	6.77	5.89	**12.66**	1.23	0.05	0.09	0.05	0.10	-	0.03	14.21	29
30	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.71	5.89	**18.60**	1.23	0.05	0.09	0.05	0.10	-	0.03	20.15	30
31	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.08	5.89	**15.97**	1.23	0.05	0.09	0.05	0.10	-	0.03	17.52	31
32	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.23	2.95	**14.18**	0.61	0.02	0.04	0.03	0.05	-	0.01	14.94	32
33																		33
34																		34

Nevada Power Company
Statement O

Proposed General Service Private Area Lighting (GS-PAL) Rate Summary

Line No.	Lamp Type	Size & Pole Type	Watts	Class	Note	Monthly kWh	BTGR	BTER	**Proposed BTGR & BTER Rate**	DEAA Rate	TRED Rate	EE Rate	REPR Rate	NDPP Rate	ESAP Rate	UEC Rate	Total All Components Rate	Line No.
9																		9
10										$ 0.01500	$ 0.00057	$ 0.00113	$ 0.00077	$ 0.00142	$ 0.00002	$ 0.00039		10
11																		11
12	GS-PAL																	12
13	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	$ 7.39	$ 5.81	**$ 13.20**	$ 1.10	$ 0.04	$ 0.08	$ 0.06	$ 0.10	$ -	0.03	$ 14.61	13
14	Mercury Vapor	RATE A (Existing pole)	200W	CLS 10		73	7.39	5.81	**13.20**	1.10	0.04	0.08	0.06	0.10	-	0.03	14.61	14
15	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.15	13.13	**24.28**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.46	15
16	Mercury Vapor	RATE A (Existing pole)	200W	CLS 12		165	11.15	13.13	**24.28**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.46	16
17	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.11	3.34	**9.45**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.26	17
18	High Pressure	RATE A (Existing pole)	100W	CLS 14		42	6.11	3.34	**9.45**	0.63	0.02	0.05	0.03	0.06	-	0.02	10.26	18
19	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.80	6.61	**14.41**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.01	19
20	High Pressure	RATE A (Existing pole)	200W	CLS 15		83	7.80	6.61	**14.41**	1.25	0.05	0.09	0.06	0.12	-	0.03	16.01	20
21	High Pressure	RATE A (Existing pole)	200W	CLS 88		165	11.15	13.13	**24.28**	2.48	0.09	0.19	0.13	0.23	-	0.06	27.46	21
22	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 11		73	13.14	5.81	**18.95**	1.10	0.04	0.08	0.06	0.10	-	0.03	20.36	22
23	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.90	13.13	**30.03**	2.48	0.09	0.19	0.13	0.23	-	0.06	33.21	23
24	Mercury Vapor	RATE B (30 Foot pole)	200W	CLS 13		165	16.90	13.13	**30.03**	2.48	0.09	0.19	0.13	0.23	-	0.06	33.21	24
25	High Pressure	RATE B (30 Foot pole)	100W	CLS 16		42	11.86	3.34	**15.20**	0.63	0.02	0.05	0.03	0.06	-	0.02	16.01	25
26	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.55	6.61	**20.16**	1.25	0.05	0.09	0.06	0.12	-	0.03	21.76	26
27	High Pressure	RATE B (30 Foot pole)	200W	CLS 17		83	13.55	6.61	**20.16**	1.25	0.05	0.09	0.06	0.12	-	0.03	21.76	27
28	LED	RATE A (Existing pole)	200W	CLS 10		70	7.18	5.57	**12.75**	1.05	0.04	0.08	0.05	0.10	-	0.03	14.10	28
29	LED	RATE A (Existing pole)	200W	CLS 12		70	5.89	5.57	**11.46**	1.05	0.04	0.08	0.05	0.10	-	0.03	12.81	29
30	LED	RATE A (Existing pole)	100W	CLS 14		35	5.57	2.79	**8.36**	0.53	0.02	0.04	0.03	0.05	-	0.01	9.04	30
31	LED	RATE A (Existing pole)	200W	CLS 15		70	6.94	5.57	**12.51**	1.05	0.04	0.08	0.05	0.10	-	0.03	13.86	31
32	LED	RATE A (Existing pole)	200W	CLS 88		70	5.89	5.57	**11.46**	1.05	0.04	0.08	0.05	0.10	-	0.03	12.81	32
33	LED	RATE B (30 Foot pole)	200W	CLS 11		70	12.88	5.57	**18.45**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.80	33
34	LED	RATE B (30 Foot pole)	200W	CLS 13		70	10.46	5.57	**16.03**	1.05	0.04	0.08	0.05	0.10	-	0.03	17.38	34
35	LED	RATE B (30 Foot pole)	100W	CLS 16		35	11.20	2.79	**13.99**	0.53	0.02	0.04	0.03	0.05	-	0.01	14.67	35
36	LED	RATE B (30 Foot pole)	200W	CLS 17		70	12.49	5.57	**18.06**	1.05	0.04	0.08	0.05	0.10	-	0.03	19.41	36
37																		37
38																		38

			Distribution Charges				Contract Demand Charges, contract kW[4]			Backup Service Variable T&G Demand Charges, metered kW			BTGR Energy, per kWh (including interclass rate rebalancing)[5,6]				Maintenance Back-up Service[7]		
Line No.		Class	Distribution Charge, per Cust:	Additional Meter/ Generation Meter Charge[8]	Facilities Charge, per customer for SS-I and II, per kW for LSR and SSR-III[3]	Facilities Charge, per kW[2,3]	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Other:	Sum On Peak:	Sum Mid Peak:	Sum Off Peak:	Other:	Set @ 50% of Summer On-peak Variable T&G Demand Charges	BTER Energy, per kWh	Line No.
9	SSR II	SS-II GS	25.50	2.00	7.75											0.00476		0.07960	9
10	SSR III	LGS-1	15.80	5.75	4.25	$ 4.25			$ 1.55			$ 3.63				0.01212	$ 1.82	0.07960	10
11	LSR I	LGS-2S	122.40	12.25	2.80	2.80	$ 4.38	$ 0.94	0.24	$ 10.21	$ 2.20	0.56	$ 0.01786	$ 0.00934	$ 0.00541	0.00549	5.11	0.07960	11
12	LSR I	LGS-2P	207.70	54.75	2.85	2.85	3.77	0.88	0.24	8.78	2.05	0.56	0.00944	0.00637	0.00535	0.00536	4.39	0.07960	12
13	LSR I	LGS-2T	182.00	89.25	CSF	0.91	4.07	0.88	0.30	9.51	2.04	0.70	0.02728	0.01132	0.00157	0.00190	4.76	0.07960	13
14	LSR II	LGS-3S	122.00	15.00	2.80	2.80	4.34	1.11	0.30	10.12	2.58	0.70	0.01732	0.00880	0.00525	0.00525	5.06	0.07960	14
15	LSR II	LGS-3P	214.10	68.25	2.65	2.65	3.83	1.03	0.33	8.93	2.40	0.77	0.01436	0.01058	0.00549	0.00635	4.47	0.07960	15
16	LSR II[2]	LGS-3T	182.00	89.25	CSF	0.91	4.07	0.88	0.30	9.51	2.04	0.70	0.02728	0.01132	0.00157	0.00190	4.76	0.07960	16
17	LSR III[9]	LGS-XS	4,743.00	16.90	2.25	2.25	4.34	1.11	0.30	10.12	2.58	0.70	0.01732	0.00880	0.00525	0.00525	5.06	0.07960	17
18	LSR III[9]	LGS-XP	4,743.00	54.30	3.05	3.05	3.83	1.03	0.33	8.93	2.40	0.77	0.01436	0.01058	0.00549	0.00635	4.47	0.07960	18
19	LSR III[1,9]	LGS-XT	4,743.00	92.70	CSF	na	4.07	0.88	0.30	9.51	2.04	0.70	0.02728	0.01132	0.00157	0.00190	4.76	0.07960	19
20	LSR I WP	LGS-2-WPS	128.70	12.25	1.10	1.10	5.32	5.32	0.24	12.41	12.41	0.56	0.03680	0.01838	0.02396	0.02397	6.21	0.07960	20
21	LSR I WP	LGS-2-WPP	208.60	54.75	1.55	1.55	4.64	4.64	0.24	10.84	10.84	0.56	0.02090	0.00582	0.00818	0.00819	5.42	0.07960	21
22	LSR I WP	LGS-2-WPT	169.10	93.00	CSF	0.91	4.95	4.95	0.30	11.55	11.55	0.70	0.01522	0.02328	0.00142	0.00673	5.78	0.07960	22
23	LSR II WP	LGS-3-WPS	149.90	15.00	1.25	1.25	5.45	5.45	0.30	12.70	12.70	0.70	0.10120	0.08565	0.00437	0.00438	6.35	0.07960	23
24	LSR II WP	LGS-3-WPP	234.20	68.25	1.00	1.00	4.86	4.86	0.33	11.33	11.33	0.77	0.02334	0.01915	0.00202	0.00203	5.67	0.07960	24
25	LSR II WP	LGS-3-WPT	189.10	89.25	CSF	0.91	5.09	5.09	0.33	11.86	11.86	0.77	0.01752	0.03933	(0.00427)	0.00067	5.93	0.07960	25

note: while not shown in this table, DEAA is applicable to standby service.

1. CSF = customer specific facilities charges.
2. The facilities charge for SSR-I includes all of the cost-based Rule 9 facilities costs not recovered in the applicable customer charge and 10 percent of the cost-based primary distribution costs. SSR-II facilities recover the balance of the cost-based primary distribution costs not recovered in the applicable basic service charge. For SSR-III, LSR-I, LSR-II and LSR-III the facilities charge, if applicable, is the cost-based charge under the otherwise applicable rate schedule (OAS), or the CSF cha (see note 1 above). For most transmission-level customers, facilities charges do not apply, as they have no primary distribution costs and have typically funded their (Rule 9) extension costs. If facilities costs do apply, then they are customer spe
3. This is a lower, alternative facilities charge which recovers only the cost based (primary) distribution facilities costs applicable under the OAS. This lower charge is applicable when the customer has paid for the all of the costs of their interconnection facilities. This alternative facilities charge is not applicable to SSR I and SSR II, and is not applicable when a CSF charge applies instead.
4. The contract demand charge is set at 30% of current tariff demand charges in each rating period, reflecting the 3-year average diversity factor of all standby customers.
5. The BTGR for SSR-1 and SSR-II is adjusted downward from the BTGR charge of the OAS because a greater portion of facilities costs are being recovered from these customers on a per customer basis than is being recovered in the OAS. See note
6. Other than as explained in note 5, the BTGR rates are those of the otherwise applicable class including the IRR.
7. Energy rates in maintenance periods are the same as those during non-maintenance periods -- see BTGR and BTER columns for applicable rates.
8. SSR-I and SSR-II charges are the incremental cost based customer and meter charges associated with this standby service. For all other classes the charge is a per meter charge and recovers the cost-based meter costs and other associated costs
9. For the LGS-XS and LGS-XP customers, in addition to the per kW charges shown, they will also continue to pay the CSF charges that are currently applicable under the otherwise applicable LGS-X schedule. For the LGS-XT class, only CSF charges

Proposed Distribution Only Service (DOS) Rates

Line No.	Class	Note	Distribution Charge, per Customer	Total Facilities Charge, per kW (1)	Additional Meter Charge, per Meter	LGSX CSF Charges (monthly dollar charge for entire class)	NDPP	ESAP	Non-Bypassable Energy Charges Interclass Rate Rebalancing (IRR)	Line No.
8	GS	1	$ 25.50		$ 2.00		$ 0.00142	$ 0.00002	$ 0.00920	8
9	LGS-1	1	15.80	$ 4.25	5.75		0.00142	0.00002	0.00369	9
10	LGS-2S		122.40	2.80	12.25		0.00142	0.00002	0.00473	10
11	LGS-2P		207.70	2.85	54.75		0.00142	0.00002	0.00512	11
12	LGS-2T	2	182.00	0.91	89.25		0.00142	0.00002	0.00369	12
13	LGS-3S		122.00	2.80	15.00		0.00142	0.00002	0.00527	13
14	LGS-3P		214.10	2.65	68.25		0.00142	0.00002	0.00610	14
15	LGS-3T	2	182.00	0.91	89.25		0.00142	0.00002	0.00334	15
16	LGS-XS	3	4,743.00	2.25	16.90	$ 1,802.00	0.00142	0.00002	0.00527	16
17	LGS-XP	3	4,743.00	3.05	54.30	$ 53,727.00	0.00142	0.00002	0.00610	17
18	LGS-XT	3	4,743.00	na	92.70	$ 30,724.00	0.00142	0.00002	0.00334	18
19	LGS-2S-WP		128.70	1.10	12.25		0.00142	0.00002	0.01178	19
20	LGS-2P-WP		208.60	1.55	54.75		0.00142	0.00002	0.00709	20
21	LGS-2T-WP	2	169.10	0.91	93.00		0.00142	0.00002	0.00837	21
22	LGS-3S-WP		149.90	1.25	15.00		0.00142	0.00002	0.00659	22
23	LGS-3P-WP		234.20	1.00	68.25		0.00142	0.00002	0.00687	23
24	LGS-3T-WP	2	189.10	0.91	89.25		0.00142	0.00002	0.00837	24
25	SL	4					0.00142	0.00002		25
26	GS-Pal	4					0.00142	0.00002		26
27										27
28	Additional Charges:									28
29	Separate Billing									29
30	DOS LGS-X & LGS-WP-X:			$ 12.00	Per additional bill					30
31	Power Factor Charges ($/kVarh)[5]:									31
32	Summer:			$ 0.00200	$/kVarh					32
33	Winter:			0.00100	$/kVarh					33
34	Non-X class Customer Specific Facilities:			0.00322	Per $ of Utility Investment					34
35				0.00059	$ per Customer Contributed Investment					35
36	R-BTER - 2016 charge ($/kWh)[6]:			0.00139						36
37	R-BTER - 2017 charge ($/kWh)[6]:			0.00095						37
38	DECOM REV									38

(1) The facilities charge is included in the per customer charge for the GS classes. For LGS-1, the charge is based on the kW monthly demand per meter. For all other customers, it is based on the highest measured demand in the billing period and the prior twelve billing periods. For non-transmission level customers and the non-LGSX customers, the facilities charges recover both the Rule 9 facility and primary distribution facilities costs.

(2) The non-LGSX transmission-level customers have customer specific facilities (CSF) charges, with the rate applied on per dollar of investment. CSF charges may apply to either the investment made by NPC in the customers facilities or the customer's contributed investment (for O&M recovery). The per kW rate shown in this table is the average per kW facility rate for the class as a whole for NPC-related facilities. This average per kW rate may be applied only to new customers on a temporary basis should the details of the facility calculations be incomplete at the start of service. All new, permanent customers served under these tariffs will be placed on a CSF charges as soon as reasonably practical.

(3) As in present rates, for the LGS-X class, the per kW distribution facility charge applies to only the LGSX-S and LGSX-P customers, who pay for their share of the primary distribution system through this charge. In addition to this charge, these customers continue to pay a CSFC based upon the cost of the facilities identified to serve them.

(4) RS-Pal is not eligible for DOS service. The Streetlights and GS-PAL proposed DOS rates are shown on pages 14 and 16 of Statement O.

(5) This charge is per kvarh in excess of 90% Power Factor (PF) for all classes except OLGS-3P HLF and LGS-X, which uses a 95% threshold. For all other classes the PF threshold is 90%.

(6) Rates do not apply to all DOS customers and are charged only to applicable customers.

Line No.	Class[1]	Sales (kWh)	Marginal Generation Revenue	Reconciled Generation Cost per kWh[2]	Line No.
8	**Bundled Service**				8
9	GS	612,055,143	$ 11,682,776	$ 0.01909	9
10	LGS-1	4,073,133,716	88,089,634	0.02163	10
11	LGS-2S	2,429,180,261	47,002,822	0.01935	11
12	LGS-2P	69,583,297	1,154,037	0.01658	12
13	LGS-2T	no customers	(set @ LGS-3T)	0.04176	13
14	LGS-3S	768,658,032	13,529,921	0.01760	14
15	LGS-3P	1,393,295,183	31,761,998	0.02280	15
16	LGS-3T	247,665,929	10,343,274	0.04176	16
17	LGS-XS	0	(set @ LGS-3S)	0.01760	17
18	LGS-XP	0	(set @ LGS-3P)	0.02280	18
19	LGS-XT	0	(set @ LGS-3T)	0.04176	19
20	LGS-2S-WP	14,877,558	239,935	0.01613	20
21	LGS-2P-WP	11,147,772	126,217	0.01132	21
22	LGS-2T-WP	no customers	(set @ LGS-3T)	0.04176	22
23	LGS-3S-WP	4,412,814	26,173	0.00593	23
24	LGS-3P-WP	19,004,483	137,822	0.00725	24
25	LGS-3T-WP	no customers	(set @ LGS-3T)	0.04176	25
26	SL	129,054,441	2,032,887	0.01575	26
27	GS-Pal	2,217,456	35,580	0.01605	27
28	IAIWP	no customers	(set @ LGS-3S)	0.02163	28
29					29
30	**Current LSR & Optional/Trial TOU Classes with Customers:**				30
31	LSR-1: LGS-2S		(set @ LGS-2S)	0.01935	31
32	LSR-1: LGS-2P		(set @ LGS-2P)	0.01658	32
33	LSR-1: LGS-2T		(set @ LGS-2T)	0.04176	33
34	LSR-2: LGS-3P		(set @ LGS-3P)	0.01760	34
35	LSR-2: LGS-3T		(set @ LGS-3T)	0.04176	35
36	LSR-2: LGS-3S-WP		(set @ LGS-3S-WP)	0.00593	36
37	LSR-2: LGS-3P-WP		(set @ LGS-3P)	0.00725	37
38	LSR-2: LGS-2S-WP		(set @ LGS-2S)	0.01613	38
39	OGS-TOU		(set @ GS)	0.01909	39
40	OLGS-1-TOU		(set @ LGS-1)	0.02163	40
41					41
42	**DOS Classes:**				42
43	DOS: GS		(set @ GS)	0.01909	43
44	DOS: LGS-1		(set @ LGS-1)	0.02163	44
45	DOS: LGS-2S		(set @ LGS-2S)	0.01935	45
46	DOS: LGS-3S		(set @ LGS-3S)	0.01760	46
47	DOS: LGS-3P		(set @ LGS-3P)	0.02280	47
48	DOS: LGS-3T		(set @ LGS-3T)	0.04176	48
49	DOS: LGS-2S-WP		(set @ LGS-2S-WP)	0.01613	49
50	DOS: LGS-2T-WP		(set @ LGS-2T-WP)	0.04176	50
51	DOS: LGS-3S-WP		(set @ LGS-3S-WP)	0.00593	51
52	DOS: LGS-3P-WP		(set @ LGS-3P-WP)	0.00725	52
53	DOS: LGS-3T-WP		(set @ LGS-3T-WP)	0.04176	53
54					54

55 1. Rates are shown only for classes containing customers with the potential of going open access under AB 661 or SB 211 provisions. 55
56 For customer served under DOS, LSR, OGS-TOU and OLGS-1-TOU, the applicable generation capacity rates will be set at those of an otherwise 56
57 applicable schedule (OAS). For these classes that presently have customers served, the applicable OAS is shown in the table. 57
58 2. This rate is the marginal generation cost reconciled to the generation revenue requirement stated on a per kWh basis for the class. 58
59 Reconciliation factor is: 107.2% 59

Calculation of Customer Specific Facilities Charges

Line No.		Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	Line No.
	Customer Specific Facility Investment & Revenue Requirement					Total			
7	Investment Cost for all Transmission level customers					$ 42,182,585			7
8	Total Annual Marginal Cost Revenue Requirement associated with the T-level customer specific investment					$ 3,293,268			8
9	Marginal Cost: $ of Revenue Req. per $ of Marginal Investment (line 8/line 7)					$ 0.07807			9
10	Distribution Reconciliation Factor					62.8%			10
11	Reconciled: Annual $ of Reconciled Revenue Req. per $ of Investment (line 9 * line 10)					$ 0.03861			11
12									12
13	**CSF Charges By Customer Per Dollar of Facilities Investment Factor Developed above**								13
16	Individual CSFC	Class	Group	NVE Investment	Annual $ Per $ of Facility Investment	Annual Fac Rev By Customer	Monthly Per $ of Fac Invest. Factor	Monthly Fac Revenue By Customer	16
17	LHOIST	LGS-3T	Bundled	$ 744,171	$ 0.03861	$ 28,755	$ 0.00322	$ 2,396.23	17
18	SA RECYCLING	LGS-3T	Bundled	1,366,297	0.03861	52,794	0.00322	4,399.48	18
19	VENETIAN	LGS-3T	Bundled	6,606,728	0.03861	255,284	0.00322	21,273.66	19
20	HOLDER	LGS-3T	Bundled	2,136,118	0.03861	82,540	0.00322	6,878.30	20
21	SNWA LAMB	LGS-3T	DOS	286,690	0.03861	11,078	0.00322	923.14	21
22	SNWA LAMB	LGS-3T	DOS	286,690	0.03861	11,078	0.00322	923.14	22
23	SNWA SLOAN	LGS-3T	DOS	697,203	0.03861	26,940	0.00322	2,244.99	23
24	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03861	24,030	0.00322	2,002.51	24
25	CITY OF HENDERSON2	LGS-3T	DOS	621,897	0.03861	24,030	0.00322	2,002.51	25
26	CCWRD2	LGS-3T	DOS	110,617	0.03861	4,274	0.00322	356.19	26
27	CCWRD2	LGS-3T	DOS	62,534	0.03861	2,416	0.00322	201.36	27
28	CCWRD2	LGS-3T	DOS	693,608	0.03861	26,801	0.00322	2,233.42	28
29	MGM	LGS-3T	DOS	22,571,345	0.03861	872,157	0.00322	72,679.73	29
30	MGM	LGS-3T	DOS	1,434,005	0.03861	55,410	0.00322	4,617.50	30
31	CAESAR'S	LGS-3T	DOS	1,025,601	0.03861	39,629	0.00322	3,302.44	31
32	AIR LIQUIDE	LGS-3T	DOS	96,488	0.03861	3,728	0.00322	310.69	32
33	SNWA PP4	LGS-3T-WP	DOS	30,192	0.03861	1,167	0.00322	97.22	33
34	SNWA PP5	LGS-3T-WP	DOS	1,370,352	0.03861	52,950	0.00322	4,412.53	34
35	SNWA PP6	LGS-3T-WP	DOS	672,178	0.03861	25,973	0.00322	2,164.41	35
36	SNWA HACIENDA	LGS-3T-WP	DOS	327,114	0.03861	12,640	0.00322	1,053.31	36
37	SNWA PP3	LGS-2T-WP	DOS	420,860	0.03861	16,262	0.00322	1,355.17	37
38	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	1,891,817	0.03861	73,100	0.00322	6,091.65	38
39	NP RED ROCK LLC	OLGS-3P HLF	Bundled	814,244	0.03861	31,462	0.00322	2,621.87	39
40	POLY-WEST INC	OLGS-3P HLF	Bundled	275,872	0.03861	10,660	0.00322	888.31	40
41	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	376,661	0.03861	14,554	0.00322	1,212.85	41
42	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	951,162	0.03861	36,753	0.00322	3,062.74	42
43	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	488,832	0.03861	18,888	0.00322	1,574.04	43
44	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	628,800	0.03861	24,297	0.00322	2,024.73	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	623,669	0.03861	24,099	0.00322	2,008.21	45
46	POLY-WEST 2089379	OLGS-3P HLF	Bundled	275,872	0.03861	10,660	0.00322	888.31	46
47									47
48									48
49									49
50									50
51	Subtotals by Class and Service								51
52	LGS-3T - Bundled	LGS-3T	Bundled	$ 10,853,314	0.03861	419,372	0.00322	34,948	52
53	LGS-3T - DOS	LGS-3T	DOS	28,508,575	0.03861	1,101,571	0.00322	91,798	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	0.03861	-	0.00322	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	420,860	0.03861	16,262	0.00322	1,355	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	0.03861	-	0.00322	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	2,399,836	0.03861	92,730	0.00322	7,727	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	6,326,928	0.03861	244,473	0.00322	20,373	58
59					avg.		avg.		59
60	Total			$ 48,509,514	0.03864	$ 1,874,408	0.00322	$ 156,201	60
61					rounding>>	$ 0		$ (0)	61
62	**Temporary Transmission level per kW Facility Charge (Charged until CSF charge is developed)**						^^^^^^^^^^^^		62
63							Proposed		63
64	Investment Cost for Transmission level customers:					$ 42,182,585	Tariff Recovery		64
65	Total Annual Marginal Cost Revenue Requirement associated with the customer specific investment (line 64 * line 11):					$ 3,293,268	Rate per Dollar		65
66	Distribution Reconciliation Factor (line 11):					62.8%	of Facility		66
67	Reconciled Investment Cost (line 66 * line 65):					$ 2,069,682	Investment		67
68	Annual facility kW determinants					2,270,623			68
69	Per kW facilty rate (line 67 / Line 68)					$ 0.91			69

Calculation of Transmission Level Customer Specific Facilities O&M and A/G Customer Specific Rates Relating to Contributed (CIAC) Investment

Line No.	**Development of Annual & Monthly Per Dollar of Investment Recovery Rate**						Line No.
7		(a)	(b)			(c)	7
8	Annual: Dist Reconciliation Factor	x	Dollar O&M/A&G Recovery Per Dollar of Contributed Investment				8
9	62.8%	x	$0.01062	=	$	0.00668	9
10	Monthly: (annual rate divided by 12)			=	$	0.00059	10
11							11
12							12

Line No.	**CIAC Investment & O&M and A&G Revenue Requirement** Customer	Class	Group	Contributed Investment	Annual Revenue Requirement	Dollar Per Dollar of Investment $ (cost based -- before reconciliation) [(b) / (a)]	Per Dollar O&M/A&G Recovery Per Dollar of CIAC'd Facility Investment & Charges by Customer: Original CIAC Investment	Monthly Per $ of CIAC'd Investment	Monthly Payment [(d) * (e)]	Annual Payment	Line No.
17											17
18	LHOIST	LGS-3T	Bundled	-	$ -	$0.01062	$ -	$ 0.00059	$ -	$ -	18
19	SA RECYCLING	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	19
20	VENETIAN	LGS-3T	Bundled	-	-	$0.01062	-	0.00059	-	-	20
21	HOLDER	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	21
22	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	22
23	SNWA LAMB	LGS-3T	DOS	453,810	4,820	$0.01062	453,810	0.00059	267.75	3,213.00	23
24	SNWA SLOAN	LGS-3T	DOS	826,580	8,780	$0.01062	826,580	0.00059	487.68	5,852.16	24
25	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	25
26	CITY OF HENDERSON2	LGS-3T	DOS	1,191,000	12,650	$0.01062	1,191,000	0.00059	702.69	8,432.28	26
27	CCWRD2	LGS-3T	DOS	374,615	3,979	$0.01062	374,615	0.00059	221.02	2,652.24	27
28	CCWRD2	LGS-3T	DOS	211,779	2,249	$0.01062	211,779	0.00059	124.95	1,499.40	28
29	CCWRD2	LGS-3T	DOS	2,348,976	24,950	$0.01062	2,348,976	0.00059	1,385.90	16,630.80	29
30	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	30
31	MGM	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	31
32	CAESAR'S	LGS-3T	DOS	-	-	$0.01062	-	0.00059	-	-	32
33	AIR LIQUIDE	LGS-3T	DOS	4,942,256	52,495	$0.01062	4,942,256	0.00059	2,915.93	34,991.16	33
34	SNWA PP4	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	34
35	SNWA PP5	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	35
36	SNWA PP6	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	36
37	SNWA HACIENDA	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	37
38	SNWA PP3	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	38
39	CLEARWATER PAPER CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	39
40	NP RED ROCK LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	40
41	POLY-WEST INC	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	41
42	STATION GVR ACQUISITION LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	42
43	TRUMP RUFFIN COMMERCIAL LLC	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	43
44	SUNSET STATION 1641830	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	44
45	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	45
46	STRATOSPHERE CORPORATION	OLGS-3P HLF	Bundled	-	-	$0.01062	-	0.00059	-	-	46
47	POLY-WEST 2089379	OLGS-3P HLF	Bundled	51,773	550	$0.01062	51,773	0.00059	30.55	366.60	47
48											48
49											49
50											50
51	Subtotals by Class and Service										51
52	LGS-3T - Bundled	LGS-3T	Bundled	7,223,845	76,729	$0.01062	7,223,845	0.00059	4,262.07	51,144.84	52
53	LGS-3T - DOS	LGS-3T	DOS	11,993,826	127,395	$0.01062	11,993,826	0.00059	7,076.36	84,916.32	53
54	LGS-2T-WP - Bundled	LGS-2T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	54
55	LGS-2T-WP - DOS	LGS-2T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	55
56	LGS-3T-WP - Bundled	LGS-3T-WP	Bundled	-	-	$0.01062	-	0.00059	-	-	56
57	LGS-3T-WP - DOS	LGS-3T-WP	DOS	-	-	$0.01062	-	0.00059	-	-	57
58	OLGS-3P-HLF Bundled	OLGS-3P HLF	Bundled	103,546	1,100	$0.01062	103,546	0.00059	61.09	733.08	58
59											59
60	Total			$ 19,321,217	$ 205,224	$0.01062	$ 38,642,434		$ 11,399.52	$ 136,794.24	60
61						Marginal O&M from MCS					61
62						$205,224					62

Nevada Power Company
Statement O

Calculation of LGS-X Specific Charges

Exhibit Prest Direct-6
Docket No. 23-06XXX
MCS, per NRS, Current TOU, Joint Dispatch, RS Cap

Line No.		Basic Service Charge: Billing Units	Basic Service Charge: Cost-Based Revenue	Basic Service Charge: Rate	Additional Meter Charge: Billing Units	Additional Meter Charge: Cost-Based Revenue	Additional Meter Charge: Rate	Separate Bill: Billing Units	Separate Bill: Cost-Based Revenue	Separate Bill: Rate	Line No.
7	**Basic Service, Additional Meter and Separate Billing Charges**										7
8			Dist Recon.	63%							8
11	LGS-XS	-	$ -		60	$ 1,013.89	$ 16.90	-	$ -		11
12	LGS-XP	24	$ 29,351.72	$ 1,222.99	156	$ 8,476.42	$ 54.30	24	$ 273.84	$11.41	12
13	LGS-XT	12	$ 14,675.86	$ 1,222.99	36	$ 3,335.91	$ 92.70	12	$ 136.92	$11.41	13
14	Total	36	$ 44,027.58	**$4,743.00**	252	$ 12,826.22	**$50.90**	36	$ 410.76	**$12.00**	14
15			Present DOS Rate:	$4,743.00					Present Rate:	$93.50	15
16			Percent Change:	0.0%					Percent Change:	-87.2%	16
17											17

Line No.	Customer	Premise	Rate Schedule	Current Charges: Monthly Facilities Charge	Current Charges: Annual Facilities Revenue	Current Charges: Investment	Proposed Charges: Monthly Facilities Charge	Proposed Charges: Annual Facilities Revenue	Proposed Charges: Investment	Line No.
18	**LGS-X Customer Specific Facilities**									18
19										19
20										20
22	Horseshoe	1231089	LGS-XP DOS	$ 3,740	$ 44,880		$ 4,191	$ 50,292		22
23	Horseshoe	1231091	LGS-XS DOS	1,608	19,296		1,802	21,624		23
24	Paris	1735149	LGS-XP DOS	5,068	60,816		5,679	68,148		24
25	Paris	1735152	LGS-XP DOS	5,068	60,816		5,679	68,148		25
26				$ 15,484	$ 185,808	$ 2,066,291	$ 17,351	$ 208,212	$ 2,189,516	26
27										27
34	New Castle Corp (Excalibur)	1396169	LGS-XP DOS	$ 4,710	$ 56,520		$ 5,006	$ 60,072		34
35	New Castle Corp (Excalibur)	1396170	LGS-XP DOS	4,687	56,244		4,981	59,772		35
36	New Castle Corp (Excalibur)	1415346	LGS-XS DOS	-	-		-	-		36
37	New Castle Corp (Excalibur)	1415347	LGS-XS DOS	-	-		-	-		37
38	Luxor	1500684	LGS-XP DOS	5,640	67,680		5,994	71,928		38
39	Luxor	1500685	LGS-XP DOS	7,006	84,072		7,446	89,352		39
40	Luxor	1511139	LGS-XS DOS	-	-		-	-		40
41	Luxor	1652129	LGS-XP DOS	1,698	20,376		1,805	21,660		41
42	Mandalay Bay	1714502	LGS-XP DOS	6,090	73,080		6,473	77,676		42
43	Mandalay Bay	1714503	LGS-XP DOS	6,090	73,080		6,473	77,676		43
44	New Castle Corp (Excalibur)	1758368	LGS-XP DOS	-	-		-	-		44
45				$ 35,921	$ 431,052	$ 4,885,159	$ 38,178	$ 458,136	$ 4,885,159	45
46										46
47	Park MGM	1607748	LGS-XT DOS	$ -	$ -		$ -	$ -		47
48	Park MGM	1607750	LGS-XT DOS	9,790	117,480		10,335	124,020		48
49	Bellagio	1656755	LGS-XP DOS	-	-		-	-		49
50	Bellagio	1656777	LGS-XP DOS	-	-		-	-		50
51	Bellagio	1693991	LGS-XT DOS	19,315	231,780		20,389	244,668		51
52	Park MGM	1782548	LGS-XP DOS	-	-		-	-		52
53				$ 29,105	$ 349,260	$ 3,841,860	$ 30,724	$ 368,688	$ 3,841,860	53
54										54
55		Subtotals by Class and Service	LGS-XS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	55
56			LGS-XP	-	-	-	-	-	-	56
57			LGS-XT	-	-	-	-	-	-	57
58			LGS-XS DOS	**1,608**	**19,296**	-	**1,802**	**21,624**	-	58
59			LGS-XP DOS	**49,797**	**597,564**	-	**53,727**	**644,724**	-	59
60			LGS-XT DOS	**29,105**	**349,260**	-	**30,724**	**368,688**	-	60
61			Total for Class	**$ 80,510**	**$ 966,120**	**$ -**	**$ 86,253**	**$ 1,035,036**	**$ -**	61
62										62

63 Note: The allocation of CSFC's among accounts was done by keeping the Transmission & Secondary charges the same as Current (Since the underlying Investment has remained the same), and allocating the Primary Charges in proportion to the 63
64 current Primary charges. 64