NEVADA POWER COMPANY
d/b/a NV Energy

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.

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Docket No. 17- 06____

VOLUME 11 of 26

Prepared Direct Testimony of:

Rate Design
Timothy Pollard
Janet Wells
Marc D. Reyes
Laura I. Walsh

Recorded Test Year ended December 31, 2016
Certification Period ended May 31, 2017
## Rate Design:

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA
Nevada Power Company d/b/a NV Energy
2017 General Rate Case
Docket No. 17-06___

Rate Design

PREPARED DIRECT TESTIMONY OF

Timothy Pollard

1. INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.
   A. My name is Timothy Pollard. I am a Technical Lead in the Regulatory Analysis,
      Policy & Regulatory Strategy group in the Rates and Regulatory Affairs
      Department for Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) and
      Nevada Power Company d/b/a NV Energy (“Nevada Power” or the “Company”
      and together with Sierra, the “Companies”). My business address is 6100 Neil
      Road in Reno, Nevada. I am filing testimony in this proceeding on behalf of
      Nevada Power.

2. Q. DOES EXHIBIT POLLARD-DIRECT-1 ACCURATELY DESCRIBE
       YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL
       EXPERIENCE AND CURRENT JOB RESPONSIBILITIES?
   A. Yes, it does.

3. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC
       UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?
A. Yes. Most recently, I filed testimony with the Commission in Sierra’s last general rate case, Docket Nos. 16-06006, et al.

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

A. First I sponsor the technical aspects and mechanics of the Company’s revenue reconciliation and price (or rate) calculations. These are set forth in the Statement O model and workpapers that support the Company’s primary proposal for this filing—to maintain the current total revenue requirement at present rate levels through the Expected Change in Circumstance ("ECIC") period. I also support three additional Statement Os and corresponding workpapers that demonstrate class revenues and rates developed to reflect:

1) A version of Statement O that reflects results through the certification period, labeled “CERT,” which also maintains the total revenue requirement at present rate revenues ("PRR");

2) A version of Statement O that reflects results through the ECIC period, and for which a revenue requirement of $31.7 million (exclusive of other revenue) is calculated pursuant to NRS Chapter 704 and NAC Chapter 703;\(^1\) and

3) A version of Statement O that reflects results through the certification, and for a revenue requirement of $31.0 million (exclusive of other

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\(^1\) In particular Nevada Revised Statutes ("NRS") § 704.110(3) and (4), and Nevada Administrative Code ("NAC") §§ 703.2201 through 703.2481, inclusive.
revenue) is calculated pursuant to NRS Chapter 704 and NAC Chapter 703.

Next I support the Company’s rate design proposals, including the rate design for two newly proposed optional schedules for residential customers. Ms. Laura Walsh supports the rationale, implementation and estimated savings for these new schedules in her prepared direct testimony.

Next, in compliance with the Commission order in Docket 14-05004, I support the analysis of the Company’s analysis of “rate tilt” within the larger commercial classes with TOU demand and energy charges.

Finally, I support the development of the load shapes of the partial requirements Net Energy Metering (“NEM”) classes. This work is supported by the hourly customer class shapes developed by Ms. Janet Wells and used by Ms. Shana Ramirez in the development of the marginal cost responsibility factors that Mr. Jeff Bohrman uses for developing the marginal cost to serve these classes. I then use Mr. Bohrman’s MCS study results to prepare the rate design for these classes.

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

A. My testimony is organized into the following five sections:

Section I, Introduction;

Section II, Statement O and Major Rate Design Proposals;

Section III, Analysis of Rate Design Proposals;
Section III, Revenue Reconciliation;

Section IV, Rate Design; and

Section V, Net-Energy Metering (“NEM”) Cost of Service Load Shapes and Billing Determinants.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?
A. Yes, four exhibits are attached to my testimony. They are:
   • Exhibit Pollard Direct-1, Statement of Qualifications;
   • Exhibit Pollard Direct-2, Statement O Revenue Comparison;
   • Exhibit Pollard Direct-3, Rate Design Whitepaper;
   • Exhibit Pollard Direct-4, Rate Tilt Analysis.

II. STATEMENT O AND MAJOR RATE DESIGN PROPOSALS

7. Q. WHAT IS THE PURPOSE OF STATEMENT O?
A. NAC § 704.2445 sets forth the requirements and purposes of Statement O. Unlike other required statements in the general rate case, NAC § 704.2445 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 that objective is to be achieved, and must be accompanied by a summary analyzing cost that would justify the design.” The regulation also provides that if the rate 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 § 704.2445, Nevada Power has set forth and described the development of proposed rates for all classes of customers, including bundled service and distribution-only service ("DOS") customers. Nevada Power has calculated four different revenue requirements, and thus I have prepared four different Statement Os. Each Statement O begins with revenues at full marginal cost from one of the two marginal cost of service studies ("MCS") as supported by Mr. Bohrman. Revenues reflecting full marginal cost are then reconciled to the unbundled embedded revenue requirement from Statement H, to set class revenue requirements. In each Statement O, deviations from, and restrictions imposed on, the adherence to marginal costs imposed by public policy are disclosed and discussed. For each Statement O, the detailed marginal cost relationships across functions, TOU periods and classes are used to set the proposed rates for each class. Rates are designed to recover the annual revenue requirement given the test period billing determinants from Statement J.

8. Q. PLEASE SUMMARIZE NEVADA POWER’S PREFERRED VERSION OF STATEMENT O.

A. The Company’s preferred proposal is to maintain residential rates at current levels so that total proposed rate revenues remain equal to the revenue resulting from current rates. In the preferred proposal, Nevada Power seeks to recognize two ECIC events that impact rate design—the conversion of two large commercial customers from bundled retail electric to DOS-only service during
the ECIC period. In order to incorporate revenues collected from the Commission-ordered regulatory asset charges from these customers, as well as changes in billing determinants associated with their conversion to DOS, as well as to implement a few minor adjustments to current rates, Nevada Power’s preferred rate proposal includes five modest adjustments that impact a subset of classes. The change in class present revenues resulting from these adjustments are credited back and allocated based on class sales to all other non-subsidized classes in order to maintain the same level of total revenues. The adjustments are detailed individually later in my testimony.

9. Q. HOW ARE THE FOUR STATEMENTS OS DIFFERENT FROM ONE ANOTHER?

A. All four Statement Os are being included in the filing, and executable electronic versions of all four Statement O models, including the corresponding workpapers, are being provided to the Commission, Staff and BCP with the filing. The four statements (with their corresponding change in revenue requirement) are:

1. **Company Proposed – Statement O – ECIC (At Present Rate Revenue).**

   The Company’s preferred proposed rates are presented in this Statement O. This proposal reflects the ECIC events described above, while maintaining the total revenue requirement at present rate (PRR) levels. Single family residential rates are proposed to remain at current levels with the modifications discussed below in order to effectuate the Company’s
Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

proposed updates while maintaining no change to the total revenue requirement.

2. **Statement O – ECIC (At NRS Revenue Requirement)**. This Statement O reflects the Company’s ECIC proposal with the fully calculated NRS revenue requirement increase incorporated into rates. Additionally, revenue requirements for all classes (excluding NEM customer classes) are set at cost in order to demonstrate the impact to classes if the Residential Service (“RS”) subsidy was eliminated. This ECIC Statement O (At NRS Revenue Requirement) provides a complete rate design that would be otherwise proposed if the Company’s proposal to reflect the ECIC events was accepted, but its proposal to retain revenue requirement at present rate revenue levels was rejected.

3. **Statement O – Cert (At Present Rate Revenue)**. The Company’s proposed rates presented in this Statement O maintain the class revenue requirement at present-rate levels. Stated differently, CERT Statement O (At Present Rate Revenue) provides a complete rate design that would be otherwise proposed if the Company’s proposals to reflect the ECIC events was rejected, but its proposal retain a revenue requirement at present rate revenue levels was accepted. Additionally, rates are maintained at current levels while incorporating the modifications necessary to result in no change to revenue requirement.
4. **Statement O – Cert (At NRS Revenue Requirement)**. This Statement O is built from Nevada Power’s calculation of the full revenue requirement as set forth in the Nevada Revised Statutes (“NRS”) and NAC. The shorthand designation of this version of Statement O presents a complete rate design as if the Company were to propose rates based on certification period estimates and following the requirements of the NRS and NAC. Stated differently, CERT Statement O (At NRS Revenue Requirement) provides a complete rate design that would be otherwise proposed if the Company’s proposals to reflect the ECIC events and to retain a revenue requirement at present rate revenue levels were rejected.

10. **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 all of the Statement Os: (1) the MCS, (2) Billing determinants, recorded and present rate revenues from Statement J, (3) the unbundled Statement H-2, and (4) the Customer-Specific Facilities (“CSF”) investment study.

The MCS is the foundation of the Company’s rate design, and the inputs from the MCS are used to develop rates that reflect long-run marginal costs. It also serves as the basis for demonstrating how far proposed rates diverge from that long-run goal of rates at a full marginal cost basis. Mr. Bohrman provides a more detailed discussion of the MCS methodology and results in his prepared direct testimony.
Class present rates, present rate revenues, proposed rate revenues, and billing
determinants come from Statement J. Ms. Erika Mclean sponsors the four
Statement Js prepared for this filing, which correspond to the four Statement Os
I discuss above.

Schedule H-2 provides the results of the revenue requirement unbundling
analysis which is sponsored by Ms. Elena Mello. Schedule H-2 shows the
allocation of Nevada Power’s total embedded revenue requirement among the
four basic electric utility functions: distribution, transmission, generation and
energy. While Nevada Power’s rates are based on marginal cost considerations,
they also must recover the embedded revenue requirement. Because revenues
based on marginal cost are unlikely to ever match the revenue requirement based
on embedded costs, the two studies must be reconciled. The “revenue
reconciliation and allocation” process, for which I am responsible, takes the
unbundled embedded revenue requirement and assigns the revenue requirement
to the individual rate classes using marginal costs, subject to other public policy
considerations and goals. The unbundled revenue requirement is a direct input
to the Cert and ECIC Statement Os that reflect a change in revenue requirement
based on calculations pursuant to the NRS and NAC. The percentage split of the
unbundled revenue requirement is used to functionalize the revenue requirement
at present rate levels in the Company’s proposed Statement O - ECIC at PRR,
and the Statement O CERT at PRR.
The CSF investment study, also sponsored by Mr. Bohrman, provides the derivation of CSF investments used in Statement O.

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

A. The overall methodology is largely the same as filed in Nevada Power’s 2014 GRC; however, the structure of Statement O has been modified to present the results and methodology more clearly. Additional sheets have been included to incorporate the Optional High Load Factor (“OLGS-3P HLF”) schedule approved in the stipulation in the 2014 GRC, as well as the separate NEM customer classes approved in Docket No. 15-07041. Each of the four Statement Os use the same structure for ease of presentation and comparison.

Each Statement O consists of 20 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 it contains, along with supplemental information relating to revenue allocation.

- **Statement O, page 1**: Summarizes the results of present rate revenue, cost-based revenue and proposed revenue for those classes included in the revenue reconciliation process. In addition, the revenue impacts for the groups of optional classes not included in reconciliation, and for which
marginal costs are not developed in the MCS (as set forth in Mr. Bohrman’s testimony, the optional, standby, DOS and wholesale classes, whose rates are based on the standard Otherwise Applicable Schedule or “OAS”) are also presented on this page.

- **Statement O, pages 2-5:** These pages present the functional cost-based revenue allocation of marginal costs to the revenue requirement, the calculation of the final revenue allocation to each class, and the resulting interclass subsidies.
  
  o Page 2 shows the Statement H-2 unbundled revenue requirement, with adjustments by function.
  
  o Page 3 shows the reconciliation of the unbundled revenue requirement revenues to the results of the MCS by class and function using the long-accepted equal percent of marginal cost (“EPMC”) methodology.
  
  o Page 4 takes the class marginal cost based revenue requirement allocations from page 5 and *reallocates* the cost based on revenue requirement, again on an EPMC basis, but this time the revenues are subject to certain caps designed to limit increases over present rates among the customer classes.
  
  o Page 5 shows the calculation of the Interclass Rate Rebalancing (“IRR”) charge. The IRR charge is stated on a per kWh basis and charged on this basis 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.

- **Statement O, pages 6-20**: These pages provide various summaries and comparisons of the proposed rate revenues by class and summarize the rate impacts of the rate design on each class.
  - Page 6 summarizes the impact to those classes included in revenue reconciliation for the BTGR and BTER rate components.
  - Page 7 summarizes the BTGR and BTER impact to those optional classes not included in revenue reconciliation.
  - Page 8-9 summarizes the revenue impact to all classes, including additional rate components that are charged to customers.
  - Pages 10-13 summarize the proposed bundled rates.
  - Page 14 summarizes the proposed rates for NEM classes.
  - Page 15 summarizes the proposed standby rates (Schedules SSR and LSR).
  - Page 16 summarizes the proposed DOS rates.
  - Page 17 summarizes the proposed rates for the generation capacity rates used in the Incremental Price (IP) rate schedule.
  - Page 18-20 summarizes the development of the Customer Specific Facility (“CSF”) charges for non-X transmission and LGS-X customer classes.
12. Q. PLEASE BRIEFLY DESCRIBE THE STATEMENT O WORKPAPERS.

A. Workpaper 1: Consists of 16 pages and contains key inputs and calculations used in the rate design and the rate impact calculations, including the present rate and marginal cost revenues (pages 1 and 2), the billing determinants (pages 3 and 4), and the proposed class revenue adjustments for proposed rates (pages 5-8). Pages 9-16 present the development of the revenues of optional classes that are “credited” against the overall revenue requirements in order to achieve the appropriate revenues required for rate design. Page 9-11 presents the revenues of Optional TOU and Electric Vehicle Recharge Rider (“EVRR”) classes. Page 12 presents the Hoover B benefit calculation. Pages 13-14 present the revenue adjustments for two Partial Requirements customers and the OLGS-3P HLF class that are included in the OAS rate design. Pages 15 and 16 provide summaries of the revenues for the DOS customer classes.

Workpaper 2: This is a new work paper that contains 14 pages of information for the NEM customer classes. Pages 1-2 summarize the billing determinants of these classes. Page 3 presents the calculated revenue shortfall related to the “grandfathered” and “laddered” rate structures billed to these customers. Pages 4-5 present the information necessary to develop the “NET ENERGY METERING SUBSIDY” bill line item ordered by the Commission in Docket No. 15-07041. Pages 6-14 calculate the NEM class revenues, related shortfalls, and the laddered rates charged to the NMR-A customer classes.
Workpaper 3: Consists of eight pages related to the Standby customer classes. 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 revenues used as revenue credits to the total revenue requirement for rate design.

Workpaper 4: This section, consisting of 50 pages, presents the rate design for individual classes.

Workpaper 5: Presents 13 pages of supplemental information, primarily providing additional presentations of the proposed bundled and DOS rates, as well as comparisons of present and proposed rates for these services.

13. **Q.** PLEASE SUMMARIZE THE MAJOR RATE DESIGN OBJECTIVES APPLIED TO THE TWO VERSIONS OF STATEMENT O THAT ASSUME THAT REVENUE REQUIREMENTS INCREASE BASED ON CALCULATIONS PERFORMED PURSUANT TO THE NRS AND NAC?

   A. Complete rate designs are presented for both the ECIC and CERT versions of Statement O that calculate an increase in revenue requirement based on the NRS and NAC. Both of these rate designs are premised on the complete elimination of the current rate design subsidy in favor of Single Family Residential customers. This rate design is not the preferred recommendation of the Company, but is intended to comply with the Commission’s directive Docket No. 14-05004 that Nevada Power include in this general rate review proceeding.
a proposal to entirely eliminate the residential subsidy in a single step. This rate design also includes all the necessary information available to the Commission to determine the BSC for all residential and small general service classes that would result if all Customer, Facilities and Primary Distribution costs were recovered through the charge. The proposed rate design changes are discussed in more detail in Section IV of my testimony and the whitepaper attached as Exhibit Pollard Direct-3.

14. **Q.** PLEASE DESCRIBE THE RATE DESIGN OBJECTIVES APPLIED TO THE TWO VERSIONS OF STATEMENT O THAT ASSUME NO CHANGE IN REVENUE REQUIREMENT?

**A.** In both the ECIC and CERT versions of Statement O that are based on no change in PRR, the Company has proposed five minor adjustments that do not impact rates for single-family residential customers. The changes to revenues resulting from these adjustments result in increased revenues that Nevada Power proposes to credit to the kWh rates of non-subsidized classes. For classes with TOU rates, the resulting $/kWh credits are allocated across TOU periods based upon present rate revenues. The five adjustments (and corresponding proposed revenue impacts) are:

1. Senate Bill 123 Regulatory Asset Rates for customers converting to DOS-only service (totaling $5.23 million). These revenues are based on charges to the individual customers who filed and have had approved by the

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2 A complete discussion of the history of the residential subsidy (dating back to 1983) and the fact that the stipulation resolving the 2014 general rate case did not reduce the residential subsidy is set forth in paragraphs 25 and 26 of the Commission’s October 15, 2014 Order.
Commission applications pursuant to NRS Chapter 704B in Docket Nos. 15-05006, 15-05017, and 16-11034. There are two separate charges (Rate-A and Rate-B) charged to the sales of the individual DOS customer. Rate-B only appears in the proposed Statement O – ECIC, as the affected customer remains a bundled customer under the Cert scenario. Because of this, the Statement O - Cert results in a total adjustment of only $3.4 million, which is lower than that presented under the Statement O – ECIC. Importantly, the impact of this adjustment will be affected if the Commission grants pending requests by two of these customers to modify their impact fees, to the extent the Commission approves modifications to the revenues that would otherwise be reflected in the Senate Bill 123 regulatory assets. Nevada Power does request that the Commission grant flexibility in this proceeding to make appropriate modifications based on any adjustments the Commission may grant with respect to impact fees for customers that utilize an alternative energy provider.

2. Updates to CSF Investments (net total of $243,000). This adjustment, presented on page 7 of 16 of Workpaper 1, calculates the difference in revenues for non-LGS-X transmission level customers once the CSF investments are updated. These investment amounts have not been updated for six years as the updates presented in Nevada Power’s 2014 GRC were stipulated and kept at the 2011 investment amounts. These investment amounts serve as a billing determinant, to which the dollar-per-dollar of investment rates are applied. The revenue adjustment is higher in the Cert Statement O ($258,000) as one customer with nine accounts remains under...
the OLGS-3P HLF class. This class has CSF charges, but the corresponding DOS class does not. Therefore, when the customer is placed under the LGS-3P DOS schedule (which does not have CSF charges), the investment updates are removed, thereby lowering the revenue adjustment in the Company’s proposal.

3. Proposed changes to Optional TOU periods ($221,000). This adjustment is the difference in revenues resulting from the proposed change to the TOU period definitions for the existing Option-A residential, general service, and NEM class optional TOU schedules. The Company proposes to move all Summer weekend On-peak (1 p.m.-7 p.m.) hours to the Off-peak period for these schedules. This increases the number of hours that these customers will pay lower Off-peak rates relative to the standard flat-rate schedules. The impact of this proposal on individual single-family residential customers is discussed in more detail in Mrs. Walsh’s testimony.

4. Updates to NMR-A laddered rates ($1,200). Updates are proposed for the laddered rates for non-grandfathered NEM customers. The laddered rates are based on the difference between the corresponding full requirements rates and the cost-based rates. As the full requirements rates incorporate a new BTER, and the proposed credit adjustments, except for the RS-NEM class, the 20 percent movement towards cost-based rates for the NMR-A schedules change the proposed rates for these classes.

5. Updates to optional TOU EVRR” rates ($1,000). The EVRR schedule provides a 10 percent discount to the BTGR and BTER rates applicable to all sales during the low cost EVRR period (10 p.m.-6 a.m.) for
those customers who have an electric vehicle and sign up for this optional schedule. The entire discount is included in the EVRR BTGR component and updated at the time of each GRC. The BTER in this filing ($0.03899 for residential customers) is lower than the BTER rate ($0.04652) from the 2014 GRC when the EVRR discount was last reset. This adjustment results in a slight increase in revenues from customers on these schedules due to the lower discount from a lower BTER rate than was used in the last update.

15. Q. IS NEVADA POWER SEEKING TO ADD OR ELIMINATE ANY RATE SCHEDULES AS PART OF ITS RATE DESIGN?

A. Yes, the Company is proposing to add two new optional TOU schedules for residential customers. The first overlays a Critical Peak Period (“CPP”) pricing structure on the modified Option-A TOU schedule. The addition of the optional CPP schedules for full requirements residential customers provides another pricing option for customers and incorporate insights gained from the Nevada Dynamic Pricing Trial (“NDPT”). The second, incorporates maximum demand and summer On-peak demand charges into an optional TOU rate structure. The proposed Planned Demand Use (“PDU”) optional schedules will offer customers another opportunity to gain savings on their utility bills by planning their usage to avoid peak periods (i.e., by deciding to not use major appliances at the same time). This schedule will also provide the Company the opportunity to gain insight into residential customer acceptance, understanding and benefits of demand charges. The development of these rates for these new schedules are also discussed in Section III.
Also, as discussed by Mr. Trevor Dillard, the Company is proposing to eliminate two obsolete schedules, Schedule PR, pursuant to which customers may rent a power pedestal, and the residential stand-by (SSR-1 RS) schedule. Nevada Power has not provided service under Schedule PR for at least 15 years. Since its initial offering, Schedule SSR-1 RS has never been utilized by a customer. For information purposes, the rates for this class are still calculated and shown on Page 15 of Statement O.

III. REVENUE RECONCILIATION

16. Q. PLEASE EXPLAIN HOW THE EQUAL PERCENTAGE OF MARGINAL COST METHOD IS USED TO RECONCILE MARGINAL COSTS TO REVENUE REQUIREMENT.

A. Since the inception of marginal cost allocation and pricing, the Commission has accepted reconciling the marginal cost revenues resulting from the MCS to the revenue requirement using the EPMC methodology. Each class is assigned a share of the utility’s functionalized revenue requirement in proportion to its share of that function’s marginal cost revenue. Thus, if a class has a 10 percent share of the marginal cost responsibility of a function, it is assigned 10 percent of the revenue requirement of that function.

The reconciliation calculations for Statement O versions that assume no change in PRR are fairly simple, since they assume that revenue requirement is kept constant. However, the reconciliation is still necessary to identify the resulting
deviations from cost and related revenue shortfalls embedded in proposed rates. The most notable of these shortfalls is related to the RS customer class, which I discussed briefly above. A second shortfall is that identified for the NEM customer classes. For Nevada Power, this shortfall was most recently a focus of Docket No. 15-07041.

The reconciliation methodology separately reconciles the marginal costs for distribution and transmission functions to their respective revenue requirements. Because of their interrelated nature, the generation and energy functions are combined for reconciliation purposes. The relationship between marginal generation and energy costs is better reflected when reconciliation of these functions is performed together. The reconciliation method described above was first approved by the Commission in Docket No. 03-11001 and most recently approved in Sierra’s 2016 GRC (Docket No. 16-06006). Page 3 of Statement O shows the revenue reconciliation, and is sometimes referred to as the pure cost-based revenue requirement of the classes.

17. Q. ARE THERE ANY SIGNIFICANT CHANGES IN THE RECONCILIATION METHODOLOGY USED IN THIS FILING COMPARED TO THE RATE DESIGN PREPARED FOR NEVADA POWER’S 2014 GRC (DOCKET NO. 14-05004)?

A. No. The overall methodology of class revenue reconciliation and rate design are the same as those in Nevada Power’s 2014 GRC. However, the presentation of Statement O has been modified to provide more clarity and incorporate the
addition of the NEM and OLGS-3P HLF customer classes. Additional sheets have also been included to incorporate the revenue-requirement credit adjustments necessary to implement the Company’s proposal of maintaining the current total revenue requirement with the minor adjustments to rates for a subset of classes.

18. Q. THE REVENUE REQUIREMENT PAGE (PAGE 2) AND REVENUE RECONCILIATION PAGE (PAGE 3) IN STATEMENT O REFLECT SEVERAL ADJUSTMENTS TO THE UNBUNDLED REVENUE REQUIREMENTS CONSISTENT WITH PAST ORDERS. PLEASE BRIEFLY EXPLAIN EACH OF THESE.

A. These adjustments are made in every general rate review proceeding. They impact the reconciliation results and establish a “target revenue requirement” for each class rate design. A minor change in this filing was implemented to reflect the appropriate allocation to the combined reconciled generation and energy revenue requirement by maintaining the BTER revenue credits within the energy function, instead of being allocated to the transmission, generation and distribution functions in relation to the magnitude of each of the functions as done in previous filings. None of these adjustments, which I describe below, impact the total amount of sales revenue ultimately collected by the Company.

**LGS-X CSF charges.** This adjustment is made to ensure that revenues are assigned to the appropriate LGS-X class, but remain at the same level (i.e., dollar amount) flowed through the MCS and included in the LGS-
X (by secondary distribution, primary distribution and transmission voltage level facilities) marginal cost revenues. The value of the adjustment is $230,000 in the Cert Statement Os but moves to zero in the ECIC models as all LGS-X accounts move out of the bundled LGS-X classes.

**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 is equal to the proposed BTER for the class multiplied by the WAPA energy, which in the test period was approximately $550,000. Since the WAPA credit pertains to the BTER component, the adjustment is made to the reconciliation of the energy/generation functions. The credit flows through to the class by increasing the combined energy and generation revenue requirement by the amount of the WAPA credit. After the EPMC 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 ($365,000) is calculated as the total Hoover B benefit determined from Nevada Power’s most recent BTER filing (Docket No. 17-02017), divided by total residential sales. The sales for the optional TOU and NEM residential schedules have been included in the calculation for this filing.

**Power Factor Revenue:** Power factor costs and revenues are not a specifically identified portion of the marginal costs. Power factor revenues ($899,000) recover costs for reactive power (kVARh) use above prescribed levels. Instead they are credited in a manner similar to that described above for LSR and optional TOU revenues. Power factor revenues are distribution-related and so are credited against only the distribution revenue requirement. At completion of the revenue reconciliation, class-specific power factor costs are added back to their

³ Consistent with the costing 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.
reconciled marginal costs, thereby assigning them to the classes generating them.

**Additional Facility and Maintenance ("AF&M") revenues:** These revenues are 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 $62,000 during the test period. For purposes of the revenue reconciliation, AF&M revenues are treated the same way as power factor revenues, with the revenues credited against the distribution revenue requirement and then directly assigned to the classes with customers that have the AF&M contracts.

**Other Revenues.** Since NPC’s 2006 GRC (Docket No. 06-11022), “Other Revenues,” (e.g. late fee charges, reconnection fees, etc.) which total approximately $4.4 million in the test period, are added to the distribution revenue requirement for reconciliation. After reconciliation, these revenues are subtracted from each of the respective classes’ revenue requirement, thereby directly assigning the benefit of payment of these tariff services to the classes that pay them.

**Credit of Standby Service (SSR/LSR) and the Optional TOU Revenue:** With two exceptions, the rates for the standby service classes and all of the optional TOU schedules (including the optional TOU
schedules for the NEM customer classes) have been set using OAS costs and are excluded from the reconciliation process. The two exceptions are two partial requirements LSR customers and the customers billed under the optional LGS-3P High Load Factor ("OLGS-3P HLF") schedule are included in the OAS schedules for revenue reconciliation and rate design\(^4\). The revenues 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. 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 BTER revenue is credited to the energy function. Customers in all rate schedules benefit from these credited revenues in proportion to their share of total marginal costs within each function.

The inclusion of the two partial requirements customers and OLGS-3P HLF customers in the OAS schedules for rate design reflect that the rates for these classes are based upon the OAS class’ 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 revenues collected from the charges under the OAS

\(^4\) Previously, another large LSR-II LGS-3T standby customer, who had also installed self-generation, was included in the same manner. However, this customer has since become a DOS-only customer and was removed from the cost of service and rate design for the LGS-3T class.
rates and those billed under the respective standby and OLGS-3P HLF rates are included as a revenue credit so that the BTGR and BTER revenues match those from Statement H. The total combined proposed LSR and Optional TOU revenue, including the adjustments for the partial requirements LSR and OLGS-3P HLF schedules, is approximately $8.9 million in this proceeding.

**DOS Revenues.** DOS revenues are treated as a revenue credit in a manner similar to the LSR and optional TOU customer classes’ revenues. Except for the portion of DOS revenues associated with the subsidy component of the non-by passable, IRR charge, DOS revenues are credited exclusively to the distribution revenue requirement. The subsidy component of DOS revenues is credited to all non-energy functions in proportion to each function’s relative share of the combined revenue requirement. The revenues from the R-BTER charges are credited back to the energy function while those revenues from the SB 123 Regulatory Asset rates are credited back directly to generation because these are designed to largely recover generation plant investments. DOS revenues total approximately $38.2 million in the Company’s ECIC proposal and $23.8 million in the Company’s Statement O – Cert model.

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 are flowed 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 revenues of all classes.

19. **Q. WHY ARE THE RATES FOR SOME CLASSES SET AT BELOW COST-BASED LEVELS?**

A. Rates can be set below cost for some classes in order to meet public policy goals of the Legislature and/or the Commission. Those classes who pay rates below the cost-based levels receive a subsidy, and the shortfall in revenue responsibility represented by the subsidy is made up by allocating the shortfall to all other customer classes. I have already discussed the historical shortfall related to the RS class. If rates are set according the Company’s preferred proposal, the RS interclass shortfall will be $43.6 million. This amount is recovered from all other customer classes in the Statement O at NRS Revenue Requirement models.

Rates for the NEM customer classes follow the methodology set forth in Docket No. 15-07041, pursuant to which rates for non-grandfathered NEM customers have been removed from the NEM customer’s former full requirement classes’ cost-based rates, and to NEM class cost-based rates, through four, three-year steps. Under the Commission’s laddering order, rates for customers in the NEM classes will reach full cost-based levels in 2028. The Excess Energy Credit (“EEC”) established in Docket No. 15-07041 follows the same four-step process
and is paid to NEM customers for any excess generation they provide back to
the grid. In its order in 15-07041, the Commission recognized that cost-based
rates for the full requirements classes and NEM classes would be updated and
reset at each general rate case.5

20. **Q. HAVE YOU QUANTIFIED THE NEM SHORTFALL UNDER ANY OF
THE FOUR STATEMENT O SCENARIOS YOU SPONSOR?**

A. Yes. For the NEM classes included in reconciliation, an $18.3 million shortfall
has been identified. This calculation has three components. The first is the extent
to which rates based on the corresponding full requirements rate schedules (i.e.,
for NEM customers who were grandfathered through Docket Nos. 16-07028 and
16-07029) under-collect cost of service. The second component of the
calculation is the difference between cost-based rates and laddered rates set
pursuant to Docket No. 15-07041 for the customers billed under the NMR-A rate
structure. These shortfalls are allocated to all other customers as summarized on
page 3 of Workpaper 2. The Company’s Statement O – ECIC per NRS model
eliminates the RS shortfall but maintains the NEM cost of service shortfalls
resulting in an amount of $16.8 million.

The third component of the total shortfall is the EEC above cost, which is the
amount that the Company pays to customers for their excess energy above the
avoided cost— the amount by which under the laddered rates established by the

5 Note that the Value of Solar calculations performed by Mr. Reyes are not the basis for the cost-based
determination of the EEC reflected in any of the four Statement Os.
Commission in Docket No. 15-07041, NEM generators are paid more than the market price of energy for excess energy they put onto Nevada Power’s system. The cost-based energy credit is based on the 2018 average of the capped Long-Term Avoided Cost approved by the Commission in Docket No. 15-07004. The EEC-related shortfall, as outlined at paragraph 336 in the Modified Order from in Docket No. 15-07041, is accounted for in the rates to other customers through the Company’s quarterly deferred energy accounting adjustment filings, and are therefore, not included in the Company’s cost-based revenue shortfall or revenue reconciliation/allocation methodology. However, it is appropriate to include the excess energy component when determining the total NEM shortfall. The cost-based value of the excess energy is included for NMR-G customers on page 3 of Workpaper 2. The result is a shortfall per customer amount of $667.56 for the RS NMR-G customers, who make up over 96 percent of all grandfathered NEM customers. Stated in different terms, this component of the shortfall is $111,970 per MW of installed RS NMR-G capacity.

21. Q. DO ALL NEM CLASSES ENJOY THE SAME BENEFITS OF A REVENUE RESPONSIBILITY SHORTFALL?

A. No. It is interesting to note that the shortfalls for the LRS NMR-A, and LRS NMR-G classes are negative. This means that these customers are paying more under the grandfathered NMR-G rates and/or laddered NMR-A rates than if they were billed at the cost-based NMR-A rates. These NEM customers are considerably smaller than the average corresponding full requirements LRS customer. As the grandfathered and laddered rates are at least partially based
upon the corresponding full requirements rate schedule, rather than the costs of these LRS NEM customers, these customers pay higher rates that reflect the higher costs of the standard LRS class.

22. Q. WHAT IS THE IMPACT OF THE NEM SHORTFALL ON OTHER CUSTOMER CLASSES?

   A. The total NEM shortfall amount, based on the combination of the shortfall from cost-based rates and overpayment for excess energy, is used on pages 4 and 5 of Workpaper 2 to develop $/kWh rates necessary to develop the “NET ENERGY METERING SUBSIDY” line item ordered by the Commission in Docket No. 15-07041. The shortfall, after including the cost-based value of the excess energy accounted for in the Company’s deferred energy filings, amounts to $13.85 million annually. Page 4 of Workpaper 2 shows the average monthly amount that customers in other classes pay towards the NEM-related shortfalls. For example, the average RS customer pays $1.04 per month while an average LGS-3T customer pays $4,978 related to the total NEM shortfall.

23. Q. WHAT ARE THE OVERALL CHANGES TO CLASS REVENUE REQUIREMENTS UNDER THE COMPANY’S PROPOSAL?

   A. As stated earlier, the proposed class revenue requirements maintain the revenue at current rate levels, with adjustments to incorporate five rate design items, while maintaining zero change in the total revenue requirement. Table Pollard Direct 1 below summarizes the change in class revenues from present rate
revenues to revenues at full marginal cost-based levels as well as those put forward in the Company’s proposal.

The table shows no proposed change for the RS and RS NEM classes as these customers are currently subsidized and do not receive a credit adjustment. The difference in cost for the RS class represents the RS subsidy resulting from proposed rates ($43.6 million) and the proposed NEM shortfall ($17.8 million for RS-NEM). The other NEM classes do receive a slight reduction due to the credit adjustments being included in the full requirements rate schedule rates that apply to the NMR-G schedules. Additionally, the increase in revenues for the LGS-3T, Optional TOU and DOS classes are offset by decreases in revenues to other classes.
### Table Pollard Direct - 1
Comparison of Proposed Revenue Changes by Class ($000s)

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present Rate Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$820,475</td>
<td>$820,475</td>
<td>($43,626)</td>
<td>0</td>
<td>-0.41%</td>
</tr>
<tr>
<td>RS</td>
<td>236,603</td>
<td>235,636</td>
<td>17,996</td>
<td>($968)</td>
<td>-0.41%</td>
</tr>
<tr>
<td>RM</td>
<td>3,752</td>
<td>3,739</td>
<td>212</td>
<td>13</td>
<td>-0.34%</td>
</tr>
<tr>
<td>LRS</td>
<td>62,366</td>
<td>62,085</td>
<td>8,681</td>
<td>281</td>
<td>-0.45%</td>
</tr>
<tr>
<td>GS</td>
<td>350,558</td>
<td>348,839</td>
<td>15,734</td>
<td>(1,919)</td>
<td>-0.55%</td>
</tr>
<tr>
<td>LGS-1</td>
<td>193,121</td>
<td>181,997</td>
<td>10,973</td>
<td>(1,124)</td>
<td>-0.61%</td>
</tr>
<tr>
<td>LGS-2S</td>
<td>5,973</td>
<td>5,932</td>
<td>189</td>
<td>(41)</td>
<td>-0.69%</td>
</tr>
<tr>
<td>LGS-2T</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S</td>
<td>65,202</td>
<td>64,778</td>
<td>2,956</td>
<td>(424)</td>
<td>-0.65%</td>
</tr>
<tr>
<td>LGS-3P</td>
<td>118,826</td>
<td>118,046</td>
<td>6,037</td>
<td>(780)</td>
<td>-0.66%</td>
</tr>
<tr>
<td>LGS-3T</td>
<td>21,967</td>
<td>22,057</td>
<td>1,845</td>
<td>90</td>
<td>0.41%</td>
</tr>
<tr>
<td>LGS-XS</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XP</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XT</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-2S-WP</td>
<td>789</td>
<td>789</td>
<td>(25)</td>
<td>(0)</td>
<td>0.00%</td>
</tr>
<tr>
<td>LGS-2P-WP</td>
<td>907</td>
<td>900</td>
<td>165</td>
<td>(7)</td>
<td>-0.77%</td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S-WP</td>
<td>442</td>
<td>437</td>
<td>94</td>
<td>(5)</td>
<td>-1.06%</td>
</tr>
<tr>
<td>LGS-3P-WP</td>
<td>628</td>
<td>621</td>
<td>124</td>
<td>(7)</td>
<td>-0.88%</td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>SL</td>
<td>7,816</td>
<td>7,804</td>
<td>248</td>
<td>(11)</td>
<td>-0.14%</td>
</tr>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>81</td>
<td>14</td>
<td>(0)</td>
<td>-0.42%</td>
</tr>
<tr>
<td>GS-Pal</td>
<td>264</td>
<td>263</td>
<td>57</td>
<td>(1)</td>
<td>-0.40%</td>
</tr>
<tr>
<td>IAWP</td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>14,118</td>
<td>(17,753)</td>
<td>(0)</td>
<td>0.00%</td>
</tr>
<tr>
<td>RM-NEM</td>
<td>68</td>
<td>87</td>
<td>22</td>
<td>(22)</td>
<td>-1.38%</td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>57</td>
<td>3</td>
<td>(0)</td>
<td>-0.59%</td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>170</td>
<td>(111)</td>
<td>(0)</td>
<td>-0.62%</td>
</tr>
</tbody>
</table>

| Rate Design and Reconciliation Revenue | $1,894,403 | $1,888,811 | $17 | ($5,492) | -0.29% |

Optional Classes not in Reconciliation:
- SSR & LSR: $7,864 (7,863 nc (1) -0.01%
- Optional TOU: $21,467 (21,609 nc 122 0.57%
- NEM Optional TOU: $427 (443 nc 16 3.72%
- DOS: $32,796 (38,154 nc 5,358 16.34%

**Total (Bundled & DOS)**: $1,936,002 $1,936,019 $17 $0.00%

The table above shows that the overall changes to class revenues is a small decrease in revenues (-0.46 percent on average) for those customer classes included in reconciliation with a slight increase (0.41 percent) for the LGS-3T class due to the proposed updates to the CSF investments. Other customer groups (Standby, Optional TOU, NEM Optional TOU, and DOS) are presented in total in the table. Individual class impacts for these groups are presented on pages 7
and 8 of Statement O. The 16.34 percent for the DOS customer classes is primarily due to the SB 123 Regulatory Asset charges to be recovered from applicable DOS customers pursuant to the orders in Dockets 15-05006, 15-05017, and 16-11034. Excluding these charges, the proposed revenue for DOS classes shows a slight 0.4 percent increase related to updates to the CSF investments for transmission level DOS customers. The proposed increase in revenues for the Optional TOU schedules are related to the proposed change to the TOU periods, where Summer weekend On-peak hours are moved to the Off-peak. This proposed change is also part of the increase for the NEM Optional TOU revenue change.

A similar comparison is presented on pages 2-4 of Exhibit Pollard Direct-2 for the proposed revenue results of each Statement O.

IV. RATE DESIGN

24. Q. PLEASE SUMMARIZE THE RATE DESIGN METHODOLOGY PRESENTED IN THE COMPANY’S FILING.

A. As previously stated, the Company’s preferred proposal is to maintain present rate revenue as the revenue requirements, keeping single family residential rates constant. Secondary attributes of the Company’s proposal is that rates for other bundled subsidized classes would remain at current levels, and consumption charges for non-subsidized bundled classes would decrease slightly to offset the proposed adjustments to rates for a subset of classes and to maintain the present rate revenue requirement. However, the Company has prepared complete rate
designs for the two Statement O versions (ECIC and CERT) that demonstrate revenue requirement calculated per the NRS and NAC. I summarize the Company’s proposal and the overall rate design for all classes here and provide a more detailed discussion of rate design in the whitepaper, Exhibit Pollard Direct 3.

25. Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE EXISTING OPTIONAL TOU SCHEDULES.

A. In an effort to support the ability of those customers who are traditionally served on a simple two-part flat-rate structure to benefit from time-varying rates, the Company is proposing an improvement to its existing Option-A Optional TOU schedules. Currently the optional TOU schedules include weekend hours in their Summer On-peak pricing. Nevada Power is proposing to remove weekend hours from the Summer On-peak period (1 p.m. - 7 p.m.), and to price usage during all Summer weekend hours at the Summer Off-peak price.

The MCS indicates that Saturday is, indeed, a lower-cost day overall and provides a cost-basis for all Saturday Summer hours in the Summer Off-peak period. The same is not indicated for Summer Sundays. However, customer outreach suggests that moving all weekend hours, not just Summer Saturdays, to Off-peak rates will improve the acceptance of a TOU pricing structure for those residential and small general service customers typically served on a simple two-part rate structure.
26. Q. DOES THE COMPANY PROPOSE TO MODIFY THE EXISTING OPTION-B TOU RATES IN A SIMILAR FASHION?

A. No. The higher cost Summer season for these schedules is limited to only the months of July and August, requiring customers on these schedules currently to pay higher rates for no more than ten weekends a year. Given that so few hours are currently defined as Summer On-peak in Option-B TOU schedules, the modifications being proposed for Option-A TOU were not likely to improve acceptance by customers on two-part rates of TOU rate structures.

27. Q. HOW ARE TOU RATES IMPACTED BY RE-PRICING ALL SUMMER WEEKEND HOURS AS SUMMER OFF PEAK FOR THE OPTION-A TOU SCHEDULES?

A. As in previous cases, rates for the Option-A TOU schedules are designed to be revenue neutral to the standard two-part schedules. In this case, the class revenue in the Company’s proposal is set at present rate levels for rate design. The proposed reductions for non-subsidized classes is applied to the individual TOU rates after rate design is completed.

The resulting TOU rates for the Summer season increase from current levels of $0.35882 to $0.44454 in the Summer On-peak period and from $0.05487 to $0.06640 in the Summer Off-peak period. Summer rates increase for both periods because the weekend hours moved to the Off-peak period are on average higher cost than those hours originally included in the Off-peak rate.
Ms. Walsh’s testimony, shows the results of the analysis identifying the potential benefits/losses associated with each of the Company’s Optional TOU proposals compared to the existing RS flat-rate.

28. **Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE RATES FOR NEM CUSTOMERS BILLED UNDER THE NMR-A PRICE STRUCTURE?**

   **A.** The development of rates for the NMR-A classes in this filing are consistent with the methodology approved in Docket No. 15-07041, in that these rates are based on a 20 percent movement toward cost-based NEM rates from the proposed rates of the standard full requirements schedules. The 20 percent movement is the first transitional step towards cost-based rates for NEM customers that was put in place to gradually move NEM customers to cost-based rates. This is consistent with paragraph 359 of the Commission’s Modified Order in Docket No. 15-07041 that stated, “For NPC, the NEM rates for its 2017 GRC will be known by January 1, 2018, but NEM ratepayers in NPC’s service territory will not experience the corresponding step change until January 1, 2019, a full year later.” In the Company’s proposal, the cost based rates for the NEM classes are updated as a result of this filing, which necessarily changes the rate that will be applied to NEM customers under this first-step change. The difference in revenue is included as part of the proposed revenue requirement adjustments applied to the current rates for non-subsidized classes.
The cost-based rates for the NEM classes are developed on the respective rate design pages of Workpaper 4. The cost-based rates are then used on pages 6, 8, 10, and 12 of Workpaper 2 to develop the updated NMR-A laddered proposed rates that move 20 percent from the proposed full requirements rates to the full NEM cost-based rates. The difference between the cost based rate revenue and the proposed rate revenue for delivery of utility service is the BTGR revenue shortfall that is recovered from all other customers through the “Passes” tab, or page 4 of Statement O. The total amount of this shortfall is approximately $54,000 in this filing for those customers billed under the NMR-A rate schedules.

The same pages in Workpaper 2 also updated the EEC that NEM NMR-A customers receive for any excess generation they provide to the system. The development of the credit moves the same 20 percent from the NEM rate, which NEM classes would receive absent the recently approved credit mechanism, and the fully cost-based credit.\(^6\) The cost-based credit is based upon the capped Long Term Avoided Cost approved by the Commission in Nevada Power’s 2015 integrated resource plan, Docket No. 15-07004, but updated to 2018 average costs and adjusted for distribution losses. The difference between the amount paid to NEM customers for their excess energy and the amount that would result if the full cost-based credit was applied represents an overpayment to NEM customers that increase the costs for all customers, which will be recovered.

\(^6\) As mentioned above, the Value of Solar calculations performed by Mr. Reyes are not the basis for the cost-based determination of the EEC reflected in any of the four Statement O's.
through the energy rates set pursuant to deferred energy accounting. In this filing, the BTER subsidy amount is identified at approximately $234,000 for those customers billed under the NMR-A rate schedules.

The excess energy credit for the optional NMR-A TOU schedules uses the flat credit amount and the TOU period relationships, relative to the annual average, of the long-term avoided costs to shape the TOU based excess energy credits in order to maintain an excess energy credit equal to the standard flat-rate NEM schedules. The TOU credit is limited to not exceed the total retail rate in any period.

29. Q. PLEASE EXPLAIN THE RATE TILT COMPLIANCE ITEM FROM DOCKET 14-05004.

A. Paragraph 27 of the Commission’s Order in NPC’s 2014 GRC, stated that “NPC will specifically address rate tilt for the large commercial and industrial classes and provide supporting information justifying the resulting percentages for those particular classes.” Exhibit Pollard Direct-4 summarizes the results of the required rate tilt analysis performed by Nevada Power in preparation for this filing. Additionally, the rate tilt is discussed in the rate design whitepaper, Exhibit Pollard Direct 3.
V. NEM COST OF SERVICE LOAD SHAPES AND BILLING DETERMINANTS

30. Q. DO THE LOAD SHAPES USED AS INPUTS TO THE MCS REFLECT THE UNIQUE CHARACTERISTICS OF THOSE CUSTOMERS WHO INSTALL PRIVATE GENERATION OR NEM SYSTEMS?

A. Yes. The electric service and load characteristics of each class are revisited and reflected in cost of service and rate design in each general rate filing. Ms. Wells supports the development of hourly class loads in her testimony. I sponsor the development of the load shapes that are inputs to the MCS and used to develop functional costs by class. Customers who install NEM generation have a distinct characteristic that differentiates them from all other customers; their ability to offset some of their energy requirements through self-generation. This results in unique load shape characteristics, load factors and billing determinants when compared to the average full requirements RS or small GS customers, for whom the traditional full requirement two-part rate structure are designed.

NEM customers meet a portion of their total electric consumption using their own generation, reducing their reliance on energy deliveries from the Company. However, generation from the NEM customer’s system does not necessarily reduce the NEM customer’s capacity requirements, especially for distribution and transmission capacity, and to a lesser extent generation capacity. On page 44 of the order in Sierra’s 2016 GRC the Commission confirmed the unique relationship that NEM customers enter in to when they choose to install self-generation.
**Individual Energy Choice to Join Separate Rate Class:** It should be remembered that it is an energy choice that a Nevadan is free to knowingly make as to whether or not he or she enters into a NEM business relationship with the public utility (and potentially a third-party solar provider) and joins that separate customer class. No person or entity forces that decision. But once entered, NEM customers are effectively becoming a part of the greater energy grid system of Nevada and with that choice they should recognize that they are thereafter a part of an interconnected network that is greater than any single individual. With that choice they may have both benefits and responsibilities which non-NEM customers do not.

Based on their distinctly different service characteristics from standard full-requirements customers, the development of load shapes for NEM customers requires special attention in order to reflect the cost of providing partial requirements service, in particular addressing the standby nature of grid services. The preponderance of these customers were previously full-requirement customers of the Company who chose to retrofit their homes with private generation installed behind their meter. Thus the primary and secondary distribution facilities serving these customers were designed and constructed by Nevada Power before the customer elected to install private generation. Before the NEM customer elected to install private generation Nevada Power used these facilities to instantaneously serve the customer’s total load. Once the NEM customer has chosen to install private generation Nevada Power continues to use these very same primary and secondary distribution facilities to stand by to instantaneously meet the NEM customer’s total load, night or day, when for whatever reason the NEM customer’s generating system is not producing more than their energy use. Moreover, if for whatever reason the NEM customer or a subsequent property owner removes or no longer utilizes the behind the meter
private generation system, Nevada Power will continue to use its facilities to
instantaneously serve the customer’s total load. Thus the appropriate starting
point for the development of the costs imposed by NEM customers on the system
is their total load (total household, or premise, usage absent generation) and total
load shape.

For a non-NEM customer, total load is the total energy use of the customer. For
a NEM customer, total load is the same, the total energy use of the customer. For
all customers, the distribution facilities that serve them were designed and
installed based on their individual and, at the system level, the collective total
loads of all customers. Adjustments to the total load shape are then made by
function to reflect the differing impacts that NEM generation have on their cost
characteristics. The load shapes used in this filing are developed in the same
manner as approved by the Commission in Docket Nos. 15-07041/07042 and
16-06006. Paragraph 84 of the Modified Order in Docket No. 15-07041 states:

While parties raised several issues pertaining to load shapes, transmission and distribution marginal costs, customer facilities costs, customer costs, etc., NV Energy adequately explained the reasons for the inputs in the MCSS. Of particular note, the other parties’ proposals for load shapes afford no weight to the standby service that NV Energy provides to partial-requirements NEM ratepayers, which would effectively shift the cost burden to non-NEM ratepayers – such cost shifting is not reasonable or in the public interest.

Customers taking service under these rate schedules receive part of their energy
requirements from the Company, and the cost of such service includes costs that
are not common to full requirements services. The cost to the Company of being
ready to stand in for and instantaneously replace all or a portion of the customers’ private generation whenever it is unavailable must be captured and appropriately recovered through rates. Even for NEM customers with a functioning private generator, the service provided by the Company is no less costly than the service provided to another notable group of partial requirements customers, commercial standby customers. For partial requirements customers taking service under standby service riders, costs are developed using the standby customer’s total load, absent on-site generation, for all components of service. For Standby customers the load shape used in the MCS is the load shape of the otherwise applicable full requirements class. Demand costs are recovered through a combination of maximum, reservation, and TOU demand charges.

For all partial requirements customers, including NEM partial requirements customers, marginal distribution, transmission and generation demand costs must reflect Nevada Power’s public service and reliability obligations to ensure it has facilities in place to meet the partial requirement customer’s total load at any time. The costs of these obligations are developed and reflected in the distribution demand cost. There is also a cost associated with load following (i.e., the quick ramp up or reduction of utility generation that is required when the NEM customer’s generation production declines or increases) but is currently not reflected in the development of costs for these classes.

Following the approved methodology, the total loads of the previously mentioned two partial requirements standby customers are included in the load shapes of the otherwise applicable classes.
31. Q. PLEASE SUMMARIZE THE LOAD SHAPE USED FOR MARGINAL GENERATION AND ENERGY COSTS?

A. The NEM class delivered load shapes are used to develop the generation load shape reflecting the deliveries from the company that are provided to the customer and fully reflects the energy that NEM customers offset with their on-site self-generation. The delivered load shapes fully recognize load diversity while ignoring any standby reservation and load following costs. Load following costs have not been quantified, and therefore, are not recognized in the marginal generation cost development. However, because system peaks occur later in the day, when rooftop solar production is declining, the delivered load shape still results in an appropriate allocation of some capacity costs to NEM customer classes.

The NEM class delivered load shapes were also used to develop the energy load shape and fully reflect the reduction in energy delivered by the Company resulting from the NEM generation. To illustrate the load shapes reflecting the unique characteristics of NEM service, Figure Pollard Direct-1 begins by presenting the annual average total load (absent generation), generation, and delivered load shapes of the RS NEM customer class.
Q. PLEASE DESCRIBE THE LOAD SHAPE USED TO DEVELOP MARGINAL TRANSMISSION COSTS FOR THE NEM CLASSES.

A. In developing marginal transmission costs, the approved load shapes begin with the class’ total load shape as the transmission system is designed to meet the total load of the customer and the company stands by to meet the total load of the customer when their private generation system is producing less than or none of their energy usage. Because NEM generation is assumed to be contained within the distribution system (i.e., that excess NEM generation is fully absorbed within the distribution system), excess energy (privately generated energy that is not contemporaneously used on-site and therefore is sent back to the grid) is not included in the transmission load shape. Second, recognizing that some load...
diversity does exist and these customers do offset a portion of their demands on
the transmission system from the installation of their private generation systems,
the total hourly load is reduced to account for the reduction in the maximum
demands that NEM customers place on the system resulting from their
generation. The adjustment uses the ratio of the maximum kW demand of the
total load and the delivered loads of NEM customers by TOU period during the
test period to adjust the class total load shape by hour to reflect the reduced
burden that NEM customers place on the transmission system resulting from
their NEM generation. Figure Pollard Direct-2 updates Figure Pollard-Direct-1
to illustrate the transmission load shape of the RS NEM class. The result of the
adjustment from total loads is a reduction of 5.3 percent from the overall total
loads of the RS NEM class with reductions of 9.8 percent in the Summer on-
peak, 2.4 percent in the Summer mid-peak, 0.0 percent in the Summer off-peak,
and 6.4 percent in the Winter periods.
33. Q. HOW DOES THE DISTRIBUTION LOAD SHAPE APPROPRIATELY REFLECT COSTS FOR NEM CUSTOMER CLASSES?

A. NEM customers rely on the distribution system to deliver energy to their meter when their generation is not meeting load, and to receive energy onto the system at any point in time whenever their generation is greater than their load. The Company’s system is designed to meet the maximum demand of the customer, thus it is necessary to include the NEM customers’ total load, including generation from NEM customers that is sent back onto the grid, in the development of marginal distribution costs. Nevada Power plans for and operates the grid to serve a NEM customer’s entire load, in the event the NEM customer’s generation is not available or is diminished. Additionally, a large
portion of NEM generation is not consumed by the NEM customer, but is physically received on the grid from NEM customers and physically redistributed across the grid using the distribution system. This is largely due to the fact that generation peaks much earlier in the day than when customer’s load needs peak. For example, the percent of generation sent back to the grid ranges from 26.9 percent for LRS NEM customers (only eight customers) to 53.8 percent of generation for the RS NEM class (19,980 customers).

The methodology for developing the Distribution load shapes was approved by the Commission in Docket Nos. 15-07041/15-07042 and 16-06006. The load shapes incorporate the additional use of the grid of NEM customers by using the higher of the hourly total loads or the excess generation loads of the class to correctly reflect the use to the Company’s distribution system. The NEM marginal distribution costs are based on the higher of the total loads (in the absence of generation) or those loads in each 15-minute interval in which the NEM customer is producing generation in excess of what its load would have been had the customer not installed a NEM system. As approved by the Commission in Docket No.15-07041 and most recently in Sierra’s 2016 GRC, this load shape appropriately captures the costs that NEM customers place on the distribution system when they send excess generation energy back onto the system, as well as the burden that NEM customers place on the distribution system in order to receive instantaneous, reliable service whenever their NEM system is not producing. Figure Pollard Direct-3 updates the previous figure below with the RS NEM distribution load shape.
34. Q. HOW WERE THE NEM CLASS BILLING DETERMINANTS DEVELOPED?

A. On October 20, 2016, tariffs were approved by the Commission reflecting the stipulation approved in Docket No. 16-07028 allowing for the grandfathering of existing NEM customers, so that they would continue to be billed with rates from the corresponding full requirements rate schedule and would retain the banking mechanism in which they would receive a kWh credit for any excess energy sent back to the grid from their NEM system. The stipulation defined a separate NMR-G schedule, reflecting the grandfathering billing structure, and a NMR-A schedule based upon the billing structure approved by the Commission in Docket...
No. 15-07041 in which the rates for NEM customers are to be based on their separate cost of service including an excess energy credit paid to NEM customers for any excess energy. As NEM customers were billed under the NMR-A rate structure for the majority of 2016 it was necessary to develop annualized billing determinants appropriately reflecting the grandfathering status of the NMR-G customers for the test period. Additionally, rates for the NMR-A classes are based on the cost of service of all NEM customers as customers who have installed self-generation have a similar relationship with the Utility and are therefore included in the development of the load shapes, cost of service and rates for the NMR-A classes. The billing determinants were developed from the annualized individual NEM customer data used in the development of the hourly class load data. The determinants were expanded to the NEM customer counts as of the end of the test period (December 2016) and incorporates the grandfathering status of individual customers as of February 2017 to reflect the most recent data available at the time the input was prepared regarding the status of these customers.

35. Q. DOES THIS COMPLETE YOUR TESTIMONY?
   A. Yes, it does.
Mr. Pollard has been an employee of Sierra Pacific Resources for over nine years and his time at the company is split between his previous position as an Economist in the Resource Planning & Analysis department and his current position within the Regulatory Pricing & Economic Analysis section of the Rates & Regulatory Affairs department. His current responsibilities are focused upon electric cost of service and rate design issues that include the preparation and maintenance of the hourly cost responsibility factor data and ancillary studies 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

**Sierra Pacific Resources, NV Energy**

**Technical Lead, Regulatory Analysis, Policy & Regulatory Strategy**

**Pricing Specialist, Regulatory Pricing & Economic Analysis**

**Staff Economist, Regulatory Pricing & Economic Analysis**

**Senior Economist, Regulatory Pricing & Economic Analysis**

January 2007 to Present

- Conduct research and prepare studies for internal and external presentation
- Provide technical support and analyze data for filings in Nevada and California, Gas and Electric case filings
- Coordinate with numerous departments to gather data for Marginal Cost Studies
- Analyze data and prepare reports for optimal TOU period definitions
- Analyze Load Research sample data for optional TOU rate schedules
- Research and prepare responses to internal and external data requests

**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.

CPUC Applications: 08-08-004.
## Revenue Comparison by Class and Customer Group

### Proposed (ECIC)

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>$ 820,475</td>
<td></td>
<td>$ 820,475</td>
<td>$(43,626)</td>
<td>$ 0</td>
<td>7.81E-10</td>
</tr>
<tr>
<td>RM</td>
<td>236,603</td>
<td>235,636</td>
<td>17,936</td>
<td>(968)</td>
<td>(13)</td>
<td>-0.34%</td>
</tr>
<tr>
<td>LRS</td>
<td>3,752</td>
<td>3,739</td>
<td>212</td>
<td>(13)</td>
<td>(1)</td>
<td>-0.69%</td>
</tr>
<tr>
<td>GS</td>
<td>62,366</td>
<td>62,085</td>
<td>8,638</td>
<td>(281)</td>
<td>(1)</td>
<td>-0.55%</td>
</tr>
<tr>
<td>LGS-1</td>
<td>350,558</td>
<td>348,639</td>
<td>15,734</td>
<td>(1,919)</td>
<td>(11,244)</td>
<td>-0.34%</td>
</tr>
<tr>
<td>LGS-2S</td>
<td>183,121</td>
<td>181,997</td>
<td>10,973</td>
<td>(41)</td>
<td>(1)</td>
<td>-0.41%</td>
</tr>
<tr>
<td>LGS-3P</td>
<td>5,973</td>
<td>5,932</td>
<td>189</td>
<td>(41)</td>
<td>(1)</td>
<td>-0.34%</td>
</tr>
<tr>
<td>LGS-2T</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S</td>
<td>65,202</td>
<td>64,778</td>
<td>4,256</td>
<td>(424)</td>
<td>(1)</td>
<td>-0.34%</td>
</tr>
<tr>
<td>LGS-3P</td>
<td>118,826</td>
<td>118,046</td>
<td>804</td>
<td>(780)</td>
<td>(1)</td>
<td>-0.66%</td>
</tr>
<tr>
<td>LGS-3T</td>
<td>21,967</td>
<td>22,057</td>
<td>1,458</td>
<td>(91)</td>
<td>(1)</td>
<td>0.41%</td>
</tr>
<tr>
<td>LGS-XS</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XT</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-2S-WP</td>
<td>789</td>
<td>789</td>
<td>(25)</td>
<td>(0)</td>
<td>-9.90E-07</td>
<td>-0.77%</td>
</tr>
<tr>
<td>LGS-2P-WP</td>
<td>907</td>
<td>900</td>
<td>185</td>
<td>(7)</td>
<td>-0.77%</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S-WP</td>
<td>442</td>
<td>437</td>
<td>94</td>
<td>(5)</td>
<td>-1.06%</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3P-WP</td>
<td>828</td>
<td>821</td>
<td>124</td>
<td>(7)</td>
<td>-0.86%</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>SL</td>
<td>7,816</td>
<td>7,804</td>
<td>48</td>
<td>(11)</td>
<td>-0.14%</td>
<td>na</td>
</tr>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>81</td>
<td>14</td>
<td>(6)</td>
<td>-0.42%</td>
<td>na</td>
</tr>
<tr>
<td>GS-Pal</td>
<td>284</td>
<td>263</td>
<td>57</td>
<td>(1)</td>
<td>-0.46%</td>
<td>na</td>
</tr>
<tr>
<td>IAIPWP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>14,118</td>
<td>(17,753)</td>
<td>(0)</td>
<td>-2.12E-05</td>
<td>na</td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>87</td>
<td>(22)</td>
<td>(1)</td>
<td>-1.38%</td>
<td>na</td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>57</td>
<td>3</td>
<td>(0)</td>
<td>-0.39%</td>
<td>na</td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>170</td>
<td>(111)</td>
<td>(0)</td>
<td>-0.28%</td>
<td>na</td>
</tr>
</tbody>
</table>

### Rate Design and Reconciliation Revenue

| Rate Design and Reconciliation Revenue | $ 1,894,403 | $ 1,888,911 | $ 17 | $ (5,492) | -0.29% |

### Optional Classes not in Reconciliation

| SSR & LSR | 7,864 | 7,863 | nc | (1) | -0.01% |
| Optional TOU | 21,487 | 21,609 | nc | 122 | 0.57% |
| NEM Optional TOU | 427 | 443 | nc | 16 | 3.72% |
| DOS | 32,796 | 38,154 | nc | 5,358 | 16.34% |

### Total (Bundled & DOS)

| Total (Bundled & DOS) | $ 1,936,002 | $ 1,936,019 | -- | $ 17 | 8.83E-06 |

---

$ 1,936,002 Statement H Revenue Requirement
$ 17 Proposed Change in Revenue Requirement
0.0% Percent Change
## Revenue Comparison by Class and Customer Group

### ECIC Per NRS at NRS Revenue Requirement

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>$ 820,475</td>
<td>$ 899,273</td>
<td>$ 889,273</td>
<td>$ 7,585</td>
<td>$ 68,798</td>
<td>8.39%</td>
</tr>
<tr>
<td>RM</td>
<td>236,603</td>
<td></td>
<td>223,956</td>
<td>1,923</td>
<td>(12,647)</td>
<td>-5.35%</td>
</tr>
<tr>
<td>LRS</td>
<td>3,752</td>
<td>3,630</td>
<td>3,630</td>
<td>35</td>
<td>(122)</td>
<td>-3.25%</td>
</tr>
<tr>
<td>GS</td>
<td>62,366</td>
<td>55,037</td>
<td>55,037</td>
<td>473</td>
<td>(7,329)</td>
<td>-11.75%</td>
</tr>
<tr>
<td>LGS-1</td>
<td>350,558</td>
<td>342,090</td>
<td>342,090</td>
<td>2,953</td>
<td>(8,468)</td>
<td>-2.42%</td>
</tr>
<tr>
<td>LGS-2S</td>
<td>183,121</td>
<td>175,576</td>
<td>175,576</td>
<td>1,500</td>
<td>(7,545)</td>
<td>-4.12%</td>
</tr>
<tr>
<td>LGS-3P</td>
<td>5,973</td>
<td>5,893</td>
<td>5,893</td>
<td>50</td>
<td>(80)</td>
<td>-1.33%</td>
</tr>
<tr>
<td>LGS-2T</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S</td>
<td>65,202</td>
<td>63,446</td>
<td>63,446</td>
<td>542</td>
<td>(1,756)</td>
<td>-2.69%</td>
</tr>
<tr>
<td>LGS-3P</td>
<td>118,454</td>
<td>114,938</td>
<td>114,938</td>
<td>983</td>
<td>(3,516)</td>
<td>-2.97%</td>
</tr>
<tr>
<td>LGS-3T</td>
<td>21,967</td>
<td>24,500</td>
<td>24,500</td>
<td>209</td>
<td>2,533</td>
<td>11.53%</td>
</tr>
<tr>
<td>LGS-XS</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-XT</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-2S-WP</td>
<td>789</td>
<td>834</td>
<td>834</td>
<td>6</td>
<td>45</td>
<td>5.73%</td>
</tr>
<tr>
<td>LGS-2P-WP</td>
<td>907</td>
<td>733</td>
<td>733</td>
<td>6</td>
<td>(174)</td>
<td>-19.14%</td>
</tr>
<tr>
<td>LGS-2T-WP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>LGS-3S-WP</td>
<td>442</td>
<td>351</td>
<td>351</td>
<td>3</td>
<td>(90)</td>
<td>-20.43%</td>
</tr>
<tr>
<td>LGS-3P-WP</td>
<td>828</td>
<td>715</td>
<td>715</td>
<td>6</td>
<td>(113)</td>
<td>-13.67%</td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>SL</td>
<td>7,816</td>
<td>7,766</td>
<td>7,766</td>
<td>67</td>
<td>(50)</td>
<td>-0.64%</td>
</tr>
<tr>
<td>RS-Pal</td>
<td>8</td>
<td>7</td>
<td>7</td>
<td>1</td>
<td>(11)</td>
<td>-14.06%</td>
</tr>
<tr>
<td>GS-Pal</td>
<td>284</td>
<td>213</td>
<td>213</td>
<td>2</td>
<td>(51)</td>
<td>-19.44%</td>
</tr>
<tr>
<td>IAIP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>na</td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>16,386</td>
<td>16,386</td>
<td>(16,172)</td>
<td>2,267</td>
<td>16.06%</td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>83</td>
<td>83</td>
<td>(28)</td>
<td>(5)</td>
<td>-5.64%</td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>59</td>
<td>59</td>
<td>4</td>
<td>2</td>
<td>2.82%</td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>168</td>
<td>168</td>
<td>(118)</td>
<td>(2)</td>
<td>-1.28%</td>
</tr>
</tbody>
</table>

### Rate Design and Reconciliation Revenue

<table>
<thead>
<tr>
<th>Class</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSR &amp; LSR</td>
<td>7,864</td>
<td>8,510</td>
<td>nc</td>
<td>646</td>
</tr>
<tr>
<td>Optional TOU</td>
<td>21,487</td>
<td>21,831</td>
<td>nc</td>
<td>344</td>
</tr>
<tr>
<td>NEM Optional TOU</td>
<td>427</td>
<td>521</td>
<td>nc</td>
<td>93</td>
</tr>
<tr>
<td>DOS</td>
<td>32,796</td>
<td>32,589</td>
<td>nc</td>
<td>(208)</td>
</tr>
</tbody>
</table>

### Total (Bundled & DOS) Revenue

<table>
<thead>
<tr>
<th>Class</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>70</td>
<td>1</td>
<td>(11)</td>
</tr>
<tr>
<td>IAIP</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>16,386</td>
<td>(16,172)</td>
<td>2,267</td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>83</td>
<td>(28)</td>
<td>(5)</td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>59</td>
<td>4</td>
<td>2</td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>168</td>
<td>(118)</td>
<td>(2)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>70</td>
<td>1</td>
</tr>
<tr>
<td>IAIP</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>16,386</td>
<td>(16,172)</td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>83</td>
<td>(28)</td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>59</td>
<td>4</td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>168</td>
<td>(118)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Rate Design and Reconciliation Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 1,894,032</td>
<td>$ 1,925,718</td>
<td>$ 30</td>
<td>$ 31,686</td>
<td>1.67%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Optional Classes not in Reconciliation</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSR &amp; LSR</td>
<td>7,864</td>
<td>8,510</td>
<td>nc</td>
<td>646</td>
</tr>
<tr>
<td>Optional TOU</td>
<td>21,487</td>
<td>21,831</td>
<td>nc</td>
<td>344</td>
</tr>
<tr>
<td>NEM Optional TOU</td>
<td>427</td>
<td>521</td>
<td>nc</td>
<td>93</td>
</tr>
<tr>
<td>DOS</td>
<td>32,796</td>
<td>32,589</td>
<td>nc</td>
<td>(208)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total (Bundled &amp; DOS)</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 1,936,002</td>
<td>$ 1,967,731</td>
<td>--</td>
<td>$ 31,729</td>
<td>1.64%</td>
</tr>
</tbody>
</table>
## Revenue Comparison by Class and Customer Group

### Proposed (Cert)

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>$820,475</td>
<td>$820,475</td>
<td>$820,475</td>
<td>$(42,811)</td>
<td>0</td>
<td>7.81E-10</td>
</tr>
<tr>
<td>RM</td>
<td>236,603</td>
<td>235,986</td>
<td>18,043</td>
<td>(618)</td>
<td>-0.26%</td>
<td></td>
</tr>
<tr>
<td>LRS</td>
<td>3,752</td>
<td>3,745</td>
<td>216</td>
<td>(7)</td>
<td>-0.19%</td>
<td></td>
</tr>
<tr>
<td>GS</td>
<td>62,377</td>
<td>62,198</td>
<td>8,395</td>
<td>(179)</td>
<td>-0.29%</td>
<td></td>
</tr>
<tr>
<td>LGS-1</td>
<td>350,837</td>
<td>349,611</td>
<td>14,743</td>
<td>(1,226)</td>
<td>-0.35%</td>
<td></td>
</tr>
<tr>
<td>LGS-2S</td>
<td>185,840</td>
<td>185,115</td>
<td>10,613</td>
<td>(725)</td>
<td>-0.39%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td>6,321</td>
<td>6,293</td>
<td>180</td>
<td>(28)</td>
<td>-0.44%</td>
<td></td>
</tr>
<tr>
<td>LGS-2T</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>-</td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-3S</td>
<td>73,559</td>
<td>73,255</td>
<td>2,964</td>
<td>(305)</td>
<td>-0.41%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td>154,308</td>
<td>153,654</td>
<td>6,491</td>
<td>(654)</td>
<td>-0.42%</td>
<td></td>
</tr>
<tr>
<td>LGS-3T</td>
<td>28,635</td>
<td>28,728</td>
<td>(2,169)</td>
<td>94</td>
<td>0.32%</td>
<td></td>
</tr>
<tr>
<td>LGS-XS</td>
<td>645</td>
<td>644</td>
<td>28</td>
<td>(1)</td>
<td>-0.10%</td>
<td></td>
</tr>
<tr>
<td>LGS-XP</td>
<td>7,609</td>
<td>7,594</td>
<td>488</td>
<td>(15)</td>
<td>-0.20%</td>
<td></td>
</tr>
<tr>
<td>LGS-XT</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>-</td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-2S-WP</td>
<td>789</td>
<td>789</td>
<td>(40)</td>
<td>(0)</td>
<td>-9.90E-07</td>
<td></td>
</tr>
<tr>
<td>LGS-2P-WP</td>
<td>907</td>
<td>902</td>
<td>178</td>
<td>(4)</td>
<td>-0.48%</td>
<td></td>
</tr>
<tr>
<td>LGS-2T-WP</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>-</td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-3S-WP</td>
<td>442</td>
<td>439</td>
<td>88</td>
<td>(3)</td>
<td>-0.68%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P-WP</td>
<td>828</td>
<td>823</td>
<td>114</td>
<td>(5)</td>
<td>-0.55%</td>
<td></td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>-</td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>SL</td>
<td>7,816</td>
<td>7,806</td>
<td>23</td>
<td>(10)</td>
<td>-0.12%</td>
<td></td>
</tr>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>82</td>
<td>12</td>
<td>(0)</td>
<td>-0.23%</td>
<td></td>
</tr>
<tr>
<td>GS-Pal</td>
<td>264</td>
<td>263</td>
<td>53</td>
<td>(1)</td>
<td>-0.26%</td>
<td></td>
</tr>
<tr>
<td>IAIWP</td>
<td>-</td>
<td>-</td>
<td>na</td>
<td>-</td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>14,118</td>
<td>(17,769)</td>
<td>(0)</td>
<td>-2.67E-05</td>
<td></td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>87</td>
<td>(22)</td>
<td>(1)</td>
<td>-1.23%</td>
<td></td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>57</td>
<td>3</td>
<td>(0)</td>
<td>-0.25%</td>
<td></td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>170</td>
<td>(111)</td>
<td>(0)</td>
<td>-0.07%</td>
<td></td>
</tr>
</tbody>
</table>

### Rate Design and Reconciliation Revenue

| Rate Design and Reconciliation Revenue | $1,957,522 | $1,953,835 | $291 | $3,687 | -0.19% |

### Optional Classes not in Reconciliation

<table>
<thead>
<tr>
<th>Class</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSR &amp; LSR</td>
<td>7,864</td>
<td>7,863</td>
<td>nc</td>
</tr>
<tr>
<td>Optional TOU</td>
<td>40,130</td>
<td>40,226</td>
<td>nc</td>
</tr>
<tr>
<td>NEM Optional TOU</td>
<td>427</td>
<td>443</td>
<td>nc</td>
</tr>
<tr>
<td>DOS</td>
<td>20,319</td>
<td>23,821</td>
<td>nc</td>
</tr>
</tbody>
</table>

### Total (Bundled & DOS)

| Total (Bundled & DOS) | $1,985,507 | $1,985,447 | $61 | -3.05E-05 |

$1,985,507 Statement H Revenue Requirement
$61 Proposed Change in Revenue Requirement
0.0% Percent Change
### Revenue Comparison by Class and Customer Group

#### Cert at NRS Revenue Requirement

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present Rate Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>$820,475</td>
<td>$886,565</td>
<td>$7,351</td>
<td>$66,091</td>
<td>8.06%</td>
<td></td>
</tr>
<tr>
<td>RM</td>
<td>236,603</td>
<td>223,717</td>
<td>1,858</td>
<td>(12,886)</td>
<td>-5.45%</td>
<td></td>
</tr>
<tr>
<td>LRS</td>
<td>3,752</td>
<td>3,624</td>
<td>33</td>
<td>(128)</td>
<td>-3.42%</td>
<td></td>
</tr>
<tr>
<td>GS</td>
<td>62,377</td>
<td>55,282</td>
<td>457</td>
<td>(7,095)</td>
<td>-11.38%</td>
<td></td>
</tr>
<tr>
<td>LGS-1</td>
<td>350,837</td>
<td>343,299</td>
<td>2,800</td>
<td>(7,538)</td>
<td>-2.15%</td>
<td></td>
</tr>
<tr>
<td>LGS-2S</td>
<td>185,840</td>
<td>178,765</td>
<td>1,475</td>
<td>(7,076)</td>
<td>-3.81%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td>6,321</td>
<td>6,260</td>
<td>52</td>
<td>(61)</td>
<td>-0.96%</td>
<td></td>
</tr>
<tr>
<td>LGS-2T</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-3S</td>
<td>73,559</td>
<td>72,173</td>
<td>596</td>
<td>(1,386)</td>
<td>-1.88%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td>153,416</td>
<td>149,344</td>
<td>1,233</td>
<td>(4,072)</td>
<td>-2.65%</td>
<td></td>
</tr>
<tr>
<td>LGS-3T</td>
<td>29,635</td>
<td>32,618</td>
<td>269</td>
<td>2,983</td>
<td>10.07%</td>
<td></td>
</tr>
<tr>
<td>LGS-XS</td>
<td>645</td>
<td>630</td>
<td>5</td>
<td>(15)</td>
<td>-2.38%</td>
<td></td>
</tr>
<tr>
<td>LGS-XP</td>
<td>7,609</td>
<td>7,285</td>
<td>60</td>
<td>(325)</td>
<td>-4.27%</td>
<td></td>
</tr>
<tr>
<td>LGS-XT</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-2S-WP</td>
<td>789</td>
<td>848</td>
<td>6</td>
<td>60</td>
<td>7.56%</td>
<td></td>
</tr>
<tr>
<td>LGS-2P-WP</td>
<td>907</td>
<td>742</td>
<td>6</td>
<td>(165)</td>
<td>-18.18%</td>
<td></td>
</tr>
<tr>
<td>LGS-2T-WP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>LGS-3S-WP</td>
<td>442</td>
<td>364</td>
<td>3</td>
<td>(77)</td>
<td>-17.53%</td>
<td></td>
</tr>
<tr>
<td>LGS-3P-WP</td>
<td>828</td>
<td>701</td>
<td>6</td>
<td>(127)</td>
<td>-15.34%</td>
<td></td>
</tr>
<tr>
<td>LGS-3T-WP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>SL</td>
<td>7,816</td>
<td>7,982</td>
<td>66</td>
<td>166</td>
<td>2.12%</td>
<td></td>
</tr>
<tr>
<td>RS-Pal</td>
<td>82</td>
<td>72</td>
<td>1</td>
<td>(10)</td>
<td>-12.17%</td>
<td></td>
</tr>
<tr>
<td>GS-Pal</td>
<td>284</td>
<td>217</td>
<td>2</td>
<td>(46)</td>
<td>-17.58%</td>
<td></td>
</tr>
<tr>
<td>IAIWP</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>na</td>
<td></td>
</tr>
<tr>
<td>RS-NEM</td>
<td>14,119</td>
<td>16,384</td>
<td>(16,129)</td>
<td>2,265</td>
<td>16.05%</td>
<td></td>
</tr>
<tr>
<td>RM-NEM</td>
<td>88</td>
<td>83</td>
<td>(28)</td>
<td>(5)</td>
<td>-5.55%</td>
<td></td>
</tr>
<tr>
<td>LRS-NEM</td>
<td>57</td>
<td>59</td>
<td>4</td>
<td>2</td>
<td>2.79%</td>
<td></td>
</tr>
<tr>
<td>GS-NEM</td>
<td>170</td>
<td>169</td>
<td>(117)</td>
<td>(1)</td>
<td>-0.83%</td>
<td></td>
</tr>
</tbody>
</table>

#### Total (Bundled & DOS) $1,985,507 $2,016,444 $30,937 1.56%

#### Rate Design and Reconciliation Revenue $1,956,630 $1,987,181 $30,551 1.56%

#### Optional Classes not in Reconciliation

<table>
<thead>
<tr>
<th>Class</th>
<th>Present Rate Revenue</th>
<th>Proposed Rate Revenue</th>
<th>Revenue</th>
<th>Difference from Cost</th>
<th>Change from Present Rate Revenue</th>
<th>% Change from Present Rate Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSR &amp; LSR</td>
<td>7,864</td>
<td>8,432</td>
<td>nc</td>
<td>568</td>
<td>7.23%</td>
<td></td>
</tr>
<tr>
<td>Optional TOU</td>
<td>40,130</td>
<td>40,537</td>
<td>nc</td>
<td>407</td>
<td>1.01%</td>
<td></td>
</tr>
<tr>
<td>NEM Optional TOU</td>
<td>427</td>
<td>520</td>
<td>nc</td>
<td>93</td>
<td>21.76%</td>
<td></td>
</tr>
<tr>
<td>DOS</td>
<td>20,319</td>
<td>20,377</td>
<td>nc</td>
<td>58</td>
<td>0.29%</td>
<td></td>
</tr>
</tbody>
</table>

#### Total (Bundled & DOS) $2,016,444 $30,937 1.56%

$2,016,436 Statement H Revenue Requirement

$30,937 Proposed Change in Revenue Requirement

1.6% Percent Change
Nevada Power Company
2017 General Rate Case
Rate Design Methodology

Docket No. 17-06____
Exhibit Pollard Direct-3
Nevada Power Company
2017 General Rate Case
Rate Design Methodology

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    PROPOSED - Planned Demand Use (PDU) Option................................................................. 9
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    LGS-2T class ....................................................................................................................... 16
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Overview

Nevada Power’s proposed rates for all classes of customers, including bundled service and unbundled distribution-only service (DOS) customers are based on marginal cost reconciled to the unbundled embedded revenue requirement.

In this case, Nevada Power has calculated four different revenue requirements, and thus four different Statement Os have been prepared. Each Statement O begins with revenue at full marginal cost from one of the two marginal cost of service studies (MCS). Revenue reflecting full marginal cost are then reconciled to the unbundled embedded revenue requirement from Statement H, to set class revenue requirements. In Statement O, deviations from, and restrictions imposed on, the adherence to marginal costs imposed by public policy are disclosed. Using Statement O, the detailed marginal cost relationships across functions, TOU periods and customer classes are used to set the proposed rates for each class of service. Rates are designed to recover the annual revenue requirement given the test period billing determinants from Statement J.

The Company’s preferred proposal is to maintain rates at current levels so that total proposed rate revenue remains equal to the revenue resulting from current rates, while recognizing two Expected Changes in Circumstance (“ECIC”) events—the conversion of two large commercial customers from bundled retail electric to DOS service during the ECIC period.

The four statements (with their corresponding change in revenue requirement) are:

1. **Company Proposed – Statement O – ECIC (at Present Rate Revenue)**. The Company’s proposed rates are presented in this Statement O. This proposal reflects the ECIC while maintaining the total revenue requirement at present rate levels. Rates are proposed to remain at current levels with the modifications discussed below in order to effectuate the Company’s proposed updates while maintaining no change to the total revenue requirement.

2. **Statement O – ECIC (at NRS Revenue Requirement)**. This Statement O reflects the Company’s ECIC proposal with the fully calculated NRS revenue requirement increase incorporated into rates. Additionally, revenue requirements for all classes (excluding NEM customer classes) are set at cost in order to demonstrate the impact to classes if the Residential Service (RS) subsidy was eliminated. This ECIC Statement O (At NRS Revenue Requirement) provides a complete rate design that would be otherwise proposed if the Company’s proposal to reflect the ECIC events was accepted, but its proposal to retain revenue requirement at present rate revenue levels was rejected.

3. **Statement O – Cert (at Present Rate Revenue)**. The Company’s proposed rates presented in this Statement O maintains class revenue requirement at present-rate levels. Stated differently, CERT Statement O (At Present Rate Revenue) provides a complete rate design that would be otherwise proposed if the Company’s proposals to reflect the ECIC events was rejected, but its proposal retain a revenue requirement at present rate revenue levels was accepted. Additionally, rates are maintained at
current levels while incorporating the modifications necessary to result in no change to revenue requirement.

4. **Statement O – Cert (at NRS Revenue Requirement).** This Statement O is built from Nevada Power’s calculation of the full revenue requirement as set forth in the Nevada Revised Statutes (NRS) and NAC. The shorthand designation of this version of Statement O presents a complete rate design as if the Company were to propose rates based on certification period estimates and following the requirements of the NRS and NAC. Stated differently, CERT Statement O (At NRS Revenue Requirement) provides a complete rate design that would be otherwise proposed if the Company’s proposals to reflect the ECIC events and to retain a revenue requirement at present rate revenue levels were rejected.
Rate Design Methodology

The rate design methodology in this case is primarily the same as that approved in past cases. The Company’s proposed rate design setting each class’s rates at present rate levels or present rate adjusted downward is specifically addressed here and in testimony. The discussion of rate design that follows is either generally applicable or specific the Company’s Statement O versions filed to inform the Commission on cost based rates.

Residential (RS, RM, LRS) and Small General Service (GS) Classes

Cost to serve, based on cost causation, should be grouped and recovered in three distinct categories, fixed or relatively fixed, demand, and variable consumption. Despite this fact, the residential and small general service classes continue to have simple two part rate designs with all costs not recovered in the basic service charge (BSC) being recovered through variable consumption rates. The BSCs for the RS and LRS classes remain below cost based levels, despite proposed increases in these charges over time. In the ECIC at NRS Statement O, the Company presents BSC rates to recover approximately 100 percent of the costs of the meter and service drop investments, customer accounting and customer service expenses, 100 percent of Rule 9 distribution facilities and 25 percent of primary distribution costs for these residential classes. For the RS class this results in a BSC of $21.00 per customer per month, however, if the BSC also included 100 percent of distribution costs the resulting rate would be $32.75 per customer per month.

The proposed GS class BSC has been set slightly below the full distribution cost based level, which has been consistent since the 2011 GRC, to recover the full customer, Rule 9 facilities and 50 percent of primary distribution facilities costs. However, there is a large decrease in Rule 9 facilities costs for these classes, discussed in the whitepaper filed as Exhibit Walsh Direct-2, resulting in a decrease in distribution cost for this class. The proposed rate decreases from $27.50 to $14.50 as a result.

The rate design for these four classes is shown on pages 1, 8, 15, and 22 of Workpaper 4 of Statement O.

LGS-1 Service

The LGS-1 rates are set in the same manner as current rates. The rate design structure continues to have a BSC and 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. The BSC is set to fully recover meter investment, customer accounting and customer service expenses. The facilities charge is set to fully recover the customer facilities and distribution demand costs. In the Statement O – ECIC at NRS, the BSC for this class is $8.50 per customer, representing a 60 percent decrease from the current rate of $21.10. The Additional Meter Charge (AMC) is proposed to decrease to $5.82 per meter per month, a 55 percent decrease. The proposed facilities rate increases by 3.1 percent from $4.22 per kW to $4.35 per kW.
The non-TOU demand charge recovers a portion of the Transmission and Generation (T&G) demand costs, and the proposed charge of $5.85 represents a 34.5 percent increase from the current demand rate of $4.35. Even with this increase, the total T&G demand costs recovered through the proposed demand charge only slightly increases. The balance of the T&G demand costs is recovered through the proposed energy charge of $0.05302, which is 9.7 percent less than the current energy rate. The LGS-1 rate design is shown on page 26 of Workpaper 4 of Statement O.

Optional Time-of-Use (TOU) Schedules

The optional TOU rates for all optional TOU classes continue to be developed from the otherwise applicable schedules and use the same rate design methodology as in previous GRCs. An update is made in this filing for the ORM Option A schedule to exclude the incremental cost of a TOU meter that was still present in their current rate. The BSC for this schedule is now set to the OAS BSC rate. For rate design purposes, 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.

While the cost based TOU energy rates are used as targets for the 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 further move, the proposed rates toward cost based TOU levels, and also aims to reasonably reflect the cost-based relationships across the TOU periods. The Company’s present optional TOU rates already were significantly reflective of cost-based TOU rates. In some cases the further 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, further movement toward cost-based rates was limited to prevent excessively large changes in the TOU rates or rate relationships over those in present 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, large changes due to the proposed changes to the classification of Summer On-peak weekend hours to the Off-peak period created a change in the TOU rate relationships existing in current rates and are mitigated in the proposed rate design.

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 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 than those hours 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 that 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, RSL, GS and LGS-1 optional TOU rate schedules is shown on the respective rate design pages in Workpaper 4 of Statement O.

**Option B versus Option A TOU schedules**

Since it was first approved, the rate structure residential TOU schedule Option B has been substantially different, with a 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. Further, the Option B schedules have an On-peak rate period during the hours of 2 p.m. to 7 p.m. in the months of July and August, rather than the proposed weekday 1 p.m. to 7 p.m. On-peak period in the months of June to September for the Option A TOU schedules. 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 the Option A schedules. Alternatively, customers on Option B experience a greater number of hours at a lower Off-peak rate potentially offsetting the higher rate that they pay during the limited On-peak hours. Because the BSC is so much greater under Option B, 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 OAS.

The rate design for the applicable Option B TOU schedules is shown on the respective rate design pages in Workpaper 4 of Statement O.

**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 thereafter 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 10 percent. The 10 percent discount is reflected in the BTGR energy rate for each class, and the discount to this rate element may be large enough to result in a negative BTGR rate component, which is permitted. As the BTER has changed from the 2014 GRC, the 10 percent discount is recalculated and incorporated in the EVRR rates. The BTER in this filing ($0.03899 for residential customers as of January 1, 2017) is lower than the BTER rate ($0.04652) from the 2014 GRC when the EVRR discount was last reset. This leads to a slightly lower discount provided to the EVRR hours and results in a small increase in revenue for these
schedules. The change in revenue is included in the revenue requirement adjustments incorporated into proposed rates that maintain a zero overall change.

The discounted Off-peak EVRR rate applies to all of the customer’s electric usage during the 10 p.m. to 6 a.m. period, not just the energy used to charge an electric vehicle. The same rate development as described above applies to all of the EVRR rate schedules. These discounted rates are developed and shown on page 10 of Workpaper 1 for residential customers, page 11 for commercial customers and page 14 of Workpaper 2 for the NEM EVRR customer classes.

**PROPOSED - Critical Peak Pricing (CPP) Option**

The proposed Optional Full Requirements Residential CPP TOU schedules provide an additional option for customers seeking a rate structure that better fits how they use energy. The new CPP TOU schedules would be made available to full requirements single-family, multi-family and large residential customers.

The CPP rate schedules follow the Option-A TOU schedules, with the proposed changes to Summer weekend hours, but include a CPP rate element. 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 from 1 p.m. – 7 p.m. on non-holiday weekdays. These CPPs are communicated to the customer on a day-ahead basis and are accompanied by a higher dollar-per-kWh rate. While the events are dispatched the day before the occurrence, the CPP rate is not communicated as it 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.

Based on the information gained from the Nevada Dynamic Pricing Trial (“NDPT”), Nevada Power is proposing three changes to the CPP for the new ORS-CPP, ORM-CPP, and OLRS-CPP schedules. In the NDPT, when a CPP event was called for the day, customers would experience two Summer On-peak hours (1 p.m. - 3 p.m.) until the CPP event would begin and continue for four hours until 7 p.m. In the present case, the proposed change of matching the CPP event duration to the On-peak hours have been made to simplify the rate structure, making it more easily understood when marketing the message about CPP events to customers, and making it easier for customers to adjust their behavior by reducing their usage during high cost hours that do not change during the Summer season.

Therefore, the length of CPP events is proposed to change from four hours (3 p.m. – 7 p.m.) to a six-hour period (1 p.m. – 7 p.m.), which is the same as the standard Summer On-peak period. While the longer period imposes a higher burden on customers when a CPP event is called, customers will have a clearer understanding of the period during which they should reduce their usage to achieve bill savings from this simpler optional schedule.
Third, the number of CPP events is being lowered from 18 required summer events to a possible 12 to 14 events, depending on the weather in a given Summer season. The reduction in the number of CPP events will help to minimize the burden on customers when not fully justified by cost. Exhibit Walsh Direct-3 provides information on the estimated number of single-family residential customers that would benefit under these proposed rates.

**PROPOSED - Planned Demand Use (PDU) Option**

The Company is proposing new optional schedules for full requirements residential customers that incorporate demand charge components. 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 kW demand charge, and Summer On-peak demand charges. In the Company’s proposal the maximum kW charge has been set to recover 100% of Primary Distribution Demand costs and 75 percent of Rule 9 Facilities costs. Therefore these schedules have a reduced BSC. For example, the ORS-PDU class will pay a $7.25/month BSC compared to the standard RS charge of $12.75, which is maintained at the current rate. The percentage of Rule 9 Facilities costs recovered through the BSC increases to 50 percent in the Statement O – Cert at NRS scenario to $10.75 as the BSC proposed for the standard RS schedule in this rate design increases to $21.25 in order to recover a proposed 100 percent of customer and Rule 9 facilities costs as well as 25 percent of primary distribution costs. Therefore, the PDU BSC is able to recover more of the Rule 9 Facilities costs in the BSC while maintaining a significant discount to the OAS BSC rate in this scenario.

The Summer On-peak demand charges will apply to the maximum 15-minute demand placed on the system during that period. These charges recover 100 percent of the transmission demand costs for the class. The costs associated with these charges have the effect of reducing 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.

**Bundled Large General Service (LGS) TOU Classes**

The rate design for the TOU-based LGS rate schedules (excluding the respective curtailable water pumping schedules) is in Workpaper 4 of Statement O. The approach to the LGS rate design is generally the same as prior GRCs. Details of the methodology 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 costing and rate design development purposes, consistent with the methodology most recently approved by the Commission in Docket No. 14-05004. Together these two large partial requirements customers are included in the costing and rate design for the respective class because they use their generation to only partially serve their own load and would otherwise be served under this rate schedule if not for their solar PV generation. Previously, another large LSR-II LGS-
3T standby customer, who had also installed self-generation, was included in the same manner. However, this customer has since become a DOS-only customer and was removed from the cost of service and rate design for the LGS-3T class. 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 the 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. In addition to the WAPA energy credit attributable to the customer with the WAPA allocation, there is also a WAPA credit component related to generation capacity - 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 class apply 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, as was done in the last two GRCs, and 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 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.

The resulting class marginal cost revenue (reflecting the inclusion of these two standby 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 RD” worksheet (page 34) of Workpaper 4 where the LGS-3T rate design (with the one standby customer included) takes place. In the LGS-3T-RD 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 RD 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) 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 customer at LGS-3T rates and billing determinants is compared to the revenue billed under the standby 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 and the OLGS-3P HLF customers for the LGS-3P class 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 Customer Specific Facilities (“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.

**Customer Specific Facilities Charges for Transmission Level Customers: Utility-Contributed Investment**

The monthly CSF charge that transmission and LGS-3P 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 but apply the current rate to develop the charge. The fully cost based charge is developed and shown in the Statement O – ECIC at NRS. Facilities investment amounts, which are reflective of the replacement cost of the facilities in rate effective year dollars (2018 dollars in this case), are updated to reflect current investments because they have not been updated since the 2011 GRC.

The CSF charge per dollar of utility contributed investment is the same for all transmission level customers. As the non-X transmission level charges were stipulated in 2014 to current rates, but the OLGS-3P HLF schedule was approved out of the stipulation based upon rates in that certification filing, the CSF charges for this class differs from the other individual classes with CSF charges. Additionally, in the Statement O – ECIC at NRS rates, the Company proposes to no longer reconcile the rate for charges that will fully recover the customer specific investment. Because the charge is calculated to recover the specific investment, if the charge is reconciled then the charges will either not recover, or will over-recover, the investment amount over the life of the investment. The monthly CSF charge developed in the Statement O – ECIC at NRS is $0.00762 per dollar of utility contributed investment. The facility investment and development of the CSF charge is detailed by customer, on pages 18 to 20 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 the LGS-3T class, 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 is calculated at the bottom of page 18 of Statement O.

Again, these investment amounts have been updated from the 2011 GRC amounts while the CSF charges are proposed to be kept at current levels. The difference in revenue collected from these charges from current investment amounts are included in the revenue requirement adjustments to the non-subsidized classes to ensure a zero change in total revenue requirement.

**CSF Charges for Transmission Level 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 of customer contributed investment basis. 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. While the Company proposes to maintain the current rates, the proposed monthly CSF charge for contributed investments is $0.00085 per dollar of the customer contributed investment in the Statement O – ECIC at NRS scenario. 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 change 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 are recovered through the proposed energy rates. This methodology is sometimes referred to as the “rate tilt.” Given that there is an interrelationship between the generation and energy functions, but there exists a disconnect 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 Nevada Power’s 2014 GRC, the rate tilt compliance rates ranged from 41 to 55 percent, with the average being about 48 percent.

The general rate design practice of rate tilt is to recover system generation capacity costs through the $/kWh energy charge does not impact the allocation of embedded revenue requirement among customer classes but 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 as more 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.

In the Statement O – ECIC at NRS scenario, the proposed rate tilts maintain the same range as in current rates but provide a slight increase in the tilt, with the average tilt increasing slightly to 50 percent. In this filing, the Company largely used the class load factor as a guide of the percent of generation revenue that should be shifted to the energy charges as the rate tilt analysis indicates that 50 percent to 75 percent is a fair balance between high and low load factor customers with the difference to marginal cost converging at the average load factor for all rate tilt percentages. Figure 1 below demonstrates this effect. The movement toward the class load factor as the rate tilt measure was mitigated for the LGS-2S, LGS-3S and LGS-3P classes because a move completely to that level caused large changes between the demand and energy charges for the class. Therefore, the movement is attenuated in the proposed rates for this Statement O scenario.

Exhibit Pollard Direct-4 to Mr. Pollard’s prepared direct testimony in this docket summarizes the results of the rate tilt analysis performed by Nevada Power in preparation for this filing ordered by the Commission in the Docket No. 14-05004. Paragraph 27 of the Order from NPC’s 2014 GRC, Docket 14-05004, the Commission ordered that “NPC will specifically address rate tilt for the large commercial and industrial classes and provide supporting information justifying the resulting percentages for those particular classes.” The Exhibit details the methodology and results of the rate tilt analysis on the LGS-3P class. The LGS-3P class was chosen for the analysis as it is a census class with a large diversity of load factors between customers. This allowed us to determine that utilizing the class load factor as a primary point of the rate tilt results in a fair balance of recovery of rates through the generation and energy functions. At the extremes, a 0 percent rate tilt resulted in the lower load factor customers paying more than marginal cost due to higher demand revenue and at 100 percent tilt some higher load factor customers are paying above marginal cost due to a higher $/kWh energy charge. Utilizing a customer class load factor as the rate tilt, provides a reasonable amount of tilt that treats all customers within the class equitably. Generally, all customers move toward cost at this level and the negative impacts to customers on either side of the load factor spectrum is minimized. The class load factors for the LGS classes range from 48-55 percent in this filing.

*Demand rates for the LGS TOU classes*

For the costs that are recovered through the TOU demand charges, we tried to preserve the cost-based relationship between the On-peak and Mid-peak rates in the cost-based demonstration, subject to limiting the increase of the Mid-peak rate to a reasonable level. In the MCS, Mid-peak demand costs (and marginal cost Mid-peak rates) increase relative to the On-peak demand costs (and marginal cost On-peak rates). If the increase in the Mid-peak costs relative to the On-peak costs were fully reflected in the proposed rates, very large increases would have to be accepted in the Mid-peak rates. Therefore, the Mid-peak and On-peak demand rates were set by moving approximately 30 percent of the way from the present Mid-peak to On-peak rate relationship toward the new Mid-peak and On-peak cost based relationship. By making this significant, yet attenuated, movement toward the
cost based relationships, the Mid-peak demand rates for these classes increase over present rate levels from 15 to 44 percent range, with the On-peak rates increasing an average of nine percent. Two exceptions are the LGS-3T class, which uses 25 percent as the amount of revenue to shift, and the OLGS-3P HLF schedule which does not increase the percentage of demand costs to the On-peak and Mid-peak periods. In future rate cases, the Company will gradually increase this percentage for all classes to make energy rates more reflective of the distribution of TOU costs developed in the MCS.

Furthermore, these increases in the Mid-peak and On-peak rates move each of these rates about 25 percent closer to their cost based levels. Also, to maintain some degree of revenue stability in the recovery of demand costs in the Winter season, as has been approved by the Commission in the prior GRCs, small increases were proposed in the Winter demand rates with the proposed Winter demand charges still well above the cost based levels. The proposed demand charge in the Winter, which is about 3 percent of the On-peak rate, is not large enough to significantly change the cost based price signals otherwise contained in these schedules’ rate designs, and does help to provide some revenue stability to the utility, and also helps to levelize customers’ monthly bills.

**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) 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.

In addition to this general approach to rate design for these TOU rate classes, there are certain other rate adjustments that occur within the rate design to incorporate power factor charges assigned to the class and to account for other special charges (such as AF&M) and credits (such as the WAPA energy credit). These adjustments have been approved by the Commission in multiple case previously and can be found, as applicable, in the detail rate design pages of Statement O for these classes.

**Optional LGS-3P High Load Factor (OLGS-3P HLF) Schedule**

The OLGS-3P HLF tariff is an optional schedule approved as part of the stipulation in Nevada Power’s 2014 GRC. Eligible customers are large commercial LGS-3P customers with an annual load factor greater than 75% 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 as 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. After costs are developed for the class rates are 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 is flowed back as adjustments to the total unbundled revenue requirement to modify the target rate design revenue requirement.

The rates for the class are developed on page 33 of Workpaper 4 in Statement O. The CSF charges are developed on pages 18 and 19 of Statement O. Revenues 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 14 of Workpaper 1.

**Curtailable Water Pumping (WP) Schedules**

These rates are set consistent 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 curtable demand rates under the LGS-WP tariffs are set at the sum of the on- and Mid-peak rates of the otherwise applicable tariffs. 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 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 the 2014 GRC, the proposed rates for this class are based upon the OLGS-1 class for the non-irrigation season (November-February) and the legislative mandated low cost irrigation rate ($0.06350) during the irrigation season, which was approved for the 2017 irrigation season in Docket No. 16-10003.
Classes without Customers

**LGS-2T class**

As with the IAIWP tariff, the Company lacks class-specific cost information for the LGS-2T class. Therefore, we 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. 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 with such charges (e.g., LGS-3T). The LGS-2T demand rates are set equal to the LGS-2P demand rates. The energy rates are set equal to the LGS-2P energy rates, adjusted downward for losses based on the relationship among the LGS-3P and LGS-3T cost based energy rates.

**LGS-X, LGS-2T-WP and LGS-3T-WP classes- no Bundled customers**

Two WP classes presently have no bundled customers, but in the ECIC proposal the LGS-X schedules will also have no bundled customers. However, the method of setting rates for these two classes essentially the same as that described for the LGS-2T class. Since marginal costs are not developed for DOS customers, the Company develops the rates for these classes the same way it does for the LGS-2T class. Customers served under these schedules pay CSF charges. They will pay the same CSF rate per dollar of investment as developed for any other bundled class with similar charges. As for the LGS-2T class, the proposed BSCs for these classes come from the MCS, and are reconciled using the distribution reconciliation factor.

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 similar to the adjustment made to set the energy rates for the LGS-2T class.

In the Company’s ECIC Statement O versions the rates for the LGS-X classes are maintained at current levels even though all customers within the schedules have exited and moved to DOS service.

**Distribution-Only Service (DOS) Schedules**

DOS rates are proposed to remain at current levels with the addition of new charges required by the Commission’s orders in the exit dockets. Generally, DOS rates are based on separately identified costs for DOS customers to allow for any cost differences between DOS and bundled service to be identified and reflected in their rates. The resulting charges are set at the reconciled marginal cost for these classes in the Statement O – ECIC at NRS.

The distribution rates for DOS classes include the BSC, the 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 interclass rate rebalancing charge, as well as the Universal Energy Charge and all applicable taxes. The Commission approved in Docket No. 01-10001 that for classes with DOS eligibility, their distribution rates should be set at cost based levels. Since that time, the rate design has generally maintained the parallel cost based rate structure between bundled and DOS rates with both set at cost-based levels. Since the development of the DOS-specific BSC and AMC, the parallel structure between DOS and bundled cost based rates for these components is no longer applicable, but the goal of the Company is to continue to set both the bundled and DOS distribution rates at cost based levels.

In this filing, the new R-BTER ($/kWh) and SB 123 Regulatory Asset charges are included as part of the revenue collected from some applicable DOS customers. The revenue requirement associated with the SB 123 Regulatory Assets, and resulting rates, are presented on page 16 of Workpaper 1. The rates are based on taking the revenue requirement of each part defined in the respective exit dockets (Part A from Docket Nos. 15-05006 and 15-05017, Part B from Docket No. 16-11034) and dividing by the total sales of the Company’s bundled service customers plus the sales of the applicable customers who will pay the charges. The resulting rates are $0.00301 per kWh for Part A and $0.00309 per kWh for the Part B rate.

The proposed rates for the DOS schedules are presented on page 16 of Statement O. The calculated revenue is summarized on pages 15 and 16 of Workpaper 1.

Small Standby (SSR) and Large Standby Service Rider (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 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 the cost of the additional meter and associated costs computed in the MCS and passed to the rate design. For SSR-I and SSR-II the meter charge is per customer and reflects the incremental cost based customer and meter charges. The facilities charges for SSR-III and LSR classes are set at the reconciled marginal cost based rates of the OAS or are 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. As stated in Mr. Dillard’s prepared direct testimony, the Company proposes to eliminate the SSR-I schedule for RS customers.

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 NPC. All supplemental use beyond the back-up or contract demand requirement is billed at the full demand rates of the OAS.

**Diversity Factor**

The method of calculating the diversity factor was established in the Settlement adopted in the Commission’s Order in Docket’s Nos. 03-0640 and 03-0641, and the update in this case continues to be consistent with that methodology and with the update made in Nevada Power’s prior GRCs. As approved by the Commission in Nevada Power’s 2014 GRC, the diversity factor in this proceeding has been updated using the hourly billing data for all standby customers over a recent three-year period – in this case the calendar years of 2014, 2015 and 2016 – 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 tends to inappropriately affect the diversity calculation for all other standby customers where the diversity factor does have a meaningful impact. The Commission also approved this adjustment in the diversity calculation in Sierra’s most recent GRC, Docket No. 16-06006. 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 21 percent, up from the 19 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 15, also summarizes the proposed rates for the SSR and LSR schedules.

**Lighting Schedules**

Rates for the lighting classes - Street Lighting (SL), Residential Private Area Lighting (RS-PAL) and Small General Service Private Area Lighting (GS-PAL) - were set using the same rate design methodology approved in the past. 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.

Page 12 of Statement O shows the proposed rates for the lighting schedules and the detail rate development is provided on pages 45-49 in Workpaper 4.

**Net-Energy Metering (NEM) Schedules**

All NEM customers are treated the same for MCS and cost-based rate development. However, the different Statement O models in this filing incorporate the split of NEM customers between the grandfathered NMR-G customers (approved in the Docket No. 16-07028 stipulation) and those customers billed under the cost-based NMR-A billing structure (approved in Docket No. 15-07041) for rate design purposes. 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. Pages 7, 9, 11, and 13 of Workpaper 2 develop the revenues for those NEM customers billed under the NMR-G schedules. The difference in the revenue from the cost-based revenue presented on these pages is the NEM shortfall, which is recovered from all other customers through the “Passes” tab, or page 4 of Statement O. In total, the NMR-G related shortfall in the Company’s proposal is nearly all (99.7 percent) of the identified $18.3 million NEM shortfall.

The rates for the NMR-A schedules reflect the approved laddering methodology in which movement towards cost-based rates are done in four three-year steps. Under the Commission’s laddering order, rates for customers in the NEM classes will reach full cost-based levels in 2028. The Excess Energy Credit (EEC) established in Docket No. 15-07041 follows the same four-step process and is paid to NEM customers for any excess generation they provide back to the grid. In its order in 15-07041, the Commission recognized that cost-based rates for the full requirements classes and NEM classes would be updated and reset at each general rate case. The laddered rates are developed on pages 6, 8, 10, and 12 of Workpaper 2.
Summary

The Company proposes in this filing to maintain the proposed class revenue requirements at current rate levels, with adjustments to incorporate five rate design items, while maintaining zero change in the total revenue requirement. The allocation and impact of the proposed adjustments modifying rates in the Company’s proposal are different from those developed under the rate design methodology described in this whitepaper and used to develop rates in the “Per NRS” Statement O models. Summaries of the proposed rates resulting from the rate design methodology discussed in this whitepaper are presented on pages 10 to 16 of the Statement O – ECIC per NRS or Statement O – Cert per NRS models. Percent change comparisons from current rates are presented in Workpaper 5.
Rate Tilt Analysis

Background:

Marginal generation capacity costs are developed on a $/kW basis in the marginal cost study for an additional kW increment of generation capacity. This cost is allocated across all hours of the year by identifying those hours that drive the need for generation capacity investment using Loss of Load Probability (“LOLP”) data from the PROMOD production cost modeling program. These hourly costs are then weighted by hourly class loads to allocate more costs to those classes with higher relative loads in those hours with higher LOLP values.

This marginal generation revenue is reconciled with marginal energy costs in the revenue reconciliation process to reflect the interrelated nature of generation and energy costs in the company’s embedded revenue requirement. While generation capacity additions are demand driven and are recovered as capital investment, there are costs or savings related to fuel that are not separable. Additionally, there are capacity components included in certain energy purchases recovered through the company’s fuel and purchased power costs (e.g. fuel or firm market purchases). As such, it is appropriate to recover a portion of generation capacity costs through $/kWh energy charges charged to customers, even when their rate structure includes a demand charge component. The recovery of generation capacity costs through a volumetric energy charge is a rate design practice referred to as “rate tilt.”

In Paragraph 27 of the Public Utilities Commission of Nevada’s (“PUCN”) Order in Nevada Power’s 2014 General Rate Case (Docket No. 14-05004) it stated that “In NPC’s next general rate case filing, NPC will specifically address rate tilt for the large commercial and industrial classes and provide supporting information justifying the resulting percentages for those particular classes.” The following analysis supports the company’s use of rate tilt as an appropriate rate design mechanism for the large commercial and industrial customer classes who have both demand and energy rate components.

This practice does not impact the allocation of total embedded revenue requirement to various customer classes but does effect the revenue that is collected from customers within a given class. Generally, if a customer has a higher load factor that customer will pay more as more 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 (where more revenues are collected through the energy charge). The total revenue requirement of the class is unaffected by the amount of rate tilt built into rate design but will impact individual customers within the class differently. Therefore it is important to implement a tilt that provides prices that are properly aligned with the cost to serve and that provide customers with information as to how their demand and energy consumption patterns impact these costs.

Methodology:

As a quantitative demonstration, following the PUCN Order in Docket No. 14-05004, the following analysis uses data for individual LGS-3P customers1 from this filing to determine the impact of using different levels of rate tilt within the rate design to recover generation and energy costs for the class. The rate design is consistent with the Company’s proposed rate design in this filing under the Statement O at NRS Revenue Requirement reflecting the full revenue requirement and cost based class revenue requirements.

Hourly customer load data, in combination with hourly LOLPs and marginal energy cost data from the Company’s proposed marginal cost study, was used to develop billing determinants and hourly costs for individual customers across all hours of the year. These costs were then reconciled to the functional embedded revenue requirement and generation $/kW demand prices and $/kWh energy prices were designed for the class under different rate tilts (0% tilt, 25%, 50%, 75%, 100% and the class average load factor – 54%). In order to simplify the analysis, we did not include current constraints on the resulting cost-based prices that can be included in a proposed rate design (e.g. allocating a portion of

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1 The total load of one partial requirements LSR-II LGS-3P customer and the data for customers billed on the Optional LGS-3P High Load Factor (“OLGS-3P HLF”) schedule are included in this analysis consistent with the proposed cost of service and rate design methodology.
generation costs on the distribution of energy costs to mitigate negative BTGR rates and/or large rate changes from present to proposed rates). The resulting cost-based prices under each scenario were multiplied by the developed billing determinants to determine the annual revenue that would be collected from individual customers within the class. This revenue was then compared to the annual reconciled generation and energy costs by customer. The resulting revenue under different amounts of rate tilt provide a comparison of how different tilts impact the amount paid by individual customers and how these amounts correlate with their costs on the system. Table 1 below summarizes the prices used in each scenario.

Table 1: Resulting LGS-3P Prices at Various Levels of Rate Tilt

<table>
<thead>
<tr>
<th>Rates</th>
<th>Cost (0% Tilt)</th>
<th>25% Tilt</th>
<th>50% Tilt</th>
<th>54% Tilt</th>
<th>75% Tilt</th>
<th>100% Tilt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation Demand (per kW)</td>
<td>$26.03</td>
<td>$19.52</td>
<td>$13.01</td>
<td>$11.69</td>
<td>$6.51</td>
<td>-</td>
</tr>
<tr>
<td>On Peak (per kW, per Mo.)</td>
<td>10.42</td>
<td>7.62</td>
<td>5.21</td>
<td>4.76</td>
<td>2.61</td>
<td>-</td>
</tr>
<tr>
<td>Mid Peak (per kW, per Mo.)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Off Peak (per kW, per Mo.)</td>
<td>0.23</td>
<td>0.17</td>
<td>0.11</td>
<td>0.10</td>
<td>0.06</td>
<td>-</td>
</tr>
<tr>
<td>Other (per kW, per Mo.)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Energy (per kWh)</td>
<td>$0.02374</td>
<td>$0.06854</td>
<td>$0.11339</td>
<td>$0.12111</td>
<td>$0.15806</td>
<td>$0.20291</td>
</tr>
<tr>
<td>On Peak (per kWh, per Mo.)</td>
<td>0.02273</td>
<td>0.04153</td>
<td>0.06035</td>
<td>0.06399</td>
<td>0.07910</td>
<td>0.09792</td>
</tr>
<tr>
<td>Off Peak (per kWh, per Mo.)</td>
<td>0.02017</td>
<td>0.02017</td>
<td>0.02017</td>
<td>0.02017</td>
<td>0.02017</td>
<td>0.02017</td>
</tr>
<tr>
<td>Other (per kWh, per Mo.)</td>
<td>0.02166</td>
<td>0.02177</td>
<td>0.02188</td>
<td>0.02190</td>
<td>0.02199</td>
<td>0.02210</td>
</tr>
</tbody>
</table>

Results:

The following pages summarize the results of the analysis. It demonstrates that prices based upon a significant amount of tilt (50% or the overall class load factor - 54.3%) provide the most reasonable results for all customers within the class. At the 0% tilt level, lower load factor customers typically pay more than their costs while higher load factor customers typically pay less. As the amount of tilt increases, both groups of customers generally move closer to cost (lower load factor = decrease in revenue, higher load factor customers = increase in revenue). However, there is a point where more and more customers in either group cross a tipping point and start to move away from cost, while others continue to move towards cost. Therefore, as you move toward 100% tilt there are more and more customers that move away from cost. The variation of the impact to customers can be considerable, due to individual customer energy usage patterns. Therefore, while it is clearly important to recover a significant portion of capacity-related costs through the S/kW charges in order to provide a strong price signal regarding the cost of capacity to customers, it is also appropriate and equitable to recover some portion of costs that are identified as being capacity-related in the marginal cost study through the corresponding TOU commodity rates.

For a group or class of customers with some reasonable level of diversity in load characteristics, no single rate design will be able to perfectly recover the costs being imposed by each individual customer from that customer. Lower load factor customers are better off when a higher rate tilt is used (and more generation capacity costs are included in the S/kWh energy charges) and the higher load factor customers within the class are harmed by this movement (they are better off when the rate tilt is lowered). The goal in establishing prices for a class is to design those prices so that intra-class subsidies among individual customers in a rate class is minimized and that all customers in the class are treated fairly. By including both rate components in the recovery of marginal generation costs, we recognize that the combined charges paid by individual customers in the class better reflect the individual costs of providing generation capacity to customers. The Company’s long-standing rate design practice of including a substantial level of rate tilt in the development of demand and energy charges, accomplishes this important goal – it both provides clear price signals that closely reflect marginal costs and is fair and equitable for both low and high load factor customers served within the class.

Overall the issue of rate tilt is a complex issue with several moving parts, but the results show that there is a balance in the amount of tilt present in rates that one should consider in rate design to not only accurately reflect costs, but also to treat all customers within the class fairly.
Sample Load Shapes for Above and Below Average Load Factor Customers:

This chart demonstrates the unitized daily hourly load shapes for individual LGS-3P customers included in the analysis that have been grouped by those who have load factors either below or above the class average. The below average group has a load factor of 32.2%, which is far more peaking in shape than that of the above average load factor customers. The above average load factor customers, with an average load factor of 69.5% have a flatter and less diverse load shape than the below average load factor customers.

The relative peak differences of the load shapes is of primary importance when one considers the portion of generation costs that should be recovered through a demand versus energy charge. The peak of the below average load factor customers is significantly greater than their overall energy use. This results in demand charges comprising a greater percentage of their bill than those customers with above average load factor energy use patterns. Therefore, the rate tilt will have a greater impact on the charges that these customers pay relative to customers with an above average load factor since their demand charges will experience significantly greater variances as the rate tilt increases and more costs are recovered through energy charges.
**Impact of Different Rate Tilt Scenarios:**

The following chart demonstrates the annual reconciled marginal costs for individual LGS-3P customers and the revenue resulting from prices developed under the different rate tilt scenarios. The revenue between the various scenarios for individual customers stack on top of each other.

Overall, the higher load factor customers show less variability in the charges under the different scenarios relative to those customers with lower load factors. This is shown by the larger variations between the annual charges under different scenarios for the lower load factor customers relative to the variation across scenarios for the higher load factor customers.

It should also be noted that the higher load factor customers are generally larger customers within the class.
Relationship of Costs to Revenue:

The following chart continues to separate customers into two groups; customers with lower than the class average load factors and those customers with higher than class average load factors. The chart demonstrates the impact of the tilt as a relationship of the difference in revenue collected from individual customers between the 100% and 0% tilt scenarios. For example, the customer with the lowest load factor of the class (approx. 10%) experiences a decrease of billed charges of more than 60% between the charges under prices developed between the 0% and 100% tilt scenarios.

As stated previously, the chart makes clear that there is substantially more variability in the impact to individual customers with lower load factors than for customers with higher than average load factors due these customers having more variation in their energy usage patterns than those customers who have more stable loads over all hours of the year (higher load factor). This variation causes larger differences in individual customer costs, and thus revenue, across the year across the different rate designs.
Range of Impacts for Individual Customers:

This chart reiterates the substantially greater impact that the rate tilt has on customers with low load factors relative to customers with typical or higher load factor characteristics. The following chart shows the range of changes from cost for individual customers from changes in the rate tilt. For those customers with very low load factors, the range can be significant.

For those customers above the horizontal axis (0%) the impact of a 25% rate tilt is represented at the bottom of the individual customer lines. Their charges will move away from the axis (higher) towards the top of the line as the rate tilt is increased until the rate tilt achieves 100%. For those customers below the horizontal axis (0%) the impact of a 25% rate tilt is represented at the top of the individual customer lines. Their charges will move away from the axis (lower) towards the bottom of the line as the rate tilt is increased until the rate tilt achieves 100%. For example, the customer with the lowest load factor shows a range of impacts from a reduction of approximately 15% at a 25% tilt rate design to a reduction of nearly 65% under a 100% rate tilt. For the customer with the highest load factor (82.7%), the range is substantially smaller with an approximate 2% increase at a 25% tilt rate design to an 8% increase under a 100% rate tilt.

The chart shows the significant variation that occurs in the charges for those customers with very low load factors while the ranges reduce as the load factor increases towards the 50%-60% range. As one looks towards customers with increasingly higher load factors the range of impacts across scenarios again begins to increase. While not as considerable as the range for lower load factor customers, the impact is more significant to these higher load factor customers than the impact to the customers with characteristics that are closer to the class average.
AFFIRMATION

STATE OF NEVADA                 )
COUNTY OF WASHOE                ) ss.

I, TIMOTHY W. POLLARD do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

TIMOTHY W. POLLARD

Subscribed and sworn to before me this 24 day of May, 2017.

NOTARY PUBLIC
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA  
Nevada Power Company d/b/a NV Energy  
2017 General Rate Case  
Docket No. 17-06___  
Rate Design  
PREPARED DIRECT TESTIMONY OF  
Janet Wells  

I. INTRODUCTION  

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

A. My name is Janet Wells. I am the Manager of Load Research 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, which is located at 6100 Neil Road in Reno, Nevada. I am filing testimony in this proceeding on behalf of Nevada Power.  

2. Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.  

A. I hold a Bachelor of Arts Degree in Geography and a Master of Science Degree in Applied Economics and Statistics. I have more than 10 years of utility experience within the Rates and Regulatory Affairs department. Prior to joining the Companies, and during an absence from the Companies, I worked in economic consulting and research. More details regarding my professional background and experience are set forth in Exhibit Wells-Direct-1.  

Wells – DIRECT 1
3. **Q.** HAVE YOU PREVIOUSLY SUBMITTED PREPARED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?


4. **Q.** WHAT IS THE PURPOSE OF YOUR TESTIMONY?

   **A.** The purpose of my testimony is to describe the process for updating class load shapes for the Nevada Power customer classes. In Section II, I describe the purpose behind class load shapes, how they are updated and highlight some differences from previous cases.

5. **Q.** ARE YOU SPONSORING ANY EXHIBITS TO YOUR PREPARED DIRECT TESTIMONY?

   **A.** Yes, I am sponsoring one exhibit: Exhibit Wells-Direct-1.

6. **Q.** ARE ANY OF THE MATERIALS YOU ARE SPONSORING CONFIDENTIAL?

   **A.** No.
II. CLASS LOAD SHAPES

7. Q. DOES THE MARGINAL COST OF SERVICE STUDY (“MCS”) REFLECT UPDATED CLASS LOAD SHAPES?
   A. Yes. Load shapes for all of Nevada Power’s rate classes have been updated using historical recorded load data for the 12 months ending September 2016. The period for class loads is set at 12 months ending September 2016, three months prior to the end of the test period, to allow for data gathering and processing requirements of 15 minute interval data. At certification, the load shapes will be updated through December 2016 for all of the customer classes at Nevada Power.

8. Q. WHAT IS THE PURPOSE OF THE CLASS LOAD SHAPES?
   A. Class load shapes reflect the way customers in a class use energy by time of day. Classes with relatively higher loads during higher use periods typically impose higher costs on the system, and are assigned or allocated a higher share of costs in the marginal cost of service (“MCS”) study. Therefore, the hourly loads are one of the building blocks from which Nevada Power develops the cost of providing components of bundled service to individual customer classes, and inform rate design in Statement O. These usage patterns are used in the MCS and Statement O as described in more detail in the testimonies of Mr. Jeffrey Bohrman, Ms. Shana Ramirez, and Mr. Tim Pollard.

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 a 12-month period, in this case the 12 months ending Wells – DIRECT
September 2016. Then class load shapes are developed from individual customer data and expanded to the class using either a census (i.e., all) of the population of customers in a rate class, or a sample of the population for the test period.

10. Q. WHAT DETERMINES WHETHER THE LOAD SHAPE FOR A RATE CLASS IS BASED ON A CENSUS OR SAMPLE?

A. Determining whether the load shape for a rate class is based on a sample or a census is driven by whether having a census is necessary to accurately reflect the shape of the class and the availability of reliable data that can be processed in a timely manner with reasonable expense producing precise results. For example, Nevada Power’s residential single family class has over 500,000 customers. Even though 15-minute interval data is available for virtually all of the 500,000 customers, it is not necessary to process every customer’s interval data in order to develop an accurate load shape for the single family residential class. Properly drawing a sample of customers that can represent the entire rate class (population) is reasonable and preferred in this example.

Sampling is the method employed by Load Research since the 1970s to produce reliable results for a reasonable cost. In 2008, the Association of Edison Illuminating Companies (“AEIC”) produced a white paper entitled “The Role of Load Research In Automated Infrastructure/Meter Data Management Initiatives.” This paper provides multiple reasons for the continued use of sampling in Load Research even when there is availability of 15-minute data for most customers. Specifically, the amount of data that would need to be processed to analyze all
customers, the cost of maintaining costly storage and retrieval structures, and the fact that not all customers will have smart meter data available for the entire period analyzed provide fundamental reasons as to why the larger customer classes should continue to have load shapes developed from sampled information.\(^1\) To process current sample classes as census classes, the Company would experience increases in costs without a corresponding increase in precision. Nevada Power has more than 50 rate classes. Load shapes for eight of these classes, the residential multi-family ("RM"), residential single family ("RS"), optional residential single family option A ("ORS-TOU-A"), residential single family net-metering ("RS-NEM"), general service ("GS"), optional 1 general service ("OGS"), large general service ("LGS-1"), and large general service secondary ("LGS2S") classes are based on samples, while the remaining rate classes are based on a census. All of the sampled classes have more than 1,200 customers in the rate class.

### 11. Q. HOW ARE LOAD SHAPES DEVELOPED USING A CENSUS OF THE RATE CLASS?

**A.** Load shapes for census rate classes are the summation of energy use of each customer in the class at each 15-minute interval of the day. For a rate case, the 15-minute interval data is then summed to the hour to produce 8,760 hours of energy use for the year. When not all 15-minute interval data is available for all

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\(^1\) The use of sampling remains a valuable load research tool as metering technologies continue to improve and more data is able to be gathered, stored and processed. See, “AMI Based Load Research-KIUC Demonstration, Confirming the Value of AMI”. Final Report. May 31, 2014. NRECA-DOE Smart Grid Demonstration project DE-OE0000222.
customers in a census-based study, the hourly data that is available is used as the shape, then applied to the remainder of the class and then summed to the hour for each month across the year. The final result is an hourly usage pattern representing the entire rate class for the entire 8,760 hours throughout the year. The hourly class loads used in the allocation of costs have been provided in past cases in a format protecting customer confidentiality.

12. Q. HOW ARE LOAD SHAPES DEVELOPED USING A SAMPLE OF THE RATE CLASS?

A. Load shapes for sampled rate classes are developed using a statistical sample of customers that represent the rate class. Nevada Power uses stratified random samples to allow the rate class to be broken into multiple segments (strata) of mutually exclusive groups based on the sampling variable. The sample used for developing the load shape is drawn randomly from each stratum. Statistical tests are completed to ensure that the samples drawn represent the entire rate class. Nevada Power samples meet or exceed a 95/5 desired accuracy, or +/-5 percent accuracy with 95 percent confidence. In 1978, the Public Utility Regulatory Policies Act ("PURPA") set the design criteria at 90/10 and later lifted those standards in 1992. However, 90/10 remained somewhat of a load research standard, particularly for samples that will be used to support rate cases or other regulatory filings. Once the sample is identified, the interval data for all customers in the sample is gathered and input into the Load Research System ("LRS"), in combination with historical billing customer data, and used to develop a class load for the entire rate class. Nevada Power uses a combined ratio
analysis to expand the sample to represent the entire rate class. The ratio method allows use of correlated variables to increase the precision of the expanded class load shape. Nevada Power uses the ratio of the sampling variable for the entire rate class (population) for each month to the sample customers for the month. The resulting ratio is used to adjust the sample data to reflect the relationship to the population, while maintaining the shape from the sample. The sample data is then expanded to represent the total number of customers by stratum in the population. The result is the same as the census analysis, 8,760 hours of 15-minute usage data that represents the hourly usage pattern of the entire rate class. As with census classes, the hourly class loads used in the allocation of costs were provided.

13. WERE LOAD SHAPES FOR THE NET-ENERGY METERING ("NEM") CLASSES UPDATED FROM THOSE USED IN DOCKET NO. 15-07041 TO SUPPORT THE DETERMINATION THAT NEM CUSTOMERS SHOULD BE MOVED TO SEPARATE CLASSES?

A. Yes. Load shapes for the total loads (absent generation), generation, delivered (energy delivered to the customer from Nevada Power), and received (excess energy put back on the grid), have been updated for this general rate case ("GRC"). As in the 2015 NEM cost of service and rate design proceeding (Docket No. 15-07041), RM-NEM, GS-NEM, ORS-TOU-NEM, GS-NEM, and LRS-NEM were processed as a census. To process these classes as a census, the Company used all available 15-minute data for the population of customers for the 12 months ending September 2016. As was done in Docket No. 15-07041, the monthly data and customer installed capacity for any individual NEM customer for whom 15
minute data was not available was still included in the overall class, but shaped based on the data from all customers with available 15-minute data. The available load shape for each month was applied to each individual NEM customer’s monthly billing and generation capacity information to develop each customer’s 15-minute load. Once all customers were represented for each of the total, delivered, received, and generation shapes, the data was aggregated to develop the resulting shapes for the rate class.

Due to the growth in the RS-NEM rate class from more than 5,000 in March of 2015 to more than 19,000 by the end of September 2016, this rate class is now processed as a sample for the delivered and received loads. The Company continues to process all available 15-minute generation data to develop the generation shape. In Docket No. 16-06006 as well as Docket No. 15-07041, all interval data used to process the NEM classes was provided along with calculations showing how loads were developed. This same information is available in this case.

14. Q. DID YOU COMPLETE STATISTICAL TESTS ON THE UNIQUENESS OF THE NEM LOAD SHAPES FROM THE FULL REQUIREMENTS CLASS?

A. Yes. On Pages 51 and 52 of the Commission’s Order in Docket No. 15-07041, the Commission referenced the following results of the Epps-Singleton tests in confirming the load levels and hourly usage differences between NEM and full requirement customers justify separate classes:

Wells – DIRECT
Besides the partial-requirements nature of NEM ratepayers' service, the load levels and hourly usage differences between NEM and non-NEM ratepayers are sufficient (alone) to justify separate ratepayer classes for NEM ratepayers. There is a significant difference between the load shapes (usage profiles) of NEM and non-NEM ratepayers, thus supporting the establishment of new NEM ratepayer classes. The total load and delivered load of the NEM ratepayer is distinct and varies from the shape of non-NEM ratepayers on an hourly basis. Differences in hourly load shapes thus reflect the differences in the costs incurred by NV Energy to provide the unique and specific energy services required by NEM ratepayers. NV Energy also conducted an Epps-Singleton equality of distribution test to further demonstrate that the total hourly loads of the two groups are statistically different. Hourly, not monthly, load shapes provide information regarding the cost of providing service to groups of ratepayers. Similarities in the ranges of monthly consumption may mask marked differences in the time-of-day consumption and, therefore, the facilities required to provide service to a class of ratepayers.

As was performed in the 2015 NEM filing, the Company has again conducted the Epps-Singleton equality of distribution tests on the total and delivered loads to confirm the unique load shape of NEM classes to their corresponding full requirements rate classes submitted in this filing. The tests were conducted for the RS-NEM, RM-NEM, GS-NEM, RS-NEM-TOU, RS-NEM-TOU-EVRR, and RSL-NEM classes (as of September 2016 there were no customers in the RM-NEM-TOU, GS-NEM-TOU, or RSL-NEM-TOU classes). In all cases, as in the 2015 NEM docket, the tests showed statistically significant results confirming the difference in the distribution of loads between the NEM classes and the full requirements classes. For all tests, the p-value was zero indicating that the probability of rejecting the null hypothesis—that the two distributions are different—was zero. In other words, there is a 0 percent probability the Company is incorrect in stating that the distributions of NEM and non-NEM customers are different. Thus, the load shapes derived from census data and sample data, again
confirm the need for separate rate classes because their time of day usage patterns are statistically different.

15. Q. ARE THERE OTHER DIFFERENCES BETWEEN THE NEM CLASSES AND THEIR CORRESPONDING FULL REQUIREMENTS CLASSES?

A. Yes. First, the differences in the hourly load shapes confirm the different cost causation between the NEM and their corresponding full requirements classes. In addition, as detailed on page 44 of the Commission’s Order in Docket No. 16-06006.

NEM customer-generators have a fundamentally distinct and unique relationship with the utility. That distinction is already somewhat recognized in Nevada law: NRS 704.768 defines a “[c]ustomer-generator” as “a user of a net metering system.” That a customer-generator produces electricity that is distributed back to the grid which must, pursuant to Nevada law, be accepted and purchased by a public utility, i.e., Sierra Pacific Power, see NRS 704.773, places that customer in a unique financial, customer-service, and infrastructure relationship with the utility that is markedly distinct from a non-NEM customer, who simply purchases electricity from Sierra Pacific Power through a monthly bill and relies upon the utility for all infrastructure, installation, generation, planning, and maintenance. Non-NEM customers produce nothing and sell nothing to no one. This distinction is relevant and persuasive.

The distinct and unique relationship described in the Commission’s prior order still exists between NEM and non-NEM customers at Nevada Power in exactly the same way. Table Wells Direct 1 and Table Wells Direct 2 provide a graphical representation of the distinct and unique relationship that the RS-NEM class has with Nevada Power versus the RS class. Table Wells Direct 1 represents the class load shape, or average annual hourly energy needs of the RS rate class, a simple relationship of use over time where the customer purchases their total energy needs from Nevada Power.
Conversely, Table Wells Direct 2 represents the distinct and unique class load shapes of the RS-NEM class. First, NEM customers represent four loads rather than one. The delivered load shape shows the time of day distribution of energy from Nevada Power as needed by the customer. The received load shape shows the time of day distribution of energy that the customer sends back to Nevada Power. The total load shape shows the time of day distribution of the total energy that a customer needs and may require from Nevada Power at any time if their NEM system does not generate. The generation load shape shows the time of day distribution of energy that the customer is generating. Not only are the shapes statistically different today, the fundamental relationship of the partial requirements NEM customer with Nevada Power is distinct and unique compared
to the full requirements non-NEM customer as it was at the time of the NEM filing in Docket No. 15-07041.

Second, specifically related to the RS-NEM average class load shown in Table Wells Direct 2, the received load exceeds the total load between hours 10 and 14.

Previously in the NEM Docket No. 15-07041, the received load never exceeded the total load. This result is because of the combination of the average total load decreasing along with the average installed capacity increasing, therefore, creating more excess energy that Nevada Power receives back onto the grid.
16. Q. ARE THERE ANY DIFFERENCES IN THE LOAD SHAPES FOR ANY CLASS WHEN COMPARED TO THE PREVIOUS GRC OR NEM DOCKETS THAT SHOULD BE HIGHLIGHTED?

A. Yes. The scale of the Optional General Service (“OGS”) rate class has increased significantly since the previous Nevada Power rate case. The increase began in late 2013, reflecting approximately 2,000 customers who joined the rate class. In addition, most of the NEM classes’ populations have significantly increased since the NEM docket, therefore, the scale of their class loads has also significantly increased. For example, the population of RS-NEM customers that contributed to the load shape in Docket No. 15-07041 was 5,174. In this GRC, the population of RS-NEM customers contributing to the class load shape is 19,235, almost four times as many customers. This change represents the change in the population of RS-NEM customers between March of 2015 and September 2016. The average capacity of the installed NEM system is very similar between the two populations, 5.7 kW for the population of RS-NEM customers as of March 2015 and 6.1 kW for the population of RS-NEM customers as of September 2016. The usage patterns by time of day also remain statistically different from the corresponding full requirements class.

17. Q. ARE THERE ANY OTHER COMPARISONS YOU WOULD HIGHLIGHT?

A. Yes. While the appropriate and relevant comparison for determining how class loads influence each rate classes’ cost responsibility is the time of day usage patterns developed from 15-minute interval data, there has been much interest in...
prior cases in monthly measurements and comparisons of class use per customer (e.g., comparisons based on monthly averages of RS-NEM class to the corresponding full requirements RS class loads). Table Wells Direct 3 shows the RS-NEM class monthly total load and delivered load per customer compared to the monthly total load of the corresponding full requirements class. In every month, the RS-NEM customer uses more energy in total than the full requirements RS customer. After consuming their own generation, the RS-NEM customer has delivered energy from Nevada Power that is less in every month than the total load of the RS customer.

<table>
<thead>
<tr>
<th>Month</th>
<th>RS</th>
<th>RS-NEM Total Load</th>
<th>RS-NEM Delivered Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oct-15</td>
<td>940</td>
<td>1,116</td>
<td>761</td>
</tr>
<tr>
<td>Nov-15</td>
<td>745</td>
<td>828</td>
<td>577</td>
</tr>
<tr>
<td>Dec-15</td>
<td>929</td>
<td>1,046</td>
<td>808</td>
</tr>
<tr>
<td>Jan-16</td>
<td>817</td>
<td>959</td>
<td>746</td>
</tr>
<tr>
<td>Feb-16</td>
<td>628</td>
<td>765</td>
<td>530</td>
</tr>
<tr>
<td>Mar-16</td>
<td>619</td>
<td>749</td>
<td>464</td>
</tr>
<tr>
<td>Apr-16</td>
<td>666</td>
<td>775</td>
<td>455</td>
</tr>
<tr>
<td>May-16</td>
<td>935</td>
<td>1,073</td>
<td>626</td>
</tr>
<tr>
<td>Jun-16</td>
<td>1,907</td>
<td>2,154</td>
<td>1,426</td>
</tr>
<tr>
<td>Jul-16</td>
<td>2,243</td>
<td>2,495</td>
<td>1,679</td>
</tr>
<tr>
<td>Aug-16</td>
<td>1,955</td>
<td>2,173</td>
<td>1,473</td>
</tr>
<tr>
<td>Sep-16</td>
<td>1,304</td>
<td>1,505</td>
<td>994</td>
</tr>
</tbody>
</table>

This table provides monthly comparisons for a better understanding of the differences between the partial requirements RS-NEM class and the corresponding full requirements RS class. However, for purposes of understanding the cost associated with serving each of these rate classes, the far more meaningful comparison is the 8,760 hourly usage patterns, which show usage across the day and year. How the statistically different load shapes for the
NEM versus non-NEM classes impacts their differing cost responsibilities is detailed in the testimonies of Mr. Bohrman and Ms. Ramirez.

18. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
A. Yes.
Mrs. Wells has been an employee of NV Energy for ten years and her time at the company includes her previous positions as a Senior Economist and Staff Economist in the Rates and Regulatory Affairs department and her current position as Manager of Load Research in the Rates and Regulatory Affairs department. Her current responsibilities are focused on managing and completing load shape development in support of all rate cases in addition to contributing to the data inputs and analysis for the Nevada Dynamic Pricing Trial (NDPT) and other projects requiring interval data support. She directly, and through her team, completes a variety of economic analyses related to load research and the increasing use of all interval data.

Prior to joining NV Energy, Mrs. Wells had experience in economic consulting and research in both corporate and academic environments, detailed below, as well as other non-profit business experience not specifically detailed below.

**Employment History**

**NV Energy**

October 2011 to Present

December 2000 to August 2005

**Manager, Load Research, Rates and Regulatory Affairs**

April 2017 to Present

**Supervisor, Load Research, Rates and Regulatory Affairs**

July 2012 to March 2017

- Manage all data and analysis related to producing hourly class loads for all Nevada Power and Sierra Pacific customer classes. Specifically, this process includes verification and estimation of interval data from multiple systems, population identification and validation, statistical sampling from populations, expansion of sample classes to produce class level total loads, and verification of final class loads to historical loads.

- Support all regulatory filings and data requests with load data and analysis ranging from: providing actual data, drafting responses, providing feedback to responses, and documenting completed analysis. Write and support testimony as needed.

- Provide validated load data and analysis to numerous areas within the company including Major Accounts, Load Forecasting, Energy Efficiency, Billing, Contracts, and to specific projects within the company such as the Energy Imbalance Market and Advanced Metering Infrastructure. In addition, provide validated load data where appropriate for external requests.

- Provide expertise and support to other major projects related to load data management and analysis including all work from raw data integrations and
management, customer specific deliverables, original programming to produce needed calculations, and both data and statistical support of final analyses and report writing for projects such as the Nevada Dynamic Pricing Trial (NDPT)

**Senior Economist, Advanced Service Delivery Project**
October 2011 to July 2013
- Managed statistical sampling for U.S. Department of Energy reporting on metrics and recruitment
- Contributed to development of statistical design for analysis
- Managed data integrations needed for implementation of project

**Staff Economist, Rates and Regulatory Affairs**
October 2001 to August 2005
- Updated the Nevada Power Cost of Service Study as an input to rate cases
- Updated Customer Weighting Factor Study for Nevada Power and Sierra Pacific as an input to rate cases
- Supported all regulatory filings with testimony review and responses to data requests

**Senior Economist, Rates and Regulatory Affairs**
December 2000 to October 2001
- Developed Nevada Power Cost of Service Study as an input to rate cases
- Developed automated system for completing Customer Weighting Factor Studies

**Other Related Employment**
University of Nevada, Reno
May 2005 to August 2006

**Research Associate**
- Developed statistical programs for data management and analysis of 20 years of data to assess the Economic Value of Hiking for publication in a book chapter
- Developed survey instrument, data management from the survey, and econometric analysis related to wild horse adoption

**Triangle Economic Research, Durham, NC**
July 1997 to December 2000

**Senior Economist, March 2000-December 2000**
**Economist, July 1997-March 2000**
- Prepared preliminary estimate of recreational fishing damages from hazardous substance release using revealed preference data in a random utility model
- Estimated random utility models to determine expected catch using multiple methods, including non-parametric estimation and a multinomial logit estimation of catch (presented at American Agricultural Economics Association annual meeting)
- Developed and administered survey of recreational boaters; acquired survey research firm and validated data. Developed analysis plan for probit model of probability of
site choice and conditional logit model of recreational benefits from restoration projects. Results were published with estimates of recreational benefits from proposed restoration projects using benefit transfer from other cases in Arizona Law Review.

- Completed data collection, data management, econometric modeling and analysis, and report writing to estimate aggregate values of recreational activities using a nested price index, published in Environmental and Resource Economics.

Prior Testimony Before Public Utilities Commissions

Education
University of Nevada, Reno
Master of Applied Economics and Statistics, August 1996

University of Manitoba, Winnipeg, Manitoba
Bachelor of Arts in Geography, June 1992

Continuing Education
NERA Marginal Cost Methodology for Electric Utilities
SAS Programming I and II
AFFIRMATION

STATE OF NEVADA  )
COUNTY OF WASHOE  ) ss.

I, JANET WELLS, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

JANET WELLS

Subscribed and sworn to before me this 24th day of May, 2017.

LYNN D'INNOCENTI
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No. 19-102682 - Expires May 2, 2021

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

A. My name is Marc D. Reyes. I am the Manager of Market Fundamentals 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 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony in this proceeding on behalf of Nevada Power.

2. Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I hold a Bachelor of Arts degree in Economics from New Mexico State University. I have been employed by the Companies since May 2007 and have served as the Manager of Market Fundamentals since May 2011. Prior to my current role in Resource Planning and Analysis, I was a Power Trader for the Companies, where I performed analysis and negotiated wholesale transactions to optimize the Companies’ economic dispatch. Before joining the Companies, I was employed as a Wholesale Power Trader for El Paso Electric Company.
As Manager of Market Fundamentals my responsibilities include the development of market price forecasts for natural gas, wholesale power, and capacity products delivered to the relevant regional market trading hubs. Additionally, I am responsible for the regional market fundamental analysis that supports the Companies’ energy supply and resource planning functions. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit Reyes-Direct-1.

3. Q. HAVE YOU SUBMITTED PREPARED TESTIMONY IN A PREVIOUS REGULATORY PROCEEDING?
   A. Yes, I have testified in a number of proceedings before the Public Utilities Commission of Nevada (“Commission”). Most recently, I filed rebuttal testimony with the Commission in Sierra’s 2016 electric regulatory rate review proceeding, which was assigned Docket No. 16-06006.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
   A. My prepared direct testimony addresses the Company’s recommendation for the valuation of the excess energy credits provided to non-grandfathered net energy metering (“NEM”) customers, as required by the Commission’s modified final order in Docket Nos. 15-07041 and 15-07042.

5. Q. BEFORE EXPLAINING NEVADA POWER’S RECOMMENDATION FOR THE PRICING OF EXCESS ENERGY, BRIEFLY DESCRIBE THE NATURE OF EXCESS ENERGY.
A. Excess energy occurs when the output from a private generation system exceeds the host customer’s energy consumption at any given instance during the day. Under these circumstances, the customer’s bi-directional energy meter will measure flows from the customer’s premise to the energy grid. Nevada Power, as a balancing authority entity subject to mandatory reliability standards, responds to changes in excess energy produced by private generation systems through dispatches of controllable resources on the energy grid. It is important to note that the quantity and timing of excess energy deliveries are not controllable by Nevada Power.

6. Q. PLEASE DESCRIBE NEVADA POWER’S RECOMMENDATION FOR PRICING THE VALUE OF EXCESS ENERGY DELIVERED TO THE GRID USING THE COMMISSION’S DIRECTIVE IN DOCKET NO. 15-07041.

A. The Company proposes to value excess energy credits for non-grandfathered NEM customers based upon the average price, adjusted for line losses, reflective of the last seven universal scale solar photovoltaic (“PV”) power purchase agreements (“PPAs”). 1 This equates to a price of $50.42 per megawatt-hour or 5.042 cents per kilowatt-hour, as shown in Table Reyes Direct-1. 2

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1 For purposes of valuing excess energy, the adjustment for transmission and distribution line losses is assumed to be 10 percent. This loss adjustment is a simplified estimate and does not reflect the estimated loss values used in the development of marginal cost of service in this proceeding.

2 Please note that the price of excess energy developed through the Company’s Statement O rate design, which is also used to quantify the subsidy associated with excess energy credits to net metering customers, is based on the last approved long-term avoided cost of energy and does not incorporate or reflect the methodology in my recommendation.
Table Reyes Direct-1

<table>
<thead>
<tr>
<th>Project</th>
<th>Levelized Cost of Energy ($/MWh)</th>
<th>Project Size (MW)</th>
<th>Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>Switch Station 1 (aka Playa 2)</td>
<td>$48.61</td>
<td>100</td>
<td>20 years</td>
</tr>
<tr>
<td>Switch Station 2 (aka Playa 1) – NPC</td>
<td>$48.03</td>
<td>27.7</td>
<td>20 years</td>
</tr>
<tr>
<td>Switch Station 2 (aka Playa 1) – SPPC</td>
<td>$48.22</td>
<td>51.3</td>
<td>20 years</td>
</tr>
<tr>
<td>Boulder Solar I</td>
<td>$48.69</td>
<td>100</td>
<td>20 years</td>
</tr>
<tr>
<td>Boulder Solar II</td>
<td>$49.61</td>
<td>50</td>
<td>20 years</td>
</tr>
<tr>
<td>Techren Solar 1</td>
<td>$40.62</td>
<td>100</td>
<td>25 years</td>
</tr>
<tr>
<td>Techren Solar 2</td>
<td>$37.09</td>
<td>200</td>
<td>25 years</td>
</tr>
<tr>
<td><strong>AVERAGE</strong></td>
<td><strong>$45.84</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 percent factor for transmission and</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>distribution losses</td>
<td>$4.58</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$50.42</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

7. Q. **PLEASE DESCRIBE HOW NEVADA POWER’S EXCESS ENERGY PRICING RECOMMENDATION AFFECTS CUSTOMERS WITH GRANDFATHERED NEM SYSTEMS.**

   A. This excess energy credit proposal does not change, in any way, the metering and billing for customers with grandfathered NEM systems.

8. Q. **PLEASE DESCRIBE WHY THE COMPANY RECOMMENDATION IS BASED ON A BASKET OF PPAS RATHER THAN THE LONG-TERM AVOIDED COSTS?**

   A. There are two primary reasons for this recommendation. First, deriving the value of excess energy from a basket of PPAs respects the “buy-sell” relationship between NEM customers and the Company. As noted in the Commission’s December 28, 2016 Order in Sierra’s 2016 electric regulatory rate review proceeding, Docket Nos. 16-06006 et al, “[a] ‘buy-sell’ framework is consistent
with the ‘customer-generator’ concept articulated by the Nevada State Legislature and the provisions of NRS 704.766-.775, inclusive. Furthermore, “[n]o compelling arguments or evidence were presented for the PUCN to depart from the ‘buy-sell’ arrangement.”

Second, the Company respects the Commission’s observations of “conflicting expert testimony” with a “lack of consensus” among the parties in Sierra’s 2016 electric regulatory rate review and seeks to improve the transparency in the pricing of excess energy for non-grandfathered NEM customers. 4,5

9. Q. PLEASE DESCRIBE HOW THE EXCESS ENERGY CREDIT PRICING RECOMMENDATION IMPROVES TRANSPARENCY.

A. First, due to economic and resource quality considerations, nearly all NEM customers have selected solar PV as their source of private generation. In aggregate, the energy production profile and capacity contribution of private generation is similar to that of universal scale solar PV generation. In short, the similarities between universal scale solar PV and private generation makes it easier to compare the two for pricing purposes.

Second, each of the universal scale solar PV PPAs was selected through a competitive bidding process. This process ensured that Nevada Power’s customers are paying a fair price for solar PV energy, along with the associated

3 Commission Docket Nos. 16-06006 et al, Order (Dec. 28, 2016) at 44.
4 Id. at 56.
5 Id. at 46.
environmental attributes to comply with Nevada’s renewable portfolio standard. Furthermore, each of the PPAs has been subject to regulatory scrutiny by interested parties, including the Commission’s Regulatory Operations Staff and the Attorney General’s Bureau of Consumer Protection, and have been approved by the Commission. Valuation of excess energy using a basket of universal scale solar PV is an example of the “what’s good for the goose is good for the gander” principle in insuring customers are paying a reasonable price for excess generation.

Third, while there is much debate on the value of avoided air emissions, namely carbon dioxide and criteria pollutant emissions, it is reasonable to conclude that universal scale solar PV generation offers benefits that are substantially similar to private generation. The value of environmental benefits, or attributes, is included in the PPA price for all seven universal scale solar PV resources.

Finally, the societal benefits attributable to private generation are substantially similar to those of universal scale solar PV resources. Such benefits include, but are not limited to, promoting economic development and job growth throughout Nevada, diversifying Nevada’s energy resources, advancement of renewable energy technologies and infrastructure, and encouraging customer choice as evidenced by the Nevada GreenEnergy Rider.

10. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?
A. Yes.
STATEMENT OF QUALIFICATIONS

MARC D. REYES

My name is Marc D. Reyes. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Manager of Market Fundamentals for Nevada Power Company, d/b/a NV Energy and Sierra Pacific Power Company, d/b/a NV Energy.

I graduated from New Mexico State University with a Bachelor of Arts Degree in Economics in 2000 and earned a Certificate in Utility Management from Willamette University in 2010.

I have been employed as the Manager of Market Fundamentals since May 2011. I am responsible for leading a staff of economists who perform fundamental analysis and market price forecasting for natural gas and wholesale power in the western U.S. I evaluate the process used to forecast natural gas and power prices and implement changes as markets evolve. I prepare reports and communicate the findings of analysis to management.

From May 2007 until May 2011, I was employed as an Energy Trader in Resource Optimization for NV Energy. I was responsible for executing daily to monthly wholesale power and natural gas transactions to optimize the Companies short-term portfolio. I performed market surveys to identify liquidity and obtain price discovery. I performed market research to identify new opportunities to reduce fuel and purchased power costs.
and worked with the credit and contracts groups to establish new counterparties. I mentored and developed junior traders.

From October 2005 until May 2007, I was employed as a Power Trader for El Paso Electric Company. I was responsible for executing real time power trades as part of the wholesale power marketing group’s profit and loss book. I worked closely with the day-ahead and term traders to optimize the company portfolio in the Western Electric Coordinating Council and Southwest Power Pool regions.
AFFIRMATION

STATE OF NEVADA  )
COUNTY OF CLARK  ) ss.

I, MARC D. REYES, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

MARC D. REYES

Subscribed and sworn to before me this 24th day of May, 2017.

Notary Public

[Signature]
BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA  
Nevada Power Company d/b/a NV Energy  
2017 General Rate Case  
Docket No. 17-06____  

Rate Design  

PREPARED DIRECT TESTIMONY OF  

LAURA I. WALSH  

I. INTRODUCTION  

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS FOR THE RECORD.  

   A. My name is Laura I. Walsh. I am the Director of Regulatory Analysis, Policy and Strategy 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 in this proceeding on behalf of Nevada Power.  

2. Q. DOES THE EXHIBIT WALSH DIRECT-1, “QUALIFICATIONS OF WITNESS LAURA I. WALSH,” ACCURATELY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?  

   A. Yes, it does.  

3. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?  

   A. Yes, I have testified in numerous proceedings before the Commission, most recently in Sierra’s last general rate case, Docket Nos. 16-06006, et al.  

Walsh-DIRECT
4. Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND RELATED EXPERIENCE.

   A. I have a Bachelor of Science Degree in Electrical Engineering and a graduate degree in Secondary Education. I have 30 years of utility experience in regulatory and tariff related matters and in transmission planning. I have performed cost of service and rate design for electric, gas and water services. My experience also includes tariff interpretation, analysis related to pricing and Rule 9 contract development for large customers. I have prepared and presented studies and testimony before this Commission and the California Public Utilities Commission in approximately 100 dockets, some of them informal investigations or rulemakings but many of them contested matters. Prior to coming to work for the Company, I worked as an Engineering Assistant for Lawrence Livermore Laboratories and EG&G Energy Measurements. My training includes marginal cost of service and rate design classes from NERA, rate and regulatory training from EEI, Transmission Planning from PTI and various other courses related to engineering, regulatory and other utility issues, and computer techniques. I now often serve as a presenter at NERA Marginal Cost Working Group meetings.

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

   A. I provide policy support for both marginal cost of service and rate design and explain how the Company's proposal in these areas achieves its related policy goals and supports the request for an Expected Change in Circumstance (“ECIC”) period. I also support the Company’s proposed update to the Rule 9 Line Extension Allowances and the Facilities Study. Mr. Jeff Bohrman supports the Company’s Marginal Cost of Service Study (“MCS”). Mr. Tim Pollard supports the proposed rate design. Ms. Shana Ramirez supports the hourly marginal energy costs, hourly
demand cost responsibility factors, and transmission and distribution marginal unit
demand costs which are inputs to the MCS. Mr. Aaron Schaar supports the
Customer Weighting Factor Study, which is also an input to the MCS. Ms. Janet
Wells supports the development of class load shapes, used to develop the class
hourly demand cost responsibility factors and marginal energy costs. Ms. Elena
Mello support Statements H and H-2. Mr. Trevor Dillard supports the Company’s
proposed tariff sheets, and, finally, Mr. Kevin Bethel is the Company’s policy
witness.

6. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY AND
EXHIBITS.

A. My testimony is organized into the following sections:

Section I. Introduction

Section II. Cost of Service & Rate Design Policy Considerations
   • Proposed Revenue Reconciliation and Rates; and
   • Single Family Residential Subsidy & Basic Service Charges
     (“BSCs”) Compliance Items

Section III. Proposed Update to Rule 9 Line Extension Allowances and
Facilities Study

Section IV. Optional Full Requirements Rate Offerings and Simplified
Optional TOU

Section V. Private Generation (or Net Energy Metering) Compliance Items.

I have attached four exhibits to my testimony. They are:

• Exhibit Walsh Direct-1, Statement of Qualification;
• Exhibit Walsh Direct-2, Updated Rule 9 Line Extension Allowances and Facilities Study White Paper;
• Exhibit Walsh Direct-3, Optional Offering Communication Plan; and
• Exhibit Walsh Direct-4, Comparison of Optional Time of Use Schedules
• Exhibit Walsh Direct-5, Average Monthly RS-NEM Bill Comparison.

II. COST OF SERVICE & RATE DESIGN POLICY CONSIDERATIONS

7. Q. PLEASE SUMMARIZE THE PRIMARY POLICY CONSIDERATIONS RELATED TO COST OF SERVICE AND RATE DESIGN IN THIS CASE.

A. Two primary policy considerations impact the Company's proposed rate design and underlying cost of service analysis in this case. The first is implementing the Company's commitment to not increase revenue requirement or residential rates, despite the demonstration made through the various Statements and Schedules that accompany a general rate review proceeding. The second is implementing the Commission’s orders in several NRS Chapter 704B dockets (“704B Orders”), pursuant to which four customers are converting from bundled to distribution only service (“DOS”). Two of those customers converted their services during the test period and two are expected to complete their conversions during the ECIC period (June 1, 2017 through the rate effective date for this filing). As set forth in Mr. Kevin Bethel’s prepared direct testimony, absent the statutory requirement to file every three years the Company would not have filed this application. Because it is important to recognize and reduce the impact of inter-class subsidies, the Company proposes to set existing rates for classes that currently receive a subsidy, most notably the single family residential class, at current rates, and to reduce the rates of classes providing those subsidies using the dollars collected from the new DOS customers through the proposed non-bypassable charges filed in compliance with
the related 704B Orders. We also propose that DOS rates remain at current levels. Net Energy Metering (“NEM”) cost based rates and optional residential and small general service rates are re-set to reflect the proposal discussed later in my testimony. Customer-Specific Facilities (“CSF”) investments are updated as discussed by Mr. Bohrman but with charges set using the current rate. This is accomplished in three steps.

- First, the Company proposes to reconcile revenue at full marginal cost to present rate revenue, functionalized using the relationship across functions resulting from the unbundled NRS revenue requirement contained in Statement H-2 supported by witness Ms. Mello to demonstrate the cost based class revenue requirement levels.

- Second, the proposed non-bypassable charges in compliance with the related 704B Orders were calculated along with the resulting revenue. I refer to these charges as regulatory asset charges. In addition, miscellaneous revenue changes from modified existing optional TOU rates and updated CSF investments are also calculated.

- Third, each bundled rate class addressed in reconciliation will have its class revenue requirement set at the present rate level with unsubsidized classes receiving a further reduction equal to their sales-based share of the additional regulatory asset related revenue\(^1\) (and miscellaneous revenue changes). Flowing these non-bypassable regulatory asset revenue back to all unsubsidized customers serves to reduce their rates below what they would have been absent a general rate case filing and effectively reduce the impact of current subsidies.

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\(^1\) Should the Commission grant modifications to any of the fees or obligations previously ordered for any of the NRS 704B customers, the Company’s calculations will have to be revisited.
As discussed by Mr. Bethel, it is the Company's goal to live within its means and provide bill stability for our customers as a result. This goal drives our policy decisions in this case. As can be seen from the graph below, all of Nevada Power’s customers have current rates lower than they were 15 years ago in real terms.

Figure Walsh Direct-1

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A. **REVENUE REQUIREMENT RECONCILIATION**

8. **Q.** PLEASE EXPLAIN FURTHER THE COMPANY’S PROPOSAL FOR RECONCILING THE REVENUE AT FULL MARGINAL COST TO PRESENT RATE REVENUE, RESULTING IN NO CHANGE IN THE COMPANY’S CORE OPERATIONS REVENUE.

A. As explained above and by Mr. Bethel in his prepared direct testimony, even though an increase in revenue requirement is indicated by the Statements and Schedules
prepared pursuant to the Commission’s regulations, the Company proposes not to change the total revenue requirement for electric operations. Therefore, revenue at full marginal cost is reconciled to revenue at present rates, functionalized using the relationship between distribution, transmission and generation to demonstrate cost based rates.

To fully comply with applicable statutes and regulations and to provide the Commission with sufficient information to make its decision in this case, the Company is filing four separate Statement O rate designs:

1. Proposed ECIC at Present Rate Revenue,
2. Cert (without ECIC) at Present Rate Revenue,
3. ECIC at NRS Revenue, and
4. Cert (without ECIC) at NRS Revenue.

The proposed class revenue requirements and rates are contained in Statement O - Proposed ECIC at Present Rate Revenue and are supported by Mr. Pollard in his Prepared Direct testimony.

B. COMPLIANCE - SINGLE FAMILY RESIDENTIAL SUBSIDY & BSCs

9. Q. PLEASE EXPLAIN HOW THE COMPANY HAS COMPLIED WITH THE COMMISSION’S ORDER IN DOCKET 14-05004, DIRECTING NEVADA POWER TO PROVIDE A PROPOSAL IN THIS CASE TO ELIMINATE THE SINGLE FAMILY RESIDENTIAL SUBSIDY.

A. The Company has provided the Commission with two Statement O versions that utilize the demonstrated revenue requirement and calculate fully cost-based class revenue requirements. Both Statement O versions, ECIC at NRS Revenue and Cert
at NRS Revenue, would serve to fully eliminate the single family residential subsidy in one step. Both also provide the Commission with information in both the Cert and ECIC Statement Os, should the Commission not approve the Company's request to hold revenue requirement and/or single family residential rates constant.

10. Q. HOW HAS THE COMPANY RESPONDED TO THE RESIDENTIAL BSC COMPLIANCE ITEM ORDERED BY THE COMMISSION IN DOCKET NO. 14-05004?

A. In Docket No. 14-05004 the Commission’s Ordering paragraph 22 states, “In NPC’s next general rate case filing, NPC shall include a basic service charge for the RS class that recovers at least 100 percent of both the customer and Rule 9 facilities costs.” For this compliance item, the Company has supplied sufficient information for the Commission to address this issue should it not approve the Company's request to hold revenue requirement and/or single family residential rates constant. The ECIC and Cert Statement Os at NRS revenue requirement both set the BSC for residential and small general service classes at levels sufficient to meet this requirement established by the Commission in its order in Nevada Power’s 2014 general rate case (“GRC”). In the same order, the Commission also directed Nevada Power to include in its next GRC filing a detailed discussion of primary distribution demand costs and whether a percentage of such costs should be included in the BSC. To improve equity, Nevada Power has ascertained that it would be appropriate to increase the residential class’s BSC to reflect a portion of primary distribution costs. However, we have only made this change in our cost-based rate calculations presented in the NRS Statement Os to demonstrate the rates
that would result. As discussed previously, Nevada Power’s proposal in this case is to keep rates at the current or lower levels.

11. Q. WHY WOULD IT BE APPROPRIATE TO RECOVER PRIMARY DISTRIBUTION DEMAND COSTS THROUGH A BSC IF THE COMPANY WERE PROPOSING TO RE-SET RATES IN THIS CASE?

A. Absent a demand charge, the BSC is the price signal most closely aligned with cost causation for the facilities closest to the customer, including primary distribution facilities. Primary distribution demand costs are driven by both non-coincident (localized) and coincident demand, with facilities closest to the customer driven by customer maximum demands. Therefore, from a cost causation perspective, the primary distribution costs are appropriately recovered through a fixed charge mechanism like the BSC in a simple two part rate structure. All other classes of customers with more complex rate structures, the BSC, in combination with a maximum monthly demand charge, reflects 100 percent of Customer and Facilities cost and 100 percent of all Distribution (substation and non-revenue feeder) demand cost. Because, as the fixed monthly charge increases, the volumetric rate is appropriately lower, recovering more cost through the BSC improves both bill stability for customers and revenue stability for the Company.

III. PROPOSED UPDATE TO RULE 9 ALLOWANCES AND FACILITIES STUDY

12. Q. PLEASE SUMMARIZE EXHIBIT WALSH DIRECT-2, UPDATED RULE 9 LINE EXTENSION ALLOWANCES AND FACILITIES STUDY WHITE PAPER.

A. Exhibit Walsh Direct-2 is a whitepaper that explains how the updates to the Rule 9 Line Extension Allowances and Facilities Study (“Facilities Study”) were
accomplished consistent with the approved methodology. The Facilities Study methodology was previously outlined in greater detail as part of the whitepaper in Appendix 2 of Advice Letter No. 423-R filed in compliance with Docket No. 12-10004. Further refinements to the Facilities Study methodology were detailed in the 2016 version of this whitepaper in Attachment 1 of Advice Letter No. 469 (“2016 Facilities Study”). Exhibit Walsh Direct-2 contains the updated Allowances, Master Plan Community (“MPC”) refund amounts and the Proportionate Share refund amounts. Additionally, the whitepaper contains a table comparing the updated results to the currently approved allowances.

13. Q. WHAT IS THE PURPOSE OF THE UPDATED FACILITIES STUDY ATTACHED AS EXHIBIT WALSH DIRECT -2?

A. The updated facilities study has two purposes. First to update the basis of the current Rule 9 Allowances, MPC refunds, and Proportionate Share Refund amounts and second to provide the marginal facilities investment per customer by class to the proposed MCS. The currently approved Allowances and refund amounts were filed by Nevada Power in Advice Letter No. 469. This update aligns the required Rule 9 updates with the triennial general rate case cycle.

14. Q. PLEASE DESCRIBE HOW THE FACILITIES STUDY DETAILED IN EXHIBIT WALSH DIRECT-2 WAS CONDUCTED.

A. Consistent with the Commission approved methodology utilized by the Company in 2012 and 2016 to update the Allowances for new line extensions, three years of Rule 9 project data was used to determine the median per-unit project cost for new line extensions for each class. The median was established as a target investment amount and the project data was used to set the level of Allowances needed to arrive
at the target investment level on average for the group of projects used for each class.

Data from Nevada Power’s work management system ("Maximo") was used to complete the Facilities Study. New business project data was extracted from Maximo for the 2014-2016 period. Information in Maximo includes, among other things, estimated project costs, the number of meters or kVA per project broken out by customer class,\(^2\) Allowances, rate classes within each project, and construction beginning and completion dates. A project screening process eliminated projects for which data was incomplete, where budget ID codes were unverified or did not include a project beginning date or project status. Projects that were cancelled or put on hold were also screened from the database.

Rule 9 facilities may serve multiple rate classes; thus, the project costs for these projects are common to more than one rate class. For projects with common costs, the Facilities Study developed allocation factors based on the expected demand of each class within the project in order to allocate total project costs to each applicable rate class.

The projects in the study have construction start dates from January 2014 through December of 2016. Consistent with the process approved in Docket No. 12-10004, costs data from years one and two were not escalated to current dollars. However, after identifying the class medians as target investments, project costs were

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\(^2\) Investment is per meter or unit for the D-1, DM-1 and GS1 classes and per kVA for the larger classes.
escalated to maintain consistency with other data input to, and developed in, the
MCS, where all values are represented in common year (2018) dollars.

An iterative analysis was then performed by re-evaluating each project and
determining the resulting utility investment under various Allowance amounts
assuming the investment was being made in 2018. Under Rule 9, an Allowance can
only be granted up to the amount of the project cost subject to Allowance.
Consequently, projects with costs less than the potential maximum Allowance are
granted an Allowance below the maximum. Projects with costs greater than the
maximum Allowance are capped at the maximum Allowance with the Applicant
responsible for the remainder of the costs of the project.

15. Q. PLEASE DESCRIBE ANY SIGNIFICANT CHANGES IN
METHODOLOGY FROM PREVIOUS FACILITIES STUDIES?
A. Compared to the 2016 Study, the 2017 Facilities Study does not have any
significant changes in methodology. The methodology used to develop the current
Line Extension Allowances is the same and the data used to prepare the Facilities
Study continues to originate from Maximo, as was done in 2016. A comparison of
the resulting Allowances to the presently-approved Allowances can be found in
Table 2 of Exhibit Walsh Direct-2. However, there was a significant change in
methodology in the 2016 Facilities Study compared to the 2012 Facilities Study,
which produced the marginal utility investments in this case compared to those
produced for the inputs to the 2014 MCS. That change in methodology was the use
of kVA-per-customer instead of the single project average project cost as a common
cost allocator for multi-class projects. In preparation of this study, we discovered
that the kVA-per-customer for the general service ("GS") class used in the 2016
Study was overstated, which led to a greater allocation of multi-project costs to the class than was appropriate. I discuss this and the other trends affecting the average size of small GS customers and multi-class projects further below.

16. Q. WHAT UPDATES WERE MADE TO THE INPUTS COMPARED TO THE 2016 FACILITIES STUDY?

A. Two significant updates were made to refresh the 2016 Facilities Study to develop the current Line Extension Allowances. Maximo project data was updated by removing calendar year 2013 projects from the Maximo data and adding projects from calendar year 2016. Second, the kVA-per-customer for each of the residential and small commercial classes was updated using data from this GRC filing. To illustrate this update, Table Walsh Direct-1 below provides the current kVA-per-customer along with the historical kVA-per-customer values. This input drives the allocator for multi-class projects as well as the investment per customer input to the MCS for classes whose Allowance is developed on a per kVA basis.

For rate classes with a high percentage of multiple class projects and common costs, changes to the allocator impact how costs are apportioned between these rate classes. For example, many GS class projects are common or multi-class cost projects; as a result GS class project costs are especially sensitive to fluctuations in the cost allocator, i.e. class average kVA-per-customer. For classes with few multi-class projects, like LRS whose kVA-per-customer changed considerably each time due to the small number of customers, there is little impact.
As a result of updating the class average kVA per customer, the Rule 9 Allowance for the GS class decreased by approximately 56 percent and for the LSR class decreased by 63 percent, while all the other classes increased or decreased by less than 10 percent when compared to the current Allowances approved in 2016. Table Walsh Direct-2 below provides the proposed Allowance and the current Allowance.

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>2012 Study</th>
<th>2016 Study</th>
<th>2017 Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>RM</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GS</td>
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Table Walsh Direct-1, Historical Class Average kVA per Customer
Table Walsh Direct-2 – Proposed and Current Allowances

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>Units</th>
<th>2017</th>
<th>2016</th>
<th>$ Change</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>Homes</td>
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<td>-$52</td>
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<tr>
<td>RM</td>
<td>Homes</td>
<td>$714</td>
<td></td>
<td>$41</td>
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</tr>
<tr>
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<td>Homes</td>
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<td>-$807</td>
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<td>GS</td>
<td>Meter</td>
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<td>-$2,464</td>
<td></td>
</tr>
<tr>
<td>LGS1</td>
<td>kVA</td>
<td>$251</td>
<td></td>
<td>-$10</td>
<td></td>
</tr>
<tr>
<td>LGS2S</td>
<td>kVA</td>
<td>$129</td>
<td></td>
<td>-$12</td>
<td></td>
</tr>
<tr>
<td>LGS2p</td>
<td>kVA</td>
<td>$61</td>
<td></td>
<td>-$6</td>
<td></td>
</tr>
<tr>
<td>LGS3S</td>
<td>kVA</td>
<td>$99</td>
<td></td>
<td>$1</td>
<td></td>
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<tr>
<td>LGS3P</td>
<td>kVA</td>
<td>$68</td>
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<td>kVA</td>
<td>$68</td>
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<td>-$2</td>
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</tbody>
</table>

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

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

A. For classes that do not have CSF investment charges (classes other than the Transmission, Optional High Load Factor (LGS-3P), and LGS-X classes), marginal Rule 9 Facilities costs are developed in the proposed MCS. This requires as input, the average Rule 9 facilities investment made on behalf of customers pursuant to Rule 9 on a per customer by class basis. Rule 9 facilities are those facilities closest...
to the customer, including, but not necessarily limited to, the line extension, transformer, and service drop.

The Rule 9 facilities investment by class was calculated using results of the Facilities Study described in Exhibit Walsh Direct-2. The MCS uses the direct result of average investment per-meter for residential and small general service classes, and the investment per-kVA, converted to a per kW basis, for all other classes without customer-specific facilities charges. These values are then further converted to a per-customer investment amount based on the class average kW per customer.

18. Q. PLEASE DESCRIBE THE METHOD USED TO CONVERT THE FACILITIES-INVESTMENT-PER-KVA RESULTING FROM THE FACILITIES STUDY TO FACILITIES-INVESTMENT-PER-CUSTOMER FOR INPUT TO THE MCS.

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 MCS requires an investment per-customer. 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, 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 are the kVA-per-customer applied to the average investment-per-kVA to convert the investment to the unit cost needed for the MCS.
19. Q. PLEASE SUMMARIZE THE MARGINAL INVESTMENT-PER-CUSTOMER USED AS AN INPUT TO THE MCS, AS IT COMPARES TO THE INPUTS FROM PRIOR STUDIES.

A. Table Walsh Direct-3 below compares the current marginal investment per customer with that used in the 2014 MCS. Many classes experience sizable changes. Overall, there was an increase in the investment-per-customer as a result of the combined impacts of the changes to the facilities study methodology previously described. LGS-2P and LGS-2P-WP, which is pegged to LGS-2P, had the largest increase in marginal investment-per-customer with respectively a 132 percent and 128 percent increase in marginal investment-per-customer. The RS and LGS-1 classes also saw sizable increases. The GS class was the only class with a lower marginal investment-per-customer with decrease of 47 percent. The factors driving change are discussed further below.
<table>
<thead>
<tr>
<th>Rate Class</th>
<th>2017 MCS</th>
<th>2014 MCS</th>
<th>% Change from 2014 MCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>RM</td>
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<td></td>
<td></td>
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<tr>
<td>LRS</td>
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<tr>
<td>GS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-1</td>
<td></td>
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<td></td>
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<tr>
<td>LGS-2S</td>
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<td></td>
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<tr>
<td>LGS-2P</td>
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<tr>
<td>LGS-3S</td>
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<td>LGS-3P</td>
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<td>LGS-WP-2S</td>
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<tr>
<td>LGS-WP-3P</td>
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</table>

20. **Q. PLEASE SUMMARIZE THE FACTORS THAT DROVE THE CHANGES IN MARGINAL INVESTMENT-PER-CUSTOMER**

A. Three primary factors drive the changes in the 2017 marginal investment-per-customer calculations when compared to the marginal investment-per-customer approved in the Nevada Power’s 2014 GRC (Docket 14-05004). The first is the combined effect of the change in the common cost allocator made to the Allowance methodology in the 2016 Facilities Study that was used to calculate the currently
approved Allowances, and a change in the allocator itself, kVA-per-customer. This methodological change aligned the Allowance calculation methodology between Nevada Power and Sierra, utilizing relative kVA-per-customer by class to allocate multi-class project costs. The difference in the kVA-per-customer for the GS class contributed to the large downward movement in the marginal investment-per-customer for this class. As stated above, the kVA-per-customer for the GS class used in the 2016 Facilities Study appears to have been overstated. Similar but smaller decreases in kVA-per-customer contributed to the 2 percent decrease in LGS-WP-3S and LGS-WP-3P marginal investment-per-customer.

The second driver is related to cost trends within rate classes (i.e., escalating/declining project costs in the underlying Maximo data) or a shift in types of projects such as more/less multi-project or common cost projects within a class. Increasing or decreasing cost trends can occur in the data for many reasons such as changes in project cost estimation methodology, economic conditions, or intrinsic changes in service within a class. The RS, RM, LGS-1, LGS-2S, and LGS-3S classes have been, at least in part, affected on a macro-economic level by the change from a Recession sample (calendar years: 2008-2010) to a Recovery sample (calendar years: 2014-2016). Examples of cost changes in the underlying project cost data were provided in Nevada Power Company Advice Letter No. 469 e.g. for the RS class, in 2012, the Company revised the project estimation cost methodology to include inspection costs which lead to an increase in project costs for this class.

Additionally, the Company identified a trend in the underlying project data which is an increase in multi-class cost projects. The intersections in the Venn Diagrams in Figures Walsh Direct-2 through Direct-4, show the number of multi-class
projects for the five rate classes that are most impacted by such projects by study.
For example, in the 2008 to 2010 data used in the 2012 Study (Figure Walsh Direct-2), there were five multi-class projects between the GS and RS classes. In the 2016 Facilities Study, there were 279 common cost projects between the GS and RS classes and this trend continues with 305 common cost projects between the GS and RS classes in the 2017 Facilities Study.

Figure Walsh Direct-2, 2008 to 2010 Single Class and Multi-Class Rule 9
The impact of the shift in the data towards a greater proportion of common cost or multi-class projects for GS is provided in Figure Walsh Direct-5. The multi-class projects show a decline in the median per-unit prost cost from the 2012 Facilities Study through the 2017 Facilities Study. Over the same facilities studies, the
proportion of multi-cost projects increased, which exaggerated the decline in GS median per-unit cost. The opposite effect, to varying degrees, occurred for the other classes shown. Figure Walsh Direct-5, the median per-unit project cost and proportion of multi-class to single class projects is provided for the RS, RM, GS, and LGS-1 rate classes for the three most recent facilities studies.

Figure Walsh Direct-5, RS, RM, GS, LGS-1 Median Per Unit Projects
RM Rate Class: Median per Unit Project Cost and Percentage of Multi-Class/Single Class Projects from the Three Most Recent Facilities Studies

GS Rate Class: Median per Unit Project Cost and Percentage of Multi-Class/Single Class Projects from the Three Most Recent Facilities Studies
The combined effects of the change in allocator method to the kVA per class, the change in the class average kVA, and the increase in multi-class projects have decreased the GS median per-unit cost while increasing the RS, RM, LGS-1 median per-unit cost as provided in Figure Walsh Direct-6. For the GS, RS, and RM classes the median per-unit cost is the marginal investment per-customer; so, impacts to median per-unit costs directly impact the marginal investment per-customer.

**Figure Walsh Direct-6** provides the trend in median per unit project costs for multi-rate class projects for the RS, RM, GS, and LGS-1 classes from the three most recent Facilities Studies.
The third significant driver of the change in marginal investment-per-customer is related to the number of projects within a rate class in the three year timeframe for each of the study updates. The LRS, LGS-2P, LGS-3P have such small sample sizes that volatility in the marginal investment-per-customer for these rate classes is unavoidable. For rate classes with less than 10 projects within the test period, the change in Allowance and corresponding change in investment-per-customer are pegged to a similar rate class as described in Exhibit Walsh Direct-2.

For example in Docket No. 12-10004, the Allowances for the LGS-3 rate class, for both primary and secondary service were not directly estimated, but instead increased in relative proportion to increases for similar classes that did have sufficient sample sizes to directly calculate the Allowances. With the larger dataset
associated with the economic recovery available for the 2017 Facilities Study, the Allowance for the LGS-3P rate class were calculated based on class specific cost data and not as a projection of cost data from another class. Even with the larger post-recession dataset, for the 2017 Facilities Study, the Allowances for the LRS and LGS-2P classes were updated in accordance with the previously established practice of using the proposed change in Allowances of similar rate classes with sufficient sample sizes. Also consistent with the previously approved methodology, the LGS-WP2S, LGS-WP2P, LGS-WP3S, and LGS-WP3P classes have been assigned the same Allowance as their corresponding rate schedule.

21. Q. IS THERE A WAY TO DAMPEN THE CHANGES FROM STUDY TO STUDY WITHOUT CHANGING THE METHODOLOGY AGREED TO AND APPROVED IN DOCKET NO. 12-10004?

A. Yes, by increasing the period of data to be evaluated, the impact of changes within the data are usually dampened. Additionally, trends are more evident looking over a longer period. The three year period was consistent with the desire to capture the most recent projects, however, lengthening that period to five or six years would still be relevant and because the projects are re-stated at effective year dollars inflation will be captured. This does not impact the methodology but simply increases the data evaluated.

22. Q. THE FACILITIES STUDY ALSO CALCULATES MASTER PLANNED COMMUNITY (“MPC”) REFUNDS. ARE THERE ANY SIGNIFICANT CHANGES IN THE METHODOLOGY USED TO CALCULATE THE MPC REFUND AMOUNTS?
A. Yes, there is one significant change to the methodology for calculating MPC Refunds. In previous facilities studies, the first step in calculating the current MPC Refund amounts was to apply an adjustment to non-revenue feeder costs to remove line transformer costs. In the process of updating the MPC Refunds for the 2017 GRC, the Company carefully reviewed its methodology and models for calculating the MPC refunds. As a result of this investigation, the Company determined that line transformer costs were already included in Rule 9 line extension costs, which are not included in the non-revenue feeder costs utilized in the MCS. Thus, the line transformer adjustment was being removed from the calculation of MPC Refunds twice. Table Walsh Direct 4 below provides a comparison between the 2012 MPC Refunds, current MPC Refunds, and the proposed 2017 MPC Refunds calculated with and without the line transformer adjustment.

Table Walsh Direct-4, MPC Refunds Comparison

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>Units</th>
<th>2012 MPC Refunds</th>
<th>2016 MPC Refunds</th>
<th>2017 MPC Refunds with Adjustment</th>
<th>2017 MPC Refunds without Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>Meter</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RM</td>
<td>Meter</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LRS</td>
<td>Meter</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GS</td>
<td>Unit</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-1</td>
<td>kVA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-2S</td>
<td>kVA</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td>LGS-2P</td>
<td>kVA</td>
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<tr>
<td>LGS-3S</td>
<td>kVA</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td>kVA</td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>
IV. OPTIONAL FULL REQUIREMENTS OFFERINGS

23. Q. WHAT NEW OPTIONAL OFFERINGS IS NEVADA POWER PROPOSING FOR FULL REQUIREMENTS RESIDENTIAL, SMALL GENERAL SERVICE CUSTOMERS AND EXISTING OPTIONAL TOU PROGRAMS?

A. Nevada Power is proposing two new offerings to be available to full requirements Residential customers. One is the optional Planned Demand Use (“PDU”) schedule and the other is an optional Critical Peak Pricing (“CPP”) schedule crafted after the recently completed Nevada Dynamic Pricing Trial (“NDPT”). In addition, the Company is proposing to move Summer weekends to the Off-peak period for all existing optional TOU Option A schedules, including all residential and small general service customer classes. The Option B schedules already have a shortened on-peak period, so the Company is not proposing to adjust the Option B TOU definitions.

The proposal for the existing optional TOU Option A schedules moves the Summer weekends entirely to the Off-peak period. Previously weekends in the months of June, July, August and September were treated like any other Summer day and contained Summer On- and Off-peak periods. The pie charts below show the change in the percent of Summer hours in each TOU period.
Mr. Pollard discusses this further, as well as resulting rates, in his prepared direct testimony. The Company asks that the implementation of the new optional TOU schedules be delayed until June 1, 2018, for marketing with rates effective October 1, 2018, in order to use new tools to develop and provide additional customer information and education regarding these new offerings. The Company is targeting April 2018 for communicating the change to existing optional schedules with existing customers as the proposed modification is to the Summer TOU periods.
Providing a structure for both existing and new optional TOU customers with fewer On-peak hours will offer an opportunity to improve customer acceptance while maintaining opportunities for customer bill savings. There is a cost basis for making one of the two weekend days Off-peak; however, it is important to note that one weekend day, Sunday, continues to be a relatively higher cost day. Knowing that, the new definitions will be easier to explain and market to all customers and having all weekends considered Off-peak has proven to be a desirable feature at other utilities with similar programs. Treating weekends as Off-peak allows customers additional opportunities to adapt their behavior to attain cost reductions and achieve customer savings while potentially maintaining their lifestyle. With the introduction of the Companies’ improved customer portals, the Company will be able to better meet residential and small commercial customer varying needs with these new and improved optional offerings. The Company intends to help customers align their lifestyle and energy use behaviors with the potential offerings. With increased understanding and awareness of this program, successful participation in the optional TOU offerings could also increase. The proposed Off-peak weekends for the Summer season also works to align Nevada Power’s existing residential and small general service optional TOU schedules with Sierra’s optional TOU offerings.

24. **Q. PLEASE EXPLAIN THE TWO NEW OPTIONAL OFFERINGS AND THE REQUESTED EFFECTIVE DATE PROPOSED BY THE COMPANY.**

A. Nevada Power’s two new optional offerings for full requirements residential classes, in addition to the proposal to have weekends classified as Off-peak in the Summer, will provide customers with greater choice and opportunities to save. Mr. Pollard supports the rate development, contained in Statement O, in his prepared
direct testimony and Mr. Dillard supports the tariff development for these new schedules in his testimony. The Company is requesting approval of the rates and tariffs for both offerings but asks for a delayed effective date of the rates, coincident with a quarterly rate change, and ideally on October 1, 2018, which is nine months later than the rate effective date of this GRC. The Company asks to be able to begin marketing the program in June 2018, but begin rate/program implementation on October 1, 2018. The Company will conduct marketing and begin the program on the same dates in both service territories. Sierra’s tariffs would be amended to reflect the requested effective date as well.

The requested delayed effective date is necessary to have a successful implementation of these programs. New processes, system integrations and billing regimes will be necessary to market, enroll and bill customers effectively. Equally important is the development of new tools, education packages, and communication options if these offerings are to be understood by customers. The six-month delay for marketing and 10-month delay in rate implementation allows the Company time to develop a complete marketing kit, educational materials, and an implementation plan, thereby allowing the Company to successfully meet our customers’ needs. This is essential to achieving savings, cost reductions and customer satisfaction.

The proposed Optional Planned Demand Use (O-PDU) schedule will include the following rate components:

- BSC that only recovers Customer and 25 percent of Rule 9 Facilities costs;
- Maximum demand charge which would recover the remaining 75 percent of Facilities and 100 percent of Primary Distribution Demand costs;
• Summer on-peak demand charge to recover 100 percent of Transmission Demand cost; and
• Corresponding lower flat energy rate compared to the flat-rate RS class.

Through this offering the Company will be able to send customers price signals that will encourage peak period demand reductions, collect information on customer acceptance of demand charges, while providing customers a choice that can save many customers money through properly planning their actions related to their concurrent use of appliances.

The proposed optional CPP rate for full requirements residential classes is based on the improved optional TOU offering discussed above and modeled after the NDPT’s CPP rates. This schedule will provide a better dynamic rate offering building on the experience gained from the NDPT. Participants in the NDPT reported improved customer satisfaction and demonstrated that they could respond to the price signals even with budget billing in place.

This optional offering provides the opportunity to reduce On-peak demand and energy resulting in system benefits and cost savings and aligns those savings with participant savings. By providing more cost-based price signals customers can choose to change their behavior and enjoy annual bill savings as a result. Because CPP is a rate driven by individual customer choice and behavior, it is an option to demand response programs that include a technological and Company controlled solution. Additionally, it is a distinct choice from the existing optional TOU as it provides a limited number of events for customers to focus on for their extreme behavioral changes and allowing more moderate, albeit still incentivized behavioral
changes during the standard On-peak period. The proposed optional CPP schedule will include the following rate components:

- BSC would remain the same as the optional TOU schedule;
- 12-14 Critical Peak events will be called by the Company from June through September – each with a duration of six hours;
- Corresponding lower on-peak energy rates compared to the ORS class.

Mr. Pollard further explains the CPP rate development in his prepared direct testimony.

Each of these optional offerings will appeal to different customers, providing them the opportunity to achieve savings that are aligned with cost reductions and the opportunity to gain understanding of customer perceptions of educational material and new rate structures. The NDPT has provided valuable insight into customers’ ability to understand more complex rates and proved that they could adapt behavior to lower cost and increase their savings as a result. The Commission’s Order in the NEM rate filing (Docket No. 15-07041) recognized the efficiency of a three-part rate design but questioned the understandability of demand rates by residential customers. By reducing On-peak usage, lowering On-peak demand and improving the class load factor, these programs can benefit more than just the participants.

25. Q. HAS THE COMPANY PREPARED AN ANALYSIS TO DETERMINE IF CUSTOMERS WILL BENEFIT FROM THESE NEW OPTIONAL OFFERINGS?

A. Yes. The Company has prepared an analysis that used the sample customers for the full requirements Single Family Residential class to evaluate how many customers
would benefit and by how much. For the CPP offering, the Company also incorporated the shifting that the NDPT participants exhibited to evaluate how savings could increase if customers changed behavior similar to what occurred in the NDPT. For the PDU offering, the Company estimated some reduction in both maximum and On-peak demand to demonstrate example savings that could occur if behavior changed. Fully 40.16 percent of all single family sample customers would benefit from the CPP offering, with 55.32 percent showing some benefit from the PDU offering without changing behavior. The average benefit is estimated to be approximately 11 percent and five percent for these programs respectively. The number benefitting and the average benefit increase as behavior is modified. Participants who can change their behavior would increase savings and those whose current patterns do not indicate savings can determine if they can change their behavior to shift their usage or lower their demand to achieve savings. **Table Walsh Direct-5** below shows the average savings and losses for each offering for customers in the Single Family Residential class (estimated without and with behavioral changes) along with the results for the Optional TOU Option A with weekends Off-peak.
Table Walsh Direct-5 Average Savings and Losses for Single Family Residential

<table>
<thead>
<tr>
<th>RS, ECIC at PRR</th>
<th>2017 GRC - Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>TOU Option A</td>
</tr>
<tr>
<td>Percent benefiting:</td>
<td>42.53%</td>
</tr>
<tr>
<td>Average % benefit:</td>
<td>10.83%</td>
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<tr>
<td>Average % loss:</td>
<td>-10.49%</td>
</tr>
<tr>
<td>Maximum % benefit:</td>
<td>54.48%</td>
</tr>
<tr>
<td>Maximum % loss:</td>
<td>-54.96%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Behavioral Movement</th>
<th>2017 GRC - Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS, ECIC at PRR</td>
<td>TOU Option A</td>
</tr>
<tr>
<td>Percent benefiting:</td>
<td>72.20%</td>
</tr>
<tr>
<td>Average % benefit:</td>
<td>11.52%</td>
</tr>
<tr>
<td>Average % loss:</td>
<td>-5.95%</td>
</tr>
<tr>
<td>Maximum % benefit:</td>
<td>54.48%</td>
</tr>
<tr>
<td>Maximum % loss:</td>
<td>-35.54%</td>
</tr>
</tbody>
</table>

% of Cust. >Avg. Benefit | 53.85% | 21.79% | 28.72% |
% of Cust. <Avg. Benefit | 45.90% | 20.26% | 13.85%

Complete results in Exhibit Walsh Direct-4, Optional Residential Offerings Benefit Analysis

Additionally, both offerings will include the Best Bill Guarantee provision that the Company has included in our other optional offerings. This allows customers to try these offerings without harm for the first year as any difference in the optional bill compared to the standard flat rate bill will be calculated and refunded at the end of the first 12 months.

26. Q. PLEASE FURTHER DESCRIBE THE ANALYSIS OF POTENTIAL BILL SAVINGS RESULTING FROM THE PROPOSED OPTIONAL TOU, CPP AND PDU RATE SCHEDULES THAT ARE SUMMARIZED IN EXHIBIT WALSH DIRECT-4.

A. Exhibit Walsh Direct-4, Comparison of Optional Time of Use Schedules shows the results of an analysis that estimates the potential benefits/losses that existing
flat-rate RS customers can expect to experience on the Company’s optional TOU schedules using the interval data of the sample customers. As stated above, the Exhibit shows that 40 to 55 percent of current flat-rate customers (based on the sample) benefit from the modified Option A TOU, new CPP, and new PDU schedules compared to the existing RS full requirements flat-rate. These percentages are visually represented by the three graphs within Exhibit Walsh Direct-4. They are each broken out into the existing flat-rate customer and where they would shift pending a move to one of the aforementioned TOU schedules. This was done by comparing the bills that the customer would pay under either billing structure. The results show the benefits/losses under an assumption of no modification in the customers’ energy behavior related to the TOU price changes as well as the results if customers responded to the TOU pricing in the same manner as those customers who participated in the NDPT. For those customers with the behavioral change similar to the NDPT we see that the percent that would benefit would be 72.20 percent for Option A, 83.88 percent for CPP, and 58.95 percent for PDU.

It should be noted that the PDU behavioral adjustment assumes that customers will reduce their Summer On-peak demand by 5 percent if placed into this category. The analysis uses the hourly data for customers in load research group’s sample for the applicable classes and calculates annual bills under both the flat-rate and optional TOU schedules using the proposed rates. As the rates proposed for the Option B schedules do not change from current levels these schedules are not included in this analysis.
Exhibit Walsh Direct-4 also includes a summary comparison that the impact of the proposed TOU period change has on existing ORS customers. The results show the percent benefiting from this change would be 71.92 percent, with an average per customer benefit of 1.61 percent for those who do benefit, and an average per customer loss of 1.63 percent for those who do not benefit.

The results for individual customers contained in the sample are then extrapolated to the population. If the customer pays less on the optional TOU schedule than they otherwise would have paid under the flat-rate schedule, they are identified as potentially “benefitting” from the optional TOU schedule. Those flat-rate customers that would pay more under the optional rate schedule are identified as potentially “losing” under the optional rate.

Using this same benefit/loss classification, the analysis also allows us to calculate: i) the average savings of those who are identified as benefitting along with the maximum potential loss; and ii) the average losses of those who are identified as losing, including the maximum potential loss. The results from this analysis are stated as a percent of the customers’ annual bill.

27. Q. WHY HAS THE COMPANY NOT PROPOSED THE NEW OPTIONAL OFFERINGS FOR THE NEM CLASSES?
   A. The Commission has established in the NEM order in Docket No. 15-07041 a laddering over 12 years for both the flat rate NEM schedules and an optional TOU schedule for each class which is based on the existing optional TOU periods. This laddering will result in changes to rates for these customers outside of GRCs in addition to the regular rate case and quarterly rate changes. These changes in rates
along the 12-year path to cost based rates will justifiably require additional communication for customers to understand each change. Adding to the complexity by increasing the number of optional schedules to which this laddering would apply would be counter-productive.

Additionally, NEM customers who were on the full requirements optional TOU were moved to the corresponding NEM TOU rate schedule and given a period of time to determine if they wanted to stay or return to the NEM flat rate schedule and make the one-year commitment to remain on TOU. The Company did not want to again make a change to that rate structure. More importantly, the proposed CPP and PDU offerings serve to provide a better reflection of cost based rates for the full requirements classes, reducing intra-class subsidies for classes that are not subsidized by others. Conversely, both the NEM flat and TOU rate schedules do not, and will not, reflect cost until the 12-year laddering is complete. Until then, customers in the NEM classes continue to be subsidized by other classes. It would be counter-productive to add a new category of subsidy to the NEM class.

28. Q. IF THE PROPOSED CHANGES TO EXISTING OPTIONAL TOU AND THE NEW OPTIONAL OFFERINGS ARE APPROVED, HOW DOES THE COMPANY PLAN TO COMMUNICATE THESE CHANGES TO CUSTOMERS?

A. Nevada Power will communicate with all existing customers affected by the change in TOU periods through a combination of communication channels. The movement of weekends to the off-peak period will not occur until the summer season, as the winter season TOU period remains a single period. The proposed demand rate and critical peak pricing rate offerings are requested to become effective for marketing
purposes in June of 2018, with rates becoming effective October 1, 2018. This allows time for successful completion of educational materials, tools, full communication plans and materials to be developed. Attached as Exhibit Walsh Direct-3 is a Communication Strategy document drafted by our Corporate Communications department outlining the preliminary communications plan.

V. NEM COMPLIANCE ITEMS

29. Q. THE COMMISSION’S ORDER IN DOCKET NO. 15-07041 SET OUT THREE DIRECTIVES TO THE COMPANY TO ADDRESS IN ITS NEXT GRC. HOW HAS THE COMPANY COMPLIED WITH THOSE DIRECTIVES IN THIS FILING?

A. In its February 17, 2016 Modified Order in the proceeding implementing S.B. 374, directives 11, 13 and 15 require the filing of information and other actions in this general rate application. Each of these are addressed below.

   **Directive 11.** In its next general rate case, Nevada Power Company d/b/a NV Energy shall recommend (with additional support) what portion of transmission and generation demand costs should be shifted (tilted) between the basic service charge and volumetric commodity rate.

The Company is not proposing that the BSC for the NEM classes be changed to include Transmission and/or Generation demand cost recovery at this time. This maintains the status quo. The cost-based BSCs for NEM customers were only recently reset with the cost based BSC designed to recover 100 percent of Customer, Facilities and Distribution costs, and future rate designs may contain demand charges to recover such costs. The laddered cost based rates are re-set using
the same ladder step but updating cost based rates. The BSC issue can be revisited in future proceedings.

Demand charges have been used for larger full and partial requirements customers for decades. The Commission should revisit this issue and the appropriateness of demand charges for these partial requirements customers in the future as transmission and distribution demand costs are not driven by volume of usage and not included in volumetric rates for larger customers.

**Directive 13.** In its next general rate case, Nevada Power Company d/b/a NV Energy shall recommend whether time-of-use rates for net energy metering ratepayers should continue to be opt-in, opt-out, or mandatory in the future.

The Company recommends that TOU rates for net energy metering ratepayers should continue to be opt-in at this time.

**Directive 15.** In Nevada Power Company d/b/a NV Energy's next general rate case filing with the Commission, Nevada Power Company d/b/a NV Energy shall propose a line item entitled "NET ENERGY METERING SUBSIDY" that will calculate the subsidy that each non-net metering ratepayer pays each month to subsidize net metering ratepayers. Nevada Power Company d/b/a NV Energy will include the same proposals in every subsequent general rate case filing with the Commission until the net energy metering ratepayers have been migrated to net energy metering rates on January 1, 2028.
In light of the Commission’s decision in Sierra’s 2016 GRC, the Company recommends against placing a line item reflecting the “net energy metering subsidy” on the bill. However, it is important that the Commission be fully informed about the NEM subsidy and its impact on other non-NEM customers. Statement O calculates the subsidy for both grandfathered (NMR-G Schedule) and NEM customers on laddered rates (NMR-A Schedule), and provides the impact of the subsidy on non-NEM customers. These results are found on pages 4 and 5 of Work paper 2 of Statement O and are supported by Mr. Pollard. Compared to Docket No. 15-07041 the net metering subsidy has increased from $662 to $667 per NEM customer per year due to changes in cost as well as a sizable increase in the amount of excess energy banked for the NEM customers at the full retail rate. As another demonstration of the subsidy, I provide a comparison of average RS net metering rates and bills and those for a rate design analogous to partial requirements on Standby rates in Exhibit Walsh Direct-5, Average Monthly RS NEM Bill Comparison. The rates shown include the current full requirements rates (Schedule NMR-G, Current Laddered (Schedule NMR-A), Proposed Laddered (Schedule NMR-A), cost based NEM, compared to those that would be derived if NEM rate design followed the approach that is applied to partial requirements customers who are not NEM customers, using Nevada Power’s Standby service tariff. This exhibit demonstrates for the Commission differences in the rates and bills paid by RS NEM customers and the resulting difference from that bill to the cost based bill as well as a bill resulting from rates similar to partial requirements customers on a long accepted Standby rate design.

30. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?
A. Yes, it does.
STATEMENT OF QUALIFICATIONS

LAURA I. WALSH
DIRECTOR, REGULATORY ANALYSIS, POLICY & STRATEGY
SIERRA PACIFIC POWER & NEVADA POWER COMPANIES d/b/a NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-5821

Ms. Walsh became an employee of NV Energy (then Sierra Pacific Power Company) thirty years ago. Her expertise and experience has been concentrated on electric cost of service and rate design issues, including the preparation and presentation of studies and testimony for general rate cases, deferred filings, rulemaking, alternative pricing proposals, investigations into restructuring of the electric utility industry, and various other regulatory dockets. Ms. Walsh has been involved in resolving issues related to the implementation of tariffs both in-house and with regulators and has provided support to contract negotiations with large customers at both utilities. She has substantial experience with issues relating to cost of service, rates, related economic analysis, tariffs, load research, unbundling, and open access. Ms. Walsh has prepared numerous statements, reports, data responses and studies on these issues for management, regulators, and interveners. She has testified before the Public Utilities Commission of Nevada (PUCN) and the California Public Utilities Commission (CPUC) in numerous dockets. She is also responsible for gas cost of service and rate design and previously responsible for water cost of service and rate design for Sierra Pacific Power Company.

In addition to her regulatory experience, Ms. Walsh has an Electrical Engineering degree and held a position within the Company’s Transmission Planning department. She also had a utility consulting business for a short time to assist the Company and large customers on rate related matters. Prior to joining the Company she worked as an Engineering Assistant for Lawrence Livermore Laboratory and EG&G Energy Measurement. Ms. Walsh also has a graduate degree in secondary education and taught high school math and computer science.

Employment History
Sierra Pacific Power & Nevada Power Companies d/b/a NV Energy
May 1987 to Present

Director, Regulatory Analysis, Policy & Strategy
August 2014 to Present

- Develop policy related to cost of service and rate design issues and direct the design and implementation of Nevada jurisdictional electric and gas cost of service analysis and rate design and provide expert testimony. Provide analysis and technical and theoretical support for Company proposals.
- Lead the creation and submission of timely and accurate regulatory statements and analysis, including those necessary for rate cases, Rule 9 and other tariff or pricing related filings.
- Provide upper management with comprehensive advice regarding pricing, cost recovery, and business practices.
- Represent the Company before various regulatory bodies as both expert witness and negotiator regarding regulatory, pricing and cost of service related issues.
- Direct the activities of the Pricing and Load Research groups.
Manager, Regulatory Pricing & Economic Analysis
March 1998 to Present

- Developing policy, analysis, and technical and theoretical support for various rate and tariff filings for the PUCN, the CPUC, and the Federal Energy Regulatory Commission (FERC)
- Support management and other divisions of the Company in resolving complex regulatory issues and preparing regulatory filings, developing cost of service and rate design, and practices and rate/tariff interpretations.
- Direct senior analysts and economists in the development of:
  - Rate design proposals - Marginal and embedded costing
  - Load research - Expert testimony and related analyses
  - Business and regulatory strategies affecting electric, and gas divisions (previously water)
  - Support for contract administration, and related regulatory activities
- Manage systems, processes, and staff in support of pricing, Rule 9, other regulatory and load research related activities for both utilities.
- Provide expert testimony and related analyses

Supervisor, Rates and Economic Analyses
April 1993 to August 1995

- Directed senior analysts in the development and presentation of financial, regulatory and economic analyses.
- Lead the team to prepared marginal and embedded cost studies for development of electric and water rates
- Provided expert testimony and related analyses

Senior Engineer, Pricing (8/97 to 2/98); Senior Engineer (5/91 to 4/93), Engineer (1/90 to 5/91), Associate Engineer (11/88 to 1/90), Cost of Service & Rate Design

- Working with finance, engineering, legal, accounting, and planning staffs:
  - Prepared marginal and embedded cost studies for development of electric and water rates and provided expert testimony.
  - Performed financial, regulatory and economic analyses.
  - Supported negotiations with large customer contracts and established methods for contract administration.

Associate Engineer (1/88 to 12/88), Engineering Intern (5/87 to 1/88), Transmission Planning

- Developed engineering and economic studies on Sierra's transmission system.
- Designed, planned for, and coordinated transmission additions for new business customers
- Developed IPS mapping software for electric system load flow maps. Created associated documentation and training material. Assisted Engineers with transmission planning cases.
Non-NV Energy Employment:

**Hug High School, Reno**  
August 1996 to July 1997

**Math & Computer Science Teacher**
- Taught classes in Algebra and Computer Science Skills.

**Mentor Consulting, Reno**  
May 1996 to July 1997

**Principal**
- Provided consultation on utility regulation, planning and engineering matters for utilities and commercial customers.

**Lawrence Livermore Laboratory, Las Vegas**  
June 1986 to January 1987

**EG&G Energy Measurements, Las Vegas**  
June 1983 to January 1985 (Schools breaks)

**Engineering Assistant**
- Assisted engineers in the design of electronic instrumentation unique to the high-speed nuclear diagnostics effort.
- Designed digital circuitry used in shaping multiple video camera signals and manipulating resulting display to monitors.
- Installed and maintained local area network; developed network manager software.

Prior Testimony/Appearance Before Public Utilities Commissions


**CPUC Application Nos.:** 92-05-040, 93-08-049, 00-07-001, 01-06-041, 04-05-004, 05-06-018, 06-04-002, 08-08-004, Rulemaking/Investigatory R.94-04-031/I.94-04-037

Education

**University of Nevada, Reno**
Bachelor of Science in Electrical Engineering, December 1987

**Sierra Nevada College, Incline**
Secondary Education Graduate Program, May 1996

Honors: Tau Beta Pi, Eta Kappa Nu, Phi Kappa Phi, Who’s Who in American College Students
**Continuing Education Courses**
- PTI Transmission Planning Techniques
- EEI Rate Fundamentals course
- NERA Marginal Cost Ratemaking in a Competitive World
- NERA Marginal Cost Methodology for Electric Utilities
- University of Nevada-Reno, Power Electronics
- Presenter/participant - professional seminars & working groups
- Various seminars on costing, supervision, computers & utility matters

**Community Involvement**
- ACE Charter High School Founding Board Member
- Nevada Womens’s Fund (NWF) Woman of Achievement
- NWF Professional Development Series Graduate
- Member of IEEE
- Tahoe Rim Trail Challenge Participant
- Nevada Foodbank Volunteer
- MATHCOUNTS Committee Member/volunteer
- Corporate Challenge Participant
- Previous HHS Student Government Advisor
- UNR Alumni Association Member
Nevada Power Company
d/b/a NV Energy

Updated Rule 9 Allowances & Facilities Study
White Paper

Allowance, Master Planned Community Refund, and Proportionate Share Refund Amounts
1. **UPDATING RULE 9 LINE EXTENSION ALLOWANCES**

   **A. Policy**

   Nevada Power Company d/b/a NV Energy (“NPC” or the “Utility”) invests in line extension projects constructed for Applicants on behalf of its customers. Virtually all customers have required, or will in the future require, a line extension to provide service to their homes or businesses. As set forth below, it is equitable for NPC to invest in some portion of these costs. The Utility’s investment in line extensions for each class of ratepayer is recovered though a portion of customers’ utility bills, including the bills of the customers for whom the line extensions are constructed.

   Determining the percent of the cost of line extensions in which the Utility should invest generally 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 median line extension costs, and that portion of the investment for higher cost projects. There are a number of trade-offs and policy questions that must be considered when developing the appropriate distribution of line extension investment as between the Utility and the customer. For example, should all customers pay for all line extension costs that are far above the average line extension cost, and if not, what portion should be reasonably assigned to all customers? 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 method for calculating Allowances, MPC refunds and Proportionate Share amounts was considered and approved in Docket 12-10004 and further refinements to the Facilities Study methodology were detailed and approved in the 2016 version of this white paper in Attachment 1 of Advice Letter No. 469. The project data utilized for this 2017 update is from the three year period of January 2014 through December 2016. Therefore, a one year lag in data will remain in place for the new allowances with a proposed effective date of January 1, 2018, as was the case in the previous study. This update does not seek to modify the approved methodology.

   **B. Results Summary**

   The proposed Allowances for all residential and general service classes decreased with the exception of the residential multi-family and large general service 3S classes. The proposed refunds for Master Plan Communities (“MPCs”) all increased. The proposed refunds for Proportionate Share all increased slightly with the exception of four categories of the 12kV system costs that had reductions in transformer unit costs. Table 2 through 4 below summarize the results.
C. Calculating the Updated Allowances

In Docket 12-10004, the median per unit project cost was chosen to represent the mid-range of line extension costs, generally dampening the effect of extreme costs, rather than using an average that can result in a few expensive line extensions with a very high cost per premise (or kVA) significantly raising the average cost beyond reasonable levels. The median cost is the line extension cost for the home or small business (or kVA for extensions to larger loads) in the middle, in other words the home that separates the lower half of projects from the upper half of projects, ranked by line extension project cost.

D. 2017 Update

As stated previously, the line extension project data from January 2014 through December 2016 was used for NPC’s Updated Rule 9 Line Extension Allowances & Facilities Study (“Facilities Study”). The line extension project costs and number of units per line extension project (homes, meters or kVA) were extracted from NPC’s work management system, Maximo. Information in Maximo includes, among other things, estimated project costs, the number of meters or kVA per project broken out by class, rate classes within each project, and project completion dates. A project screening process is then used to eliminate projects from the data set if: the data was incomplete, service was intended to be temporary, the project status was cancelled or on hold, the estimated project demand was zero, the budget ID codes were unverified, or if the project was not eligible to receive an allowance. In addition, projects that received allowances but were halted and subsequently restarted with only service hookups were not included in the Facilities Study.

Often, line extension facilities projects will serve multiple rate classes, for example an apartment complex with a common area clubhouse. For 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. Allocating common project costs by relative kVA is the method used in the Sierra Pacific service territory and is the method utilized by the Company to determine the current NPC Allowances. The class average kVA for all classes was updated in this Facilities Study. The updated kVA values for the Residential and GS classes, which make up a majority of the projects that are split between multiple classes, are shown in Table 1:

<table>
<thead>
<tr>
<th>Class</th>
<th>Old Average kVA</th>
<th>New Average kVA</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>9.43</td>
<td>9.67</td>
<td>-2%</td>
</tr>
<tr>
<td>RM</td>
<td>11.02</td>
<td>12.33</td>
<td>-11%</td>
</tr>
<tr>
<td>LRS</td>
<td>68.66</td>
<td>184.67</td>
<td>-63%</td>
</tr>
<tr>
<td>GS</td>
<td>6.79</td>
<td>15.44</td>
<td>-56%</td>
</tr>
</tbody>
</table>

Table 1 – Change in Class Average kVA-per-Customer
The projects in the study have construction start dates from January 2014 through December of 2016. Consistent with the process approved in Docket No. 12-10004, cost data was not initially escalated to current, or effective year dollars to determine the median project cost. Instead, after identifying the class medians as target investments the project costs were escalated to common year dollars reflecting the first year the proposed allowances would be in effect, in this case 2018.

Next, an iterative analysis was performed by re-evaluating each project and determining the resulting utility investment under various Allowance amounts assuming the investment was being made in 2018. Under Rule 9, an Allowance can only be granted up to the lower of the amount of the project cost or the class potential maximum Allowance. Consequently, projects with costs less than the potential maximum Allowance are granted an Allowance below the maximum. Projects with costs greater than the maximum Allowance are capped at the maximum Allowance with the Applicant responsible for the remaining project costs.

As indicated above, a one year lag in data remains the same as for the previous study approved in Docket 12-10004. Using 2014-2016 data, Allowances were calculated as follows:

1. Average line extension costs for units in each project were calculated (total cost for project/units) and ranked from lowest cost to highest cost.
   a. Consistent with the previously approved study, three years of cost data (2014-2016) were used to capture current cost trends.
   b. Project cost data was not escalated to current, or effective year dollars because cost variations within this relatively short period do not establish a significant trend.
   c. The median project cost was identified for each rate class using the three years of project cost data (sorted lowest to highest).
   d. Services-only line extension projects were identified by job status in the database and removed from the data sample. Services-only projects frequently involved projects where a line extension was previously installed, but due to the downturn in the economy the development was not completed and the only portion of the line extension remaining to be installed was the service line from the transformer to the new meter. Existing jobs had received a full allowance but the final connection and service drop were not completed by the utility. At a later point when development picked up again, Applicants applied for the service drop, but were ineligible for an allowance. Therefore, these jobs are exceptions and were appropriately removed from the database.
2. For customer rate classes with ten or more projects, the median cost was used as the target level of Utility investment, consistent with the approved methodology described above.

3. To derive the updated Allowance level for each class, the Facilities Study model containing the database of all the project data was applied to find (through iteration) the maximum Allowance level that yielded the target Utility investment which is the median line extension cost for that class.

4. As shown in italics in Table 2, for rate classes with less than ten projects there was insufficient data to produce reliable, robust results. To derive the updated Allowance levels for these classes, the percentage change in maximum Allowance of similar larger classes was applied to adjust the 2016 Allowance level to current levels.

5. Below is a description of how these average percentages from appropriate grouping of similar classes with a robust enough number of projects were applied to rate classes with an insufficient number of projects in the Facilities Study.

   a. The percentage change for LGS-1 rate class was applied to the LRS rate class, because the members of both classes have similar average levels of demand, both classes receive three phase service, and the line extension facilities are similar.

   b. The Allowances for the net metering classes (RS-NEM, RM-NEM, LRS-NEM, and GS-NEM) are the same as those for the corresponding full requirements rate classes, because the Maximo data does not yet contain a sufficient sample size for these classes to create separate Allowances for them.

   c. The corresponding percentage change of the LGS-2S, rate class was applied to the 2016 maximum Allowances of the LGS-2P rate class, because of the commonalities between these two classes.

2. **UPDATING REFUNDS FOR MASTER PLANNED COMMUNITIES**

MPCs 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 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.

3. **UPDATING PROPORTIONATE SHARE ALLOCATION UNIT VALUES**

A Proportionate Share Refund enables an Applicant(s) that previously funded a secondary, primary, or HVD Line Extension and transformers to obtain a Refund from a subsequent Applicant(s) that directly connects to the Line Extension funded by the original Applicant(s) (See Section A.16 of Rule 9). The Proportionate Share Refund received by the original Applicant(s) is calculated from the values in Rule 9, Attachment 1 by using the length or amount of facilities required to serve the subsequent Applicant(s) but funded by the original Applicant(s). This pass-through mechanism is administered by the Utility. The Utility does not keep any portion of the Proportionate Share Allocation.

This mechanism requires the subsequent Applicant(s), who benefit from the original Applicant’s investment (during the term of his contract) to provide the original Applicant compensation for that investment. It is not intended to provide the original Applicant sufficient Proportionate Share Refunds to recover the entire amount or even the remaining Proportionate Share of its initial Advance Subject to Potential Refund.

The methodology for calculating Proportionate Share Refunds is unchanged. The calculation is performed by taking the installed cost of different distribution facilities, and unitizing it on its capacity or footage, as appropriate, to develop either cost per foot per kVA for cable or cost per kVA for transformers and switches. These cost per unit values are the Proportionate Share Allocations applied to the type and amount of installed distribution facilities required to serve the subsequent Applicant(s) but funded by the original Applicant(s) to calculate the amount of the Proportionate Share Allocation. This amount is paid by the subsequent Applicant(s) to the original Applicant(s) through the Utility as a Proportionate Share Refund.

4. **RESULTS**

The 2017 proposed Allowances, Master Planned Community Refunds and Proportionate Share Refund Amounts are shown below in Table 2 through 4.

**A. Allowances**

Rule 9 Allowances were last updated in 2016. Therefore the currently effective Allowance values are based on construction data from 2013 to 2015, and reflect the current economic landscape. With the current economic recovery, the project counts, the number of units, and the resulting Utility investment continue to be robust. For example, for the GS class within the 2013-15 data period, there were 479 projects with 1,457 units. By replacing the
calendar year 2013 data within the Facilities Study with calendar year 2016 data, the number of GS projects and units increased to 566 projects and 1,765 units.

The larger number of post-recession projects continues to allow for direct estimation of allowances for the LGS-3 rate class. Now, with a more robust data set to directly calculate LGS-3 allowances we find that these allowances are relatively stable when compared to the 2016 Allowances. For the LGS-3P class, one project not contained in Maximo was added to the class data because the project met the criteria to be included in the facilities study. Additionally, project costs for two projects were adjusted in accordance with the following guidelines. As a general rule with regard to line extension costs, Nevada Power’s customers are not responsible for substation or HVD costs. As such, the facilities study does not include the cost of these facilities. In turn, the facilities study is the basis for “standard” Rule 9 Allowances, which also generally do not include the cost of substation and HVD facilities. However, in a very small number of cases Section B.2 of Rule 9 applies, and the customer is assigned some portion of the cost of new substation or HVD facilities. In these limited instances, and after applying the substation, HVD, and case specific Allowances to the substation and HVD costs allocated to the customer, the remainder of the substation and HVD costs are eligible to be offset by any surplus standard Rule 9 Allowance; therefore, on this remainder of substation and HVD costs are added to the feeder costs, and this sum is included in the total project costs in the facilities study.

Even with the larger data set associated with economic recovery, six rate classes had less than ten projects within the 2014-16 data period. Therefore, the Allowances for the LRS and LGS-2P classes were updated in accordance with the previously established practice of using the proposed change in Allowances of similar rate classes with sufficient sample sizes. Also consistent with the previously approved methodology, the LGS-WP2S, LGS-WP2P, LGS-WP3S, and LGS-WP3P classes have been assigned the same Allowance as their corresponding rate schedule.

Table 2 provides the proposed and current Allowances below. For most of the classes the proposed Allowance is less than the current Allowance. The GS class is the only class with a proposed Allowance decrease that exceeds 10%. The significant decrease in GS Allowance is due to the previously discussed change in class average kVA that occurred when the class average maximum kVA was updated for all the classes for the 2017 general rate case. It became apparent that the average maximum kVA was overstated for GS and LRS classes in the 2016 Facilities Study. In 2016, due to conversion to smart meters later than the single-family and multi-family residential classes, data available for sample customers was diminished, with certain intervals missing for the LRS and GS classes. The average maximum kVA calculated at the time of the 2016 study was impacted by this missing data. By 2017, a new sample had been drawn with nearly full saturation of smart meters resulting in more representative results. This sampling was not complete at the time the 2016 Facilities Study was conducted.

Because the class average kVA is used as a weight to allocate common project costs for multiple rate class projects, the GS class was impacted the most. The decrease from 15.44
kVA to 6.79 kVA in this study changed the relative weighting for common costs for projects that included the GS class. The greater the percentage of common cost projects within the population of projects for a given rate class, the greater the sensitivity of that class to changes in the common cost allocator methodology or a change in the allocator itself. For example, 74% of all GS class projects are multi-class projects; thus, a change in the common cost allocator methodology or a change in the relative weighting of the allocator itself is going to affect the per-unit project costs for 74% of GS projects.

Table 2 – Proposed and Current Allowances

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>Units</th>
<th>2017</th>
<th>$ Change</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS Homes</td>
<td>$3,312</td>
<td></td>
<td>-$52</td>
<td></td>
</tr>
<tr>
<td>RM Homes</td>
<td>$714</td>
<td></td>
<td>$41</td>
<td></td>
</tr>
<tr>
<td>LRS Homes</td>
<td>$20,249</td>
<td></td>
<td>-$807</td>
<td></td>
</tr>
<tr>
<td>GS Meter</td>
<td>$5,084</td>
<td></td>
<td>-$2,464</td>
<td></td>
</tr>
<tr>
<td>LGS1 kVA</td>
<td>$251</td>
<td></td>
<td>-$10</td>
<td></td>
</tr>
<tr>
<td>LGS2S kVA</td>
<td>$129</td>
<td></td>
<td>-$12</td>
<td></td>
</tr>
<tr>
<td>LGS2P kVA</td>
<td>$61</td>
<td></td>
<td>-$6</td>
<td></td>
</tr>
<tr>
<td>LGS3S kVA</td>
<td>$99</td>
<td></td>
<td>$1</td>
<td></td>
</tr>
<tr>
<td>LGS3P kVA</td>
<td>$68</td>
<td></td>
<td>-$2</td>
<td></td>
</tr>
<tr>
<td>LGSwp2S kVA</td>
<td>$129</td>
<td></td>
<td>-$12</td>
<td></td>
</tr>
<tr>
<td>LGSwp2P kVA</td>
<td>$61</td>
<td></td>
<td>-$6</td>
<td></td>
</tr>
<tr>
<td>LGSwp3S kVA</td>
<td>$99</td>
<td></td>
<td>$1</td>
<td></td>
</tr>
<tr>
<td>LGSwp3P kVA</td>
<td>$68</td>
<td></td>
<td>-$2</td>
<td></td>
</tr>
</tbody>
</table>

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

B. Master Planned Community Refunds

As with all other aspects of the Rule 9 facilities study being described herein, the methodologies and calculations remain consistent with those approved by the Commission in 2016 with the exception of one change to the MPC methodology. In the Model utilized to calculate the current MPC Refunds, the first step in calculating the MPC Refund amounts is to apply an adjustment to non-revenue feeder costs to remove line transformer costs. In the process of updating the MPC Refunds for the 2017 GRC, the Company investigated the methodology and model utilized to calculate the current MPC refunds to determine the necessity of the line transformer adjustment to non-revenue feeder costs. As a result of this investigation, the Company determined that line transformer costs were already included in Rule 9 line extension costs which are not included in the development of non-revenue feeder unit investment costs, and was therefore being removed from the balance twice. Thus, the line transformer adjustment was removed from the calculation of MPC Refunds. The results of the MPC calculation are provided in Table 3.
### C. Proportionate Share Refunds

A Proportionate Share Refund enables an Applicant(s) that previously funded a secondary, primary, or HVD Line Extension and associated transformers to obtain a Refund from a subsequent Applicant(s) that directly connects to the Line Extension funded by Applicant(s) (See Section A.16). The Proportionate Share Refund received by the original Applicant(s) is calculated using the values in Rule 9, Attachment 1 using the length or amount of facilities required to serve the subsequent Applicant(s) but funded by the original Applicant(s). This pass-through mechanism is administered by the Utility, but the Utility does not keep any portion of the Proportionate Share Allocation.

The factors used in calculating the Proportionate Share Allocation unit values are based on the average installed cost and loading capacities (or lengths) of the different distribution facilities. The resulting Proportionate Share Allocation per unit values for different categories of facilities compared to 2016 were revised based on the change in various cost inputs, and weight that cost input had on the total cost. For example, the changes in Proportionate Share for 1-50 kVA transformers reflect changes in the cost of material and labor. The 12 kV transformers have seen a 22.2% decrease in unit price, offsetting labor cost increases; however, the 25 kV transformers have seen a 9.2% increase in unit price. A comparison of 2017 and 2016 Proportionate Share Allocations per unit are shown in Table 4 below.

#### Table 3 – Proposed Nevada Power 2018 Master Planned Community (“MPC”) Refunds

<table>
<thead>
<tr>
<th>Steps</th>
<th>Cost Components and Calculations</th>
<th>Rate Classes ——&gt;</th>
<th>Nevada Power Company ——&gt;</th>
<th>Applicable Units ——&gt;</th>
<th>Meter Based</th>
<th>Load Based</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>NRF Marginal Demand Revenues</td>
<td>RS $98,609,799</td>
<td>RM $23,450,881</td>
<td>LRS $397,529</td>
<td>$4,725,566</td>
<td>LGS-1 $33,508,475</td>
</tr>
<tr>
<td>B</td>
<td>Units (Meters or kW)</td>
<td>14,819</td>
<td>263,367</td>
<td>227</td>
<td>71,633</td>
<td>999,443</td>
</tr>
<tr>
<td>C</td>
<td>Units (Meters or kva)</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>1,110,492</td>
</tr>
<tr>
<td>D</td>
<td>Economic Carrying Charge</td>
<td>7.87%</td>
<td>7.87%</td>
<td>7.87%</td>
<td>7.87%</td>
<td>7.87%</td>
</tr>
<tr>
<td>E</td>
<td>Supported Investment / Meter or kW</td>
<td>2,433</td>
<td>1,131</td>
<td>222,242</td>
<td>$838</td>
<td>426</td>
</tr>
<tr>
<td>F</td>
<td>Percent of Capital (with O&amp;M Removed)</td>
<td>85.59%</td>
<td>85.59%</td>
<td>85.59%</td>
<td>85.59%</td>
<td>85.59%</td>
</tr>
<tr>
<td>G</td>
<td>Supported Investment Capital / Meter or kW</td>
<td>2,082</td>
<td>968</td>
<td>19,036</td>
<td>$717</td>
<td>364</td>
</tr>
<tr>
<td>H</td>
<td>Reconciliation Factor</td>
<td>57.91%</td>
<td>57.91%</td>
<td>57.91%</td>
<td>57.91%</td>
<td>57.91%</td>
</tr>
<tr>
<td>I</td>
<td>Reconciled Supported Investment / Meter or kW</td>
<td>$1,206</td>
<td>$561</td>
<td>$11,024</td>
<td>$415</td>
<td>$211</td>
</tr>
</tbody>
</table>

#### Summary

<table>
<thead>
<tr>
<th>Steps</th>
<th>MPC Refund / Meter or kVA</th>
<th>Rate Classes ——&gt;</th>
<th>Nevada Power Company ——&gt;</th>
<th>Applicable Units ——&gt;</th>
<th>Meter Based</th>
<th>Load Based</th>
</tr>
</thead>
<tbody>
<tr>
<td>K</td>
<td>2016 MPC Refunds / Meter or kVA</td>
<td>$1,206</td>
<td>$561</td>
<td>$11,024</td>
<td>$415</td>
<td>$211</td>
</tr>
<tr>
<td>L</td>
<td>Percent Increase 2017 from 2016</td>
<td>96%</td>
<td>98%</td>
<td>108%</td>
<td>114%</td>
<td>125%</td>
</tr>
</tbody>
</table>
### Table 4 – Proposed Nevada Power 2018 Proportionate Share Refunds

#### Proportionate Share Costs – 4-12 KV - Proposed

<table>
<thead>
<tr>
<th>Phase</th>
<th>Type</th>
<th>Wire</th>
<th>Transformer</th>
<th>Switch</th>
<th>Cost/kVA</th>
<th>Cost/ Ft/kVA</th>
<th>2016 Values</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O/H</td>
<td>2/0</td>
<td></td>
<td></td>
<td>$0.01691</td>
<td>$ 0.01666</td>
<td>1.48%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>O/H</td>
<td>2/0</td>
<td></td>
<td></td>
<td>$0.00791</td>
<td>$ 0.00779</td>
<td>1.54%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>O/H</td>
<td>954</td>
<td></td>
<td></td>
<td>$0.00502</td>
<td>$ 0.00495</td>
<td>1.46%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.02317</td>
<td>$ 0.02289</td>
<td>1.25%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.03616</td>
<td>$ 0.03555</td>
<td>1.73%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.01804</td>
<td>$ 0.01787</td>
<td>0.98%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.03347</td>
<td>$ 0.03289</td>
<td>1.76%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1000</td>
<td></td>
<td></td>
<td>$0.00297</td>
<td>$ 0.00293</td>
<td>1.38%</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Phase</th>
<th>Type</th>
<th>Wire</th>
<th>Transformer</th>
<th>Switch</th>
<th>Cost/kVA</th>
<th>Cost/ Ft/kVA</th>
<th>2016 Values</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O/H</td>
<td>1-50 kVA</td>
<td></td>
<td></td>
<td>$91.02</td>
<td>$ 98.90330</td>
<td>-7.97%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>O/H</td>
<td>51-167 kVA</td>
<td></td>
<td></td>
<td>$46.13</td>
<td>$ 45.82466</td>
<td>0.66%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1-50 kVA</td>
<td></td>
<td></td>
<td>$54.17</td>
<td>$ 53.80000</td>
<td>0.68%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>51-167 kVA</td>
<td></td>
<td></td>
<td>$36.44</td>
<td>$ 36.20810</td>
<td>0.64%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1-315 kVA</td>
<td></td>
<td></td>
<td>$67.48</td>
<td>$ 68.57278</td>
<td>-1.59%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>316-1000 kVA</td>
<td></td>
<td></td>
<td>$17.98</td>
<td>$ 18.36911</td>
<td>-2.13%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1001-2500 kVA</td>
<td></td>
<td></td>
<td>$17.80</td>
<td>$ 17.61494</td>
<td>-1.03%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>600 Amp</td>
<td></td>
<td></td>
<td>$1.85</td>
<td>$ 1.84076</td>
<td>0.45%</td>
<td></td>
</tr>
</tbody>
</table>

#### Proportionate Share Costs - 25 KV - Proposed

<table>
<thead>
<tr>
<th>Phase</th>
<th>Type</th>
<th>Wire</th>
<th>Transformer</th>
<th>Switch</th>
<th>Cost/kVA</th>
<th>Cost/ Ft/kVA</th>
<th>2016 Values</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O/H</td>
<td>2/0</td>
<td></td>
<td></td>
<td>$0.00838</td>
<td>$ 0.00825</td>
<td>1.47%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>O/H</td>
<td>2/0</td>
<td></td>
<td></td>
<td>$0.00402</td>
<td>$ 0.00396</td>
<td>1.52%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>O/H</td>
<td>954</td>
<td></td>
<td></td>
<td>$0.00251</td>
<td>$ 0.00248</td>
<td>1.47%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.01455</td>
<td>$ 0.01437</td>
<td>1.28%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.01938</td>
<td>$ 0.01908</td>
<td>1.57%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1000</td>
<td></td>
<td></td>
<td>$0.01162</td>
<td>$ 0.01147</td>
<td>1.31%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1/0</td>
<td></td>
<td></td>
<td>$0.01804</td>
<td>$ 0.01776</td>
<td>1.60%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1000</td>
<td></td>
<td></td>
<td>$0.00113</td>
<td>$ 0.00113</td>
<td>0.71%</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Phase</th>
<th>Type</th>
<th>Wire</th>
<th>Transformer</th>
<th>Switch</th>
<th>Cost/kVA</th>
<th>Cost/ Ft/kVA</th>
<th>2016 Values</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O/H</td>
<td>1-50 kVA</td>
<td></td>
<td></td>
<td>$95.92</td>
<td>$ 90.51920</td>
<td>5.96%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>O/H</td>
<td>51-167 kVA</td>
<td></td>
<td></td>
<td>$36.68</td>
<td>$ 36.39589</td>
<td>0.77%</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>U/G</td>
<td>1-167 kVA</td>
<td></td>
<td></td>
<td>$54.17</td>
<td>$ 54.73353</td>
<td>0.48%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1-315 kVA</td>
<td></td>
<td></td>
<td>$74.99</td>
<td>$ 74.59556</td>
<td>0.53%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>316-1000 kVA</td>
<td></td>
<td></td>
<td>$17.70</td>
<td>$ 17.61494</td>
<td>0.46%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>1001-2500 kVA</td>
<td></td>
<td></td>
<td>$21.23</td>
<td>$ 21.18411</td>
<td>0.22%</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>U/G</td>
<td>600 Amp</td>
<td></td>
<td></td>
<td>$1.08</td>
<td>$ 1.07826</td>
<td>0.42%</td>
<td></td>
</tr>
</tbody>
</table>
The secondary purpose of updating the Facilities Study is to provide the marginal facilities investment per customer by class as an input to the Company’s proposed MCS. 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 only stated on a per meter basis for the 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 as a conversion factor.1

### Table 5 – Marginal Facilities Investment-per-Customer

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>2017 GRC</th>
<th>2014 GRC</th>
<th>% Change from 2014 GRC</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LRS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-2S</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-2P</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-3S</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-3P</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-WP-2S</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-WP-2P</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-WP-3S</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LGS-WP-3P</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figures 1, 2, 3 and 4 illustrate the change in marginal utility investments over the last three general rate cases. As a general rule, project costs have increased on a regular basis. Resulting marginal investment-per-customer by class is shown below:

---

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.
## Rule 9 Facilities Marginal Investment per Customer
### (Residential Rate Classes)

**Figure 1**

<table>
<thead>
<tr>
<th></th>
<th>2011 GRC</th>
<th>2014 GRC</th>
<th>2017 GRC</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>1,174</td>
<td>1,656</td>
<td>2,857</td>
</tr>
<tr>
<td>RM</td>
<td>402</td>
<td>534</td>
<td>692</td>
</tr>
<tr>
<td>LRS</td>
<td>8,540</td>
<td>11,412</td>
<td>18,407</td>
</tr>
</tbody>
</table>

## Rule 9 Facilities Marginal Investment per Customer
### (Small Commercial Rate Classes)

**Figure 2**

<table>
<thead>
<tr>
<th></th>
<th>2011 GRC</th>
<th>2014 GRC</th>
<th>2017 GRC</th>
</tr>
</thead>
<tbody>
<tr>
<td>GS</td>
<td>1,713</td>
<td>3,044</td>
<td>1,618</td>
</tr>
<tr>
<td>LGS-1</td>
<td>5,513</td>
<td>5,754</td>
<td>10,831</td>
</tr>
</tbody>
</table>
Rule 9 Facilities Marginal investment per Customer
(Large Commercial Rate Classes)
Figure 3

Rule 9 Facilities Marginal investment per Customer
(WP Rate Classes)
Figure 4
EXHIBIT WALSH-DIRECT-3
Time of Use Rates Communications Strategy Overview

Summary

NV Energy remains committed to customers in Nevada who expect and deserve safe and reliable service at reasonable prices, as well as options to help them conserve energy and save money.

Toward that end, it is imperative that NV Energy continue to educate customers on the various programs and services available to them to help manage energy use and save on costs, including different pricing structures that better fit particular usage patterns, such as time of use rates. Historically, time of use rates (TOU) have not been widely promoted. The Choose When You Use pilot program offered insight into the design of these rates, which led the company to seek changes to TOU rates, associated peak periods, etc. The following outlines an overall communications strategy designed to accomplish three major goals:

1. Communicate changes in rate design to existing TOU customers
2. Increase awareness of TOU as an option and encourage adoption among customers willing to adjust usage patterns or whose existing usage patterns, and ultimately their energy bill, would benefit from the TOU option.
3. Conduct outreach on new critical peak and demand rate options (seeking 15-month implementation delay)

Communications

NV Energy already engages in a number of different communication activities related to the company’s operations, energy efficiency and conservation programs, customer service options, rates, and other pertinent company news. An overview of those activities follows.

Marketing/Public Outreach/Earned Media

NV Energy disseminates information to its customers and promotes its programs and services in many different ways, including a quarterly bill insert, website, mobile app, special events, brochure and collateral production and distribution, presentations to stakeholder groups, guest articles, press conferences, envelope and bill messages, IVR (phone), social media, etc.

The company also hosts and attends numerous local community events to provide information, services and other assistance. These tactics provide NV Energy the opportunity to have direct contact with customers in order to teach them how they can take control of their energy use, understand the changing technology and rate options.

Employee communications is also a major component. Detailed information will be made available and frequent updates regarding the program will be published in the company’s standard employee communications. This education is key to provide to employees as ambassadors of the company.

Paid Media

NV Energy engages in paid media efforts to increase awareness and participation in energy efficiency and conservation programs, as well as inform customers of evolving technology and
services that may positively impact their relationship with their energy company. All of these
efforts are intended to promote system reliability, advocate energy conservation, support
program participation and to encourage customers to utilize the tools available to help decrease
their energy use and thereby save money on their bills. Engaging in a paid media effort
augments other communications strategies and provides a platform for the company to tailor its
message in a specific direction. Analysis will be conducted as to whether a paid media
component for TOU, critical peak, and demand rate offerings are specifically warranted.

Communicating to a targeted audience
Communications will occur to two primary customer groups in both NV Energy service
territories: existing TOU customers and non-TOU customers.

TOU Customers
Existing TOU customers are easily identified through NV Energy’s billing systems. Direct
communication will occur with this group in order to communicate changes to the TOU rate
structure. The company will determine the most effective way to do so, whether electronically
or direct mail, and at what frequency, to ensure changes to the structure are clearly understood.

Non TOU Customers
NV Energy will also proactively communicate TOU, critical peak and demand rate offerings as
options to the broader customer base through various means as outlined above.

Training
While not the primary responsibility of the Communications team, it is important to note that
training will occur with Customer Contact representatives. Any training materials that are
developed will reflect similar messaging for consistency.

MyAccount Tools
Access to energy usage information is essential for customers to take advantage of these pricing
options. Robust upgrades will occur in the MyAccount portal to enable NV Energy customers to
identify the best option for their household or business and track their progress. This will be
particularly helpful upon introduction and potential adoption of optional critical peak and
demand rates in order to ensure an accurate price signal and program information is sent to
customers. MyAccount technology affords the opportunity to communicate with customers on a
more regular basis through email and text, rather than once a month through the energy bill. This
two-way communications effort is intended to create partnership between the company and the
customer in helping to better manage energy usage and costs by clearly outlining the relationship
between usage and costs to the total bill. For example, if a customer uses more energy in one
week than they did the previous, NV Energy would be able to call that fact to their attention so
they are able to identify the root cause of the discrepancy. In other words, messaging will be
more customized to the individual customer through the MyAccount portal.

Messaging and Timing
A detailed calendar of communications will be produced and message development will occur
concurrently with the regulatory process and focus on the goals outlined above. This will afford
NV Energy the ability to activate a communications effort on specific components of time of use in a timely manner once a decision is issued. With a proposal to make rates effective October 2018, it is anticipated that communications materials and tools associated with the newly proposed rates will be finalized by May 2018 with messaging to existing optional TOU customers beginning during the month of June 2018. In addition to the separate TOU communications effort, information on TOU rates and benefits as well as the options available to customers, will be incorporated into the company’s broader communications activities on a going-forward basis.

**Conclusion**
Making changes to TOU rates and providing more choice for our residential customers in response to customer feedback provide additional opportunities for NV Energy to communicate the variety of available customer offerings. While communications tactics and vehicles may vary as resources and opportunities are identified, it will be critical to continue to educate all customer classes on TOU options and new rate option if approved, as well as other programs and services available to them, to help manage energy usage and costs.
Comparison of Optional Time-of-Use Schedules for Single-Family (RS) Customers

Summary of Price Response - The behavioral movement estimated in the price response scenarios were obtained using data from the Nevada Dynamic Pricing Trial. It was found that individuals who did partake in the trial showed the following changes in their energy usage during the different TOU periods. These percentages were then used to extrapolate their would-be bill had they followed this same behavior.

<table>
<thead>
<tr>
<th>NDPT Trial &amp; Load Shift</th>
<th>Option A</th>
<th>CPP</th>
<th>PDU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer Critical Peak Period</td>
<td>0.00%</td>
<td>-33.44%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Summer On-peak</td>
<td>-16.79%</td>
<td>-21.32%</td>
<td>-5.00%</td>
</tr>
<tr>
<td>Summer Off-peak</td>
<td>1.33%</td>
<td>4.60%</td>
<td>0.00%</td>
</tr>
</tbody>
</table>

### 2017 GRC - Proposed

<table>
<thead>
<tr>
<th>RS Proposed</th>
<th>TOU Option A</th>
<th>CPP</th>
<th>PDU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent benefiting:</td>
<td>42.53%</td>
<td>40.16%</td>
<td>55.32%</td>
</tr>
<tr>
<td>Average % benefit:</td>
<td>10.83%</td>
<td>11.13%</td>
<td>5.09%</td>
</tr>
<tr>
<td>Average % loss:</td>
<td>-10.49%</td>
<td>-11.15%</td>
<td>-6.77%</td>
</tr>
<tr>
<td>Maximum % benefit:</td>
<td>54.48%</td>
<td>54.48%</td>
<td>37.66%</td>
</tr>
<tr>
<td>Maximum % loss:</td>
<td>-50.96%</td>
<td>-54.10%</td>
<td>-32.29%</td>
</tr>
<tr>
<td>% of Cust. &gt;Avg. Benefit</td>
<td>53.85%</td>
<td>21.79%</td>
<td>28.72%</td>
</tr>
<tr>
<td>% of Cust. &lt;Avg. Benefit</td>
<td>45.90%</td>
<td>20.26%</td>
<td>13.85%</td>
</tr>
</tbody>
</table>

### 2017 GRC Proposed with Price Response*

<table>
<thead>
<tr>
<th>RS Proposed</th>
<th>TOU Option A</th>
<th>CPP</th>
<th>PDU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent benefiting:</td>
<td>72.20%</td>
<td>83.88%</td>
<td>58.95%</td>
</tr>
<tr>
<td>Average % benefit:</td>
<td>11.52%</td>
<td>12.51%</td>
<td>5.18%</td>
</tr>
<tr>
<td>Average % loss:</td>
<td>-5.95%</td>
<td>-4.90%</td>
<td>-6.72%</td>
</tr>
<tr>
<td>Maximum % benefit:</td>
<td>54.48%</td>
<td>54.30%</td>
<td>37.66%</td>
</tr>
<tr>
<td>Maximum % loss:</td>
<td>-35.54%</td>
<td>-30.17%</td>
<td>-31.78%</td>
</tr>
<tr>
<td>% of Cust. &gt;Avg. Benefit</td>
<td>78.46%</td>
<td>47.95%</td>
<td>31.54%</td>
</tr>
<tr>
<td>% of Cust. &lt;Avg. Benefit</td>
<td>21.28%</td>
<td>4.36%</td>
<td>12.31%</td>
</tr>
</tbody>
</table>
Comparison of Existing Optional Time-of-Use Schedules Single-Family (ORS) Customers

<table>
<thead>
<tr>
<th>ORS Proposed</th>
<th>TOU Option A</th>
<th>CPP</th>
<th>PDU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent benefiting:</td>
<td>71.16%</td>
<td>71.16%</td>
<td>64.31%</td>
</tr>
<tr>
<td>Average % benefit:</td>
<td>24.74%</td>
<td>24.22%</td>
<td>12.02%</td>
</tr>
<tr>
<td>Average % loss:</td>
<td>-33.80%</td>
<td>-34.68%</td>
<td>-20.85%</td>
</tr>
<tr>
<td>Maximum % benefit:</td>
<td>49.59%</td>
<td>49.76%</td>
<td>27.23%</td>
</tr>
<tr>
<td>Maximum % loss:</td>
<td>-181.42%</td>
<td>-183.49%</td>
<td>-106.89%</td>
</tr>
</tbody>
</table>

Note: Existing ORS customers have already modified their behavior in response to the different price signals in the existing Option A TOU rates. Therefore, an additional behavioral change was not included in the analysis for the CPP and PDU schedules for these customers.
## Average Monthly RS NEM Bill Comparison

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BSC</td>
<td>1 $</td>
<td>12.75 $</td>
<td>17.90 $</td>
<td>17.40 $</td>
<td>35.90 $</td>
</tr>
<tr>
<td>Distribution Dmd</td>
<td>10.87 $</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Contract Dmd</td>
<td>6.10 $</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
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<tr>
<td>Backup Dmd</td>
<td>6.10 $</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
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<tr>
<td>Supplemental Dmd</td>
<td>4.77 $</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Delivered (BTER and BTGR only)</td>
<td>957</td>
<td>$0</td>
<td>$101.38</td>
<td>$101.78</td>
<td>$94.87</td>
</tr>
<tr>
<td>Net Billed (BTER and BTGR only)</td>
<td>408</td>
<td>$44.15</td>
<td>$51.10</td>
<td>$50.91</td>
<td>$18.24</td>
</tr>
<tr>
<td>Excess Energy Delievered to the System</td>
<td>555</td>
<td>$0</td>
<td>$51.10</td>
<td>$50.91</td>
<td>$18.24</td>
</tr>
</tbody>
</table>

### Total Average Monthly Bill
- $56.90
- $68.18
- $68.27
- $112.53
- $243.65

### Difference from Cost Based
- $55.63
- $44.35
- $44.26
- $121.53
- $243.65

### Difference from Standby
- $186.75
- $175.47
- $175.38
- $131.12

**Note:** Proposed rates and billing determinants are based on the Proposed Statement O. For comparability, all rates reflect the January 2017 BTER of $0.03899.
### Standby Calculation

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Customers</td>
<td>20,299</td>
<td></td>
</tr>
<tr>
<td>RS NEM Customer &amp; Facilities Cost</td>
<td>$4,327,907</td>
<td>$17.77 per customer per month</td>
</tr>
<tr>
<td>RS NEM Distribution Demand Cost</td>
<td>$4,416,707</td>
<td>$18.13 per customer per month</td>
</tr>
<tr>
<td>RS NEM Transmission Cost</td>
<td>$3,615,088</td>
<td>$14.84 per customer per month</td>
</tr>
<tr>
<td>RS NEM Generation Cost</td>
<td>$11,815,361</td>
<td>$50.74 Total Grid and Customer/Facilities cost per customer per month</td>
</tr>
<tr>
<td>Trans &amp; Gen Demand Cost</td>
<td>$15,430,449</td>
<td></td>
</tr>
<tr>
<td>Total Dist, Trans &amp; Gen Demand</td>
<td>$19,847,156</td>
<td></td>
</tr>
<tr>
<td>Contract kW Billing Determinants</td>
<td>1,485,893</td>
<td>6.10 average connected generation per customer</td>
</tr>
<tr>
<td>Max Demand Billing Determinants</td>
<td>2,647,802</td>
<td>10.87 maximum delivered load per customer</td>
</tr>
<tr>
<td>Standby BSC</td>
<td>$17.77</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max Demand Dist Rate</td>
<td>$1.67</td>
<td>applied to max demand</td>
</tr>
<tr>
<td>Diversity factor</td>
<td>80.2%</td>
<td>1-(experienced sum 15 minute gen/8760<em>4</em>sum of max gen)</td>
</tr>
<tr>
<td>Contract Demand T&amp;G Charge</td>
<td>$8.33/kW</td>
<td>applied to the contract demand</td>
</tr>
<tr>
<td>Backup Demand T&amp;G Charge</td>
<td>$2.06/kW</td>
<td>applied to max demand up to contract demand</td>
</tr>
<tr>
<td>Supplemental Demand full T&amp;G Charge</td>
<td>$10.38/kW</td>
<td>applied to max kW- contract kW</td>
</tr>
</tbody>
</table>

*Note: Analogous standby rate development and billing determinants are based on the Proposed Statement O (ECIC at Current Rates).*
AFFIRMATION

STATE OF NEVADA  )
COUNTY OF WASHOE  ) ss.

I, LAURA I. WALSH, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

LAURA I. WALSH

Subscribed and sworn to before me
this __24__ day of May, 2017.

LYNN D'INNOCENTI
NOTARY PUBLIC