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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV
Energy for approval of a cost of service study and net
metering tariffs.

Docket No. 15-07____

VOLUME 2 OF 2

NARRATIVE AND TECHNICAL APPENDIX

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NARRATIVE

NET METERING COST OF SERVICE AND RATE DESIGN NARRATIVE NEVADA POWER COMPANY D/B/A NV ENERGY

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Net Metering Cost of Service and Rate Design

SECTION 1: SUMMARY OF FILING AND NET METERING RULES AND RATES ONCE THE 235 MW CAP IS MET

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, “NV Energy” or the “Companies”) prepared and make this filing pursuant to Senate Bill 374 (SB 374). The 78th Nevada Legislature passed SB 374 on May 30, 2015.¹ On June 5, 2015, the Governor signed SB 374 and the bill became effective. SB 374 establishes a framework for transitioning between the existing net energy metering rules (“NEM1”) and new net energy metering rules (“NEM2”).² NV Energy’s data demonstrates that customers who install renewable distributed generation have unique load and cost characteristics. For instance, on an annual basis, the average single family residential NEM1 customer has a higher total load than the average full requirements single family residential customer at Nevada Power. The new rules, which recognize these facts, will apply to customer-generators,³ who install renewable distributed generating facilities after the Companies accept and approve applications for 235 megawatts (“MW”) of capacity under NEM1.⁴

This filing meets the Companies’ obligations under SB 374. The filing contains a marginal cost of service study (“MCS”) that uses actual load and production data from net metered partial requirements customers (*i.e.*, customer-generators) currently served by NV Energy as the basis for NEM2 cost development.⁵ The filing contains a simple three part NEM2 offering (the “standard NEM2 rate”) and an optional three-part NEM2 offering that contains time-

¹ On May 30, 2015, the Senate concurred in amendments made by the Assembly and the bill was sent to enrollment.

² *Id.* at 25. Before SB 374, the Commission directed Nevada Power and Sierra to “each conduct a cost of service study to determine whether any systemic rate design changes should be made for its customer classes in response to the requirements of NEM/distributed generation customers” and to file those cost of service studies and proposed rate design changes with the Commission no later than July 31, 2015. *See Order*, Ordering ¶ 2, Docket No. 14-06009 (iss. March 31, 2015).

³ Customer-generators refer to users of net metering systems. Nev. Rev. Stat. § 704.768 (2013). A net metering system is a distributed generation unit that “uses renewable energy as its primary source of energy to generate electricity,” has a generating capacity of no more than 1 megawatt (“MW”), is located on the customer’s premises, operates in parallel with the Companies’ transmission and distribution systems, and is intended to offset part or all of the customer-generator’s on-site load. *See id.* § 704.771(1)(a) (2013). Nevada law recognizes that customer-generators are partial requirements customers. *See, e.g., id.* § 704.773(3)(c) (prohibiting the Companies from charging NEM1 customers who install systems larger than 25 kilowatts (“kW”) a “standby” service fee). The Companies incur distinct costs to provide the services, including load following and standby service, required by partial requirements customers. The Companies rules of service have recognized these facts, establishing specific charges for customers who receive standby service.

⁴ *See* Senate Bill 374, 78th Session of the Nevada Legislature, Section 2.3(1) (“SB 374”) (requiring the Companies to offer net metering under terms and conditions approved by the Commission to “customer-generators who submit applications to install net metering systems within [their] service [territories] after the date on which the cumulative capacity requirement described in paragraph (a) of subsection 1 of NRS 704.773 is met”).

⁵ NEM1 customers provide the sound sample base for NEM2 customers for costing and rate design. NEM2 will use the same generating technologies as NEM1 customers.

differentiated demand and energy charges (the “optional NEM2 rate”). The standard NEM2 rate will be the default NEM2 rate; if a NEM2 customer-generator does not choose the optional NEM2 rate, they will go on the standard NEM2 rate. The new NEM2 rates reflect the unique load and cost characteristics of NEM customers. By providing both standard and optional NEM2 rates, the filing enhances customer choice. Equally important, the standard and optional NEM2 offerings should minimize controversy in this proceeding. To the extent that customer-generators provide demand benefits to NV Energy’s system, the standard and optional rates allow customer-generators the opportunity to optimize their net energy metering (“NEM”) systems, reduce their demand and energy usage, and realize the resulting benefits.

In summary, the NEM2 rules and rates proposed by NV Energy establishes a foundation upon which a long-term solution that furthers Nevada’s energy policy can be built. The NEM2 rules facilitate the interconnection of additional renewable distributed generation (“renewable DG”) after the 235 MW-limitation on NEM1 is met. The standard and optional NEM2 rules and rates better reflect the cost of providing service to customer-generators than the NEM1 rules and rates. The NEM2 rules and rates are just, reasonable and fair to all customers.

Finally, the NEM2 rules and rates reduce the shifting of costs from customer-generators to the Companies’ other customers that occurs under NEM1 and provide a more sustainable framework for future renewable energy growth. To be clear, however, customers who choose to install renewable DG can reduce their Nevada Power bill under the NEM2 rules and rates, even though a customer who installs renewable DG might end up paying more for energy when the cost of buying or leasing the system, or purchasing the output of the system is taken into consideration.⁶

A. NV Energy’s Standard and Optional NEM2 Offerings Promote Customer Choice and Treat All Customers Equitably.

Section 4.5 of SB 374 establishes a preference for the NEM2 billing regime. The preference established by the law is a three-part rate structure that consists of a basic service charge, a demand charge, and an energy charge. Consistent with the preference established by Section 4.5, the structure of the standard and optional NEM2 rates proposed by NV Energy contains three basic parts: a monthly basic service charge, a demand charge, and an energy charge.

These charges are based on the specific costs that the Companies incur to provide electric service to customers who install intermittent, renewable generation. The basic service charge, pursuant to SB 374, reflects marginal customer costs associated with back-office systems (*e.g.*, accounting, billing, and customer service systems), meters and employees. The NEM2 basic service charges also reflect marginal facilities costs (*e.g.*, the terminals, transformers, and wires that are closest to the customer’s premise). These costs – which are necessary to provide reliable

⁶ See Table 3-5, below, which contains a single-family residential (“RS”) bill comparison under the standard, simple three-part NEM rate and the optional time-of-use three-part net metering rate. This table shows that an average NEM2 customer can reduce their utility bill by 33 percent. These bill reductions largely reflect energy savings. This does not mean, of course, that the NEM2 customer will reduce their overall cost of energy. If the cost of energy includes the cost of buying or leasing the renewable DG system, or the amount paid to a system-owner under a power purchase agreement, the amount the customer spends on energy can increase. See Order, 1, Docket No. 13-07010 (iss. Sept. 30, 2014) (“NEM participants pay more than they otherwise would have”); see also Commission Report at 3, Docket No. 13-07010 (iss. Sept. 30, 2014).

service and ensure that a customer has service when needed – are fixed, and do not vary based on the amount of electricity a customer consumes. The NEM2 rules and rates are consistent with the Commission’s decisions in electric general rate cases,⁷ and treat customers who install renewable distribution equitably.

The demand charge, pursuant to SB 374, reflects the bi-directional use of the grid by the customer-generator, including the need to accommodate energy delivered to the grid by the customer-generator. The demand charge reflects the maximum load requirements of the customer-generator and, therefore, is consistent with subsection 7(b) of section 4.5 of SB 374. The demand charge also reflects a unique cost characteristic of the NEM customer – *i.e.*, the customer’s bi-directional use of the distribution system.⁸ Overall, the NEM2 demand charges are designed to reflect NV Energy’s investment in the generation, transmission, and distribution facilities needed to provide reliable service to customers, consistent with NV Energy’s public service obligations.

The energy charge, again pursuant to the preference established by SB 374, reflects the volume of energy consumed by a customer. Energy costs, such as fuel and purchased power, typically vary based on consumption.

The three-part rate structure is neither new nor novel. Utilities across the country have offered three- and multi-part rate structures to commercial customers for many years. Indeed, the Companies have used a three-part rate structure to bill commercial accounts for more than six decades. The design, which better reflects the cost of providing service, is well-established, and the approach provides a fair and reasonable way to recognize the cost of serving customer-generators.

The NEM2 rates proposed by NV Energy are just, reasonable and fair; the rates reflect the cost of providing electric service, including the inherent standby characteristics of such service, to customers who choose to install intermittent DG. Not only do the NEM2 rates reduce or eliminate the unreasonable shifting of costs from customer-generators to other customers that

⁷ In Docket No. 10-06001, the Commission established basic service charges that reflected 95.8 percent, 90.2 percent and 94.7 percent of the marginal customer and facilities costs associated with serving the multi-family and single-family residential classes and the general service classes. See Order at ¶¶ 535 & 543, Docket No. 10-06001 (iss. Dec. 29, 2010). In Docket No. 13-06004, the Commission continued to set basic service charges that reflected 100 percent of marginal customer and facilities costs, rounded to the nearest quarter for the single-family residential class. Modified Final Order at ¶ 464, Docket No. 13-06004 (iss. Feb. 3, 2014). For the general service class, the Commission established a basic service charge that reflected 100 percent of marginal customer and facilities costs, as well as a small percentage of primary distribution facilities. *Id.* These changes were necessary to “not lose ground in moving toward cost-based rates.” *Id.* Recently, the Commission again expressed the importance of setting basic service charges that reflect cost when it approved a stipulation in Docket No. 14-05004. The Commission’s order provides, Nevada Power “shall include a basic service charge for the single-family Residential service class that recovers at least 100 percent of both the customer and Rule 9 facilities costs.” Order, Directive ¶ 10, Docket No. 14-05004 (iss. Oct. 15, 2014). The order further directs Nevada Power to “include a detailed discussion of primary distribution fixed costs and whether any percentage of those costs should be included in the basic service charge for” the single-, large- and multi-family residential classes and the general service class. *Id.*

⁸ *See Section 3*, below describing the use of the total load plus excess energy curve in the development of the marginal cost of serving a NEM customer.

occurs under NEM1,⁹ but the rules also fairly compensate customer-generators for any capacity and energy benefits associated with their systems. By developing demand charges in the standard offering and setting the monthly basic service charge to recover fixed customer and facilities costs, and by developing an optional offering with time-differentiated demand and energy charges, the proposal is designed to set fair and reasonable rates and to minimize controversy in this proceeding. To the extent a customer-generator reduces the demand placed on NV Energy's generation and transmission system, the customer will reduce the demand charge component of their bill from NV Energy.

In summary, this filing begins the process of establishing an environment in which renewable DG works in a symbiotic relationship with the electric grid. Under the NEM2 rules and rates, customers who install renewable DG can reduce their Nevada Power bills in a manner that treats all customers fairly. The proposal recognizes the energy and capacity benefits of DG systems. The proposal is directly in line with the intent of SB 374 which recognizes that the inherent subsidy embedded in NEM1 rules and rates for the purpose of promoting the initial development of renewable DG is no longer needed to ensure the growth of that industry. Furthermore, those customers who do not have DG systems should not have to continue to subsidize the cost of new systems going forward.

B. NV Energy's Filing Effects the Purpose of SB 374 by Providing an Opportunity for the Commission to Establish New NEM Rules and Rates That are Fair to All Customers.

The statute requires the Companies to file cost of service studies and NEM2 rules by July 31, 2015.¹⁰ SB 374 allows the Public Utilities Commission of Nevada (the "Commission") to:

1. Establish new rate classes consisting of customer-generators;¹¹
2. Establish the terms and conditions of participating in NEM2, which may include a limitation on enrollment in NEM2;¹² and
3. Authorize the Companies to establish just and reasonable rates for providing service to partial requirements customers (*i.e.*, customer-generators) to avoid, reduce or eliminate the unreasonable shifting of costs from customer-generators to other customers of the Companies.¹³

⁹ See, e.g., Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities, at 29, Lawrence Berkley National Laboratory ("At 10 percent PV penetration, for example, average retail rates for the [Southwest] utility are 0.35cents/kWh (2.5 percent) higher than without PV.") (Sept. 2014).

¹⁰ SB 374, Section 4.5(1).

¹¹ *Id.* Section 2.3(2)(a). Under NEM2, separate customer classes are created for customer-generators in a manner that advances the basic purpose of the law by reducing or eliminating any unreasonable shifting of costs from customer-generators to other customers.

¹² *Id.* Section 2.3(2)(b). This filing does not request that the Commission limit the amount of capacity that can enroll in NEM2.

¹³ *Id.* Section 2.3(2)(d) & (e).

SB 374 expressly establishes a preference for a three-part rate structure: one that includes a basic service charge, a demand charge and an energy charge.¹⁴ NV Energy has used a three-part rate structure for commercial customers for more than six decades primarily because the design establishes clear, transparent and accurate price signals. A three-part rate structure allows the Commission to establish rates that adequately reflect the marginal cost of providing electric service to a specific group of customers. In this vein, SB 374 specifies that:

1. The basic service charges proposed by the Companies must reflect the marginal fixed costs incurred by the Companies to provide service to customer-generators;¹⁵
2. The demand charge proposed by the Companies must reflect the marginal costs associated with the “maximum load requirement of a customer,” which are “typically represented by [the Companies’] investment in generating units, transmission facilities and the distribution system;”¹⁶ and
3. The energy charge proposed by the Companies must reflect marginal energy costs (“MECs”), which often vary based on the volume of energy delivered by the Companies and are represented by fuel and purchased power costs.¹⁷

Pursuant to SB 374, the Commission must review the cost of service studies filed by the Companies and evaluate whether the terms and conditions of NEM2 are just and reasonable. SB 374 requires the Commission to approve NEM2 rules and rates before December 31, 2015.¹⁸ SB 374 specifies that the NEM2 rules and rates adopted by the Commission must not unreasonably shift costs from customer-generators to the Companies’ other customers.¹⁹

Section 4.5 of SB 374 requires NV Energy to file cost of service studies and tariffs that establish the terms and conditions of service provided to “new” NEM customers (“NEM2 customer-generators”).²⁰ Until now, “no [formal cost of service study focusing on the cost of serving partial requirements customers] has been conducted in Nevada.”²¹ Pursuant to the report issued

¹⁴ *Id.* Section 4.5(3).

¹⁵ *See id.* Section 4.5(3)(a) (noting that the basic service charges should reflect marginal fixed costs) & Section 4.5(7)(d) (defining fixed costs to mean those “investments and expenses that do not vary with output and which typically reflect the electric utility’s investment in back office systems, customer facilities, customer-related expenses and labor costs”).

¹⁶ *Id.* Section 4.5(7)(b).

¹⁷ *Id.* Section 4.5(7)(c).

¹⁸ *Id.* Section 4.5(4).

¹⁹ *Id.* Section 2.3(2)(e).

²⁰ Before the passage of SB 374, net energy metering was limited to customer-generators who installed net metering systems before the “cumulative capacity of all net metering systems operating in this State is equal to 3 percent of the total peak capacity of all utilities in this State.” Nev. Rev. Stat. § 704.773(1) (2013). SB 374 defined the 3 percent limitation to be 235 MW. *See* SB 374, Section 2.95. In this filing, “new” net metering customers, or NEM2 customer-generators, refers to customers who apply to NV Energy to interconnect variable, on-site generation and request a net meter after the Companies have accepted and approved applications to interconnect 235 MW of customer-generators.

²¹ Commission Report at 23, Docket No. 14-06009 (iss. March 31, 2015).

by the Commission in Docket No. 14-06009, the Companies prepared the cost of service study consistent with the Commission's regulations and standards that have "evolved over the past 30 years."²² And, consistent with SB 374, the MCS focuses on the marginal cost of providing electric service (as opposed to an embedded cost of service or cost/benefit study).²³ Furthermore, consistent with Commission's directive in the report, the MCS uses "well-supported . . . load shapes for NEM/DG customers and the same allocators that have long been accepted by the Commission."²⁴ Indeed, the MCS uses load shapes for customer-generators based on actual NEM data.²⁵

C. NV Energy's Transition Proposal is Transparent, Understandable and Explainable to Customer-generators.

NV Energy anticipates that it will accept 235 MW of applications under NEM1 sooner than previously anticipated.²⁶ NV Energy developed a transition proposal that is consistent with the purpose of SB 374, which was to avoid the "cliff" for the DG solar installers when the 235 MW cap was reached while at the same time reducing or eliminating an unreasonable shifting of costs from customer-generators that occurs under NEM1, is transparent and may be authorized by the Commission.

First, the Companies propose to continue to accept applications for the installation of a net meter under NEM2 rules even after NV Energy has accepted 235 MW of applications for net metering under NEM1 rules and rates. Second, consistent with the spirit of SB 374, NV Energy will time-stamp each application for net metering under NEM2 rules. As projects within the NEM1 pipeline are cancelled,²⁷ NV Energy will continue to manage the queue and move applicants from the NEM2 queue to NEM1 rules and rates until 235 MW of customer-generators are served under NEM1 rules. Third, through this filing, the Companies have requested Commission permission to begin providing service and billing at an appropriate point,²⁸ under the proposed NEM2 rules and rates to all customer-generators who apply for service after NV Energy has accepted 235 MW of NEM1 applications, subject to a refund in the event the Commission establishes NEM2 rules and rates that would have resulted in a lower bill from NV Energy. This proposal provides an efficient and transparent process for transitioning from NEM1 to NEM2 that is consistent with both the letter and purpose of SB 374.

²² *Id.* at 25.

²³ See Section 4.5, Subsections 3(a) through 3(c) (noting that the tariffs filed by the Companies may include basic service, demand and energy charges that reflect the marginal costs).

²⁴ *Id.*

²⁵ See Section 4 below.

²⁶ See Comments Regarding and Answer to Emergency Petition for a Declaratory Order, at pp. 9 – 11, Docket No. 15-07021 (filed July 22, 2015).

²⁷ Historically, about 6 percent of applications have been cancelled as projects are not completed. See Section 8.E below.

²⁸ NV Energy is preparing to begin billing under NEM2 rules and rates as soon as September 15, 2015. However, billing under NEM2 rules and rates would not actually begin until the Companies have received applications for 235 MW of net metering under NEM1, and have actually installed a net meter for a NEM2 customer.

In order to implement this transition plan, Nevada Power in its application requests that the Commission issue an interim order in this docket directing that the proposed NEM2 tariffs that are in Exhibit A to the application become effective on September 15, 2015, subject to refund. Nevada Power has also requested that it be authorized to issue bill credits to customers of record on the date the final order is issued in this docket and paid during the customer's next full billing cycle after the effective date of the final NEM2 tariffs, if a bill credit is necessary.

During the 2015 Session of the Nevada Legislature, representatives of the rooftop solar industry stated that the industry could adjust to "new rules" quickly after the new rules were released.²⁹ As of the date of this filing, the NEM2 rules and rates – together with the three-part rate structure preference established by SB 374 – are known. The fact that the Commission has the power and authority to modify those rules and rates creates no more uncertainty with respect to the NEM2 rules and rates than that which already exists under NEM1. Before SB 374, NV Energy's rates and rate design were subject to revision by the Commission. The Commission has plenary authority to establish just and reasonable rates; the Commission has the power to change NV Energy's net metering rules and rates after investigating such rules and rates and determining that the rules and rates were unjust and unreasonable;³⁰ and the Commission has the authority to change NV Energy's rate design, as well as the power to adjust the percentage of fixed costs that are recovered through fixed charges and establish demand charges, which have been used in Nevada for more than six decades. Moreover, under Nevada law, two elements – the base tariff energy rate and the deferred energy accounting adjustment – change every three months,³¹ other elements of NV Energy's rates – the charge associated with the temporary renewable energy development trust, renewable energy program rates, and energy efficiency program and implementation rates – change annually, and NV Energy's base rates are subject to change at least every three years.³² These changes in rates, rules and rates design apply to all residential customers, including NEM1 customers. Accordingly, NV Energy's proposal does not create any uncertainty for NEM2 customers that did not exist for NEM1 customers.

NV Energy's proposal provides for a transition between NEM1 and NEM2 in a manner that is transparent and understandable for customers.

D. A Previous Cost-benefit Report Did Not Evaluate the Cost of Providing Reliable Electric Service to Customer-generators Who Purchase Some, but not All, of Their Electric Energy From the Companies.

As shown in the MCS, customers-generators who purchase some, but not all of their electric energy from the Companies have unique service and cost characteristics. NV Energy's NEM2 rules and rates recognize and respond to the distinctive attributes and needs of partial requirements customers.

²⁹ See May 20, 2015 Hearing Before Assembly Commerce and Labor, recording of hearing at approximately 3:32:00; http://nvleg.granicus.com/MediaPlayer.php?view_id=14&clip_id=4959.

³⁰ See Nev. Rev. Stat. § 704.120 (2013) (authorizing the Commission to investigate the rates and schedules of a utility and, when such are found to be unjust or unreasonable, to fix and order substituted "therefore such rates. . . or schedules as shall be just and reasonable").

³¹ See, e.g., Nev. Rev. Stat. § 704.110(10) (2013).

³² *Id.* § 704.110(3) (2013).

In 2013, in the same legislation that increased the net metering cap from two percent to three percent,³³ the Nevada Legislature directed the Commission to investigate the costs and benefits of net metering.³⁴ To fulfill this obligation, the Commission opened Docket No. 13-07010 and supervised an analysis prepared by Energy and Environmental Economics, Inc. (“E3”). The Commission then issued a report, which was subsequently adopted through an order issued September 30, 2014. The order and report identified nine key points about DG, net metering and cash-incentive programs in Nevada. Those points are: (1) NEM systems “are a small percentage of generation as of the end of 2013, but [should be] expected to grow rapidly over the next three years;” (2) NEM “increases the overall cost of energy for the State of Nevada;” (3) NEM “has little impact on emissions due to renewable portfolio standards requirements for Nevada;” (4) customer-generators who receive little or no cash incentives will “pay more than they would have otherwise for energy over the life of the installed system;” (5) the impact of NEM on “non-NEM participants varies by vintage of the NEM system;” (6) NEM “results in lower utility revenue requirements” primarily because a utility must generate less electricity; (7) NEM “has few macroeconomic impacts;” (8) customer-generators “have higher than median incomes;” and (9) the impacts of Senate Bill 123 from the 2013 session “were not considered” in the E3 analysis.³⁵

While some of the key takeaways listed by the Commission have gone underreported, a portion of the E3 analysis has often been quoted: “We estimate a total [net present value] benefit of 2004-2016 NEM systems to non-participating ratepayers of \$36 million during the systems’ lifetimes.” Much of this identified benefit was derived from the comparison of DG to utility-scale renewable energy at an assumed cost of \$100 per megawatt hour.³⁶ In particular, one key point – that the E3 analysis did not consider the impacts of SB 123 – is particularly important to discuss and must be taken into consideration. The results of the first two requests for renewable energy proposals required by SB 123 demonstrate that the costs of utility-scale solar generation has declined significantly since the E3 analysis was prepared. NV Energy has entered into power purchase agreements with renewable energy developers – one at a 20-year fixed price of \$46 per megawatt hour and one 20-year contract with a first-year price of \$38.70 per megawatt hour that escalates at 3 percent annually. When compared to current prices for utility-scale solar projects, the benefits calculated by the E3 analysis reverse, and show a negative value – or detriment – to non-participating customers.³⁷

The E3 analysis itself recognizes this fact. Because there was “a fair amount of uncertainty surrounding the cost of procuring utility-scale renewable resources,” in Section 4.5.5 E3

³³ Assembly Bill 428 (2013), Section 24.

³⁴ Assembly Bill 428 (2013), Section 26.5.

³⁵ Commission Report at 2-4, Docket No. 13-07010 (iss. September 30, 2014).

³⁶ “Consequently, the relative capital costs of NEM systems and utility-scale renewables are a key driver of the cost-effectiveness results.” E3 Analysis at 129.

³⁷ Recent studies corroborate this conclusion. See Lazard’s Levelized Cost of Energy Analysis – Version 8.0 (noting that utility-scale solar development “could be a particularly cost effective way of limiting carbon emissions” while “rooftop solar and solar thermal remain expensive, by comparison”); see also Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado’s Service (noting that utility-scale solar photovoltaic systems are “significantly more cost effective” than rooftop PV systems “as a vehicle for achieving the economic and policy benefits of PV solar”).

discusses its “sensitivity” analysis comparing the cost-effectiveness of NEM to utility-scale projects with a price of \$80 per megawatt hour.³⁸ After doing so, the E3 analysis concludes that the difference between an \$80 per megawatt hour contract and the base case is enough to switch net benefits to net costs.³⁹ In the \$80 per megawatt hour scenario, the net benefits turn negative and the net cost of NEM exceeds \$200 million.⁴⁰ Because the benefit-cost relationship is linear, at \$60 per megawatt hour, the net cost exceeds \$400 million.⁴¹ And, when utility scale prices drop below \$50 per megawatt hour, net costs of NEM would exceed \$500 million. The E3 analysis, consequently, does not support the proposition that existing NEM1 rules do not unreasonably shift the cost of providing electric service away from customer-generators to other customers.

To the contrary, the E3 analysis confirms that NEM1 rules do unreasonably shift costs from customers who install renewable DG even though E3 did not prepare a cost of service study for partial requirements customers.⁴² The E3 analysis provides, “Rate structure plays a large role in the overall cost impact to both participants [*i.e.*, customer-generators] and non-participant” customers.⁴³ Recognizing this, the E3 analysis evaluated “two plausible sets of alternative future rates, designed to recover a higher portion of utility costs through fixed charges.”⁴⁴ In both cases, the total value of monetary benefits to non-participating customers increased in significant amounts.⁴⁵ In this regard, the E3 analysis supports the conclusion that NEM1 rules negatively impact customers who do not install DG by shifting the cost of providing electric service away from customer-generators.

E. NV Energy’s Filing Does Not Impose Any New Terms and Conditions of Service on Customer-generators who Qualify for NEM1.

Pursuant to subsection 3 of Section 2.3 of SB 374, the Commission may determine which terms and conditions of NEM2 service, including the rate structure and rates, apply to NEM1 customers. Specifically, subsection 3 provides:

In approving any tariff submitted pursuant to subsection 1, the Commission shall determine whether and the extent to which any tariff approved or rates or charges authorized pursuant to this section are applicable to customer-generators who, on or before the date on which the cumulative capacity requirement described in paragraph (a) of subsection

³⁸ *Id.* at 129.

³⁹ *See id.* at 129 (“As shown in figure 42, this assumption about PPA pricing has the potential to substantially impact results. In the RIM, TRC, and SCT, the difference between a low PPA price and high PPA price is enough to switch from net costs to net benefits.”)

⁴⁰ *Id.* at 130.

⁴¹ *Id.*

⁴² *See* note 30, above.

⁴³ E3 Analysis at 122.

⁴⁴ *Id.* at 123.

⁴⁵ In the first scenario, the monetary value of benefits to non-participating customers increased by 1/3 or approximately 33 percent. In the second scenario, benefits increased by 2.64 times, or 264 percent. *Id.* at 124.

1 of NRS 704.773 is met, submitted a complete application to install a net metering system within the service territory of a utility.⁴⁶

In this filing, NV Energy does not ask the Commission to apply any of the terms and conditions of NEM2 service to customer-generators eligible for NEM1. Accordingly, the rights and obligations of NEM1 customers remain unchanged.

The following sections of this narrative further explain the stated policy goals and filing requirements and how they are achieved both in conceptual terms and in application. Section 2 provides a discussion of cost of service and rate design policy as well as an overview of the methodologies used. Sections 3 and 4 go further into detail on the implementation of marginal cost, rate design and the development of the hourly shapes used for cost allocation. Sections 5-10 discuss and support the inputs to the cost allocation. Section 11 describes the new tariffs and tariff modifications.

SECTION 2: ECONOMIC ANALYSIS

A. Marginal Cost of Service and Rate Design Policy

The underlying methodology for both marginal cost of service and rate design used for this filing is consistent with that traditionally filed and approved in “”general rate cases with a few adaptations to accommodate the costing and rate design needs for the new NEM2 classes. The general MCS methodology was described in Docket 14-06009 and addressed by the Commission in Procedural Order No. 2. The starting point for this MCS is the MCS filed by Nevada Power in Docket No. 14-05004. In compliance with both the commitments made in Docket 14-06009 and requirements set out in SB 374, the MCS contains certain updated inputs and new inputs necessary to add the new NEM2 classes.

This filing develops cost of service and cost based rates for the subset of DG customers who qualify and apply for NEM2 service. The mechanics of NEM1 and NEM2 service, including metering and billing, are discussed in Attachment A. Most NEM1 customers today have solar generation, with a relatively small portion, mostly at Sierra, having wind generation. The unique billing, metering and banking of kilowatt hours (“kWh”) associated with the NEM1 and NEM2 tariff paradigms create costs that are not incurred to provide electric service to full requirements customers.⁴⁷ These costs, such as the expense associated with incremental banking, administration, billing and record keeping; need to be recognized in computing the cost of providing electric service to NEM customers. NV Energy described the anticipated modifications necessary to develop costs for new NEM2 classes in Docket No. 14-06009. NV Energy stated:

The cost of service methodology should remain basically the same as those previously approved by the Commission, which form the foundation for current rates for all other NVE customers. In Nevada, rates are based

⁴⁶ SB 374, Section 2.3(30); *see also id.* Section 2.95(5)(c).

⁴⁷ Any regime that provides value to NEM customers for excess energy creates additional costs that are not incurred to provide service to a full-requirements customer. For instance, a regime that provides a per kWh payment requires accounting systems to register excess energy deliveries, accumulate such deliveries, assign a value to the deliveries, and provide a payment to the customer-generator for the deliveries.

upon marginal costs. The marginal costs are identified by the four functions -- distribution, transmission, generation capacity and energy -- and are ultimately reconciled to the embedded functional revenue requirements. All marginal costs, with the exception of customer and Rule 9 facilities cost, are developed on an 8,760 hourly basis. The overall structure and analytical approach in the most recent marginal cost studies of both Sierra and Nevada Power should require little overall modifications to separately identify the cost of service for DG and NEM customers, not currently served under the existing standby tariffs. However, the development of capacity costs should reflect the reliance on utility capacity similar to the development of these costs for non-NEM partial requirements customers where the total hourly load requirement for which capacity is reliably planned is modeled. An adjustment should be made for the expected availability of the DG resource during peak periods by re-scaling the load shape used for generation capacity costs. To appropriately identify the costs associated with providing service to customers who install self-generation that provide energy while the sun shines or the wind blows but remain reliant on the grid for capacity and one hundred percent of their energy needs when their generator is not operating, the full cost of investments made by the Companies to meet these obligations must be measured. Failure to properly identify and reflect the cost of partial requirements customers will ultimately result in rates to full requirement customers that are inflated beyond their cost of service.⁴⁸

NV Energy continued:

The Company agrees with BCP's Comments that externalities (*e.g.* societal, economic, and environmental benefits and costs) should not be included in the proposed cost of service analysis that will develop costs for NEM customers.⁴⁹ Rates are based on marginal costs and do not reflect societal, economic or environmental benefits for any class. The Companies in conducting a MCOS do not attempt to assess and reflect the saturation of energy efficiency measures taken, demand response programs, charitable contributions, or other investments our customers make that are charged for electricity in other classes of service. No such societal costs are included in the cost recovery NV Energy's rates provide, and, therefore, do not warrant any offset. Instead, all customers receive the direct benefits from their participation and investment in such things. No exception should be made for NEM/DG customers.

The Companies also agree with BCP's statement that "for rate design purposes, a cost of service study needs to assign costs (revenue

⁴⁸ Comments of NV Energy, Docket No. 14-06009 (filed Jan. 14, 2015).

⁴⁹ Comments of the Bureau of Consumer Protection, at 2, Docket No. 14-06009 (filed Jan. 14, 2015).

requirement) to all classes of service in a manner that is consistent, equitable and reasonable.”⁵⁰ The Company does agree with BCP’s second recommendation that updated load profile and hourly PROMOD data should be used in the cost of service study analysis developed in this proceeding.

NV Energy has produced an updated MCS for each utility based on the last approved MCS to comply with both the commitments made in Docket 14-06009 and the requirements of SB 374. The details of Nevada Power’s MCS, its inputs and results are discussed throughout the remainder of this supporting narrative. Once the marginal cost of service was developed for these new partial requirements NEM classes, NV Energy designed the standard and optional NEM2 rates based on that cost of service. NV Energy’s primary goal in designing electric rates for all its customers is to establish prices that accurately reflect the cost of providing electric service. A fair and equitable rate design recognizes that all costs are not the same – some vary based solely on the fact that Nevada Power provides service to a specific type of customer, others vary based on the customer’s demand requirements, while other costs vary based on the volume of energy required by the customer. To ensure equity among customers, different types of charges must be developed to reflect the different categories of costs. Costs that do not change when a customer uses more or less electricity should be charged on a fixed or flat monthly basis. Costs that vary based on demand should generally be charged on the demand the customer places on the system. Costs that change when more or less energy is used should be charged based on how much is used and, possibly ideally, when it is used – on a per kWh or energy basis.

B. NEM2 Rate Design

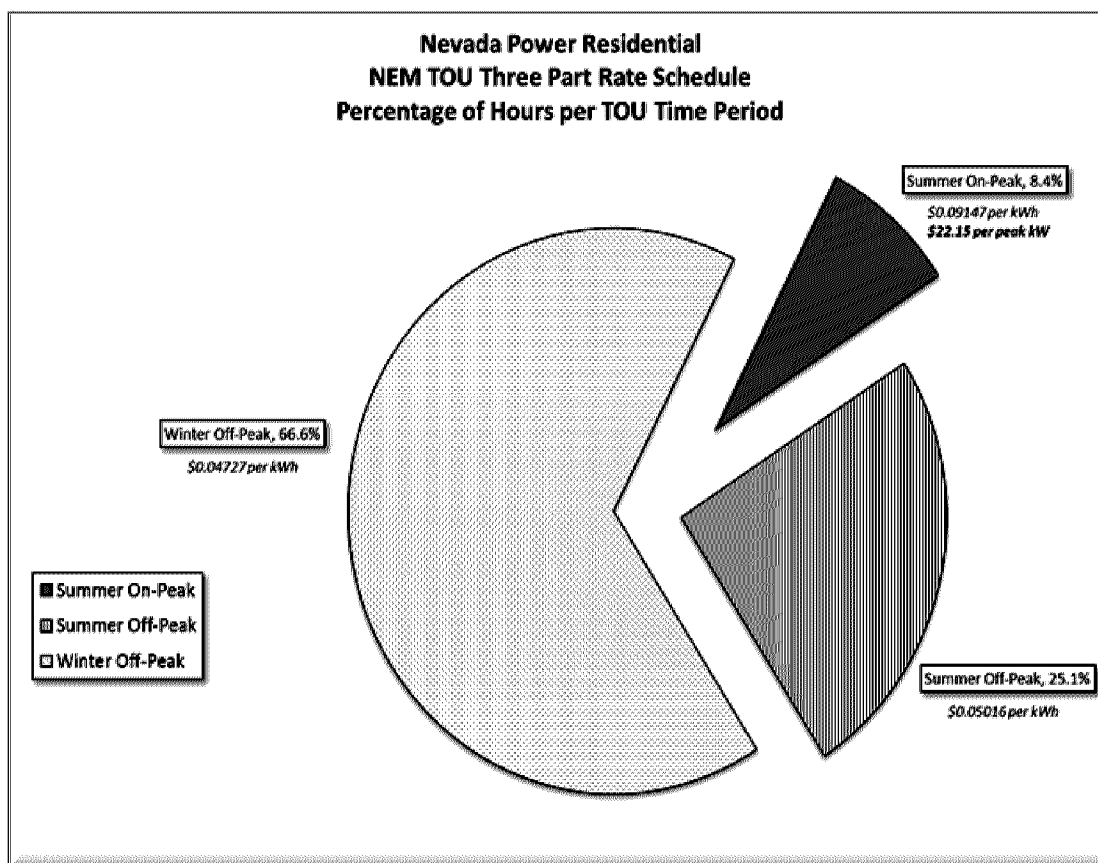
SB 374 expressly specifies that NV Energy may file a multi-part rate with a basic service charge (“BSC”), a demand charge, and an energy charge. The statute also gives the Commission the flexibility to establish just and reasonable rates. NV Energy’s filing proposes a standard NEM2 rate for residential and general service customers that consists of a BSC, a maximum demand charge, an energy charge, and a generation meter charge applicable to non-incentivized customers. The filing also proposes an optional NEM2 rate for residential and general service customers that also contains on-peak demand and time of use (“TOU”) energy charges. Both rate schedules are filed for each of the new NEM2 rate classes. Rate structures with a sufficient number of components to reflect different cost causation will result in customers within a class paying bills that are reflective of the cost incurred to serve the customers and will reduce subsidies among customers within the class. The standard and optional NEM2 rates thus better reflect cost causation than the existing NEM1 rates. NEM2 reduces or eliminates any unreasonable shifting of costs from customer-generators to other customers. The NEM2 tariffs also reduce, if not eliminate, intra-class subsidies (*i.e.*, cost shifting between NEM customers) and are based on an MCS allocation that is fair and balanced. As discussed below, the load shapes that drive the cost allocations reflect, where appropriate, diversity in NEM loads. For marginal generation and energy cost development, the load shapes only reflect the hourly loads delivered from the utility to the NEM customers, net of the NEM customer’s generation, which gives the NEM2 customers full benefit of their generation in that cost development.

⁵⁰ *Id.* at 2.

The proposed rates provide NEM customers an incentive to install efficient renewable DG in a manner that can provide benefits to all users of the electric grid, and provides the NEM customer a choice in energy supply and rates paid to the utility. The standard NEM2 maximum demand charge reflects certain distribution demand costs, 100 percent of transmission demand costs, and 62 percent of generation demand costs. The energy charge reflects 38 percent of generation demand cost and marginal energy cost. In contrast, the optional NEM2 maximum demand charge only reflects certain distribution demand costs. The TOU demand charge reflects 100 percent of transmission and 62 percent of generation demand costs.

As shown in the Chart 2-1, the on-peak period at Nevada Power represents only 8.4 percent of all hours in the year. The optional NEM2 rate provides customers a choice that can provide additional bill savings for the customer in a fair and equitable matter by encouraging the customer to optimize the design of their system to reduce demand and energy requirements in those hours.

Chart 2-1. Nevada Power Percentage of Hours per TOU Periods



Cost based price signals also generally incent all customers to use electricity efficiently and, at a minimum, have them pay a fair amount for what they use regardless of whether they choose to be efficient or not. If customers face a reasonable approximation of the marginal cost of providing electric service at any point in time, then the incremental use of energy at that time by those customers implies that the incremental consumption was economically efficient because the marginal value of consuming that unit must have been greater than the marginal cost. Table

3-5, below, shows the average bill comparison for the single family residential NEM2 customers based on the billing determinants of the existing NEM1 customers. That table demonstrates that NEM2 customers can continue to obtain utility bill reductions. With NEM2 proposed rates, customers are expected to respond to the new price signals to some degree, resulting in greater bill reductions.

Rate schedules that have fixed and capacity-related costs recovered through variable energy rates will unavoidably shift a portion of those costs from customers with below average energy use to customers with above average energy use. From an efficient pricing and cost recovery perspective, fixed customer and capacity-related costs should be recovered in customer and demand components, not in the volumetric energy charges. A cost based rate schedule with appropriate customer and demand charges in addition to energy charges is a superior rate design structure to that of the existing simple two-part rate structures that exist for full requirements residential and small general service customers at both companies. All other things being equal, a three-part rate structure that includes a cost-based customer charge and a demand charge has lower energy charges than those that result under the two-part rate counterpart. Some might find this result contrary to the goal of energy efficiency and conservation, and wish to continue the practice of inflating the energy rate component above the cost based level.⁵¹ However, a customer responds not only to energy rates, but to the overall cost of service and the overall bill. Both demand and energy charges are avoidable. Bill reductions customers receive from any action they take to modify their electric usage should be tied to the resulting demand and energy cost reductions. For this to occur there has to be a rate structure with both demand and energy rate components. Commercial rate schedules have had demand charges as an accepted and equitable means of charging capacity costs to customers for decades, without claims that it thwarts energy efficiency and conservation.

In Docket No. 15, 03010, the Companies stated:

The general goal of effective rate design is to develop rate structures and design rates that reflect the cost of service. The Commission has successfully moved class revenue requirements toward cost based levels with differing inter-class subsidies at the two utilities. The subsidy represents the difference between cost based class revenue requirement and approved class revenue requirement. For Sierra, cost based class revenue requirements have been attained with only one legislatively mandated inter-class subsidy of \$9.2 million to the optional interruptible irrigation ("IS-2") class. At Nevada Power, the single-family residential ("RS") class has for many years received a relatively large inter-class subsidy, which today is estimated to be approximately \$52.9 million. Along with eliminating interclass subsidies to the extent possible under Nevada law, rate design improvements resulting in more cost based rate structures and more efficient price signals to customers should be introduced, including those that recover a greater proportion of fixed costs

⁵¹ NV Energy's load research shows that the average residential NEM customer actually uses more energy annually than the average full-requirements residential customer. *See* Section 3, Chart 3-5, below.

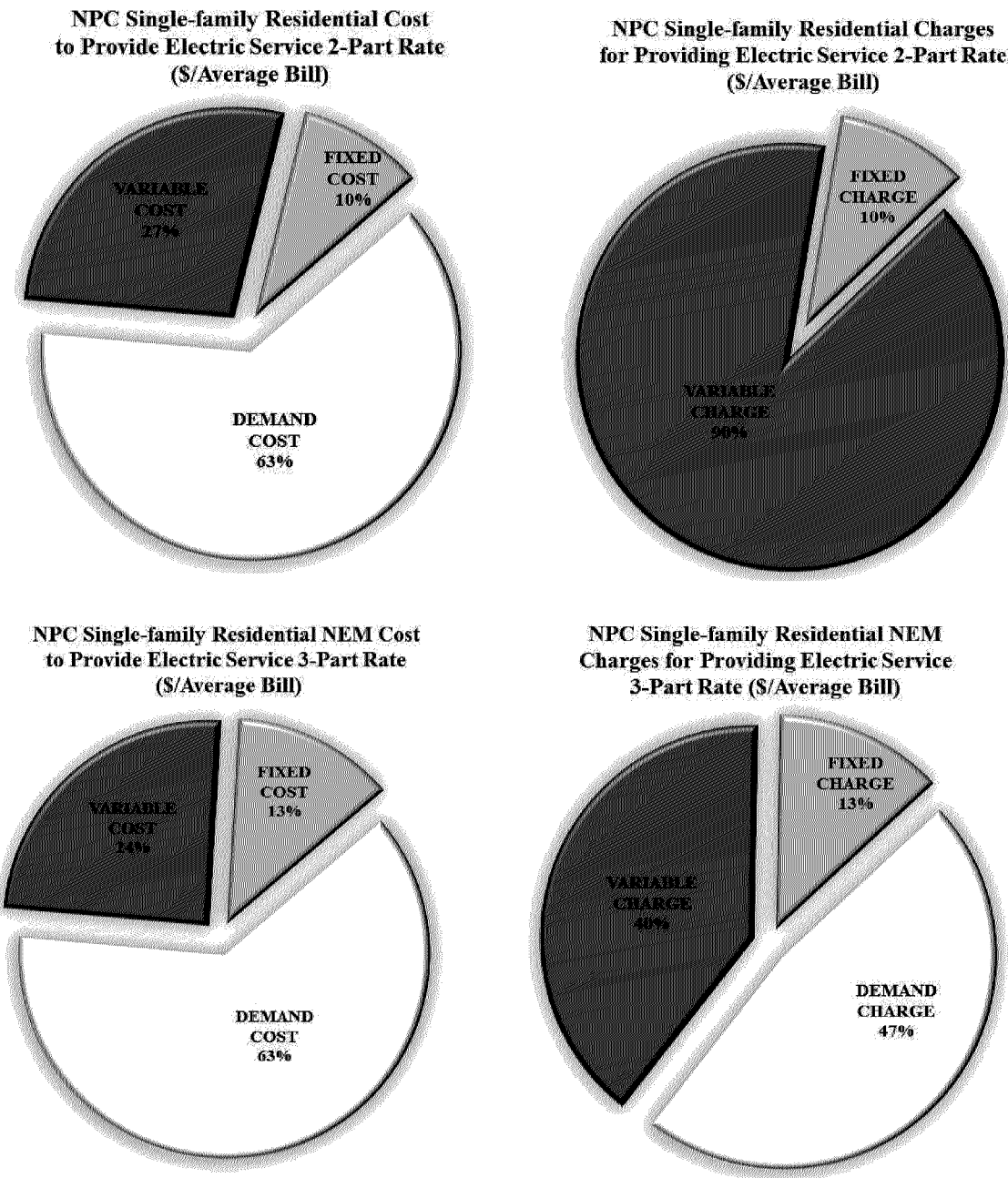
in customer and demand-related billing elements and those that inform customers of the varying costs to provide electric service across seasons and time of day ...⁵²

Reducing subsidies between and within classes of customers is and always has been an accepted goal of sound rate design. To integrate DG into the grid under a net metering construct in a manner that provides maximum value and minimum harm to the grid and the customers it serves, service under the NEM2 rates must reflect the NEM customer class cost of service and service characteristics. A properly designed rate will encourage NEM installations, operation and maintenance that benefit the NEM customer in a manner that does not harm other customers and provides benefits at least some of the benefits to the grid that advocates claim. A sound NEM rate will provide bill reductions that correlate with energy and demand cost reductions. Clear price signals will allow customers to determine if NEM installations are uneconomic or if they benefit the customer without subsidization by other customers. SB 374 requires that rates be set in a manner that does not unreasonably shift costs to other customers (including low-income and fixed-income customers) who may not have the means or the authority to install self-generation or who choose not to add solar panels or wind turbines on their premises.

The NEM2 rates proposed by Nevada Power in this docket meet these goals. The standard NEM2 rate, by having rates that directly correlate to cost of service calculated for the unique NEM2 classes, reduces intra-class subsidies, aligns bill reductions with cost reductions and avoids unreasonable shifting of costs to other customers. Likewise, the optional NEM2 rate provides a means for TOU energy and on-peak bill reductions for NEM customers and motivates customers to reduce purchases from the grid during the on-peak period. The NEM2 rate should motivate customers to avoid sharply ramping up purchases from the grid as generation production wanes, and to deliver self-generated electricity into the grid at the time of greatest benefit to the system and the customers it serves. The charts below demonstrate that a two part rate design is insufficient to accurately reflect cost causation and that a three-part rate structure more closely mirrors cost causation.

⁵²Comments of NV Energy, Docket No. 15-03010 (filed May 21, 2015).

Chart 2-2. Comparison of Costs to Charges for Two Part and Three-part Rate Structures



The Company will develop an education plan to help customers understand the new rates and to provide information that will assist them in understanding how they may assess the potential impact on their utility bill of adding DG. Additionally, the application materials for NEM2 service will be revised to explain the standard and optional NEM2 rate offerings so the customer can make an informed decision.

C. NEM Structure

New NEM2 customers will pay rates that reflect the cost of serving them and that are reflective of their service characteristics. Similar to existing NEM1 rules, both the default and optional NEM2 tariffs will use a kWh banking system for excess energy delivered by the NEM customer. Demand charges will be assessed on the delivered 15-minute demand. The proposed rate design includes 38 percent of generation costs in the energy charge, treating distributed renewable generation similar to utility-scale solar. Preliminary data indicates that NEM production at the time of system peak is below the 38 percent of the nameplate capacity that NV Energy uses for utility-scale solar facilities in its long-term planning capacity requirements. Ideally, NV Energy would rely on the actual, experienced production coincident with the system peak and will update this percentage in future general rate cases when sufficient data is available.

Both the standard and optional NEM2 tariffs will require customers who request NEM to permit the installation of generation meters. Generation meters will facilitate compliance with SB 374's requirement that Nevada Power assess the effect of DG on its distribution system, accurately measure the cost of service, and could aid in demonstrating compliance with the Clean Power Plan.⁵³ The optional NEM2 rate will require a commitment to the schedule for a period of one year, similar to other optional TOU tariffs.

D. Marginal Cost of Service Unique to Net Metering Service

NEM customers have a distinctly different load shape, load factors and billing determinants when compared to the average full requirements residential or small general service customers for whom the traditional full requirements two-part rates were designed. NEM customers obtain a portion of their total electric consumption from their own generation reducing their reliance on energy deliveries from the utility, but do not necessarily reduce the capacity requirements necessary to serve them, especially for distribution and transmission capacity, and to a lesser extent generation capacity. A three-part rate structure will reduce intra-class subsidies and the NEM1 subsidy. As previously noted, an efficient rate design needs to recognize the nature of costs being imposed and have a rate structure that recovers the cost associated with the service provided from the customers that impose them.

To incorporate the new NEM2 classes into the MCS, hourly load and cost allocation shapes were created for these new customers using the installed capacity and experienced 15-minute interval load⁵⁴ and production data of the existing NEM customers. For single family residential NEM customers Nevada Power had sufficient data from its existing NEM customers, but for large single family, multi-family and small general service customers Nevada Power used the load shapes from the otherwise applicable schedules ("OAS") sample data to supplement the NEM data. As with all classes, especially optional classes, the class characteristics change over time based on the actual class participants' characteristics. The electric service and load

⁵³ Section 111(d) of the Clean Air Act, 42 U.S.C. 111(d), as implemented by the Environmental Protection Agency Code 111(d).

⁵⁴ All available experienced 15-minute interval data for existing NEM1 customers was utilized to develop hourly shapes for those existing NEM1 customers who did not have complete or available 15-minute interval data.

characteristics of each class is revisited and reflected in cost of service and rate design in each general rate case.

There are class characteristics that are unique to NEM service that must be reflected in marginal cost of service. The customers taking service under these new rate schedules will receive partial requirements service from the utility, and the cost of such service includes costs that are not common to full requirements service. The cost to the utility for being ready to back up the customers' renewable generation when it is unavailable and the cost of providing the energy banking service must be captured and appropriately recovered through rates. These costs are similar, in general, to back-up costs, which are incorporated into the cost of service and rate design for larger partial requirements customers (*e.g.*, the standby service riders). For these large standby customers, costs are developed using their total load, absent on-site generation, for all components of service by using the load shape of the otherwise applicable class. The demand costs are recovered through a combination of maximum, reservation, and TOU demand charges. NV Energy in this filing is recognizing the unique costs of serving new NEM customers by creating distinct classes of service and updating the MCS in this filing to appropriately identify those unique costs.

For NEM and other partial requirements customers, marginal distribution, transmission and generation demand costs must reflect the fact that Nevada Power's public service and reliability obligations require that it have facilities in place to meet the partial requirements customer's total loads. Additionally, identifying the use of capacity on the utility grid associated with the flow of excess energy by an NEM customer solely for that customer's future financial benefit is necessary to fully develop an appropriate approximation of the distribution portion of banking costs. This is done as part of the development of distribution demand costs in this filing. 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.

E. Marginal Customer Cost

Marginal Customer costs are developed for NEM2 classes of customers in the same way that they are developed for all other classes of customers. As discussed in Section 3, MCS inputs reflective of the cost of service to the NEM2 classes were developed including meter costs discussed in Section 7 and updated customer service and customer accounting costs through an updated Customer Weighting Factor Study discussed in detail in Section 5.

F. Marginal Facilities Cost

NV Energy's distribution system required to serve a customer has three primary components: 1) the local area distribution facilities (Rule 9 investment) that are the basis of marginal Facilities cost ("Facilities") including the service line, service transformer and secondary lines to the service transformer, plus some local feeders that tie service transformers to the primary distribution system; 2) distribution substations; and 3) the primary substation feeders that connect one or more local areas to a distribution substation or to the transmission system.

The Companies size additions to the distribution system based on maximum loading on the grid. The Facilities cost in the MCS reflect the installed investment made by the Companies' under Rule 9 of the Companies' tariffs governing line extensions. The investments are limited by Rule 9 to a fixed amount per customer in the residential and small general service classes. If the Rule 9 cost exceeds the maximum allowable investment under the Rule, the applicant for the new service is responsible for the excess beyond the Company's maximum investment. If a new NEM customer requires additional investment to connect their load/generation to our system, the applicant will pay the additional costs that exceed the maximum investment allowance under Rule 9. If an existing customer switches to NEM service, and modifications or additions to the distribution system are necessary to provide for the change in service, the customer will be responsible for the additional investment going forward. Changes to the Company's Rule 15 reflect this cost responsibility. Therefore, the marginal Facilities investment and the resulting annualized marginal Facilities cost for the NEM classes are the same as those for the OAS. The changes to Rule 9 add the new NEM2 classes but retain the same Rule 9 Allowance. Allowances are revisited for all customer classes at each GRC going forward. The current NEM1 rules shift these costs to other customers.

G. Marginal Distribution Demand and Banking Costs

Distribution substations and primary feeders (including high voltage distribution) must be sized to serve, within established standards, at least the maximum anticipated total load of the customers served through them, including NEM customers who intend to serve as much of their total load as possible through their own on-site generation. It is inappropriate to base the marginal distribution demand costs for NEM customers on their deliveries from NV Energy alone. For NEM customers, these components must also be sized to meet the customer's total load and reverse flow requirements for excess customer generation being absorbed by and "banked" in NV Energy's system. Using only the deliveries or simply the total load would result in continued subsidies from non-NEM customers to NEM customers. For this reason, NV Energy has developed the total load plus excess energy shape

To reflect the full distribution demand cost of providing partial requirements service to net metering customers, load shapes were created for these classes which reflect both their back-up demand requirements and the additional requirements that are created when NEM customers place excess energy from their own generation onto the grid to facilitate their banking, adding to their overall use of the distribution system. For each 15-minute interval, the load shape created for costing purposes is the maximum, for that interval, of either the total load or excess generation returned to the NV Energy system. The total load is calculated for each 15-minute interval as NV Energy's deliveries, plus the customer's own generation, less energy received by NV Energy back onto the distribution system. These 15-minute interval load shapes represent the maximum potential burden on the distribution system and are reflective of the cost of adding distribution capacity. The load shapes serve as the cost basis for the distribution demand cost component of the MCS, much as delivered load shapes would for any full-service class. For ease of calculation, the distribution related banking cost is calculated as part of the marginal distribution demand cost. This component of cost is separable and small in magnitude, but is the portion of banking cost appropriately included with distribution demand cost as it represents an increased use of the distribution system. The detailed discussion of marginal costs in Section 3 presents and defends the mechanics of this adjustment to the MCS.

H. Marginal Transmission Demand Costs

Conceptually, marginal transmission demand costs are impacted by service to partial requirements customers in much the same way as marginal distribution demand costs. However, there may be some lessening of the back-up requirement given the greater diversity at the transmission system level. Accordingly, rather than using the same total load shape Nevada Power uses as the cost driver for marginal distribution demand cost, an adjusted lower load shape as the cost driver for measuring marginal transmission demand cost. In comparison to large scale energy generators and purchased power contracts, NEM customers benefit by having no required commitment for performance or reliability, and by being able to lean on the utility for reliability. If a NEM customer chooses not to maintain a DG system, or installs it improperly, they have certainty that they can rely on the utility for as much or as little energy as they need. The utility must plan on any given day or hour to meet all or none of that customer's requirements. In this way, the energy generated by the customer has significant value to the net metered customer since it offsets their energy rate, but no transmission capacity value to the utility since the utility can never know how much of that energy will be delivered back to the system, and the utility has the responsibility to bank whatever is received for the individual NEM customer's future benefit. Therefore, to address the standby nature of the transmission service provided and recognize some diversity, an appropriate transmission load shape for cost development was determined to be the total load shape, scaled downward to reflect the difference between the non-coincident peaks of the total load shape and the delivered load shape (net of contemporaneous generation serving load behind the meter).

For transmission, the excess generation (banking aspect) that exceeds the total load for an NEM class is not included in the NEM load shape. Further, using the entire total load shape as the cost driver for transmission demand costs implies that NV Energy is reserving 100 percent of the transmission plant required to serve the net metered class' total load. To recognize load diversity in transmission back up requirements for a class, Nevada Power reduced the total load shape before using its adjusted values as the cost driver for marginal transmission demand costs. In hours within each TOU period Nevada Power multiplied the hourly total load kWh by the ratio for that TOU period of the maximum 15-minute delivered KW to the maximum 15-minute total load kW. The adjusted total load kWh are constrained to never be less than the corresponding hourly delivered kWh.

I. Marginal Generation Demand Costs

The marginal generation costs for the new NEM2 classes are computed in the same way marginal generation costs are computed for other classes, but using only the delivered energy (excluding generation contemporaneously serving load behind the meter). For purposes of our marginal generation cost development, using the delivered load shape reflects the capacity and energy contributions to NV Energy's system by DG. It does not reflect any back-up reservation demand cost in recognition of the load diversity at the generation level, however using the fully diversified delivered load shape for the NEM classes to derive the marginal generation demand costs does not fully identify all the generation cost that should be attributed to NEM customers. As Nevada Power has not quantified the backup or load following cost associated with generation capacity, the MCS does not attempt to capture this cost. Because the system peaks are at a time later in the day, when solar production is steeply declining, the use of the NEM

delivered load shape still results in significant capacity costs being allocated to the NEM class. This is a balanced approach for this filing.

J. Marginal Energy Costs

The MECs for the new NEM2 classes are computed in the same way marginal energy costs are computed for other classes, using only the delivered energy. Essentially, NV Energy incurs MECs contemporaneous with the energy produced and delivered to the customer, so there is no “backup” energy cost. Hourly MECs, including losses, are identified by voltage level for all classes, including the new NEM2 classes at issue in this proceeding. For each class, a load-weighted average MEC is computed for each TOU period, using that class’ specific hourly energy deliveries from NV Energy as the weights on the hourly marginal costs within the TOU period. Each TOU MEC is then multiplied by the class’ corresponding total energy delivered by NV Energy for that period. This yields the class’ full MECs for each TOU period, and then for each season and for the whole year.

K. Marginal Demand Costs Not Captured

As discussed in Section 9, as DG penetration increases, costs incurred to protect and strengthen the grid and manage situational impacts, such as handling two-way power flows and high levels of DG installation on distribution lines, will be incurred. As higher concentrations of DG are seen in other utilities’ service territories, new impacts on the distribution system have arisen that require remedial action, including changes that push peak hours past sunset when DG is no longer generating. Additionally, as the Companies have to plan to the highest reliability standards, the Companies may need to consider different types of generation that can be quickly deployed to follow additional intermittent resources as NEM concentrations increase. Ultimately, such costs will be included in rates and should be properly reflected in cost of service; however, the Companies have not quantified these costs or included them in this filing except to mention the eventual need to include them and the need for future study of these costs. Please refer to Section 9 – Distribution Design and Planning for more on this point.

SECTION 3: MARGINAL COST OF SERVICE STUDY AND RATE DESIGN IMPLEMENTATION

A. Marginal Cost of Service Study

(1) Overview

As described above, the MCS from the certification filing in Docket No. 14-05004 was the starting point. Under the terms of the Stipulation and Settlement in that proceeding, rates remained essentially unchanged but the MCS was approved. The methodology utilized for this proceeding remains consistent with those which have been vetted and approved in the past by the Commission. This portion of the narrative focuses on the differing cost characteristics of NEM customers. The MCS for Nevada Power has been developed in a manner consistent with the presentation made by Laura Walsh at the May 1, 2015, workshop in Docket No. 14-06009 and in the Company’s prior comments in that docket. The details of the MCS methodology were

discussed in the direct and certification testimonies of Jeffrey Bohrman filed in Docket No. 14-05004.

The MCS that includes the new NEM2 classes is contained in Technical Appendix 1. The MCS is comprised of Tables 1 through 11 and Workpapers 1 through 18, which are found in Appendices A-D to the MCS. The Tables (pp. 1-12) display results by function which are summarized in Table 1. Appendix A (pp.13-23) to Technical Appendix 1 contains the workpapers used to develop marginal energy, generation and other demand costs; Appendix B (pp. 24-39) to Technical Appendix 1 encompasses operations and maintenance (“O&M”) expenses; Appendix C (pp. 40-46) covers customer related expenses and loading factors; and Appendix D (pp. 47-52) contains the price indices, cash working capital, and economic carrying charges.

Technical Appendix 1, Table 1, of the MCS summarizes revenue at full marginal cost by rate class and by the following four functional components: (1) facilities, (2) customer, (3) demand-related (non-revenue distribution feeders, substations, transmission, generation) and (4) energy. These revenues at full marginal cost would be realized if the hourly differentiated prices equal to the Company’s marginal costs were charged to customers in each rate class. These revenues are the end result of the MCS and guide the development of total class revenue requirement and rate design. Marginal unit costs associated with each functional component of service are developed in the MCS tables and workpapers.

While the overriding methodology remains consistent with those used in previous Nevada Power MCS, several updates were made for this filing. These updates, summarized here and discussed in further detail later in this narrative, were determined to either be specifically relevant to the NEM2 customer classes or were deemed necessary to revise outdated and/or stale information.

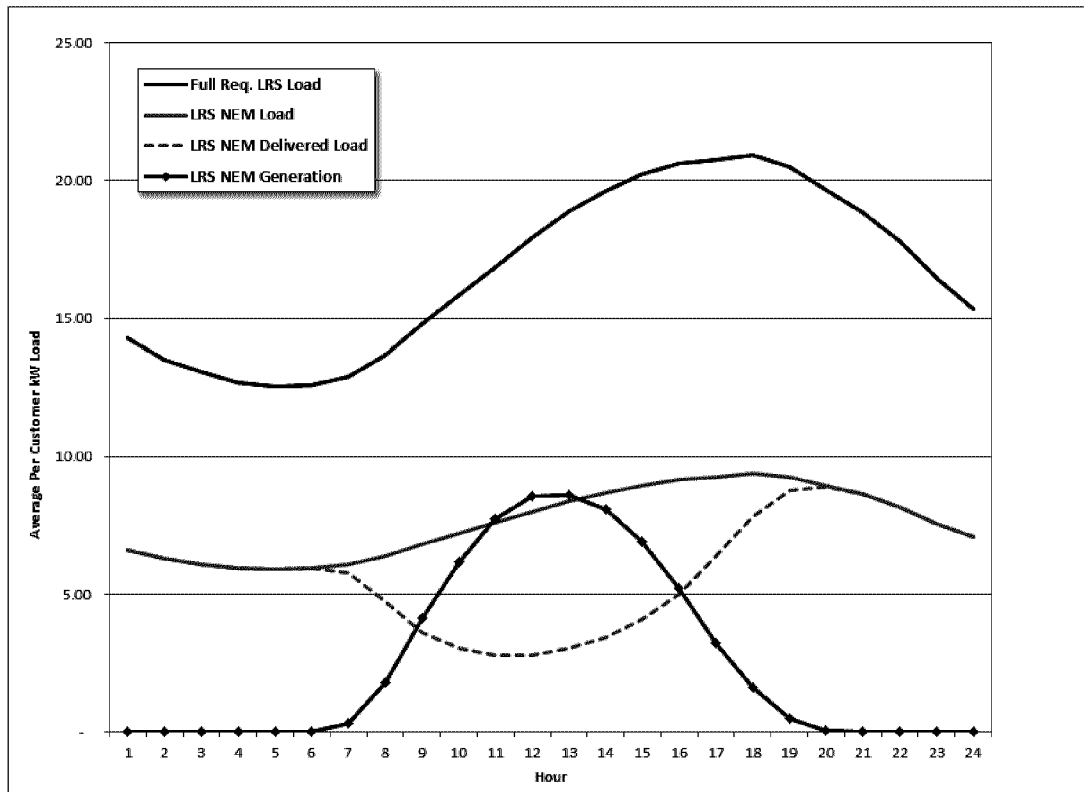
- Four new NEM rate classes, corresponding to the existing full requirements residential (RS, RM and LRS) and small general service (GS) schedules (where most existing NEM1 customers reside) were added to the MCS. While it is also appropriate to develop separate rate classes for all sizes of NEM customers, the issue of the inter- and intra-class subsidies are significantly reduced in rate structures that currently contain demand charges. The NEM1 customers served under the LGS-1 and larger load rate schedules are more appropriately priced since these schedules have cost based customer and facility distribution charge, and TOU demand charges that recover transmission and a significant portion of generation capacity costs. Therefore new rate classes were not established for those large classifications of NEM customers.
- Billing determinants from Docket No. 14-05004 with 12 months ended May 2014 were used in the analysis. Billing determinants for the four new NEM2 classes had to be developed. Because the NEM customers were previously included in the four full requirements rate classes, their billing determinants were removed from the four corresponding full requirements rate classes. The development of the NEM2 billing determinants is described and discussed in detail in Section 4.

- Load shapes for the NEM2 classes used in the MCS were developed for the 12 month period ending May 2015. The load shapes were removed from the respective full requirement class load shapes to reflect the new NEM2 classes. Section 4 provides a detailed description of the development of the NEM load shapes. The load shapes of all customer classes are used in the MCS in conjunction with the hourly system cost responsibility factors and MEC to identify the revenue at full marginal cost for each class by function. These results are the basis for the development of the proposed rate structures and rates for the four new NEM2 rate classes – each with a standard (default) non-time-of-use three-part rate structure and an optional TOU three-part rate structure. The rate design and proposed rates are discussed in the following section.
- The MCS includes updates to the hourly MECs and Loss of Load Probabilities (“LOLP”) from updated PROMOD results. The updated PROMOD results are based on the preferred plan filed by Nevada Power in Docket No. 15-07004. Section 5 discusses the PROMOD updates further. For additional information on the application and use of the PROMOD MECs and LOLP’s in the MCS please refer to the testimony of Jeffrey Bohrman in Docket No. 14-05004.
- The probability of peak (“POP”) system cost responsibility factor has been updated, reflecting the ten years of historical hourly system loads for 2005 through 2014, with the addition of the 2016 forecast year. The POP cost responsibility factor is used to allocate both distribution demand and transmission capacity costs among the classes. Again, please refer to Mr. Bohrman’s testimony in Docket No. 14-05004 for additional information on the development and application of the POP cost responsibility factor in the MCS.
- Meter investment costs now include meter costs specific to each of the four new NEM2 rate classes. The development of this input is described in Section 7. These marginal meter costs were incorporated into the MCS in Workpaper 12 and Table 4, and are reflected in the distribution marginal cost revenues that are used in Statement O (rate design), which is located in Technical Appendix 2. As explained more fully in Section 7, the marginal meter cost (after reconciliation in Statement O) is a portion of the customer-related cost recovered through the proposed BSC for each NEM2 class.
- The Customer Weighting Factor Study (“CWFS”) from Docket No. 14-05004 has been updated to include the new NEM2 rate classes. New surveys of the pertinent departments serving NEM customers were made to determine the relative proportion of customer service and accounts expenses attributable to the separate NEM rate classes. The results were excluded from the costs for the otherwise applicable class. As with the meter cost, the CWFS is reflected in Workpaper 12 and Table 4 of the MCS and the identified costs (after reconciliation in Statement O) will be recovered through the BSC for the new NEM2 customers applying after the cap is reached. The CWFS results and its impacts on the BSC of the new classes are discussed further in Section 6.
- The MCS was updated to reflect the weighted cost of capital that resulted from the settlement (versus what was used in the certification MCS) which affects the

development of the marginal cost revenues, including most directly the economic carrying charge and cash working capital elements in the model.

- The current NEM participants from the LRS customer class have characteristics that differentiate those customers from the full requirements class as a whole. Overall, the eight participants are smaller in size than the otherwise applicable class as a whole. Perhaps more telling, the participants average load factor is 52.4 percent, based on total load, in comparison to a LRS class average load factor of 41.9 percent. Even the load factor of the delivered load 48.2 percent is still significantly higher than the full requirements class. Generally speaking, customers with a higher load factor are more efficient users of both delivered energy and the system's installed facilities resulting in a lower effective cost kWh than the average for the class and will generally benefit from the implementation of demand rates, because of the corresponding decrease in energy rates. Because of these cost characteristics, which are illustrated in Chart 3-1, and as shown in Table 3-6, resulting bill comparisons for the LRS-NEM class show savings for the NEM class versus rates developed from the corresponding full requirements rate schedule.

Chart 3-1. Nevada Power NEM & Full Requirements LRS Customers Annual Average Loads



The following sections discuss the changes to each functional cost of service calculation and the resulting impacts of these updates on the NEM customer's marginal cost of service.

(2) Customer Costs

As is true with all of the functional cost components of the MCS, customer costs are calculated using the same methodology that has been used and approved in past Nevada Power filings. Marginal customer costs include the typical meter investment for each class annualized (using the economic carrying charge rate) and related expenses associated with meters, plus customer accounting and customer service costs. The full development of the marginal customer costs can be found in Tables 3 and 4, pages 3 through 5 of the MCS, and Workpaper 12, pages 42 and 43.

The meter cost used in the development of the marginal customer costs are determined by the meter cost analysis, which is an input to the MCS, the results of which are found in Workpaper 12, page 42. The typical meter investment is provided by the Company's Electric Meter Operations department. All currently installed NEM meters, as well as considerations for future meter installations, were used in developing the cost of a typical NEM meter by rate schedule. The same information was provided for NEM generation meters, which were again developed by rate schedule. As described in further detail in Section 7 (Meter Costs), there were several factors driving the difference in cost between a typical NEM meter and that of the corresponding full requirements class' meter. Among those are additional programming time, additional installation time and labor, including the need for an actual on-site technician in many cases, and additional testing and grid integration time.

In developing marginal customer accounting and customer service cost, the Company has used the results of the CWFS as an input to the MCS in Workpaper 12. The weighting factor results establish the relative per-customer accounts costs and service costs among customer classes. In this case the results of the CWFS were applied to the same historical expense dollars that were used in the last approved MCS.

The results of the CWFS, as revised to reflect the relative costs of NEM customer classes, are discussed in further detail later in Section 6 (Customer Weighting Factor Study). In some areas, NEM customers were less costly compared to their corresponding full requirements rate schedules. Though several areas did demonstrate NEM customers caused customer accounting and services costs that were greater than their counterparts. For instance, the Company's Billing department has dedicated employees fielding customer service phone calls and manually reviewing bills solely for the NEM customer classes. Another cost driver specific to customer services and NEM customers are expenses related to the Renewable Energy department. This department spends a great deal of time and resources administering the Company's SolarGenerations incentive program, reviewing and approving NEM applications, and tracking information specific to NEM customers, as well as promoting customer education to make sure customers are informed of their renewable energy options. These programs and associated responsibilities are discussed in further detail later in Section 6 (Customer Weighting Factor Study) and Section 8 (Renewable Energy Administrative Costs).

The annualized meter investment, customer accounts and services expense, as well as the appropriate cost adders and loading factors used to develop the total annual customer cost are shown in Table 4A, page 4 of the MCS. Table 3-1 shows a comparison of the monthly marginal cost to serve a NEM customer in comparison to the corresponding full requirements customer. With the exception of the LRS-NEM class, which has a lower marginal customer cost than the

full requirements schedule – due to their smaller overall size, the NEM customers have a higher marginal customer cost than the respective full requirements schedule.

Table 3-1. Comparison of Monthly Marginal Costs (from Table 3, page 3 of the MCS)

Monthly Marginal Customer Cost	NEM	Full Requirements	Diff
RS	\$ 11.46	\$ 7.19	59%
RM	\$ 11.61	\$ 7.18	62%
LRS	\$ 12.88	\$ 17.42	-26%
GS	\$ 23.84	\$ 8.88	168%

(3) Facilities Costs

Marginal Facilities costs represent the costs of, and associated with, the Company’s investment in distribution facilities installed for, and closest to, the customer. Those facilities include service drops, transformers, secondary distribution, and some primary distribution facilities, where appropriate. The Company’s investments in these facilities are made in accordance with the Company’s line extension Rule No. 9, and are therefore often referred to as “Rule 9 facilities investment.” The methodology for determining facilities cost has been well vetted before the Commission and is not repeated here.

Marginal Facilities cost remain the same for NEM classes as the corresponding full requirements class. The Facilities cost per customer results are found in Workpaper 11, page 41 of the MCS. Facilities costs per customer on a monthly basis are found in Table 3, page 3 of the MCS. At this time, the Company has made the determination that there are no distinct differences in the cost of installing these facilities for NEM versus full requirements customers. As the number and density of NEM customers grow, facilities costs may in fact vary for these customers with different characteristics. However, as discussed in Section 9 (Distribution Design and Planning), there currently are no additional facilities required for, nor are there savings in facilities investment, for NEM customers. Table 3-2 shows the monthly marginal cost of facilities for the NEM and corresponding full requirements customer classes.

Table 3-2. Monthly Marginal Facilities Costs (from Table 3, page 3 of the MCS)

Monthly Marginal Facilities Cost	NEM & Full Requirements
RS	\$ 14.27
RM	\$ 4.60
LRS	\$ 98.31
GS	\$ 26.22

The pie charts shown below demonstrate the breakdown of the customer and Facilities cost for single-family residential customers for both the NEM and full requirements classes. Marginal customer and Facilities cost is recovered through the proposed BSC. Charts 3-2 and 3-3 show that, on average, the combined cost for NEM customers are driven primarily by the higher meter and customer services cost. Chart 3-4 shows the full monthly customer and Facilities marginal costs for NEM and full requirements single and multi-family customers side by side. The full monthly marginal costs for single and multi-family residential NEM customers are \$25.73/month and \$16.21/month, respectively, in contrast to \$21.45/month and \$11.78/month for corresponding full requirements customers. These costs flow into Statement O (rate design) and are reconciled to the distribution revenue requirement, as discussed in further detail below, to become the full cost based BSC.

Chart 3-2. RS-Full Requirements Components of Customer and Facilities Marginal Cost

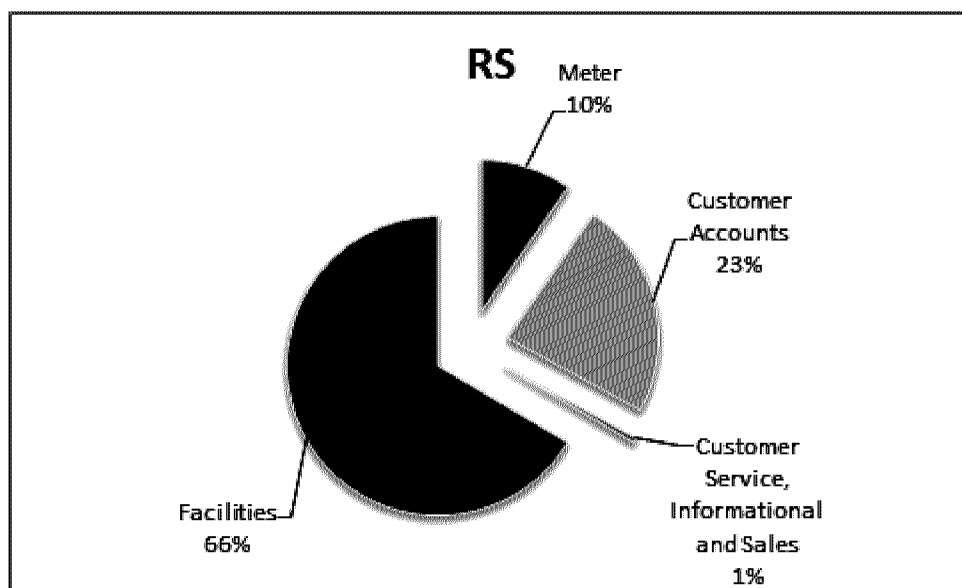


Chart 3-3. RS-NEM Components of Customer and Facilities Marginal Cost

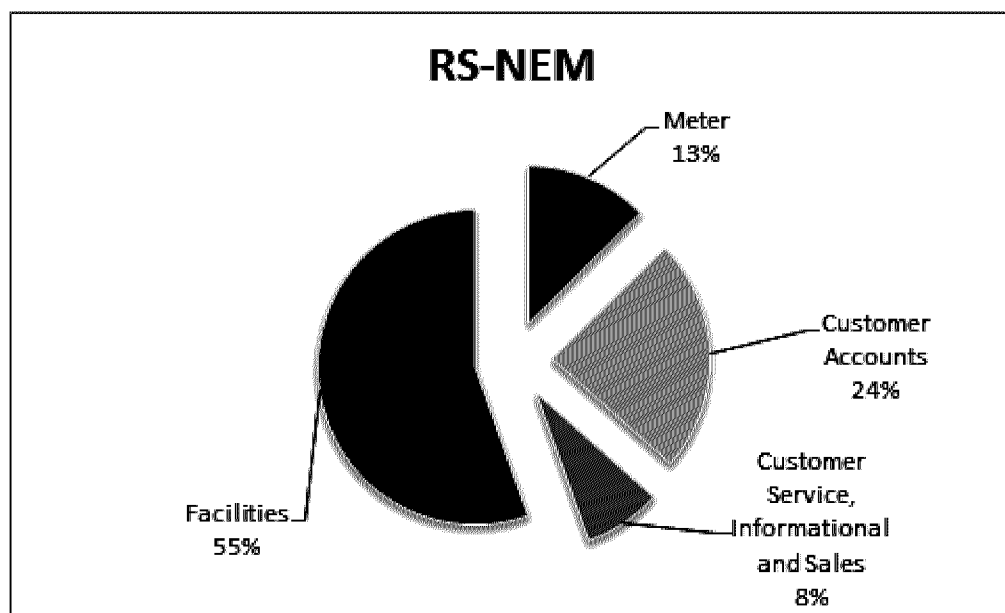
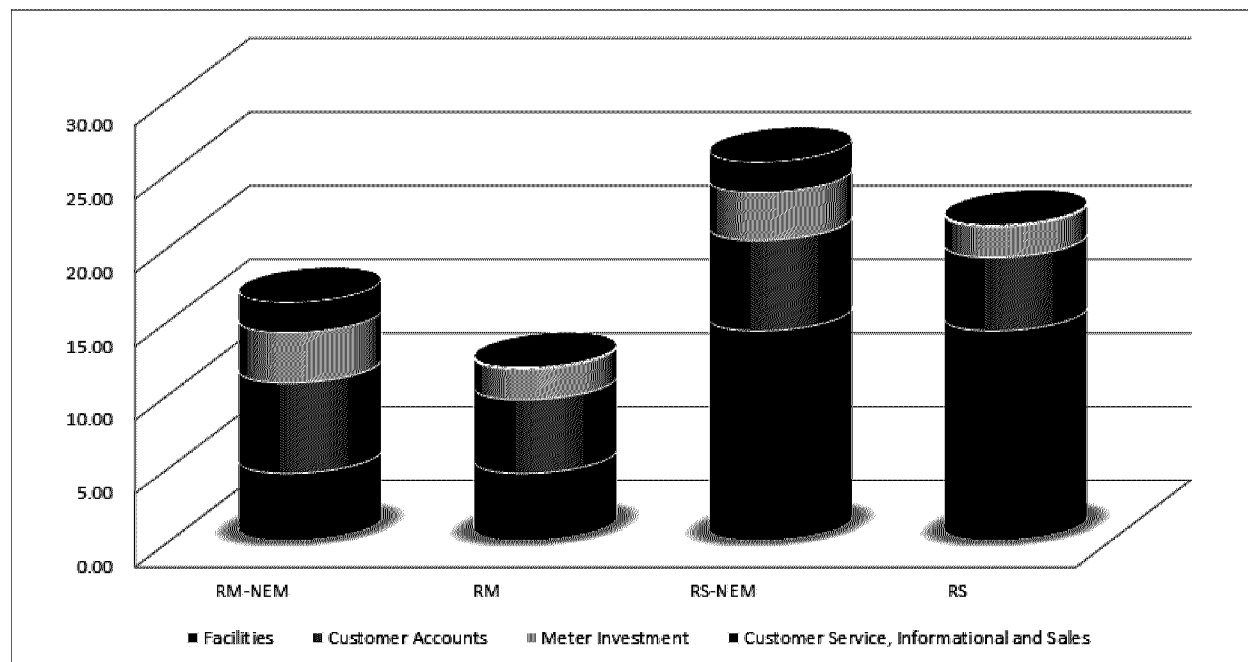


Chart 3-4. Residential Single-Family and Multi-Family Customer and Facilities Related Marginal Cost Comparison



(4) Hourly Marginal Demand and Energy Costs

Marginal cost is determined for the remaining functions using hourly data, developed from hourly PROMOD outputs and historical information, to develop updated POP, LOLP and MEC hourly marginal cost responsibility factors. These factors are weighted by individual class load shapes for all classes and aggregated by TOU for input into the MCS. Class load shapes were developed for the new NEM2 classes and used to develop the hourly weighted cost responsibility factors for this proceeding. As discussed above, separate appropriate load shapes are used for development of cost for each function. The distribution and transmission load shapes reflect the standby nature of the service provided (and the additional cost of the distribution grid for distribution cost development); while the generation and energy cost development use only the delivered energy load shape. The following discussion focuses on the annual load shape that is based on the hourly data developed and discussed in Section 4. Information for the months of July and March, which demonstrate large seasonal variations, are provided in Attachment B.

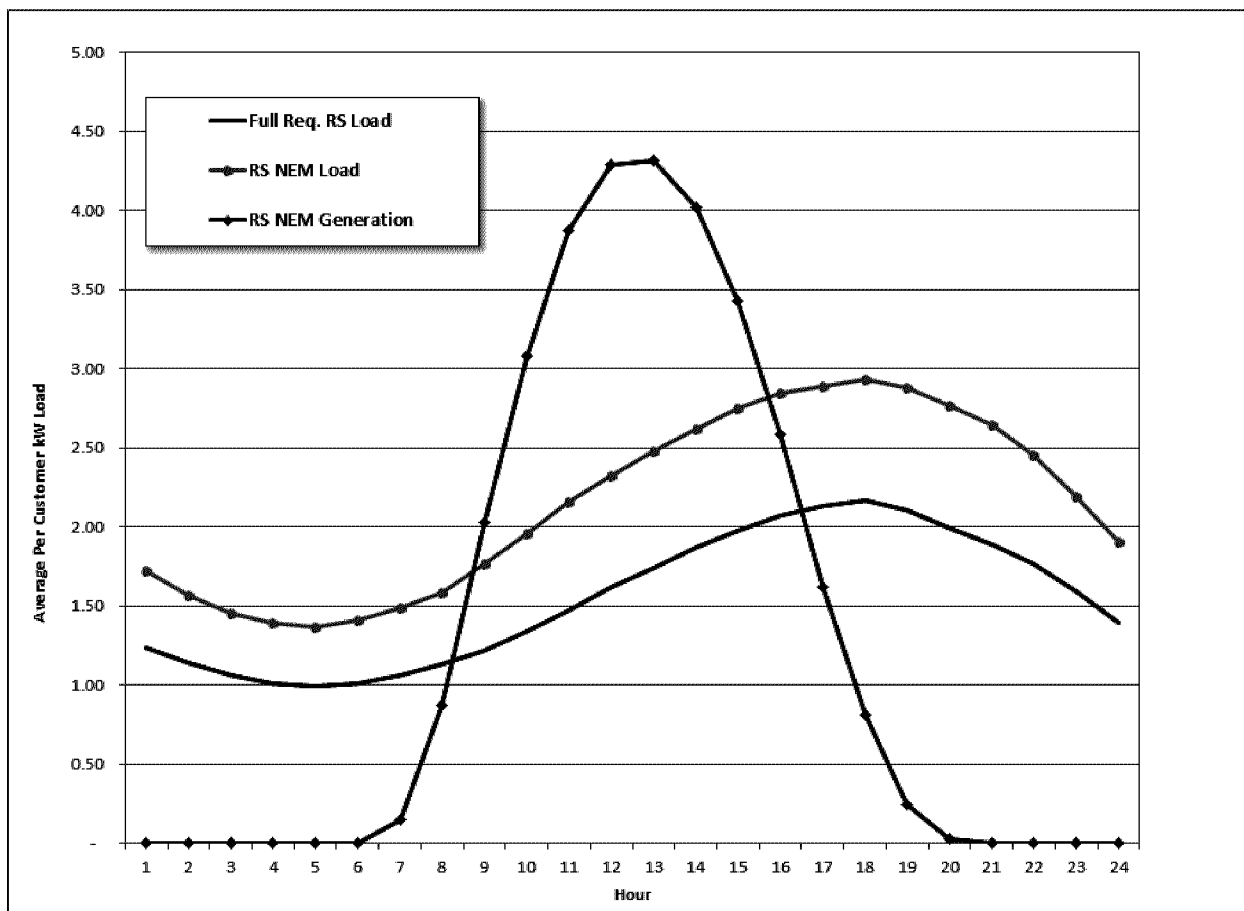
(5) NEM Class Hourly Load Shapes

Customers who have installed self-generation differ from full-requirements customers who receive all of their energy from the utility. The NEM customer offsets a portion of their usage from their generation. The NEM customer relies on the grid entirely for energy service from the utility when their unit is not producing the required energy demanded by the customer and when the customer delivers excess energy to the grid. The NEM customer requires load following services when the customer's generation output drops, but their load does not. Therefore, the appropriate hourly load information for development of hourly marginal cost requires identifying

the loads that are delivered to the customers, the customer's total load, and excess energy deliveries. This is necessary because Nevada Power must stand ready to serve the customer's entire load, as well as receive excess energy at any point in time.

To properly develop costs for these separate NEM customer classes, it is necessary to understand the unique load characteristics of these customers and how their different load shapes can be used to appropriately develop cost to serve these customers for each function. To understand how the load shapes are determined, the first step is to examine the average customer daily load shapes shown in Chart 3-5, which includes the total load of the average single-family RS-NEM customer, their average generation, as well as the average customer load shape of the full requirements RS class. It should be noted that overall, the chart shows that the average customer in the RS-NEM class has a higher annual average total load than the average full requirements RS customer.

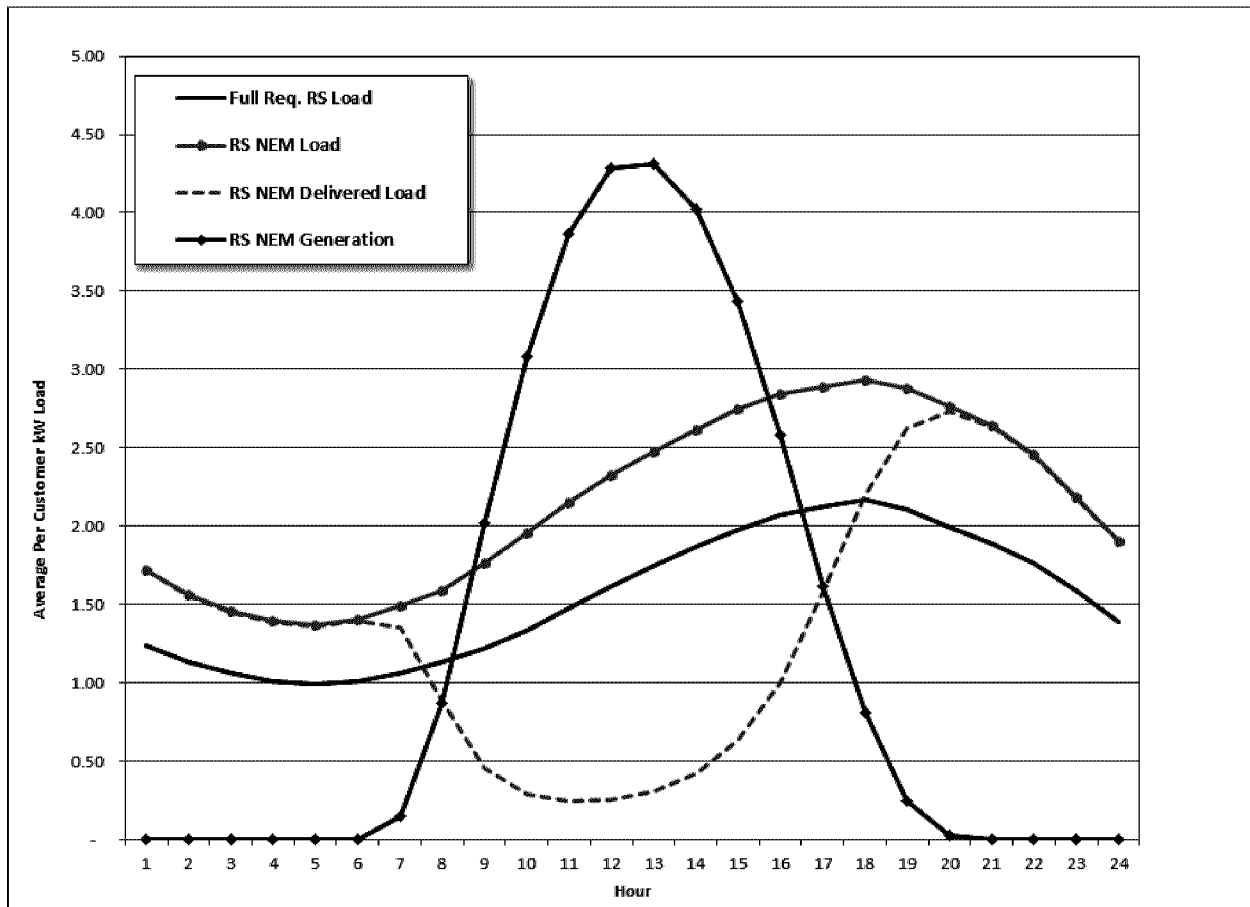
Chart 3-5. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads



Since NEM customers are allowed to install capacity sufficient enough to offset 100 percent of their annual usage, even though the generation will only produce energy during daylight hours and is not matched in time to their load, the generation from the installed capacity is substantially

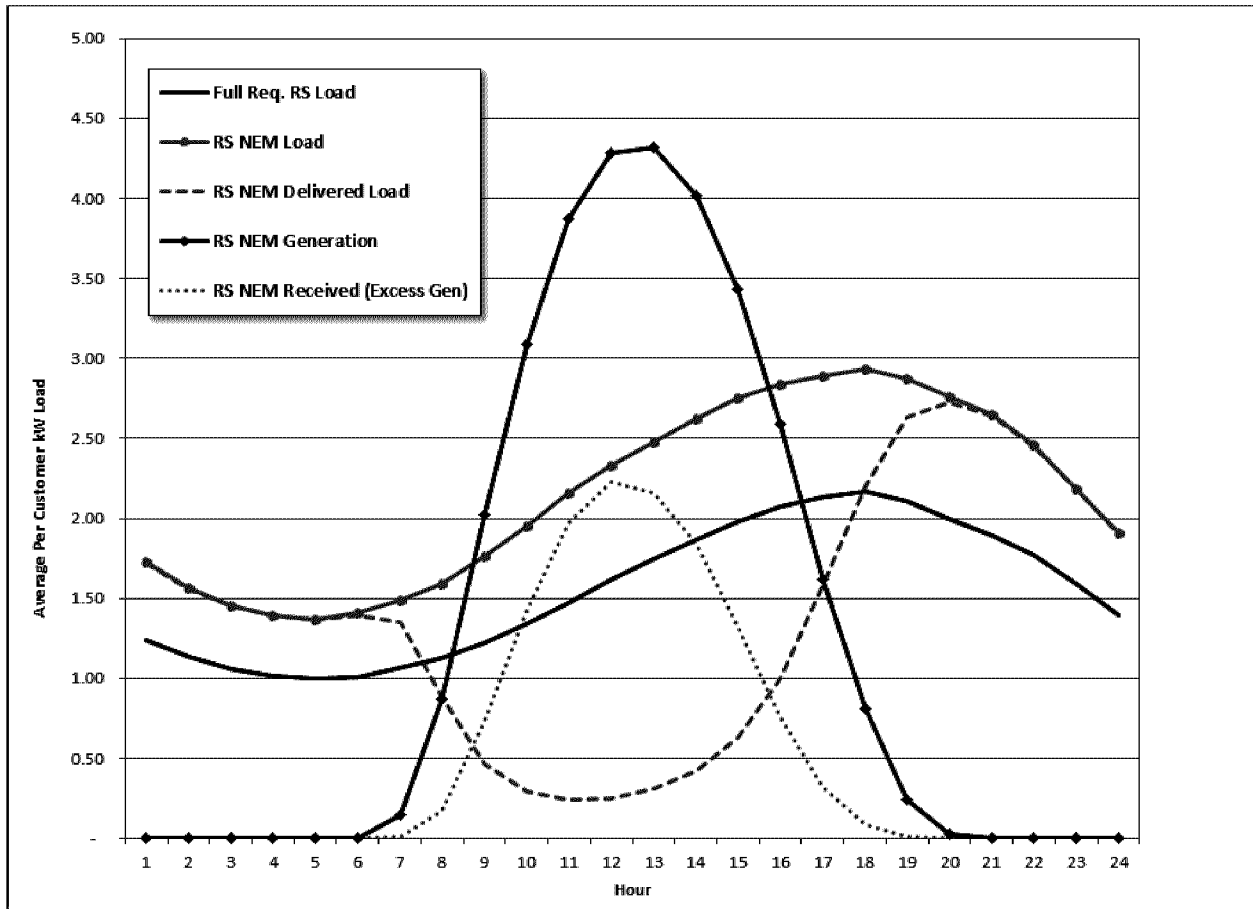
more than the customer's total load during the generator's peak production. NEM customers send this excess generation back on to the Company's system and use this excess energy to offset their billed usage amounts in the future. In hours when their generation is not producing or not producing enough to serve their total load, the Company delivers energy to the customer through the grid and applies banked amounts to reduce the customer's bill to the utility. Chart 3-6 adds the average delivered energy shape for the average NEM customer to the previous chart.

Chart 3-6. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads



Because the generation is significantly greater than the total load of the customer in peak production hours and on an annual average basis, shown here, there are several hours across the day in which these customers send energy back to the grid. This excess generation amount (average annual shown) is represented in Chart 3-7 by the line comprised of small dots.

Chart 3-7. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads

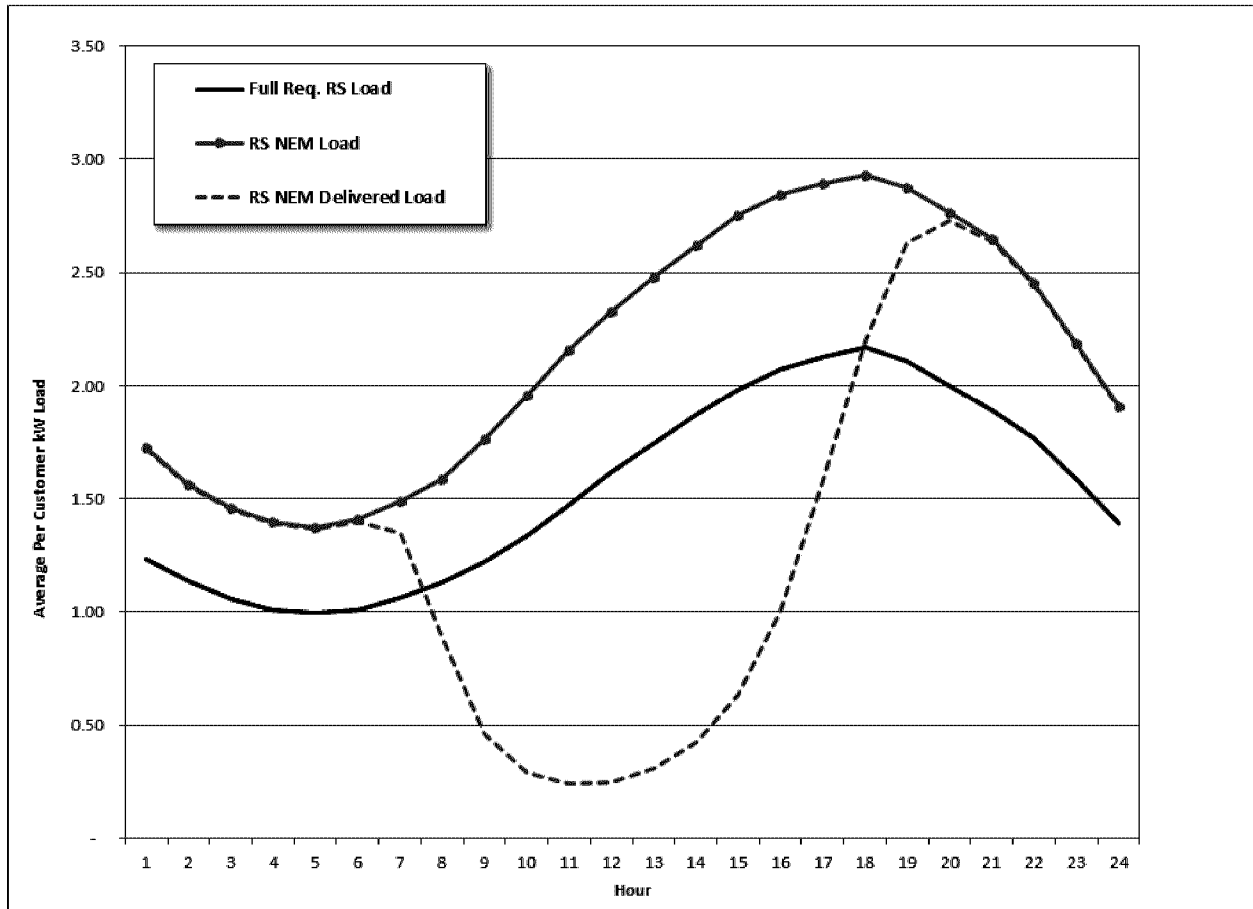


Using the above as a basis, the charts in the following sections identify the different load shapes that are used as the basis for hourly marginal cost responsibility factors to appropriately develop the marginal demand and energy costs by function for the separate NEM customer classes.

(6) Marginal Energy Costs

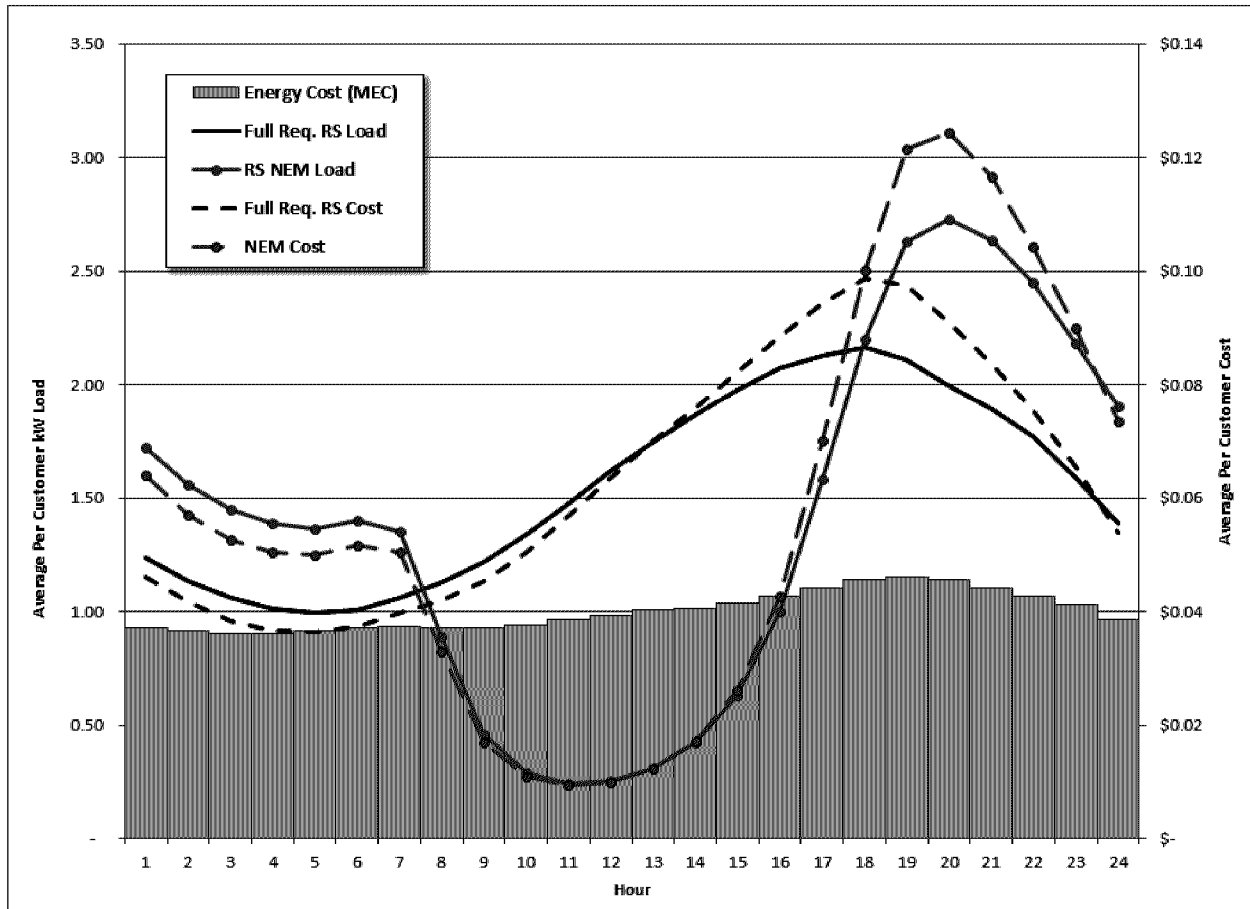
The development of MEC for the NEM classes is consistent with the approved methodology from Docket No. 14-05004 and uses MEC data for the 2016 to 2018 period reflective of the energy cost over the three-year period in which BTGR rates were set to recover. These hourly MECs are averaged by month, day of the week, and hour and then re-expanded to apply to the 2016 rate effective period as was done in the last approved MCS. These MECs are adjusted for losses to the secondary distribution voltage level for the NEM classes and multiplied by the delivered load shape for each NEM class and aggregated by TOU period for input into the MCS. Chart 3-8 shows the relevant average annual load shapes for the development of MECs.

Chart 3-8. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads for Marginal Energy Costs



The following Chart 3-9 shows the average hourly marginal energy costs from the RS-NEM customer and the average full-requirements single-family residential customer. Overall, the average NEM customer has an annual marginal energy cost of \$490.41 based on their delivered load, which is 15 percent lower than the \$579.52 energy cost of the average full requirements RS customer. However, on a dollar-per-kWh basis, the two classes' costs are nearly identical, \$0.04214/kWh for the RS-NEM customer class and \$0.04226/kWh for the full requirements RS class.

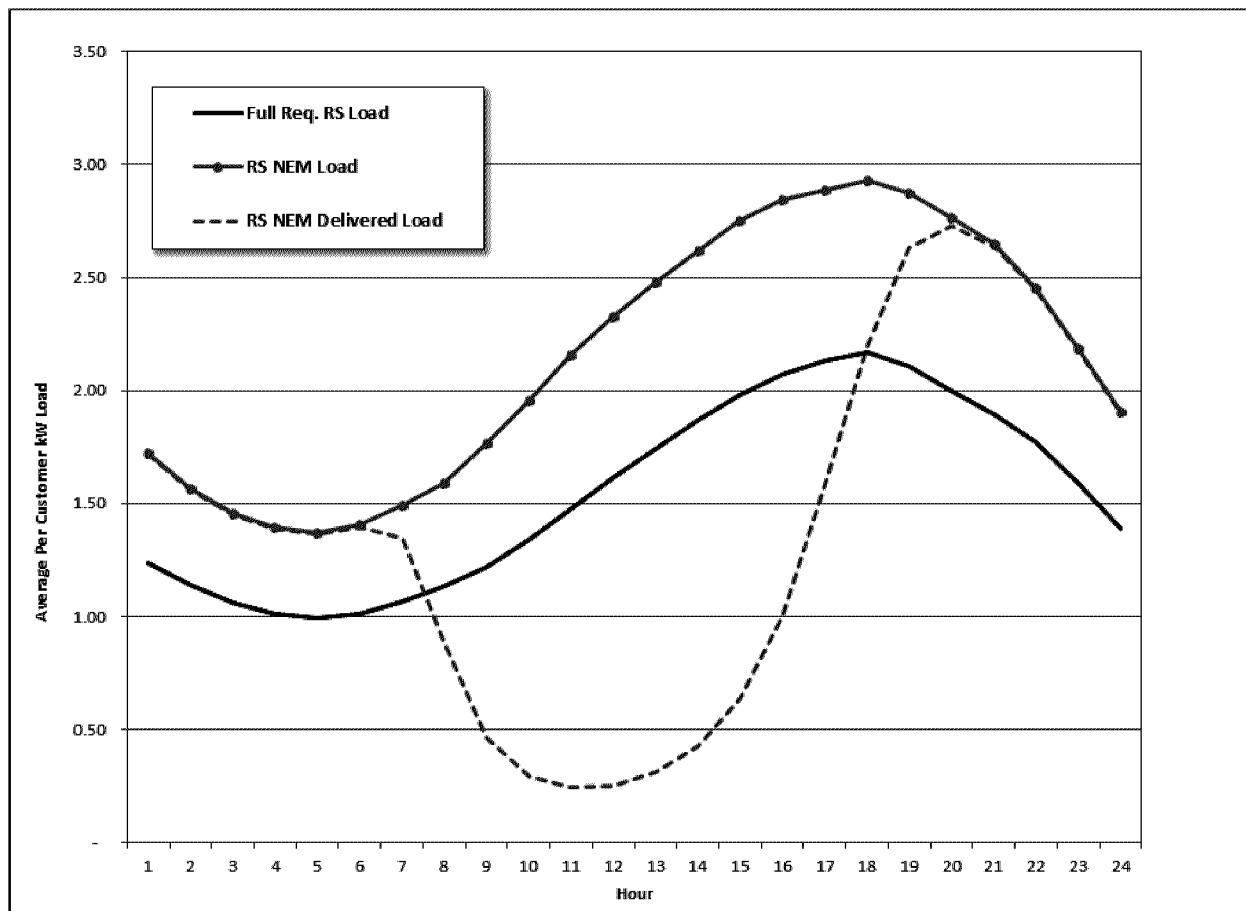
**Chart 3-9. Nevada Power NEM & Full Requirements RS Customers Annual Average
Hourly Burden for Marginal Energy Costs**



(7) Marginal Generation Demand Costs

While the Company stands by to provide service at the total load of the customer if their generation system does not produce the energy required by the customer, the MCS uses the delivered load shape for development of marginal generation demand costs for NEM classes as a reasonable approach for this filing. Because there is some capacity value associated with the energy produced by the NEM customer and Nevada Power has not yet been able to quantify the standby and load following impact associated with this provision of generation capacity to NEM customers, the load shape used to weight the hourly marginal cost responsibility factor used in the marginal generation capacity cost calculations is the delivered shape. Chart 3-10 shows the relevant average annual load shapes for the development of marginal generation capacity cost.

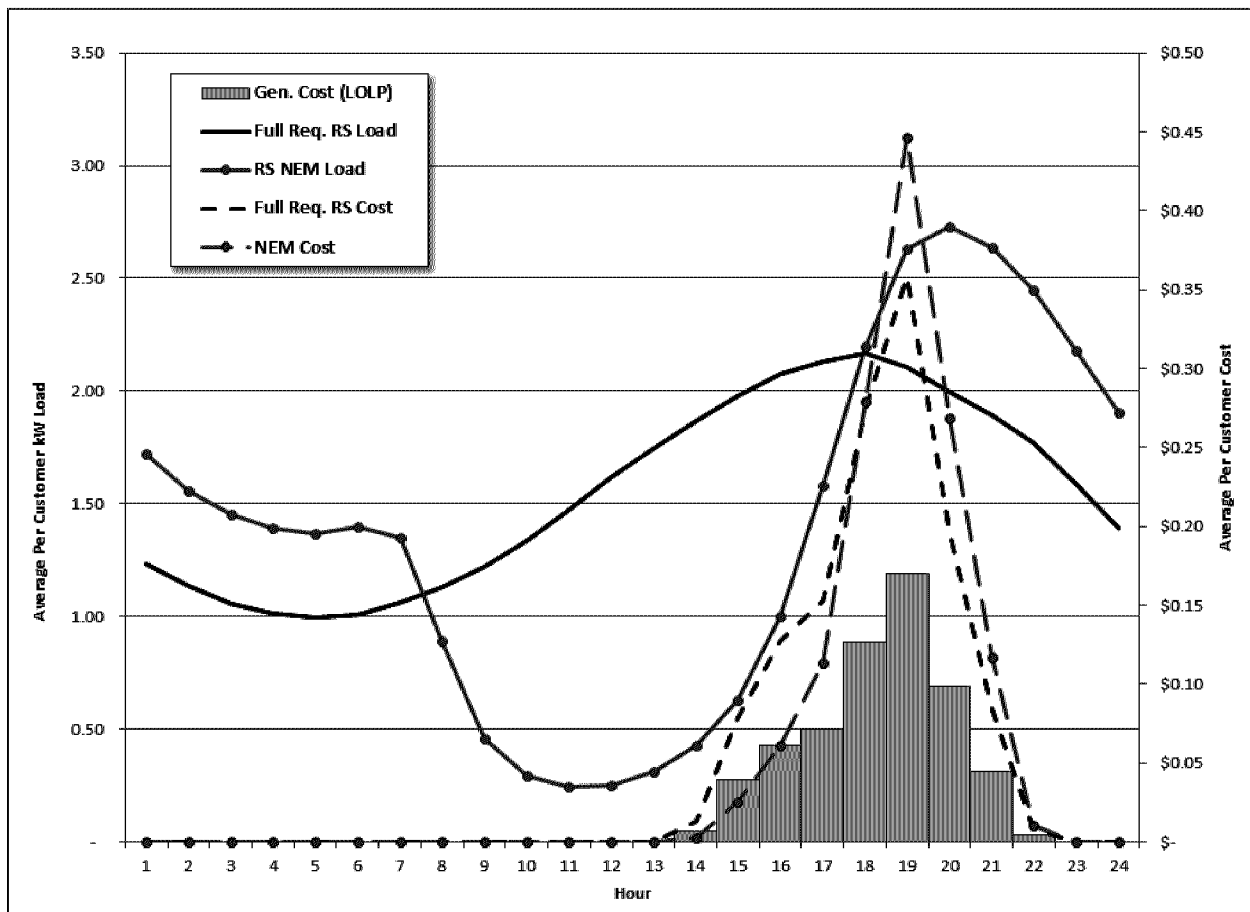
Chart 3-10. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads for Marginal Generation Costs



The LOLP data produced by PROMOD is the hourly cost responsibility factor used to spread the generation unit demand cost. For this filing, the hourly LOLP data from 2016 through 2019 reflects the period prior to significant incremental capacity additions in 2020 at Nevada Power. These factors, in combination with the delivered load shapes, are used to develop the marginal generation capacity cost.

Chart 3-11 includes the hourly LOLP cost information as well as the average marginal generation costs for both the average RS-NEM and full requirements RS customer.

Chart 3-11. Nevada Power NEM & Full Requirements RS Customers Annual Average Hourly Burden for Marginal Generation Costs

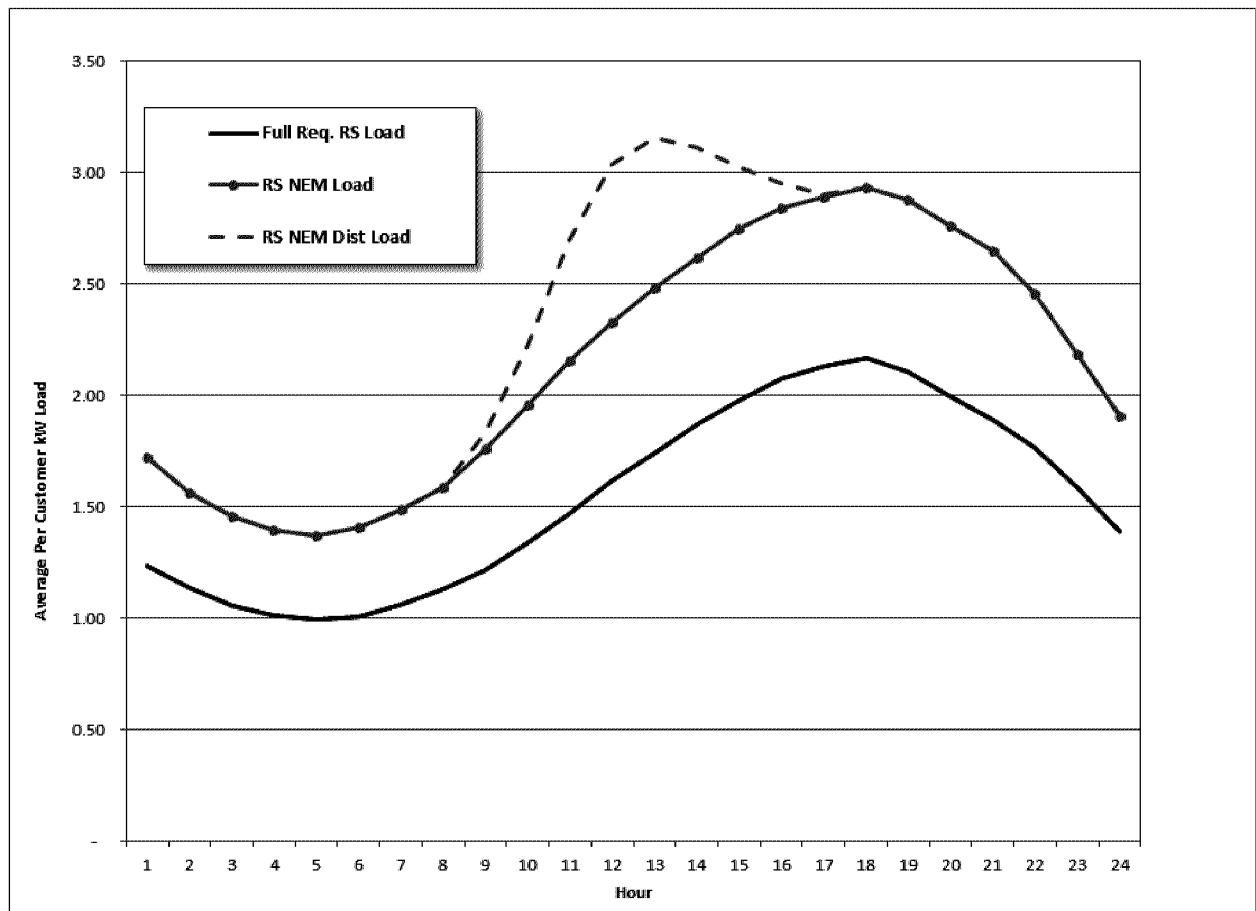


This chart shows that NEM customer load is increasing as its generation production is in significant decline during the evening hours as the marginal generation capacity costs are rising. However, using the delivered load shape in the calculation of marginal generation cost rather than the total load shape for the single-family NEM customers reduces the overall total marginal generation costs for these customers by 27 percent. Additionally, while there is some reduction in the peak delivered loads when the normalized LOLPs (and hence marginal generation costs) are at their highest, the difference is significantly less than hours earlier in the day. Using the delivered loads for the development of the marginal generation costs results in the average NEM customer having 12 percent lower annual marginal generation demand cost (\$796.97), than the generation demand cost of the full requirements RS customer (\$906.19). Though, as shown in Chart 3-11, the RS-NEM customer class as a whole remains costlier at peak times than the full requirements RS class. This is illustrated by the NEM class's marginal cost-per-kWh of generation of \$0.06848/kWh being 3.6 percent higher than \$0.06607/kWh for the corresponding full requirements class.

(8) Marginal Distribution Demand Costs

As discussed in Section 9, there is no quantified reduction in cost for the primary distribution system when a customer installs their own generation. However, it is still unclear as to whether or not there are additional costs (e.g. transformer replacement, switch upgrades, etc.) that are imposed on the distribution system from a customer deciding to install NEM generation beyond the cost that NEM customers impose by sending excess generation back to the grid for banking. Consistent with the requirements of SB 374, this is subject to future study and not addressed in this filing. Therefore, the load shape used in the development of primary distribution demand costs for NEM customers uses the higher of either 1) the total load of the customer or 2) the amount of excess generation that is sent back on to the distribution system. Chart 3-12 shows the average daily NEM customer load shape used in the development of the marginal primary distribution costs. The additional burden on the distribution system associated with the excess is limited to that above the total load in any hour to ensure no double counting occurs.

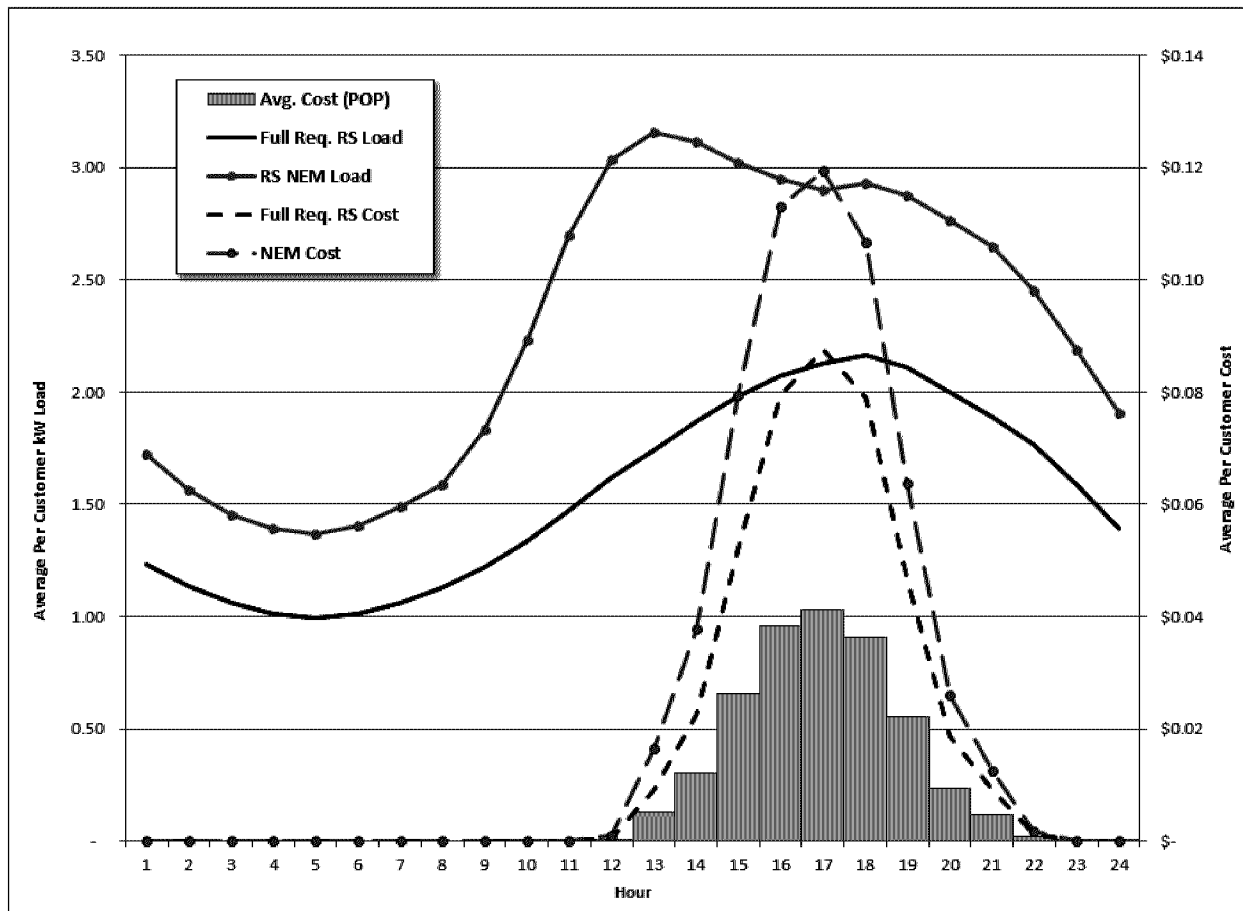
Chart 3-12. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads for Marginal Distribution Costs



This modified total load shape is used in conjunction with the hourly normalized POP marginal cost responsibility factor, used for all customer classes. The POP is based on those hours with

probability of exceeding 90 percent of annual system peak and is used to develop marginal distribution demand costs. For this proceeding, the data used in the development of the POP factor are 10 years of historical system data (2005-2014) and one year of PROMOD forecast system load (2016). Chart 3-13 includes the average hourly marginal distribution demand cost for both the average RS-NEM and full requirements RS customer, which are \$334.84 and \$292.47, respectively. This \$42.37 difference in cost represents a 14 percent higher overall distribution demand cost for NEM customers relative to the full requirements RS customer and a 0.1 percent increase in the distribution costs above that calculated at the NEM customer's total load. This small percentage of difference in cost represents one component of the cost imposed by the NEM customer to receive banking service for their generation. The impact to Marginal Distribution cost associated with the excess energy fed back to the grid is small due to the fact that it occurs at times that are relatively low in cost, primarily the Winter season when distribution capacity costs are low. NEM total loads and distribution capacity costs are at their highest in the Summer season when there is little, if any, excess generation. This seasonal variation is shown in Attachment B.

Chart 3-13. Nevada Power NEM & Full Requirements RS Customers Annual Average Hourly Burden for Marginal Distribution Costs



(9) Marginal Transmission Demand Costs

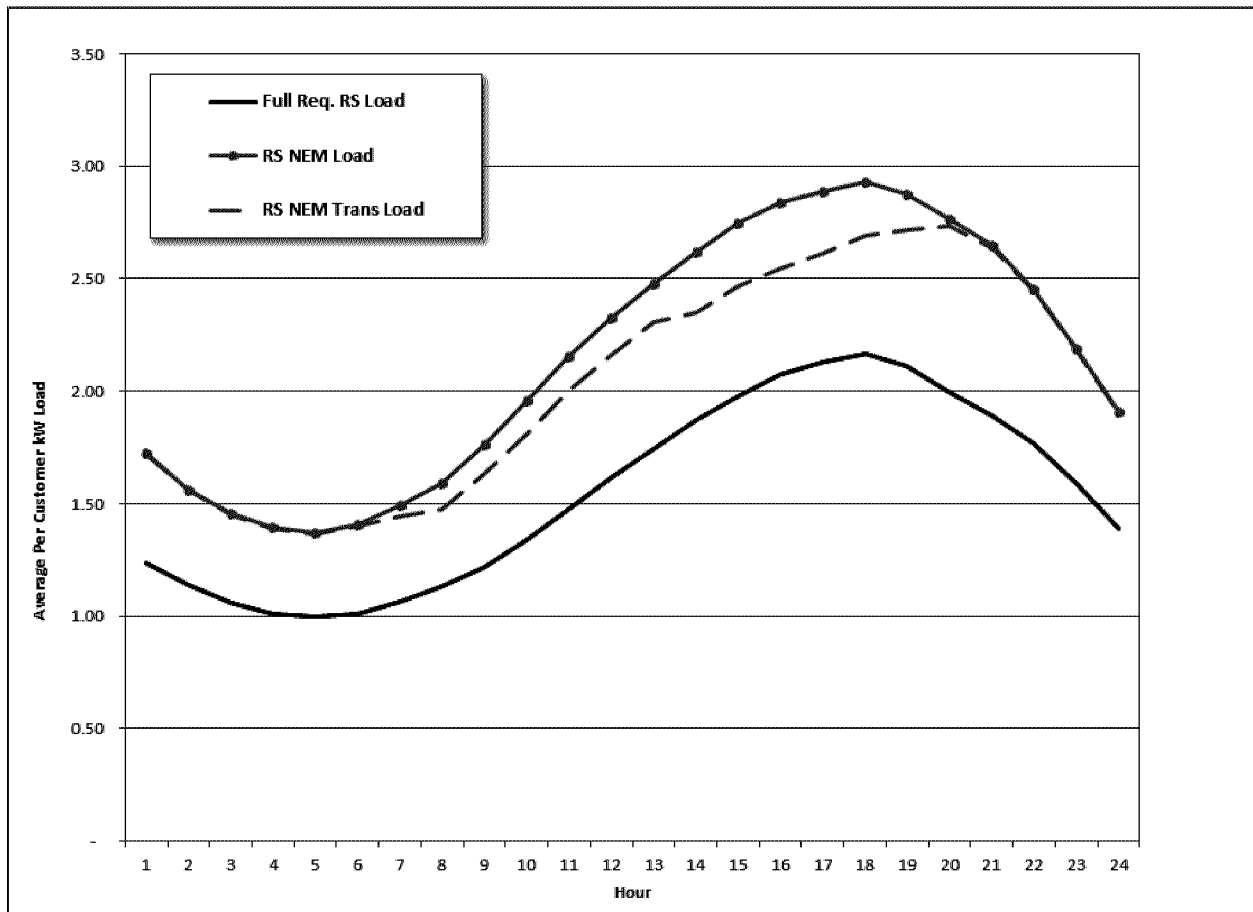
The development of marginal transmission cost is also consistent with that for all other classes of customers. While the company must continue to stand by to provide the total load of the NEM customer, similar to the distribution grid, the impact associated with the excess NEM generation is assumed to be contained within the primary distribution system. A primary concern of the transmission system is maintaining the reliability of service to all customers. The load shape used for developing cost of service reflects the standby nature of the grid for serving these partial requirements customers but also accounts for the diversity in the load requirements of each NEM class. However, as you move further out into the system, there is some diversity that should be considered. Therefore, the load shape used in the development of the marginal transmission demand cost is the total load shape adjusted downward to reflect the difference in the total class delivered load non-coincident peak compared to the total load non-coincident peak. This is accomplished by multiplying the hourly total load shape by the ratio of the delivered maximum kW billing determinants relative to the kW determinants for the total load shape, by TOU period, of all NEM customers within a class. This results in a transmission cost that is roughly 11 percent lower than that which would result if the total load shape were used and appropriately reflects the diversity of the NEM self-generation and its impact on the loads of all customers within the class. Table 3-3 summarizes these adjustment factors by class.

Table 3-3. Transmission Load Adjustments

	RS NEM	RM NEM	RSL NEM	GS NEM	ORS NEM
Total Load kW Billing Determinants					
Maximum kW	329,618	2,099	1,260	6,125	14,534
Summer On	158,412	882	505	2,586	7,411
Summer Off	146,984	838	449	2,505	7,009
Winter	168,747	1,218	755	3,539	7,123
Delivered Load kW Billing Determinants					
Maximum kW	302,739	2,053	1,171	5,550	11,087
Summer On	140,435	839	440	2,071	5,321
Summer Off	140,764	837	426	2,217	4,584
Winter	156,791	1,195	727	3,318	5,719
Adjustment Ratio					
Total kW	91.8%	97.8%	93.0%	90.6%	76.3%
Summer On	88.7%	95.2%	87.2%	80.1%	71.8%
Summer Off	95.8%	99.9%	95.0%	88.5%	65.4%
Winter	92.9%	98.1%	96.3%	93.7%	80.3%

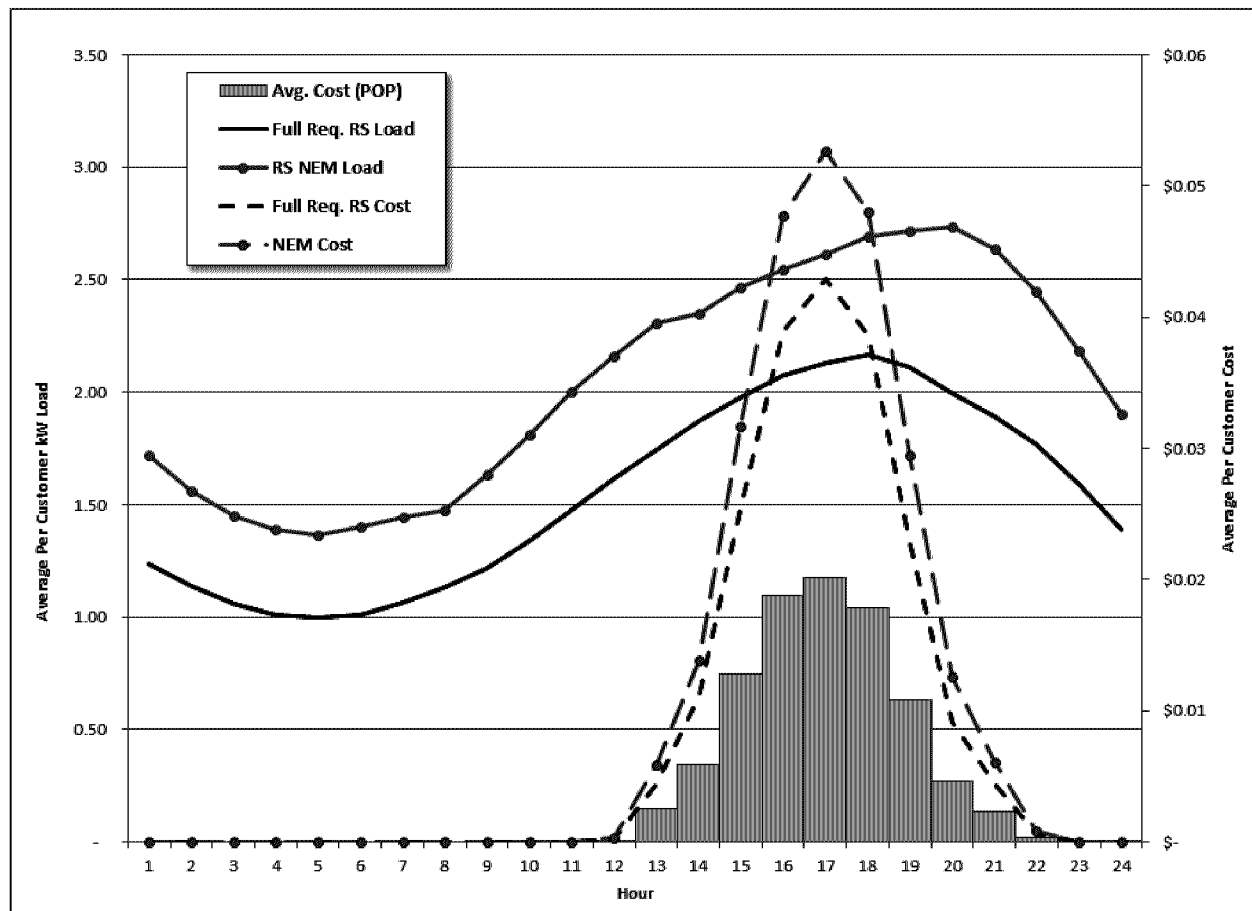
The resulting transmission marginal cost for the RS-NEM class is shown in Chart 3-14, which also shows the adjusted load shape (on an annual average basis) used in the development of the hourly marginal transmission costs.

Chart 3-14. Nevada Power NEM & Full Requirements RS Customers Annual Average Loads for Marginal Transmission Costs



The development of marginal transmission costs uses the same POP factor as the distribution calculations and is consistent with cost development for all classes of customers. Chart 3-15 includes the average hourly marginal transmission demand costs for both the NEM and full requirements RS customers, who have annual average marginal transmission costs of \$145.79 and \$143.13, respectively.

Chart 3-15. Nevada Power NEM & Full Requirements RS Customers Annual Average Hourly Burden for Marginal Transmission Costs



B. Rate Design

As with the MCS, the reconciliation and rate design has been developed in a manner consistent with the presentation made by Laura Walsh at the May 1, 2015 workshop in Docket 14-06009. The rate design reflects the MCS updates that began with the Certification MCS and was based upon the Certification Statement O filed in Docket No. 14-05004. Below the principal modifications made to the certification rate design for this filing are identified.

- Eight New NEM2 Schedules Incorporated into the Rate Design: The Statement O from Docket No. 14-05004 was modified to add the four new NEM2 rate classes as described above for the MCS – RS-NEM, RM-NEM, LRS-NEM and GS-NEM. These are the default NEM2 rate schedules, and they have a simple three-part rate structure. There are also four corresponding optional TOU three-part NEM2 rate schedules developed in Statement O.⁵⁵ These four optional rate structures are based on the same marginal cost of

⁵⁵ The four new non-optional residential and small general service rate classes are referred to as the “default” or “standard” NEM classes. After the NEM cap is reached, individual NEM customers will be given a choice between

service revenues as the rates for the four default NEM2 rate schedules, but the rates reflect the costs by TOU period. The specifics of the proposed rate structures are discussed below.

- Default and Optional TOU Rate Structures: The rate structures for the four default residential and small general service rate schedules consist of: i) a per customer per month BSC that recovers customer related costs including the cost of the revenue meter and Rule 9 facilities; ii) when applicable, a generation meter charge per month per generation meter;⁵⁶ iii) a monthly demand charge per maximum kW demand (measured on a 15-minute delivered basis over the billing period) that recovers all of the cost-based distribution and transmission demand cost and, as described earlier, 62 percent of the generation demand cost;⁵⁷ and iv) a kWh charge based on delivered energy. The optional TOU three-part rate schedule has the same BSC and generation meter charge components. Similar to the default rate structure, the Optional TOU rate structure has a maximum kW demand component, however, it only recovers the distribution demand cost; and thus, is a lower rate than that of the default schedule.

For the three optional TOU NEM2 rate schedules, the TOU periods are those currently offered under Option A of the existing full requirements optional residential TOU rate schedules.⁵⁸ Based on these TOU periods, the NEM2 optional TOU rate offerings will additionally have a summer on-peak TOU demand charge per maximum summer on-peak kW, which is designed to recover all of the transmission demand cost and 62 percent of the generation demand cost. The remaining 38 percent of the generation demand cost is recovered in the appropriate TOU energy charge. Demand charges will only be assessed in the summer on-peak TOU period. As previously mentioned, the on-peak periods represent only 8.4 percent of the total hours across the year. The TOU energy rates are differentiated for the summer on-peak, summer off-peak and winter periods. The individual NEM class rate design pages of the updated Statement O contain the proposed rates and show the rate development for the four default NEM2 schedules and their corresponding optional TOU alternatives. In addition, the proposed NEM2 rates are shown in Table 3-4.

- Billing Determinants: As with the class kWh sales discussed in the MCS section, all other billing determinants for all classes remain the same as in the certification filing except: i) the billing determinants for the four default NEM2 rate schedules, which were developed for the 12 month period ending May 2015, and ii) the corresponding billing determinants for the four standard (full requirement) rate classes were reduced to remove the NEM

the standard and optional TOU rate schedule, if no election is made, the customer will be served “by default” under the non-TOU rate structure and tariff.

⁵⁶ As discussed further below, customers participating in the SolarGenerations program will be exempt from paying the generation meter charge.

⁵⁷ The remaining 38 percent of generation demand costs are reflected in the energy charge.

⁵⁸ This schedule has a summer season from June 1 through Sept 30, with a summer on-peak period from 1-7 p.m. daily and summer off-peak consisting of all other hours. The winter season is for the remainder of the non-summer months, October through May, with a single rating period within the season.

determinants. Both the simple and TOU three-part NEM2 rate proposals have a maximum billing demand (kW) element. This billing determinant was developed for each class from the individual NEM customers' 15-minute delivered load data, described in Section 4 (Net Metered Load Shape Development). Similarly, the TOU demand billing determinants and TOU energy billing determinants needed for the TOU rate designs are also developed from this same load shape information.

- Present Rate Revenues: Consistent with keeping the billing determinants unchanged from the 2014 certification filing, except for reflecting the four new default NEM2 classes, the BTGR revenue requirement is the same as that approved by the Commission in the Nevada Power general rate case settlement. The high load factor ("HLF") rate class (LGS-3P-HLF) that was introduced as part of the approved settlement is reflected in each class's present rate revenues in Statement O. Additionally, to remain consistent with present rates as of July 1, 2015, the current residential and non-residential BTER rates were incorporated into this Statement O model, and the energy component of the revenue requirement has been adjusted to be consistent with current BTER rates.⁵⁹
- Proposed Rate Revenue Requirement is set the same as Present Rate Revenue: The rate design is being done by setting the total present rate revenues equal to the proposed rate revenues, and thus, there is no overall system change in revenue requirement reflected in the rate design. This is observed by referring to column F line 38 on page 6 of Statement O, which shows that the proposed total rate revenue upon which rates are to be set are the same as the total present rate revenue.
- Unbundled Revenue Requirement for Reconciliation: As described above the total and individual class revenue requirement for the energy function is updated to reflect the current residential and non-residential BTERs. The total BTGR revenue requirement is allocated to the distribution, transmission and generation functions, using their respective percentage shares of the total BTGR revenue requirement from the Certification Statement O. Page 1, line 12 of Statement O provides the unbundled revenue requirement used in this filing. Due to the updates to the MCS, the revenue requirement is redistributed to all rate classes within Statement O. However, the sole objective of this filing is to establish NEM class rates consistent with the updated MCS and to utilize rate design structures sufficient to reflect that cost for partial requirements customers. Rates for existing classes of customers will not be modified until the next GRC.
- Marginal Costs and Revenue Reconciliation: The updated MCS results are input to the rate design. The resulting marginal cost revenues by class and by function, including the marginal cost revenue for the four NEM2 classes are incorporated into the revenue reconciliation of Statement O, which is shown on page 5.⁶⁰ The reconciliation of the marginal cost revenue to the revenue requirement by the distribution, transmission and

⁵⁹ The Energy revenue requirement component is derived as the sum of the residential and non-residential kWh sales times their respective, currently effective as of July 1, 2015, BTER rates.

⁶⁰ Because the functional costs for the default and optional TOU rate structures are one and the same, only the four default NEM rate classes are represented in the reconciliation. The optional TOU rate designs are based on the same revenue requirement resulting from the reconciliation for the corresponding default rate classes.

combined generation and energy functions, on this page establishes the cost-based revenue requirement for all rate classes included in the revenue reconciliation. The results for the four new NEM2 rate classes establish the cost of service for these classes, developed on the same costing methodology used for all other classes. In Docket No. 14-05004, Page 6 of the Certification Statement O was used to establish caps on the permitted increases in class revenue requirement; and thus modifying the cost based revenue allocations from Page 5, resulting in subsidies to some classes paid by other classes. However, in this filing the cost allocations are entirely cost based, without the imposition of any caps or other constraints, and therefore Page 5 of Statement O reflects the final cost allocations used for designing rates and these are simply repeated on Page 6.⁶¹ Page 6, however, does additionally show the resulting class revenue requirements for each class compared to the present rate revenue of the class (in columns E and F), and identifies the rate impacts that would result if rates were re-set using these class revenue requirements.

- Existing Subsidy Receipt/Payment is reflected in the proposed NEM2 Rates: The existing subsidy rate reduction of \$0.00551/kWh in the current rates of the RS residential class, under which existing NEM customers are billed, is being provided to the default and optional TOU RS-NEM rate classes. This is done by reducing the cost-based energy rates by this subsidy amount. This adjustment can be observed in the NEM2 rate design pages. Similarly the existing subsidy payments of \$0.00388/kWh from the RM class, \$0.00368/kWh from the LRS class, and the \$0.00150/kWh from the GS class are added to the respective cost based rates of the RM, LRS and GS-NEM default and optional schedules. This adjustment can be observed on the individual rate design pages for these classes. The new net metering classes were included in the revenue reconciliation, thus directly producing the unique reconciled cost of service and revenue requirement for these classes.
- Revenue Associated with the Value of NEM kWh Banking: While rates are designed on the energy delivered to the new NEM2 classes, because customers are able to offset their billed usage with any banked kWh credits they have accumulated, there is a difference in the revenue in which rates are designed for and the revenues that are collected from these classes. Therefore, the difference between the revenues used for rate design and those that are to be recovered from NEM customers, because of the banking mechanism, is debited back to the total revenue requirement and recovered from all customer classes through an allocation of generation and energy costs relative to the rates that the customers pay for their energy deliveries. At Nevada Power, \$1.13 million in total is allocated to all classes through this mechanism, of which 96 percent of this amount is related to the revenue difference associated with the RS-NEM class. The recovery of these costs through the generation and energy components is appropriate as these banked kWh credits were used to offset system generation and energy costs that would otherwise be incurred by all customers.

⁶¹ The current Interclass Rate Rebalancing rate for the existing full requirements class is applied to the final rates of the new NEM classes.

- **Discounted Off-peak Rates for the Electric Vehicle Recharge Rider (EVRR):** The Company continues development of the EVRR optional rates using the same method as when these rates were first introduced and thereafter updated. NEM2 customers under the EVRR are required to take service under the optional three-part 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, in order to provide an incentive to charge electric vehicles in the lowest-cost hours. 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. This discounted off-peak 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 the electric vehicle.

(1) Proposed Nevada Power NEM2 Rates

The proposed NEM2 rates for Nevada Power are presented in Table 3-4.

Table 3-4. Nevada Power NEM2 Rates

Rates	RS			RM		
	Current Flat-rate	NEM	Optional NEM TOU	Current Flat-rate	NEM	Optional NEM TOU
BSC	\$ 12.75	\$ 18.15	\$ 18.15	\$ 9.00	\$ 11.22	\$ 11.22
Generation Meter	\$ -	\$ 1.43	\$ 1.43	\$ -	\$ 1.40	\$ 1.40
Max Demand Rate (\$/kW)	\$ -	\$ 14.33	\$ 4.04	\$ -	\$ 13.95	\$ 3.97
TOU Demand Rate (\$/kW)						
Summer On	\$ -	\$ -	\$ 22.15	\$ -	\$ -	\$ 24.39
Winter On	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Flat kWh Rate (\$/kWh)	\$ 0.11642	\$ 0.05470	\$ -	\$ 0.10939	\$ 0.05648	\$ -
TOU kWh Rate (\$/kWh)						
Summer On	\$ -	\$ -	\$ 0.09147	\$ -	\$ -	\$ 0.11491
Summer Off	\$ -	\$ -	\$ 0.05016	\$ -	\$ -	\$ 0.05787
Winter Off	\$ -	\$ -	\$ 0.04727	\$ -	\$ -	\$ 0.04727

Rates	RSL			GS		
	Current Flat-rate	NEM	Optional NEM TOU	Current Flat-rate	NEM	Optional NEM TOU
BSC	\$ 82.50	\$ 78.86	\$ 78.86	\$ 27.50	\$ 35.43	\$ 35.43
Generation Meter	\$ -	\$ 8.98	\$ 8.98	\$ -	\$ 7.57	\$ 7.57
Max Demand Rate (\$/kW)	\$ -	\$ 14.84	\$ 4.11	\$ -	\$ 15.27	\$ 4.72
TOU Demand Rate (\$/kW)						
Summer On	\$ -	\$ -	\$ 28.54	\$ -	\$ -	\$ 28.27
Winter On	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Flat kWh Rate (\$/kWh)	\$ 0.10955	\$ 0.05358	\$ -	\$ 0.07335	\$ 0.04960	\$ -
TOU kWh Rate (\$/kWh)						
Summer On	\$ -	\$ -	\$ 0.09046	\$ -	\$ -	\$ 0.06653
Summer Off	\$ -	\$ -	\$ 0.05547	\$ -	\$ -	\$ 0.05049
Winter Off	\$ -	\$ -	\$ 0.04727	\$ -	\$ -	\$ 0.04695

(2) Bill Impacts

As summarized in Table 3-5, the average NEM customer under full requirements RS class rates would have had average yearly bill reductions of \$1,180.88 “flat-rate with NEM generation bill” (\$1,081.28) versus the “flat-rate with no generation” annual bill (\$2,262.17). This represents an average bill reduction of 52 percent per year. Under the proposed NEM2 simple three-part rates, the average utility bill reduction decreases to \$739.74 but still results in a 33 percent reduction from the utility bill without generation. Under the proposed optional TOU three-part rate, similar bill reductions of \$724.52 result, representing a 32 percent average annual reduction over the bill without generation.

On average, RS-NEM customers will continue to have the opportunity to reduce the bill they receive from NV Energy with the addition of DG and movement onto the proposed rates. Using the existing NEM1 customers for the calculation, some customers with very low load factors and high demand had bill increases or no bill reductions, however, the calculations showed approximately 95 percent of customers had bill reductions. The highest reduction estimated was 80 percent. It is important to note that NEM1 customers do not receive the price signal that NEM2 customers will receive under the proposed rates. If NEM2 customers respond to that price signal, they will reduce overall demand and on the optional TOU schedule will reduce on peak usage and demand as well. This would result in greater bill reductions.

Additionally, approximately 6 percent of the existing NEM1 customers would have lower bills under the RS-NEM simple three-part rates compared to the NEM1 rates due to higher load factors. Tables of bill comparisons for the typical customer in each of the other NEM class are included in Attachment C.

Table 3-5. Nevada Power RS-NEM Average Bill Comparison

NEVADA POWER							
NEM Bills*							
MONTH	Current			Simple			Net Percent Change**
	Flat-Rate (No Generation)	Current Flat-Rate	Current TOU	3- Part	TOU 3-Part		
Jan	\$ 156.35	\$ 83.75	\$ 42.18	\$ 108.40	\$ 63.33		29.4%
Feb	\$ 138.32	\$ 55.58	\$ 30.57	\$ 97.79	\$ 52.78		75.9%
Mar	\$ 132.39	\$ 41.97	\$ 24.93	\$ 83.28	\$ 45.00		98.4%
Apr	\$ 124.24	\$ 30.45	\$ 20.13	\$ 84.64	\$ 42.24		178.0%
May	\$ 130.13	\$ 30.72	\$ 20.24	\$ 84.24	\$ 42.20		174.2%
Jun	\$ 259.04	\$ 122.17	\$ 157.53	\$ 172.63	\$ 257.98		41.3%
Jul	\$ 304.79	\$ 179.71	\$ 225.84	\$ 201.25	\$ 290.50		12.0%
Aug	\$ 298.83	\$ 171.49	\$ 221.49	\$ 198.31	\$ 290.57		15.6%
Sep	\$ 265.88	\$ 148.82	\$ 202.63	\$ 186.22	\$ 278.22		25.1%
Oct	\$ 188.34	\$ 87.96	\$ 43.84	\$ 131.57	\$ 70.92		49.6%
Nov	\$ 135.20	\$ 59.22	\$ 31.98	\$ 86.22	\$ 50.41		45.6%
Dec	\$ 128.66	\$ 69.44	\$ 36.08	\$ 87.87	\$ 53.50		26.5%
Total	\$ 2,262.17	\$ 1,081.28	\$ 1,057.44	\$ 1,522.42	\$ 1,537.65		40.8%
NEM Savings		\$ 1,180.88		\$ 739.74	\$ 724.52		
		52%		33%	32%		

*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3- Part versus Current Flat Rate

Nevada Power's standard and optional NEM2 rates provide customers who choose to install renewable DG an opportunity to significantly reduce the bills they receive from NV Energy.⁶² The bill reductions will reflect energy savings and capacity savings to the extent they occur. At the same time, the NEM2 rates reduce or eliminate the unreasonable shifting of costs to non-NEM customers that exists under NEM1. In this regard, NV Energy's proposal is fair – it treats all customers equitably and advances Nevada's energy policy by establishing a sustainable environment for renewable DG. In summary, NV Energy's proposal achieves the result that the Nevada Legislature envisioned when it passed SB 374.

It is also important to note the potential for additional benefits to customers of the proposed three-part rate structures as a result of the rate design. For example, as mentioned in Section 3.B above, the LRS-NEM customer class has a higher load factor and has lower marginal cost characteristics overall than its corresponding full requirements class. This is an illustration of how customers can benefit from rate designs that contain a demand charge if they have a higher

⁶² As previously noted, NEM2 customers might not reduce their overall energy costs.

load factor. Table 3-6 shows the benefits to the LRS-NEM customer class whose cost characteristics allow them to benefit, on average, under both the Simple three-part and TOU three-part proposed rate structures versus the current flat rate.

Table 3-6. Nevada Power LRS-NEM Average Bill Comparison

NEVADA POWER							
NEM Bills*							
MONTH	Current Flat-Rate (No Generation)	Current Flat-Rate	Current TOU	Simple 3- Part	TOU 3-Part	Net Percent Change**	
Jan	\$ 583.30	\$ 455.80	\$ 290.09	\$ 405.47	\$ 286.32	-11.0%	
Feb	\$ 815.22	\$ 652.86	\$ 399.67	\$ 554.85	\$ 386.03	-15.0%	
Mar	\$ 703.15	\$ 497.23	\$ 313.13	\$ 452.69	\$ 311.66	-9.0%	
Apr	\$ 718.58	\$ 484.30	\$ 305.94	\$ 529.43	\$ 329.09	9.3%	
May	\$ 808.56	\$ 595.91	\$ 368.01	\$ 591.76	\$ 379.39	-0.7%	
Jun	\$ 596.28	\$ 356.91	\$ 450.21	\$ 382.67	\$ 603.69	7.2%	
Jul	\$ 801.32	\$ 568.63	\$ 752.10	\$ 529.40	\$ 821.51	-6.9%	
Aug	\$ 823.42	\$ 578.60	\$ 765.17	\$ 547.27	\$ 869.75	-5.4%	
Sep	\$ 808.56	\$ 564.29	\$ 719.86	\$ 565.64	\$ 905.84	0.2%	
Oct	\$ 543.09	\$ 360.90	\$ 235.15	\$ 356.47	\$ 242.97	-1.2%	
Nov	\$ 507.28	\$ 300.28	\$ 202.10	\$ 299.86	\$ 209.86	-0.1%	
Dec	\$ 582.76	\$ 408.02	\$ 257.12	\$ 375.12	\$ 258.81	-8.1%	
Total	\$ 8,291.52	\$ 5,823.74	\$ 5,058.56	\$ 5,590.61	\$ 5,604.93	-4.0%	

NEM Savings	\$ 2,467.78	\$ 2,700.91	\$ 2,686.59
	30%	33%	32%

*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3- Part versus Current Flat Rate

SECTION 4: NET METERED LOAD SHAPE DEVELOPMENT

A. Overview of Load Data Development

The prime objective of the data acquisition and development of net metered loads is to establish the load shapes to be used for these classes in the Companies' marginal cost studies as well as quantifying the billing units with which to design rates. The available 15-minute data was used to develop the total load, generation, and excess load shapes for all customers in the NEM classes.

Total load (TL) is the sum of NV Energy's deliveries (D) to the customer, plus that portion of the customer's energy requirements being met by the customer's own generation, for which NV Energy is standing by to serve. Because some of the customer's generation flows back into NV

Energy's distribution system, the customer's total load is the sum of NV Energy's deliveries to the customer and the customer's generation output (G), less the energy received from the customer (R) by NV Energy, in any 15-minute interval.

Where D, G and R data are all available in 15-minute intervals, $TL_i = D_i + G_i - R_i$ (where subscript i represents one 15-minute period). Where D and R are not separately identifiable from 15-minute interval data, $TL = (D - R) + G$ for each month. D-R are the net billing units retained in the monthly billing data for customers with legacy meters, before their smart meters were installed. Monthly TL is spread to 15-minute intervals using the applicable load shape for each rate class for each month.

Early in 2015, Load Research began the process of determining and identifying the net metered customers as the relevant population for load shape development. For purposes of the Net-Metered Docket No. 14-06009, all active net metered customers as of March 31, 2015 were identified in establishing the population of customers to include in a load shape for marginal cost analysis. Nevada Power includes the entire population of Nevada Power net metered customers identified by the end of March 2015 for the entire study period of June 2014 through May of 2015.

Due to issues discovered during the installations of the north net metered customers' smart meters and the loss of some quarantined⁶³ 15-minute data, the effort to exchange south net metered customers from legacy to smart meters was delayed from its original target date. Therefore, net metered customers remained on legacy meters for some or all of the test period of this study. This applies to their bi-directional billing meter that measures the delivered and received energy. Some customers already had a smart meter on their generation meter and these meters were largely unimpacted by the quarantine.

In August of 2014, a new incentive program for renewable generation became available to customers, and as a result many were applying to become net metered customers. Meters for these customers were not exchanged to smart meters until the quarantine issue was resolved in mid-January 2015. Beginning March 2015, 15-minute smart meter data was available from both the bi-directional and generation meters for estimating load shapes. Prior to March 2015, there was sufficient 15-minute generation data from smart meters and 15-minute smart meter total load data for calculating representative load shapes. For customers without smart meters, interval generation is imputed from their installed capacity and the interval generation data of similarly sized NEM systems, and total load is imputed from their monthly billing determinants.

The following describes how NV Energy managed the data associated with the Nevada Power population of net metered customers and produced population level load shapes.

⁶³ Due to a manufacturer setting on the smart meters (related to protection against theft), some valid data being received by NV Energy from customers was flagged as potentially problematic and quarantined. Once quarantined, the data could not be recovered for use in the analysis. The resolution was a system wide upgrade that was implemented in January of 2015.

B. Generation Output

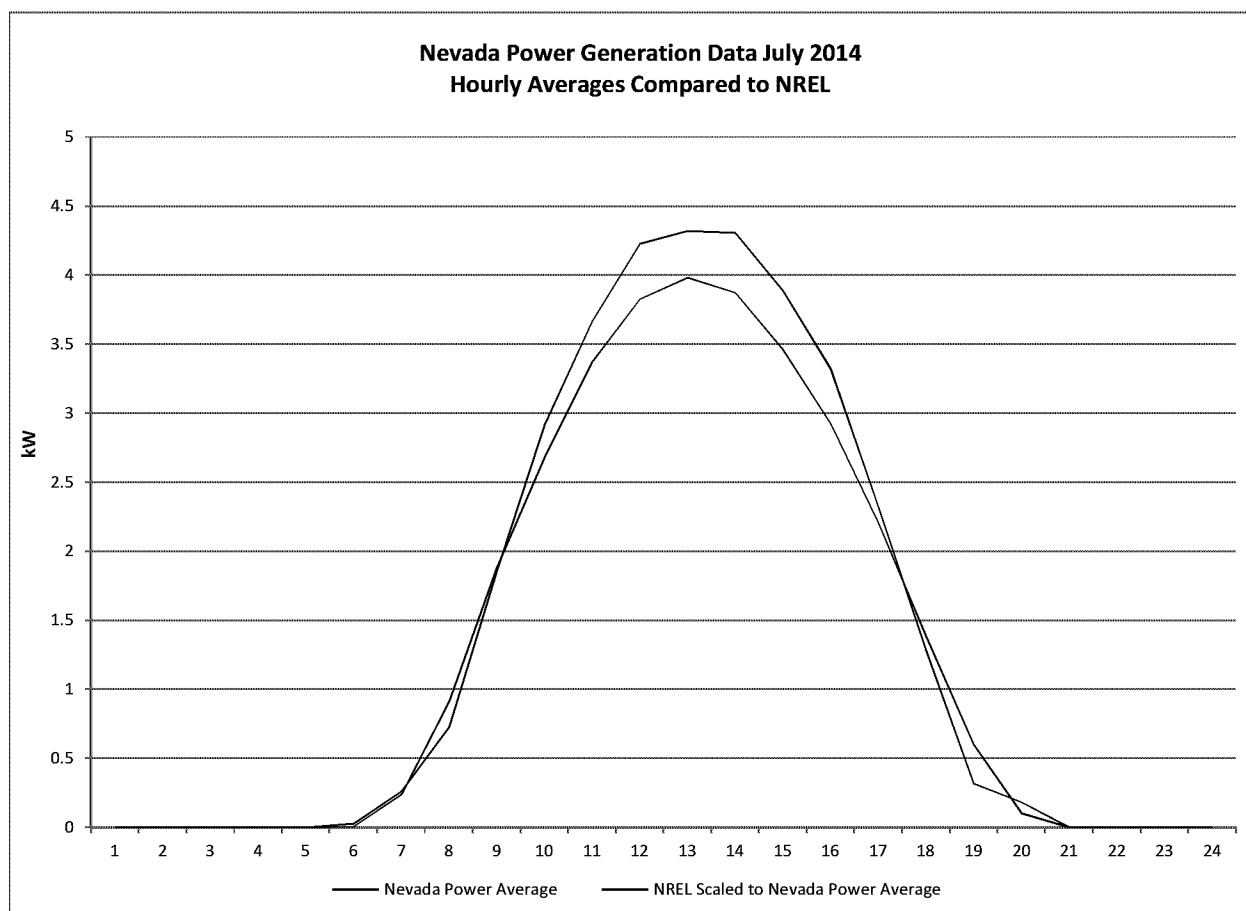
Some customers had a smart meter as their generation meter even when no smart meters were installed as their bi-directional meter. For these customers, actual generation data was used where available. Generation production for net metered customers without a smart meter on their generation was developed using information from customers described above with generation smart meter information. Average generation, by 15-minute intervals, were calculated for generation-metered customers, sorted by installed generation capacity into capacity blocks with 1,000 Watt block widths. For any customer with 15-minute generation data to fill, the estimated generation for that interval in the customer's capacity block was re-scaled by the ratio of the customer's own installed capacity to the average capacity for the block for each 15-minute interval. The average estimate is based on the customers who have at least 95 percent of the expected 15-minute interval generation data as detailed in Table 4-1.

Table 4-1. Total Count of Customers With Available 15-Minute Generation Data

Nevada Power Generation Data Customer Count	
	Solar Customers with Available Smart Meter Data
June, 2014	752
July, 2014	541
Aug, 2014	755
Sep, 2014	753
Oct, 2014	755
Nov, 2014	753
Dec, 2014	755
Jan, 2015	757
Feb, 2015	757
Mar, 2015	2174
Apr, 2015	2339
May, 2015	2340

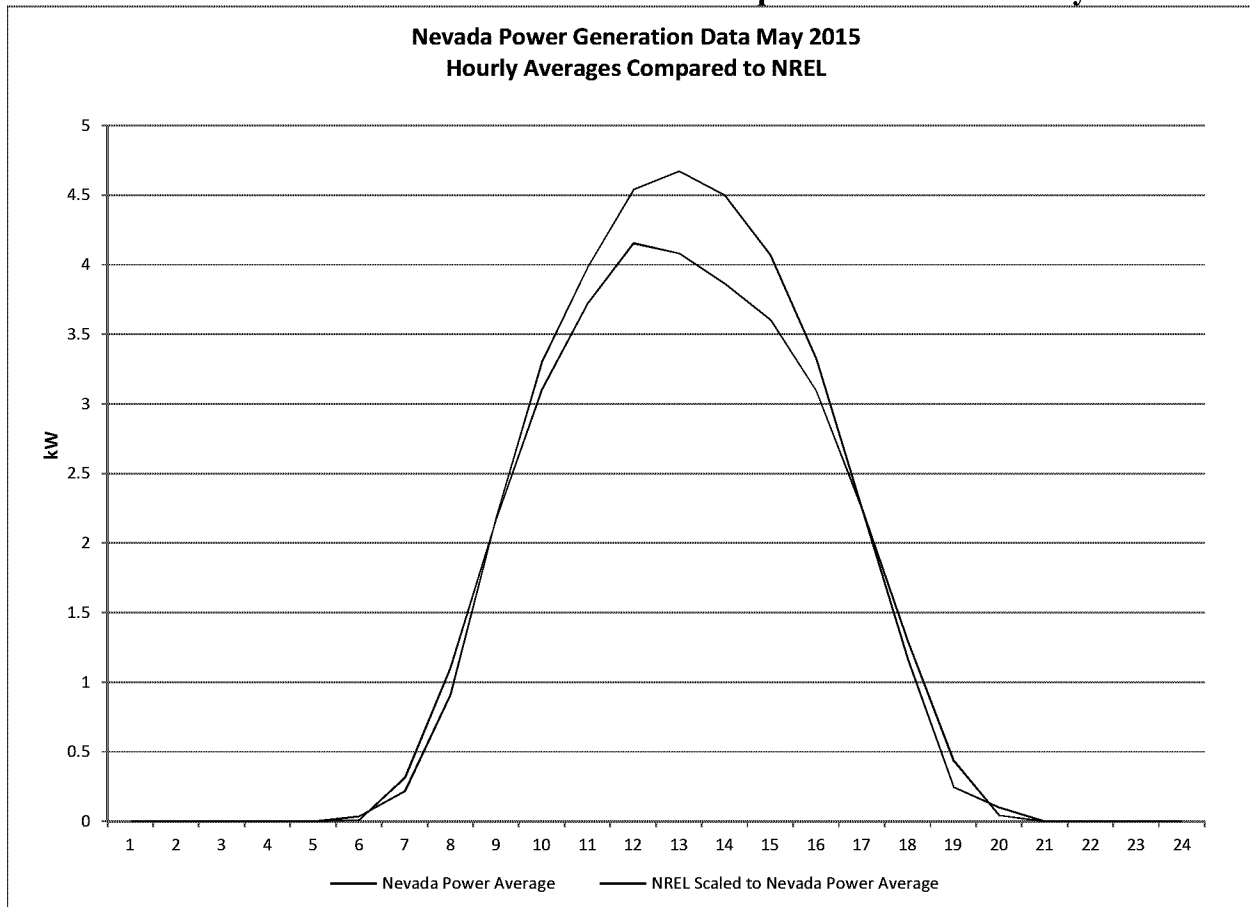
These counts of actual 15-minute generation data are more than sufficient to represent the average generation for Nevada Power net meter customers. Applying actual generation meter data from Nevada Power Customers, in combination with the averages from those customers re-scaled by relative capacity, to each of the customers without a smart generation meter, provides an accurate representation of what actually occurred for all net metered customers. Charts 4-1 and 4-2 show the comparison between actual generation data for Nevada Power net metered customers to the National Renewable Energy Laboratory's ("NREL") estimated generation for the Las Vegas MSA for the months of July 2014 and May 2015.⁶⁴ These charts show both the reasonableness of the NV Energy actual generation shapes as well as the uniqueness of them supporting the use of actual data, rather than NREL data.

Chart 4-1. Nevada Power Generation Data Compared to NREL for July 2014



⁶⁴ For details describing NREL's estimation tool, please see <http://pvwatts.nrel.gov/>. For our estimates the location was Las Vegas, DC System size 1.2 KW, and the array type was fixed (roof mount). Under cautions for interpreting the results, NREL notes the weather data used is representative of long term averages. Weather variations about average conditions in any particular year can cause observed generation to vary from NREL estimates by plus or minus 10 percent.

Chart 4-2. Nevada Power Generation Data Compared to NREL for May 2015



Charts 4-3 and 4-4 show the daily variability, in July 2014 and May 2015, respectively, of the actual daily maximum generation of Nevada Power NEM customers, compared to NREL data. These charts again reinforce the need to use actual data as it captures the daily fluctuations of actual generation compared to the NREL average estimates.

Chart 4-3. Nevada Power Daily Generation Maximums Compared to NREL for July 2014

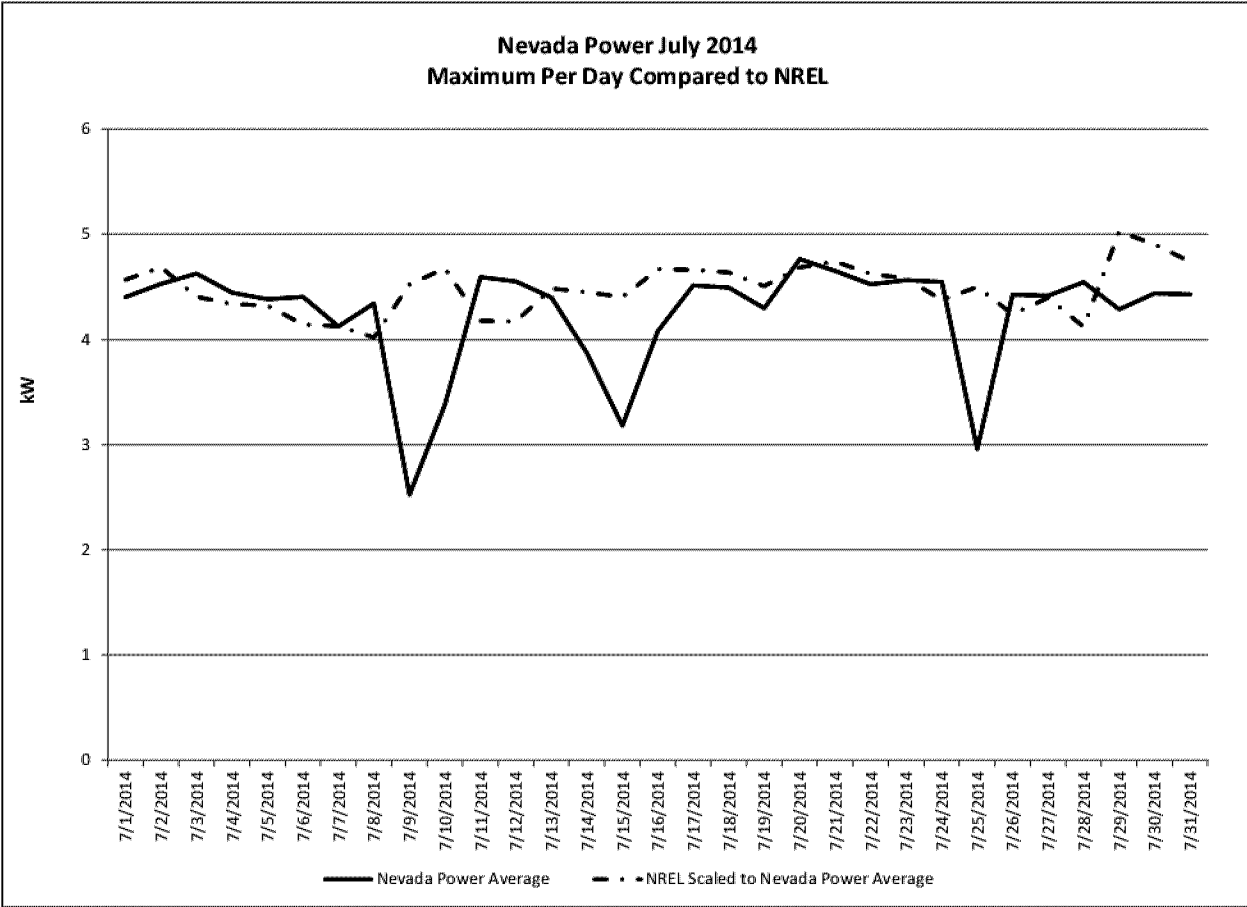
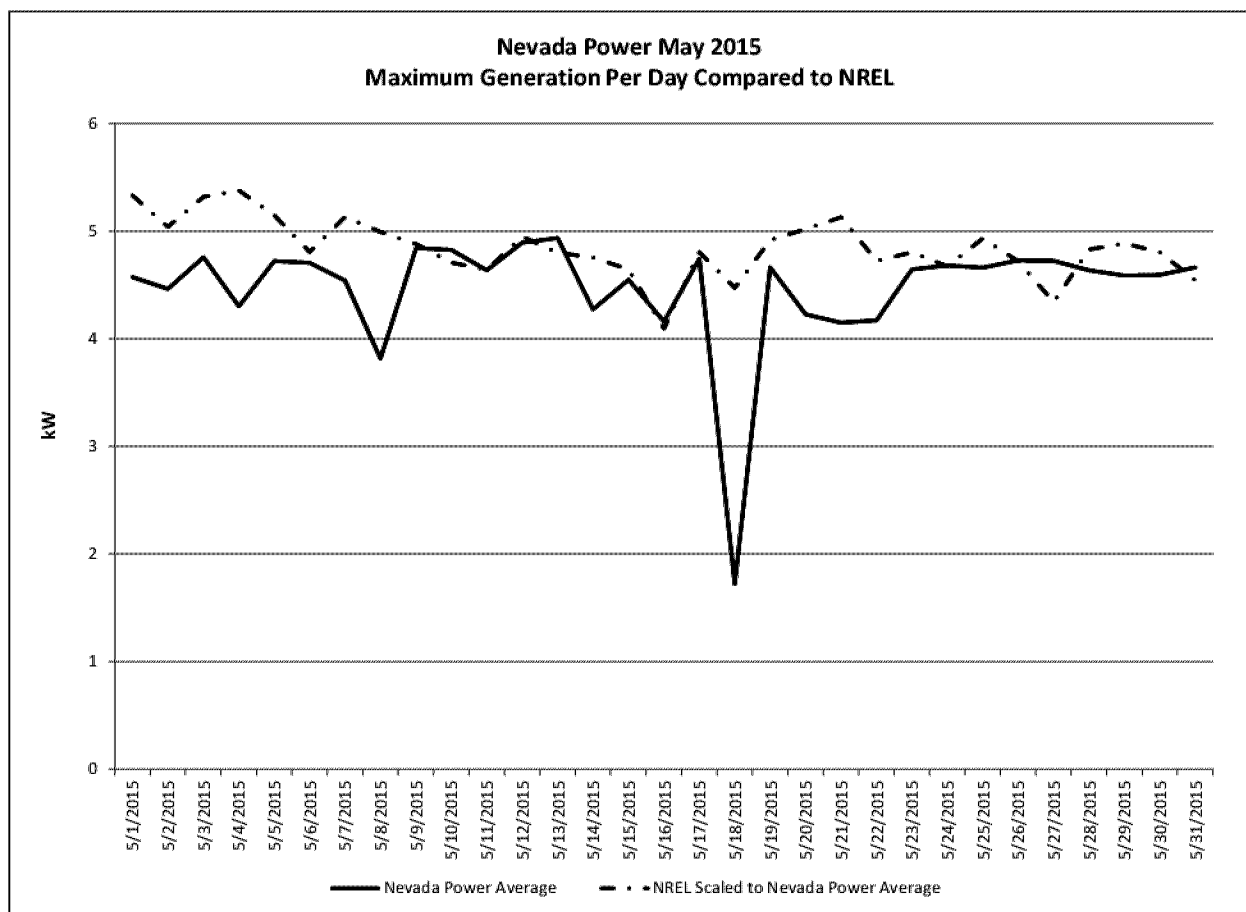


Chart 4-4. Nevada Power Daily Generation Maximums Compared to NREL for May 2015



C. Delivered and Received Energy

Population Sub-Groups

As of March, 2015, not all active net metered customers have 15-minute data available on both their generation meter as well as their bi-directional (billing) meter. The net metered population is split into two groups as a result.

Group 1

Group 1 consists of customers who became net metered customers by the end of March 2015 and who, prior to becoming a net metered customer but no later than June 1, 2014, had a smart meter for their residential flat rate service. The only Nevada Power rate class with customers in this group is Residential Single family (RS). For group 1 customers, in any period where smart meter data is not available, data was imputed by spreading their monthly billing determinants based on the shape of total load for those customers with available smart meter data. This is the load shape of other customers with available 15-minute total load data, prior to them becoming a net metered customer or subsequent to them becoming a net metered customer. These shapes are more applicable than using the otherwise applicable rate class load shape in order to capture the usage pattern of customers who become net metered. Using the spread total load for each

customer and subtracting either their own generation or imputed generation 15-minute data, the delivered and received levels were calculated. If the difference was positive, the usage was classified as delivered, if it was negative, the usage was classified as received. Group 1 as described above was broken down into two sub-groups: customers with all available data (coded “YES” in the data base) and those without all available data (coded “NO” in the data base.) The following describes each of the subgroups and how their load shapes were resolved for different months of the year:

1. Group 1: June 2014-February 2015

- a. YES – Group 1 customers that have available 15-minute kWh data from a smart meter, either as a net metered or as a flat rate residential customer prior to becoming net metered. Prior to a customer becoming net metered, Nevada Power uses their available 15-minute delivered kWh data as their total load and subtracts their estimated generation to estimate their net delivered and received to reconstruct each customer’s use as if they had been net metered during the study period. For each 15-minute interval, $TL-G = (D-R)$. After becoming net metered and the installation of smart meters, these customers will have 15-minute data for delivered, received and generated kWh, and their total load is: $TL = D+G-R$ as described below in 2a.
- b. NO –Group 1 customers without all available smart meter data, either because some data are not available prior to the customer becoming net metered, or after the customer became net metered prior to the availability of the smart meter data:
 - i. For customers who are not yet smart-metered, their total monthly billing kWh was spread by the shape developed from Group 1 a. above (YES group). From total load, subtracting the actual or estimated 15-minute generation produces net delivered and received. $TL-G=(D-R)$.
 - ii. During the month when a customer moves to net metering and subsequently, until 15-minute smart meter data are available, total monthly billing determinants were a) delivered minus received for the intervals of the month where the customer was net metered and b) total kWh data for all other usage when the customer was not net metered. To calculate the monthly total load, generation data for the month was added to the monthly billing determinants only for the intervals where the customer was net metered. The monthly kWh billing determinant when a customer is not net metered is the total load. The monthly total load is then spread by the shape developed from group 1a. and the 15-minute generation subtracted to calculate delivered and received for each 15-minute interval.

2. Group 1: March 2015-May 2015

- a. YES – These are Group 1 customers that have sufficient actual net metered 15-minute data for delivered, received and generated energy, to create total load. TL

= D+G-R. Sufficient data on the delivered level was conditioned on there being delivered usage within the first six hours of the first day of the month in order to process the entire month using actual data. These customers develop the shape of the total load for other customers who do not have sufficient interval data.

- b. NO - These are Group 1 customers whose 15-minute delivered and received data is not available. Total load was calculated from monthly billing determinants for delivered – received and the total generation for the month, based on actual metered generation data or average generation calculations scaled to the customer’s specific capacity. Total monthly load was spread based on the 15-minute total load shape from Group 1a. and the 15-minute generation subtracted to calculate delivered and received for each 15-minute interval.

Group 2

Group 2 consists of a) all customers who are net metered by March 31st, 2015, but do not have a smart meter prior to June 2014, and therefore do not have smart meter data available prior to becoming a net metered customer and b) net metered customers who have remained on a legacy meter. Customers in this group include residential single family (RS), residential multi-family (RM), optional residential single family (ORS), large residential single family (RSL), small commercial (GS), and medium commercial (LGS-1).

1. Group 2: June 2014-February 2015

- a. RS – these customers are processed exactly the same as the Group 1b. (NO) customers, using monthly billing determinants and actual or estimated generation to estimate monthly total load kWh, which are spread to 15-minute intervals by the total load shapes developed above in 1a, and using either estimated or actual generation where available to back out delivered and received.
- b. RM, ORS, RSL, GS, LGS-1 – all these customers are processed using monthly billing determinants. These totals are all spread by the shape of the otherwise applicable rate class because Nevada Power does not have any way to develop a total load shape based on just the net metered customers from these classes, as Nevada Power did with RS. Estimated generation scaled to capacity of each customer was used for calculating delivered and received from the spread total load.

2. Group 2: March 2015-May 2015

- a. RS – these customers are processed exactly the same as the Group 2b. (NO) customers, using monthly billing determinants, spread by the shapes developed above in 2a for the March – May 15 period, and using either estimated or actual generation where available to back out delivered and received.
- b. RM, ORS, RSL, GS, LGS-1 – all these customers are processed using monthly billing determinants. These totals are all spread by the shape of the otherwise applicable class because Nevada Power does not have any way to develop a shape

based on just the net metered customers from these classes, as Nevada Power did for RS. Estimated generation scaled to capacity of each customer was used for calculating delivered and received from the spread total load.

Total Population

Table 4-2 shows the breakdown of the Group 1 customers with complete data (Yes) and Group 1 customers that needed monthly billing determinant data because of unavailable interval data for the single-family residential rate class (RS). In addition, by rate class, the number of customers in Group 2 shows the remaining customers needing billing determinant data. These are customers identified as net metered by the end of March 2015 and included in the analysis for every month as if they were net metered the entire study period (thus the count remains the same for each month of the study). Group 2 customers do not have a smart meter prior to becoming a net metered customer or were already a net metered customer but again without a smart meter yet installed.

Table 4-2. Monthly Customer Counts by Population Sub-Group for Load Shape Development and Total Population⁶⁵

Nevada Power Total Customer Counts and Counts for Load Shape Development														
Nevada Power Group 1			Nevada Power Group 2						Nevada Power Total					
	RS		RS	RM	ORS	RSL	GS	LGS	RS	RM	ORS	RSL	GS	LGS
	YES	NO												
June, 2014	1847	32	3295	80	332	8	69	234	5174	80	332	8	69	234
July, 2014	1846	33	3295	80	332	8	69	234	5174	80	332	8	69	234
Aug, 2014	1845	34	3295	80	332	8	69	234	5174	80	332	8	69	234
Sep, 2014	1847	32	3295	80	332	8	69	234	5174	80	332	8	69	234
Oct, 2014	1845	34	3295	80	332	8	69	234	5174	80	332	8	69	234
Nov, 2014	1781	98	3295	80	332	8	69	234	5174	80	332	8	69	234
Dec, 2014	1643	236	3295	80	332	8	69	234	5174	80	332	8	69	234
Jan, 2015	1337	542	3295	80	332	8	69	234	5174	80	332	8	69	234
Feb, 2015	751	1128	3295	80	332	8	69	234	5174	80	332	8	69	234
Mar, 2015	1565	314	3295	80	332	8	69	234	5174	80	332	8	69	234
Apr, 2015	1710	169	3295	80	332	8	69	234	5174	80	332	8	69	234
May, 2015	653	1226	3295	80	332	8	69	234	5174	80	332	8	69	234

All of the customers in Group 1 with adequate data (YES) form the basis for the shape that is applied to all other RS customers. There is more than sufficient data for the load shape development given that current Nevada Power sample sizes for the RS class are typically around 500 customers to represent all other RS customers. In comparing the total load shapes of the Residential net metered customers to the otherwise applicable class, there were differences that warranted using actual net metered customer data for those with data rather than the otherwise

⁶⁵ For May of 2015, not all bi-directional meter data was available when the input was needed. A subsequent comparison of the total load shape once all data were available showed negligible change indicating that the 653 customers with available data were representative.

applicable class as shown in Charts 4-5 and 4-6 for July 2014 and May 2015. The delivered load shape is also included in the charts.

Chart 4-5. Unitized Residential Load Shape for Nevada Power July 2014

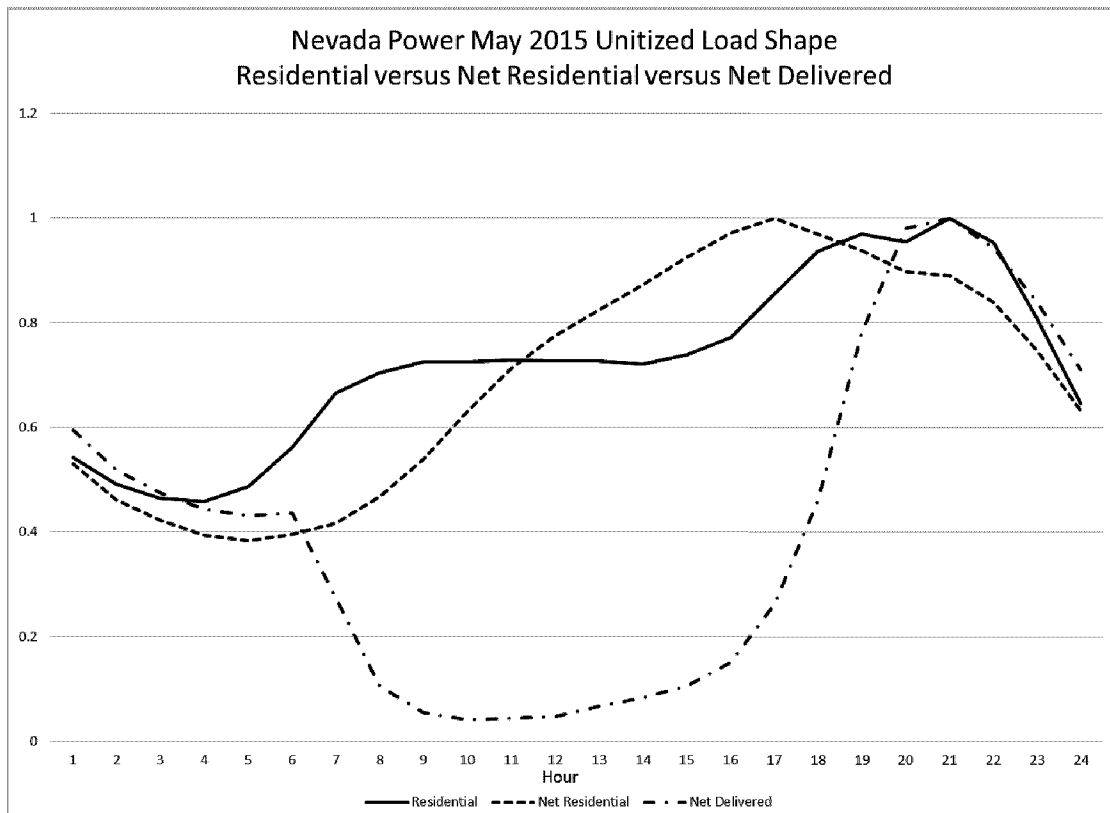
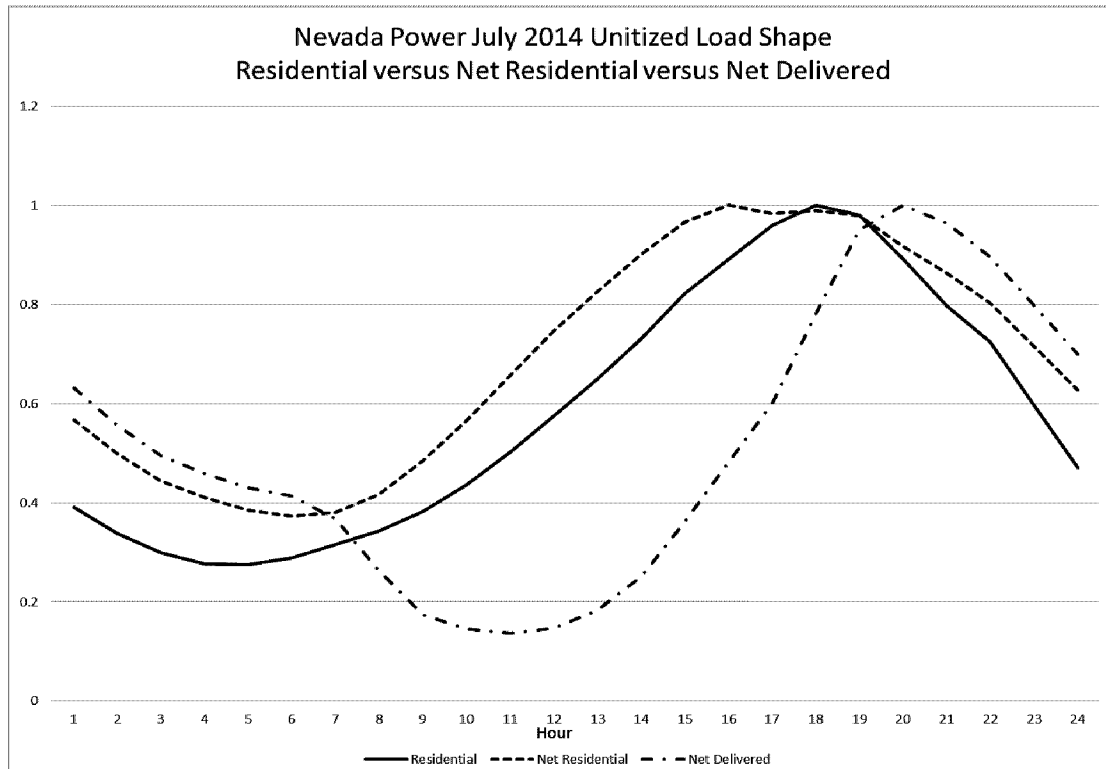


Chart 4-6. Unitized Residential Load Shape for Nevada Power May 2015



Monthly Notes

1. June 2014 through October of 2014 was processed without any actual delivered and received data because no customers have moved to the net metered class and received a smart meter.
2. November of 2014 through February of 2015 – many customers moved to the net metered class from the flat rate residential however the 15-minute data were not available for an entire month until smart meters were installed.
3. March through May 2015 – full months of delivered and received data were now available for almost all group 1 customers, allowing a load shape to be developed based on net metered customer's data as an actual net metered customer.

SECTION 5: PRODUCTION COST MODELING

The Resource Planning Department provided hourly loads, MEC and LOLP information as input to the Nevada Power and Sierra MCS for net metering customers in this filing.

All the data provided for use in the Nevada Power and Sierra MCS is based on the Preferred Plan from the 2015 Nevada Power Integrated Resource Plan, Docket No. 15-07004 ("2015 Nevada

Power IRP”). The data provided was either an input or output of the production cost model PROMOD.⁶⁶

PROMOD computes production cost by performing hourly, chronological economic unit commitment and dispatch of the Company’s electric production resources and market purchases to satisfy load requirements in a least cost solution over the planning period.

Hourly Loads. The Hourly Loads forecast is an input into PROMOD. The base hourly load forecast used in the analysis of the Preferred Plan was developed in January 2015 for Nevada Power and in March 2015 for Sierra.

Additional information on the development of the Hourly Loads can be found in the narrative and technical appendices of the 2015 Nevada Power IRP application. Additional information on how the hourly loads are used in the MCS can be found in Section 4.

Marginal Energy Costs. The MECs, which are an output from PROMOD, are a function of the hourly unit commitment and dispatch determined by PROMOD and represents the cost of the next MW to be generated or purchased. Many PROMOD inputs factor into the computation of the MEC, including the hourly load forecast, generator characteristics (*e.g.*, heat rate, max/min capacity), fuel and purchase power prices, and operating reserves.

The fuel and purchased power price forecasts used in the analysis of the Preferred Plan assumed the Clean Power Plan model. This forecast was prepared in May 2015. Additional information on the development of the fuel and purchase power price forecasts can be found in the narrative and technical appendices of the 2015 Nevada Power IRP application. Additional information on how the MEC is used in the MCS can be found in Section 3.

Hourly Loss of Load Probability. The LOLP is an output from PROMOD. The analysis starts with the Preferred Plan from the 2015 Nevada Power IRP. The analysis requires an additional PROMOD run because LOLP is determined for each Company on a stand-alone basis. That is, Nevada Power resources cannot prevent a loss of load occurrence for Sierra and Sierra resources cannot prevent a loss of load occurrence for Nevada Power. Several changes are made to the inputs to perform this analysis to determine under which conditions a loss of load will occur. Those changes include removing the One Nevada Transmission Line connecting Nevada Power and Sierra, removing the ability to make market purchases, and removing seasonal contracts. Additional information on how the LOLP is used in the MCS can be found in Section 3.

SECTION 6: CUSTOMER WEIGHTING FACTOR STUDY

The CWFS is an input into the MCS that contributes to the calculation of class Basic Service Charges. The customer class weighting factors are derived by determining the allocation of Customer Accounts expense (FERC accounts 901-905) and Customer Service and Informational expense (FERC accounts 906-910) among the groups of customer classes for each company (Nevada Power and Sierra). Those expenses are allocated to the class groupings based on a survey of the specific departments within each company that charge expenses to Customer

⁶⁶ PROMOD is a proprietary software product that the Company licenses from Ventyx, an ABB Company.

Accounts and Customer Services and Informational accounts in the test period for each Company. The allocation of expenses by class and by FERC account is divided by the number of customers in the class to derive a cost per customer. The cost per customer of the residential class is used as the basis to determine the weighting factor for each class grouping. That is, all weights are calculated relative to the residential class grouping. As such, the residential class grouping will have a weight of 1.00 and the weights of the remaining class groupings are calculated on a relative basis as the ratio of their expenses per customer to the residential class expense per customer. The resulting weights from the CWFS are then used as an input to the MCS study for each company and contribute to the calculation of the BSC for each class. The MCS and rate design, including specific discussion of the BSC components and calculation, are discussed above in Section 3.

In this particular case, the process of updating the CWFS started with existing studies for each company and a review of those studies from the filings in Docket No. 13-06002 and Docket No. 14-05004. Those studies were then updated with the appropriate allocations for two new Residential and Small Commercial NEM class groupings being separated out of the previous Residential and Small Commercial class groupings. The NEM groupings represented Residential NEM and Small General Service NEM customers. The allocations for all departments that had expenses in the FERC accounts 901 to 904 in the study for each company were reviewed. Collectively, those FERC accounts represent the Customer Accounts portion of the Customer Accounts and Services expenses represented in the CWFS.

The process was identical for updating each Company's study. NV Energy reviewed and discussed the survey results for the departmental Customer Accounts expenses with the designated representative from each department. The study identified and isolated the expenses related exclusively to NEM customers as a fraction or percentage of the total Customer Accounting expense of that department. NV Energy determined the percentage or dollar amount relative to total expenses that were incurred in that department on behalf of the Residential and Small General Service NEM customers. For some departments (such as the Call Centers), the allocation for the NEM groupings would unpredictably be zero. In that particular case, calls for NEM customers were routed to a different department and were not served by the Call Centers. For several other departments, the allocation would be equal on a per customer basis as the otherwise applicable class grouping. However, there were a few departments that had specific allocations of expenses to serve NEM customers.

There are expenses from the Billing Departments that are directly attributable to service provided for NEM customers. In the Nevada Power territory, there are three dedicated customer service representatives ("CSRs") for NEM customers as well as a portion of the supervisor's time in that department. The total expense related to those activities specifically identified as NEM is \$241,909. That total is allocated based on the percentage of premise numbers in each grouping relative to the total number of NEM premises. Similarly, in the Sierra territory, one CSR works full time in support of NEM customers while another spends half of their time in that support. A portion of the supervisor's time at Sierra is also dedicated to NEM customers. The total related expense at Sierra is \$111,761 and it is allocated using the same methodology as above. The employees in the Billing departments field telephone calls and manually review bills for the NEM customers. Many of the calls are to assist customers with understanding their bills. In addition to providing the customer with an overview of how the billing, including the banking of

kilowatt hours works, the CSRs also discuss the bill magnitudes and calculations with many customers. Customers often have an expectation that their NEM bill through NV Energy will be very small. The CSRs take the time to discuss each element of a customer's bill and help them to understand the fixed and variable charges on their bill as well as the banking mechanism. Despite being labeled Billing, when dealing with NEM customers the CSRs essentially serve as the customer's liaison to the company. In an informal poll of the department staff, some of the most common questions received show the diversity of the areas in which each representative must be able to serve the needs of NEM customers. The most common questions based on that informal poll are:

- Where am I in line to get my meter set?
- The PowerClerk Interconnect link in my email does not work. How do I get it to work?
- What is the Renewables Energy Package?
- The Survey Questionnaire is not working. What do I do?
- Why was I not notified there was a problem with access, the inspection, or any issues with the meter change?
- Why was my system not turned on when the meter was installed?
- How do I correct errors on my application?
- Why does my meter display a channel 5 and 15 and I am on time of use?
- Why does my meter show an error?
- How long will it take to see my usage online?
- The website says to look at my bill for my credits. Why do the credits not show online?
- What does net usage mean?
- Do I still need to conserve energy?
- Will I still have a bill after my system is installed?
- Why do I need two meters with the renewable energy system
- How can I find out how much energy I use?
- How do I read my bill?
- What does each of the line items on my bill mean?

As part of the study, a discussion was held with the department head, and it was indicated that the charges would increase proportionately as the number of NEM customers increased. As such, the cost per customer was not expected to change significantly as the number of customers increased.

Similarly, there were additional expenses related to NEM customers in the Electric Meter Operations Department. The expense in FERC 903 in each of those departments for residential NEM customers is estimated to be one third of the total FERC 903 expense to the residential classes (inclusive of NEM customers). Although the current percentage of expense related to NEM is also higher in other metering departments, since meters are still read manually, there are changes being implemented in those departments to eliminate the need for manual reads. That change is expected to be complete within the next 6 months, at which point, the NEM customers would incur the same expense per customer as the otherwise applicable class in each of those departments. Therefore, the same expense per customer was used for the NEM grouping as was used for the otherwise applicable grouping.

There were also NEM expenses reported by the Customer Programs and Services department. That department addresses complaints forwarded from the Commission. Based on correspondence with the head of that department, NEM issues have accounted for nearly 12 percent of the total complaints statewide. However, there are solutions presently being implemented that are expected to significantly reduce these complaints. Reflecting those solutions going forward, the allocation at Nevada Power of the department expenses for Residential NEM was estimated at 1.5 percent of the total expenses and the General Service NEM allocation was estimated at 0.25 percent. The allocation of those expenses at Sierra was estimated to be 1.0 percent and 0.10 percent for Residential and General Service NEM groupings respectively.

Additionally, departmental expenses were identified in the Customer Services FERC accounts, (906–910) that necessitated an investigation into their specific applicability to NEM customers. The result of this investigation was the determination that a portion of expenses from the Solar, Wind and Water Renewables department were directly attributable to the NEM customers. The department administers the application process for NEM customers. The majority of the labor in Solar, Wind and Water Renewable department is dedicated to processing the applications for NEM customers. Those expenses fall under the Services category, but were included in the study since they specifically serve the NEM customers. A more detailed discussion of the responsibilities of this department can be found in Section 8.

The allocation of expenses by each department was summed together and expressed as a weighting relative to the Residential Service class grouping. The resulting weightings for Nevada Power and Sierra with new NEM class groupings separately identified are shown in the Table 6-1 and Table 6-2.

Table 6-1. Customer Weighting Factor Study – Nevada Power

Nevada Power - 2015 Update to Customer Weighting Factor Study (updated from 2014 GRC filing)						
	Customer Accounts Expenses		Customer Services Expenses		Total	
	FERC 901-904		FERC 907-909		FERC 901-909	
Customer Class	Cost per Customer	Weight	Cost per Customer	Weight	Cost per Customer	Weight
Residential Service	\$41.91	1.00	\$0.78	1.00	\$42.69	1.00
Residential Service - NEM	\$51.62	1.23	\$14.08	17.95	\$65.70	1.54
General Service	\$45.04	1.07	\$0.66	0.84	\$45.70	1.07
General Service - NEM	\$118.87	2.84	\$29.75	37.91	\$148.62	3.48
General Service - DOS	\$116.58	2.78	\$0.00	0.00	\$116.58	2.73
Large General Service-1	\$78.92	1.88	\$6.65	8.48	\$85.58	2.00
Large General Service-1 - DOS	\$444.92	10.62	\$0.00	0.00	\$444.92	10.42
Large General Service-2 and 3	\$299.61	7.15	\$816.02	1039.75	\$1,115.63	26.13
Large General Service - 2 and 3 DOS	\$477.65	11.40	\$704.12	897.17	\$1,181.78	27.68
Extra-Large General Service - X	\$16,023.12	382.34	\$42,566.76	54237.24	\$58,589.88	1372.37
Overall Weight (n1)		1.05		3.50		1.10

The resulting weighting for the NEM class groupings have been highlighted in each of the tables. In the results for Nevada Power, it can be seen that the Total weighting for Residential NEM was 1.54 and can be compared to the 1.00 weighting of the Residential grouping. Whereas, the General Service NEM Total weighting was 3.48 in comparison to 1.07 for the General Service grouping. The higher weighting for the NEM groupings is driven primarily by the allocation of Billing and Customer Programs and Services in the Customer Accounts Expenses and the Solar, Wind and Water Renewables allocation in the Customer Services Expenses.

Table 6-2. Customer Weighting Factor Study – Sierra

Sierra Pacific Power - 2015 Update to Customer Weighting Factor Study (updated from 2013 GRC filing)						
	Customer Accounts Expenses		Customer Services Expenses		Total	
	FERC 901-904		FERC 907-909		FERC 901-909	
Customer Class	Cost per Customer	Weight	Cost per Customer	Weight	Cost per Customer	Weight
Residential	\$25.91	1.00	\$1.34	1.00	\$27.24	1.00
Residential - NEM	\$90.13	3.48	\$39.38	29.47	\$129.50	4.75
Small General Service	\$24.34	0.94	\$4.02	3.01	\$28.37	1.04
Small General Service - NEM	\$87.89	3.39	\$69.28	51.85	\$157.17	5.77
Med. General Service	\$32.63	1.26	\$47.68	35.69	\$80.31	2.95
Med. General Service -TOU	\$1,030.65	39.78	\$1,536.67	1150.14	\$2,567.31	94.24
Large General Service	\$775.17	29.92	\$4,918.83	3681.58	\$5,694.00	209.01
Large Transmission Service	\$1,907.72	73.64	\$13,396.21	10026.62	\$15,303.93	561.75
Large Transmission Service - DOS	\$2,719.80	104.98	\$11,683.88	8745.00	\$14,403.68	528.70
Overall Weight (n1)		1.032		3.55		1.16

The results for Sierra show that the Total weighting for Residential NEM was 4.75 and can be compared to the 1.00 weighting of the Residential grouping. The Small General Service NEM Total weighting was 5.77 in comparison to 1.04 for the Small General Service grouping. The higher weighting for the NEM groupings is driven primarily by the allocation of Customer Accounts Expenses for Billing and the Customer Services Expenses for the Solar, Wind and Water Renewable department.

The weightings for each of the class groupings in the CWFS serve as an input to the MCSs for Sierra and Nevada Power. The Customer Accounts and Services weightings combine with the meter costs in the MCS, found in Table 3 for Sierra and Table 4 for Nevada Power, to determine the cost used in developing marginal customer cost by class for the respective NEM classes.

SECTION 7: METERING COSTS

Similar to the analysis performed for a standard meter cost as input to the MCS in past GRCs, the metering costs incurred to serve NEM customers were prepared by the Companies' metering department. The studies were prepared as follows:

- Queries of the Nevada Power customer information system and the Sierra customer information system were conducted to identify all residential and small commercial NEM customers;
- NEM records were segmented by rate class and meter form;
- The rate class and meter form data was compiled into the appropriate residential and small commercial types in the South;
- The rate class and meter form data was compiled into the appropriate residential and small commercial types in the North;
- The resultant data was analyzed and processed to produce a weighted cost for each unique meter form type within the rate classes; and
- The weighted cost was also evaluated as to whether it was reflective of the costs going forward. No changes to the results were required.

A. Net Metering Billing Meter Exchange Process

In a NEM meter configuration, the flow of electricity is bi-directional, and requires a billing meter that can accurately measure the flow of power from the utility to the customer and subtract from it any excess generation returned to the grid, thereby indicating the net energy flow either into or out of a customer's point of service. When a customer elects the net metering service, the Company is required to perform a billing meter exchange from a standard billing meter to a net billing meter. It is noteworthy to mention that the replacement billing meter is identical to the existing billing meter except that the net billing meter is configured (programmed) specifically to perform the measurement of bi-directional energy flows while the standard billing meter is configured to only measure the flow of energy delivered to the customer.

B. Net Metering Installation Process

The Company is required to perform a utility safety inspection prior to the installation of a net billing meter. The purpose of the utility safety inspection is to ensure the DG system is electrically installed and connected to the service equipment properly, in adherence to the Companies' installation standards. This utility safety inspection is performed by either a utility metering engineer, a journeyman metering electrician classification in the south, or an equivalent journeyman meter technician classification in the north. Once the inspection is completed, for either an incentive or a non-incentive net metering customer, the Companies replace the existing standard billing meter with a billing meter that is programmed to measure bi-directional energy flows. The billing meter replacement process includes the unlocking of a meter security lock and ring, a complete inspection of the meter socket (including performance of voltage and back-feed

checks), exchanging the meter, and then re-locking the meter security ring and sealing the lock. Due to the skillset requirements associated with understanding the complexity of DG system installations and the associated electrical connections, a journeyman metering electrician or meter technician performs all net metering installation activities.

C. Billing Meter Exchange Cost

The NEM billing meter cost of service detail includes the following components for exchange of a billing meter:

- Cost of programmed net billing meter
- Labor to exchange billing meter
- Additional safety inspection labor
- Average cost for Residential Single Family NEM South customer - \$222.01
- Average cost for Large Residential Single Family NEM South customer - \$319.17
- Average cost for Residential Multi-Family NEM South customer - \$232.40
- Average cost for Small General Service NEM South customer - \$363.79
- Average cost for Residential Single Family NEM North customer - \$217.86
- Average cost for Small General Service NEM North customer - \$366.55

D. Net Metering Generation Meter Installation Process

In order to accurately measure the generation of the system energy output, the Companies install a second meter at these premises on the customer's generation source which is referred to as the generation meter. The primary purpose of the generation meter is to measure the energy produced by the generator ahead of, and separately from any connected load to the home or business. Under the NEM2 proposal, all NEM2 customers will have a generation meter. As a result of this requirement, the Companies are required to install an additional meter which typically matches the service characteristics of renewable generation source and the existing net meter. For all meter installations, the customer is responsible for providing the meter socket under Rule 16.

The generation meter cost of service detail includes the following components:

- Cost of the meter, including the cost of any current transformers ("CTs") and potential transformers ("PTs") (if required)
- Engineering labor for review of renewable generation source service connection and equipment

- Installation of generation meter
- Average cost for Residential Single Family NEM South customer generation meter - \$137.98
- Average cost for Large Residential Single Family NEM South customer generation meter - \$866.89⁶⁷
- Average cost for Residential Multi-Family NEM South customer - \$137.98
- Average cost for Small General Service NEM South customer generation meter -- \$730.43
- Average cost for Residential Single Family NEM North customer generation meter - \$228.58
- Average cost for Small General Service NEM North customer generation meter - \$1,007.72

The average cost of generation meter installations is higher in the north than in the south primarily because the mix of meter types in the available data queries is slightly different in the two regions, and the volume of the simpler form 2S meter installations is much higher in the south, which brings down the weighted average meter cost.

E. Cost Differential Between Standard and Net Metered Customers

Differences in metering costs between net metered service and standard service are driven by differences in the physical installation of renewable generation. The primary difference is that every renewable generation system is configured for its particular orientation and the space available to install it, and that results in the service equipment connection being somewhat unique at each net metered service point. To ensure public and employee safety and the National Electrical Code promulgated by the National Fire Protection Association, the Companies perform inspections to ensure that the connections are correct and secure. This is both in the interest of safety for our customers and in compliance with NRS 278.583 which states, in part:

After January 1, 1974, any construction, alteration or change in the use of a building or other structure in this State by any person, firm, association or corporation, whether public or private, must be in compliance with the technical provisions of the *National Electrical Code* of the National Fire Protection Association in the form most recently approved by the governing body of the city or county in which the building or other structure is located.....

⁶⁷ The cost for Large Residential Single Family generation meters was derived using the same meter forms as the installed net meter for the class, as found in other classes in the existing database. This is appropriate as meter investment costs are based upon the meter form and are not dependent on customer class.

Additionally, the meter must be readily accessible for ongoing maintenance per established Utility Rules. Because most of the installations are retrofits rather than new construction, space limitations frequently present challenges. It should be noted that in past years, the failure rate of the necessary safety inspections was less than 10 percent. With the recent marked increase of net metering installations, that figure is well in excess of 25 percent. The Companies are working to educate many of the new installers that have entered in to the Nevada market to ensure they are aware of Nevada code and safety standards. However, it is apparent that the large number of new contractors and installers, many of whom are new to Nevada, are not in compliance with or providing the necessary training to be aware of the Companies' safety standards. The increased ratio of failed safety inspections necessarily leads to substantial additional work by the Companies metering personnel to re-inspect the failed installations, along with the work the Companies are doing to educate and communicate with the contractors. Finally, past experience is that many of the net metering installations require adjustment or rework to meet the Companies' standards, thereby requiring additional inspection labor.

SECTION 8: RENEWABLE ENERGY ADMINISTRATIVE COSTS

A. Description of Existing Programs

NV Energy administers several programs to encourage the development of DG systems. Collectively, they are referred to as the RenewableGenerations program, and encourage development in solar photovoltaic, wind, and hydro systems less than 500 kW in capacity. The program was originally conceived with legislation passed in 2003 and augmented in 2009. The 2009 changes drive the current parameters of the program. In that session, \$255 million was allocated for the development of solar photovoltaic DG, and \$40 million was allocated for wind and waterpower generation.

The program costs include incentive payments, an implementation contractor, program management software, marketing, education, training, and utility administration. Most of these costs are included in the Renewable Energy Program Rate ("REPR") established by statute under NRS 701B. These program costs are paid for by all NV Energy customers under the REPR. NRS 701B excludes utility administration labor from being recovered through that mechanism. These labor costs are instead included as part of the Base Tariff General Rate ("BTGR").

The program plan is subject to review and approval by the Commission on an annual basis. The recovery of program expenditures under REPR are also subject to the annual Deferred Energy Accounting Adjustment proceeding. Utility administration labor costs are included for review and approval through the program annual plan process, and those costs are included in the GRC filings made by the Companies every three years for proposed inclusion in the BTGR.

Utility administration labor is applied in the following critical areas of this program. This labor may be used to conduct all or part of these activities:

- The onsite day-to-day management of the implementation contractor.

- The coordination of program activities with other utility departments and programs, including accounting, billing, metering, corporate communications, legal, distribution planning, engineering, information technology, regulation, and governance.
- The development of program policies and procedures.
- Reporting and analysis of program participation.
- Educating customers and contractors on how to participate in the program.
- Consultation with customers on program rules and guidelines.
- Consultation with the existing customer base on net metering billing issues.
- Development and submission of the required regulatory filings.
- Providing technical expertise on distributed generation systems.
- Tracking distributed generation system production for the application of Portfolio Energy Credits for the Renewable Portfolio Standard.

In the 2014-2015 Plan Year (July 1 – June 30), the program received 13,497 applications totaling 103.93 MW of capacity. This represents a forty-fold increase over the 308 applications received in the 2013-2014 Plan Year. It is anticipated that in the 2015-2016 plan year, these application rates will continue. As of July 9, 2015, \$215.4 million in incentives have either been paid or reserved toward the \$255 million solar allocation. Additionally, \$29.3 million in incentives have either been paid or reserved toward the \$40 million wind and hydro allocation.

B. Total Costs Incurred Used for the MCS

The costs utilized for the MCS included in this filing are based on the actual costs incurred from the most recent GRC filings for each Company respectively. The company department overseeing the program is a shared resource between the Companies. Therefore, the total cost is a summation of the actuals from the two filings. While the volumes have increased tremendously since those costs were incurred, the increased volume has been addressed mostly through the addition and retooling of outside resources. The utility department responsible for managing the RenewableGenerations has a similar make-up as during the last GRC, resulting in a reasonable approximation of total costs for both combined utilities as of this filing. While the costs in total did not change from those used in the most recent GRCs, the allocation of these costs between Companies was updated to reflect the most recently approved budgets on a percent of total basis.

As the program transitions from attracting new customers to serving a much larger base of existing customers, additional utility administration labor is needed going forward. Based on this MCS, the additional utility administration labor would grow at a rate similar to the growth of the net metering customer base.

C. Allocation Between the Utilities

A significant change in the program since the last GRC filing is how the utility administration labor is allocated between the Companies. At the time of the GRC filing, the program only processed a few hundred applications per year. More of the projects utilized wind and waterpower technology, which generally have better resources in the Sierra's service territory, which is reflected in the actual cost incurred. Table 8-1 illustrates the previous allocation based on the costs incurred:

Table 8-1. GRC Actuals Allocation

	cost	percent
NPC actual 907/908 costs	\$ 48,610	35%
SPPC actual 907/908 costs	\$ 89,424	65%
TOTAL	\$ 138,034	100%

Since that time, the solar photovoltaic industry has grown substantially in southern Nevada. Recognizing this changing trend, the Companies proposed a change in allocation in the annual plan filed and approved by the Commission in Docket No. 15-01052, as shown in Table 8-2.

Table 8-2. RenewableGenerations Budget Filed and Approved in Docket 15-01052

Utility Administration July 1, 2015 June 30, 2016				Percentage Overall Allocation		
	Total Both Companies	NPC	SPPC	Total Percentage Allocation	NPC	SPPC
SolarGenerations	\$ 284,000.00	\$ 206,042.00	\$ 77,958.00	76.8%	55.7%	21.1%
WindGenerations	\$ 62,000.00	\$ 6,200.00	\$ 55,800.00	16.8%	1.7%	15.1%
HydroGenerations	\$ 24,000.00		\$ 24,000.00	6.5%	0.0%	6.5%
Total	\$ 370,000.00	\$ 212,242.00	\$ 157,758.00	100%	57%	43%

For the Solar utility administration budget, the allocation was based on the overall customer allocation between the Companies. The overall customer allocation was 72.55 percent south and 27.45 percent north as of December 31, 2014. The wind budget allocation did not change from previous filings, and was based on a 90 percent allocation to the north and a 10 percent allocation to the south as originally approved in the annual plan filing in Docket No. 11-02001. This split is reflective of the historical utilization of the wind program, with a superior wind resource concentrated in the north. The hydro budget is fully allocated to the north, as those resources exist only in that region. This allocation was also approved in Docket No. 11-02001.

To derive the utility allocation cost for this study, the 57 percent / 43 percent allocation from Table 8-2 was applied to the total cost summed in Table 8-1 to arrive at an adjusted actual cost for the programs for each utility. These total adjusted costs are shown in Table 8-3.

Table 8-3. GRC Adjusted Actuals

	cost	percent
NPC adjusted actual 907/908 costs	\$ 78,679	57%
SPPC adjusted actual 907/908 costs	\$ 59,355	43%
TOTAL	\$ 138,034	100%

D. Allocation Between the Customer Classes - Sierra

The allocation by category for the Residential, Residential Net Metered, Small General Service and Small General Service Net Metered at Sierra are based on the total number of net metered systems that are installed and the total net metered systems that are reserved and currently active as of July 9, 2015. Due to the rapidly changing customer counts, utilizing the latest customer counts is a reasonable approach to ensure accurate allocation.

Sierra currently has 1,186 installed projects and 409 projects that are reserved and active for residential customers. There are 508 installed commercial projects and 58 commercial projects that are reserved and active. A 6 percent attrition rate in these categories was used to allocate some of the costs to the Residential and Small General Service categories for the customers who apply to the program, but do not proceed with their proposed projects. The 6 percent attrition rate is an approximation based on what is being experienced in the current program year. The attrition rate in prior program years has been higher, but the change in the program from a lottery to being open all the time, as well as the newly instituted application fee has greatly reduced attrition. The majority of the allocation goes to the Residential Net Metered Rate with 69.38 percent of the allocation and 4.43 percent of the allocation to the standard residential rates. The Small General Service Net Metered category is allocated 24.62 percent and the Small General Service is allocated 1.57 percent. Table 8-4 outlines these allocations.

Table 8-4. Customer Class Allocations

SPPC	Incentivized Pipeline	Installed	Total	% of Total	% per Category Non-Net Metered*	% per category Net Metered
Residential Customers	409	1,186	1,595	73.81%	4.43%	69.38%
Commercial Customers	58	508	566	26.19%	1.57%	24.62%
Total	467	1,694	2,161	100%	6%	94%

E. Allocation Between the Customer Classes – Nevada Power

The allocation by category for the Residential, Residential Net Metered, Small General Service and Small General Service Net Metered at Nevada Power are based on the total number of net metered systems that are installed and the total net metered systems that are reserved and currently active as of July 9, 2015. Due to the rapidly changing customer counts, utilizing the latest customer counts is a reasonable approach to ensure accurate allocation.

Nevada Power has a high penetration of residential customers compared to commercial customers. This is due to most of the installations being installed through third party solar providers that market heavily to residential customers. In the Nevada Power service territory there are currently 7,075 installed residential projects and 10,861 reserved and currently active projects as of July 9, 2015. A 6 percent attrition rate in these categories was used to allocate some of the costs to the Residential and Small General Service categories for the customers who apply to the program, but do not proceed with their proposed projects. The 6 percent attrition rate is an approximation based on what is being experienced in the current program year. The commercial sector has 402 installed projects and 75 reserved and currently active projects. The majority of the allocation goes to the Residential Net Metered Rate with 91.54 percent of the allocation and 5.84 percent of the allocation to the standard residential rates. The Small General Service Net Metered category is allocated 2.46 percent and the Small General Service is allocated 0.16 percent. Table 8-5 outlines these allocations.

Table 8-5. Customer Class Allocations

NPC	Incentivized Pipeline	Installed	Total	% of Total	% per Category Non-Net Metered*	% per category Net Metered
Residential Customers	10,681	7,075	17,756	97.38%	5.84%	91.54%
Commercial Customers	75	402	477	2.62%	0.16%	2.46%
Total	10,756	7,477	18,233	100%	6%	94%

SECTION 9: ACCOUNTING FOR NEM INSTALLATION IN DISTRIBUTION DESIGN AND PLANNING

The distribution system, from both design and capacity planning standpoints, must be able to accommodate the full estimated peak load demand of a net metering customer in a standby mode should the net metering installation generation output be zero for any reason. The distribution design for customer additions with net metering installations is completed based upon the expected estimated peak load demand of the customer, with required cables and transformers being sized based upon the need to reliably serve the estimated peak load demand of the customer. The capacity allocated on the distribution system and the service requirements to connect the customer's load to the distribution system, other than metering requirements, are based upon the estimated peak load demand for the customer absent any generation. There is no quantified reduction in cost for the primary distribution system when a customer installs their own generation. The potential increase to cost has also not yet been directly studied by the Companies.

There are approximately 9,171 net metering installations in NV Energy's service territory, 7,477 at Nevada Power and 1,694 at Sierra.⁶⁸ This represents approximately 0.76 percent⁶⁹ of all NV Energy customers, which is a very low level of overall penetration. These installations are currently dispersed in the service territory sufficiently that there are not significant clusters of

⁶⁸ Total Number of Net Meter Customers as of July 8, 2015. See Tables 8-4 and 8-5 above.

⁶⁹ Based on Total Customer Count in the Revenue Analysis by Rate Schedule Report as of March 31, 2015.

such installations on a distribution feeder or physical area. This is because the vast majority of such installations occurred well after the construction of the residential homes or businesses through customers' application and approval into NV Energy's Solar Generations program. Lower overall penetration levels of Net Metering customers that are geographically dispersed (not clustered) do not yet cause any significant detrimental effects on the distribution system, and therefore, do not support altering of distribution design criteria and distribution planning methods to account for such installations.

Additionally, although targeted to answer different questions regarding DG installations on the distribution system, the results of a study performed by Navigant Consulting, Inc. in 2010 on NV Energy's distribution system associated with Docket 10-04008 did not reveal any necessity for altering distribution design criteria and distribution planning methods in response to DG installations, and did not support any cost reductions.

A. Factors in Evaluating Potential Effect of Net Metering Installations on the Distribution System

The general factors to consider in determining whether or not there may be potential effects on NV Energy's distribution system that may result in cost impacts due to Net Metering customers include:

- Installed generating capacity
- Excess energy flowed back onto the distribution system
- Penetration level
- Logistics
- Local distribution system characteristics

Lower installed Net Metering generating capacity and lower penetration levels associated with Net Metering customer installations will generally not cause significant effects on the distribution system, while higher capacity and penetration levels could result in effects, depending upon other factors.

Logistics, both in terms of physical location and orientation, play a great part in the potential effects of Net Metering customer installations on the distribution system. For example, the generating output of an installed rooftop solar PV installation will vary dependent upon both the local solar irradiance and the directional orientation in which the panels are installed. Logistical differences also determine what distribution feeder or substation the installation will be connected to, and the distance from the substation to the net metering installation is also a factor with respect to the installation's effect on the distribution system.

Clustering of net metering installations such as residential rooftop solar PV could occur if all or most of the homes in a residential subdivision are marketed and sold with the PV array already integrated into the home design, or if the majority of homes in a subdivision were to install PV arrays after construction due to a targeted marketing effort. Significant localized clustering of

residential rooftop solar PV could have an effect on the local distribution system with respect to load flow, voltage, or power quality.

The voltage class, length and sizing of conductors, and the number and location of distribution line capacitors and voltage regulators, are also factors in determining whether or not net metering installations will have significant effects on the distribution system. Lower voltage class, longer length distribution feeders with smaller conductor sizes may be more susceptible to the effects of net metering installations as those feeders will tend to be more susceptible to a wider variability of voltage along the feeder, and will generally have more distribution line capacitors and voltage regulators installed whose operation could be affected.

B. Determining the Effects and Cost Impacts of Net Metering Installations on the Distribution System

Thus far, the Companies have not experienced any documented detrimental effects on the distribution system as a result of DG or net metering installations. Nor have the Companies experienced any documented beneficial effects on the distribution system as a result of DG or net metering installations.

The determination of whether or not net metering installations will have significant effects on the distribution system resulting in cost impacts is site-specific. Should installed net metering generating capacity, penetration level and clustering of net metering installations become sufficiently large in the future, the following effects on the distribution system could occur and require actions that would produce cost impacts:

- Thermal overload of distribution primary and secondary cables/conductors or transformers due to reverse power flow, resulting in a capital cost requirement to install new or upgraded facilities.
- Limitations imposed on operational switching to avoid creating detrimental effects on the distribution system that previously did not exist, resulting in increased operating and maintenance cost.
- Increased requirement to manage line voltage regulator and line capacitor bank switching and control settings, resulting in possible operating and maintenance and capital costs to implement new methods or systems.
- Unacceptable voltage rise, unbalance, or flicker, and harmonics, resulting in a capital cost requirement to install new or upgraded facilities.
- Decreased power factor due to reduction of kW demand without a corresponding reduction in kVAR demand, resulting in a capital cost requirement to install new distribution capacitors.
- Increased operation of substation transformers load tap changer operations resulting in possible operating and maintenance and capital replacement costs.

- Requirement for new or upgraded tracking and monitoring systems, including DMS and/or SCADA, and consequent communication infrastructure, resulting in possible operating and maintenance and capital costs to implement such new systems.
- Requirement for new or upgraded protection schemes and equipment to ensure reliable system operation under reverse power flow conditions or to limit such power flow, resulting in possible operating and maintenance and capital costs to implement such new schemes and equipment.

The Companies have not included these possible cost impacts in the MCSs, because they will require more study as to the level of the problem, the remedies and the eventual costs.

Through tracking of existing and new Net Metering applications, installations, and generating output, NV Energy can determine if an individual installation, or a group of installations, may cause effects on the distribution system that may result in cost impacts.

Two main approaches can be used to determine the effects and consequent potential cost impacts of net metering installations. The first approach is proactive and requires advanced study of the distribution system to identify potential constraints and the corrective actions that may be necessary. Such studies are commonly referred to as hosting capacity studies, which can be performed either system-wide or targeted to specific areas of the system or to specific distribution feeders, with the goal of quantifying the ability of the distribution system to accommodate an aggregate of net metering installations before the effects of such installations may result in system constraints, and consequently the requirement for system improvements resulting in cost impacts.

The second approach is reactive and involves studying individual net metering installations as they enter an application queue, for example, as part of the Solar Generations program. Distribution system constraints, necessary system improvements, and consequent cost impacts can be identified at that time.

C. Modeling the Effects of Net Metering Installations on the Distribution System

In order to fully understand the effect of net metering installations, and PV installations in particular, time-sequence load flow modeling studies are required on the distribution system under variable load and PV generation output conditions (both time of day and seasonal). In addition to steady-state modeling, dynamic studies on the distribution system may be required. However, NV energy has never performed dynamic studies on the distribution system.

NV Energy recently obtained the DNV-GL Synergi Electric load flow modeling software which has the capability of modeling solar PV generation and performing steady-state time-sequence studies to model the effect of changing solar PV output versus changing load demand. However, the Companies are in the process of implementing the new software and it is not yet in production. Once the software is implemented, NV Energy will be transitioning to using it in the performance of various types of studies of the distribution system. Consequently, NV Energy has not yet performed time-sequence and/or hosting capacity studies on the distribution system.

NV Energy presently plans to implement the new DNV-GL Synergi Electric load flow modeling software and receive training on the performance of steady-state time-sequence and hosting capacity studies utilizing the software by the end of 2015. Therefore, it is anticipated that the Companies should be in a position to begin utilizing the software to perform such studies in 2016. NV Energy would also anticipate utilizing the services of an industry consultant to perform or participate in the performance of such studies.

Until future studies indicate otherwise,, the Companies do not believe there is any basis for altering the distribution design criteria and planning methods for the distribution system based upon NEM installations.

SECTION 10: ACCOUNTING FOR NEM INSTALLATION IN TRANSMISSION DESIGN AND PLANNING

NV Energy has not experienced documented beneficial effects on the transmission system as a result of DG or NEM installations. For example, DG and net metering have not reduced current transmission investment and are expected to have limited impact, if any, in reducing the need for future transmission investment. While the current level of DG does not negatively impact the NV Energy transmission system, if DG levels, and solar PV in particular, were higher, cloud and time of day caused variations in the output of PV are expected to significantly increase daily ramping and reactive requirement. That could require transmission operator actions similar to responding to conventional unit tripping but without the power pool reserve sharing capability available.

A. Factors that are Considered in the Planning of the NV Energy Transmission System

The NV Energy transmission system is a sub-component of a large interstate grid known as the Western Interconnection. The NV Energy grid was, and is, designed to meet numerous needs and to supply varied services. These include load service, import, export, generation interconnection, transmission interconnection, cross system wheeling, inter-regional reserve sharing, and increased outage flexibility and reliability.

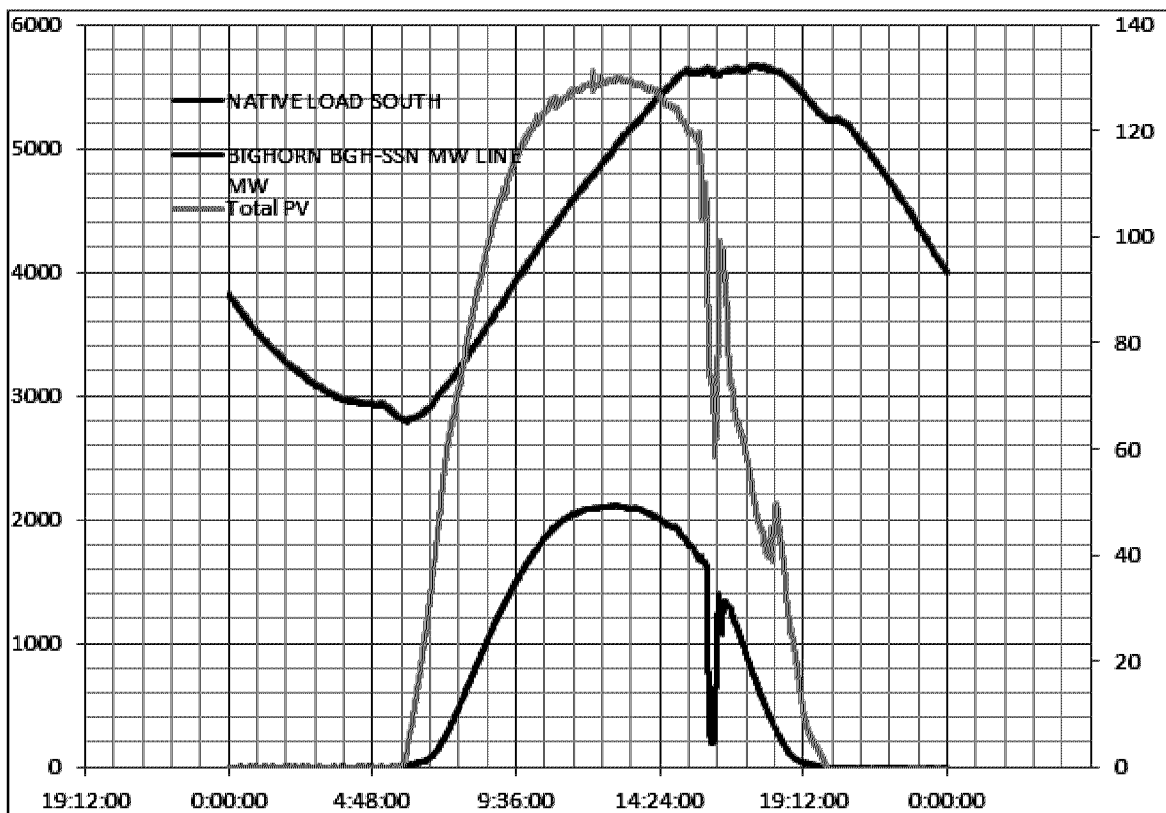
The NV Energy bulk electric transmission system planning focus has shifted dramatically over the last 15 years. The Company has changed from primarily designing for import capacity and system upgrades to serve load growth to primarily providing transmission and generation interconnection and access for alternate energy supplies. Since 2008, load growth in non-industrial, non-major commercial areas has been flat with the majority of load service expansion planning being for mines, casinos, server farms, and new technology. Major transmission has been focused on integrating and delivering renewable and/or high efficiency thermal resources to replace retiring generation and/or market purchases. The ON Line project, Harry Allen transformer addition, and numerous PV, geothermal and wind interconnections are examples.

B. Factors that are Considered when Distributed Generation Output is Compared to Transmission System Peaks

This information is based on Nevada Power data, including the northern PV project under contract to Nevada Power. These are transmission level interconnected resources so they will generally outperform rooftop installations. This data therefore slightly overstates rooftop PV performance. PV output has historically been seen to peak around 2 p.m. and then decrease rapidly between 4 p.m. (~80 percent output) and 7 p.m. (~15 percent output). For transmission facilities in primary use for load service, the specific time that local loads peak determines whether a benefit of deferral of future transmission can be made related to DG. NV Energy has seen system peaks as late as 6 (~33 percent) to 7 p.m. – particularly if Air Conditioning Load Management is being utilized. Please see the Nevada Power system data plot from July 1, 2014 below.

The chart represents actual, measured utility scale PV output versus Nevada Power load. The scale for the diagram on the left is for Nevada Power load and on the right for PV output, both are shown in MW. Chart 10-1 shows the significant PV reduction that is occurring during system peak. This limits the amount of PV capacity that can potentially offset future transmission facilities to the reliable output of PV at the time of peak load. Sierra was not plotted due to the limited utility scale interconnected PV. It is expected that the PV effects on Sierra are largely identical - with the PV capacity availability dependent on time of peak which can occur earlier at Sierra.

Chart 10-1. Solar Output vs. Nevada Power Total Load



C. Existing and Expected Effects of Net Metering to the Transmission System

The impacts on the transmission system created by DG can be divided into three functional areas: (1) The bulk electric transmission system; (2) Local electric transmission; and (3) Transmission system operations. Again, transmission level data is used to draw these conclusions for both Nevada Power and Sierra.

(1) Bulk Electric Transmission System Impacts

In the next ten years, because of evolving efficiencies in lighting and consumer goods NV Energy does not see major bulk electric transmission upgrades for load growth aside from point loads in the industrial and commercial industries noted above. Some supporting infrastructure growth will require added sub-regional service. Because of these trends, DG will have little effect on the existing bulk system or upgrades necessary to serve new discrete location loads. The major expected effect for expansion projects will be indirect via energy resource competition with other generation options and their associated transmission connection and delivery needs.

(2) Local Electric Transmission Impacts

DG available on peak has the obvious ability to offset local transmission to the extent it is equally reliable and diverse in nature. To date, these two conditions have been met, but at significantly reduced levels from installed capacity. With the advent of reliable storage to allow PV nameplate capacity use at 6 to 8 P.M., and in significant quantities diverse enough to ensure a comparable level of reliability, this will change. Currently local transmission capacity expansions plans cannot be downscaled significantly based on PV output accounting for possible peak times. Going forward, if local load growth expected to drive new transmission facilities is less than the DG to be installed at the same local area and within the planning horizon for a transmission expansion project, that project may be able to be deferred.

(3) Transmission System Operational Impacts

To date, NV Energy transmission has not seen dramatic shifts in operational complexity or costs due to distributed PV generation. If PV – whether distributed, industrial, or utility in scale – reaches significant penetrations relative to load requirements at any time during the year, NV Energy expects to see dramatic shifts in reactive power switching, generation dispatch, and unit ramping requirements. This will be largely due to the “duck curve”⁷⁰ effect. If this level of penetration does occur in NV Energy, the daily ramping and reactive requirement for the generation and transmission system will approximately double because of the two intermediate rampings (mid-morning down and mid-afternoon up) required to offset PV output with other resources. Second, extensive reactive switching, both automated and manual will be required as loadings on bulk and local transmission elements shift dramatically with the resource changes. Tertiary, a lesser effect that still needs transmission action is the intermittency of PV due to clouds. As the above diagram illustrates on this particular day, 50 percent of the PV output was

⁷⁰ Please see Exhibit Whalen Direct-2 which is a California Independent System Operator paper describing the net load service effect of large PV penetrations.

momentarily interrupted midday. While current PV penetration does not cause system problems, if penetration was higher, cloud caused intermittency of PV could begin to require actions similar to conventional unit tripping but without the power pool reserve sharing capability available.

SECTION 11: TARIFF DESIGN

With this filing, Nevada Power is proposing eight new rate classes. All are applicable only to net metering customers after the date on which the cumulative capacity of all net metering systems for which all utilities in Nevada have accepted or approved completed applications for net metering is equal to 235 MW. Nevada Power is also modifying Schedule NMR – Net Metering Rider to designate it as NMR-1, add the clarification of the cap, and create NMR-2 to incorporate the changes adopted by the enactment of Senate Bill 374 in the 2015 session of the Nevada Legislature. With the addition of the new NEM2 Schedules, the modification to Schedule NMR-1, the addition of NMR-2, and changes to Rules 9 and 15, the terms and conditions of NEM2 service are well-described. Several other optional schedules also have been modified.

The proposed tariffs are attached to the Application as Exhibit A, Exhibit B contains the current versions of the tariffs that are proposed to be modified. The following is the list of the new schedules and existing schedules that require modification:

New NEM2 Rate Schedules

- RS-NEM – Residential Service –Net Metering
- ORS-TOU-NEM – Optional Residential Time-of-Use – Net Metering
- RM-NEM – Residential Multi-Family Service –Net Metering
- ORM-TOU-NEM – Optional Residential Multi-Family -Time-of-Use – Net Metering
- LRS-NEM – Large Residential Service-Net Metering
- OLRS-TOU-NEM – Optional Large Residential Service-Net Metering Time-of-Use – Net Metering
- GS-NEM – General Service-Net Metering
- OGS-TOU-NEM - Optional General Service-Time-of-Use-Net Metering
- NMR-2 – Net Metering Rider-2 (Applicable after the cap)

Modified Rate Schedules

- NSMO-1 – Non-Standard Metering Option Rider (Residential)
- NSMO-2 – Non-Standard Metering Option Rider (Non-Residential)

- REVRR-TOU – Residential Electric Vehicle Recharge Rider – Time-of-Use
- RMEVRR-TOU – Residential Multi-Family Electric Vehicle Recharge Rider – Time-of-Use
- GSEVRR-TOU – General Service Electric Vehicle Recharge Rider – Time-of-Use
- NMR – Net Metering Rider (NMR-1)
- Statement of Rates
- Table of Contents

Modified Rules

- Rule 9 – Electric Line Extensions
- Rule 15 – Generator Facility Interconnections

For the new NEM2 rate schedules include both the standard and optional schedules for each NEM2 class of customers, both incorporating a BSC, generation meter charge, and maximum demand charge. The standard offering retains a simple flat per kWh energy charge, and the optional schedule includes TOU demand and energy charges. These new schedules will be applicable to all new residential and small general service NEM2 customers after the date on which the cumulative capacity of all net metering systems for which all utilities in Nevada have accepted or approved completed applications for net metering is equal to 235 MW. The new monthly generation meter charge recovers the cost of the installation of the generation meter that is separate and apart from the billing meter. The generation meter will record the production of the Customer's generation facilities. If the Portfolio Energy Credits generated by the net metering customer's generation are owned by NV Energy, the Generation Meter Charge will not apply.

Schedule NMR-1 is the modified Net Metering Rider renamed and modified to include language clarifying that Schedule NMR-1 is closed to new Customers after the date on which the cumulative capacity of all net metering systems for which all utilities in Nevada have accepted or approved completed applications for net metering is equal to 235 MW. The new Schedule NMR-2 contains the terms and condition that are applicable to all net metering customers after the date on which the cumulative capacity of all net metering systems have accepted or approved completed applications for net metering is equal to 235 MW. This new rider will work in conjunction with the eight new NEM service schedules (as applicable) to establish all the rates, terms and conditions for residential and small general service NEM customers after the cap is reached. It will also work in conjunction with otherwise applicable general service schedules for new NEM2 customers whose energy consumption, absent generation, greater than 3,500 kWh.

Schedule NSMO-1 and Schedule NSMO-2 are being modified to incorporate the new net metering schedules and to state that customers taking service under the new net metering

schedules would not be able to take service under either Schedule NSMO-1 or Schedule NSMO-2, as applicable.

Schedules REVERR-TOU, RMEVERR-TOU and GSREVERR-TOU are being modified to incorporate a reference to the new optional time-of-use net metering schedules and to state that customers taking service under the time-of-use net metering schedules would be able to also receive service under Schedules REVERR-TOU, RMEVERR-TOU or GSREVERR, as applicable.

The Statement of Rates and Table of Contents sections of the tariff book are being modified to incorporate the eight new rate schedules and the rates and charges proposed in this filing.

Rule 15 is modified to reflect NEM2 generation facility cost responsibility (as appropriately determined under the rule) for interconnection costs. The interconnection costs will be determined consistent with the manner in which the interconnection costs of other generators operating in parallel with the utility system are determined. However, NEM2 customers will continue to be exempt from paying study fees and their cost responsibility for identified interconnection costs will be determined pursuant to the applicable sections of Rule 9.

Rule 9 is modified to include the new NEM2 classes and list the allowances for each class and to provide a single clarification to the Definitions section. NEM2 allowances are initially set equal to the allowances of the otherwise applicable rate classes.

ATTACHMENT A

Attachment A

THE BILLING MECHANICS OF NET ENERGY METERING UNDER NEM1 AND NEM2

NEM2 customers will be subject to new rate schedules, modified terms and conditions of net metered service, and rate structures under which they are billed. However, the Company's proposals under the proposed new NEM2 net metering rules and the associated tariff provisions will not change the general mechanics of net energy metering billing, including the method of banking excess energy production and the use of any banked energy to offset the energy (kWh) deliveries of the company. The purpose of this attachment is to describe the process of billing net metered customers, which will apply equally to both NEM1 and NEM2 net metering customers, even though different rate structures, as explained in the body of this narrative, will apply to the NEM 1 and NEM2 customers.

Nature of Net Metered Customers Generally for both NEM1 and NEM2

NEM1 and NEM 2 customers with on-site self-generation of less than 1 MW of generation capacity are eligible for net meter service and billing. Both NEM1 and NEM2 customers of NV Energy, like other customers with self-generation connected to the utility's system are *partial requirements* customers. Unlike *full requirements* customers that rely solely on NV Energy for their power requirements, net metering customers may serve all or portions of their own (host) load requirements from their on-site generation at times, with NV Energy providing these customers with power to serve their load when their own generation is not sufficient to do so, or is entirely unavailable. Because of the partial reliance on the utility for their power requirements, net metering and other customers with self-generation installed to serve their own load, are referred to as partial requirements customers. While these customers serve some of their own load, reducing electric purchases from the utility, they do not necessarily reduce their total electric consumption.

When the net metering customer's generation produces more power than is required to serve their load at any point in time, the excess power production is allowed to be returned to the utility's local distribution facilities (the "grid"). The term "net metering" comes from the billing arrangement that allows for this excess or returned kWh energy (often referred simply as received energy) to offset, or to be "netted" against, the energy delivered to the customer by the utility (the "Delivered energy") in the current billing period or a future billing period.¹

¹ In the 2013 Nevada Legislative session, Assembly Bill 428 was enacted that in part requires net metered customers to pay for the various "public purpose program" per kWh surcharge rates on the utility's delivered energy, not the net energy. With this change to the net metering arrangement, only the BTGR, BTER and DEAA energy (per kWh) rate components are subject to being billed on a net energy basis in the billing period.

Metering Requirements under NEM1 and NEM2

In a net-metering meter configuration, the flow of electricity is bidirectional, and requires a meter that can measure the flow of power from the utility to the customer and the excess generation returned to the grid. The power delivered by the utility to serve the net metered customer's load is measured and registered (in kWh) in one channel, and the excess energy returned to the grid is separately metered in the second channel. At any instantaneous point in time power will either be flowing to the customer's load from the utility or back to the utility's grid due to excess power production of the customer generation,² as power cannot flow both directions at the same time. A customer can look at their bidirectional smart meters to determine if the utility is delivering power to it at that point in time, or if it is returning power to the utility (which would mean it is serving its entire load, and has excess production).

As explained in the body of this narrative, all NEM2 customers, regardless of size, will be required to have a smart generation meter to measure the energy production of their generator. Both the customer and the utility can use the generation output information to better understand the net meter service. First, it will inform the customer as to the actual performance of the generation system. Second, in conjunction with the information from the bidirectional revenue meter, the generation output information allows the customer and utility to understand the total load of the customer, not just the energy deliveries from the utility to the customer. Third, knowing the total load of the customer, in conjunction with the excess or received energy from the bidirectional revenue meter, it is possible to identify the amount of generation production being consumed on site. Under the proposed NEM2 tariffs, NEM2 customers who do not participate in NV Energy's Renewable Generations program will pay the new generation meter charge. NV Energy will waive the generation meter charge for customers who participate in NV Energy's Renewable Generations program.

Net Energy Billing under NEM1 and NEM2

Currently, NEM1 net metered customers are billed under the otherwise applicable rate schedule ("OAS"). Heretofore, there has been no separate cost of service analysis performed for these customers and therefore the cost to serve these customers has not been identified. For both NEM1 residential and small general service customers at both Nevada Power and Sierra, the OAS are simply a two part rate structure with a Basic Service Charge ("BSC") per customer and an energy rate. At their choice, NEM1 residential and small general service net metered customers can be served under the flat rate energy schedules, or under the optional time-of-use ("TOU") energy rate schedules.

² To be complete, the exception to the above statement is when the customer's load is zero and the generation output of the generator is zero.

The purpose of this filing is to identify the unique cost characteristics of net energy metering customers as a standalone rate class, and to establish appropriate rate structure and rates to recover the identified cost of service. The Company's intent is to have the new rate structure, rates and tariffs resulting from this filing apply to the NEM2 customers and not NEM1 customers. The NEM1 customers would continue to be billed under the current rules and OAS tariffs.

As discussed herein, the new rate structures applicable to the NEM2 customers will include a higher basic service charge than that which exists under the comparable OAS schedules, the generation meter charge previously discussed, and will include demand charges that unlike energy is not subject to netting. NEM2 customers will also have a choice between a non-TOU rate structure and a TOU rate structure, similar to the choice NEM1 customers currently have today.

However, despite the differing rate and tariffs the net energy billing aspects for NEM1 and NEM2 billing remain unchanged. Over the course of an entire billing period for a net meter customer, NEM1 or NEM2, there will often be both delivered and excess energy use recorded in the period. Under the net metering billing arrangement, the excess generation recorded in the period can be used to reduce the delivered energy from the utility recorded in the period. Thus the customer is billed on the "net energy delivered." If the excess production is larger than the delivered energy, the net energy billed is zero (it cannot be negative), and the remainder of the excess generation that is above the delivered energy is banked (or saved), and available to offset utility energy deliveries in future billing periods when possible. Any unused accumulation of banked kWh can be carried forward indefinitely without loss; but the customer will not be able to redeem the banked kWh except by offsetting the utility energy's deliveries; i.e., the customer will not be paid for the bank.

As noted above, current NEM1 and the new NEM2 residential and small general service net metering customers can choose between a flat rate and optional TOU rate structures. Under the flat rate option the application of the bank to future billing periods is straight-forward and remains the same. If there is excess energy production in the billing period, both NEM1 and NEM2 customers will be able use any excess energy production to reduce their deliveries in the current period that are charged against the (non-surcharge) energy rate, limited by the requirement that the delivered energy billed cannot be less than zero. Any received energy not applied to offset delivered energy is added to the energy bank and can be applied to offset the utility's billed energy deliveries in the future.

NEM billing under the TOU options and the application of the banked energy amounts is a little more involved, but will continue to be applied the same way for the new NEM2 customers as is currently done for the NEM1 customers. The banked kWh energy credits will be applied to the

same TOU period in which they are generated. If the billing period lacks a corresponding time-of-use period, such energy credits will be apportioned evenly among the available time-of-use periods as currently done today.³ The optional TOU energy periods proposed for the new NEM2 rate classes are the same as those available to NEM1 customers under the OAS optional TOU rate schedules,⁴ and thus, the net energy billing and banking processes will be the same for the NEM1 and NEM2 customers.

³ The current net metered billing provisions are set forth in the Net Metering Rider (“NMR”) at each company, consistent with the requirements of NRS 704.775.

At Nevada Power, the two part TOU rate schedules for the residential and small commercial rate classes consist of summer on-peak and summer off-peak periods and a winter season rate. At the end of the summer season, any bank remaining in the summer on and off-peak periods are placed in the winter season bank. At the conclusion of the winter season, any winter bank among that remains is allocated equally to the two summer rating periods.

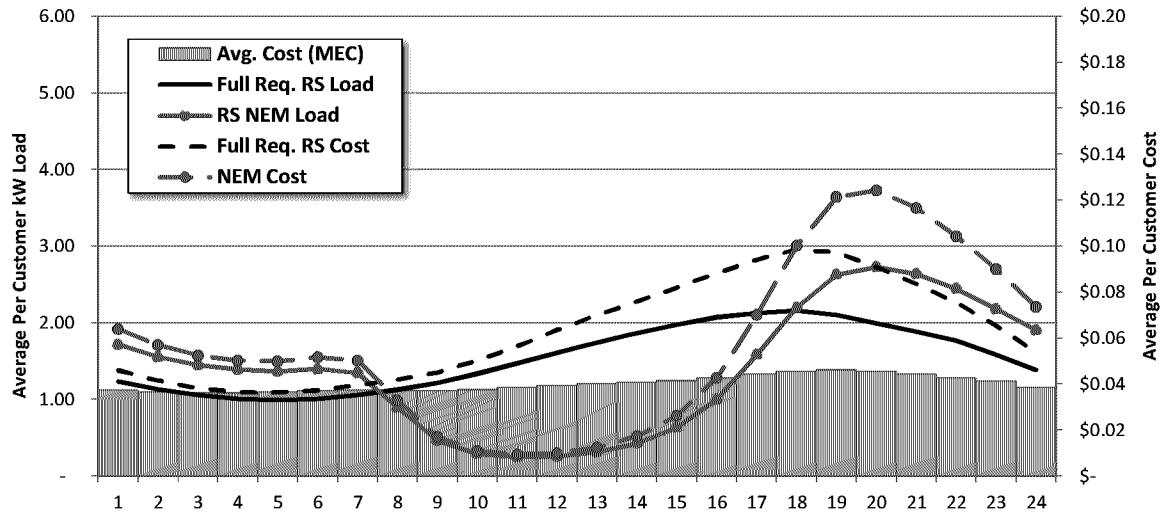
At Sierra, the two-part TOU optional rate schedules for the residential and small commercial classes consist of summer on-peak, mid-peak and off-peak periods and the winter season consists of on-peak and off-peak periods. As noted above, the banks in the on-peak and mid-peak periods in the summer transfer at the season change to the corresponding winter on-peak and off-peak periods. The transfer is also period to period when moving from winter to summer. With respect to the summer mid-peak period, no corresponding rating period exists in winter. Therefore at the conclusion of the summer season the summer mid-peak bank is distributed equally amongst the winter on-peak and mid-peak periods.

⁴ The TOU periods for Residential NEM2 customers at Nevada Power will mirror the full requirements Optional Residential TOU Rate A TOU periods. The optional schedule for full requirements customers currently has two TOU options, but the Rate B TOU periods were not used for the NEM2 rate structure.

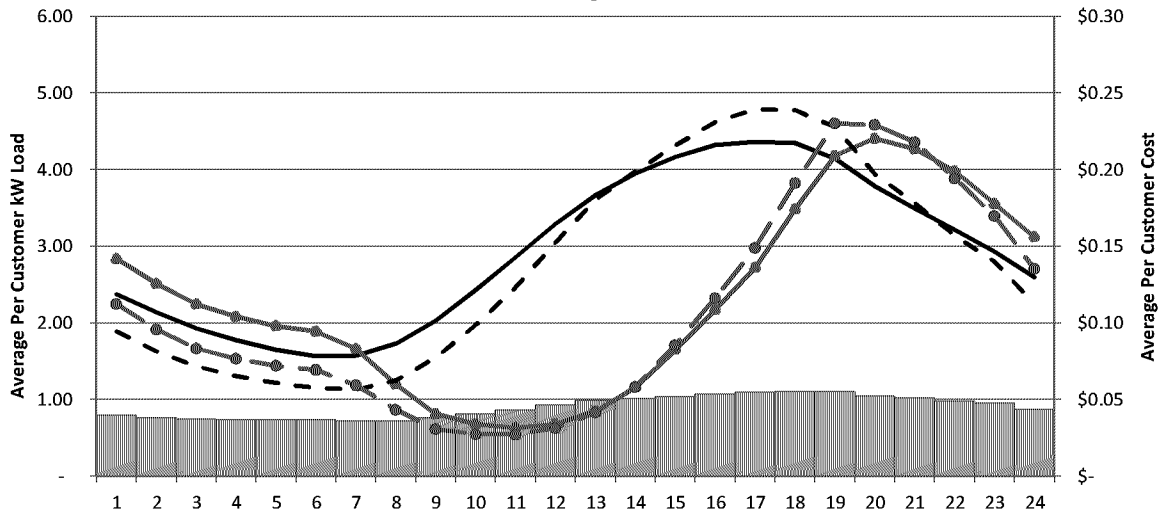
ATTACHMENT B

Nevada Power NEM and Full Requirements RS Customers Average Hourly Burden on Marginal Energy Costs

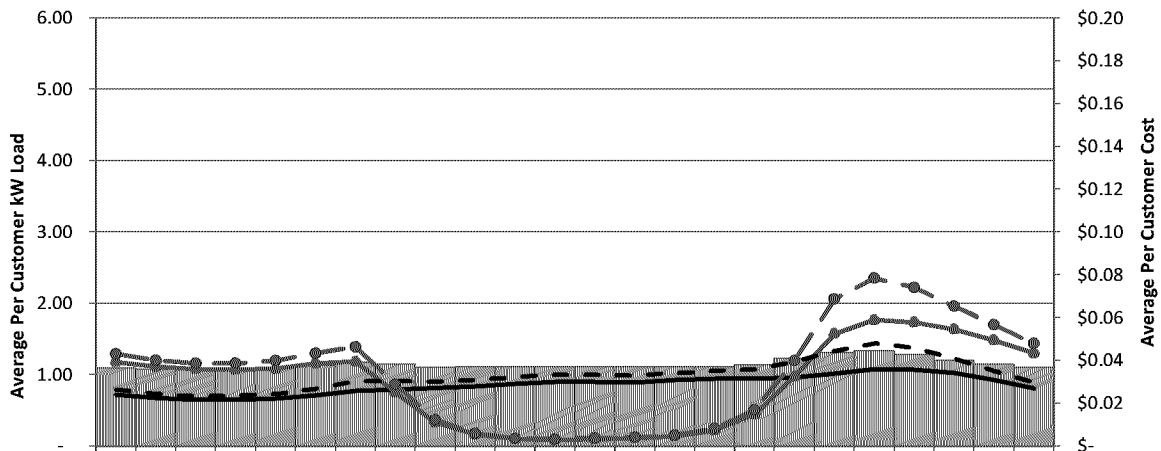
Annual



July

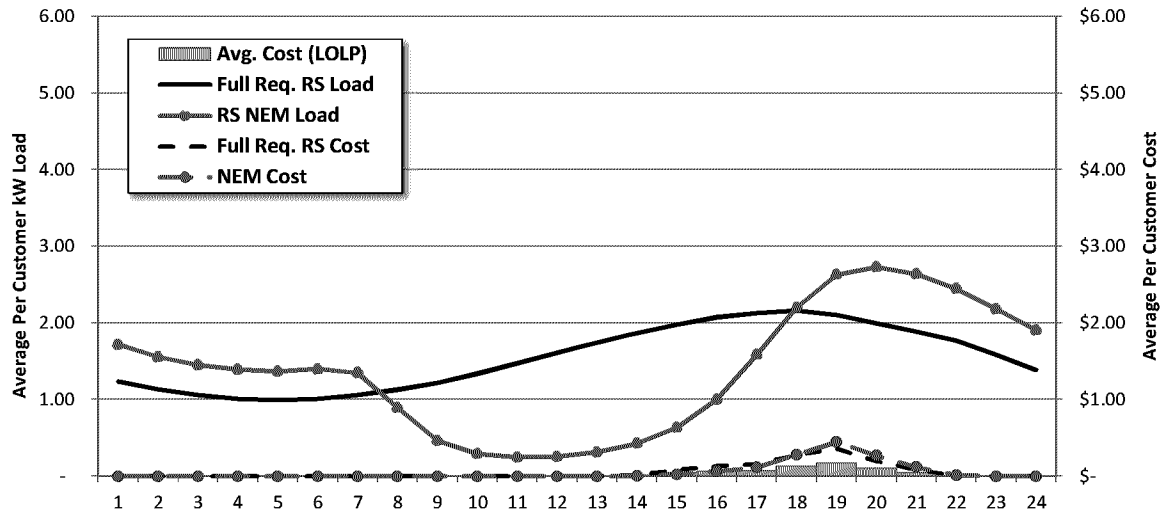


March

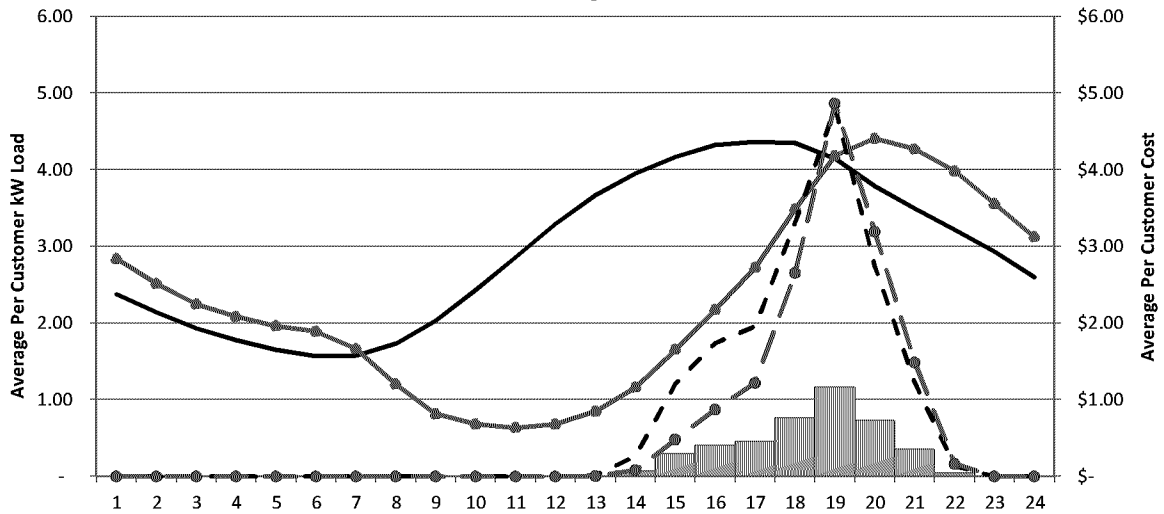


Nevada Power NEM and Full Requirements RS Customers Average Hourly Burden on Generation System and Costs

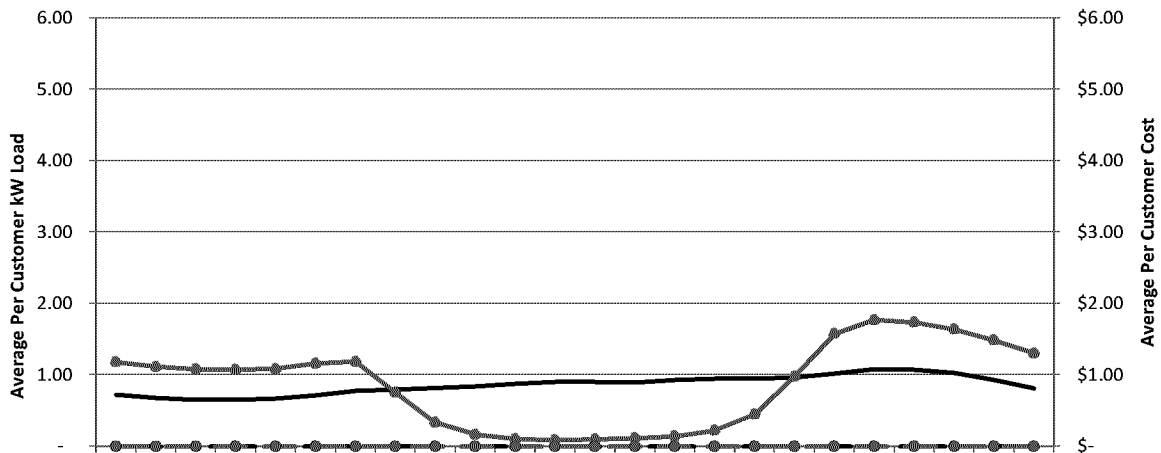
Annual



July

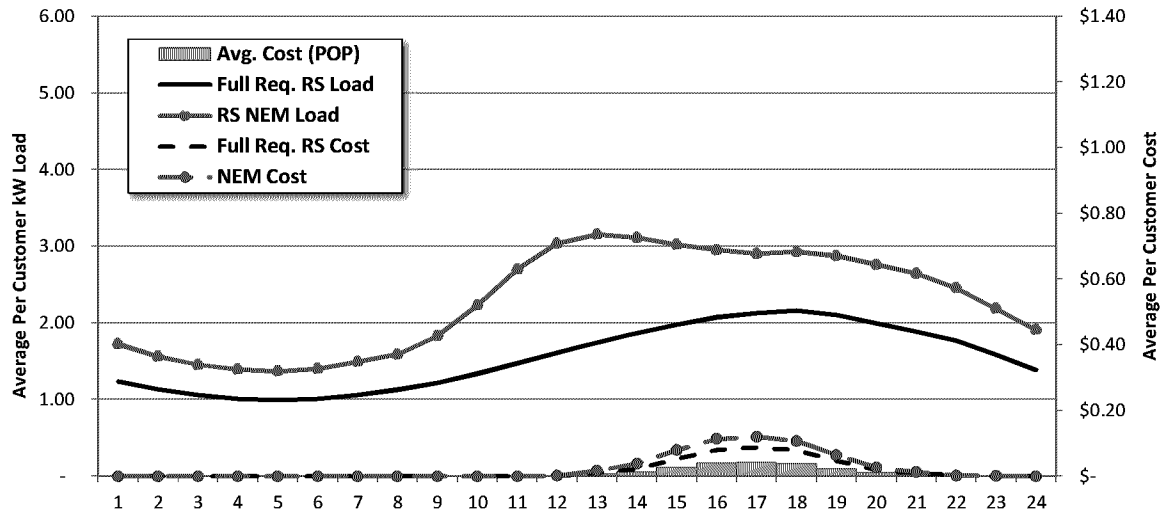


March

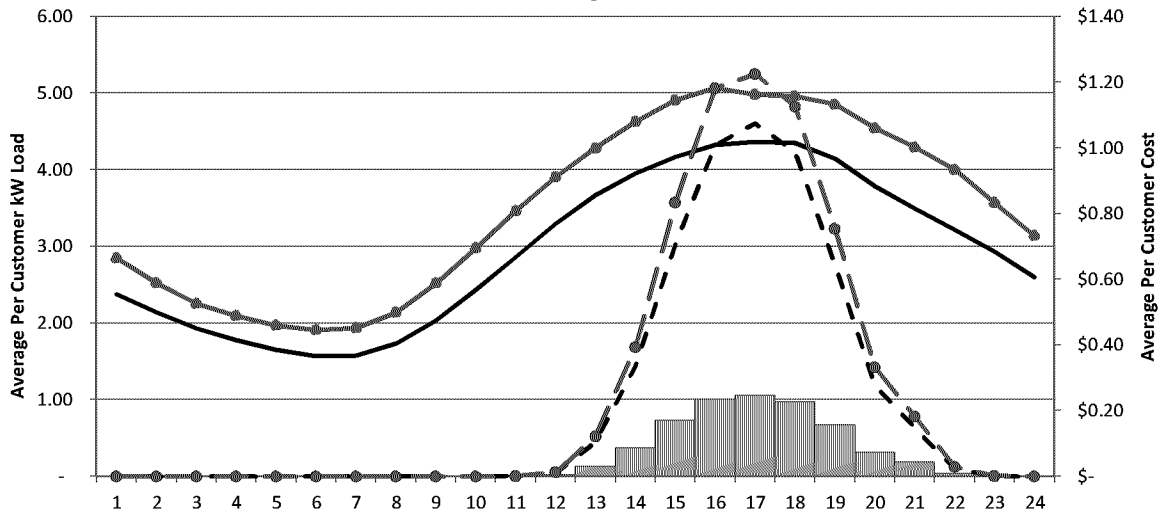


Nevada Power NEM and Full Requirements RS Customers Average Hourly Burden on Distribution System and Costs

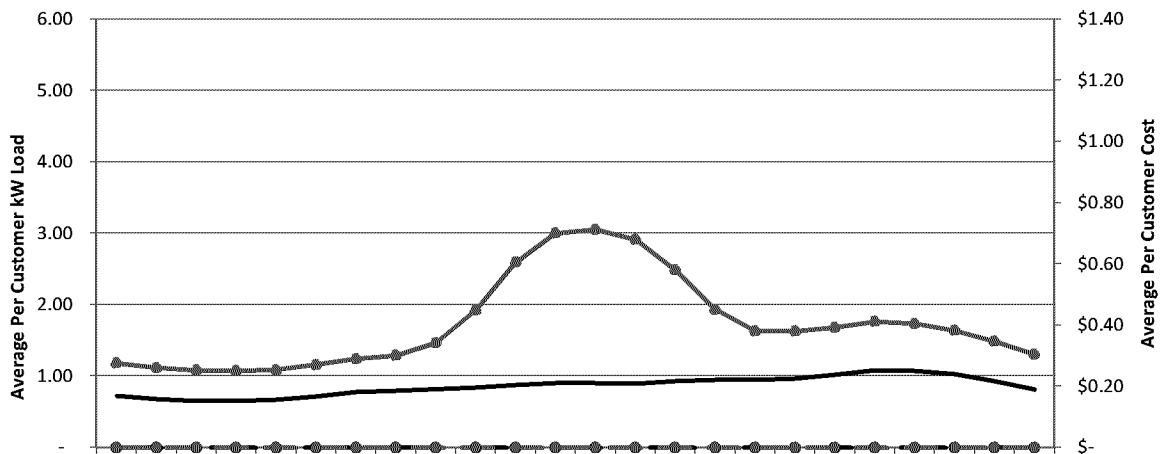
Annual



July

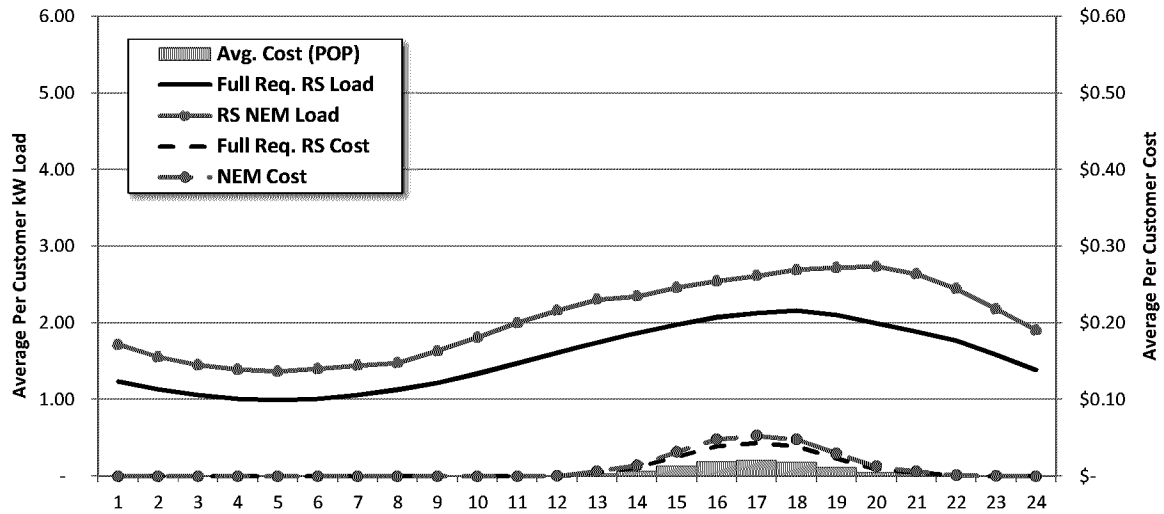


March

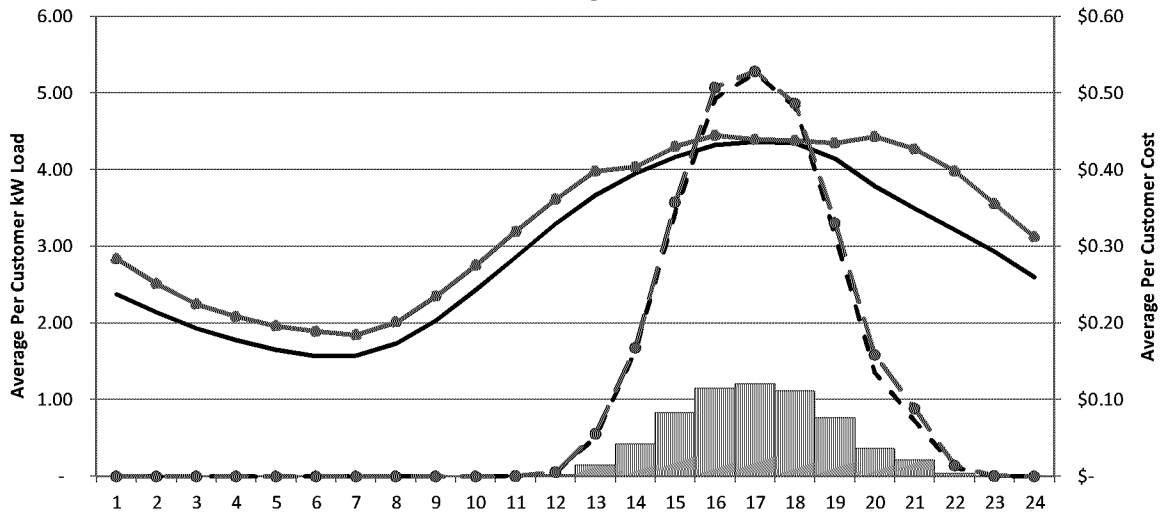


Nevada Power NEM and Full Requirements RS Customers Average Hourly Burden on Transmission System and Costs

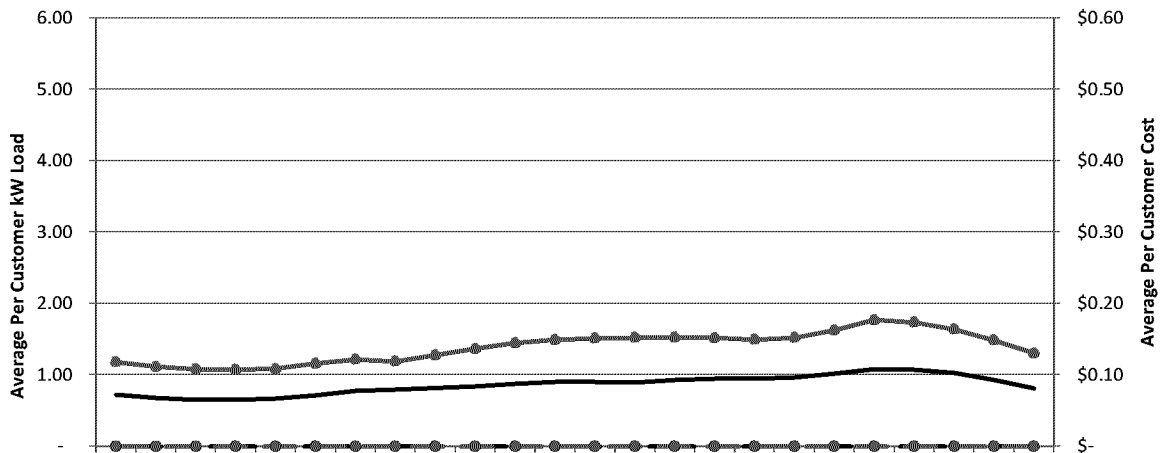
Annual



July



March



ATTACHMENT C

Table C-1 - Average Single Family Residential (RS) Customer Monthly Bill Comparisons

One NEM Customer Billing Example

Average Monthly Estimates

RS Summary

Average Values										NEM Bills*				Net Percent Change**			
MONTH	Delivered kWh	Generated kWh	Excess kWh	Customer Load (No Generation)	Max kW (No Generation)	Max kW (Delivered)	Current		Current TOU	Simple 3-Part	TOU 3-Part						
1	910	612	291	1,233	4.00	3.92	\$	156.35	\$	83.75	\$	42.18	\$	108.40	\$	63.33	29.4%
2	734	782	439	1,079	4.23	4.10	\$	138.32	\$	55.58	\$	30.57	\$	97.79	\$	52.78	75.9%
3	618	941	549	1,028	3.81	3.54	\$	132.39	\$	41.97	\$	24.93	\$	83.28	\$	45.00	98.4%
4	517	1,122	679	958	4.54	4.01	\$	124.24	\$	30.45	\$	20.13	\$	84.64	\$	42.24	178.0%
5	532	1,097	618	1,008	4.55	3.97	\$	130.13	\$	30.72	\$	20.24	\$	84.24	\$	42.20	174.2%
6	1,249	1,212	356	2,116	7.85	7.14	\$	259.04	\$	122.17	\$	157.53	\$	172.63	\$	257.98	41.3%
7	1,651	1,043	199	2,508	8.00	7.25	\$	304.79	\$	179.71	\$	225.84	\$	201.25	\$	290.50	12.0%
8	1,603	1,070	227	2,457	8.15	7.32	\$	298.83	\$	171.49	\$	221.49	\$	198.31	\$	290.57	15.6%
9	1,430	1,000	265	2,174	7.89	7.22	\$	265.88	\$	148.82	\$	202.63	\$	186.22	\$	278.22	25.1%
10	969	905	372	1,508	5.92	5.40	\$	188.34	\$	87.96	\$	43.84	\$	131.57	\$	70.92	49.6%
11	702	714	367	1,052	3.34	3.18	\$	135.20	\$	59.22	\$	31.98	\$	86.22	\$	50.41	45.6%
12	747	490	245	996	3.07	2.96	\$	128.66	\$	69.44	\$	36.08	\$	87.87	\$	53.50	26.5%
Total	11,662	10,989	4,606	18,117	8.15	7.32	\$	2,262.17	\$	1,081.28	\$	1,057.44	\$	1,522.42	\$	1,537.65	40.8%

NEM Savings		\$ 1,180.88	52%
		\$ 739.74	33%
		\$ 724.52	32%

*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3-Part versus Current Flat Rate

Graph C-1

Average Monthly Bill for Single Family Residential (RS) Rate Class

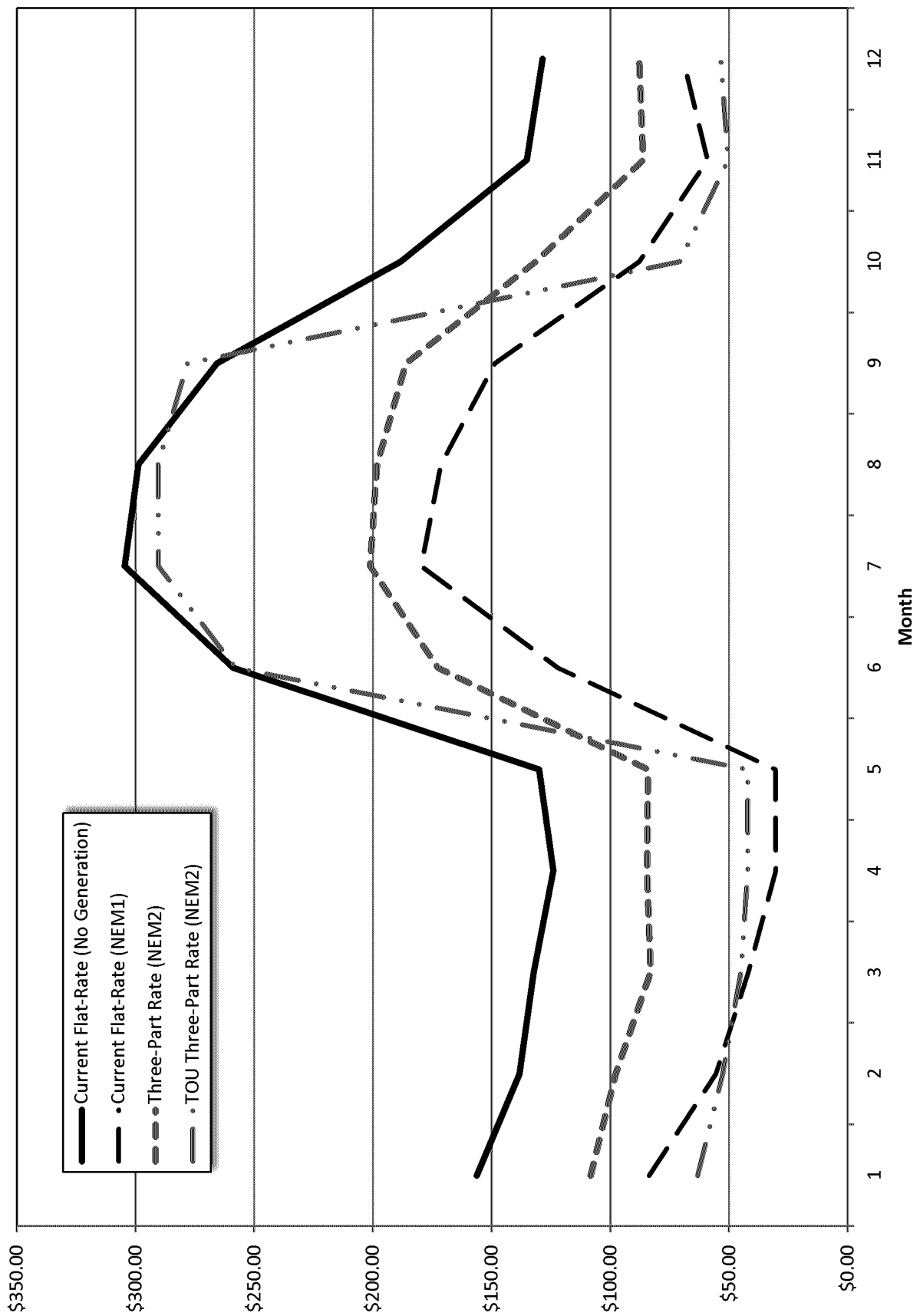


Table C-2 - Average Multi-Family Residential (RM) Customer Monthly Bill Comparisons

One NEM Customer Billing Example

Average Monthly Estimates

RM Summary

Average Values										NEM Bills*			
MONTH	Delivered kWh	Generated kWh	Excess kWh	Customer Load (No Generation)	Max kW (No Generation)	Max kW (Delivered)	Current Flat-Rate (No Generation)	Current Flat-Rate	Current TOU	Simple 3- Part	TOU 3-Part	Net Percent Change**	
1	747	432	166	1,015	2.46	2.46	\$ 120.00	\$ 70.47	\$ 39.96	\$ 78.55	\$ 48.54	11.5%	
2	646	543	223	966	2.18	2.18	\$ 114.68	\$ 53.14	\$ 31.83	\$ 65.77	\$ 40.28	23.8%	
3	509	604	296	817	1.73	1.73	\$ 98.36	\$ 35.56	\$ 23.22	\$ 50.42	\$ 30.90	41.8%	
4	397	655	347	704	2.19	2.13	\$ 86.03	\$ 24.11	\$ 17.61	\$ 50.06	\$ 27.53	107.6%	
5	370	631	339	663	1.85	1.80	\$ 81.53	\$ 26.24	\$ 18.65	\$ 46.58	\$ 27.15	77.5%	
6	518	777	348	936	2.44	2.35	\$ 111.42	\$ 42.92	\$ 47.52	\$ 62.88	\$ 98.04	46.5%	
7	775	733	255	1,254	2.80	2.71	\$ 146.18	\$ 67.56	\$ 80.93	\$ 80.64	\$ 123.98	19.4%	
8	825	704	215	1,315	3.18	3.09	\$ 152.85	\$ 73.60	\$ 90.68	\$ 89.04	\$ 143.45	21.0%	
9	800	676	220	1,248	3.33	3.29	\$ 145.56	\$ 74.75	\$ 90.50	\$ 92.32	\$ 147.55	23.5%	
10	618	617	253	983	2.70	2.51	\$ 116.53	\$ 51.85	\$ 30.00	\$ 69.65	\$ 39.96	34.3%	
11	495	508	244	759	1.62	1.62	\$ 92.07	\$ 38.53	\$ 24.35	\$ 50.36	\$ 31.44	30.7%	
12	486	356	172	671	1.51	1.51	\$ 82.43	\$ 43.93	\$ 26.89	\$ 51.58	\$ 33.24	17.4%	
Total	7,187	7,234	3,078	11,332	3.33	3.29	\$ 1,347.63	\$ 602.68	\$ 522.14	\$ 787.85	\$ 792.05	30.7%	

NEM Savings		\$ 744.95	55%	\$ 559.78	42%	\$ 555.57	41%
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*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3- Part versus Current Flat Rate

Graph C-2

Average Monthly Bill for Multi-Family Residential (RM) Rate Class

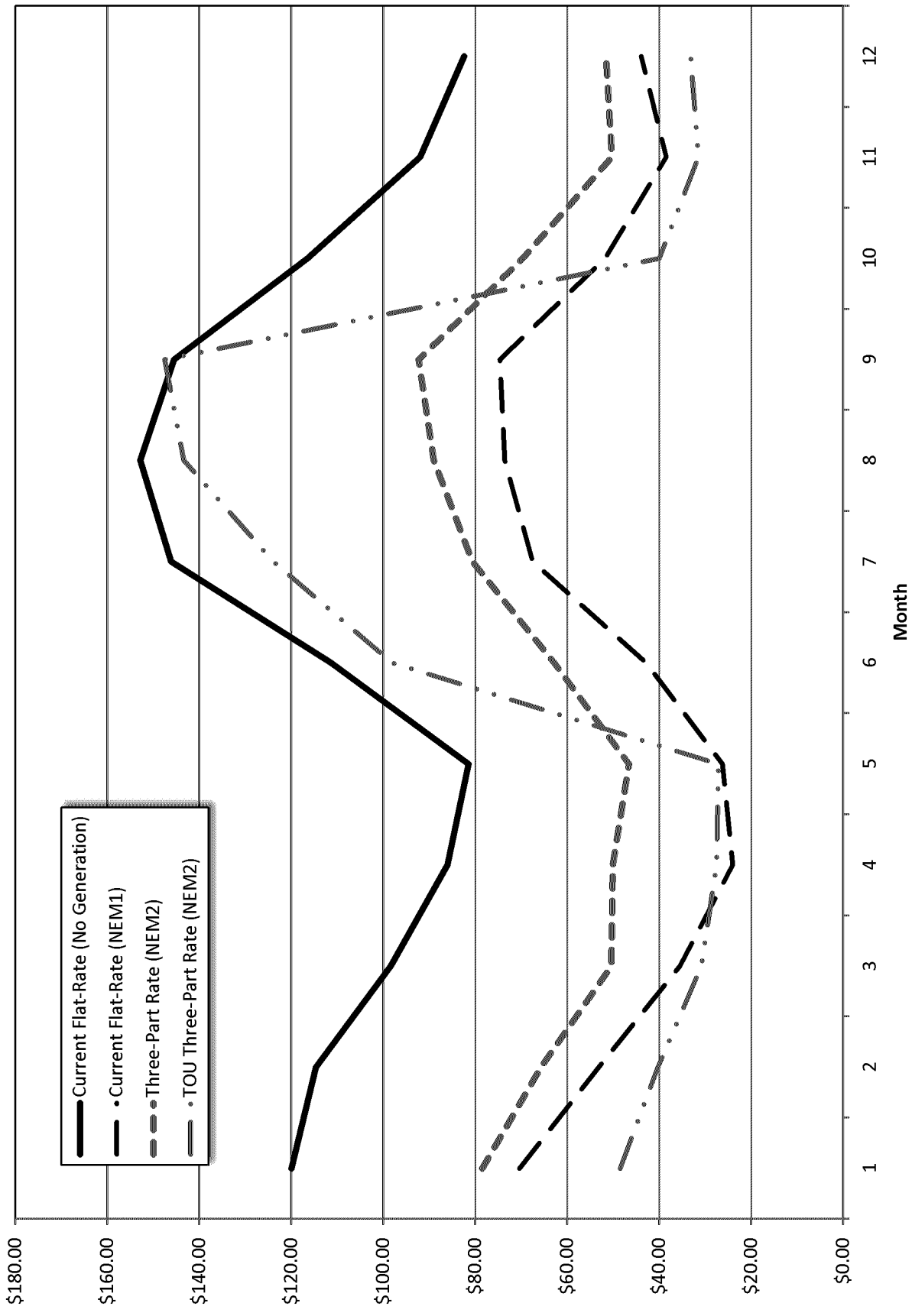


Table C-3 -- Average Large Single Family Residential (RSL) Customer Monthly Bill Comparisons

One NEM Customer Billing Example

Average Monthly Estimates

RSL Summary

Average Values										NEM Bills*				Net Percent Change**		
MONTH	Delivered kW/h	Generated kW/h	Excess kW/h	Customer Load (No Generation)	Max kW (No Generation)	Max kW (Delivered)	Current		Current Flat- Rate	Current TOU	Simple 3- Part		TOU 3-Part			
							(No Generation)	Flat-Rate			Simple 3-	Part				
1	3,726	1,160	318	4,571	9.10	9.10	583.30	\$	455.80	\$	290.09	\$	405.47	\$	286.32	-11.0%
2	5,661	1,477	455	6,688	12.67	12.67	815.22	\$	652.86	\$	399.67	\$	554.85	\$	386.03	-15.0%
3	4,433	1,925	697	5,665	10.92	10.92	703.15	\$	497.23	\$	313.13	\$	452.69	\$	311.66	-9.0%
4	4,426	2,458	1,082	5,806	17.64	16.51	718.58	\$	484.30	\$	305.94	\$	529.43	\$	329.09	9.3%
5	5,325	2,222	923	6,628	18.24	17.04	808.56	\$	595.91	\$	368.01	\$	591.76	\$	379.39	-0.7%
6	2,891	2,363	567	4,690	11.98	10.82	596.28	\$	356.91	\$	450.21	\$	382.67	\$	603.69	7.2%
7	4,903	1,920	266	6,562	15.06	13.73	801.32	\$	568.63	\$	752.10	\$	529.40	\$	821.51	-6.9%
8	4,931	2,070	242	6,763	16.39	14.61	823.42	\$	578.60	\$	765.17	\$	547.27	\$	869.75	-5.4%
9	4,757	2,226	360	6,628	19.64	16.32	808.56	\$	564.29	\$	719.86	\$	565.64	\$	905.84	0.2%
10	3,071	1,711	580	4,204	10.10	8.93	543.09	\$	360.90	\$	235.15	\$	356.47	\$	242.97	-1.2%
11	2,779	1,837	740	3,877	7.11	7.11	507.28	\$	300.28	\$	202.10	\$	299.86	\$	209.86	-0.1%
12	3,614	1,592	642	4,567	8.63	8.63	582.76	\$	408.02	\$	257.12	\$	375.12	\$	258.81	-8.1%
Total	50,518	22,961	6,872	66,650	19.64	17.04	8,291.52	\$	5,823.74	\$	5,058.56	\$	5,590.61	\$	5,604.93	-4.0%

NEM Savings		\$ 2,467.78	30%
		\$ 2,700.91	33%
		\$ 2,686.59	32%

*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3- Part versus Current Flat Rate

Average Monthly Bill for Large Single Family Residential (RSL) Rate Class Graph C-3

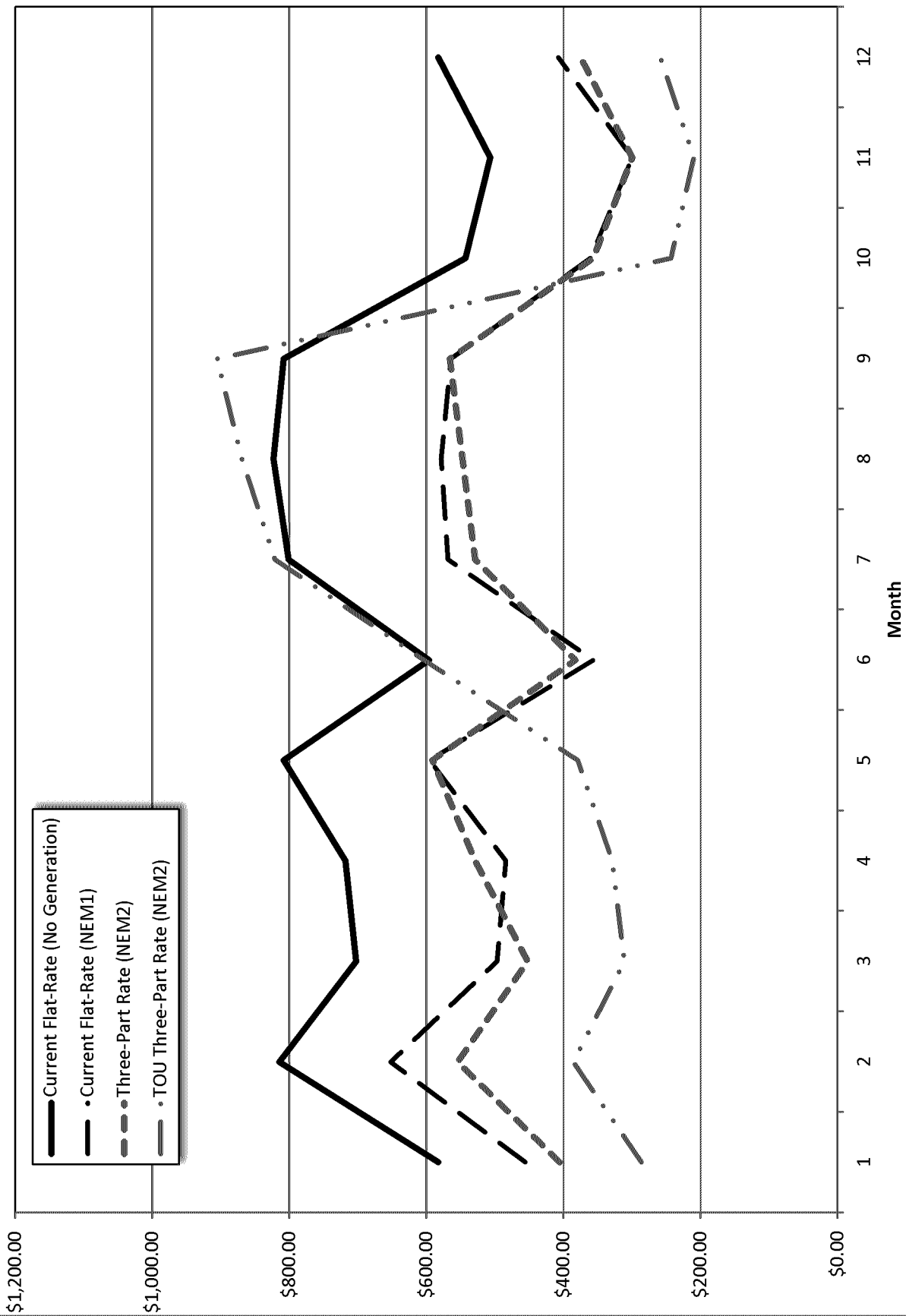


Table C-4 - Average General Service (GS) Customer Monthly Bill Comparisons

One NEM Customer Billing Example
Average Monthly Estimates
GS Summary

Average Values										NEM Bills*			
MONTH	Delivered kWh	Generated kWh	Excess kWh	Customer Load (No Generation)	Max kW (No Generation)	Max kW (Delivered)	Current Flat-Rate (No Generation)	Current Flat- Rate	Current TOU	Simple 3- Part	TOU 3-Part	Net Percent Change**	
1	2,353	1,640	754	3,208	5.40	5.40	262.83	\$ 142.84	\$ 102.30	\$ 198.96	\$ 137.64	39.3%	
2	2,633	2,081	927	3,787	6.72	6.72	305.30	\$ 152.51	\$ 108.36	\$ 225.59	\$ 149.81	47.9%	
3	2,184	2,724	1,433	3,465	6.24	5.89	281.65	\$ 113.36	\$ 83.31	\$ 186.43	\$ 121.23	64.5%	
4	2,228	3,548	1,980	3,785	8.06	7.05	305.12	\$ 108.19	\$ 79.95	\$ 200.63	\$ 123.38	85.4%	
5	1,746	3,125	1,732	3,115	6.30	5.40	255.96	\$ 95.26	\$ 71.54	\$ 166.83	\$ 107.36	75.1%	
6	2,296	3,343	1,462	3,957	8.08	7.15	317.77	\$ 146.69	\$ 190.39	\$ 228.24	\$ 333.59	55.6%	
7	3,096	2,696	1,053	4,652	8.91	7.75	368.70	\$ 209.62	\$ 286.62	\$ 280.05	\$ 416.30	33.6%	
8	3,754	2,924	1,012	5,655	10.90	9.56	442.31	\$ 237.83	\$ 331.34	\$ 376.70	\$ 500.69	37.4%	
9	3,359	2,703	953	5,005	10.71	8.85	394.60	\$ 215.12	\$ 299.11	\$ 300.52	\$ 466.10	39.7%	
10	3,088	2,418	1,040	4,456	9.07	8.10	354.34	\$ 195.04	\$ 129.05	\$ 275.40	\$ 176.69	41.2%	
11	2,434	1,901	965	3,355	6.07	6.02	273.56	\$ 155.53	\$ 105.54	\$ 216.92	\$ 143.72	39.5%	
12	2,237	1,318	639	2,892	4.96	4.95	239.66	\$ 142.44	\$ 100.98	\$ 191.81	\$ 134.20	34.7%	
Total	31,408	30,421	13,951	47,332	10.90	9.56	3,801.82	\$ 1,914.41	\$ 1,888.50	\$ 2,798.06	\$ 2,810.71	46.2%	

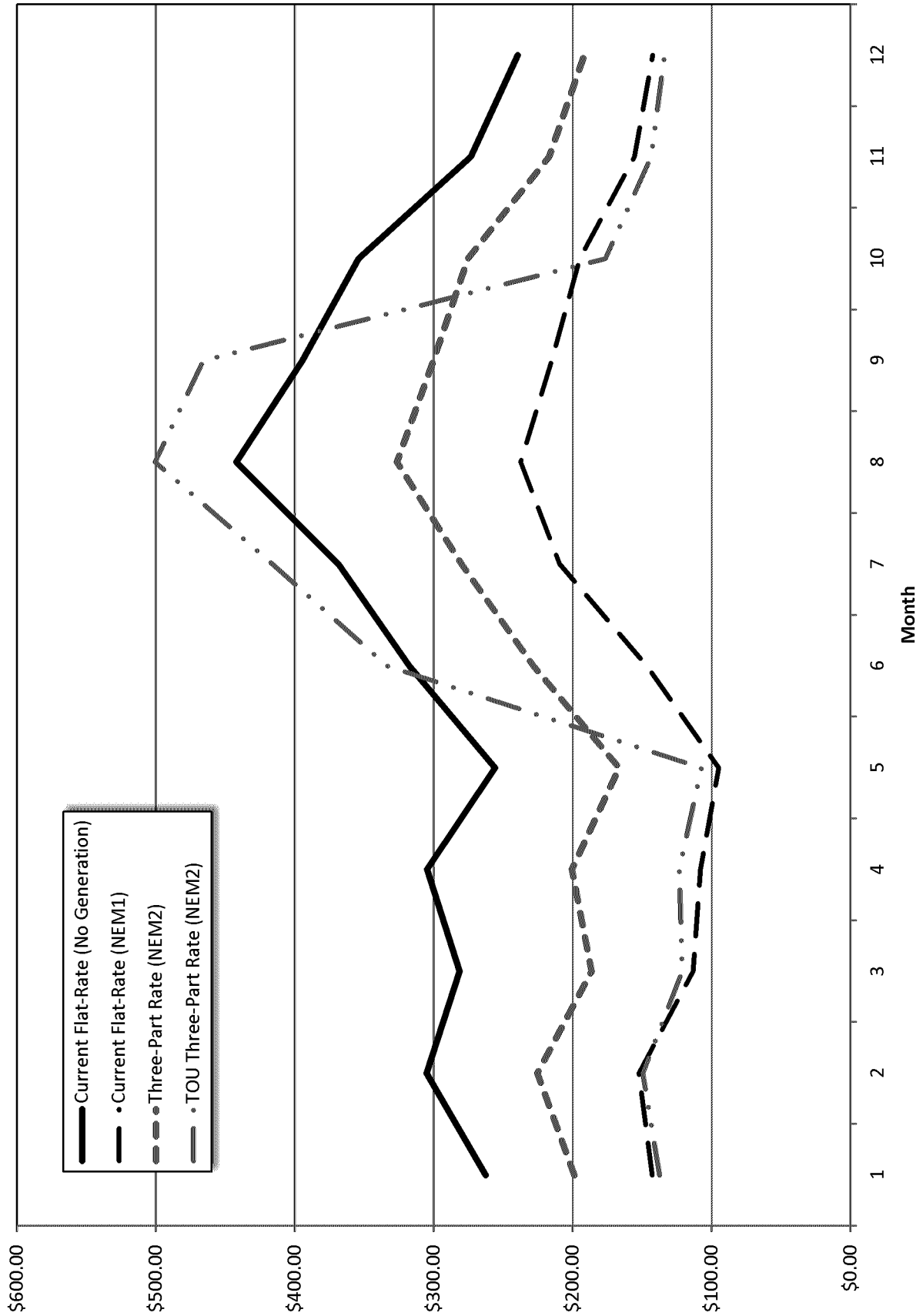
NEM Savings		\$ 1,887.41	50%	\$ 1,003.76	26%	\$ 991.11	26%
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*NEM Bills incorporate offsets to billed usage from the banked kWh amounts.

**Simple 3- Part versus Current Flat Rate

Graph C-4

Average Monthly Bill for General Service (GS) Rate Class



TECHNICAL APPENDIX

TA-1

MARGINAL COST STUDY

NEVADA POWER COMPANY - d/b/a NV ENERGY

MARGINAL COSTS OF PROVIDING ELECTRIC SERVICE

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Based on Docket No. 14-05004 Certification Filing

PREPARED BY THE

REGULATORY PRICING AND ECONOMIC ANALYSIS DEPARTMENT

July 2015

THIS MARGINAL COST STUDY WAS PREPARED TO SERVE AS THE
BASIS FOR RATE DESIGN IN DOCKET NO. 15-07 ____

STUDY: NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

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NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Table 1: Summary of Marginal Revenues by Rate Class

Line No.	Rate Class	Marginal Facilities Revenue (n1)(n6) (SL and PAL - flat rate and customer revenue)	Marginal Customer and Meter Revenue (n2), (n6)	Marginal Distribution NonRevenue (n3)	Marginal Distribution Revenue (n3)	Marginal Substation Revenue (n3)	Marginal Transmission Revenue (n3)	Marginal Generation Revenue (n4)	Marginal Energy Revenue (n6)	Total Marginal Revenue (n6)	Total Marginal Revenue %	Line No.
9	RS-Multi Family	\$14,042,553	\$21,926,272	\$19,204,055	\$14,784,541	\$16,633,170	\$110,581,622	\$82,751,598	\$279,923,811	\$1,100,548,184	11.07%	9
10	RS	\$86,473,795	\$43,555,050	\$33,474,391	\$64,264,059	\$72,299,508	\$457,746,625	\$292,734,757	\$1,100,548,184	\$4,485,939	43.53%	10
11	RS-L	\$272,516	\$48,285	\$336,405	\$266,987	\$291,370	\$1,449,653	\$1,449,653	\$88,792,946	\$1,449,653	0.18%	11
12	GS	\$23,444,592	\$7,940,019	\$3,848,006	\$2,962,448	\$3,332,866	\$20,308,731	\$26,956,285	\$151,441,182	\$26,956,285	3.51%	12
13	LGS-1 (n7)	\$16,305,078	\$6,990,756	\$25,509,189	\$19,638,646	\$22,094,223	\$135,518,544	\$151,441,182	\$377,497,618	\$151,441,182	14.93%	13
14	LGS-2S (n7)	\$6,376,850	\$2,596,176	\$14,369,761	\$11,062,784	\$12,446,053	\$77,620,367	\$94,601,038	\$219,073,029	\$94,601,038	8.67%	14
15	LGS-2P (n7)	\$49,184	\$88,586	\$381,959	\$294,057	\$330,825	\$2,126,515	\$3,106,925	\$6,378,051	\$3,106,925	0.25%	15
16	LGS-2T (n7)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.00%	16
17	LGS-3S (n7)	\$1,630,630	\$369,372	\$6,417,527	\$4,940,633	\$5,558,400	\$35,235,819	\$44,220,093	\$98,372,474	\$44,220,093	3.89%	17
18	LGS-3P (n7)	\$2,377,476	\$438,581	\$13,771,754	\$10,602,400	\$11,928,102	\$77,555,721	\$97,398,471	\$214,072,505	\$97,398,471	8.47%	18
19	LGS-3T (n7)	\$1,932,627	\$53,294	\$0	\$0	\$2,195,503	\$13,062,831	\$17,209,841	\$34,454,096	\$17,209,841	1.36%	19
20	LGS-XS	\$22,985	\$2,232	\$33,778	\$26,004	\$58,512	\$389,003	\$398,658	\$931,171	\$398,658	0.04%	20
21	LGS-XP	\$866,707	\$308,952	\$1,118,155	\$860,829	\$1,936,931	\$12,622,086	\$15,147,650	\$32,861,310	\$15,147,650	1.30%	21
22	LGS-2-WPS (n7)	\$648,576	\$200,894	\$0	\$24,793	\$2,825,293	\$171,158	\$22,985,647	\$45,109,564	\$22,985,647	1.78%	22
23	LGS-2-WPP (n7)	\$147,418	\$67,100	\$68,196	\$33,988	\$38,238	\$27,893	\$524,760	\$1,335,351	\$524,760	0.05%	23
24	LGS-2-WPT (n7)	\$18,495	\$4,409	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.04%	24
25	LGS-3-WPS (n7)	\$33,059	\$22,844	\$18,791	\$6,767	\$7,613	\$48,687	\$257,480	\$395,241	\$257,480	0.02%	25
26	LGS-3-WPP (n7)	\$46,417	\$40,850	\$66,003	\$36,799	\$41,400	\$213,549	\$621,662	\$1,066,680	\$621,662	0.04%	26
27	LGS-3-WPT (n7)	\$0	\$17,636	\$96,056	\$73,950	\$94	\$754,199	\$6,031,811	\$17,636	\$6,031,811	0.00%	27
28	SL	\$2,501,490	\$262,351	\$122	\$94	\$106	\$2,100	\$33,421	\$120,308	\$33,421	0.00%	28
29	RS-Pal	\$84,466	\$0	\$392	\$302	\$340	\$26,070	\$22,223	\$81,867	\$22,223	0.01%	29
30	GS-Pal	\$247,319	\$12,178	\$6,652	\$5,121	\$5,483	\$26,070	\$22,223	\$81,867	\$22,223	0.01%	30
31	RS-M-NEM	\$4,140	\$804,090	\$1,015,573	\$781,854	\$782,581	\$4,278,128	\$2,632,514	\$11,213,689	\$4,278,128	0.44%	31
32	RS-NEM	\$918,949	\$2,453	\$3,829	\$2,948	\$2,906	\$16,969	\$16,441	\$54,985	\$16,441	0.00%	32
33	RS-L-NEM	\$9,438	\$22,631	\$20,897	\$16,088	\$14,821	\$76,083	\$85,344	\$256,948	\$85,344	0.01%	33
34	GS-NEM	\$21,083	\$85,811,102	\$169,815,665	\$130,678,092	\$152,935,333	\$968,883,967	\$861,564,203	\$2,528,164,207	\$861,564,203	100%	34
35												35
36												36
37												37
38												38
39												39
40												40
41												41
42												42
43												43
44												44
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47												47
48												48
49												49
50												50

Source:

Table 3: Monthly Marginal Customer and Facilities Costs (page 3), monthly facilities cost per customer * Table 2: Annualized Sales and Customers by Rate Class (page 2), number of customers.
Table 3: Monthly Marginal Customer and Facilities Costs (page 3), monthly customer costs per customer * Table 3: Monthly Marginal Customer and Facilities Costs (page 3), number of customers.
Table 8: Marginal Demand Revenues: NonRevenue Feeder, Table 7: Marginal Demand Revenues: Substation, Table 6: Marginal Demand Revenues: Transmission, respectively. (pages 9, 8, 7).
Table 10: Marginal Generation Revenues (page 11), sum over time of use periods.
Worksheet 1: Marginal Energy Costs by Costing Period (page 14) * Table 2: Annualized Sales and Customers by Rate Class (page 2).
Table 3: Monthly Marginal Customer and Facilities Costs (page 3), class monthly facilities cost * 12 for LGS-3T, LGS-XS, LGS-XP, LGS-XT, LGS-2-WPT, LGS-3-WPT, and SL.
DOS customer revenue included with the otherwise applicable class.
Includes Additional Meter Charge revenue

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 2: Annualized Sales and Customers by Rate Class

Line	Class	No. Customers (n1)	Separate Meter (n2)	Facilities (n3)	Demanded On Peak (n4)	Demanded Mid Peak (n5)	Demanded Off Peak (n6)	Energy SCOP Peak (n7)	Energy On Peak (n8)	Energy Off Peak (n9)	Energy SCOP Peak (n10)	Energy On Peak (n11)	Energy Off Peak (n12)	Energy SCOP Peak (n13)	Energy On Peak (n14)	Energy Winter Peak (n15)	Energy Total kWh (n16)	Conceded Peak Demand kW (n17)	No. Conceded Peak Demand kW (n18)	Ln
9	RS-Multi-Family	3,052,584	0	11,022,888	4,105,037	2,041,430	6,896,851	310,939,894	64,048,928	64,048,928	310,939,894	64,048,928	64,048,928	310,939,894	64,048,928	1,032,533,865	1,965,228,455	373,689	438,312	9
10	RS	5,071,596	0	7,412,877	1,893,868	53,849	3,539,460	1,393,927,774	230,418,355	230,418,355	1,393,927,774	230,418,355	230,418,355	1,393,927,774	230,418,355	3,265,057,442	6,927,763,270	11,650	10	
11	RS-1A	1,161,161	0	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	1,161,161	11
12	RS-1B	855,048	0	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	855,048	12
13	LS-1	328,544	12	11,022,888	4,105,037	2,041,430	6,896,851	447,697,527	65,418,853	65,418,853	447,697,527	65,418,853	65,418,853	447,697,527	65,418,853	2,199,322,733	3,726,968,852	373,689	438,312	13
14	LS-2S	14,428	12	1,893,868	53,849	110,960	3,539,460	254,483,712	7,103,858	7,103,858	254,483,712	7,103,858	7,103,858	254,483,712	7,103,858	1,439,892,638	2,345,404,167	11,650	12,470	14
15	LS-3S	33	0	232,507	53,849	110,960	3,539,460	7,079,744	12,948,997	12,948,997	7,079,744	12,948,997	12,948,997	7,079,744	12,948,997	517,469,948	78,660,347	11,650	12,470	15
16	LS-3P	1,520	150	2,782,654	855,030	811,640	1,316,613	113,060,688	198,288,141	198,288,141	113,060,688	198,288,141	198,288,141	113,060,688	198,288,141	676,752,244	1,039,043,560	168,489	183,978	16
17	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	17
18	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	18
19	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	19
20	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	20
21	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	21
22	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	22
23	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	23
24	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	24
25	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	25
26	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	26
27	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	27
28	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	28
29	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	29
30	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	30
31	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	31
32	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	32
33	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	33
34	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	34
35	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	35
36	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	36
37	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	37
38	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	38
39	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	39
40	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	40
41	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	41
42	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	42
43	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	43
44	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	44
45	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	45
46	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	46
47	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	47
48	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	48
49	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	49
50	LS-3P	1,464	60	2,622,599	1,692,730	1,691,763	2,927,269	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	437,110,420	246,310,791	437,110,420	1,537,295,188	2,463,370,325	350,426	373,974	50
51																				

Table 3: Monthly Marginal Customer and Facilities Costs

Line No.	Rate Class	Monthly Customer Cost (n1)	Monthly Facilities Cost per Customer (n2)	Line No.
9	RS-Multi Family	7.18	4.60	9
10	RS	7.19	14.27	10
11	RS-L	17.42	98.31	11
12	GS	8.88	26.22	12
13	LGS-1	21.25	49.57	13
14	LGS-2S	179.60	441.99	14
15	LGS-2P	273.41	151.80	15
16	LGS-2T	362.58	0.00	16
17	LGS-3S	186.98	849.29	17
18	LGS-3P	280.46	1,623.96	18
19	LGS-3T (n3)	362.58	161,052.26	19
20	LGS-XS (n3)	8,156.22	1,915.42	20
21	LGS-XP (n3)	8,258.82	72,225.58	21
22	LGS-XT (n3)	8,337.91	54,048.00	22
23	LGS-2-WPS	179.60	472.49	23
24	LGS-2-WPP	273.41	140.12	24
25	LGS-2-WPT	362.58	0.00	25
26	LGS-3-WPS	186.98	918.31	26
27	LGS-3-WPP	280.46	967.03	27
28	LGS-3-WPT (n3)	362.58	0.00	28
29	SL (n3)	2.25	203,757.85	29
30	RS-Pal	3.88	0.00	30
31	GS-Pal	3.88	0.00	31
32	AIWP	24.49	849.29	32
33	ORS-MF	7.18	4.60	33
34	ORS	7.19	14.27	34
35	ORS-L	17.42	98.31	35
36	OGS	8.88	26.22	36
37	OLGS-1	21.25	49.57	37
38				38
39	Distribution-only-Service:			39
40	DOS GS	17.30		40
41	DOS LGS-1	63.87		41
42	DOS LGS-2S	184.43		42
43	DOS LGS-2P	278.24		43
44	DOS LGS-2T	367.41		44
45	DOS LGS-3S	191.82		45
46	DOS LGS-3P	285.29		46
47	DOS LGS-3T	367.41		47
48	DOS 2-WPS	184.43		48
49	DOS 2-WPP	278.24		49
50	DOS 2-WPT	367.41		50
51	DOS 3-WPS	191.82		51
52	DOS 3-WPP	285.29		52
53	DOS 3-WPT	367.41		53
54				54
55	Distributed Generation/Net Metering:			55
56	RS-M-NEM	11.61	4.60	56
57	RS-NEM	11.46	14.27	57
58	RS-L-NEM	12.88	98.31	58
59	GS-NEM	23.84	26.22	59
60				60
61				61
62				62
63	Sources:			63
64	(n1)			64
65	(n2)			65
66	(n3)			66
67				67

Table 4A: Computation of Annual Marginal Unit Cost: Customer Related (page 4), monthly customer cost divided by 12.

Table 5: Computation of Annual Marginal Unit Cost: Facilities (page 4), monthly facilities cost divided by 12.

Facilities costs are per month for the entire class.

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 4A: Computation of Annual Marginal Unit Cost: Customer Related

Line No.	Cost Components	RS-M	RS	RSL	GS	LGS-1	LGS-2S	LGS-2P	LGS-2T	Line No.
9	Meter Investment (n1):	141.79	141.97	840.91	233.45	742.7290	1672.45	8080.00	14169.93	9
10	With General Plant Loading (n2):	147.91	148.09	877.17	243.52	774.75	1744.56	8428.37	14780.98	10
11	Annual Economic Charge Related to Capital Investment (n3):	8.13%	8.13%	8.13%	8.13%	8.13%	8.13%	8.13%	8.13%	11
12	A&G Loading (n4):	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	12
13	Total: (11) + (12)	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%	13
14	Annualized Costs:	12.77	12.78	75.71	21.02	66.87	150.57	727.43	1275.69	14
15	Customer Accounts Expenses less Uncollectibles (FERC 904) (n5):	28.99	28.99	28.99	30.73	53.84	204.36	204.36	204.36	15
16	Customer Service, Informational and Sales Expenses (n6):	9.93	9.93	9.93	10.75	17.92	70.62	70.62	70.62	16
17	Meter-Related O&M Expense (n6):	9.91	9.91	49.53	10.75	47.91	187.01	187.01	187.01	17
18	With A&G Loading (n7):	37.63	37.64	77.59	44.98	104.21	1270.61	1636.91	1895.05	18
19	Uncollectibles Accounts Expense (FERC 904) (n5):	55.49	55.50	114.42	66.15	153.67	1873.68	2413.83	2927.21	19
20	Total Customer-Related Cost:	17.70	17.70	17.70	19.02	33.33	126.52	126.52	126.52	20
21	Materials and Supplies (n8):	85.95	85.98	207.82	108.18	253.86	2150.76	3267.78	4329.43	21
22	Prepayments (n8):	1.00	1.00	5.92	1.64	5.23	11.78	56.91	99.81	22
23	Customer-Related Cash Working Capital (n9):	0.69	0.69	4.08	1.13	3.94	8.12	39.24	68.81	23
24	Total Working Capital:	0.64	0.64	1.31	0.76	1.76	21.51	27.71	33.60	24
25	Revenue Requirement for Working Capital (n9):	2.32	2.32	11.32	3.54	10.60	123.86	202.22	202.22	25
26	Revenue Requirement for Working Capital (n9):	0.25	0.25	1.20	0.38	1.13	4.40	21.51	21.51	26
27	Total Customer-Related Marginal Cost:	86.19	86.22	209.03	106.56	254.99	2155.17	3280.95	4350.94	27
28	Meter Investment and Meter O&M Percent (n10)									28
29	Customer Accounts Percent (n11)		28.79%		38.33%	51.00%	13.56%	43.10%	57.06%	29
30	Customer Service, Informational and Sales Percent (n12)									30
31	Meter Investment and Meter O&M Portion (n10)									31
32	Customer Accounts Portion (n11)		24.82		40.84	130.05	292.15	1414.25	2492.49	32
33	Customer Service, Informational and Sales Portion (n12)									33
34	Customer Billing Portion (n16)									34
35	Total Customer-Related Marginal Cost (32)+(34)+(33, less meter reading and extra meters) (n13):									35
36	Billing Portion of Total Customer Related Marginal Cost (n14)									36
37	Meter, Meter O&M, and Meter Reading Portion of Total Customer Related Marginal Cost (n15)									37
38										38
39										39
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41										41
42										42
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NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 4B: Computation of Additional Meter Charge

Line No.	RS-M	RS	RS-L	GS	LGS-1	LGS-2S	LGS-2P	LGS-2T	Line No.
9									9
10									10
11	28.88%	28.90%	70.50%	38.43%	51.07%	13.69%	43.21%	57.10%	11
12	69.52%	69.50%	28.84%	60.48%	44.35%	19.89%	13.17%	10.00%	12
13	1.80%	1.60%	0.66%	1.09%	4.58%	66.41%	43.62%	32.90%	13
14	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	14
15									15
16	\$24.89	\$24.92	\$147.36	\$40.95	\$130.22	\$295.10	\$1,417.57	\$2,484.41	16
17	\$59.93	\$59.93	\$60.29	\$64.45	\$113.10	\$428.77	\$432.08	\$436.22	17
18	\$1.38	\$1.38	\$1.38	\$1.16	\$11.67	\$1,431.30	\$1,431.30	\$1,431.30	18
19	\$56.19	\$56.22	\$209.03	\$106.56	\$254.99	\$2,155.17	\$3,280.95	\$4,350.94	19
20									20
21	\$24.89	\$24.92	\$147.36	\$40.95	\$130.22	\$295.10	\$1,417.57	\$2,484.41	21
22	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	22
23	\$0.05	\$0.05	\$0.05	\$0.06	\$0.10	\$0.38	\$0.38	\$0.39	23
24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	24
25	\$24.95	\$24.98	\$147.42	\$41.01	\$130.32	\$295.48	\$1,417.96	\$2,484.80	25
26									26
27	0	0	0	0	1	2	0	0	27
28									28
29	\$0.00	\$0.00	\$0.00	\$0.00	\$130.32	\$590.95	\$0.00	\$0.00	29
30									30
31									31
77									77
78									78
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Additional Meter Cost Calculation:									
Meter Investment Percent									
Customer Accounts Percent									
Customer Service, Informational and Sales Percent									
Meter Investment Portion									
Customer Accounts Portion									
Customer Service, Informational and Sales Portion									
Meter Portion of Total Customer Related Marginal Cost									
Meter Reading Portion of Total Customer Related Marginal Cost									
Billing Portion of Total Customer Related Marginal Cost									
Customer Service, Informational Portion									
Extra Meter Charge									
Number of extra meters (n2)									
Total annual cost of extra meters									

Distributed Generation/Net Metering									
Net Meters					Generation Meters				
RS-M-NEM	RS-NEM	RS-L-NEM	GS-NEM	RS-M-NEM	RS-NEM	RS-L-NEM	GS-NEM		
29.28%	28.35%	36.23%	22.35%	19.77%	19.77%	60.58%	36.57%		
52.99%	53.69%	47.79%	59.41%	60.11%	60.11%	29.57%	48.54%		
17.73%	17.96%	15.98%	18.24%	20.12%	20.12%	9.85%	14.89%		
100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		
40.81	38.98	56.01	63.94	24.26	24.26	151.96	128.17		
73.84	73.83	73.88	169.96	73.79	73.79	74.16	170.14		
24.70	24.70	24.70	52.18	24.70	24.70	24.70	52.18		
139.35	137.52	154.59	286.07	122.76	122.76	250.82	350.49		
40.81	38.98	56.01	63.94	24.26	24.26	151.96	128.17		
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
0.07	0.07	0.07	0.15	0.07	0.07	0.07	0.15		
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
40.87	39.05	56.07	64.09	24.33	24.33	152.02	128.32		
Number of extra meters (n2)				71	2708	8	27		
Total annual cost of extra meters	\$0.00	\$0.00	\$0.00	\$1,727	\$65,886	\$1,216	\$3,465		

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 5: Computation of Annual Marginal Unit Cost: Facilities

Line	No.	Cost Components	RS	RSL	GS	LGS-1	LGS-2S	LGS-2P	LGS-2T	Line
9	Long-Run Unit Investment (n1):									No.
10	With General Plant Loading (n2):		1,794.14	12,363.94	3,297.92	6233.88	55586.58	19091.36	0.00	9
11	Annual Economic Charge Related to Capital Investment (n3):	(9) x 1.0431	1871.49	12,897.02	3,440.11	6502.66	57983.24	19914.50	0.00	10
12	A&G Loading (n4):		7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	11
13	Total Annual Carrying Charge:		0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	12
14	Annualized Cost:	(11)+(12)	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	13
15	O&M Expenses (n5)	(10)x(13)	50.26	1074.06	286.49	541.54	4828.82	1668.47	0.00	14
16	With A&G Loading (n6):		8.85	60.97	16.26	30.74	274.11	94.14	0.00	15
17	Total Cost:	(15) x 1.4746	4.21	89.91	23.98	45.33	404.20	138.83	0.00	16
18	Materials and Supplies (n7):		54.47	1163.96	310.47	596.87	5233.02	1797.30	0.00	17
19	Prepayments (n7):	(10)x 0.68%	4.08	87.09	23.23	43.91	391.54	134.47	0.00	18
20	Cash Working Capital (n8):	(10)x 0.47%	2.81	60.04	16.02	30.27	269.84	92.71	0.00	19
21	Total Working Capital:	(16)x 1.15%	0.05	1.03	0.28	0.52	4.64	1.59	0.00	20
22	Revenue Requirement for Working Capital (n8):	(18)+(19)+(20)	6.93	148.16	39.52	74.70	686.12	228.78	0.00	21
23	Total Marginal Costs:	(17)+(22)	0.74	15.76	4.20	7.95	70.85	24.34	0.00	22
24			55.20	1179.72	314.68	594.82	5303.88	1821.63	0.00	23
25										24
26										25
27	Cost Components									26
28	Long-Run Unit Investment (n1):		1,762.78	0.00	11,549.50	12,161.78	LGS-3-WPT (n9)	SL (n9)	RS-Pal	27
29	With General Plant Loading (n2):		18381.55	0.00	120,469.96	126,881.32	0.00	57,19.66	0.00	28
30	Annual Economic Charge Related to Capital Investment (n3):	(29)x 1.0431	7.83%	7.83%	7.83%	7.83%	0.00	5966.27	0.00	29
31	A&G Loading (n4):		0.50%	0.50%	0.50%	0.50%	0.50%	7.83%	7.83%	30
32	Total Annual Carrying Charge:	(31)+(32)	8.33%	8.33%	8.33%	8.33%	0.50%	8.33%	0.50%	31
33	Annualized Cost:	(30)x(33)	5162.06	1530.81	10032.68	10564.95	0.00	8.33%	8.33%	32
34	O&M Expenses (n5)		293.02	86.90	589.50	599.72	0.00	496.87	0.00	33
35	With A&G Loading (n6):		432.10	128.14	839.80	884.36	0.00	28.20	0.00	34
36	Total Cost:	(35)x 1.4746	5594.16	1658.95	10,872.48	11,449.31	0.00	41.59	0.00	35
37	Materials and Supplies (n7):	(30)x 0.68%	418.56	124.12	0.00	856.65	0.00	538.46	0.00	36
38	Prepayments (n7):	(30)x 0.47%	288.57	85.58	813.49	856.65	0.00	40.29	0.00	37
39	Cash Working Capital (n8):	(36)x 1.15%	4.96	1.47	0.00	590.60	0.00	27.78	0.00	38
40	Total Working Capital:	(38)+(39)+(40)	712.09	211.17	0.00	10.15	0.00	0.48	0.00	39
41	Revenue Requirement for Working Capital (n8):	(41)x 10.64%	75.74	22.45	0.00	1,457.40	0.00	68.54	0.00	40
42	Total Marginal Costs:	(37)+(42)	5689.91	1681.41	0.00	155.02	0.00	7.29	0.00	41
43					11,019.70	11,604.33	0.00	545.75	0.00	42
44	Transformer (m10)									43
45										44
46										45
47										46
48	Cost Components									47
49	Long-Run Unit Investment (n1):		1,794.14	12,363.94	3,297.92					48
50	With General Plant Loading (n2):		1,871.49	12,897.02	3,440.11					49
51	Annual Economic Charge Related to Capital Investment (n3):	1.0431	7.83%	7.83%	7.83%					50
52	A&G Loading (n4):		0.50%	0.50%	0.50%					51
53	Total Annual Carrying Charge:		8.33%	8.33%	8.33%					52
54	Annualized Cost:		50.26	1074.06	286.49					53
55	O&M Expenses (n5)		2.85	8.85	16.26					54
56	With A&G Loading (n6):		4.21	13.05	23.98					55
57	Total Cost:	1.4746	54.47	168.90	310.47					56
58	Materials and Supplies (n7):		4.08	87.09	23.23					57
59	Prepayments (n7):	0.68%	2.81	60.04	16.02					58
60	Cash Working Capital (n8):	0.47%	0.05	1.03	0.28					59
61	Total Working Capital:	1.15%	6.93	148.16	39.52					60
62	Revenue Requirement for Working Capital (n8):	10.64%	0.74	15.76	4.20					61
63	Total Marginal Costs:		55.20	1,179.72	314.68					62
64										63
65										64
66	Sources:									65
67	(n1)	Worksheet 11: Derivation of Marginal Facilities Charges (page 41)								66
68	(n2)	1 - Worksheet 13: Loading Factors, General Plant, Materials and Supplies, and Prepayments (page 46)								67
69	(n3)	Worksheet 17: Annual Economic Carrying Charge Related to Capital Investment (page 51), distribution facilities								68
70	(n4)	Worksheet 13: Loading Factor for A&G and Social Security and Unemployment Taxes (page 44)								69
71	(n5)	Worksheet 8: Facilities Charge O&M Expenses per Customer (page 30), - Worksheet 11: Derivation of Marginal Facilities Charges weighted facilities investment								70
72	(n6)	1 - Worksheet 13: Loading Factor for A&G and Social Security and Unemployment Taxes (page 44)								71
73	(n7)	Worksheet 13: Loading Factors, General Plant, Materials and Supplies, and Prepayments (page 46)								72
74	(n8)	Worksheet 16: Cash Working Capital Factor and Derivation of Revenue Requirement for Working Capital Factor (page 50)								73
75	(n9)	Facilities costs are for the entire class. O&M Costs for CIG's facilities are added in Row 24.								74
76	(n10)	Percentage of time a transformer is required for Street Light addition.								75
77										76
78										77
										78

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 6: Marginal Demand Revenues: Transmission

Line No.	Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter Peak	Total	Line No.
9	RS-Multi Family	0	14,947,513	0	1,654,360	0	0	0	0	31,297	16,633,170	9
10	RS	0	65,747,462	0	6,426,887	0	0	0	0	125,189	72,299,508	10
11	RS-L	0	264,579	0	26,279	0	0	0	0	512	291,370	11
12	GS	0	2,967,973	0	357,517	0	0	0	0	7,377	3,332,866	12
13	LGS-1	0	19,859,288	2,180,351	1,641	0	0	0	0	52,943	22,094,223	13
14	LGS-2S	0	11,147,146	1,264,529	931	0	0	0	0	33,447	12,446,053	14
15	LGS-2P	0	295,801	34,025	29	0	0	0	0	970	330,825	15
16	LGS-2T	0	0	0	0	0	0	0	0	0	-	16
17	LGS-3S	0	4,970,549	572,698	458	0	0	0	0	14,695	5,558,400	17
18	LGS-3P	0	10,671,776	1,224,548	1,022	0	0	0	0	30,755	11,928,102	18
19	LGS-3T	0	1,966,668	223,064	188	0	0	0	0	5,584	2,195,503	19
20	LGS-XS	0	52,205	6,171	6	0	0	0	0	130	58,512	20
21	LGS-XP	0	1,733,103	198,694	168	0	0	0	0	4,966	1,936,931	21
22	LGS-XT	0	2,527,355	290,330	246	0	0	0	0	7,363	2,825,293	22
23	LGS-2WPS	0	24,982	2,834	2	0	0	0	0	75	27,893	23
24	LGS-2WPP	0	34,189	3,933	3	0	0	0	0	112	38,238	24
25	LGS-2WPT	0	0	0	0	0	0	0	0	0	-	25
26	LGS-3WPS	0	6,808	784	1	0	0	0	0	20	7,613	26
27	LGS-3WPP	0	37,040	4,250	4	0	0	0	0	107	41,400	27
28	LGS-3WPT	0	0	0	0	0	0	0	0	0	-	28
29	SL	0	58,760	24,096	114	0	0	0	0	226	83,197	29
30	RS-Pal	0	0	105	1	0	0	0	0	0	106	30
31	GS-Pal	0	0	338	2	0	0	0	0	0	340	31
32	AIWP	0	0	0	0	0	0	0	0	0	-	32
33	ORS-MF (Opt B) (n1)	0	11,991,010	0	2,128,188	0	0	0	0	2,555,552	16,674,730	33
34	ORS (Opt B) (n1)	15,380,849	36,415,203	0	9,162,976	936,316	8,701,372	0	1,404,165	124,360	72,125,242	34
35	ORS-L (Opt B) (n1)	0	204,195	0	39,504	0	0	0	0	46,680	289,379	35
36	RS-M-NEM	0	4,908	0	566	0	0	0	0	9	5,483	36
37	RS-NEM	0	702,379	0	79,288	0	0	0	0	933	782,581	37
38	RS-L-NEM	0	2,604	0	293	0	0	0	0	10	2,906	38
39	GS-NEM	0	13,108	0	1,682	0	0	0	0	31	14,821	39
40												40
41												41
42												42
43												43
44												44
45												45
46												46
47	TOTAL	0	138,036,195	6,030,750	8,551,635	0	0	0	0	316,753	152,935,333	47
48												48
49												49
50												50
51	Source:											51
52	=											52
53	x											53
54	x											54
55	(n1)											55
56												56
57												57
58												58

Table 9: Computation of Annual Marginal Unit Cost: Demand Related (page 10), for transmission with losses
Worksheet 3: Load Weighted Probability of Peak (page 20A) * rescaling factor (page 20A).
Table 2: Annualized Sales and Customers by Rate Class (page 2).

Determinants for Opt TOU classes (Opt B and NDPT) are included with the otherwise applicable schedule above.

Table 7: Marginal Demand Revenues: Substation

Line No.	Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter Peak	Total	Line No.
9	RS-Multi Family	0	13,286,229	0	1,470,493	0	0	0	0	27,819	14,784,541	9
10	RS	0	58,440,215	0	5,712,569	0	0	0	0	111,275	64,264,059	10
11	RS-L	0	235,173	0	23,358	0	0	0	0	456	258,987	11
12	GS	0	2,638,109	0	317,782	0	0	0	0	6,557	2,962,448	12
13	LGS-1	0	17,652,104	1,938,025	1,458	0	0	0	0	47,059	19,638,646	13
14	LGS-2S	0	9,908,240	1,123,987	828	0	0	0	0	29,729	11,062,784	14
15	LGS-2P	0	262,925	30,244	26	0	0	0	0	862	294,057	15
16	LGS-2T	0	4,418,116	509,048	407	0	0	0	0	13,062	4,940,633	16
17	LGS-3S	0	9,485,703	1,088,451	909	0	0	0	0	27,337	10,602,400	17
18	LGS-3P	0	23,201	2,743	2	0	0	0	0	58	26,004	18
19	LGS-3T	0	770,242	88,305	75	0	0	0	0	2,207	860,829	19
20	LGS-XS (n1)	0	22,205	2,519	2	0	0	0	0	67	24,793	20
21	LGS-XP (n1)	0	30,390	3,496	3	0	0	0	0	100	33,988	21
22	LGS-XS (n3)	0	6,051	697	1	0	0	0	0	18	6,767	22
23	LGS-2-WPS (n3)	0	32,923	3,778	3	0	0	0	0	95	36,799	23
24	LGS-2-WPP (n3)	0	52,229	21,418	101	0	0	0	0	201	73,950	24
25	LGS-2-WPT (n3)	0	0	93	1	0	0	0	0	0	94	25
26	LGS-3-WPS (n3)	0	0	300	2	0	0	0	0	0	302	26
27	LGS-3-WPP (n3)	0	0	0	0	0	0	0	0	0	0	27
28	LGS-3-WPT (n3)	0	0	0	0	0	0	0	0	0	0	28
29	SL	0	10,658,316	0	1,891,641	0	0	0	0	2,271,525	14,821,482	29
30	RS-Pal	0	32,367,977	0	8,144,592	832,253	7,734,292	0	1,248,105	110,538	64,109,161	30
31	GS-Pal	0	181,500	0	35,114	0	0	0	0	40,603	257,217	31
32	AIWP	0	0	0	0	0	0	0	0	0	0	32
33	ORS-MF (Opt B) (n2)	0	0	0	0	0	0	0	0	0	0	33
34	ORS (Opt B) (n2)	13,671,405	0	0	0	0	0	0	0	0	0	34
35	ORS-L (Opt B) (n2)	0	0	0	0	0	0	0	0	0	0	35
36	RS-M-NEM	0	4,601	0	511	0	0	0	0	9	5,121	36
37	RS-NEM	0	708,211	0	72,674	0	0	0	0	969	781,854	37
38	RS-L-NEM	0	2,665	0	274	0	0	0	0	10	2,948	38
39	GS-NEM	0	14,474	0	1,582	0	0	0	0	32	16,088	39
40												40
41												41
42												42
43												43
44												44
45												45
46												46
47	TOTAL	0	117,994,009	4,813,103	7,603,059	0	0	0	0	267,921	130,678,092	47
48												48
49												49
50												50
51												51
52												52
53												53
54												54
55												55
56												56
57												57
58												58
59												59
60												60

(n3) Ratio of CP to be used in WP substation demand allocation: 1.00

Source:

= Table 9: Computation of Annual Marginal Unit Cost: Demand Related (page 10), for substation with losses

x Worksheet 3: Load Weighted Probability of Peak (page 20A) * rescaling factor (page 20A).

x Table 2: Annualized Sales and Customers by Rate Class (page 2).

(n1) Allocation of costs for LGS-XS and LGS-XP are decreased by 50% to reflect their customer specific distribution.

(n2) Determinants for Opt B and NDPT are included with the otherwise applicable schedule above

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Table 8: Marginal Demand Revenues: NonRevenue Feeder

Line No.	Class	SOCP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter Peak	Total	Line No.
9	RS-Multi Family	0	17,257,856	0	1,910,064	0	0	0	0	36,134	19,204,055	9
10	RS	0	75,909,636	0	7,420,216	0	0	0	0	144,538	83,474,391	10
11	RS-L	0	305,473	0	30,341	0	0	0	0	592	336,405	11
12	GS	0	3,426,714	0	412,776	0	0	0	0	8,517	3,848,006	12
13	LGS-1	0	22,928,814	2,517,355	1,894	0	0	0	0	61,126	25,509,189	13
14	LGS-2S	0	12,870,091	1,459,979	1,075	0	0	0	0	38,616	14,369,761	14
15	LGS-2P	0	341,521	39,284	33	0	0	0	0	1,120	381,959	15
16	LGS-2T	0	5,738,815	661,217	528	0	0	0	0	16,966	6,417,527	16
17	LGS-3S	0	12,321,246	1,413,819	1,181	0	0	0	0	35,509	13,771,754	17
18	LGS-3P	0				0	0	0	0			18
19	LGS-3T	0				0	0	0	0			19
20	LGS-XS (n1)	0	30,137	3,562	3	0	0	0	0	75	33,778	20
21	LGS-XP (n1)	0	1,000,489	114,702	97	0	0	0	0	2,867	1,118,155	21
22	LGS-XI	0				0	0	0	0			22
23	LGS-2-WPS (n3)	0	61,079	6,929	5	0	0	0	0	183	68,196	23
24	LGS-2-WPP (n3)	0	48,438	5,572	5	0	0	0	0	159	54,173	24
25	LGS-2-WPT (n3)	0				0	0	0	0			25
26	LGS-3-WPS (n3)	0	16,804	1,936	2	0	0	0	0	50	18,791	26
27	LGS-3-WPP (n3)	0	59,051	6,776	6	0	0	0	0	170	66,003	27
28	LGS-3-WPT (n3)	0				0	0	0	0			28
29	SL	0	67,842	27,821	132	0	0	0	0	261	96,056	29
30	RS-Pal	0	0	121	1	0	0	0	0	0	122	30
31	GS-Pal	0	0	390	2	0	0	0	0	0	392	31
32	AIWP	0	0	0	0	0	0	0	0	0	0	32
33	ORS-MF (Opt B) (n2)	0	13,844,385	0	2,457,106	0	0	0	0	2,950,547	19,252,039	33
34	ORS (Opt B) (n2)	17,758,171	42,043,673	0	10,579,240	1,081,037	10,046,288	0	1,621,198	143,581	83,273,189	34
35	ORS-L (Opt B) (n2)	0	235,756	0	48,610	0	0	0	0	52,741	334,106	35
36												36
37	RS-M-NEM	0	5,977	0	864	0	0	0	0	11	6,852	37
38	RS-NEM	0	919,916	0	94,399	0	0	0	0	1,258	1,015,573	38
39	RS-L-NEM	0	3,461	0	356	0	0	0	0	12	3,829	39
40	GS-NEM	0	18,601	0	2,054	0	0	0	0	42	20,897	40
41												41
42												42
43												43
44												44
45												45
46												46
47	TOTAL	0	153,332,161	6,259,462	9,875,833	0	0	0	0	348,209	169,815,665	47
48												48
49												49
50												50
51												51
52												52
53												53
54												54
55												55
56												56
57												57
58												58
59												59
60												60

(n3) Ratio of CP to be used in WP NR Feeder demand allocation: 0.90

Table 9: Computation of Annual Marginal Unit Cost: Demand Related (page 10), for nonrevenue feeder with losses

Worksheet 3: Load Weighted Probability of Peak (page 20A) * rescaling factor (page 20A).

Table 2: Annualized Sales and Customers by Rate Class (page 2).

Allocation of costs for LGS-XS and LGS-XP are decreased by 50% to reflect their customer specific distribution. Determinants for Opt B and NDPT are included with the otherwise applicable schedule above

Table 9: Computation of Annual Marginal Unit Cost: Demand Related

Line No.	Cost Components	Generation	Transmission	Substation	NonRevenue Feeder	Line No.
9	Long-Run Unit Investment (n1),(n2),(n3),(n4):	1,731.76	309.98	262.06	322.46	9
10	With General Plant Loading (n5): (9) X	1806.43	323.35	273.36	336.36	10
11	Annual Econ. Charge Related to Capital Investment (n6):	8.29%	7.22%	7.46%	7.83%	11
12	A&G Loading (n7):	0.50%	0.50%	0.50%	0.50%	12
13	Total Annual Carrying Charge: (11) + (12)	8.80%	7.72%	7.96%	8.33%	13
14	Annualized Cost: (10) X (13)	158.90	24.97	21.77	28.01	14
15	Demand-Related O&M Expenses (n8), (n9), (n10), (n11):	1.96	0.35	0.78	1.21	15
16	With A&G Loading (n12): (19) X	2.88	0.52	1.14	1.78	16
17	Demand-Related Cost: (14) + (16)	161.78	25.49	22.91	29.79	17
18	Materials and Supplies (n13): (10) X	12.20	2.18	1.85	2.27	18
19	Prepayments (n13): (10) X	8.49	1.52	1.28	1.58	19
20	Cash Working Capital (n14): (16) X	0.03	0.01	0.01	0.02	20
21	Total Working Capital: (18) + (19) + (20)	20.72	3.71	3.14	3.87	21
22	Revenue Requirements for Working Capital (n14):	2.20	0.39	0.33	0.41	22
23	(21) X					23
24	Total Demand-Related Costs: (17) + (22)	163.99	25.88	23.24	30.21	24
25		5908.32	5908.32	5621.93	5621.93	25
26			\$152,935,333	\$130,678,092	\$169,815,665	26
27						27
28	Secondary Costs (n15):					28
29	Primary Costs (n15):	@ 1.0636	27.53	24.19	31.44	29
30	Transmission Costs (n15):	@ 1.0381	26.87	23.61	30.69	30
31		@ 1.0219	26.45			31
32						32
33						33
34	Source:					34
35	(n1)	Provided by Resource Planning, the total project cost of building a Combustion Turbine Generator including AFUDC and planning reserves of 12%.				35
36	(n2)	Worksheet 3: Page 18-19, T&D Investment and Regression Analysis				36
37	(n6)	1 + Worksheet 13: Loading Factors: General Plant, Materials and Supplies, and Prepayments (page 46).				37
38	(n6)	Worksheet 17: Annual Economic Carrying Charges Related to Capital Investment (page 51), transmission, substation, and facilities, respectively.				38
39	(n7)	Worksheet 13: Loading Factor for A&G and Social Security and Unemployment Taxes (page 44).				39
40	(n8)	Worksheet 6: Transmission O&M Expenses per kW of System Peak Demand (page 25) * generation capacity proportion of total transmission investment.				40
41	(n9)	Worksheet 6: Transmission O&M Expenses per kW of System Peak Demand (page 25) * transmission proportion of total transmission investment.				41
42	(n10)	Worksheet 7: Distribution Substation O&M Expenses per kW of Distribution Peak Demand (page 28).				42
43	(n11)	Worksheet 8: Facilities Charges O&M Expenses per kW (page 31).				43
44	(n12)	1 + Worksheet 13: Loading Factor for A&G and Social Security and Unemployment Taxes (page 44).				44
45	(n13)	Worksheet 13: Loading Factors: General Plant, Materials and Supplies, and Prepayments (page 46).				45
46	(n14)	Worksheet 16: Cash Working Capital Factor and Derivation of Revenue Requirement for Working Capital Factor (page 50).				46
47	(n15)	Worksheet 5: System Peak Demand Losses (page 23).				47
48						48
49						49
50						50
51						51
52						52

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Table 10: Marginal Generation Revenues

Line No.	Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter Peak	Total	Line No.
9	RS-Multi Family	0	84,761,119	0	25,620,503	0	0	0	0	0	110,581,622	9
10	RS	0	360,576,312	0	97,170,313	0	0	0	0	0	457,746,625	10
11	RS-L	0	1,437,575	0	391,148	0	0	0	0	0	1,828,723	11
12	GS	0	15,018,026	0	5,290,705	0	0	0	0	0	20,308,731	12
13	LGS-1	0	104,324,057	31,194,487	0	0	0	0	0	0	135,518,544	13
14	LGS-2S	0	59,672,831	17,947,536	0	0	0	0	0	0	77,620,367	14
15	LGS-2P	0	1,623,764	502,731	0	0	0	0	0	0	2,126,515	15
16	LGS-ZT	0	0	0	0	0	0	0	0	0	-	16
17	LGS-3S	0	26,967,500	8,268,320	0	0	0	0	0	0	35,235,819	17
18	LGS-3P	0	59,299,084	18,256,636	0	0	0	0	0	0	77,555,721	18
19	LGS-3T	0	10,036,086	3,026,744	0	0	0	0	0	0	13,062,831	19
20	LGS-XS	0	294,605	94,398	0	0	0	0	0	0	389,003	20
21	LGS-XP	0	9,651,605	2,970,481	0	0	0	0	0	0	12,622,086	21
22	LGS-XT	0	14,093,791	4,355,364	0	0	0	0	0	0	18,449,154	22
23	LGS-2-WPP	0	124,289	46,869	0	0	0	0	0	0	171,158	23
24	LGS-2-WPT	0	188,614	55,908	0	0	0	0	0	0	244,522	24
25	LGS-2-WPT	0	0	0	0	0	0	0	0	0	-	25
26	LGS-3-WPP	0	36,017	12,670	0	0	0	0	0	0	48,687	26
27	LGS-3-WPT	0	157,567	55,982	0	0	0	0	0	0	213,549	27
28	SL	0	0	0	0	0	0	0	0	0	-	28
29	GS-Pal	0	319,812	434,388	0	0	0	0	0	0	754,199	29
30	GS-Pal	0	0	2,100	0	0	0	0	0	0	2,100	30
31	GS-Pal	0	0	6,762	0	0	0	0	0	0	6,762	31
32	AWP	0	0	0	0	0	0	0	0	0	-	32
33	ORS-MF (Opt B) (n1)	0	83,681,228	0	25,388,537	0	0	0	0	1,105,000	110,174,766	33
34	ORS (Opt B) (n1)	142,889,694	209,015,051	0	101,321,342	586,221	2,578,764	0	1,492,274	0	457,883,347	34
35	ORS-L (Opt B) (n1)	0	1,385,056	0	426,778	0	0	0	0	18,364	1,830,199	35
36	RS-M-NEM	0	17,221	0	8,849	0	0	0	0	0	26,070	36
37	RS-NEM	0	3,029,712	0	1,246,417	0	0	0	0	0	4,276,129	37
38	RS-L-NEM	0	12,450	0	4,519	0	0	0	0	0	16,969	38
39	GS-NEM	0	50,369	0	25,714	0	0	0	0	0	76,083	39
40												40
41												41
42												42
43												43
44												44
45												45
46												46
47	TOTAL	0	751,692,423	87,231,375	129,960,168	0	0	0	0	0	968,883,967	47
48												48
49												49
50												50
51	Source:											51
52	=											52
53	x											53
54	x											54
55												55
56												56
57	(n1)											57
58												58
59												59
60												60

Table 9: Computation of Annual Marginal Unit Cost - Demand Related (page 10), for Generation with losses
Worksheet 2: Load Weighted Loss of Load Probability (page 17) x rescaling factor (page 17)
Table 2: Annualized Sales and Customers by Rate Class (page 2).

Determinants for Opt TOU classes (Opt B and NDPT) are included with the otherwise applicable schedule above

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

[illegible]

APPENDIX A

Energy, Generation, and Demand

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Worksheet 1: Marginal Energy Costs by Costing Period

Line No.	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter
9	Variable O&M \$/MWH	1.9467	1.9467	1.9467	1.9467	1.9467	1.9467	1.9467	1.9467	1.9467
10	A&G loading for Variable O&M	0.4746	0.4746	0.4746	0.4746	0.4746	0.4746	0.4746	0.4746	0.4746
11	Incremental Cost of Fuel Stock	0.1231	0.1231	0.1231	0.1231	0.1231	0.1231	0.1231	0.1231	0.1231
12	Cash Working Capital for Variable O&M	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115
13	Revenue Requirements for Working Capital	0.1064	0.1064	0.1064	0.1064	0.1064	0.1064	0.1064	0.1064	0.1064
14	Renewable Portfolio Standard Adder	9.6993	9.6993	9.6993	9.6993	9.6993	9.6993	9.6993	9.6993	9.6993
15	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Summer SH On-Peak	Summer SH Mid-Peak	Summer SH Off-Peak	Winter
16	RS-Multi Family	0.0000	51.3951	0.0000	41.5127	0.0000	0.0000	0.0000	0.0000	38.6885
17	RS	0.0000	51.3577	0.0000	41.9072	0.0000	0.0000	0.0000	0.0000	38.6741
18	RS-L	0.0000	51.2968	0.0000	41.4648	0.0000	0.0000	0.0000	0.0000	38.6018
19	GS	0.0000	51.0811	0.0000	40.7757	0.0000	0.0000	0.0000	0.0000	38.4493
20	LGS-1	0.0000	51.0536	45.8656	37.6019	0.0000	0.0000	0.0000	0.0000	38.4020
21	LGS-2S	0.0000	51.0469	45.8233	37.4807	0.0000	0.0000	0.0000	0.0000	38.3802
22	LGS-2P	0.0000	49.8307	44.9100	36.8609	0.0000	0.0000	0.0000	0.0000	37.8332
23	LGS-2T	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
24	LGS-3S	0.0000	51.0636	45.8826	37.4704	0.0000	0.0000	0.0000	0.0000	38.3103
25	LGS-3P	0.0000	49.9328	44.9928	36.9190	0.0000	0.0000	0.0000	0.0000	37.7573
26	LGS-3T (n6)	0.0000	49.1348	44.2520	36.5399	0.0000	0.0000	0.0000	0.0000	37.3955
27	LGS-XS	0.0000	51.3628	46.2167	37.6158	0.0000	0.0000	0.0000	0.0000	38.2885
28	LGS-XP	0.0000	49.9211	44.9989	36.9842	0.0000	0.0000	0.0000	0.0000	37.7806
29	LGS-XT	0.0000	49.2049	44.4253	36.6042	0.0000	0.0000	0.0000	0.0000	37.4833
30	LGS-2-WPS	0.0000	51.0392	45.2321	37.2073	0.0000	0.0000	0.0000	0.0000	38.1484
31	LGS-2-WPP	0.0000	49.7302	44.6136	36.5401	0.0000	0.0000	0.0000	0.0000	37.4656
32	LGS-2-WPT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
33	LGS-3-WPS	0.0000	50.9406	45.6887	37.2024	0.0000	0.0000	0.0000	0.0000	37.4174
34	LGS-3-WPP	0.0000	49.5440	44.4990	36.5495	0.0000	0.0000	0.0000	0.0000	37.6383
35	LGS-3-WPT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	SL	0.0000	50.6600	46.9387	37.9763	0.0000	0.0000	0.0000	0.0000	38.4850
37	RS-Pal	0.0000	0.0000	47.2070	38.0415	0.0000	0.0000	0.0000	0.0000	38.5196
38	GS-Pal	0.0000	0.0000	47.2081	38.0403	0.0000	0.0000	0.0000	0.0000	38.5297
39	AIWP	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40	ORS-MF (Opt B)	0.0000	54.6180	0.0000	43.4269	0.0000	0.0000	0.0000	0.0000	39.7782
41	ORS (Opt B)	55.5072	54.3793	0.0000	43.9034	53.2325	48.7472	0.0000	40.3198	38.6807
42	ORS-L (Opt B)	0.0000	54.6091	0.0000	43.4612	0.0000	0.0000	0.0000	0.0000	39.7118
43	RS-M-NEM	0.0000	52.5544	0.0000	41.6442	0.0000	0.0000	0.0000	0.0000	39.3529
44	RS-NEM	0.0000	52.0421	0.0000	41.9723	0.0000	0.0000	0.0000	0.0000	39.3630
45	RS-L-NEM	0.0000	51.8952	0.0000	41.4992	0.0000	0.0000	0.0000	0.0000	38.6568
46	GS-NEM	0.0000	52.0096	0.0000	40.8488	0.0000	0.0000	0.0000	0.0000	38.9303
47										
48										
49										
50										
51										
52										
53	SYSTEM	0.0000	51.2074	48.1478	37.7909	0.0000	0.0000	0.0000	0.0000	38.5020
54										
55	Source:									
56	=									
57	Worksheet 1: Load Weighted Marginal Running Costs (Including Losses) (page 15)									
58	(Variable O&M \$/MWH x A&G loading for Variable O&M)									
59	[(Incremental Cost of Fuel Stock + ((Variable O&M \$/MWH) + (Variable O&M \$/MWH x (n2))) x Cash Working Capital for Variable O&M) x Revenue Requirements for Working Capital]									
60	(Incremental Cost of Renewable Portfolio Standard Requirement x Class Specific Load Weighted Average Loss Factor by TOU Period)									
61	Average of monthly estimates from Marginal Energy Costs PROMOD Run. Used to calculate A&G and Working Capital. VOM is already included in the MEC.									
62	Worksheet 1: Loading Factor for A&G and Social Security and Unemployment Taxes (page 41).									
63	Worksheet 1: Incremental Cost of Fuel Stock (page 16).									
64	Worksheet 16: Cash Working Capital Factor and Derivation of Revenue Requirement for Working Capital Factor (page 50).									
65	Renewable Portfolio Standard Adder, calculated separately, and then adjusted for appropriate loss factor.									
66	Nellis full load with WAPA included for E, T, and D functions. For G, Nellis full load without WAPA is included.									
67										

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Worksheet 1: Load Weighted Marginal Running Costs (Including Losses)

Average of MECs from the Rate Effective Period

Line No.	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Shoulder On-Peak	Shoulder Mid-Peak	Shoulder Off-Peak	Winter Peak	Line No.
9	RS-Multi Family	0.00	40.17	0.00	30.42	0.00	0.00	0.00	0.00	27.70	9
10	RS	0.00	40.13	0.00	30.81	0.00	0.00	0.00	0.00	27.70	10
11	RS-L	0.00	40.07	0.00	30.38	0.00	0.00	0.00	0.00	27.63	11
12	GS	0.00	39.86	0.00	29.70	0.00	0.00	0.00	0.00	27.48	12
13	LGS-1	0.00	39.83	34.71	26.58	0.00	0.00	0.00	0.00	27.43	13
14	LGS-2S	0.00	39.83	34.67	26.46	0.00	0.00	0.00	0.00	27.41	14
15	LGS-2P	0.00	38.85	33.97	26.00	0.00	0.00	0.00	0.00	27.01	15
16	LGS-2T	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16
17	LGS-3S	0.00	39.84	34.73	26.45	0.00	0.00	0.00	0.00	27.34	17
18	LGS-3P	0.00	38.95	34.05	26.06	0.00	0.00	0.00	0.00	26.94	18
19	LGS-3T (n1)	0.00	38.30	33.44	25.77	0.00	0.00	0.00	0.00	26.65	19
20	LGS-XS	0.00	40.14	35.06	26.59	0.00	0.00	0.00	0.00	27.32	20
21	LGS-XP	0.00	38.93	34.05	26.12	0.00	0.00	0.00	0.00	26.96	21
22	LGS-XT	0.00	38.37	33.61	25.84	0.00	0.00	0.00	0.00	26.74	22
23	LGS-2-WPS	0.00	39.81	34.08	26.19	0.00	0.00	0.00	0.00	27.18	23
24	LGS-2-WPP	0.00	38.74	33.67	25.68	0.00	0.00	0.00	0.00	26.64	24
25	LGS-2-WPT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25
26	LGS-3-WPS	0.00	39.74	34.55	26.18	0.00	0.00	0.00	0.00	26.46	26
27	LGS-3-WPP	0.00	38.56	33.56	25.69	0.00	0.00	0.00	0.00	26.82	27
28	LGS-3-WPT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28
29	SL	0.00	39.45	35.78	26.95	0.00	0.00	0.00	0.00	27.52	29
30	RS-Pal	0.00	0.00	36.04	27.01	0.00	0.00	0.00	0.00	27.56	30
31	GS-Pal	0.00	0.00	36.04	27.01	0.00	0.00	0.00	0.00	27.57	31
32	AIWP										32
33	ORS-MF (Opt B)	0.00	43.34	0.00	32.31	0.00	0.00	0.00	0.00	28.77	33
34	ORS (Opt B)	44.21	43.11	0.00	32.78	41.98	37.58	0.00	29.25	27.71	34
35	ORS-L (Opt B)	0.00	43.33	0.00	32.34	0.00	0.00	0.00	0.00	28.71	35
36											36
37	RS-MF-NEM	0.00	41.33	0.00	30.56	0.00	0.00	0.00	0.00	28.38	37
38	RS-NEM	0.00	40.82	0.00	30.88	0.00	0.00	0.00	0.00	28.39	38
39	RS-L-NEM	0.00	40.67	0.00	30.42	0.00	0.00	0.00	0.00	27.69	39
40	GS-NEM	0.00	40.79	0.00	29.78	0.00	0.00	0.00	0.00	27.96	40
41											41
42											42
43											43
44											44
45											45
46	SYSTEM	0.00	39.98	34.99	26.76	0.00	0.00	0.00	0.00	27.53	46
47											47
48											48
49	Source:										49
50											50
51	(n1)										51
52											52

Load Weighted Marginal Energy Costs (from PROMOD run).
Nellis full load with WAPA included for E, T, and D functions. For G, Nellis full load without WAPA is included.

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

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Worksheet 1: Incremental Cost of Fuel Stock

Line No.	Year	Average Fuel Stock for the Year (\$'s) (n1)	Carrying Cost of Fuel Stock (\$)	Net Generation Plus Purchases (MWh) (n2)	2013 Cost of Fuel Stock (\$/MWh) (1) / (2)	Line No.
9	2013	25,331,768	2,694,533	22,618,068	0.1191	9
10						10
11						11
12						12
13				Cost of Fuel Stock (2015\$):	0.12306	13
14						14
15	Source:					15
16	(n1)					16
17	(n2)					17
18						18

Calculated by NPC's Regulatory Accounting Department as of December 31, 2010
Revenue Requirement on Average Fuel Inventory

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Worksheet 2: Load Weighted Loss of Load Probability (n1)

Line No.	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Shoulder On-Peak	Shoulder Mid-Peak	Shoulder Off-Peak	Winter Peak	Line No.
9	RS-Multi Family	0.0000	1.1947	0.0000	0.1747	0.0000	0.0000	0.0000	0.0000	0.0000	9
10	RS	0.0000	1.1532	0.0000	0.1846	0.0000	0.0000	0.0000	0.0000	0.0000	10
11	RS-L	0.0000	1.1180	0.0000	0.1805	0.0000	0.0000	0.0000	0.0000	0.0000	11
12	GS	0.0000	0.9787	0.0000	0.1189	0.0000	0.0000	0.0000	0.0000	0.0000	12
13	LGS-1	0.0000	1.0199	0.3208	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	13
14	LGS-2S	0.0000	1.0283	0.3184	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	14
15	LGS-2P	0.0000	1.0286	0.3174	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	15
16	LGS-2T	0.0000	1.0440	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	16
17	LGS-3S	0.0000	1.0796	0.3374	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	17
18	LGS-3P	0.0000	1.0331	0.3129	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	18
19	LGS-3T (n3)	0.0000	1.1920	0.3837	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	19
20	LGS-XS	0.0000	1.0757	0.3388	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	20
21	LGS-XP	0.0000	1.0783	0.3393	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	21
22	LGS-XI	0.0000	1.0776	0.3121	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	22
23	LGS-2-WPS	0.0000	0.9983	0.2939	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	23
24	LGS-2-WPT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	24
25	LGS-3-WPS	0.0000	0.9171	0.2302	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	25
26	LGS-3-WPP	0.0000	0.9256	0.2613	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	26
27	LGS-3-WPT	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	27
28	SL	0.0000	0.9395	0.2063	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	28
29	RS-Pal	0.0000	0.0000	0.1907	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	29
30	GS-Pal	0.0000	0.0000	0.1902	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	30
31	AWP	0.0000	2.4804	0.0000	0.3008	0.0000	0.0000	0.0000	0.0000	0.0033	31
32	ORS-MF (Opt B)	0.0000	1.7940	0.0000	0.3122	0.0745	0.0233	0.0000	0.0060	0.0000	32
33	ORS (Opt B)	4.8658	2.3639	0.0000	0.2748	0.0000	0.0000	0.0000	0.0000	0.0031	33
34	ORS-L (Opt B)	0.0000	1.6153	0.0000	0.2249	0.0000	0.0000	0.0000	0.0000	0.0000	34
35	RS-M-NEM	0.0000	1.4669	0.0000	0.2425	0.0000	0.0000	0.0000	0.0000	0.0000	35
36	RS-NEM	0.0000	1.3482	0.0000	0.1990	0.0000	0.0000	0.0000	0.0000	0.0000	36
37	RS-L-NEM	0.0000	1.3553	0.0000	0.1667	0.0000	0.0000	0.0000	0.0000	0.0000	37
38	GS-NEM	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	38
39	SYSTEM	0.0000	1.1285	0.3723	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	39
40											40
41											41
42											42
43											43
44											44
45											45
46											46
47											47
48											48
49											49
50											50
51											51
52	Generation										52
53	Rescaling Factor (n2) =	1.30986144									53
54											54
55											55
56	Source:										56
57	(n1)										57
58	(n2)										58
59	(n3)										59
60											60

Generation
Rescaling Factor (n2) =
1.000000

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Worksheet 3: T&D Investment Regression Data

Line No.	Year	Transmission Plant (2015\$)	Adjusted System Peak (kW) (n2)	Binary Variable (0,1) (n1)	Distribution Sub Plant (2015\$)	Distribution Loads (kW)	Binary Variable (0,1) (n1)	Year	NR Feeders Plant (2015\$)	Distribution Loads (kW)	Binary Variable (0,1) (n1)	Line No.	
9												9	
10												10	
11	1997	\$ 597,937,442	3,481,000	0	\$ 392,009,816	3,220,330	0	1997	\$ 493,284,724	3,220,330	0	11	
12	1998	\$ 720,021,661	3,688,000	0	\$ 470,412,241	3,368,268	0	1998	\$ 512,578,122	3,368,268	0	12	
13	1999	\$ 782,110,819	3,935,000	0	\$ 513,772,680	3,591,387	0	1999	\$ 507,162,900	3,591,387	0	13	
14	2000	\$ 828,137,199	4,295,000	0	\$ 596,477,513	4,000,460	0	2000	\$ 490,516,425	4,000,460	0	14	
15	2001	\$ 866,423,964	4,322,000	0	\$ 643,172,269	4,019,578	0	2001	\$ 578,776,920	4,019,578	0	15	
16	2002	\$ 897,906,547	4,526,000	0	\$ 656,407,395	4,225,904	0	2002	\$ 627,892,425	4,225,904	0	16	
17	2003	\$ 1,044,346,572	4,661,000	0	\$ 726,751,953	4,360,452	0	2003	\$ 734,761,924	4,360,452	0	17	
18	2004	\$ 1,068,064,692	4,911,000	0	\$ 773,707,926	4,594,300	0	2004	\$ 851,255,186	4,594,300	0	18	
19	2005	\$ 1,113,293,606	5,233,000	0	\$ 827,963,608	4,908,607	0	2005	\$ 921,571,903	4,908,607	0	19	
20	2006	\$ 1,202,546,815	5,568,000	0	\$ 870,553,402	5,251,975	0	2006	\$ 1,050,158,719	5,251,975	0	20	
21	2007	\$ 1,317,984,658	5,657,000	0	\$ 976,727,727	5,348,685	0	2007	\$ 1,104,154,519	5,348,685	0	21	
22	2008	\$ 1,372,956,369	5,720,000	0	\$ 1,059,635,360	5,392,154	0	2008	\$ 1,174,702,151	5,392,154	0	22	
23	2009	\$ 1,473,180,768	5,481,000	1	\$ 1,094,848,511	5,166,351	1	2009	\$ 1,250,877,321	5,166,351	1	23	
24	2010	\$ 1,483,714,619	5,488,000	1	\$ 1,093,109,106	5,160,433	1	2010	\$ 1,302,174,142	5,160,433	1	24	
25	2011	\$ 1,490,166,516	5,556,000	1	\$ 1,104,615,315	5,252,063	1	2011	\$ 1,282,716,417	5,252,063	1	25	
26	2012	\$ 1,496,382,757	5,571,000	1	\$ 1,096,568,989	5,263,308	1	2012	\$ 1,269,404,675	5,263,308	1	26	
27	2013	\$ 1,505,676,146	5,604,000	1	\$ 1,092,323,394	5,309,134	1	2013	\$ 1,272,049,431	5,309,134	1	27	
28	2014	\$ 1,506,317,717	5,656,000	1	\$ 1,095,997,172	5,360,567	1	2014	\$ 1,272,049,431	5,360,567	1	28	
29	2015	\$ 1,517,210,831	5,629,000	1	\$ 1,103,738,761	5,333,745	1	2015	\$ 1,272,049,431	5,333,745	1	29	
30	2016	\$ 1,517,210,831	5,654,000	1	\$ 1,108,430,589	5,357,198	1	2016	\$ 1,273,299,620	5,357,198	1	30	
31												31	
32												32	
33												33	
34	(n1)	The binary variable used in the unit investment regression removes the effect of the current recession on the underlying relationship between plant investment and system peak load.											34
35	(n2)	Historic system peak adjusted for weather normalization (Worksheet 4).											35
36												36	

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Workpaper 3: T&D Unit Demand Cost Development

[illegible]

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Worksheet 3: Load Weighted Probability of Peak (n1)

Line No.	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Shoulder On-Peak	Shoulder Mid-Peak	Shoulder Off-Peak	Winter Peak	Line No.
9	RS-Multi Family	0.0000	1.3653	0.0000	0.0725	0.0000	0.0000	0.0000	0.0000	0.0009	9
10	RS	0.0000	1.3626	0.0000	0.0791	0.0000	0.0000	0.0000	0.0000	0.0011	10
11	RS-L	0.0000	1.3334	0.0000	0.0699	0.0000	0.0000	0.0000	0.0000	0.0008	11
12	GS	0.0000	1.2534	0.0000	0.0521	0.0000	0.0000	0.0000	0.0000	0.0005	12
13	LGS-1	0.0000	1.2582	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	13
14	LGS-2S	0.0000	1.2424	0.1453	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	14
15	LGS-2P	0.0000	1.2142	0.1392	0.0001	0.0000	0.0000	0.0000	0.0000	0.0005	15
16	LGS-2T	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	16
17	LGS-3S	0.0000	1.2470	0.1464	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	17
18	LGS-3P	0.0000	1.2591	0.1467	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	18
19	LGS-3T (n4)	0.0000	1.2507	0.1426	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	19
20	LGS-XS	0.0000	1.3689	0.1626	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	20
21	LGS-XP	0.0000	1.2517	0.1460	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	21
22	LGS-XT	0.0000	1.2530	0.1466	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	22
23	LGS-2-WPS										23
24	LGS-2-WPP										24
25	LGS-2-WPT										25
26	LGS-3-WPS										26
27	LGS-3-WPP										27
28	LGS-3-WPT										28
29	SL	0.0000	1.1186	0.0741	0.0001	0.0000	0.0000	0.0000	0.0000	0.0001	29
30	RS-Pal	0.0000	0.0000	0.0617	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	30
31	GS-Pal	0.0000	0.0000	0.0615	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	31
32	AIWP										32
33	ORS-MF (Opt B)	0.0000	2.3033	0.0000	0.1634	0.0000	0.0000	0.0000	0.0000	0.0492	33
34	ORS (Opt B)	3.3941	2.0255	0.0000	0.1630	0.7710	0.5098	0.0000	0.0364	0.0011	34
35	ORS-L (Opt B)	0.0000	2.2584	0.0000	0.1648	0.0000	0.0000	0.0000	0.0000	0.0507	35
36											36
37	RS-M-NEM	0.0000	1.2541	0.0000	0.0859	0.0000	0.0000	0.0000	0.0000	0.0005	37
38	RS-NEW	0.0000	1.2620	0.0000	0.0732	0.0000	0.0000	0.0000	0.0000	0.0006	38
39	RS-L-NEM	0.0000	1.2525	0.0000	0.0676	0.0000	0.0000	0.0000	0.0000	0.0009	39
40	GS-NEM	0.0000	1.2159	0.0000	0.0549	0.0000	0.0000	0.0000	0.0000	0.0005	40
41											41
42											42
43											43
44											44
45											45
46											46
47	SYSTEM	0.00000	1.29645	0.15983	0.00008	0.00000	0.00000	0.00000	0.00000	0.00076	47
48											48
49	Rescaling Factor =										49
50											50
51											51
52											52
53											53
54											54
55											55
56											56
57											57
58											58
59											59
60											60

Source:

(n1) Load Weighted Probability of Peak Allocators ("1000).

(n2) Set to equate the transmission allocators and the system peak unit cost. Table 6: Marginal Demand Revenues: Transmission (page 7).

(n3) Set to equate the transmission and nonrevenue feeder allocators and the distribution peak unit cost. Table 7: Marginal Demand Revenues: Substation (page 8), and Table 8: Marginal Demand Revenues: NonRevenue Feeder (page 9).

(n4) Nellis full load with WAPA included for E, T, and D functions. For G, Nellis full load without WAPA is included.

Worksheet 3: Load Weighted Probability of Peak (n1)

Line No.	Rate Class	SCPP	Summer On-Peak	Summer Mid-Peak	Summer Off-Peak	SHCPP	Shoulder On-Peak	Shoulder Mid-Peak	Shoulder Off-Peak	Winter Peak	Line No.
9	RS-Multi Family	0.0000	1.3653	0.0000	0.0725	0.0000	0.0000	0.0000	0.0000	0.0009	9
10	RS	0.0000	1.3626	0.0000	0.0791	0.0000	0.0000	0.0000	0.0000	0.0011	10
11	RS-L	0.0000	1.3334	0.0000	0.0699	0.0000	0.0000	0.0000	0.0000	0.0008	11
12	GS	0.0000	1.2534	0.0000	0.0521	0.0000	0.0000	0.0000	0.0000	0.0005	12
13	LGS-1	0.0000	1.2582	0.1453	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	13
14	LGS-2S	0.0000	1.2424	0.1454	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	14
15	LGS-2P	0.0000	1.2142	0.1392	0.0001	0.0000	0.0000	0.0000	0.0000	0.0005	15
16	LGS-2T	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	16
17	LGS-3S	0.0000	1.2470	0.1464	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	17
18	LGS-3P	0.0000	1.2591	0.1467	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	18
19	LGS-3T (n4)	0.0000	1.2507	0.1426	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	19
20	LGS-XS	0.0000	1.3689	0.1626	0.0001	0.0000	0.0000	0.0000	0.0000	0.0007	20
21	LGS-XP	0.0000	1.2517	0.1460	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	21
22	LGS-XT	0.0000	1.2530	0.1466	0.0001	0.0000	0.0000	0.0000	0.0000	0.0006	22
23	LGS-2-WPS										23
24	LGS-2-WPP										24
25	LGS-2-WPT										25
26	LGS-3-WPS										26
27	LGS-3-WPP										27
28	LGS-3-WPT										28
29	SL	0.0000	1.1186	0.0741	0.0001	0.0000	0.0000	0.0000	0.0000	0.0001	29
30	RS-Pal	0.0000	0.0000	0.0617	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	30
31	GS-Pal	0.0000	0.0000	0.0615	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	31
32	AIWP										32
33	ORS-MF (Opt B)	0.0000	2.3033	0.0000	0.1634	0.0000	0.0000	0.0000	0.0000	0.0492	33
34	ORS (Opt B)	3.3941	2.0255	0.0000	0.1630	0.7710	0.5098	0.0000	0.0364	0.0011	34
35	ORS-L (Opt B)	0.0000	2.2584	0.0000	0.1648	0.0000	0.0000	0.0000	0.0000	0.0507	35
36											36
37	RS-M-NEM	0.0000	1.2607	0.0000	0.0667	0.0000	0.0000	0.0000	0.0000	0.0005	37
38	RS-NEM	0.0000	1.2575	0.0000	0.0733	0.0000	0.0000	0.0000	0.0000	0.0006	38
39	RS-L-NEM	0.0000	1.2480	0.0000	0.0676	0.0000	0.0000	0.0000	0.0000	0.0009	39
40	GS-NEM	0.0000	1.2091	0.0000	0.0549	0.0000	0.0000	0.0000	0.0000	0.0005	40
41											41
42											42
43											43
44											44
45											45
46											46
47	SYSTEM	0.00000	1.29645	0.15983	0.00008	0.00000	0.00000	0.00000	0.00000	0.00076	47
48											48
49	Transmission (n2)	1.28053077						1.00000000	1.00000000	Nonrevenue Feeder	49
50	Substation (n3)									1.00000000	50
51	Nonrevenue Feeder (n3)										51
52											52
53											53
54											54
55											55
56											56
57											57
58											58
59											59
60											60

Source:

(n1) Load Weighted Probability of Peak Allocators (*1000).

(n2) Set to equate the transmission allocators and the system peak unit cost. Table 6: Marginal Demand Revenues: Transmission (page 7).

(n3) Set to equate the substation and nonrevenue feeder allocators and the distribution peak unit cost. Table 7: Marginal Demand Revenues: Substation (page 8), and Table 8: Marginal Demand Revenues: Nonrevenue Feeder (page 9).

(n4) Nellis full load with WAPA included for E, T, and D functions. For G, Nellis full load without WAPA is included.

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Worksheet 4: Derivation of Distribution Peak Loads: Historical

Line No.	Line No.	Marginal Demand Loss Factors:		
9	9	Transmission -	0.0219 (n1)	
10	10	Primary -	0.0381 (n1)	
11	11	Substation to Primary -	1.0159	
12	12			
13	13			
14	14			
15	15			
16	16			
17	17			
18	18			
19	19			
20	20			
21	21			
22	22			
23	23			
24	24			
25	25			
26	26			
27	27			
28	28			
29	29			
30	30			
31	31			
32	32			
33	33			
34	34			
35	35			
36	36			
37	37			
38	38			
39	39			
40	40			

Transmission Loads (MW), (n2)		Primary Loads (MW), (n2)	
Year	Total	Year	Total With Losses
2008	172.0	2008	373.4
2009	167.0	2009	381.5
2010	187.4	2010	416.9
2011	163.6	2011	423.7
2012	167.4	2012	443.0
2013	153.8	2013	440.2

System Peak Loads (MW), (n2)(n4)		Distribution Peak Loads (MW), (n3)	
Year	Actual	Year	Weather Normalized
2008	5,504	2008	5,544
2009	5,586	2009	5,310
2010	5,604	2010	5,297
2011	5,530	2011	5,389
2012	5,761	2012	5,400
2013	5,854	2013	5,447

System Peak Loads (MW), (n2)(n4)		Distribution Peak Loads (MW), (n3)	
Year	Actual	Year	Weather Normalized
2008	5,504	2008	5,544
2009	5,586	2009	5,310
2010	5,604	2010	5,297
2011	5,530	2011	5,389
2012	5,761	2012	5,400
2013	5,854	2013	5,447

Source:	(n1)	Worksheet 5: System Peak Demand Losses (page 23).
	(n2)	Provided by Resource Planning.
	(n3)	System Load - (Metered Transmission Load adjusted for losses to Generator) = Distribution Load at Generator.
	(n4)	Distribution Load at Substation = Distribution Load at Generator reduced by losses to Substation.

Worksheet 4: Derivation of Distribution Peak Loads: Projected

Line No.	Line No.	Marginal Demand Loss Factors:		Primary Loads (MW), (n2)		Transmission Loads (MW), (n2)		With Losses (At Generator)		Distribution Load	
		Transmission -	Primary -	Year	Total	Year	Total	Year	System	Primary	at Substation (n3)
9	9	0.0219 (n1)	0.0381 (n1)	2014	440.2	2014	457.0	2014	5,656	5,500	5,382
10	10			2015	441.6	2015	458.5	2015	5,629	5,472	5,355
11	11			2016	444.3	2016	461.2	2016	5,654	5,496	5,378
12	12			2017	448.3	2017	465.4	2017	5,713	5,554	5,435
13	13			2018	453.3	2018	470.6	2018	5,795	5,634	5,513
14	14										
15	15										
16	16										
17	17										
18	18										
19	19										
20	20										
21	21										
22	22										
23	23										
24	24										
25	25										
26	26										
27	27										
28	28										
29	29										
30	30										
31	31										
32	32										
33	33										
34	34										

Weather adjustment to estimate peak of filing year, 2014 (n4): 1.0446
Estimated Peak Loads: 5,908

Source:

(n1) Worksheet 5: System Peak Demand Losses (page 23).

(n2) Provided by Resource Planning.

(n3) Distribution Load at Substation = Distribution Load at Generator reduced by losses to Substation.

(n4) Per Commission order in docket 06-11022, the loads used to rescale demand costs are estimated based on the ratio of annualized to weather normalized sales for the month of the Test Year in which the peak load occurs.

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Workpaper 5: System Peak Demand Losses

Line	DEMAND LOSSES DISAGGREGATION:	Line
9		9
10		10
11	Voltage Level:	11
12		12
13	Distribution Secondary:	13
14	Distribution Primary:	14
15	Transmission:	15
16		16
17		17
18	Source:	18
19	NPC engineering personnel supplied system peak demand losses, and estimates of these	19
20	losses disaggregated by voltage level and fixed and variable components, used to	20
21	calculate average demand losses.	21
22		22
23		23
24		24
	Average Demand	
	1.06363	
	1.03812	
	1.02187	

APPENDIX B

Operations and Maintenance Expenses

Worksheet 6: Transmission O&M Expenses per kW of System Peak Demand

Line No.	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Transmission O&M Expenses (n1):	10,364	11,678	11,619	12,396	11,459	11,856	9
10								10
11	System Peak Demand (n2):	5,720	5,481	5,488	5,556	5,571	5,604	11
12								12
13	Expense per kW of System Peak Demand (Current \$): (9)/(11)	1.81	2.13	2.12	2.23	2.06	2.12	13
14								14
15	Weighted Average Labor & Material Cost Index (n3):	91	88	94	98	98	100	15
16								16
17	Expense per kW of System Peak Demand (2015 \$): (13)/(15)x100	2.05	2.49	2.33	2.36	2.17	2.19	17
18	(2013 dollars from weighted average labor cost index escalated to 2015)							18
19	Transmission O&M Expenses in 2015 Dollars (5-Year Average):						2.31 /kW	19
20								20
21								21
22								22
23	Source:							23
24	(n1) Worksheet 6: Transmission O&M Expenses (page 27).							24
25	(n2) Worksheet 4: Derivation of Distribution Peak Loads: Historical (page 21).							25
26	(n3) Worksheet 6: Weighted Labor and Materials Index: Transmission Plant							26
27								27

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Worksheet 6: Weighted Labor and Materials Index: Transmission Plant

Line No.	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	Transmission O&M Expenses (n1):	10,364	11,678	11,619	12,396	11,459	11,856	9
10								10
11	Wages and Salaries (n2):	4,466	4,712	4,302	4,765	4,368	4,621	11
12								12
13	Labor Index (2013 = 100) (n3):	85	89	94	97	98	100	13
14								14
15	Transmission Plant Index (2013 = 100) (n4):	96	88	94	98	98	100	15
16								16
17	Expenses Other than Wages & Salaries: (9)-(11)	5,898	6,966	7,317	7,630	7,091	7,235	17
18								18
19	Labor as a Percent of O&M: (11)/(9)	43%	40%	37%	38%	38%	39%	19
20								20
21	Non-Labor as a Percent of O&M: (17)/(9)	57%	60%	63%	62%	62%	61%	21
22								22
23	Weighted Labor & Materials Index: [(13)x(19)]+[(15)x(21)]	91	88	94	98	98	100	23
24								24
25								25
26								26
27								27
28	Source:							28
29	(n1)	Worksheet 6: Transmission O&M Expenses (page 27), total transmission / 1,000.						29
30	(n2)	FERC Form 1, pg. 354, lines 4 and 14.						30
31	(n3)	Worksheet 15: Labor and Wage Inflation for Production, Transmission, and Distribution Workers (page 49).						31
32	(n4)	Worksheet 14: Handy-Whitman Indices: Plateau Region (page 48), total transmission plant.						32
33								33

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Workpaper 6: Transmission O&M Expenses

Line No.	FERC Acct	2008	2009	2010	2011	2012	2013	Line No.
9	560	504,151	221,980	209,986	586,559	358,733	454,959	9
10	561	4,281,301	4,152,013	4,060,117	4,027,154	4,271,564	4,452,635	10
11	562	365,481	361,027	198,648	291,061	334,799	492,212	11
12	563	2,084,343	2,469,908	3,557,363	3,649,570	1,911,009	4,520,419	12
13	564	0	0	0	0	0	0	13
14	566	1,985,927	3,115,113	2,386,424	2,468,373	3,468,468	1,201,520	14
15		9,221,203	10,320,041	10,412,538	11,022,717	10,344,573	11,121,745	15
16								16
17								17
18	FERC	<u>MAINTENANCE EXPENSES (n1)</u>						18
19	568	46,255	44,117	21,414	57,093	53,764	55,250	19
20	569	5,851	5,758	218	0	0	0	20
21	570	990,436	1,107,688	1,088,796	1,121,553	1,037,870	505,778	21
22	571	98,382	198,745	91,137	193,774	19,613	166,922	22
23	572	0	0	0	0	0	0	23
24	573	1,838	1,425	4,686	640	3,135	6,043	24
25		1,142,762	1,357,733	1,206,251	1,373,060	1,114,382	733,993	25
26								26
27		10,363,965	11,677,774	11,618,789	12,395,777	11,458,955	11,855,738	27
28								28
29								29
30	Source:							30
31	(n1)							31
32	(n2)							32
33	(n3)							33

FERC Form 1, pg. 321, lines 83-99, excluding Transmission of Electricity by Others and Rents, lines 88 and 90, respectively.

FERC Form 1, pg. 321, lines 101-110.

H-CERT Adjustments for unusual and non-recurring expenses

Workpaper 7: Distribution Substation O&M Expenses per kW of Distribution Peak Demand

Line No.	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Substation O&M Expenses (n1):	5,069	4,165	3,842	3,660	3,616	3,560	9
10								10
11	Distribution Peak Demand (n2):	5,544	5,310	5,297	5,389	5,400	5,447	11
12								12
13	Expense per kW of System Peak Demand (Current \$): (9)/(11)	0.91	0.78	0.73	0.68	0.67	0.65	13
14								14
15	Weighted Average Labor & Material Cost Index (n3):	84	87	92	95	97	100	15
16								16
17	Expense per kW of System Peak Demand (2015 \$): (13)/(15)x100	1.13	0.94	0.82	0.74	0.71	0.68	17
18	(2013 dollars from weighted average labor cost index escalated to 2015)							18
19	Substation O&M Expenses in 2015 Dollars (5-Year Average):						0.78 /kW	19
20								20
21								21
22	Source:							22
23	(n1)							23
24	(n2)							24
25	(n3)							25
26								26

Workpaper 7: Distribution O&M Expenses: Substations (page 29).

Workpaper 4: Derivation of Distribution Peak Loads: Historical (page 21).

Workpaper 10: Weighted Labor and Materials Index: Distribution (page 38).

Worksheet 7: Distribution O&M Expenses: Substations

Line No.	Cost Components (\$)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Distribution Operation Expenses Less Overheads and Rents (n1):	10,154,014	10,247,618	9,443,511	9,064,503	7,622,085	8,280,112	9
10	Total Distribution Maintenance Expenses Less Overheads (n2):	4,964,723	5,630,925	6,142,505	5,900,659	5,963,011	7,139,240	10
11	Operation Overheads (n3):	6,477,025	7,426,726	5,649,515	7,519,484	7,094,636	8,526,736	11
12	Maintenance Overheads (n4):	2,969,399	2,090,182	2,267,534	2,482,516	2,353,631	2,102,228	12
13								13
14								14
15								15
16	Distribution Substation:							16
17								17
18	Operation Expenses (n5) (removed Grid Meter exp where applicable)(n7):	812,172	656,271	730,727	524,573	673,475	569,170	18
19	Operations as a Percent of Total Operation Expenses Less Overheads and Rent: (18)/(9)	8.00%	6.40%	7.74%	5.79%	8.84%	6.87%	19
20	Substations Share of Operation Overheads: (11)x(19)	518,067	475,617	437,152	435,161	626,871	586,123	20
21	Maintenance Expenses (n6):	2,339,677	2,211,879	1,952,891	1,900,655	1,660,405	1,857,358	21
22	Maintenance as a Percent of Total Maintenance Expenses Less Overheads: (21)/(10)	47.13%	39.28%	31.79%	32.21%	27.85%	26.02%	22
23	Substations Share of Maintenance Overheads: (12)x(22)	1,399,360	821,043	720,919	799,641	655,371	546,920	23
24								24
25	Total Substation O&M Expenses: (18)+(20)+(21)+(23)	5,069,276	4,164,810	3,841,689	3,660,029	3,616,122	3,559,571	25
26								26
27								27
28								28
29								29
30								30
31								31
32	Source:							32
33	(n1) Worksheet 10: Distribution O&M Expenses (page 39), line 35.							33
34	(n2) Worksheet 10: Distribution O&M Expenses (page 39), line 37.							34
35	(n3) Worksheet 10: Distribution O&M Expenses (page 39), line 33.							35
36	(n4) Worksheet 10: Distribution O&M Expenses (page 39), line 36.							36
37	(n5) Worksheet 10: Distribution O&M Expenses (page 39), line 11.							37
38	(n6) Worksheet 10: Distribution O&M Expenses (page 39), line 24.							38
39	(n7) Grid Meter expense added, pursuant to order in Docket #01-10001. No grid meters installed from 2006-2013, change in technology.							39
40								40

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Workpaper 8: Facilities Charges O&M Expenses per Customer

Line No.	Cost Components	2008	2009	2010	2011	2012	2013	Line No.
9	Facilities Charges O&M Expenses (n1):	10,187,737	12,140,406	11,195,612	12,711,984	13,577,881	15,308,659	9
10								10
11	Average Number of Customers (n2)	825,721	826,685	830,059	838,482	849,435	859,012	11
12	Expense per Customer: (9) / (11)	12.34	14.69	13.49	15.16	15.98	17.82	12
13								13
14	Weighted Average Labor & Materials Cost Index (n3):	84	87	92	95	97	100	14
15								15
16	Expense per Customer (2015 \$): (13)/(15)x100	15.20	17.52	15.23	16.51	16.96	18.41	16
17	(2013 dollars from weighted average labor cost index escalated to 2015)							17
18	Facilities O&M Expenses in 2015 \$, 5-Year Average:						16.93 /customer	18
19								19
20							16.26 /customer	20
21	Ratio of Relative Investment Weighted Customers to Customers (n4)	1.04						21
22							8.85 /customer	22
23	Facilities O&M Expense without Revenue Feeder (n5)	54.42%						23
24								24
25								25
26								26
27	Source:							27
28	(n1)							28
29	(n2)							29
30	(n3)							30
31	(n4)							31
32	(n5)							32
33	The remainder of distribution facilities projected investment that is not for Nonrevenue Feeders.							33

Workpaper 8: Facilities Charges O&M Expenses per kW

Line No.	Cost Components	2008	2009	2010	2011	2012	2013	Line No.
9	Facilities Charges O&M Expenses (\$000's) (n1):	10,188	12,140	11,196	12,712	13,578	15,309	9
10								10
11	Distribution Peak Demand (n2)	5,544	5,310	5,297	5,389	5,400	5,447	11
12								12
13	Expense per kW: (9) / (11)	1.84	2.29	2.11	2.36	2.51	2.81	13
14								14
15	Weighted Average Labor & Materials Cost Index (n3):	84	87	92	95	97	100	15
16								16
17	Expense per kW (2015 \$): (13) / (15) X 100	2.26	2.73	2.39	2.57	2.67	2.90	17
18	(2013 dollars from weighted average labor cost index escalated to 2015)							18
19	Facilities O&M Expenses in 2015 \$, 5-Year Average:							19
20								20
21	Facilities O&M Expense for Nonrevenue Feeder Only (n4)	45.58%						21
22								22
23								23
24								24
25	Source:							25
26	(n1) Workpaper 8: Distribution O&M Expenses: Facilities (page 32)							26
27	(n2) Workpaper 4: Derivation of Distribution Peak Loads: Historical (page 21).							27
28	(n3) Workpaper 10: Weighted Labor and Materials Index: Distribution (page 38).							28
29	(n4) The share of Nonrevenue Feeder distribution facilities investment to total distribution additions, 20-year average, based on plant investment data from 1997-2016.							29
30								30

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Worksheet 8: Distribution O&M Expenses: Facilities

Line No.	Cost Components (\$)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Distribution Operation Expenses Less Overheads and Rents (n1):	10,154,014	10,247,618	9,443,511	9,064,503	7,622,085	8,280,112	9
10	Total Distribution Maintenance Expenses Less Overheads (n2):	4,964,723	5,630,925	6,142,505	5,900,659	5,963,011	7,139,240	10
11	Operation Overheads (n3):	6,477,025	7,426,726	5,649,515	7,519,484	7,094,636	8,526,736	11
12	Maintenance Overheads (n4):	2,969,399	2,090,182	2,267,534	2,482,516	2,353,631	2,102,228	12
13								13
14								14
15								15
16	<u>Distribution Facilities</u>							16
17								17
18	Operation Expenses (n5):	3,660,138	4,320,903	3,419,279	3,842,244	3,959,871	4,220,156	18
19	Operations as a Percent of Total Operation Expenses - Overheads and Rent: (18)/(9)	36.05%	42.16%	36.21%	42.39%	51.95%	50.97%	19
20	Facilities Share of Operation Overheads: (11)x(19)	2,334,723	3,131,475	2,045,560	3,187,344	3,685,848	4,345,854	20
21	Maintenance Expenses (n6):	2,623,664	3,418,931	4,185,629	3,999,664	4,253,345	5,208,846	21
22	Maintenance as a Percent of Total Maintenance Expenses Less Overheads: (21)/(10)	52.85%	60.72%	68.14%	67.78%	71.33%	72.96%	22
23	Facilities Share of Maintenance Overheads: (12)x(22)	1,569,212	1,269,097	1,545,144	1,682,732	1,678,817	1,533,803	23
24								24
25	Total Facilities O&M Expenses: (18)+(20)+(21)+(23)	10,187,737	12,140,406	11,195,612	12,711,984	13,577,881	15,308,659	25
26								26
27								27
28	Source:							28
29	(n1)							29
30	(n2)							30
31	(n3)							31
32	(n4)							32
33	(n5)							33
34	(n6)							34
35								35
36								36

Worksheet 10: Distribution O&M Expenses (page 39), line 35.
Worksheet 10: Distribution O&M Expenses (page 39), line 37.
Worksheet 10: Distribution O&M Expenses (page 39), line 33.
Worksheet 10: Distribution O&M Expenses (page 39), line 36.
Worksheet 10: Distribution O&M Expenses (page 39), sum of lines 10, 12, and 13.
Worksheet 10: Distribution O&M Expenses (page 39), sum of lines 23, 25, 26, and 27.

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Worksheet 9: Meter Related O&M Expenses by Customer Class

Line No.		RS-M	RS	RS-L	GS	LGS-1	LGS-2S	LGS-2P	LGS-2T	Line No.
9	Installed Cost in 2015 Dollars (n1):	141.79	141.97	840.91	233.45	742.73	1672.45	8080.00	14169.93	9
10										10
11	Annual Meter Expense Weighting Factors:	1.00	1.00	5.92	1.64	5.23	11.78	56.91	99.81	11
12	(9) / 141.97									12
13										13
14	Annual Meter Expense per Customer (n2):	8.11	8.12	48.07	13.35	42.46	95.61	461.91	810.05	14
15	(11) x 8.12									15
16										16
17										17
18										18
19	Installed Cost in 2015 Dollars (n1):	1672.45	8080.00	14169.93	2177.00	8561.46	14169.93	144.05	RS-Pal 0.00	19
20										20
21	Annual Meter Expense Weighting Factors:	11.78	56.91	99.81	15.33	60.31	99.81	1.01	0.00	21
22	(19) / 141.97									22
23										23
24	Annual Meter Expense per Customer (n2):	95.61	461.91	810.05	124.45	489.43	810.05	8.23	0.00	24
25	(21) x 8.12									25
26										26
27										27
28										28
29	Distributed Generation/Net-Metering									29
30	Installed Cost in 2015 Dollars (n1):	232.40	222.01	319.17	363.79	137.98	137.98	866.89	730.43	30
31										31
32	Annual Meter Expense Weighting Factors:	1.64	1.56	2.25	2.56	0.97	0.97	6.11	5.15	32
33	141.97									33
34										34
35	Annual Meter Expense per Customer (n2):	13.29	12.69	18.25	20.80	7.89	7.89	49.56	41.76	35
36	8.12									36
37										37
38										38
39										39
40	Source:									40
41	(n1)									41
42	Worksheet 12: Customer Related Expenses by Customer Class (page 42).									42
43	(n2)									43
44	Worksheet 9: Meter Related O&M Expenses per Weighted Customer (page 34).									44

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Workpaper 9: Meter Related O&M Expenses per Weighted Customer

Line No.	Cost Components	2008	2009	2010	2011	2012	2013	Line No.
9	Total Meter O&M Expenses (\$000's) (n1):	9,307	9,088	8,460	8,595	5,839	7,180	9
10								10
11	Average Number of Customers (n2):	864,467	869,060	874,647	874,851	878,009	883,050	11
12								12
13	Weighted Average Number of Customers (n3):	1,055,670	1,061,279	1,068,101	1,068,350	1,072,206	1,078,363	13
14								14
15	Meter Expense per Weighted Customer:	8.82	8.56	7.92	8.05	5.45	6.66	15
16								16
17	Weighted Average Labor & Materials Cost Index (n4):	84	87	92	95	97	100	17
18								18
19	Meter Expense per Weighted Customer in Const. 2015 Dollars:							19
20	(2013 dollars from weighted average labor cost index escalated to 2015)	10.86	10.22	8.94	8.76	5.78	6.88	20
21	Estimated Annual Weighted Meter O&M Expenses for the Planning Period							21
22	in Constant 2015 Dollars (5-Year Average):						8.12	22
23								23
24	Source:							24
25	(n1) Workpaper 9: Distribution O&M Expenses: Meters (page 37).							25
26	(n2) Workpaper 9: Average Number of Meter Customers (page 36).							26
27	(n3) Workpaper 9: Derivation of Meter O&M Expenses Weighting Factor (page 35).							27
28	(n4) Workpaper 10: Weighted Labor and Materials Index: Distribution (page 38).							28
29								29
30								30

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Workpaper 9: Derivation of Meter O&M Expenses Weighting Factor

Line No.	Cost Components	Residential	GS	LGS-1	Lq Comm	WP	SL	TOTAL	Line No.
9	Installed Cost in 2015 Dollars (n1):	142.13	233.45	742.73	2,471.46	3,779.86	144.05		9
10									10
11	Annual Meter Expense Weighting Factors:								11
12		1.00	1.64	5.23	17.41	26.62	1.01		12
13									13
14	Customers (n2):	754,365	75,630	27,350	1,550	47	5	858,947	14
15									15
16	Locked Meters (n3):	18,326	1,861	309	2	0	2	20,500	16
17									17
18	Total Customers Plus Locked Meters: (14)+(16)								18
19									19
20	Weighted Customers: (12)x(18) (n4)	772,691	77,491	27,659	1,552	47	7		20
21									21
22	Sum of Weighted Customers:	773,577	127,428	144,704	27,018	1,251	7		22
23								1,073,985	23
24	Sum of Total Customers Plus Locked Meters:								24
25								879,465	25
26	Customer Weighting Factor for Meters: (22)/(24)							1.22	26
27									27
28	Source:								28
29	(n1)	Workpaper 12: Customer Related Expenses by Customer Class (page 42).							29
30		Weighted average of all classes used where applicable.							30
31	(n2)	From Financial Reports for 12/31/13 - NVPWR Revenue Analysis							31
32	(n3)	Workpaper 9: Distribution O&M Expenses: Meters (page 37).							32
33	(n4)	For Large Commercial and Large Commercial Water Pumping the weighted customers is the average weighting factor x total customers plus locked meters.							33

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Worksheet 9: Average Number of Meter Customers

Line No.		2008	2009	2010	2011	2012	2013	Line No.
9	Locked Meters on Customers' Premises, Year-End (n1):	38,751	46,009	43,176	29,571	27,586	20,500	9
10								10
11	Average Locked Meters on Customers' Premises, Average (n2):	38,751	42,380	44,593	36,374	28,579	24,043	11
12								12
13	Total Average Number of Customers (n3):	825,721	826,685	830,059	838,482	849,435	859,012	13
14								14
15	Street Lighting Customers (n4):	5	5	5	5	5	5	15
16								16
17	Distribution Avg. Number of Customers: (13)-(15)+(11)	864,467	869,060	874,647	874,851	878,009	883,050	17
18								18
19								19
20								20
21								21
22	Source:							22
23	(n1)							23
24	(n2)							24
25	(n3)							25
26	(n4)							26
27								27

Meters are an instantaneous count and are run on an annual basis. Banner Report for 2001-2005 period.

The average of the current end-of-year and previous end-of-year customer totals.

Worksheet 12: Customer Related Expenses by Customer Class (page 42).

FERC Form 1, pg. 301, line 6.

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Workpaper 9: Distribution O&M Expenses: Meters

Line No.	Cost Components (\$)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Distribution Operation Expenses Less Overheads and Rents: (n1):	10,154,014	10,247,618	9,443,511	9,064,503	7,622,085	8,280,112	9
10	Total Distribution Maintenance Expenses Less Overheads (n2):	4,964,723	5,630,925	6,142,505	5,900,659	5,963,011	7,139,240	10
11	Operation Overheads (n3):	6,477,025	7,426,726	5,649,515	7,519,484	7,094,636	8,526,736	11
12	Maintenance Overheads (n4):	2,969,399	2,090,182	2,267,534	2,482,516	2,353,631	2,102,228	12
13								13
14								14
15								15
16	Distribution Meters:							16
17								17
18	Operation Expenses (n5)(n7): (586) (Pre-2006, Less: Grid Meter \$)	5,680,932	5,269,141	5,289,938	4,697,686	2,988,568	3,490,752	18
19	Operations as a Percent of Total Operation Expenses Less Overheads and Rent: (18)/(9)	55.95%	51.42%	56.02%	51.83%	39.21%	42.16%	19
20	Meters Share of Operation Overheads: (11)x(19)	3,623,743	3,818,689	3,164,669	3,896,979	2,781,759	3,594,724	20
21	Maintenance Expenses (n6):	1,382	115	3,985	340	49,262	73,036	21
22	Maintenance as a Percent of Total Maintenance Expenses Less Overheads: (21)/(10)	0.03%	0.00%	0.06%	0.01%	0.83%	1.02%	22
23	Meters Share of Maintenance Overheads: (22)x(12)	827	43	1,471	143	19,444	21,506	23
24								24
25	Total Meters O&M Expenses: (18)+(20)+(21)+(23)	9,306,884	9,087,988	8,460,063	8,595,149	5,839,032	7,180,018	25
26								26
27	Source:							27
28	(n1) Workpaper 10: Distribution O&M Expenses (page 39), line 35.							28
29	(n2) Workpaper 10: Distribution O&M Expenses (page 39), line 37.							29
30	(n3) Workpaper 10: Distribution O&M Expenses (page 39), line 33.							30
31	(n4) Workpaper 10: Distribution O&M Expenses (page 39), line 36.							31
32	(n5) Workpaper 10: Distribution O&M Expenses (page 39), line 15.							32
33	(n6) Workpaper 10: Distribution O&M Expenses (page 39), line 29.							33
34	(n7) Grid Meter expense removed to be allocated to substations, pursuant to order in Docket #01-10001 from Meter Operations.							34
35	There were no grid meters installed from 2006 through 2013. Current operational practices use separate technology to accomplish what was once done with substation grid meters.							35
36								36

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Worksheet 10: Weighted Labor and Materials Index: Distribution

Line No.	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	Distribution O&M (n1):	24,565	25,395	23,503	24,967	23,033	26,048	9
10								10
11	Wages and Salaries (n2):	12,878	11,914	11,506	11,412	9,943	10,895	11
12								12
13	Labor Index (2013 = 100) (n3):	85	89	94	97	98	100	13
14								14
15	Distribution Plant Index (2013 = 100) (n4):	83	84	89	93	97	100	15
16								16
17	Expenses Other than Wages & Salaries: (9) - (11)	11,687	13,481	11,997	13,556	13,090	15,153	17
18								18
19	Labor as a Percent of O&M: (11)/(9)	52%	47%	49%	46%	43%	42%	19
20								20
21	Non-Labor as a Percent of O&M: (17)/(9)	48%	53%	51%	54%	57%	58%	21
22								22
23	Weighted Labor & Materials Index: [(13)x(19)]+[(15)x(21)]	84	87	92	95	97	100	23
24								24
25								25
26								26
27								27
28	Source:							28
29	(n1) Worksheet 10: Distribution O&M Expenses (page 39).							29
30	(n2) FERC Form 1, pg. 354, line 23.							30
31	(n3) Worksheet 15: Labor and Wage Inflation for Production, Transmission, and Distribution Workers (page 49).							31
32	(n4) Worksheet 14: Handy-Whitman Indices: Plateau Region (page 48).							32
33								33

Worksheet 10: Distribution O&M Expenses

Line No.	FERC Acct	2008	2009	2010	2011	2012	2013	Line No.
9	OPERATION EXPENSES (n1)							
10	Supervision and Engineering:	1,094,926	812,738	1,303,656	4,011,204	4,044,510	3,506,973	9
11	Load Dispatching:	1,463,584	1,568,859	1,724,800	2,018,148	2,162,593	2,004,693	10
12	Station Expenses:	812,172	656,271	730,727	524,573	673,475	569,170	11
13	Overhead Line Expenses:	496,018	742,273	416,241	499,906	573,424	949,961	12
14	Underground Line Expenses:	1,700,536	2,009,771	1,278,238	1,324,190	1,223,854	1,265,502	13
15	Meter Expenses: (n4)	5,680,932	5,269,141	5,289,938	4,697,686	2,988,568	3,490,752	14
16	Customer Installations Expenses:	772	1,303	3,567	0	170	34	15
17	Miscellaneous Expenses: (n4)	5,382,099	6,613,988	4,345,859	3,508,281	3,050,125	5,019,763	16
18	Rents: (n4)	897,766	1,939,903	1,619,313	471,233	478,934	210,214	17
19	Total Operation Expenses:	17,528,805	19,614,247	16,712,339	17,055,220	15,195,655	17,017,062	18
20	MAINTENANCE EXPENSES (n1)							19
21	Supervision and Engineering:	2,765	47	14,557	5,992	58	5,487	21
22	Structures:	0	1,787	106	36	0	0	22
23	Station Equipment:	2,339,677	2,211,879	1,952,891	1,900,655	1,660,405	1,857,358	23
24	Overhead Lines:	1,477,654	2,282,540	2,763,990	2,568,463	2,778,850	2,977,279	24
25	Underground Lines:	1,146,010	1,134,604	1,421,533	1,431,164	1,474,494	2,231,567	25
26	Line Transformers:	0	0	0	0	0	0	26
27	Meters:	1,382	115	3,985	340	49,262	73,036	27
28	Misc. Distribution Plant:	2,966,634	2,090,135	2,252,977	2,476,524	2,353,573	2,096,742	28
29	Total Maintenance Expenses:	7,934,122	7,721,107	8,410,039	8,383,175	8,316,643	9,241,468	29
30	Total Distribution O&M Expenses:	25,462,927	27,335,354	25,122,378	25,438,396	23,512,297	26,258,531	30
31	Operation Overheads: (9) + (17)	6,477,025	7,426,726	5,649,515	7,519,484	7,094,636	8,526,736	31
32	Rents: (18)	897,766	1,939,903	1,619,313	471,233	478,934	210,214	32
33	Total Distribution Operation Expenses Less Overheads and Rents:	10,154,014	10,247,618	9,443,511	9,064,503	7,622,085	8,280,112	33
34	Maintenance Overheads: (22) + (30)	2,969,399	2,090,182	2,267,534	2,482,516	2,353,631	2,102,228	34
35	Total Distribution Maintenance Expenses Less Overheads:	4,964,723	5,630,925	6,142,505	5,900,659	5,963,011	7,139,240	35
36	Total Distribution O&M Less Rent:	24,585,161	25,395,451	23,503,065	24,967,162	23,033,363	26,048,317	36
37								37
38								38
39								39
40								40
41	STREET LIGHTING O&M (n2)							41
42	Street Lighting and Signal Systems:	300	0	0	790	586	1,509	42
43	Street Lighting and Signal Systems:	377	280	3,171	0	1,991	495	43
44	Total Lighting related O&M	677	280	3,171	790	2,577	2,004	44
45	5-yr Average O&M Expense						1,764	45
46	(n3) Net Dist Facilities O&M Adders							46
47								47
48	Lighting Related O&M increased with O&M Adders						1,936	48
49								49
50	Utility Operated and Maintained Street Lights							50
51							309	51
52							3414	52
53							3723	53
54	Source:						\$0.52	54
55	(n1)							55
56	Street Lighting O&M - calculated separately							56
57	Adders calculated from Worksheet 8: Page 36. (Total Dist Customer Facilities O&M / Dist O&M Expense per Customer)							57
58	H-CERT Adjustments for unusual and non-recurring expenses							58
59								59
60								60

APPENDIX C

Customer Related Expenses and Loading Factors

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Worksheet 11: Derivation of Marginal Facilities Charges

Line No.	Rate Class	Facilities Cost per Customer (2015\$)	Investment Relative to Residential (RS)	Weighted Customers (n6)	Line No.
9	RS-M	\$579	0.32	984,348	9
10	RS	1,794	1.00	6,061,596	10
11	RS-L	12,364	6.89	19,103	11
12	GS	3,298	1.84	1,643,407	12
13	LGS-1	6,234	3.47	1,142,945	13
14	LGS-2S (n4)	55,587	30.98	447,001	14
15	LGS-2P (n4)	19,091	10.64	3,448	15
16	LGS-2T (n3)	0	0.00	0	16
17	LGS-3S (n4)	106,810	59.53	114,303	17
18	LGS-3P (n4)	204,236	113.84	166,655	18
19	LGS-3T (n3)	20,254,646	11,289.36	0	19
20	LGS-XS (n3)	22,985	12.81	0	20
21	LGS-XP (n3)	866,707	483.08	0	21
22	LGS-XT (n3)	648,576	361.50	0	22
23	LGS-2-WPS (n4)	59,423	33.12	10,334	23
24	LGS-2-WPP (n4)	17,622	9.82	1,296	24
25	LGS-2-WPT (n3)	0	0.00	0	25
26	LGS-3-WPS (n4)	115,490	64.37	2,317	26
27	LGS-3-WPP (n4)	121,618	67.79	3,254	27
28	LGS-3-WPT (n3)	0	0.00	0	28
29	SL (n3)	5,720	3.19	3	29
30	RS-Pal		0.00	0	30
31	GS-Pal		0.00	0	31
32	AIWP	106,810	59.53	0	32
33	ORS-MF (n5)	579	0.32	809	33
34	ORS (n5)	1,794	1.00	34,735	34
35	ORS-L (n6)	12,364	6.89	0	35
36	OGS (n5)	3,298	1.84	57,116	36
37	OLGS-1 (n5)	6,234	3.47	5,019	37
38					38
39	RS-M-NEM	579	0.32	290	39
40	RS-NEM	1,794	1.00	64,416	40
41	RS-L-NEM	12,364	6.89	862	41
42	GS-NEM	3,298	1.84	1,478	42
43	ORS-MF-NEM	579	0.32	21,062	43
44	ORS-NEM	1,794	1.00	64,512	44
45	ORS-L-NEM	12,364	6.89	6,202	45
46	OGS-NEM	3,298	1.84	1,478	46
47					47
48	SUM	\$22,689,927		10,857,790	48
49					49
50					50
51					51

Based on data from current workorders. For SST the estimate is based on primary investment increased for the differential in transmission additions (limited by estimated revenues). For LGS-2-WPT, LGS-3T, and LGS-3-WPT is based on the typical facilities installation cost provided by project services.

Investment relative to residential x Table 2: Annualized Sales and Customers by Rate Class (page 2).

Facilities costs are for the entire class, based on customer specific facilities investments

Facilities costs are for the entire class, based on \$/kVA allowance multiplied by total kVA of the class

Optional TOU customer counts include all optional customers, Option A, Option B, and HEV/RR

Based on annualized customer bills, see Table 2

Source:

(n1)

(n2)

(n3)

(n4)

(n5)

(n6)

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEW RATE FILING

Worksheet 12: Customer Related Expenses by Customer Class

Line No.	Bundled		RS-M	RS	RS-L	GS	LG-S-1	LG-S-2S	LG-S-2P	LG-S-2T	Line No.
9	Installed Cost of Meters in 2015 Dollars(n1):		\$ 141.79	\$ 141.97	\$ 840.91	\$ 233.45	\$ 742.73	\$ 1,672.45	\$ 8,080.00	\$ 14,169.93	9
10	Accounts Expenses Weighting Factor(n2):		1.00	1.00	1.00	1.07	1.88	7.15	7.15	7.15	10
11	Annual Accounts Expense per Customer less FERC 904(n3):		28.59	28.59	28.59	30.73	53.84	204.38	204.38	204.38	11
12	(11) x 28.59										12
13	Uncollectibles Accounts Expense (FERC 904) per Customer(n3):		17.70	17.70	17.70	19.02	33.33	126.52	126.52	126.52	13
14	(11) x 17.70										14
15	Services, Info. and Sales Expenses Weighting Factor(n2):		1.00	1.00	1.00	0.84	8.48	1039.75	1039.75	1039.75	15
16	Annual Services, Info. and Sales Expense per Customer(n3):		0.93	0.93	0.93	0.78	7.92	970.62	970.62	970.62	16
17	(16) x 0.93										17
18											18
19											19
20											20
21											21
22											22
23											23
24											24
58											58
59											59
60	Distributed Generation/Net-Metering										60
61	Installed Cost of Meters in 2015 Dollars(n1):		\$ 232.40	\$ 222.01	\$ 319.17	\$ 363.79	\$ 137.98	\$ 137.98	\$ 866.89	\$ 730.43	61
62	Accounts Expenses Weighting Factor(n2):		1.23	1.23	1.23	2.84	1.23	1.23	1.23	2.84	62
63	Annual Accounts Expense per Customer(n3):		35.21	35.21	35.21	81.08	35.21	35.21	35.21	81.08	63
64	(11) x 28.59										64
65	Uncollectibles Accounts Expense (FERC 904) per Customer(n3):		21.80	21.80	21.80	50.19	21.80	21.80	21.80	50.19	65
66	(11) x 17.70										66
67	Services, Info. and Sales Expenses Weighting Factor(n2):		17.95	17.95	17.95	37.91	17.95	17.95	17.95	37.91	67
68	Annual Services, Info. and Sales Expense per Customer(n3):		16.75	16.75	16.75	35.39	16.75	16.75	16.75	35.39	68
69	(16) x 0.93										69
70											70
71											71
72											72
73											73
74											74
75											75
76											76
77											77
78											78
79											79
80											80
81											81
82											82
83											83
84	Source:										84
85	(n1)	Based on information provided by Meter Services.									85
86	(n2)	Based on results from customer weighting factor study for 12 months ended December 31, 2013.									86
87	(n3)	Worksheet 12: Customer Accounts and Service, Informational, and Sales Expenses (page 43).									87
88	(n4)	SL Accounts, Services, and Uncollectible expense are reflected on a per light basis. (GS CWF x SL Cust Ct / Annual SL count)									88
89											89
90											90

Based on information provided by Meter Services.
Based on results from customer weighting factor study for 12 months ended December 31, 2013.
Worksheet 12: Customer Accounts and Service, Informational, and Sales Expenses (page 43).
SL Accounts, Services, and Uncollectible expense are reflected on a per light basis. (GS CWF x SL Cust Ct / Annual SL count)

Worksheet 12: Customer Accounts and Service, Informational, and Sales Expenses

Line No.	Cost Components	2008	2009	2010	2011	2012	2013	Line No.
9	Average Number of Customers (n1):	825,721	826,685	830,059	838,482	849,435	859,012	9
10								10
11	Customer Accounts Expenses (\$000's) (n2):	42,766	40,305	36,819	35,691	38,211	37,939	11
12								12
13	Uncollectibles Accounts Expense (\$000) (n2)	16,384	17,312	12,846	13,373	14,433	14,115	13
14								14
15	Weighted Customers (n3): (9)x 1.05	867,460	868,473	872,017	880,866	892,373	902,434	15
16								16
17	Expense per Weighted Customer less FERC 904: [(11)-(13)]/(15)x1,000	30.41	26.48	27.49	25.34	26.65	26.40	17
18								18
19	Uncollectibles Expense per Weighted Customer FERC 904: (13)/(15)x1,000	18.89	19.93	14.73	15.18	16.17	15.64	19
20								20
21	Labor Cost Index (n4):	85	89	94	97	98	100	21
22								22
23	Expense per Weighted Customer in 2015 Dollars: (17)/(21)x100	36.97	30.62	30.09	26.98	27.97	27.27	23
24	(2013 dollars from weighted average labor cost index escalated to 2015)							24
25	Estimated Customer Accounts Expense for the Planning Period (5-Year Average):						28.59	25
26								26
27	Uncollectibles Expense per Weighted Customer in 2015 Dollars: (19)/(21)x100	22.96	23.06	16.12	16.17	16.98	16.16	27
28	(2013 dollars from weighted average labor cost index escalated to 2015)							28
29	Estimated Uncollectibles Accounts Expense for the Planning Period (5-Year Average):						17.70	29
30								30
31	Service, Informational, and Sales Expenses (\$000's) (n5):	2,528	2,552	2,511	2,644	2,389	2,625	31
32								32
33	Weighted Customers (n3): (9)x 3.50	2,892,043	2,895,419	2,907,236	2,936,738	2,975,100	3,008,643	33
34								34
35	Expense per Weighted Customer: (23)/(25)x1,000	0.87	0.88	0.86	0.90	0.80	0.87	35
36								36
37	Expense per Weighted Customer in 2015 Dollars: (27)/(17)x100	1.06	1.02	0.95	0.96	0.84	0.90	37
38	(2013 dollars from weighted average labor cost index escalated to 2015)							38
39	Estimated Service, Informational and Sales Expense for the Planning Period (5-Year Average):						0.93	39
40								40
41								41
42	Source:							42
43	(n1) FERC Form 1, pg. 301, line 10.							43
44	(n2) FERC Form 1, pg. 322, line 164(901-905 accounts) and FERC Form 1 line 162(904 account) and remove 904 related non-customer uncollectibles (from Distribution Planning) for Line No. 11 & 13.							44
45	(n3) Based on results from customer weighting factor study for 12 months ending December 31, 2013.							45
46	(n4) Worksheet 15: Labor and Wage Inflation for Production, Transmission, and Distribution Workers (page 55).							46
47	(n5) FERC Form 1, pg. 322, line 171 & 178; removing DSM Amortization expense and EE&C program cost expense from Acct 908.							47
48								48

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Worksheet 13: Loading Factor for A&G and Social Security and Unemployment Taxes

Line No.	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	Total Applicable to Non-Plant Related Expenses (n1):	93,813	110,418	98,091	104,816	102,584	95,936	9
10								10
11	Total Applicable to Plant-Related Expenses (n1):	42,249	40,650	43,679	39,033	37,058	37,573	11
12								12
13	Total A&G and Social Security and Unemployment Taxes: (9)+(11)	136,062	151,068	141,770	143,849	139,642	133,508	13
14								14
15	Social Security and Unemployment Taxes (n1):	8,512	9,366	9,583	9,532	9,384	9,479	15
16								16
17	Total A&G Expenses: (13)-(15)	127,551	141,702	132,187	134,317	130,258	124,030	17
18								18
19	Total O&M Excluding Fuel, Purchased Power, Deferred Energy Adjustments, and							19
20	A&G Expenses (n2):	166,409	183,265	188,234	215,408	283,096	239,503	20
21								21
22	A&G Loading Factor Applicable to Non-Plant Related Expenses: (9)/(20)	56.38%	60.25%	52.11%	48.66%	36.24%	40.06%	22
23								23
24	Non-Plant Related Loading Factor for A&G (5-Year Average):						47.46%	24
25								25
26	Total Gross Plant (n3):	6,893,078	7,315,295	7,443,060	8,249,070	8,269,220	8,460,761	26
27								27
28	A&G Loading Factor Applicable to Plant-Related Expenses: (11)/(26)	0.61%	0.56%	0.59%	0.47%	0.45%	0.44%	28
29								29
30	Plant-Related A&G Loading Factor (5-Year Average):						0.50%	30
31								31
32								32
33	Source:							33
34	(n1)	Worksheet 13: Non-Plant and Plant Related A&G Expenses (page 45).						34
35	(n2)	FERC Form 1, pg. 320-323, line 19g(Total Ops&Maint) less lines 5(501), 63(547), 76(555), 197(Total A&G), 78(557), 162(904).						35
36	(n3)	Worksheet 13: Loading Factors: General Plant, Materials and Supplies, and Prepayments (page 46).						36

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

Worksheet 13: Non-Plant and Plant Related A&G Expenses

Applicable to Non-Plant Related Expenses (n1):

Line No.	FERC A/C	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	Line No.
9	920	Administrative & General Salaries: (n2)	33,292	42,464	37,046	46,595	50,964	44,331	9
10	921	Office Supplies & Expenses: (n2)	14,067	13,819	13,798	15,123	13,596	13,740	10
11	922	Administrative Expenses Transferred:	(4,433)	(10,466)	(9,074)	(11,302)	(11,214)	(12,180)	11
12	925	Injuries and Damages: (n2)	7,178	8,471	9,817	8,890	7,784	6,861	12
13	926	Employee Pensions and Benefits: (n2)	28,471	38,083	28,435	26,224	25,601	28,590	13
14	929	Duplicate Charges:	(3,330)	(2,777)	(2,111)	(931)	(943)	(1,141)	14
15	930.1	General Advertising Expenses:	105	25	43	32	26	23	15
16	930.2	Miscellaneous General Expenses: (n2)	9,952	11,434	10,554	10,652	7,387	6,232	16
17	408.1	Social Security and Unempl. Insurance Taxes: (n2)	8,512	9,366	9,583	9,532	9,384	9,479	17
18									18
19		TOTAL:	93,813	110,418	98,091	104,816	102,584	95,936	19
20									20
21		Applicable to Plant Related Expenses (n1):							21
22	FERC A/C	Cost Components (\$000's)	2008	2009	2010	2011	2012	2013	22
23	923	Outside Services Employed: (n2)	18,842	15,788	15,977	11,082	12,558	13,036	23
24	924	Property Insurance:	3,258	3,478	3,517	3,290	2,808	2,673	24
25	927	Franchise Requirements:	0	0	0	0	0	0	25
26	928	Regulatory Commission Expenses: (n2)	9,412	9,703	9,776	9,776	9,040	10,769	26
27	931	Rents:	6,926	7,953	10,466	10,146	7,855	6,863	27
28	935	Maintenance of General Plant:	3,811	3,728	3,943	4,738	4,797	4,231	28
29									29
30		TOTAL:	42,249	40,650	43,679	39,033	37,058	37,573	30
31									31
32									32
33	Source:								33
34	(n1)	FERC Form 1, pgs. 322-323; NPC Monthly Financial Report for acct. 408.100 and 408.110.							34
35	(n2)	I-CERT Adjustments for unusual and non-recurring expenses (Schedules: 19, 20, 24, 27, 39, 45, 49, 50, 52)							35
36									36

Worksheet 13: Loading Factors: General Plant, Materials and Supplies, and Prepayments

Line No.	General Plant Loading Factor:	2008	2009	2010	2011	2012	2013	Line No.
9	Cost Components (\$000's)							9
10	General Plant (n1):	232,844	332,052	326,473	330,898	327,107	318,979	10
11	Total Plant (n2):	6,893,078	7,315,295	7,443,060	8,249,070	8,269,220	8,460,761	11
12	Total Plant less General Plant: (10)-(9)	6,660,234	6,983,243	7,116,587	7,918,172	7,942,113	8,141,782	12
13	General Plant as a Percent of Total Plant Less General Plant: (9)/(11)	3.50%	4.75%	4.59%	4.18%	4.12%	3.92%	13
14								14
15	Loading Factor for the Planning Period (5-Year Average):						4.31%	15
16								16
17								17
18	Materials and Supplies Loading Factor:							18
19	Cost Components (\$000's)							19
20	Materials and Supplies 13 month average (n3):	52,557	54,607	51,242	51,150	53,940	50,877	20
21	Electric Plant in Service (EPIS) (n4):	6,233,832	7,104,186	7,379,178	7,846,065	8,259,145	8,364,990	21
22	M&S as a Percent of EPIS: (19)/(20)	0.84%	0.77%	0.69%	0.65%	0.65%	0.61%	22
23								23
24	Loading Factor for the Planning Period (5-Year Average):						0.68%	24
25								25
26								26
27	Prepayments Loading Factor:							27
28	Cost Components (\$000's)							28
29	Prepayments (n5):	43,021	44,662	38,781	32,606	29,223	33,805	29
30	Electric Plant in Service (EPIS) (n4):	6,233,832	7,104,186	7,379,178	7,846,065	8,259,145	8,364,990	30
31	Prepayments as a Percent of EPIS: (28)/(29)	0.69%	0.63%	0.53%	0.42%	0.35%	0.40%	31
32								32
33	Loading Factor for the Planning Period (5-Year Average):						0.47%	33
34								34
35	Source:							35
36	(n1) FERC Form 1, pg. 206-207 end-of-year amounts (line 99).							36
37	(n2) FERC Form 1, pg. 206-207 end of year amounts (line 104).							37
38	(n3) Provided by Supply Chain Management Material & Supplies							38
39	(n4) FERC Form 1, pg. 206-207, average of two years. Note: Year "n" = average of year "n" and year "(n-1)".							39
40	(n5) FERC Form 1, pg. 111; 2 year average. Note: Year "n" = average of year "n" and year "(n-1)".							40

APPENDIX D

Price Indices, Cash Working Capital, and Carrying Charges

NEVADA POWER COMPANY MARGINAL COST OF SERVICE STUDY FOR NEM RATE FILING

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Worksheet 14: Handy-Whitman Indices: Plateau Region

Line	No.	Account	2008	2009	2010	2011	2012	2013	Line
9		Total Transmission Plant:	566	517	552	579	578	590	No.
10		Total Distribution Plant:	521	531	560	587	609	631	9
11									10
12									11
13		<u>Account</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	12
14		Total Transmission Plant:	96	88	94	98	98	100	13
15		Total Distribution Plant:	83	84	89	93	97	100	14
16									15
17									16
18		Source:							17
									18

Workpaper 15: Labor and Wage Inflation for Production, Transmission, and Distribution Workers

Line No.	Cost Components	2008	2009	2010	2011	2012	2013	Line No.
9	Wage Increase (n1):	4.83%	5.08%	5.69%	2.77%	1.45%	1.62%	9
10								10
11	Wage Inflation (2008=100) (n2):	100	105	111	114	116	118	11
12								12
13	Labor Index (2013=100) (n3):	85	89	94	97	98	100	13
14								14
15								15
16	Source:							16
17	(n1) Supplied by NPC's Human Resources Department(production, transmission and distribution wages).							17
18	(n2) Setting 2008=100, calculates index for wage increases.							18
19	(n3) Line 13 adjusted so 2013 equals 100.							19
20								20

Workpaper 16: Cash Working Capital Factor and Derivation of Revenue Requirement for Working Capital Factor

[illegible]

Workpaper 17: Annual Economic Carrying Charges Related to Capital Investment

Line No.		Generation Plant	Transmission Plant	Distribution Substation	Distribution Facilities	Distribution Meters	Dist SL - Lamp	Line No.
9	Present Value of							9
10	Revenue Requirements							10
11	Related to \$1,000 Investment (n1):	110.14	109.98	113.61	113.71	113.77	137.76	11
12								12
13	Annual Economic Charge							13
14	Rate Related to Marginal Investment (n1):	8.29%	7.22%	7.46%	7.83%	8.13%	29.14%	14
15								15
16								16
17	Average Service Life (n2):	30	56	61	40	35	5.5	17
18								18
19								19
20	Source:							20
21	(n1)							21
22	(n2)							22
23								23
24								24

Sum of revenue requirement for plant.

Provided by developing weighted average using approved depreciable lives and plant balances.

Depreciable lives from most recent NPC depreciation study. SL - Lamp life based on distribution design estimate.

Worksheet 18: Present Value Indices

Line No.	Year	Other Plant - Gas Turbogenerator (n1)/(n2)	Total Transmission Plant (n1)/(n2)	Total Distribution Plant (n1)/(n2)	Distribution: Meters Installed (n1)/(n2)	GDP Deflator (n3)	Line No.
9	1992	358.0	288.0	272.0	198.0	2.80%	9
10	1993	361.0	298.0	276.0	197.0	2.60%	10
11	1994	360.0	311.0	283.0	188.0	2.40%	11
12	1995	363.0	326.0	295.0	184.0	2.20%	12
13	1996	366.0	334.0	299.0	189.0	1.90%	13
14	1997	371.0	337.0	297.0	200.0	2.00%	14
15	1998	380.0	348.0	305.0	206.0	1.23%	15
16	1999	398.0	339.0	306.0	198.0	1.41%	16
17	2000	387.0	358.0	312.0	193.0	2.28%	17
18	2001	403.0	372.0	325.0	225.0	2.17%	18
19	2002	421.0	374.0	332.0	257.0	1.75%	19
20	2003	430.0	376.0	338.0	267.0	2.16%	20
21	2004	425.0	411.0	361.0	304.0	2.74%	21
22	2005	418.0	440.0	386.0	291.0	3.21%	22
23	2006	436.0	479.0	432.0	298.0	3.07%	23
24	2007	512.0	517.0	471.0	306.0	2.66%	24
25	2008	589.0	566.0	521.0	308.0	1.92%	25
26	2009	648.0	517.0	531.0	311.0	0.80%	26
27	2010	682.0	552.0	560.0	326.0	1.22%	27
28	2011	694.0	579.0	587.0	315.0	1.96%	28
29	2012	764.0	578.0	609.0	315.0	1.75%	29
30	2013	787.0	590.0	631.0	321.0	1.39%	30
31	2014	828.0	592.3	645.9	331.9	1.62%	31
32	2015	855.3	604.5	659.8	343.7	1.65%	32
33	2016	878.0	619.5	677.8	351.1	1.68%	33
34	2017	895.7	635.8	699.5	357.7	1.66%	34
35	2018	922.8	652.1	722.4	365.2	1.71%	35
36							36

Line No.	Year	Gas Turbogenerator Multiplier for 2015 Dollars	Transmission Multiplier for 2015 Dollars	Distribution Multiplier for 2015 Dollars	Distribution Meters Multiplier for 2015 Dollars	GDP Multiplier for 2015 Dollars	Line No.
37	1992	2.39	2.10	2.43	1.75	1.58	37
38	1993	2.37	2.03	2.39	1.74	1.54	38
39	1994	2.44	1.94	2.33	1.85	1.50	39
40	1995	2.42	1.85	2.24	1.87	1.47	40
41	1996	2.34	1.81	2.21	1.82	1.44	41
42	1997	2.31	1.79	2.22	1.72	1.41	42
43	1998	2.25	1.74	2.16	1.67	1.40	43
44	1999	2.15	1.78	2.16	1.74	1.38	44
45	2000	2.21	1.89	2.11	1.78	1.35	45
46	2001	2.12	1.63	2.03	1.53	1.32	46
47	2002	2.03	1.62	1.99	1.34	1.30	47
48	2003	1.99	1.61	1.95	1.29	1.27	48
49	2004	2.01	1.47	1.83	1.13	1.23	49
50	2005	2.05	1.37	1.71	1.18	1.20	50
51	2006	1.96	1.26	1.53	1.15	1.16	51
52	2007	1.87	1.17	1.40	1.12	1.13	52
53	2008	1.45	1.07	1.27	1.12	1.11	53
54	2009	1.32	1.17	1.24	1.11	1.10	54
55	2010	1.25	1.10	1.18	1.06	1.09	55
56	2011	1.23	1.04	1.12	1.09	1.07	56
57	2012	1.12	1.05	1.08	1.09	1.05	57
58	2013	1.09	1.02	1.05	1.07	1.03	58
59	2014	1.03	1.02	1.02	1.04	1.02	59
60	2015	1.00	1.00	1.00	1.00	1.00	60
61	2016	0.97	0.88	0.97	0.86	0.98	61
62	2017	0.96	0.95	0.94	0.96	0.97	62
63	2018	0.93	0.93	0.91	0.94	0.95	63
64							64
65							65
66							66
67							67
68							68
69							69
70							70
71							71
72							72

Source:

(n1)/(n2) "Coal Trends of Electric Utility Construction: Plains Region" historical indices for (1992-2013), provided by Plant Acc. Dept.
 (n1)/(n2) "Coal Trends of Electric Utility Construction: Plains Region" indices projected (2014-2016) from IHS Global Insights, Inc. (Q4'13)
 (n3) From 2014 Financial Planning Guidelines, Feb. 7 Update, provided by Finance Department for 2004-2016.

TA-2

STATEMENT O

NEVADA POWER COMPANY - d/b/a NV ENERGY

Statement O

2015 Net Metering Rate Design

Based on Docket No. 14-05004 Certification Filing

PREPARED BY THE

REGULATORY PRICING AND ECONOMIC ANALYSIS DEPARTMENT

July 2015

Nevada Power Company

Statement O

Statement I Revenue Requirement

(Revenue requirement from settlement in Docket No. 14-05004⁵)

2015 Net Metering Rate Design

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Line No.	Note	Total	Energy	Generation	Transmission	Distribution	Line No.	
9							9	
10		\$ 2,528,021	\$ 861,564	\$ 968,884	\$ 152,935	\$ 544,638	10	
11							11	
12	1	\$ 2,190,322	\$ 996,360	\$ 626,984	\$ 175,559	\$ 391,419	12	
13					Total G, T & D	\$ 1,193,962	13	
14							14	
15		(1,197)				(1,197)	15	
16		(872)				(872)	16	
17		(325)				(325)	17	
18	2	(14,828)		(7,786)	(2,180)	(4,861)	18	
19	3	(1,673)				(1,673)	19	
20		-		-	-	-	20	
21		1,130	979	151			21	
22		\$ (16,566)	\$ 979	\$ (7,635)	\$ (2,180)	\$ (7,730)	22	
23							23	
24							24	
25	4	(4,578)				(4,578)	25	
26		1,538				1,538	26	
27		(4,706)	(2,889)	(1,818)			27	
28		\$ (7,746)	\$ (2,889)	\$ (1,818)	\$ -	\$ (3,039)	28	
29							29	
30		\$ 2,166,010	\$ 994,451	\$ 617,531	\$ 173,379	\$ 383,689	30	
31							31	
32		85.7%	88.3%	88.3%	113.4%	71.2%	32	
33			88.3%	88.3%	113.4%	71.2%	33	
34							34	
35	1. Typically, this page includes the Unbundled Revenue Requirement from Unbundling Study (Statement H in Direct Filing, Statement I in Certification Filing)							35
36	2. Includes LSR revenues and optional time-of-use revenues.							36
37	3. Includes all "non-tax" DOS revenues, but excludes subsidy-related revenues.							37
38	4. Other Revenues include misc. revenues, returned check, power pedestal, and misc. damage revenues.							38
39	5. See section 3(B) of the NPC Narrative in this filing.							39
40	6. The difference in revenues from those revenues used in rate design and the revenues that are collected using the net billed billing determinants,							40
41	which are adjusted for NEM banking calculations.							41
42								42

Nevada Power Company

Statement O

Comparison of Present, Cost-based and Proposed Rate Revenue

(Bundled Service Classes Only -- Includes both BTER and BTGR Revenue)

2015 Net Metering Rate Design

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Line No	Class	Note	Sales (MWh)	Present Rate Revenues	Class Revenue Requirements Set @ Reconciled Cost ¹		Final Class Revenue Requirements		Line
					Total Cost-Based	% Change from Present	Total Proposed Rate Revenue	% Change from Present	
8	RM		1,990,428	\$ 245,235,382	\$ 237,156,132	-3.29%	\$ 237,164,880	-3.29%	8
9	RS		6,947,607	886,125,736	939,362,381	6.01%	939,345,580	6.01%	9
10	LSR		34,963	4,088,858	3,870,150	-5.35%	3,870,111	-5.35%	10
11	GS		667,892	73,639,118	72,454,842	-1.61%	72,457,711	-1.60%	11
12	LGS-1		3,726,999	351,825,017	327,942,458	-6.79%	327,928,615	-6.79%	12
13	LGS-2S		2,342,404	201,399,474	191,387,134	-4.97%	191,386,988	-4.97%	13
14	LGS-2P		78,881	6,010,607	5,606,708	-6.72%	5,606,888	-6.72%	14
15	LGS-2T	3	-	-	-	na	-	na	15
16	LGS-3S		1,099,044	89,977,629	86,309,391	-4.08%	86,309,266	-4.08%	16
17	LGS-3P		2,463,370	193,699,765	188,290,592	-2.79%	188,291,337	-2.79%	17
18	LGS-3T	5	218,721	29,875,141	29,921,830	0.16%	29,909,890	0.12%	18
19	LGS-XS		9,855	769,311	833,159	8.30%	833,162	8.30%	19
20	LGS-XP		381,888	30,484,590	29,463,062	-3.35%	29,462,949	-3.35%	20
21	LGS-XT		586,194	41,312,255	40,751,286	-1.36%	40,751,576	-1.36%	21
22	LGS-2S-WP		21,724	1,121,079	1,134,139	1.16%	1,133,446	1.10%	22
23	LGS-2P-WP		13,671	980,859	829,597	-15.42%	829,622	-15.42%	23
24	LGS-2T-WP	4	-	-	-	na	-	na	24
25	LGS-3S-WP		6,785	375,568	329,929	-12.15%	330,055	-12.12%	25
26	LGS-3P-WP		16,257	1,039,598	904,129	-13.03%	904,792	-12.97%	26
27	LGS-3T-WP	4	-	-	-	na	-	na	27
28	SL		154,679	8,999,766	8,190,128	-9.00%	8,189,772	-9.00%	28
29	RS-Pal		859	103,168	91,418	-11.39%	91,416	-11.39%	29
30	GS-Pal		2,775	317,713	278,582	-12.32%	278,577	-12.32%	30
31	IAIWP	3	-	-	-	na	-	na	31
32	RM-NEM		339	45,201	68,287	51.07%	59,088	30.72%	32
33	RS-NEM		42,659	5,787,670	9,474,193	63.70%	8,046,189	39.02%	33
34	LSR-NEM		353	46,590	45,979	-1.31%	44,725	-4.00%	34
35	GS-NEM		1,447	128,266	216,909	69.11%	187,470	46.16%	35
36									36
37	Optional Classes								37
38	SSR & LSR		257,186	20,590,111	nc	nc	20,871,571	1.37%	38
39	Optional TOU		97,516	9,521,484	nc	nc	9,515,788	-0.06%	39
40	DOS		386,446	2,280,230	nc	nc	1,672,625	-26.65%	40
41									41
42	Bundled Total (Exc. DOS)		21,164,497	\$ 2,188,042,057	\$ 2,174,912,418	na ¹	\$ 2,188,281,566	0.01%	42
43									43
44	Total (Bundled & DOS)		21,550,942	\$ 2,190,322,287	\$ 2,174,912,418	na ¹	\$ 2,189,954,192	-0.02%	44
45									45

nc = Classes with existing customers, but for which reconciled marginal costs cannot or have not been determined.

1. Percent Change in revenues at full reconciled cost does not include classes where reconciled marginal costs cannot or have not been determined. Therefore, the overall change will not match the value when all revenues are included in the calculations.

2. The revenues are based upon the proposed rates, and because final rates are rounded, revenues will not exactly match the 'final' class revenue requirements shown on page 5 of Statement O. Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits.

3. No Customers in class

4. All customers in class are DOS customers; no bundled customers.

5. Cost-based revenue requirement for the LGS-3T class includes two large standby (LSR) customers as explained in rate design testimony. The LGS-3T results shown here include these customers.

Nevada Power Company Statement O

Class Shares of Bundled Present and Proposed BTGR and BTER Rate Revenue¹

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Class Percentage Share of Total

Line No.	Class	Sales (MWh)	Total Present Rate Revenue	% of total	Total Proposed Rate Revenue	% of total	Percent Change from Present Revenues ²	Line No.
8	RM	1,990,428	\$ 245,235,382	11.21%	\$ 237,164,880	10.84%	-3.29%	8
9	RS	6,947,607	886,125,736	40.50%	939,345,580	42.93%	6.01%	9
10	LRS	34,963	4,088,858	0.19%	3,870,111	0.18%	-5.35%	10
11	GS	667,892	73,639,118	3.37%	72,457,711	3.31%	-1.60%	11
12	LGS-1	3,726,999	351,825,017	16.08%	327,928,615	14.99%	-6.79%	12
13	LGS-2S	2,342,404	201,399,474	9.20%	191,386,988	8.75%	-4.97%	13
14	LGS-2P	78,881	6,010,607	0.27%	5,606,688	0.26%	-6.72%	14
15	LGS-2T	-	-	0.00%	-	0.00%	na	15
16	LGS-3S	1,099,044	89,977,629	4.11%	86,309,266	3.94%	-4.08%	16
17	LGS-3P	2,463,370	193,699,765	8.85%	188,291,337	8.60%	-2.79%	17
18	LGS-3T	218,721	14,417,241	0.66%	14,390,193	0.66%	-0.19%	18
19	LGS-XS	9,855	769,311	0.04%	833,162	0.04%	8.30%	19
20	LGS-XP	381,888	30,484,590	1.39%	29,462,949	1.35%	-3.35%	20
21	LGS-XT	586,194	41,312,255	1.89%	40,751,576	1.86%	-1.36%	21
22	LGS-2S-WP	21,724	1,121,079	0.05%	1,133,446	0.05%	1.10%	22
23	LGS-2P-WP	13,671	980,859	0.04%	829,622	0.04%	-15.42%	23
24	LGS-2T-WP	-	-	0.00%	-	0.00%	na	24
25	LGS-3S-WP	6,785	375,568	0.02%	330,055	0.02%	-12.12%	25
26	LGS-3P-WP	16,257	1,039,598	0.05%	904,792	0.04%	-12.97%	26
27	LGS-3T-WP	-	-	0.00%	-	0.00%	na	27
28	SL	154,679	8,999,766	0.41%	8,189,772	0.37%	-9.00%	28
29	RS-Pal	859	103,168	0.00%	91,416	0.00%	-11.39%	29
30	GS-Pal	2,775	317,713	0.01%	278,577	0.01%	-12.32%	30
31	IAIWP	-	-	0.00%	-	0.00%	na	31
32	RM-NEM	339	45,201	0.00%	59,088	0.00%	30.72%	32
33	RS-NEM	42,659	5,787,670	0.26%	8,046,189	0.37%	39.02%	33
34	LRS-NEM	353	46,590	0.00%	44,725	0.00%	-4.00%	34
35	GS-NEM	1,447	128,266	0.01%	187,470	0.01%	46.16%	35
36								36
37	Optional Classes							37
38	SSR & LSR	257,186	20,590,111	0.94%	20,871,571	0.95%	1.37%	38
39	Optional TOU	97,516	9,521,484	0.44%	9,515,788	0.43%	-0.06%	39
40	DOS	386,446	2,280,230	0.10%	1,672,625	0.08%	-26.65%	40
41								41
42	Bundled Total (Exc. DOS)	21,164,497	\$ 2,188,042,057	100.00%	\$ 2,188,281,566	100.00%	0.01%	42
43								43
44	TOTAL Bundled & DOS	21,550,942	\$ 2,190,322,287	100.00%	\$ 2,189,954,192	100.00%	-0.02%	44
45								45
46	DOS as a percent of Total (Bundled & DOS)			0.10%		0.08%		46
47								47
48	(1) The present rate revenues are BTER and BTGR revenues combined. They exclude ML and BTGR Deferred revenues. The proposed revenues are based upon the proposed rates, and due to the rounding of final rates, the revenues will not exactly match the class revenue requirements shown on page 5 of Statement O. The proposed BTER revenues reflect the annualized sales in this proceeding applied to the present BTER.							48
49								49
50	(2) Classes not in reconciliation, and whose rates are set off of the reconciled classes' rates, may realize overall rate impacts that are outside of the cap limits. (Not applicable in this NEM docket)							50
51								51

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* Rounding for the DG classes includes the current subsidy payment or receipt for the otherwise applicable class as well as a small rounding amount. Most of the value is the subsidy either being received (a negative value) or being provided (a positive value).

Nevada Power Company
Statement O
Class Revenue Adjustments Due to Cap & Floor Criteria (1)

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First Allocation - Cap													Second Allocation													
Line No.	Class	Sum of Functional Cost Based Class Revenue	Percent of Total	Present Rate Revenue	% change over Present Rate Revenue	Rebate Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.	Class	Sum of Functional Cost Based Class Revenue	Percent of Total	Present Rate Revenue	% change over Present Rate Revenue	Rebate Revenue for classes subject to Cap Criteria (1)	Revenue to be re-allocated	Cost Based Class Revenue of Remaining Classes	Percent of Total	Class share of re-allocated Revenue	Class Revenue Requirement, after 1st Allocation	% change over Present Rate Revenue	Line No.
9	RM	237,156	10.90%	245,235	-3.29%	894,987	44,375	237,156	19.38%	9,335	246,491	0.51%	9	RM	237,156	10.90%	245,235	-3.29%	894,987	44,375	237,156	19.38%	9,335	246,491	0.51%	9
10	RS	939,362	43.19%	886,126	6.01%	-	-	-	0.00%	-	894,987	1.00%	10	RS	939,362	43.19%	886,126	6.01%	-	-	-	0.00%	-	894,987	1.00%	10
11	LRS	3,870	0.18%	4,089	-5.35%	-	-	3,870	0.32%	152	4,022	-1.62%	11	LRS	3,870	0.18%	4,089	-5.35%	-	-	-	0.32%	152	4,022	-1.62%	11
12	GS	72,455	3.33%	73,639	-1.61%	-	-	72,455	5.92%	2,852	75,307	2.28%	12	GS	72,455	3.33%	73,639	-1.61%	-	-	-	5.92%	2,852	75,307	2.28%	12
13	LGS-1	327,942	15.08%	351,825	-6.79%	-	-	327,942	26.80%	12,908	340,851	-3.12%	13	LGS-1	327,942	15.08%	351,825	-6.79%	-	-	-	26.80%	12,908	340,851	-3.12%	13
14	LGS-2S	191,387	8.80%	201,389	-4.97%	-	-	191,387	15.64%	7,533	198,920	-1.23%	14	LGS-2S	191,387	8.80%	201,389	-4.97%	-	-	-	15.64%	7,533	198,920	-1.23%	14
15	LGS-2P	5,607	0.26%	6,011	-6.72%	-	-	5,607	0.46%	221	5,827	-3.05%	15	LGS-2P	5,607	0.26%	6,011	-6.72%	-	-	-	0.46%	221	5,827	-3.05%	15
16	LGS-2T	-	0.00%	-	-	-	-	-	0.00%	-	-	-	16	LGS-2T	-	0.00%	-	-	-	0.00%	-	-	-	-	-	16
17	LGS-3S	86,309	3.97%	89,978	-4.08%	-	-	86,309	7.05%	3,397	89,707	-0.30%	17	LGS-3S	86,309	3.97%	89,978	-4.08%	-	-	-	7.05%	3,397	89,707	-0.30%	17
18	LGS-3P	188,291	8.66%	193,700	-2.79%	-	-	188,291	15.65%	1,411	189,702	1.03%	18	LGS-3P	188,291	8.66%	193,700	-2.79%	-	-	-	15.65%	1,411	189,702	1.03%	18
19	LGS-3T	29,922	1.36%	29,875	0.16%	-	-	29,922	0.00%	-	31,100	4.10%	19	LGS-3T	29,922	1.36%	29,875	0.16%	-	-	-	0.00%	-	31,100	4.10%	19
20	LGS-XS	833	0.04%	789	5.33%	-	-	833	0.00%	-	777	1.00%	20	LGS-XS	833	0.04%	789	5.33%	-	-	-	0.00%	-	777	1.00%	20
21	LGS-XP	29,463	1.35%	30,485	-3.35%	-	-	29,463	3.35%	1,160	30,623	0.45%	21	LGS-XP	29,463	1.35%	30,485	-3.35%	-	-	-	3.35%	1,160	30,623	0.45%	21
22	LGS-X1	40,751	1.87%	41,312	-1.36%	-	-	40,751	3.33%	1,604	42,355	2.52%	22	LGS-X1	40,751	1.87%	41,312	-1.36%	-	-	-	3.33%	1,604	42,355	2.52%	22
23	LGS-2S-WP	1,134	0.05%	1,121	1.16%	-	-	1,134	0.00%	-	1,132	1.00%	23	LGS-2S-WP	1,134	0.05%	1,121	1.16%	-	-	-	0.00%	-	1,132	1.00%	23
24	LGS-2P-WP	830	0.04%	981	-15.42%	-	-	830	0.00%	-	862	-12.09%	24	LGS-2P-WP	830	0.04%	981	-15.42%	-	-	-	0.00%	-	862	-12.09%	24
25	LGS-2T-WP	-	0.00%	-	-	-	-	-	0.00%	-	-	-	25	LGS-2T-WP	-	0.00%	-	-	-	0.00%	-	-	-	-	-	25
26	LGS-3S-WP	330	0.02%	376	-12.15%	-	-	330	0.03%	13	343	-8.69%	26	LGS-3S-WP	330	0.02%	376	-12.15%	-	-	-	0.03%	13	343	-8.69%	26
27	LGS-3P-WP	904	0.04%	1,040	-13.03%	-	-	904	0.07%	36	940	-9.61%	27	LGS-3P-WP	904	0.04%	1,040	-13.03%	-	-	-	0.07%	36	940	-9.61%	27
28	LGS-3T-WP	8,190	0.38%	9,000	-9.00%	-	-	8,190	0.67%	322	8,513	-5.41%	28	LGS-3T-WP	8,190	0.38%	9,000	-9.00%	-	-	-	0.67%	322	8,513	-5.41%	28
29	SL	91	0.00%	103	-11.39%	-	-	91	0.01%	4	95	-7.90%	29	SL	91	0.00%	103	-11.39%	-	-	-	0.01%	4	95	-7.90%	29
30	RS-Pal	279	0.01%	318	-12.32%	-	-	279	0.02%	11	290	-8.87%	30	RS-Pal	279	0.01%	318	-12.32%	-	-	-	0.02%	11	290	-8.87%	30
31	GS-Pal	-	-	-	-	-	-	-	-	-	-	-	31	GS-Pal	-	-	-	-	-	-	-	-	-	-	-	31
32	IAIWP	-	-	-	-	-	-	-	-	-	-	-	32	IAIWP	-	-	-	-	-	-	-	-	-	-	-	32
33	RM-NEW	68	0.00%	45	51.07%	-	-	68	0.00%	-	46	1.00%	33	RM-NEW	68	0.00%	45	51.07%	-	-	-	0.00%	-	46	1.00%	33
34	RS-NEW	9,474	0.44%	5,788	63.70%	-	-	9,474	0.00%	-	5,846	3.629	34	RS-NEW	9,474	0.44%	5,788	63.70%	-	-	-	0.00%	-	5,846	3.629	34
35	LRS-NEW	46	0.00%	47	-1.31%	-	-	46	0.00%	-	46	0.00%	35	LRS-NEW	46	0.00%	47	-1.31%	-	-	-	0.00%	-	46	0.00%	35
36	GS-NEW	217	0.01%	218	-0.46%	-	-	217	0.00%	-	217	0.00%	36	GS-NEW	217	0.01%	218	-0.46%	-	-	-	0.00%	-	217	0.00%	36
37	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	37	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	37
38	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	38	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	38
39	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	39	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	39
40	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	40	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	40
41	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	41	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	41
42	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	42	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	42
43	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	43	Total	2,190,322	100.00%	2,190,322	0.00%	902,917	48,172	1,233,823	100%	48,172	2,174,912	0.00%	43
44	RM	237,156	10.90%	245,235	-3.29%	894,987	44,375	237,156	19.38%	9,335	246,491	0.51%	44	RM	237,156	10.90%	245,235	-3.29%	894,987	44,375	237,156	19.38%	9,335	246,491	0.51%	44
45	RS	939,362	43.19%	886,126	6.01%	-	-	-	0.00%	-	894,987	1.00%	45	RS	939,362	43.19%	886,126	6.01%	-	-	-	0.00%	-	894,987	1.00%	45
46	LRS	3,870	0.18%	4,089	-5.35%	-	-	3,870	0.32%	152	4,022	-1.62%	46	LRS	3,870	0.18%	4,089	-5.35%	-	-	-	0.32%	152	4,022	-1.62%	46
47	GS	72,455	3.33%	73,639	-1.61%	-	-	72,455	5.92%	2,852	75,307	2.28%	47	GS	72,455	3.33%	73,639	-1.61%	-	-	-	5.92%	2,852	75,307	2.28%	47
48	LGS-1	327,942	15.08%	351,825	-6.79%	-	-	327,942	26.80%	12,908	340,851	-3.12%	48	LGS-1	327,942	15.08%	351,825	-6.79%	-	-	-	26.80%	12,908	340,851	-3.12%	48
49	LGS-2S	191,387	8.80%	201,389	-4.97%	-	-	191,387	15.64%	7,533	198,920	-1.23%	49	LGS-2S	191,387	8.80%	201,389	-4.97%	-	-	-	15.64%	7,533	198,920	-1.23%	49
50	LGS-2P	5,607	0.26%	6,011	-6.72%	-	-	5,607	0.46%	221	5,827	-3.05%	50	LGS-2P	5,607	0.26%	6,011	-6.72%	-	-	-	0.46%	221	5,827	-3.05%	50
51	LGS-2T	-	0.00%	-	-	-	-	-	0.00%	-	-	-	51	LGS-2T	-	0.00%	-	-	-	0.00%	-	-	-	-	-	51
52	LGS-3S	86,309	3.97%	89,978	-4.08%	-	-	86,309	7.05%	3,397	89,707	-0.30%	52	LGS-3S	86,309	3.97%	89,978	-4.08%	-	-	-	7.05%	3,397	89,707	-0.30%	52
53	LGS-3P	188,291	8.66%	193,700	-2.79%	-	-	188,291	15.65%	1,411	189,702	1.03%	53	LGS-3P	188,291	8.66%	193,700	-2.79%	-	-	-	15.65%	1,411	189,702	1.03%	53
54	LGS-3T	29,922	1.36%	29,875	0.16%	-	-	29,922	0.00%	-	31,100	4.10%	54	LGS												

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Line No.	Class	(a) ETR Revenue		(c) Percent Change	(d) ETR & STER* Revenue		(e) Percent Change	(f) Percent Change	(g) Col (d) and Col (a) Plus C&A*		(i) Percent Change	(j) Col (g) and Col (h) Plus E&E		(k) Percent Change	(l) Col (j) and Col (k) Plus M/L*		(m) Percent Change	(n) Col (m) and Col (n) Plus REPR*		(o) Percent Change	(p) Line		
		Present	Proposed		Present	Proposed			Present	Proposed		Present	Proposed		Present	Proposed		Present	Proposed			Present	Proposed
BUNDLED SERVICE																							
12	12	RES	\$ 149,097,337	-5.34%	\$ 245,256,359	\$ 337,164,880	-3.20%	\$ 245,256,359	\$ 337,164,880	-3.24%	\$ 245,256,359	\$ 337,164,880	-3.24%	\$ 245,256,359	\$ 337,164,880	-3.24%	\$ 245,256,359	\$ 337,164,880	-3.24%	\$ 245,256,359	\$ 337,164,880	-3.24%	12
13	13	RES	\$ 151,167,739	9.54%	\$ 337,164,880	\$ 337,164,880	0.0%	\$ 337,164,880	\$ 337,164,880	0.0%	\$ 337,164,880	\$ 337,164,880	0.0%	\$ 337,164,880	\$ 337,164,880	0.0%	\$ 337,164,880	\$ 337,164,880	0.0%	\$ 337,164,880	\$ 337,164,880	0.0%	13
14	14	RES	\$ 57,781,840	-2.89%	\$ 57,781,840	\$ 57,781,840	-0.01%	\$ 57,781,840	\$ 57,781,840	-0.01%	\$ 57,781,840	\$ 57,781,840	-0.01%	\$ 57,781,840	\$ 57,781,840	-0.01%	\$ 57,781,840	\$ 57,781,840	-0.01%	\$ 57,781,840	\$ 57,781,840	-0.01%	14
15	15	RES	\$ 2,458,458	-8.78%	\$ 2,458,458	\$ 2,458,458	-0.01%	\$ 2,458,458	\$ 2,458,458	-0.01%	\$ 2,458,458	\$ 2,458,458	-0.01%	\$ 2,458,458	\$ 2,458,458	-0.01%	\$ 2,458,458	\$ 2,458,458	-0.01%	\$ 2,458,458	\$ 2,458,458	-0.01%	15
16	16	RES	\$ 41,106,880	-2.79%	\$ 41,106,880	\$ 41,106,880	-0.01%	\$ 41,106,880	\$ 41,106,880	-0.01%	\$ 41,106,880	\$ 41,106,880	-0.01%	\$ 41,106,880	\$ 41,106,880	-0.01%	\$ 41,106,880	\$ 41,106,880	-0.01%	\$ 41,106,880	\$ 41,106,880	-0.01%	16
17	17	RES	\$ 12,559,737	-1.50%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	17
18	18	RES	\$ 2,347,554	-10.95%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	18
19	19	RES	\$ 2,347,554	-17.55%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	\$ 2,347,554	\$ 2,347,554	-0.01%	19
20	20	RES	\$ 38,385,508	-8.95%	\$ 38,385,508	\$ 38,385,508	-0.01%	\$ 38,385,508	\$ 38,385,508	-0.01%	\$ 38,385,508	\$ 38,385,508	-0.01%	\$ 38,385,508	\$ 38,385,508	-0.01%	\$ 38,385,508	\$ 38,385,508	-0.01%	\$ 38,385,508	\$ 38,385,508	-0.01%	20
21	21	RES	\$ 1,450,482	-0.85%	\$ 1,450,482	\$ 1,450,482	-0.01%	\$ 1,450,482	\$ 1,450,482	-0.01%	\$ 1,450,482	\$ 1,450,482	-0.01%	\$ 1,450,482	\$ 1,450,482	-0.01%	\$ 1,450,482	\$ 1,450,482	-0.01%	\$ 1,450,482	\$ 1,450,482	-0.01%	21
22	22	RES	\$ 3,705,633	20.82%	\$ 3,705,633	\$ 3,705,633	0.0%	\$ 3,705,633	\$ 3,705,633	0.0%	\$ 3,705,633	\$ 3,705,633	0.0%	\$ 3,705,633	\$ 3,705,633	0.0%	\$ 3,705,633	\$ 3,705,633	0.0%	\$ 3,705,633	\$ 3,705,633	0.0%	22
23	23	RES	\$ 3,705,633	-8.13%	\$ 3,705,633	\$ 3,705,633	-0.01%	\$ 3,705,633	\$ 3,705,633	-0.01%	\$ 3,705,633	\$ 3,705,633	-0.01%	\$ 3,705,633	\$ 3,705,633	-0.01%	\$ 3,705,633	\$ 3,705,633	-0.01%	\$ 3,705,633	\$ 3,705,633	-0.01%	23
24	24	RES	\$ 12,559,737	-1.50%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	\$ 12,559,737	\$ 12,559,737	-0.01%	24
25	25	RES	\$ 13,133,907	12.20%	\$ 13,133,907	\$ 13,133,907	0.0%	\$ 13,133,907	\$ 13,133,907	0.0%	\$ 13,133,907	\$ 13,133,907	0.0%	\$ 13,133,907	\$ 13,133,907	0.0%	\$ 13,133,907	\$ 13,133,907	0.0%	\$ 13,133,907	\$ 13,133,907	0.0%	25
26	26	RES	\$ 339,140	-44.55%	\$ 339,140	\$ 339,140	-15.42%	\$ 339,140	\$ 339,140	-15.42%	\$ 339,140	\$ 339,140	-15.42%	\$ 339,140	\$ 339,140	-15.42%	\$ 339,140	\$ 339,140	-15.42%	\$ 339,140	\$ 339,140	-15.42%	26
27	27	RES	\$ 11,992	-76.74%	\$ 11,992	\$ 11,992	-12.12%	\$ 11,992	\$ 11,992	-12.12%	\$ 11,992	\$ 11,992	-12.12%	\$ 11,992	\$ 11,992	-12.12%	\$ 11,992	\$ 11,992	-12.12%	\$ 11,992	\$ 11,992	-12.12%	27
28	28	RES	\$ 375,698	-8.13%	\$ 375,698	\$ 375,698	-0.01%	\$ 375,698	\$ 375,698	-0.01%	\$ 375,698	\$ 375,698	-0.01%	\$ 375,698	\$ 375,698	-0.01%	\$ 375,698	\$ 375,698	-0.01%	\$ 375,698	\$ 375,698	-0.01%	28
29	29	RES	\$ 1,039,395	-8.13%	\$ 1,039,395	\$ 1,039,395	-0.01%	\$ 1,039,395	\$ 1,039,395	-0.01%	\$ 1,039,395	\$ 1,039,395	-0.01%	\$ 1,039,395	\$ 1,039,395	-0.01%	\$ 1,039,395	\$ 1,039,395	-0.01%	\$ 1,039,395	\$ 1,039,395	-0.01%	29
30	30	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	30
31	31	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	31
32	32	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	32
33	33	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	33
34	34	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	34
35	35	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	35
36	36	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	36
37	37	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	37
38	38	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	38
39	39	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	39
40	40	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	40
41	41	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	41
42	42	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	42
43	43	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	43
44	44	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	44
45	45	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	45
46	46	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	46
47	47	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	47
48	48	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	48
49	49	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	49
50	50	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	50
51	51	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	51
52	52	RES	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395	\$ 1,039,395	-12.12%	\$ 1,039,395			

Nevada Power Company

2015 Net Metering Rate Design

Docket No 15-07 ____

Statement O

Workpaper 1

Nevada Power Company
Statement O Workpapers

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Summary of Present Rate Revenues from Statement J

Line No.	Class	Note	Sales (kWh)	PRESENT RATE BTGR REVENUES	PRESENT RATE BTER REVENUES	PRESENT RATE TOTAL REVENUES	Line No.
9	Full Requirements:						9
10	RM (Excluding NEM)		1,990,428,321	\$ 151,167,739	\$ 94,067,642	\$ 245,235,382	10
11	RS (Excluding NEM)		6,947,606,771	557,781,840	328,343,896	886,125,736	11
12	LRS (Excluding NEM)		34,963,180	2,436,498	1,652,360	4,088,858	12
13	GS (Excluding NEM)		667,892,002	42,288,268	31,350,851	73,639,118	13
14	Net Metering:						14
15	RM-NEM		339,164	29,172	16,029	45,201	15
16	RS-NEM		42,659,044	3,771,603	2,016,066	5,787,670	16
17	LRS-NEM		352,989	29,908	16,682	46,590	17
18	GS-NEM		1,447,249	60,332	67,934	128,266	18
19	Class Total (Full Requirements and NEM):						19
20	RM		1,990,767,485	151,196,912	94,083,671	245,280,583	20
21	RS		6,990,265,815	561,553,444	330,359,962	891,913,406	21
22	LRS		35,316,169	2,466,406	1,669,042	4,135,448	22
23	GS		669,339,251	42,348,600	31,418,784	73,767,384	23
24	LGS-1		3,726,998,862	176,879,690	174,945,327	351,825,017	24
25	LGS-2S		2,342,404,167	91,447,022	109,952,452	201,399,474	25
26	LGS-2P		78,880,547	2,307,954	3,702,653	6,010,607	26
27	LGS-2T	1	-	-	-	-	27
28	LGS-3S		1,099,043,950	38,388,506	51,589,123	89,977,629	28
29	LGS-3P		2,463,370,325	78,069,162	115,630,603	193,699,765	29
30	LGS-3T		218,720,906	4,150,482	10,266,759	14,417,241	30
31	LGS-XS		9,855,104	306,713	462,599	769,311	31
32	LGS-XP		381,887,573	12,558,787	17,925,803	30,484,590	32
33	LGS-XT		586,194,006	13,796,309	27,515,947	41,312,255	33
34	LGS-2S-WP		21,724,315	101,340	1,019,739	1,121,079	34
35	LGS-2P-WP		13,671,060	339,140	641,720	980,859	35
36	LGS-2T-WP	2	-	-	-	-	36
37	LGS-3S-WP		6,785,112	57,075	318,493	375,568	37
38	LGS-3P-WP		16,257,372	276,477	763,121	1,039,598	38
39	LGS-3T-WP	2	-	-	-	-	39
40	SL		154,679,312	1,739,119	7,260,647	8,999,766	40
41	RS-Pal		859,128	62,565	40,602	103,168	41
42	GS-Pal		2,774,664	187,470	130,243	317,713	42
43	IAIWP	1	-	-	-	-	43
44	SSR - RS	1	-	-	-	-	44
45	SSR - GS	1	-	-	-	-	45
46	SSR - LGS-1		655,642	36,544	30,776	67,320	46
47	LSR - LGS-2S	1	-	-	-	-	47
48	LSR - LGS-2P	1	-	-	-	-	48
49	LSR - LGS-2T		855,678	19,673	40,166	59,838	49
50	LSR - LGS-3S	1	-	-	-	-	50
51	LSR - LGS-3P		50,082,153	1,691,716	2,350,856	4,042,572	51
52	LSR - LGS-3T		205,592,061	6,769,889	9,650,491	16,420,380	52
53	LSR - LGS-2S-WP	1	-	-	-	-	53
54	LSR - LGS-2P-WP	1	-	-	-	-	54
55	LSR - LGS-2T-WP	1	-	-	-	-	55
56	LSR - LGS-3S-WP	1	-	-	-	-	56
57	LSR - LGS-3P-WP	1	-	-	-	-	57
58	LSR - LGS-3T-WP	1	-	-	-	-	58
59	ORM-TOU Option A		1,366,063	98,339	64,560	162,899	59
60	ORM-TOU Option B		57,617	3,804	2,723	6,527	60
61	ORS-TOU Option A		32,981,329	2,284,736	1,558,698	3,843,434	61
62	ORS-TOU Option A EVRR		2,469,725	138,294	116,719	255,013	62
63	ORS-TOU Option B		2,743,507	130,814	129,658	260,472	63
64	ORS-TOU Option B EVRR		2,409,867	105,023	113,890	218,913	64
65	OLRS-TOU Option A		-	-	-	-	65
66	OLRS-TOU Option A EVRR		-	-	-	-	66
67	OLRS-TOU Option B		-	-	-	-	67
68	OLRS-TOU Option B EVRR		-	-	-	-	68
69	OGS-TOU		28,884,315	1,212,318	1,355,830	2,568,148	69
70	OGS-TOU EVRR		-	-	-	-	70
71	OLGS-1-TOU		26,603,576	957,306	1,248,772	2,206,078	71
72	OLGS-1-TOU EVRR		-	-	-	-	72
73							73
74	TOTAL Bundled		21,164,496,656	\$ 1,191,681,628	\$ 996,360,429	\$ 2,188,042,057	74
75							75
76	DOS CLASSES						76
77	GS-DOS		46,025	\$ 1,553	\$ -	\$ 1,553	77
78	LGS-1-DOS		600,537	7,049	-	7,049	78
79	LGS-2S-DOS		7,470,946	87,998	-	87,998	79
80	LGS-2P-DOS	1	-	-	-	-	80
81	LGS-2T-DOS	1	-	-	-	-	81
82	LGS-3S-DOS		8,506,535	150,115	-	150,115	82
83	LGS-3P-DOS		67,270,805	749,443	-	749,443	83
84	LGS-3T-DOS		145,563,828	345,276	-	345,276	84
85	LGS-2S-WP-DOS		5,781,240	53,274	-	53,274	85
86	LGS-2P-WP-DOS	1	-	-	-	-	86
87	LGS-2T-WP-DOS		962,838	32,162	-	32,162	87
88	LGS-3S-WP-DOS		24,690,215	185,964	-	185,964	88
89	LGS-3P-WP-DOS		60,175,152	473,027	-	473,027	89
90	LGS-3T-WP-DOS		65,377,452	194,367	-	194,367	90
91	TOTAL DOS		386,445,572	\$ 2,280,230	\$ -	\$ 2,280,230	91
92							92
93	TOTAL Bundled & DOS		21,550,942,228	\$ 1,193,961,858	\$ 996,360,429	\$ 2,190,322,287	93
94							94
95	1. No customers in class						95
96	2. All customer in class are DOS.						96

Nevada Power Company Statement O Worksheets

2015 Net Metering Rate Design
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Worksheet 1

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Summary of Marginal Revenue Requirement By Function¹

Line No.	Class	Note	Total Distribution Services ---D---	Transmission Demand ---E---	Generation Demand ---F---	Energy ---G---	Total	Line No.	
8	RM		\$ 69,957	\$ 16,633	\$ 110,582	\$ 82,752	\$ 279,924	8	
9	RS		277,767	72,300	457,747	292,735	1,100,548	9	
10	LRS		916	291	1,829	1,450	4,486	10	
11	GS		38,194	3,333	20,309	26,956	88,792	11	
12	LGS-1		68,443	22,094	135,519	151,441	377,497	12	
13	LGS-2S		34,401	12,446	77,620	94,601	219,069	13	
14	LGS-2P		814	331	2,127	3,107	6,378	14	
15	LGS-2T	2	-	-	-	-	-	15	
16	LGS-3S		13,354	5,558	35,236	44,220	98,368	16	
17	LGS-3P		27,170	11,928	77,556	97,398	214,052	17	
18	LGS-3T		1,951	2,196	13,063	17,210	34,419	18	
19	LGS-XS		85	59	389	399	931	19	
20	LGS-XP		3,155	1,937	12,622	15,148	32,861	20	
21	LGS-XT		849	2,825	18,449	22,986	45,110	21	
22	LGS-2S-WP		296	28	171	829	1,324	22	
23	LGS-2P-WP		143	38	245	525	950	23	
24	LGS-2T-WP	3	-	-	-	-	-	24	
25	LGS-3S-WP		65	8	49	257	379	25	
26	LGS-3P-WP		163	41	214	622	1,039	26	
27	LGS-3T-WP	3	-	-	-	-	-	27	
28	SL		2,934	83	754	6,032	9,803	28	
29	RS-Pal		85	0	2	33	120	29	
30	GS-Pal		248	0	7	108	363	30	
31	IAIWP	2	-	-	-	-	-	31	
32	RM-NEM		28	5	26	22	82	32	
33	RS-NEM		3,520	783	4,278	2,633	11,214	33	
34	LRS-NEM		19	3	17	16	55	34	
35	GS-NEM		81	15	76	85	257	35	
36								36	
37	TOTAL		\$ 544,638	\$ 152,935	\$ 968,884	\$ 861,564	\$ 2,528,021	37	
38								38	
39	Note: Marginal costs are not developed for optional TOU and Standby classes. Rates for these classes are based on the otherwise applicable class.								39
40	1. The marginal revenue requirements are from the Marginal Cost Study.								40
41	2. No customers in the class to base marginal cost on.								41
42	3. There are only DOS customers in the class. Marginal cost is developed only for bundled service, with DOS rates set using the bundled, cost-based distributor								42
43	otherwise applicable class, including non-bypassable charges.								43

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Smt J Billing Units by Component, TOU Period and Rate Class

Line No.	Cites	No. Customers ¹ (customers meters bills)	Facilities	Maximum kW	Demand On Peak	Demand Mid Peak	Demand Chrg ² --H--	Energy On Peak ³ --K--	Energy Mid Peak ³ --K--	Energy Off Peak ³ --L--	Energy Chrg ² --M--	Energy Summer EVRR	Energy Winter EVRR	Energy Total kWh	Line No.
8	RM	3,052,564						310,535,684		647,043,926	1,032,639,855			1,990,420,321	8
9	RS	6,051,586						1,368,627,774		2,304,103,353	3,255,057,142			6,947,600,771	9
10	LRS	864,772						5,026,001		10,863,306	18,617,520			24,963,160	10
11	GS	323,944						67,162,658		184,793,498	408,276,948			667,892,062	11
12	LGS-1	14,426						447,697,927		654,416,893	2,159,302,733			3,728,960,862	12
13	LGS-2S	324						254,463,712		401,289,691	1,439,692,538			2,342,404,167	13
14	LGS-2P	0						7,079,744		7,103,658	12,946,997			76,660,547	14
15	LGS-2T	0													15
16	LGS-3S	1,920						113,060,688		188,298,141	676,752,284			1,099,043,950	16
17	LGS-3P	1,464						246,310,781		437,110,420	1,537,685,168			2,463,370,333	17
18	LGS-3T	60						20,963,750		38,264,127	137,697,363			218,720,906	18
19	LGS-XS	0						1,061,747		2,021,307	9,675,272			9,665,104	19
20	LGS-XP	36						38,597,885		68,244,990	233,846,522			381,687,573	20
21	LGS-XI	24						59,546,784		103,261,943	364,908,025			596,194,006	21
22	LGS-2S-WP	312						687,331		11,813,951	7,732,950			21,724,315	22
23	LGS-2P-WP	132						847,254		852,963	4,237,673			13,671,060	23
24	LGS-2T-WP	0													24
25	LGS-3S-WP	36						171,891		340,918	3,031,384			6,785,112	25
26	LGS-3P-WP	46						763,432		960,621	9,066,214			16,257,572	26
27	LGS-3T-WP	0													27
28	SLR														28
29	SL	flat metered						1,489,964		9,218,131	110,377,691			154,679,312	29
30	RS-Pal	10,546								190,400	620,479			659,128	30
31	GS-Pal	29,904								165,975	2,004,304			2,774,664	31
32	AWP	0													32
33	Optional TOU														33
34	ORM-TOU Opt A	2,426						189,416		434,899	741,649			1,366,063	34
35	ORM-TOU Opt B	64						3,036		8,652	46,329			57,617	35
36	ORS-TOU Opt A	307,800						5,113,234		11,057,627	18,810,468			32,991,328	36
37	ORS-TOU Opt A EVRR	1,940						312,714		461,895	816,737			2,498,723	37
38	ORS-TOU Opt B	1,530						130,265		566,531	2,046,771			2,743,567	38
39	ORS-TOU Opt B EVRR	786						143,011		301,149	1,164,217			2,409,667	39
40	OLRS-TOU Opt A	0													40
41	OLRS-TOU Opt A EVRR	0													41
42	OLRS-TOU Opt B	0													42
43	OLRS-TOU Opt B EVRR	31,072													43
44	OGS-TOU	0						1,043,260		10,843,710	16,997,345			28,884,315	44
45	OGS-TOU EVRR	0													45
46	OLGS-I-TOU	1,445						43,744		7,424,110	16,695,148			26,603,576	46
47	OLGS-I-TOU EVRR	0													47
48	GS-DOS	48													48
49	LGS-I-DOS	12													49
50	LGS-ZS-DOS	24													50
51	LGS-ZP-DOS	0													51
52	LGS-ZT-DOS	0													52
53	LGS-3S-DOS	24													53
54	LGS-3P-DOS	72													54
55	LGS-3T-DOS	96													55
56	LGS-2S-WP-DOS	60													56
57	LGS-2P-WP-DOS	0													57
58	LGS-2T-WP-DOS	12													58
59	LGS-3S-WP-DOS	84													59
60	LGS-3P-WP-DOS	96													60
61	LGS-3T-WP-DOS	0													61
62	LGS-3T-WP-DOS	48													62
63	Distributed Generation Net Metering														63
64	Net Metered														64
65	RM-NEM	900						1,195		125,472	183,141			338,684	65
66	RS-NEM	64,416						162,510		18,637,265	16,456,423			42,746,079	66
67	LRS-NEM	96						727		91,018	224,717			352,989	67
68	GS-NEM	804						3,318		529,615	788,374			1,451,352	68
69	Delivered														69
70	RM-NEM	900						1,195		172,217	320,139			539,019	70
71	RS-NEM	64,416						162,510		22,530,366	30,930,029			62,472,546	71
72	LRS-NEM	96						727		99,387	264,279			404,142	72
73	GS-NEM	804						3,318		675,102	1,266,542			2,104,316	73
74	TOTAL	10,469,617						29,076,033		9,381,453	1,165,050,098			597,395	74
75								16,230,479		5,163,787,316	11,555,624,178			21,248,955,249	75
76															76
77															77
78	1. Statement J.														78
79	2. Statement J for all classes except RS-Multi Family, RS, RS-Large, GS, LGS-1, SL, RS_PAL, and GS_PAL. Total kWh for these classes are spread proportionally to time of use using hourly class loads from MCS.														79
80	3. Metered customers are the number of meters.														80

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Other Billing Units And Adjustments to Class Revenue Requirement

Line No.	Class	Power Factor Revs @ Proposed Seasonal Rates & New Threshold of 50% By Class	Sales of classes eligible for open access	Other Revenues to be Assigned to Specific Classes After Revenue Crediting to Dist RR's	Customer Specific Facilities Charges	Revenue Credits for classes revenues	Revenue Credits for DOS class revenues (Total hand input to Rev Req page)	WAPA Sales and BTER Credit	Additional Facilities and Maintenance	Summer PF kWh from Column C	Winter PF kWh from Column C	Line No.
7	RM											8
8	RS			\$ 1,912								9
9	RS			\$ 2,150								10
10	LRS			\$ 388								11
11	LGS			\$ 89								12
12	LGS-1			\$ 2								13
13	LGS-2S			\$ 89								14
14	LGS-2P			\$ 2								15
15	LGS-2T			\$ 2								16
16	LGS-3S			\$ 118								17
17	LGS-3P			\$ 229								18
18	LGS-3T			\$ 39								19
19	LGS-XS			\$ 2								20
20	LGS-XP			\$ 96								21
21	LGS-2S-WP			\$ 23								22
22	LGS-2P-WP			\$ 6								23
23	LGS-2T-WP			\$ 3								24
24	LGS-3S-WP			\$ 4								25
25	LGS-3P-WP			\$ 2								26
26	LGS-3T-WP			\$ 154,879,312								27
27	LSR (all)			\$ 4								28
28	SL			\$ 154,879,312								29
29	RS-Pd			\$ 0								30
30	RS-Pd			\$ 0								31
31	GS-Pd			\$ 0								32
32	IA/WP			\$ 0								33
33	Optional TOU											34
34	ORM-TOU Opt A											35
35	ORM-TOU Opt A EVRR											36
36	ORM-TOU Opt B											37
37	ORM-TOU Opt B EVRR											38
38	ORS-TOU Opt A											39
39	ORS-TOU Opt A EVRR											40
40	ORS-TOU Opt B											41
41	ORS-TOU Opt B EVRR											42
42	OLRS-TOU Opt A											43
43	OLRS-TOU Opt A EVRR											44
44	OLRS-TOU Opt B											45
45	OLRS-TOU Opt B EVRR											46
46	OGS-TOU											47
47	OGS-TOU EVRR											48
48	OLGS-1-TOU											49
49	OLGS-1-TOU EVRR											50
50	DOS											51
51	GS-DOS											52
52	LGS-1-DOS											53
53	LGS-2S-DOS											54
54	LGS-2P-DOS											55
55	LGS-2T-DOS											56
56	LGS-3S-DOS											57
57	LGS-3P-DOS											58
58	LGS-3T-DOS											59
59	LGS-2S-WP-DOS											60
60	LGS-2P-WP-DOS											61
61	LGS-2T-WP-DOS											62
62	LGS-3S-WP-DOS											63
63	LGS-3P-WP-DOS											64
64	LGS-3T-WP-DOS											65
65	Distributed Generation Net Metering											66
66	RM-NEM			398,164								67
67	RS-NEM			42,559,044								68
68	LRS-NEM			352,969								69
69	GS-NEM			1,447,249								70
70												71
71												72
72												73
73												74
74												75
75												76
76												77
77	TOTAL bundled			\$ 4,972,188,035		\$ 4,554		\$ 811	\$ 324,740	\$ 221,885,777	\$ 387,798,887	78
78	TOTAL DOS									\$ 9,798,436	\$ 13,352,594	79
79												80
80												81

1) Other Revenues for Optional TOU, Standby and DOS included in Otherwise Applicable Schedule.

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Verification of Present Rate Components & Comparison to Proposed Revenues

Line No	Class	Sales	BTER Revenues			DEAA Revenues			EE Revenues			ML Revenues			REPR Revenues			Line No
			Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	Present	Proposed	Percent Change	
		Residential Rate	\$ 0.04726	\$ 0.04726	0.0%	\$ -	\$ -	-	Rates vary by Class			\$ 0.00083	\$ 0.00083	0.0%	\$ 0.00083	\$ 0.00083	0.0%	
11		Non-Residential Rate	\$ 0.04726	\$ 0.04694	-0.7%	\$ -	\$ -	-	\$ 3,890,857	\$ 3,890,857	0.0%	\$ 1,652,056	\$ 1,652,056	0.0%	\$ 0.00083	\$ 0.00083	0.0%	11
12																		12
13																		13
14	RM		\$ 1,990,428,321	\$ 94,067,642	0.0%	-	\$ -	-	\$ 17,646,921	\$ 17,646,921	0.0%	\$ 5,766,514	\$ 5,766,514	0.0%	\$ 0.00083	\$ 0.00083	0.0%	14
15	RS		\$ 328,343,896	\$ 328,343,896	0.0%	-	\$ -	-	\$ 17,646,921	\$ 17,646,921	0.0%	\$ 5,766,514	\$ 5,766,514	0.0%	\$ 0.00083	\$ 0.00083	0.0%	15
16	LRS		\$ 34,963,180	\$ 1,652,360	0.0%	-	\$ -	-	\$ 67,129	\$ 67,129	0.0%	\$ 28,019	\$ 28,019	0.0%	\$ 0.00083	\$ 0.00083	0.0%	16
17	GS		\$ 687,892,002	\$ 31,350,851	0.0%	-	\$ -	-	\$ 1,122,059	\$ 1,122,059	0.0%	\$ 420,772	\$ 420,772	0.0%	\$ 0.00083	\$ 0.00083	0.0%	17
18	LGS-1		\$ 3,726,998,862	\$ 174,945,327	0.0%	-	\$ -	-	\$ 6,224,088	\$ 6,224,088	0.0%	\$ 2,348,009	\$ 2,348,009	0.0%	\$ 0.00083	\$ 0.00083	0.0%	18
19	LGS-2S		\$ 2,342,404,167	\$ 109,952,452	0.0%	-	\$ -	-	\$ 4,192,903	\$ 4,192,903	0.0%	\$ 1,475,715	\$ 1,475,715	0.0%	\$ 0.00083	\$ 0.00083	0.0%	19
20	LGS-2P		\$ 78,890,547	\$ 3,702,653	0.0%	-	\$ -	-	\$ 93,868	\$ 93,868	0.0%	\$ 49,695	\$ 49,695	0.0%	\$ 0.00083	\$ 0.00083	0.0%	20
21	LGS-2T		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	21
22	LGS-3S		\$ 1,098,043,560	\$ 51,589,123	0.0%	-	\$ -	-	\$ 2,121,155	\$ 2,121,155	0.0%	\$ 892,398	\$ 892,398	0.0%	\$ 0.00083	\$ 0.00083	0.0%	22
23	LGS-3P		\$ 2,463,370,325	\$ 115,630,603	0.0%	-	\$ -	-	\$ 3,890,857	\$ 3,890,857	0.0%	\$ 1,551,923	\$ 1,551,923	0.0%	\$ 0.00083	\$ 0.00083	0.0%	23
24	GS-3T		\$ 219,720,006	\$ 10,266,759	0.0%	-	\$ -	-	\$ 426,506	\$ 426,506	0.0%	\$ 137,794	\$ 137,794	0.0%	\$ 0.00083	\$ 0.00083	0.0%	24
25	LGS-XS		\$ 8,955,104	\$ 462,599	0.0%	-	\$ -	-	\$ 11,629	\$ 11,629	0.0%	\$ 6,209	\$ 6,209	0.0%	\$ 0.00083	\$ 0.00083	0.0%	25
26	LGS-XP		\$ 381,887,573	\$ 17,925,803	0.0%	-	\$ -	-	\$ 614,839	\$ 614,839	0.0%	\$ 240,580	\$ 240,580	0.0%	\$ 0.00083	\$ 0.00083	0.0%	26
27	LGS-XT1		\$ 586,194,068	\$ 27,515,947	0.0%	-	\$ -	-	\$ 1,119,631	\$ 1,119,631	0.0%	\$ 389,382	\$ 389,382	0.0%	\$ 0.00083	\$ 0.00083	0.0%	27
28	LGS-2S-WP		\$ 2,172,431,315	\$ 1,019,739	0.0%	-	\$ -	-	\$ 14,555	\$ 14,555	0.0%	\$ 13,686	\$ 13,686	0.0%	\$ 0.00083	\$ 0.00083	0.0%	28
29	LGS-2P-WP		\$ 13,671,060	\$ 641,720	0.0%	-	\$ -	-	\$ 19,823	\$ 19,823	0.0%	\$ 9,613	\$ 9,613	0.0%	\$ 0.00083	\$ 0.00083	0.0%	29
30	LGS-2T-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	30
31	LGS-3S-WP		\$ 6,785,112	\$ 318,493	0.0%	-	\$ -	-	\$ 1,686	\$ 1,686	0.0%	\$ 4,275	\$ 4,275	0.0%	\$ 0.00083	\$ 0.00083	0.0%	31
32	LGS-3P-WP		\$ 16,257,372	\$ 763,121	0.0%	-	\$ -	-	\$ 15,445	\$ 15,445	0.0%	\$ 10,242	\$ 10,242	0.0%	\$ 0.00083	\$ 0.00083	0.0%	32
33	LGS-3T-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	33
34	SL		\$ 154,679,312	\$ 7,260,647	0.0%	-	\$ -	-	\$ 146,945	\$ 146,945	0.0%	\$ 97,448	\$ 97,448	0.0%	\$ 0.00083	\$ 0.00083	0.0%	34
35	RS-Fall		\$ 899,128	\$ 40,602	0.0%	-	\$ -	-	\$ 713	\$ 713	0.0%	\$ 713	\$ 713	0.0%	\$ 0.00083	\$ 0.00083	0.0%	35
36	GS-Fall		\$ 2,774,684	\$ 130,243	0.0%	-	\$ -	-	\$ 4,661	\$ 4,661	0.0%	\$ 1,748	\$ 1,748	0.0%	\$ 0.00083	\$ 0.00083	0.0%	36
37	IAI-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	37
38	SSR - RS		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	38
39	SSR - GS		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	39
40	SSR - LGS-1		\$ 655,642	\$ 30,776	0.0%	-	\$ -	-	\$ 1,095	\$ 1,095	0.0%	\$ 413	\$ 413	0.0%	\$ 0.00083	\$ 0.00083	0.0%	40
41	LSR - LGS-1		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	41
42	LSR - LGS-2S		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	42
43	LSR - LGS-2T		\$ 855,078	\$ 40,166	0.0%	-	\$ -	-	\$ 394	\$ 394	0.0%	\$ 539	\$ 539	0.0%	\$ 0.00083	\$ 0.00083	0.0%	43
44	LSR - LGS-3S		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	44
45	LSR - LGS-3P		\$ 50,082,153	\$ 2,350,856	0.0%	-	\$ -	-	\$ 75,123	\$ 75,123	0.0%	\$ 31,552	\$ 31,552	0.0%	\$ 0.00083	\$ 0.00083	0.0%	45
46	LSR - LGS-3T		\$ 205,592,061	\$ 9,650,491	0.0%	-	\$ -	-	\$ 400,905	\$ 400,905	0.0%	\$ 140,406	\$ 140,406	0.0%	\$ 0.00083	\$ 0.00083	0.0%	46
47	LSR - LGS-2S-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	47
48	LSR - LGS-2P-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	48
49	LSR - LGS-2T-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	49
50	LSR - LGS-3S-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	50
51	LSR - LGS-3P-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	51
52	LSR - LGS-3T-WP		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	52
53	Optional Time of Use		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	53
54	ORM-TOU Opt A		\$ 1,366,063	\$ 64,560	0.0%	-	\$ -	-	\$ 2,732	\$ 2,732	0.0%	\$ 1,134	\$ 1,134	0.0%	\$ 0.00083	\$ 0.00083	0.0%	54
55	ORM-TOU Opt B		\$ 57,617	\$ 2,723	0.0%	-	\$ -	-	\$ 115	\$ 115	0.0%	\$ 48	\$ 48	0.0%	\$ 0.00083	\$ 0.00083	0.0%	55
56	ORS-TOU Opt A		\$ 32,981,329	\$ 1,558,688	0.0%	-	\$ -	-	\$ 83,773	\$ 83,773	0.0%	\$ 27,375	\$ 27,375	0.0%	\$ 0.00083	\$ 0.00083	0.0%	56
57	ORS-TOU Opt A EV/RR		\$ 2,489,725	\$ 116,719	0.0%	-	\$ -	-	\$ 6,273	\$ 6,273	0.0%	\$ 2,050	\$ 2,050	0.0%	\$ 0.00083	\$ 0.00083	0.0%	57
58	ORS-TOU Opt B		\$ 2,743,507	\$ 129,658	0.0%	-	\$ -	-	\$ 6,969	\$ 6,969	0.0%	\$ 2,277	\$ 2,277	0.0%	\$ 0.00083	\$ 0.00083	0.0%	58
59	ORS-TOU Opt B EV/RR		\$ 2,409,867	\$ 113,890	0.0%	-	\$ -	-	\$ 4,820	\$ 4,820	0.0%	\$ 2,000	\$ 2,000	0.0%	\$ 0.00083	\$ 0.00083	0.0%	59
60	OLRS-TOU Opt A		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	60
61	OLRS-TOU Opt A EV/RR		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	61
62	OLRS-TOU Opt B		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	62
63	OLRS-TOU Opt B EV/RR		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	63
64	OGS-TOU		\$ 28,894,315	\$ 1,355,830	0.0%	-	\$ -	-	\$ 48,526	\$ 48,526	0.0%	\$ 18,197	\$ 18,197	0.0%	\$ 0.00083	\$ 0.00083	0.0%	64
65	OGS-TOU EV/RR		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	65
66	OLGS-1-TOU		\$ 26,603,576	\$ 1,248,772	0.0%	-	\$ -	-	\$ 44,428	\$ 44,428	0.0%	\$ 16,780	\$ 16,780	0.0%	\$ 0.00083	\$ 0.00083	0.0%	66
67	OLGS-1-TOU EV/RR		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	67
68	Distributed Generation/Net Metering		-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	68
69	RR-NEM		\$ 339,164	\$ 16,029	0.0%	-	\$ -	-	\$ 108,354	\$ 108,354	0.0%	\$ 282	\$ 282	0.0%	\$ 0.00083	\$ 0.00083	0.0%	69
70	LRS-NEM		\$ 42,859,044	\$ 2,016,066	0.0%	-	\$ -	-	\$ 878	\$ 878	0.0%	\$ 35,407	\$ 35,407	0.0%	\$ 0.00083	\$ 0.00083	0.0%	70
71	RS-NEM		\$ 352,889	\$ 16,882	0.0%	-	\$ -	-	\$ 678	\$ 678	0.0%	\$ 293	\$ 293	0.0%	\$ 0.00083	\$ 0.00083	0.0%	71
72	GS-NEM		\$ 1,447,249	\$ 67,934	0.0%	-	\$ -	-	\$ 2,431	\$ 2,431	0.0%	\$ 912	\$ 912	0.0%	\$ 0.00083	\$ 0.00083	0.0%	72
73			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	73
74			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	74
75			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	75
76			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	76
77			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	77
78			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	78
79			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	79
80	TOTAL		\$ 21,164,486,656	\$ 996,360,429	0.0%	-	\$ -	-	\$ 42,307,058	\$ 42,307,058	0.0%	\$ 15,155,363	\$ 15,155,363	0.0%	\$ 0.00083	\$ 0.00083	0.0%	80
81			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	81
82			-	-	-	-	\$ -	-	-	-	-	-	-	-	-	-	-	82

Nevada Power Company

2015 Net Metering Rate Design

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Statement O

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Line No.	Component	Billing Units	Marginal Cost (MC) Revenue Rate	Reconciled MC & IRR Revenue Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	---B---	---C---	---D--- ---E---	---F--- ---G---	---H---	---I---	---J---	
9								9
10	Distribution Services							10
11	Customer (per Cust, per Mo.)	900	\$ 10.45 \$ 11.61	\$ 7 \$ 8.04	\$ 11.22	\$ 10	14.3%	11
12	Generation Meter Charge (per Meter, per Mo.)	852	\$ 1.73 \$ 2.03	\$ 1 \$ 1.40	\$ 1.40	\$ 1	1.7%	12
13	Addtl Meter Charge (per Meter, per Mo.)							13
14	Fac Chg (per Cust, per Mo.)		\$ 4.14 \$ 4.60	\$ 3 \$ 3.18	in BSC			14
15	Primary (per kW, per Mo.)	2,053	\$ 12 \$ 13.08	\$ 8 \$ 3.97				15
16	Total Distribution Services		\$ 28	\$ 19				16
17								17
18	Transmission Demand (per kW)							18
19	On Peak (per kW, per Mo.)		\$ 5					19
20	Mid Peak (per kW, per Mo.)		\$ -					20
21	Off Peak (per kW, per Mo.)		\$ 1					21
22	Other (per kW, per Mo.)		\$ 0					22
23	Total Transmission, per kW	2,053	\$ 5 \$ 2.67	\$ 6 \$ 3.03				23
24								24
25	Generation Demand (per kW)							25
26	On Peak (per kW, per Mo.)		\$ 17					26
27	Mid Peak (per kW, per Mo.)		\$ -					27
28	Off Peak (per kW, per Mo.)		\$ 9					28
29	Other (per kW, per Mo.)		\$ -					29
30	Total Generation, per kW	2,053	\$ 26 \$ 12.70	\$ 23 \$ 11.21	\$ 13.95	\$ 29	40.7%	30
31								31
32	Energy (per kWh)							32
33	On Peak (per kWh, per Mo.)	46,663	\$ 2					33
34	Mid Peak (per kWh, per Mo.)	-	\$ -					34
35	Off Peak (per kWh, per Mo.)	172,217	\$ 7					35
36	Other (per kWh, per Mo.)	320,139	\$ 13					36
37	Total Energy, per kWh	539,019	\$ 22 \$ 0.04123	\$ 20 \$ 0.03639	\$ 0.05260	\$ 28	40.3%	37
38								38
39	Adjustments:							39
40	PF-Seasonal Smr & Wntr Revs							40
41	Add. Fac. & Maintenance							41
42	Total Adjustments			\$ -				42
43								43
44	Cost Based Total		\$ 82	\$ 68 \$ 0.12669				44
45								45
46	Interclass Rate Rebalancing (IRR):			\$ -	\$ 0.00388	\$ 2	3.0%	46
47								47
48	Total		\$ 82 \$ 0.15188	\$ 68 \$ 0.12669		\$ 70	100.0%	48
49	Checks, s/b zero:		\$ -	\$ - \$ -	subsidy and rounding:	\$ 2		49
50					rounding isolated:	\$ (0.0021)		50
51	RATE SUMMARY							51
52								52
53								53
54	BTER							54
55	Interclass Rate Rebalancing (IRR, per kWh):							55
56								56
57	Distribution Charges							57
58	Basic Service Charge, per Bill	Customer and Facilities						58
59	Facilities Charge, per kW:							59
60								60
61	PD, T & G Demand Charges, per metered kW							61
62	All Periods							62
63	On Peak (per kW, per Mo.)							63
64	Mid Peak (per kW, per Mo.)							64
65								65
66								66
67								67
68	Total Energy Charges (BTGR & BTER):							68
69	All Periods, or:							69
70	On Peak (per kWh, per Mo.)							70
71	Mid Peak (per kWh, per Mo.)							71
72	Off Peak (per kWh, per Mo.)							72
73	Other (per kWh, per Mo.)							73
74								74
75	Overall effective rate (per kWh, OAS if currently no customers):							75

Nevada Power Company

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Line No.	Component	Billing Units	Marginal Cost (MC) Revenue ---D---	Rate ---E---	Reconciled MC & IRR Revenue ---F---	Rate ---G---	Proposed Rates ---H---	Proof of Revenue ---I---	Percent of Revenue ---J---	Line No.
9	---B---	---C---								9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	900	\$ 10.45	\$ 11.61	\$ 7	\$ 8.04	\$ 11.22	\$ 10	14.3%	11
12	Generation Meter Charge (per Meter, per Mo.)	852	\$ 2	\$ 2.03	\$ 1	\$ 1.40	\$ 1.40	\$ 1	1.7%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 4	\$ 4.60	\$ 3	\$ 3.18	in BSC			14
15	Primary (per kW, per Mo.)	2,053	\$ 12	\$ 13.08	\$ 8	\$ 3.97	\$ 3.97	\$ 8	11.6%	15
16	Total Distribution Services		\$ 28		\$ 19					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)	839	\$ 5	\$ 5.85	\$ 6	\$ 6.63				19
20	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					20
21	Off Peak (per kW, per Mo.)	-	\$ 1	na	\$ 1	na				21
22	Other (per kW, per Mo.)	1,195	\$ 0	\$ 0.48	\$ 0	\$ 0.55				22
23	Total Transmission, per kW	2,034	\$ 5	\$ 2.70	\$ 6	\$ 3.06				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)	839	\$ 17	\$ 20.52	\$ 15	\$ 18.11	\$ 24.39	\$ 20	29.1%	26
27	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					27
28	Off Peak (per kW, per Mo.)	-	\$ 9	na	\$ 8	na				28
29	Other (per kW, per Mo.)	1,195	\$ -	\$ 7.41	\$ -	\$ 6.54				29
30	Total Generation, per kW	2,034	\$ 26	\$ 12.82	\$ 23	\$ 11.31				30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	46,663	\$ 2	\$ 0.05255	\$ 2	\$ 0.04639	\$ 0.11103	\$ 5	7.4%	33
34	Mid Peak (per kWh, per Mo.)	-	\$ -		\$ -					34
35	Off Peak (per kWh, per Mo.)	172,217	\$ 7	\$ 0.04164	\$ 6	\$ 0.03676	\$ 0.05399	\$ 9	13.2%	35
36	Other (per kWh, per Mo.)	320,139	\$ 13	\$ 0.03935	\$ 11	\$ 0.03474	\$ 0.04339	\$ 14	19.7%	36
37	Total Energy, per kWh	539,019	\$ 22	\$ 0.04123	\$ 20	\$ 0.03639				37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 82		\$ 68	\$ 0.12669				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ 0.00388	\$ 2	3.0%	46
47										47
48	Total		\$ 82	\$ 0.15188	\$ 68	\$ 0.12669		\$ 70	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ 2		49
50							rounding isolated:	\$ (0.00273)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):									55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill Customer and Facilities		\$ 10.20	\$ 11.22	\$ 11.22				10.0%	58
59	Primary Distribution Charge, per Max kW:		\$ -	\$ 3.97	\$ 3.97				0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods		\$ -	\$ -	\$ -				0.0%	62
63	On Peak (per kW, per Mo.)		\$ -	\$ 24.39	\$ 24.39				0.0%	63
64	Mid Peak (per kW, per Mo.)		\$ -	\$ -	\$ -				0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:		\$ -	\$ -	\$ -	\$ -			0.0%	69
70	On Peak (per kWh, per Mo.)		\$ 0.34897	\$ 0.17019	\$ 0.11103	\$ 0.11491			-67.1%	70
71	Mid Peak (per kWh, per Mo.)		\$ -	\$ -	\$ -	\$ -			0.0%	71
72	Off Peak (per kWh, per Mo.)		\$ 0.07425	\$ 0.05400	\$ 0.05399	\$ 0.05787			-22.1%	72
73	Other (per kWh, per Mo.)		\$ 0.05361	\$ 0.03477	\$ 0.04339	\$ 0.04727			-11.8%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.08386		\$ 0.13056				55.7%	75

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Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	64,416	\$ 738	\$ 11.46	\$ 521	\$ 8.09	\$ 18.15	\$ 1,169	12.8%	11
12	Generation Meter Charge (per Meter, per Mo.)	32,496	\$ 66	\$ 2.03	\$ 46	\$ 1.43	\$ 1.43	\$ 46	0.5%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 919	\$ 14.27	\$ 648	\$ 10.07	in BSC			14
15	Primary (per kW, per Mo.)	313,825	\$ 1,797	\$ 27.90	\$ 1,268	\$ 4.04				15
16	Total Distribution Services		\$ 3,520		\$ 2,484					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)		\$ 702							19
20	Mid Peak (per kW, per Mo.)		\$ -							20
21	Off Peak (per kW, per Mo.)		\$ 79							21
22	Other (per kW, per Mo.)		\$ 1							22
23	Total Transmission, per kW	313,825	\$ 783	\$ 2.49	\$ 887.19	\$ 2.83				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)		\$ 3,030							26
27	Mid Peak (per kW, per Mo.)		\$ -							27
28	Off Peak (per kW, per Mo.)		\$ 1,248							28
29	Other (per kW, per Mo.)		\$ -							29
30	Total Generation, per kW	313,825	\$ 4,278	\$ 13.63	\$ 3,778	\$ 12.04	\$ 14.33	\$ 4,497	49.3%	30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	9,040,130	\$ 470							33
34	Mid Peak (per kWh, per Mo.)	-	\$ -							34
35	Off Peak (per kWh, per Mo.)	22,530,386	\$ 946							35
36	Other (per kWh, per Mo.)	30,902,029	\$ 1,216							36
37	Total Energy, per kWh	62,472,545	\$ 2,633	\$ 0.04214	\$ 2,325	\$ 0.03721	\$ 0.06021	\$ 3,761	41.2%	37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 11,214		\$ 9,474	\$ 0.15165				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ (0.00551)	\$ (344)	-3.8%	46
47										47
48	Total		\$ 11,214	\$ 0.17950	\$ 9,474	\$ 0.15165		\$ 9,130	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ (344)		49
50							rounding isolated:	\$ 0.0179		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):									55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill	Customer and Facilities			\$ 12.75	\$ 18.15	\$ 18.15		42.4%	58
59	Facilities Charge, per kW:				n/a	n/a	n/a		0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods				\$ -	\$ 14.33	\$ 14.33		0.0%	62
63	On Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	63
64	Mid Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:				\$ 0.11642	\$ 0.06019	\$ 0.06021	\$ 0.05470	-53.0%	69
70	On Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	70
71	Mid Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	71
72	Off Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	72
73	Other (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.09264		\$ 0.14614				57.7%	75

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Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	64,416	\$ 738	\$ 11.46	\$ 521	\$ 8.09	\$ 18.15	\$ 1,169	12.8%	11
12	Generation Meter Charge (per Meter, per Mo.)	32,496	\$ 66	\$ 2.03	\$ 46	\$ 1.43	\$ 1.43	\$ 46	0.5%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 919	\$ 14.27	\$ 648	\$ 10.07	in BSC			14
15	Primary (per kW, per Mo.)	313,825	\$ 1,797	\$ 27.90	\$ 1,268	\$ 4.04	\$ 4.04	\$ 1,268	13.9%	15
16	Total Distribution Services		\$ 3,520		\$ 2,484					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)	145,756	\$ 702	\$ 4.82	\$ 796	\$ 5.46				19
20	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					20
21	Off Peak (per kW, per Mo.)	-	\$ 79	na	\$ 90	na				21
22	Other (per kW, per Mo.)	162,510	\$ 1	\$ 0.49	\$ 1	\$ 0.56				22
23	Total Transmission, per kW	308,266	\$ 783	\$ 2.54	\$ 887	\$ 2.88				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)	145,756	\$ 3,030	\$ 20.79	\$ 2,676	\$ 18.36	\$ 22.15	\$ 3,228	35.4%	26
27	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					27
28	Off Peak (per kW, per Mo.)	-	\$ 1,248	na	\$ 1,103	na				28
29	Other (per kW, per Mo.)	162,510	\$ -	\$ 7.68	\$ -	\$ 6.78				29
30	Total Generation, per kW	308,266	\$ 4,278	\$ 13.88	\$ 3,778	\$ 12.26				30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	9,040,130	\$ 470	\$ 0.05204	\$ 415	\$ 0.04596	\$ 0.09698	\$ 877	9.6%	33
34	Mid Peak (per kWh, per Mo.)	-	\$ -		\$ -					34
35	Off Peak (per kWh, per Mo.)	22,530,386	\$ 946	\$ 0.04197	\$ 835	\$ 0.03707	\$ 0.05567	\$ 1,254	13.7%	35
36	Other (per kWh, per Mo.)	30,902,029	\$ 1,216	\$ 0.03936	\$ 1,074	\$ 0.03476	\$ 0.05278	\$ 1,631	17.9%	36
37	Total Energy, per kWh	62,472,545	\$ 2,633	\$ 0.04214	\$ 2,325	\$ 0.03721				37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 11,214		\$ 9,474	\$ 0.15165				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ (0.00551)	\$ (344)	-3.8%	46
47										47
48	Total		\$ 11,214	\$ 0.17950	\$ 9,474	\$ 0.15165		\$ 9,130	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ (344)		49
50							rounding isolated:	\$ (0.2344)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):						\$ (0.00551)			55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill Customer and Facilities		\$ 12.75	\$ 18.15	\$ 18.15				42.4%	58
59	Primary Distribution Charge, per Max kW:		\$ -	\$ 4.04	\$ 4.04				0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods		\$ -	\$ -	\$ -				0.0%	62
63	On Peak (per kW, per Mo.)		\$ -	\$ 22.15	\$ 22.15				0.0%	63
64	Mid Peak (per kW, per Mo.)		\$ -	\$ -	\$ -				0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:		\$ -	\$ -	\$ -	\$ -			0.0%	69
70	On Peak (per kWh, per Mo.)		\$ 0.36709	\$ 0.15843	\$ 0.09698	\$ 0.09147			-75.1%	70
71	Mid Peak (per kWh, per Mo.)		\$ -	\$ -	\$ -	\$ -			0.0%	71
72	Off Peak (per kWh, per Mo.)		\$ 0.06314	\$ 0.05567	\$ 0.05567	\$ 0.05016			-20.6%	72
73	Other (per kWh, per Mo.)		\$ 0.04857	\$ 0.03479	\$ 0.05278	\$ 0.04727			-2.7%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.09264		\$ 0.14614			\$ 57.7%		75

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Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	96	\$ 1.24	\$ 12.88	\$ 1	\$ 9	\$ 78.86	\$ 8	15.9%	11
12	Generation Meter Charge (per Meter, per Mo.)	96	\$ 1.22	\$ 12.67	\$ 1	\$ 9	\$ 8.98	\$ 1	1.8%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 9.44	\$ 98.31	\$ 7	\$ 69.73	in BSC			14
15	Primary (per kW, per Mo.)	1,171	\$ 6.78	\$ 70.60	\$ 5	\$ 4.11				15
16	Total Distribution Services		\$ 18.67		\$ 13					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)		\$ 3							19
20	Mid Peak (per kW, per Mo.)		\$ -							20
21	Off Peak (per kW, per Mo.)		\$ 0							21
22	Other (per kW, per Mo.)		\$ 0							22
23	Total Transmission, per kW	1,171	\$ 3	\$ 2.48	\$ 3	\$ 2.81				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)		\$ 12							26
27	Mid Peak (per kW, per Mo.)		\$ -							27
28	Off Peak (per kW, per Mo.)		\$ 5							28
29	Other (per kW, per Mo.)		\$ -							29
30	Total Generation, per kW	1,171	\$ 17	\$ 14.49	\$ 15	\$ 12.77	\$ 14.84	\$ 17	36.6%	30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	40,477	\$ 2							33
34	Mid Peak (per kWh, per Mo.)	-	\$ -							34
35	Off Peak (per kWh, per Mo.)	99,387	\$ 4							35
36	Other (per kWh, per Mo.)	264,279	\$ 10							36
37	Total Energy, per kWh	404,142	\$ 16	\$ 0.04068	\$ 14	\$ 0.03585	\$ 0.04990	\$ 20	42.5%	37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 55		\$ 46	\$ 0.11377				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ 0.00368	\$ 1	3.1%	46
47										47
48	Total		\$ 55	\$ 0.13605	\$ 46	\$ 0.11377		\$ 47	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ 1		49
50							rounding isolated:	\$ (0.0006)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):									55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill	Customer and Facilities			\$ 82.50	\$ 78.87	\$ 78.86		-4.4%	58
59	Facilities Charge, per kW:				n/a	n/a	n/a		0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods				\$ -	\$ 14.84	\$ 14.84		0.0%	62
63	On Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	63
64	Mid Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:				\$ 0.10955	\$ 0.04991	\$ 0.04990	\$ 0.05358	-51.1%	69
70	On Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	70
71	Mid Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	71
72	Off Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	72
73	Other (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):				\$ 0.11528		\$ 0.11745		1.9%	75

Nevada Power Company

Statement O Workpapers
Calculation of Rates

2015 Net Metering Rate Design

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NEM Workpaper

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LRS-NEM

Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	96	\$ 1	\$ 12.88	\$ 1	\$ 9.14	\$ 78.86	\$ 8	15.9%	11
12	Generation Meter Charge (per Meter, per Mo.)	96	\$ 1	\$ 12.67	\$ 1	\$ 8.99	\$ 8.98	\$ 1	1.8%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 9	\$ 98.31	\$ 7	\$ 69.73	in BSC			14
15	Primary (per kW, per Mo.)	1,171	\$ 7	\$ 70.60	\$ 5	\$ 4.11	\$ 4.11	\$ 5	10.1%	15
16	Total Distribution Services		\$ 19		\$ 13					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)	440	\$ 3	\$ 5.92	\$ 3	\$ 6.71				19
20	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					20
21	Off Peak (per kW, per Mo.)	-	\$ 0	na	\$ 0	na				21
22	Other (per kW, per Mo.)	727	\$ 0	\$ 0.42	\$ 0	\$ 0.47				22
23	Total Transmission, per kW	1,167	\$ 3	\$ 2.49	\$ 3	\$ 2.82				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)	440	\$ 12	\$ 28.31	\$ 11	\$ 24.94	\$ 28.54	\$ 13	26.4%	26
27	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					27
28	Off Peak (per kW, per Mo.)	-	\$ 5	na	\$ 4	na				28
29	Other (per kW, per Mo.)	727	\$ -	\$ 6.21	\$ -	\$ 5.48				29
30	Total Generation, per kW	1,167	\$ 17	\$ 14.54	\$ 15	\$ 12.81				30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	40,477	\$ 2	\$ 0.05190	\$ 2	\$ 0.04574	\$ 0.08678	\$ 4	7.4%	33
34	Mid Peak (per kWh, per Mo.)	-	\$ -		\$ -					34
35	Off Peak (per kWh, per Mo.)	99,387	\$ 4	\$ 0.04150	\$ 4	\$ 0.03657	\$ 0.05179	\$ 5	10.8%	35
36	Other (per kWh, per Mo.)	264,279	\$ 10	\$ 0.03866	\$ 9	\$ 0.03407	\$ 0.04359	\$ 12	24.3%	36
37	Total Energy, per kWh	404,142	\$ 16	\$ 0.04068	\$ 14	\$ 0.03585				37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 55		\$ 46	\$ 0.11377				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ 0.00368	\$ 1	3.1%	46
47										47
48	Total		\$ 55	\$ 0.13605	\$ 46	\$ 0.11377		\$ 47	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ 1		49
50							rounding isolated:	\$ (0.0010)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):									55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill Customer and Facilities		\$ 82.50	\$ 78.87	\$ 78.86				-4.4%	58
59	Primary Distribution Charge, per Max kW:		\$ -	\$ 4.11	\$ 4.11				0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods		\$ -	\$ -	\$ -				0.0%	62
63	On Peak (per kW, per Mo.)		\$ -	\$ 28.55	\$ 28.54				0.0%	63
64	Mid Peak (per kW, per Mo.)		\$ -	\$ -	\$ -				0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:		\$ -	\$ -	\$ -	\$ -			0.0%	69
70	On Peak (per kWh, per Mo.)		\$ 0.38306	\$ 0.14874	\$ 0.08678	\$ 0.09046			-76.4%	70
71	Mid Peak (per kWh, per Mo.)		\$ -	\$ -	\$ -	\$ -			0.0%	71
72	Off Peak (per kWh, per Mo.)		\$ 0.05041	\$ 0.05180	\$ 0.05179	\$ 0.05547			10.0%	72
73	Other (per kWh, per Mo.)		\$ 0.06092	\$ 0.03411	\$ 0.04359	\$ 0.04727			-22.4%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.11528		\$ 0.11745				1.9%	75

Nevada Power Company

Statement O Workpapers
Calculation of Rates

2015 Net Metering Rate Design

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NEM Workpaper

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GS-NEM

Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	804	\$ 19	\$ 23.84	\$ 14	\$ 16.87	\$ 35.43	\$ 28	12.9%	11
12	Generation Meter Charge (per Meter, per Mo.)	324	\$ 3	\$ 10.69	\$ 2	\$ 7.57	\$ 7.57	\$ 2	1.1%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 21	\$ 26.22	\$ 15	\$ 18.56	in BSC			14
15	Primary (per kW, per Mo.)	5,550	\$ 37	\$ 46.00	\$ 26	\$ 4.72				15
16	Total Distribution Services		\$ 81		\$ 57					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)		\$ 13							19
20	Mid Peak (per kW, per Mo.)		\$ -							20
21	Off Peak (per kW, per Mo.)		\$ 2							21
22	Other (per kW, per Mo.)		\$ 0							22
23	Total Transmission, per kW	5,550	\$ 15	\$ 2.67	\$ 17	\$ 3.03				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)		\$ 50							26
27	Mid Peak (per kW, per Mo.)		\$ -							27
28	Off Peak (per kW, per Mo.)		\$ 26							28
29	Other (per kW, per Mo.)		\$ -							29
30	Total Generation, per kW	5,550	\$ 76	\$ 13.71	\$ 67	\$ 12.14	\$ 15.27	\$ 85	38.5%	30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	162,672	\$ 8							33
34	Mid Peak (per kWh, per Mo.)	0	\$ -							34
35	Off Peak (per kWh, per Mo.)	675,102	\$ 28							35
36	Other (per kWh, per Mo.)	1,266,542	\$ 49							36
37	Total Energy, per kWh	2,104,316	\$ 85	\$ 0.04056	\$ 76	\$ 0.03592	\$ 0.04810	\$ 101	46.0%	37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 257		\$ 217	\$ 0.10308				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ 0.00150	\$ 3	1.4%	46
47										47
48	Total		\$ 257	\$ 0.12211	\$ 217	\$ 0.10308		\$ 220	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ 3		49
50							rounding isolated:	\$ (0.0051)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):						\$ 0.00150			55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill	Customer and Facilities			\$ 27.50	\$ 35.43	\$ 35.43		28.8%	58
59	Facilities Charge, per kW:				n/a	n/a	n/a		0.0%	59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods				\$ -	\$ 15.27	\$ 15.27		0.0%	62
63	On Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	63
64	Mid Peak (per kW, per Mo.)				\$ -	\$ -	\$ -		0.0%	64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:				\$ 0.07335	\$ 0.04809	\$ 0.04810	\$ 0.04960	-32.4%	69
70	On Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	70
71	Mid Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	71
72	Off Peak (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	72
73	Other (per kWh, per Mo.)				\$ -	\$ -	\$ -	\$ -	0.0%	73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.06095		\$ 0.10458				71.6%	75

Nevada Power Company

Statement O Workpapers
Calculation of Rates

2015 Net Metering Rate Design

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NEM Workpaper

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GS-NEM

Line No.	Component	Billing Units	Marginal Cost (MC) Revenue	Rate	Reconciled MC & IRR Revenue	Rate	Proposed Rates	Proof of Revenue	Percent of Revenue	Line No.
	--B--	--C--	--D--	--E--	--F--	--G--	--H--	--I--	--J--	
9										9
10	Distribution Services									10
11	Customer (per Cust, per Mo.)	804	\$ 19	\$ 23.84	\$ 14	\$ 16.87	\$ 35.43	\$ 28	12.9%	11
12	Generation Meter Charge (per Meter, per Mo.)	324	\$ 3	\$ 10.69	\$ 2	\$ 7.57	\$ 7.57	\$ 2	1.1%	12
13	Addtl Meter Charge (per Meter, per Mo.)									13
14	Fac Chg (per Cust, per Mo.)		\$ 21	\$ 26.22	\$ 15	\$ 18.56	in BSC			14
15	Primary (per kW, per Mo.)	5,550	\$ 37	\$ 46.00	\$ 26	\$ 4.72	\$ 4.72	\$ 26	11.9%	15
16	Total Distribution Services		\$ 81		\$ 57					16
17										17
18	Transmission Demand (per kW)									18
19	On Peak (per kW, per Mo.)	2,071	\$ 13	\$ 6.33	\$ 15	\$ 7.17				19
20	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					20
21	Off Peak (per kW, per Mo.)	-	\$ 2	na	\$ 2	na				21
22	Other (per kW, per Mo.)	3,318	\$ 0	\$ 0.52	\$ 0	\$ 0.59				22
23	Total Transmission, per kW	5,389	\$ 15	\$ 2.75	\$ 17	\$ 3.12				23
24										24
25	Generation Demand (per kW)									25
26	On Peak (per kW, per Mo.)	2,071	\$ 50	\$ 24.32	\$ 45	\$ 21.54	\$ 28.27	\$ 59	26.6%	26
27	Mid Peak (per kW, per Mo.)	-	\$ -		\$ -					27
28	Off Peak (per kW, per Mo.)	-	\$ 26	na	\$ 23	na				28
29	Other (per kW, per Mo.)	3,318	\$ -	\$ 7.75	\$ -	\$ 6.87				29
30	Total Generation, per kW	5,389	\$ 76	\$ 14.12	\$ 67	\$ 12.51				30
31										31
32	Energy (per kWh)									32
33	On Peak (per kWh, per Mo.)	162,672	\$ 8	\$ 0.05201	\$ 7	\$ 0.04607	\$ 0.06504	\$ 11	4.8%	33
34	Mid Peak (per kWh, per Mo.)	0	\$ -		\$ -					34
35	Off Peak (per kWh, per Mo.)	675,102	\$ 28	\$ 0.04085	\$ 24	\$ 0.03618	\$ 0.04899	\$ 33	15.0%	35
36	Other (per kWh, per Mo.)	1,266,542	\$ 49	\$ 0.03893	\$ 44	\$ 0.03448	\$ 0.04545	\$ 58	26.2%	36
37	Total Energy, per kWh	2,104,316	\$ 85	\$ 0.04056	\$ 76	\$ 0.03592				37
38										38
39	Adjustments:									39
40	PF-Seasonal Smr & Wntr Revs									40
41	Add. Fac. & Maintenance									41
42	Total Adjustments				\$ -					42
43										43
44	Cost Based Total		\$ 257		\$ 217	\$ 0.10308				44
45										45
46	Interclass Rate Rebalancing (IRR):				\$ -		\$ 0.00150	\$ 3	1.4%	46
47										47
48	Total		\$ 257	\$ 0.12211	\$ 217	\$ 0.10308		\$ 220	100.0%	48
49	Checks, s/b zero:		\$ -		\$ -	\$ -	subsidy and rounding:	\$ 3		49
50							rounding isolated:	\$ (0.0070)		50
51	RATE SUMMARY									51
52										52
53										53
54	BTER									54
55	Interclass Rate Rebalancing (IRR, per kWh):						\$ 0.00150			55
56										56
57	Distribution Charges									57
58	Basic Service Charge, per Bill Customer and Facilities		\$ 27.50	\$ 35.43	\$ 35.43			28.8%		58
59	Primary Distribution Charge, per Max kW:		\$ -	\$ 4.72	\$ 4.72			0.0%		59
60										60
61	T & G Demand Charges, per metered kW									61
62	All Periods		\$ -	\$ -	\$ -			0.0%		62
63	On Peak (per kW, per Mo.)		\$ -	\$ 28.27	\$ 28.27			0.0%		63
64	Mid Peak (per kW, per Mo.)		\$ -	\$ -	\$ -			0.0%		64
65										65
66										66
67										67
68	Total Energy Charges (BTGR & BTER):									68
69	All Periods, or:		\$ -	\$ -	\$ -	\$ -		0.0%		69
70	On Peak (per kWh, per Mo.)		\$ 0.27613	\$ 0.15029	\$ 0.06504	\$ 0.06654		-75.9%		70
71	Mid Peak (per kWh, per Mo.)		\$ -	\$ -	\$ -	\$ -		0.0%		71
72	Off Peak (per kWh, per Mo.)		\$ 0.05659	\$ 0.04900	\$ 0.04899	\$ 0.05049		-10.8%		72
73	Other (per kWh, per Mo.)		\$ 0.04768	\$ 0.03451	\$ 0.04545	\$ 0.04695		-1.5%		73
74										74
75	Overall effective rate (per kWh, OAS if currently no customers):		\$ 0.06095		\$ 0.10457			71.6%		75

Nevada Power Company

Statement O Worksheets
Calculation of Rates

Residential EVRR Optional TOU Schedule Revenues

2015 Net Metering Rate Design
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Line No.		Single Family Residential (RS-NEM)	Multi-Family Residential (RM-NEM)	Large Single Family Residential (LRS-NEM)	Line No.
8	Discounted Off-peak BTGR rates for Electric Vehicle Rider ¹				8
9					9
10					10
11					11
12	Summer Off Peak BTGR Rate	\$ 0.00290	\$ 0.01061	\$ 0.00821	12
13	Winter Other BTGR Rate	\$ 0.00001	\$ 0.00001	\$ 0.00001	13
14					14
15	BTER	\$ 0.04726	\$ 0.04726	\$ 0.04726	15
16	Total BTGR+BTER				16
17	Summer Off Peak	\$ 0.05016	\$ 0.05787	\$ 0.05547	17
18	Winter Other	\$ 0.04727	\$ 0.04727	\$ 0.04727	18
19					19
20	10% Discount on above Total rate				20
21	Summer Off Peak	\$ (0.00502)	\$ (0.00579)	\$ (0.00555)	21
22	Winter Other	\$ (0.00473)	\$ (0.00473)	\$ (0.00473)	22
23					23
24	Discounted EVRR Period BTGR				24
25	Summer Off Peak	\$ (0.00212)	\$ 0.00482	\$ 0.00266	25
26	Winter Other	\$ (0.00472)	\$ (0.00472)	\$ (0.00472)	26
27					27
28	Check 10% Discount on Total BTGR & BTER				28
29	Summer Off Peak	10.0%	10.0%	10.0%	29
30	Winter Other	10.0%	10.0%	10.0%	30
31					31
32	(1) Discounted Off-peak/Winter BTGR For Electric Vehicle Rider with all other TOU rates is the same as in the respective Optional TOU Schedules.				32
33	The discounted rate represents a 10% discount to the off-peak BTER and BTGR rate components in the representative optional and alternative optional TOU schedules. All of the discount is placed in the BTGR component.				33
34					34

Nevada Power Company

Statement O Worksheets
Calculation of Rates

Commercial EVRR Optional TOU Schedule Revenues

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Line No.		Line No.
8	Discounted Off-peak BTGR rates for Electric Vehicle Rider¹	8
9		9
10		10
11		11
12	Summer Off Peak BTGR Rate	12
13	Winter Other BTGR Rate	13
14		14
15	BTER	15
16	Total BTGR+BTGR	16
17	Summer Off Peak	17
18	Winter Other	18
19		19
20	10% Discount on above Total rate	20
21	Summer Off Peak	21
22	Winter Other	22
23		23
24	Discounted EVRR Period BTGR	24
25	Summer Off Peak	25
26	Winter Other	26
27		27
28	Check 10% Discount on Total BTGR & BTGR	28
29	Summer Off Peak	29
30	Winter Other	30
31		31
32	(1) Discounted Off-peak/Winter BTGR For Electric Vehicle Rider with all other TOU rates is the same as in the respective Optional TOU Schedules.	32
33	The discounted rate represents a 10% discount to the off-peak BTER and BTGR rate components in the representative optional and alternative optional TOU schedules.	33
34	All of the discount is placed in the BTGR component.	34

Nevada Power Company

Statement O Workpapers
Calculation of NEM Class Value of Banking Revenue

2015 Net Metering - Customer Classes of Service
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Line No.			Billing Determinants	Present Rates	Proposed Rates	
9	RM-NEM					
10	Distribution Services					
11	Customer (per Cust, per Mo.)		900	\$ 9.00	\$ 11.22	
12	Generation Meter Charge (per Meter, per Mo.)		852		\$ 1.40	
13						
14	Total PD, T, and 50% G, per Max kW		2,053		\$ 13.95	
15						
16	Energy (per kWh)	Delivered				
17	On Peak (per kWh, per Mo.)		31,081		\$ -	
18	Off Peak (per kWh, per Mo.)		125,472		\$ -	
19	Other (per kWh, per Mo.)		183,141		\$ -	
20	Total Energy, per kWh		339,694			
21	Total non-TOU Energy Net Billed		339,154	\$ 0.10535	\$ 0.05648	
22						
23	Revenues			\$ 43,831	\$ 59,088	
24	Average Bill			\$ 48.70	\$ 65.65	
25				Percent Change		34.8%
26						
27	Rate Design Revenues			\$ 70,376		
28	Rate Design Revenue - Value of Banked Energy			\$ (11,288)		
29	Pct of Rate Design Revenues				84%	
30						
31						
32	LRS-NEM					
33	Distribution Services					
34	Customer (per Cust, per Mo.)		96	\$ 82.50	\$ 78.86	
35	Generation Meter Charge (per Meter, per Mo.)		96		\$ 8.88	
36						
37	Total PD, T, and 50% G, per Max kW		1,171		\$ 14.84	
38						
39	Energy (per kWh)	Delivered				
40	On Peak (per kWh, per Mo.)		37,254		\$ -	
41	Off Peak (per kWh, per Mo.)		91,018		\$ -	
42	Other (per kWh, per Mo.)		224,717		\$ -	
43	Total Energy, per kWh		352,989			
44	Total non-TOU Energy Net Billed		352,989	\$ 0.10417	\$ 0.05358	
45						
46	Revenues			\$ 44,591	\$ 44,725	
47	Average Bill			\$ 465.53	\$ 465.88	
48				Percent Change		0.1%
49						
50	Rate Design Revenues			\$ 47,466		
51	Rate Design Revenue - Value of Banked Energy			\$ (2,741)		
52	Pct of Rate Design Revenues				94%	

Line No.			Billing Determinants	Present Rates	Proposed Rates	
9	RS-NEM					
10	Distribution Services					
11	Customer (per Cust, per Mo.)		64,416	\$ 12.75	\$ 18.15	
12	Generation Meter Charge (per Meter, per Mo.)		32,486		\$ 1.43	
13						
14	Total PD, T, and 50% G, per Max kW		313,825		\$ 14.33	
15						
16	Energy (per kWh)	Delivered				
17	On Peak (per kWh, per Mo.)		7,650,391		\$ -	
18	Off Peak (per kWh, per Mo.)		22,530,386		\$ -	
19	Other (per kWh, per Mo.)		18,637,285		\$ -	
20	Total Energy, per kWh		30,902,029		\$ -	
21	Total non-TOU Energy Net Billed		42,746,079			
22			42,659,044	\$ 0.12155	\$ 0.05470	
23						
24	Revenues			\$ 6,006,511	\$ 8,046,189	
25	Average Bill			\$ 93.25	\$ 124.91	
26				Percent Change		34.0%
27	Rate Design Revenues			\$ 9,129,987		
28	Rate Design Revenue - Value of Banked Energy			\$ (1,063,759)		
29	Pct of Rate Design Revenues				88%	
30						
31						
32	GS-NEM					
33	Distribution Services					
34	Customer (per Cust, per Mo.)		804	\$ 27.50	\$ 35.43	
35	Generation Meter Charge (per Meter, per Mo.)		324		\$ 7.57	
36						
37	Total PD, T, and 50% G, per Max kW		5,550		\$ 15.27	
38						
39	Energy (per kWh)	Delivered				
40	On Peak (per kWh, per Mo.)		133,504		\$ -	
41	Off Peak (per kWh, per Mo.)		529,515		\$ -	
42	Other (per kWh, per Mo.)		788,374		\$ -	
43	Total Energy, per kWh		1,451,392			
44	Total non-TOU Energy Net Billed		1,447,249	\$ 0.07201	\$ 0.04960	
45						
46	Revenues			\$ 126,326	\$ 187,470	
47	Average Bill			\$ 157.12	\$ 233	
48				Percent Change		48.4%
49						
50	Rate Design Revenues			\$ 220,061		
51	Rate Design Revenue - Value of Banked Energy			\$ (32,591)		
52	Pct of Rate Design Revenues				85%	