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26-05007

Public Utilities Commission of Nevada
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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2026 Joint Triennial Integrated Resource Plan (2027-2046)
Docket No. 26-05007

Prepared Rebuttal Testimony of
Janet Wells
(Phase II)

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

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

A. My name is Janet Wells. I am Vice President of Integrated Resource Planning for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed prepared direct testimony in this docket on May 6, 2026. My qualifications were described in Q&As 2 and 3 and in **Exhibit Wells-Direct-1** of my direct testimony.

3. Q. WHAT IS THE PURPOSE OF YOUR PREPARED REBUTTAL TESTIMONY?

A. My rebuttal testimony, together with the testimony of Shawn EliceGUI, Misha Pascal, and Samantha Prest, responds to the positions of all parties related to the Form Large Load Electric Service Agreement ("LLESA") and proposes the

position of the Companies in response to those proposals.¹ I also support the Companies' overall positions within the Distributed Resources Plan and Demand Side Management Plan and a few minor items more appropriately addressed in Phase III.

4. Q. HOW IS YOUR PREPARED REBUTTAL TESTIMONY ORGANIZED?

A. My prepared rebuttal testimony is organized into eight sections. Section I, "The Companies' Position on the Form LLESA," summarizes the parties' positions and explains why the Companies continue to request approval of the Form LLESA. Section II, "Clarification of Misunderstood Concepts," addresses issues concerning large-load growth, the LTER, transparency, indicative costs, customer-reserved positions, resource identification, and communications with interveners. Section III, "Key Provisions of the Form LLESA and Response to Intervener Positions," addresses the principal commercial and existing customer protection provisions of the Form LLESA and the alternatives proposed by interveners. Section IV, "Applicability of the Form LLESA," addresses the customers and loads to which the Form LLESA should apply and the implementation of the Commission's determinations. Section V, "The Companies' Overall Response and Request for Commission Approval," summarizes the Companies' requested findings and approvals. Section VI, "Demand Side Management Plan and Distributed Resources Plan," addresses selected DSM and DRP issues and identifies the supporting Company witnesses. Section VII, "Other Items," is reserved for additional matters. Section VIII, "Conclusion and Appreciation for the Public Process," provides the Companies' final observations regarding this proceeding.

¹ My rebuttal testimony responds to the testimony filed by parties to this proceeding on September 22, 2026. The Companies will separately respond to any additional testimony filed by parties to this proceeding on October 2, 2026, as required by the Commission's Procedural Order No. 4.

1 **5. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

2 A. I am sponsoring the following Exhibits:

3 Exhibit Wells-Rebuttal-1: Draft redline edits to the Form LLESA

4 Exhibit Wells-Rebuttal-2: Discovery responses referenced in this testimony.

5
6 **6. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING**
7 **CONFIDENTIAL?**

8 A. Yes, my testimony contains customer-specific information and, therefore, is
9 confidential.

10
11 **7. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL**
12 **TREATMENT OF THIS INFORMATION?**

13 A. The requested period for confidential treatment is five years.

14
15 **8. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE**
16 **COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR**
17 **THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER**
18 **PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION**
19 **SET FORTH IN THIS FILING?**

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

SECTION I. THE COMPANIES' POSITION ON THE FORM LLESA

9. Q. PLEASE SUMMARIZE THE POSITIONS PRESENTED BY THE INTERVENERS REGARDING THE FORM LLESA.

A. The intervener testimony reflects broad agreement on the governing policy objective: new or accelerated large loads should pay for a slice of the existing system and bear the incremental costs and risks they cause so that existing customers are protected. The parties disagree principally about the mechanism and the details to achieve this objective. Staff recommends denial of the Form LLESA and opening an investigatory docket; BCP proposes its own High Energy Use Tariff; Microsoft advocates for, with support from PowerHouse Reno Britian LLC ("PowerHouse Reno") its ratepayer-protection tariff; SV RNO Property Owner 1, LLC and PR RNO Property Owner 1, LLC (collectively, "Fleet") and Novva Holdings LLC ("Novva") support approval or use of the LLESA framework with modifications followed by a tariff proceeding; Google, Advanced Energy United ("AEU")/Southwest Energy Efficiency Project ("SWEEP") and others advocate for a separate or consolidated tariff proceeding; and Western Power Association ("WPA") and Interwest Energy Alliance ("IEA") propose alternative customer-funded or customer-choice pathways. Other parties—including Amazon Data Services ("Amazon"), Prologis L.P. and North Las Vegas Power LLC (collectively, "Prologis"), and Western Resources Advocates ("WRA")—support approval or use of the LLESA framework if specified terms are modified. The most disputed terms are minimum demand and energy obligations, the Customer-Specific Generation Charge ("CSGC"), the Long-Term Energy Rate ("LTER"), security terms, termination payments, mitigation, contract term, eligibility, and the treatment of

existing or project-specific commitments. Please see **Figure Wells-Rebuttal-1** below for a table summarizing stakeholder positions.²

FIGURE WELLS-REBUTTAL-1

Intervening Party and Witness(es)	Position Regarding Approval of the Form LLESA
Regulatory Operations Staff Adam E. Danise, Swetha Venkat, Gaurav Shil, Manuel N. Lopez, Karen Olesky, and Kimberly Burakowski	Opposes approval. Recommends creation of an investigatory docket to establish a ratepayer protection mechanism for bundled service to large loads.
Bureau of Consumer Protection Patrick A. Morton	Opposes approval. Recommends adoption of BCP's High Energy Use Tariff and companion Rule 1 and Rule 9 amendments. If the Commission approves an LLESA, BCP requests additional protections.
Amazon Data Services Justin Bieber	Supports approval with targeted modifications, including changes to minimum demand, security, termination, mitigation, and related commercial terms. Requests a final determination of the Form LLESA issues in this proceeding.
Microsoft Corporation Mark E. Garrett	Opposes approval. Recommends adoption of Microsoft's Ratepayer Protection Tariff.
Google LLC Carolyn Berry and Edward Burgess	Views the Form LLESA as directionally aligned with ratepayer protection goals but as requiring refinement. Recommends development of a comprehensive large-load tariff in a separate or consolidated proceeding; also identifies future treatment of clean-resource and flexible-connection options to be addressed.
Fleet / SV RNO Property Owner 1, LLC and PR RNO Property Owner 1, LLC Dennis Bartlett	Supports approval of modified LLESAs for this proceeding only. Recommends a dedicated extra-large-load tariff proceeding and a standardized, nondiscriminatory framework.
Prologis Paul Augustine and Lee Ye	Supports approval of modified LLESAs, for customers with executed LLESAs. Describes the LLESA as an appropriate bridge while a comprehensive future framework is developed separately.
Novva Holdings, LLC Wes Swenson	Supports approval of modified LLESAs for Novva Las Vegas and Proton NLV LLESAs. Maintains that Novva Reno should not be subject to an LLESA and recommends a separate large-load tariff proceeding.
MECP 1 Reno, LLC / EdgeCore Therese Kerfoot	Opposes requiring an LLESA for EdgeCore's existing project – Mt. Elbert Recommends a separate, dedicated proceeding to develop a large-load tariff.
Redwood Materials Alex Heard	Opposes a blanket requirement that all large-load customers execute an LLESA. Recommends customer-by-customer review, recognition of existing Rule 9 commitments, transparent eligibility and cluster criteria, and billing based on actual rather than forecast usage.
PowerHouse Reno William McCausland	Opposes approval in its current form. Prefers Microsoft's Ratepayer Protection Tariff; alternatively, requests changes tying eligibility,

² Prepared Direct Testimony of Adam E. Danise, Q&As 60–62; Prepared Direct Testimony of Swetha Venkat, Q&As 4 and 32; (note all Staff witness' contain the same or similar recommendation but are not repeated here); Prepared Direct Testimony of Patrick A. Morton, p. 1; Prepared Direct Testimony of Mark E. Garrett, p. 3; Prepared Direct Testimony of Carolyn Berry Q&A 33; Prepared Direct Testimony of Dennis Bartlett, p. 7; Prepared Direct Testimony of Wes Swenson Q&A 37; Prepared Direct Testimony of Brian Turner, p. 3; Prepared Direct Testimony of Justin Bieber, pp. 7–8, 35–37; Prepared Direct Testimony of Paul Augustine, pp. 6–11; Prepared Direct Testimony of Lee Ye, pp. 17–18; Prepared Direct Testimony of Andy Eiden Q&A 20.

	security, termination payments, pricing, and capacity adjustments to objective and cost-causative standards.
Western Power Association Terry Page	Opposes making the LLESA the exclusive avenue for service. Recommends an alternative customer-funded framework or compliance filing and development of durable rules for qualifying projects.
Interwest Energy Alliance Benjamin Fitch-Fleischmann	Does not specifically endorse or oppose the Form LLESA. Recommends two transparent, technology-neutral service pathways: traditional utility planning and procurement for bundled service and a voluntary customer-choice resource pathway.
Western Resource Advocates Andy Eiden	Supports approval with strengthened and uniform protections. Recommends modifications regarding minimum billing, cost allocation, contract, and termination protections across individual LLESA.
Advanced Energy United / Southwest Energy Efficiency Project Brian Turner	Prefers a standardized Large Load Tariff over individualized LLESA. Recommends that the Commission order a tariff filing promptly after the Phase II decision.

Due to the volume of testimony and recommendations presented, the Companies cannot address every suggestion or comment raised by interveners in the time allotted for rebuttal. I will address key issues in my rebuttal but my lack of response to a particular recommendation or point should not be construed as agreement on the part of the Companies. Other than the recommendations expressly agreed to in the Companies' rebuttal testimony, the Companies continue to ask that the Commission approve the Form LLESA as filed.

10. Q. DO THE INTERVENER POSITIONS CHANGE THE COMPANIES' REQUEST IN THIS PROCEEDING?

A. No. The Companies continue to request that the Commission approve the Form LLESA. As explained in my direct testimony and in responses to discovery, the Form LLESA is intended to operate under the applicable LGS-3 or GS-3 tariff and alongside Rule 9 arrangements (which do not address supply) and to establish the additional commitments needed before the Companies undertake long-term generation, energy-supply obligations, fuel transportation commitments, and

transmission integration projects needed to serve large loads. The Form LLESA’s integrated protections—including minimum billing, the CSGC,³ security, termination-payment obligations, mitigation, and Commission oversight—are designed to provide contributions in aid of construction (“CIAC”), revenue, and planning certainty; at the same time, these protections reduce the risk that costs incurred for a large load that does not materialize, ramps more slowly than represented, or terminates early, will be shifted to existing customers.

A core tenet of the Form LLESA is that applicable large-load customers continue to pay all embedded generation and energy-resource costs recovered through their otherwise-applicable tariff rates and, in addition, pay the CIAC that reduces the Companies’ investment in generation and transmission projects, and pay the long-term energy-supply costs caused by their load. This structure prevents incremental costs from being shifted to existing customers by requiring large-load customers to pay the difference between the incremental resource costs and the embedded costs already recovered through otherwise-applicable rates. As a result, the incremental resources are available to serve the integrated system at embedded cost because the applicable large-load customers pay the difference between that embedded cost and the incremental cost of the resources added to serve all retail load, including the large-load customers.

Misha Pascal’s testimony provides the specific description of the incremental long-term energy costs, including how the LTER is determined after recognizing the customers’ contribution through embedded base tariff energy rate (“BTER”) and deferred energy accounting adjustment (“DEAA”) rates, and Samantha Prest’s

³ The customer specific generation charge produces contributions in aid of construction, which reduce the Companies’ investment in generation and transmission assets.

testimony provides the corresponding description of the incremental generation and related costs recovered through the CSGC and how those costs are determined in relation to embedded rates.

11. Q. WHY IS COMMISSION APPROVAL OF THE FORM LLESA IMPORTANT TO RESOURCE PLANNING?

A. Mr. Elicegui's direct testimony explains that the Companies start with a Base Minus Load Forecast and then add large-load service requests when directed by the Commission or when the load is supported by an electric service agreement such as a LLESA. The Companies can then use PLEXOS LT to identify the resources needed to serve the confirmed load. In response to Staff Data Request 3, the Companies explained that approval of a standard Form LLESA therefore provides a disciplined means to confirm customer commitment, align the load forecast with the obligation to serve, and identify the resources that should be procured without transferring the load non-materialization risk to existing customers.⁴

12. Q. HOW DO THE COMPANIES RESPOND TO RECOMMENDATIONS THAT LARGE-LOAD SERVICE INSTEAD BE GOVERNED BY A TARIFF SCHEDULE OR EXPLORED IN AN INVESTIGATORY DOCKET?

A. The Companies recognize that a tariff schedule may ultimately provide a standardized vehicle for large-load service and that further investigation may be useful as market conditions, technologies, customer-supplied options, and Commission policy develop. The Form LLESA is intended to provide a *uniform* service agreement for use under tariff schedules such as Schedule No. GS-3 and Schedule LGS-3. The possibility of a tariff schedule does not require rejection of

⁴ Prepared Direct Testimony of Shawn Elicegui, Q&As 16, 18 and 19; Staff Data Request 3; Response to Staff Data Request 6; Response to IEA Data Request 1-08; Companies' June 4, 2026 Supplemental Filing.

the Form LLESA now. The record shows immediate need for a Commission-approved framework that connects customer commitments to load forecasting, resource procurement, cost recovery, and provides financial protection for existing customers. Several interveners likewise characterize a modified LLESA as an appropriate “bridge” or request approval for executed agreements while a broader framework is developed. Accordingly, the Companies recommend approval of the Form LLESA as the starting point. If the Commission directs a subsequent tariff filing, the Companies would begin with the approved LLESA and translate its protective provisions into proposed tariff terms for further stakeholder and Commission review through an Advice Letter filing. An Advice Letter filing would provide a second public forum for specific, directed feedback from interested parties and is designed to result in an approved tariff; an investigatory docket could prolong the process and ultimately still require a subsequent Advice Letter proceeding to approve the tariff.

13. Q. WHAT ACTIONS DO THE COMPANIES REQUEST FROM THE COMMISSION?

A. The Companies request that the Commission approve the Form LLESA, including the core cost-causation and financial-protection provisions necessary to prevent incremental large-load costs and non-performance risks from being shifted to existing customers. To the extent the Commission modifies particular terms based on the record, the approved framework should preserve clear minimum billing, the CSGC and LTER cost recovery, security, termination, mitigation, and Commission-review provisions. An approved form will allow customers and the Companies to confirm whether to proceed, permit the Companies to update the load

forecast and expansion plan on a timely basis, and provide a defined foundation for any later tariff filing or investigatory docket the Commission directs.

SECTION II. CLARIFICATION OF MISUNDERSTOOD CONCEPTS

14. Q. HOW DO THE COMPANIES RESPOND TO STAFF’S ASSERTION THAT THERE HAS NOT BEEN A STEP CHANGE IN LARGE-LOAD REQUESTS?

A. The Companies disagree. The relevant comparison is not whether Nevada has previously received individual large-load requests, but how the aggregate magnitude, maturity, and pace of those requests changed between the information available for the 2024 IRP and the information confirmed for the 2026 IRP. The 2024 IRP large-customer inputs were confirmed by October 2023; the 2026 IRP large-customer inputs were confirmed in August 2025, only 22 months later. Over that period, NV Energy’s line extension study-phase requests for large loads increased from 4,615 MW to 9,484 MW, the Estimated Full Build-out Project Load (“EFBPL”) of signed line extension projects increased from 2,723 MW to 4,596 MW, and the combined subtotal increased from 7,339 MW to 14,080 MW. The peak demand associated with such incorporated into the Base Load Forecast as of 2032 more than doubled from 2,082 MW to 4,241 MW, and 3,436 MW was associated with Energy Service Agreements in the 2026 IRP. Those changes demonstrate a step change in both the requested-load pipeline and the portion sufficiently advanced to affect planning. The comparison is summarized below.

FIGURE WELLS-REBUTTAL-2

NV Energy Large-Customer Load Comparison (MW)			
Category	2024 IRP	2026 IRP	Change
Study Phase Projects	4,615	9,484	+4,869 (105.5%)
Signed Projects	2,723	4,596	+1,873 (68.8%)

Subtotal	7,339	14,080	+6,741 (91.9%)
Base Load Forecast	2,082	4,241	+2,159 (103.7%)
Energy Service Agreements	—	3,436	New category in comparison

15. Q. HAVE THE COMPANIES CLARIFIED OR UPDATED THEIR PROPOSAL FOR THE LONG-TERM ENERGY RATE?

A. Yes. Consistent with the clarification provided in discovery responses,⁵ the Companies propose that the LTER be updated quarterly through the applicable BTER filing process. The quarterly calculation will reconcile the revenues collected from the LLESA customer group with the actual incremental long-term energy-supply costs incurred for that group, including applicable power purchase agreement (“PPA”) invoices and gas transportation costs, after recognizing the customers’ contribution through BTER and DEAA. The Companies also propose a separate deferred account for the LTER so that over- or under-collections, including applicable carrying charges, remain attributable to the LLESA customer group rather than existing customers. This clarification should be reflected in the approved Form LLESA and the implementing accounting and rate filings. Proposed language to implement these clarifications is provided in **Exhibit Wells-Rebuttal-1**. For further discussion of the LTER, please see the testimony of Misha Pascal.

16. Q. ARE THE COMPANIES PROPOSING ANY OTHER UPDATED LANGUAGE TO THE FORM LLESA?

A. Yes. Consistent with Rule 10, the Companies propose to add language to clarify that the LLESA is subject to changes or modifications by the Commission in the

⁵ For example, Response to Staff Data Request 126; Response to Staff Data Request 143 and supplemental response, including the LTER White Paper and workpaper; Response to Staff Data Request 240.

exercise of its jurisdiction. This edit to the form is also reflected in **Exhibit Wells-Rebuttal-1**.

17. **Q. HOW DO THE COMPANIES RESPOND TO ASSERTIONS THAT DEVELOPMENT AND REVIEW OF THE FORM LLESA WERE NOT TRANSPARENT?**

A. The assertion rests on a misunderstanding of the process. Transparency does not mean that every proposed redline must be accepted or that commercially sensitive customer information must be made public. The requirement for a service agreement addressing generation and energy supply is grounded in Schedules GS-3 and LGS-3, which have long permitted the Companies to require a contract for service as a condition of providing bundled electric service. The LLESA process made that requirement explicit and placed the proposed form before the Commission for review. The Companies circulated the form, met with affected customers, received and reviewed feedback, revised provisions, documented unresolved customer positions, and publicly filed those customer positions with the original applications for Commission consideration. The Companies also sought to vet the form in a public Commission forum in this docket, supplied testimony, exhibits, workpapers, white papers, data-request responses, and technical discussions, and proposed that the Commission determine the final form before customers confirm whether they will proceed. Presenting the common form, the Companies' positions, and the customers' competing reserved positions on a public record is transparency by design. Disagreement about the outcome or the pace of production does not establish that the process itself was nontransparent.

18. Q. ARE THE CSGC AND LTER VALUES TRANSPARENT EVEN THOUGH
THE FILED VALUES ARE INDICATIVE?

A. Yes. The filed CSGC and LTER values are necessarily indicative because the final customer group, confirmed load ramps, resource portfolio, project costs, in-service dates, PPA prices, generation output, gas transportation needs, and financing and integration costs are not fully known when the form agreement is reviewed. The methodologies, cost categories, allocation principles, illustrative workpapers, and reconciliation mechanisms have nevertheless been disclosed. These rates will be updated once the form agreement is approved and the LLESA customers commit to the LLESA. As actual costs are incurred, the CSGC will be recalculated and reviewed through general rate cases, with actual investment and CIAC collections reconciled for the LLESA customer group. The LTER will be updated through quarterly BTER filings using actual energy-supply costs and the separate deferred account. Those filings provide Staff, BCP, interveners, and the Commission with the appropriate record to test the inputs, prudence, allocation, and reconciliation. Calling an estimate “indicative” identifies its proper context and function; it does not make the methodology opaque.

19. Q. HOW DO THE COMPANIES RESPOND TO CRITICISM THAT
CUSTOMERS ARE BEING ASKED TO COMMIT BASED ON
INDICATIVE COSTS, INCLUDING STAFF’S CONCERN REGARDING
PPA OUTPUT AND RESULTING COSTS?

A. Indicative estimates will remain necessary when customers make LLESA commitments because the sequence cannot be reversed: the Companies must first know which customers will proceed and the monthly ramps to which they will commit; the Companies can then complete resource planning, identify and obtain

1 approval of the generation-capacity and energy resources needed to serve that load,
2 and convert estimates to approved and ultimately actual costs. Waiting for every
3 project and invoice to be final before obtaining a customer commitment defeats the
4 purpose—it would require the Companies and existing customers to bear the
5 development and non-materialization risk that the LLESA is intended to prevent.
6 The agreement, therefore, couples an initial cost estimate with defined update and
7 reconciliation mechanisms so that the governing principle remains intact—no
8 incremental cost caused by applicable large loads is shifted to existing customers.
9 Mr. Shil raises a concern that PPA output may differ from the energy attributed to
10 the LLESA customer group and may therefore affect the resulting LTER costs. The
11 Companies' quarterly LTER update addresses that concern. The quarterly filings
12 will use actual invoices and actual applicable PPA and gas-transportation costs,
13 recognize the applicable BTER and DEAA contribution, reconcile revenues and
14 costs through the separate deferred account, and carry any over- or under-collection
15 forward for the specific LLESA customer group. The Companies' system
16 dispatches the resource portfolio to serve combined bundled retail load rather than
17 reserving each PPA's physical output for a particular customer or group of
18 customers; cost responsibility, not physical dispatch, is what the LTER assigns.
19 Quarterly actual-cost reconciliation therefore captures differences between forecast
20 and realized PPA output and cost without shifting the resulting incremental cost to
21 existing customers.

1 **20. Q. DO THE CUSTOMER-RESERVED POSITIONS MEAN THAT THE**
2 **COMPANIES INTEND TO IMPLEMENT DIFFERENT VERSIONS OF**
3 **THE FORM LLESA FOR DIFFERENT CUSTOMERS?**

4 A. No. Some intervener testimony appears to misunderstand the purpose of the
5 Customer-Reserved Positions and to assume that the positions listed in Exhibit G
6 would produce multiple versions of the Form LLESA with different substantive
7 protections. Exhibit G did not amend the operative agreement language or reflect
8 terms accepted by the Companies. It identified the issues on which an executing
9 customer wished to preserve a different position so that the Commission could
10 evaluate those positions in this public proceeding when deciding the final form.
11 Once the Commission determines the final Form LLESA, including whether any
12 position identified in Exhibit G should be incorporated, the Companies intend to
13 conform the applicable agreements to that approved standard. The provisions
14 governing minimum demand, minimum energy, the CSGC, the LTER, termination
15 payments, security, and the other existing customer protections will, therefore, be
16 the provisions approved by the Commission, not customer-by-customer variations
17 derived from Exhibit G. The filing also demonstrates the transparency of the
18 proposed framework. The Form LLESA and all of its substantive provisions were
19 filed publicly and each application filed that employed the Form LLESA⁶ was filed
20 with very limited redactions. What will appropriately differ among agreements are
21 the customer-specific monthly load values, Maximum Demand, Ramp Schedule,
22 Ramp Demand, service dates, project and facility information, and any customer-
23 specific values or supporting information used to determine security.⁷ To the extent
24 those items contain commercially sensitive customer information, they would
25 remain protected in the individual agreement or filing. Those limited customer-

26 ⁶ See Docket Nos. 26-05026, 26-05027, 26-05028, 26-05029, and 26-05030.

27 ⁷ Additional modifications to the form LLESA are necessary to address the specific context of customers with sleeved
28 resources, as demonstrated in Docket No. 26-05027.

specific fields do not alter the uniform legal, pricing, and ratepayer-protection framework established by the Commission-approved form.

21. **Q. DOES IDENTIFYING RESOURCES NEEDED WHEN LARGE-LOAD REQUESTS ARE INCLUDED IN THE RETAIL LOAD FORECAST MEAN THOSE RESOURCES WILL EXCLUSIVELY SERVE LARGE-LOAD CUSTOMERS?**

A. No. The resources identified as needed when large-load requests are included in the retail load forecast are not the only resources that will provide generation capacity and energy to those customers, nor are those resources physically dedicated to serving large loads. NV Energy will continue to employ system dispatch across its resource portfolio to meet the needs of all bundled retail load. The comparison between the Base Minus Load Forecast and the Base Load Forecast is a planning and cost-allocation construct used to identify the incremental generation-capacity and energy needs, transmission integration investment, and fuel transportation commitments that arise when confirmed large-load requests are added to the retail load forecast. Identifying the resources associated with that incremental need allows the Companies to determine and appropriately allocate the resulting incremental costs to the customers causing those costs, while continuing to operate and dispatch the system as an integrated portfolio. This approach does not alter system dispatch; it provides a transparent method to apply cost causation and ensure that costs incurred to serve large-load growth are not shifted to existing customers. It also ensures that the Companies dispatch available generation in the most cost-effective manner to meet the needs of its electric service customers.

22. Q. HOW DO THE COMPANIES RESPOND TO INTERVENER TESTIMONY
DESCRIBING MEETINGS OR UNDERSTANDINGS FROM
DISCUSSIONS WITH NV ENERGY THAT MAY DIFFER FROM THE
COMPANIES' UNDERSTANDING?

A. A number of interveners summarize meetings with NV Energy or describe understandings they attribute to those discussions. In some instances, those accounts may not be consistent with the Companies' communication. The Companies have not addressed each such statement individually in this rebuttal testimony, and the absence of a response should not be interpreted as agreement with an intervenor's characterization. In addition, certain customer representations concerning those meetings and other matters were submitted in this docket on a confidential basis and withheld from the Companies; accordingly, the Companies are unable to respond to those representations at this time.

The Companies first developed the Framework Agreement and then the Form LLESA, requested and considered customer feedback, revised the drafts, and worked toward executed commitments, including short-term agreements. During that process, the Companies held hundreds of meetings involving energy supply agreements, answering questions and vetting concepts. Given the number of participants, meetings, drafts, and issues discussed, recollections and understandings of particular conversations may differ. The Companies' positions are reflected in their filed testimony, exhibits, discovery responses, and the Form LLESA presented for Commission review.

**SECTION III. KEY PROVISIONS OF THE FORM LLESA AND RESPONSE TO
INTERVENER POSITIONS.**

**23. Q. WHAT ARE THE PARTIES' POSITIONS ON MINIMUM DEMAND, AND
DO THE COMPANIES RECOMMEND A CHANGE?**

A. The Form LLESA requires Minimum Demand equal to at least 90 percent of Ramp Demand during the ramp period and 90 percent of Maximum Demand thereafter. Some intervener proposals generally reduce that obligation or replace it with another framework; others, such as WRA would increase Minimum Demand. The Companies continue to support the original 90 percent proposal.⁸ The Companies updated the original Form LLESA, as discussed above, to require each customer to provide a monthly load forecast, placing the greatest practical level of control over the requested load ramp—and therefore the greatest influence over the resulting minimum charges—with the customer. The Companies also previously updated the form to establish processes through which a customer may request changes to Ramp Demand and Maximum Demand. The Companies' proposal incentivizes accurate forecasting. A 90 percent minimum produces more consistent and predictable revenue from customers whose requested ramps drive resource commitments. Reducing the percentage does not eliminate the revenue requirement; it requires the CSGC and other demand-based charges to increase so the same customer group continues to provide CIAC and the revenue stream needed to protect existing customers. Retaining 90 percent also reduces the magnitude of later true-ups when actual load or cost differs from forecast. More specifically, a customer whose load materializes in magnitude and timing closer to its forecasted request would be penalized if lower minimums were approved because the lower billing determinants would require a higher rate to provide the necessary CIAC receipts, and that

⁸ Response to BCP Data Request 6-25; supplemental response to Staff Data Request 143, including the CSGC White Paper.

customer would pay the higher rate on actual demand above the reduced minimum. No intervenor proposal demonstrated equivalent protection with less volatility without recalibrating the associated rates. References to large-load tariffs adopted in other jurisdictions do not necessarily reflect the specific facts and circumstances presented in Nevada, and the record does not establish that a single minimum-demand percentage is uniformly appropriate across jurisdictions. The Companies therefore request that the Commission approve the 90 percent minimum that best fits Nevada's load-growth, resource-planning, cost-recovery, and existing-customer-protection needs.

FIGURE WELLS-REBUTTAL-3

Intervening Party	Position on Minimum Demand
Staff	Recommends further investigation of appropriate minimum demand and billing determinants.
BCP	Proposes HEUT minimum demand beginning at 60% and increasing to 85%.
Amazon	Recommends 80%, conditioned on recalculating other charges to preserve recovery.
Google	Supports minimum billing but recommends a 70%–80% range.
Fleet	Would establish the percentage through a standardized tariff; cites lower generation minimums used elsewhere.
Prologis	Recommends 80% and commercially reasonable minimum billing tied to available service.
Microsoft / PowerHouse Reno	Prefers Microsoft's tariff framework, that framework does not propose any minimum billing requirements.
WRA	Supports strong, uniform minimum-billing protection; no specific percentage identified.
Other interveners	No sufficiently specific alternative percentage identified.

24. Q. WHAT ARE THE PARTIES' POSITIONS ON MINIMUM ENERGY, INCLUDING AMAZON'S PROPOSED CREDIT?

A. The Form LLESA establishes Minimum Energy by applying an 80 percent load factor to the 90 percent Minimum Demand, producing an equivalent 72 percent utilization level. The Companies continue to support that proposal. As with Minimum Demand, the customer-provided monthly load requests place the greatest practical control over the forecasted load profile—and therefore the resulting

1 Minimum Energy charges—with the customer. The Companies also updated the
2 Form LLESA, as discussed above, to allow a customer to request a change to the
3 load factor used to determine Minimum Energy. Under that provision, the
4 Companies may implement the requested change where the generation and energy
5 costs associated with the prior load factor can be avoided without shifting costs to
6 existing customers. The Companies require up to 18 months to implement an
7 approved reduction because the laddering strategy used to secure energy and the
8 resource commitments made to serve the forecast load may already have imposed
9 costs that cannot immediately be avoided; the implementation period allows those
10 commitments to roll off, be modified, or be reflected in subsequent procurement
11 while preserving existing-customer protection. Lowering Minimum Energy would
12 require a corresponding increase in the LTER and other energy-based charges to
13 maintain the revenue stream needed to prevent cost shifting and could result in
14 larger true-ups to actual costs. More specifically, a customer whose load
15 materializes in magnitude and timing closer to its forecasted request would be
16 penalized if lower minimums were approved because the lower billing determinants
17 would require a higher rate to provide the necessary revenue flow, and that
18 customer would pay the higher rate on actual energy usage above the reduced
19 minimum. Amazon's concept of crediting a customer for energy paid for but not
20 consumed is understandable in the abstract, but it cannot be reliably administered.
21 A day-ahead or day-of market sale may result from economic dispatch, abnormal
22 weather, changes in aggregate system consumption, renewable output, unit
23 availability, or many other actions and conditions. The Companies cannot trace a
24 particular sale to a particular customer's unused minimum quantity. Under the
25 Companies' proposal, all customers, including large customers with minimum
26 energy charges, already benefit from such sales because the credits flow through
27

the existing BTER mechanism paid by all customers, including large customers with minimum energy charges. Assigning the same value again to one LLESA customer would risk double crediting.

FIGURE WELLS-REBUTTAL-4

Intervening Party	Position on Minimum Energy
Staff	Questions the current BTER/BTGR billing determinants and recommends resolving them in another proceeding.
BCP	Proposes Minimum Energy equal to Minimum Demand multiplied by billing-period hours and an 80% load factor under HEUT.
Amazon	Generally supports a minimum-energy obligation but requests a credit for energy paid for and not consumed.
Google	Opposes the proposed 80% load factor and favors a more flexible tariffed structure.
Fleet	Would establish any minimum-energy requirement through a tariff and cost-of-service record.
Prologis	Requests commercially reasonable minimums and clearer component-level billing treatment.
Microsoft / PowerHouse Reno	Prefers Microsoft's tariff framework rather than the proposed LLESA minimum-energy design.
Other interveners	No discrete replacement formula identified.

25. Q. WHAT ARE THE PARTIES' POSITIONS ON THE CUSTOMER-SPECIFIC GENERATION CHARGE?

A. The CSGC is a demand-based contribution designed to collect CIAC that offsets the Companies investment in certain assets, and prevent upward pressure on rates. The CSGC will be reconciled in each general rate case ("GRC"). The Companies continue to support the proposed methodology. Staff and BCP seek additional accounting and reconciliation detail; Amazon supports the methodology with GRC updates; other parties prefer tariff, asset-specific, or post-in-service recovery. None demonstrates that the original proposal should be replaced. The CSGC is one element of an integrated structure that also includes Minimum Demand, otherwise-applicable rates, the LTER, security, and termination protection. If Minimum Demand is reduced, the CSGC must increase to offset the Companies' investment based on lower billing determinants. Maintaining the proposed minimum produces

a steadier revenue stream and smaller true-ups as forecasts become actual results. Please see the rebuttal testimony of Samantha Prest for further discussion of the CSGC, its calculation, and the transparent implementation that will be presented in each GRC for review and approval.

FIGURE WELLS-REBUTTAL-5

Intervening Party	Position on the CSGC
Staff	Seeks further review of allocation, accounting, inputs, reconciliation, and possible cost shifting.
BCP	If an LLESA is approved, requests binding accounting, collection, mapping, and true-up requirements.
Amazon	Supports the methodology and recommends recalculation in each GRC using updated costs and loads.
Microsoft/PowerHouse Reno	Prefers asset-based but-for attribution and payment under Microsoft's tariff framework.
Fleet	Opposes demand-proportional, upfront nonrefundable CIAC; favors approved tariff recovery after assets are in service.
Prologis	Objects to upfront CIAC as interest-free financing and requests transparent, nonduplicative cost mapping.
Google	Seek transparent, cost-causative pricing or use of an alternative tariff framework.
WPA	Proposes direct developer funding rather than the Companies' rate-base methodology.
Other interveners	No discrete replacement CSGC formula identified.

26. Q. WHAT ARE THE PARTIES' POSITIONS ON THE LONG-TERM ENERGY RATE?

A. The LTER recovers the incremental long-term energy-supply costs assigned to the LLESA customer group, net of the group's BTER and DEAA contribution. As clarified in discovery, it will be updated quarterly through BTER filings using actual applicable invoices and will have a separate deferred account for group-specific over- or under-collections and carrying charges. The Companies continue to support the proposed methodology with those clarifications. Minimum Energy and the LTER rate are interdependent: lowering the minimum billing quantity requires a higher per-MWh LTER to produce the revenue needed to protect existing customers. The proposed minimum provides greater predictability and reduces

quarterly true-up volatility. The quarterly actual-cost process also addresses concerns about PPA output, replacement energy, gas transportation, and forecast variance. Please see the rebuttal testimony of Misha Pascal for further discussion of the LTER, its calculation, and the transparent implementation that will be presented in each quarterly filing.

FIGURE WELLS-REBUTTAL-6

Intervening Party	Position on the LTER
Staff	Seeks resolution of fixed-versus-variable treatment, quarterly updates, accounting, BTER contribution, PPA costs, gas transportation, reconciliation, and double-recovery concerns.
BCP	If approved, requests binding accounting, collection, and true-up provisions.
Amazon	Supports the methodology with periodic actual-cost updates and Commission review.
Microsoft/ PowerHouse Reno	Prefers its tariff and raises potential duplicative recovery with embedded energy charges.
Fleet	Would recover demonstrated incremental energy premiums through a Commission-approved tariff.
Google	Objects to opaque pricing and unlimited market-price risk; supports a transparent tariffed framework.
Prologis	Request commercially reasonable, quantified treatment and clearer interaction among rate components.
WPA	Prefers a developer-funded resource pathway rather than exclusive LTER treatment.
Other interveners	No discrete replacement LTER formula identified.

27. Q. WHAT ARE THE PARTIES' POSITIONS ON THE \$2 PER MWH ADMINISTRATIVE CHARGE?

A. The Companies propose a \$2/MWh administrative charge for the incremental work required to procure, schedule, settle, account for, reconcile, and administer the specialized energy service and customer-specific obligations under the LTESA. Fleet objects that the record does not quantify incremental administrative costs; Staff requests tracking and accounting; no other intervenor offers a specific replacement amount. The Companies continue to support \$2/MWh. Revenues from the charge will be separately and transparently shown in each GRC for Staff, BCP, intervenor, and Commission review, permitting comparison with the costs and

activities associated with administering the LLESA portfolio and adjustment if the record warrants. That transparent review eliminates any basis to assume the charge will escape regulatory scrutiny.

FIGURE WELLS-REBUTTAL-7

Intervening Party	Position on the Administrative Charge
Staff	Requests tracking and accounting of administrative-fee revenues.
Fleet	Opposes approval on the current record unless tied to demonstrated incremental administration costs and sized accordingly.
Amazon, BCP, Google, Microsoft, PowerHouse Reno, Prologis, WPA, IEA, WRA, and AEU/SWEEP	No discrete recommendation on the \$2/MWh amount identified.

28. Q. WHAT ARE THE PARTIES' POSITIONS ON CUSTOMER SECURITY?
- A. The Form LLESA requires security sufficient to support the customer's remaining payment exposure, subject to stated creditworthiness standards and acceptable instruments. The intent of the security provision is to secure payment and performance of all customer obligations under the LLESA, and it therefore intentionally differs from the narrower Termination Payment calculation, which addresses the consequences of early termination. The Companies continue to support the original proposal because the security must be available before resource commitments expose existing customers and must remain aligned with the obligation it secures. Interveners propose caps, shorter look-forward periods, declining balances, or exposure-based alternatives. Those concepts do not justify a general reduction unless the replacement demonstrably covers the same residual exposure, including changes in rates, load, resource costs, and remaining term. Annual review and adjustment are appropriate administration of the existing construct, not a reason to weaken it.

FIGURE WELLS-REBUTTAL-8

Intervening Party	Position on Security
Staff	Recommends resolving security through an investigatory docket.
BCP	Seeks stronger protection, posting before commitments, and release tied to remaining or residual exposure.
Amazon	Would cap security at the Termination Payment, adjust at least annually, and cap rate-driven increases at 150% of the initial estimate.
Fleet	Would size security to net residual exposure; offers 50% of termination-payment NPV or an interim \$1.5 million/MW concept.
Prologis	Proposes ten years of minimum bills at 80% demand, declining over time and reflecting creditworthiness.
Google	Favors collateral tied more closely to actual utility investment, default risk, and mitigation.
Microsoft/PowerHouse Reno	Would use the collateral framework in its proposed tariff.
WPA	Would size developer security to completion, removal, and site-restoration exposure.
WRA / AEU-SWEEP / other parties	Favor uniform protection or tariff treatment; no specific replacement formula identified.

29. Q. WHAT ARE THE PARTIES' POSITIONS ON TERMINATION PAYMENT AND MITIGATION?

A. The Form LLESA requires a terminating customer to pay the remaining minimum-bill exposure, net of specified tariff contributions, and requires the Companies to use commercially reasonable efforts for 36 months to mitigate through qualifying replacement bundled load, with refunds as provided by the agreement. The Companies updated the mitigation provisions from the first draft LLESA based on customer feedback to continue seeking a qualifying replacement customer even after the Termination Payment is paid at the end of the three-year mitigation period and also invited the terminating customer to participate in identifying a replacement customer. The Companies continue to support this structure. The termination obligation is not a penalty; it substitutes for the revenue commitment on which resource planning and procurement relied. Interveners generally seek actual-cost limitations, broader credits, longer mitigation, or tariff-based exit rules. Those proposals do not establish that existing customers would remain protected throughout the life of the obligations undertaken for the terminating customer.

Mitigation must avoid double recovery, but it must also be traceable, attributable, and supported by a replacement commitment containing equivalent protections. Staff suggests that a termination charge also be developed for the Short-Term Period. The Companies disagree. In addition to the difficulty of determining an appropriate termination amount before the long-term resource portfolio and associated obligations are final, the Short-Term Period is not indefinite. In this case, all resources are anticipated to be in service by 2032, when the Long-Term Period would begin. Because the Form LLESA requires three years' advance notice of termination, the first potential notice could be submitted in 2029. Customers therefore would be in the Short-Term Period during 2027 and 2028 before the first potential opportunity to submit a termination request. The limited duration, combined with the uncertainty regarding the costs and obligations that would be avoidable during that period, does not support creating a separate Short-Term Period termination charge.⁹

FIGURE WELLS-REBUTTAL-9

Intervening Party	Position on Termination and Mitigation
Staff	Regards exit treatment as unresolved, including termination during the ramp or short-term period.
BCP	Would preserve complete payment responsibility across every exit pathway and require a residual-cost test.
Amazon	Supports the formula with broader mitigation, credits for net revenues and avoided costs, and refunds through the remaining original term.
Fleet	Would limit payment to demonstrated stranded or underutilized cost net of mitigation and permit transition without punitive charges.
Prologis	Would limit liability to actual prudently incurred stranded costs net of mitigation.
Google	Favors clear, cost-causative cancellation charges tied to actual exposure and an enforceable mitigation duty.
Microsoft/PowerHouse Reno	Would use its tariff exit provisions and questions alignment with asset-life costs.
WRA	Supports refund protection and a minimum contract term while questioning discretion.
WPA / AEU-SWEEP / other parties	Prefer alternative or tariff-standardized exit provisions; no complete replacement formula identified.

⁹ Prepared Direct Testimony of Karen Olesky Q&A 28 and 29. See responses to Staff Data Requests 155 and 156.

30. Q. WHAT ARE THE PARTIES' POSITIONS ON THE LLESA TERM?

A. The Form LLESA establishes a minimum ten-year term, while the executed agreements generally use terms of approximately 25 years aligned with the associated long-term resource obligations. The Companies continue to support that approach. The appropriate term must correspond to the duration of the generation, energy, and related incremental commitments required to meet the retail load needs including the large load customers. A shorter term is not inherently objectionable, but it would require accelerated recovery or payment for remaining costs so that expiration does not shift a PPA tail, undepreciated investment, or other residual obligation to existing customers. Intervener proposals for 15- or 20-year terms therefore cannot be evaluated independently of minimum billing, security, termination, and residual-cost protection. No party's proposal warrants changing the Form LLESA's minimum term or eliminating Commission review of each final agreement.

FIGURE WELLS-REBUTTAL-10

Intervening Party	Position on Contract Term
BCP	Requires a residual-cost test at expiration and alignment of security release with <u>remaining exposure</u> .
Amazon	Recommends a 20-year term.
Prologis	Supports a commercially reasonable term and cites a 20-year benchmark.
WRA	Supports a 15-year minimum term with associated customer protections.
Fleet	Would establish duration and transition rules in a standardized tariff tied to <u>actual exposure</u> .
Staff / Microsoft / Google / PowerHouse Reno / WPA / IEA / AEU-SWEEP	No discrete replacement term identified, or the party would address duration through its preferred alternative framework.

31. Q. HOW DO THE COMPANIES RESPOND TO THE TARIFF STRUCTURES PROPOSED BY MICROSOFT AND BCP?

A. Microsoft and BCP each propose a tariff structure intended to address large-load service and protect existing customers. The Companies do not recommend adopting either proposed tariff in place of the Form LLESA in this proceeding. The Form

LLESA provides the immediate, integrated framework needed to obtain customer commitments, support load forecasting and resource planning, recover incremental costs, and protect existing customers from non-materialization and termination risks. The Companies have already executed provisional LLESA's for nine projects and filed for approval of these LLESA's with the Commission to start providing electric service under those agreements as soon as 2027. If, however, the Commission directs the Companies to submit an Advice Letter proposing a large-load tariff, the Companies can consider the characteristics proposed in Microsoft's and BCP's tariff structures, together with the positions of other parties and the record developed in this proceeding. In that event, the Companies recommend using the Commission-approved Form LLESA as the starting point for the proposed tariff so that its core customer-commitment, minimum-billing, cost-recovery, security, termination, mitigation, and Commission-oversight protections are preserved while specific tariff provisions are evaluated through the Advice Letter process.

32. Q. CAN THE COMMISSION RELY ON THE TABLE IN MICROSOFT'S TESTIMONY COMPARING MICROSOFT'S PROPOSED TARIFF WITH THE FORM LLESA?

A. No. Mr. Garrett's comparison cannot be relied upon because his characterization of the Form LLESA reflects many of the same misunderstandings addressed throughout this rebuttal testimony. Among other things, the comparison does not accurately account for how the Form LLESA operates together with the otherwise-applicable tariff and Rule 9 arrangements; how customer commitments support load forecasting and resource planning; how Minimum Demand, Minimum Energy, the CSGC, and the LTER work together to recover incremental costs while recognizing amounts collected through embedded rates; or how the security, termination, and mitigation provisions protect existing customers from load non-

materialization and early-termination risks. For example, regarding the claim that the specific calculation method is unclear for the CSGC, please see the testimony of Samantha Prest for a summary of the documentation provided through the White Paper and discovery responses addressing the CSGC. A comparison based on those misunderstandings does not provide a reliable basis for determining that Microsoft's proposed tariff offers protections equivalent or superior to the integrated protections in the Form LLESA. The Commission should instead evaluate the two proposals based on the complete explanations and clarifications provided in the Companies' rebuttal testimony.

SECTION IV. APPLICABILITY OF THE FORM LLESA

33. Q. AFTER REVIEWING THE INTERVENERS' POSITIONS, DO THE COMPANIES RECOMMEND CHANGES TO THE PROPOSED APPLICABILITY OF THE FORM LLESA?

A. No. The Companies continue to support the proposed applicability standard outlined in the direct case. As explained in my direct testimony, the Form LLESA is intended for bundled customers taking service under Schedule LGS-3 or GS-3 whose requested load is at least 25 MW and whose load ramp timing, volatility, or acceleration may require incremental generation, energy supply, or related transmission commitments beyond those needed for existing customers. As explained in the Direct Testimony of Mr. Elicegui, the purpose is to establish sufficient customer commitment before the Companies add the requested ramp to the load forecast used as an input to the IRP and procure the resources needed to serve it. Requiring all customers that meet this threshold to execute an LLESA will improve the process by allowing the Companies to move to a proactive, uniform process in which all customers meeting the applicability criteria may be asked to confirm their commitments and requested ramps on comparable terms. The

confirmed ramps can then be incorporated into the load forecast and evaluated through the IRP.

34. Q. HOW DO THE COMPANIES RESPOND TO STAFF’S ASSERTION THAT THE COMPANIES “PICKED WINNERS AND LOSERS”?

A. The Companies disagree with Staff’s characterization of the process. The Companies do not understand the terms “winner” and “loser” to describe a defined planning, tariff, contractual, or service outcome. After the Commission approved the 2024 IRP in December 2024, the Companies began addressing an accelerating volume of large-load requests that exceeded the assumptions and timing available through the ordinary three-year IRP cycle. The Companies evaluated expected ramps, available and prospective resources, and the commitments needed to avoid shifting risk to existing customers. In April 2025, the Companies presented framework agreements to customers for whom firm commitments were needed for their full requested ramps; those letters included protections later reflected in the Form LLESA. The first draft Form LLESA became available on November 7, 2025, was revised following customer feedback and minimum-bill discussions, was largely finalized by March 11, 2026, and received a final update on April 23, 2026. The Companies engaged customers identified as meeting the applicability criteria. Those steps were taken in response to an unprecedented and evolving planning need, not to confer a preference or disadvantage. The agreement framework is being publicly vetted in this proceeding.

35. Q. HOW DO THE COMPANIES RESPOND TO CRITICISMS OF THE
PROCESS THAT BEGAN WITH THE LETTER OF INTENT AND
CONTINUED THROUGH DEVELOPMENT OF THE FORM LLESA?

A. The process was designed to respond to a step-change in the volume and pace of large-load requests while giving customers an opportunity to comment. Given the volume, magnitude, and acceleration of large-load requests after the 2024 IRP load forecast inputs were finalized, it was necessary first to use a letter of intent to request customer commitments and then to develop a more complete Form LLESA containing the financial, forecasting, and resource-planning protections needed before the Companies could undertake the material financial commitments to serve the requested loads.

The Companies acknowledge criticisms that not all customer redlines, comments, and suggested edits were incorporated. Although the Companies did not accept every proposed revision, they made material updates to the first draft circulated in November 2025 in response to customer feedback. Most importantly, the revised form expressly incorporates requests for a customer-provided monthly Ramp Schedule and Ramp Demand. Those monthly values support calculation of the demand and energy minimums while giving each customer the greatest practical control over its own forecasted ramp and, therefore, its minimum bills. The customer controls its anticipated deployment schedule—an input the Companies cannot control—while the resulting contractual commitment provides the strongest protection reasonably available to existing customers against the cost of resources planned for load that does not materialize as forecast. The Companies also added procedures through which customers may request changes to Maximum Demand and reductions in the load factor used to determine Minimum Energy. Those

procedures respond to customer concerns regarding the difficulty of forecasting anticipated load needs, while preserving notice, review, system-capability, investment moderation, cost-recovery, and resource-planning considerations so the Companies can make efficient use of a resource portfolio that accommodates LLESA generation-capacity and energy needs. This flexibility also demonstrates the benefit of planning for a full bundled retail load forecast that includes a portfolio of committed large loads with a systemwide portfolio of resources. Pooling loads and resources permits the Companies to evaluate changes across customers, available system capability, timing, and resource commitments, rather than linking each customer to an asset-specific resource in the manner contemplated by Microsoft's proposed tariff. These are just some examples of changes that were made in response to feedback over the course of developing the form LLESA.

36. Q. WHICH PARTIES CONTEND THAT THE COMPANIES SHOULD NOT BE PERMITTED TO REQUIRE AN LLESA?

A. EdgeCore argues that its existing amended HVD Agreement and GS-3T service rights preclude the Companies from conditioning service on a new LLESA. Redwood argues against a blanket LLESA requirement and asks the Commission to evaluate existing agreements and additional requests customer-by-customer. Novva advances project-specific arguments that its Novva Reno project should remain under its existing HVD and GS-3T arrangements. Fleet, Google, Microsoft, PowerHouse Reno, AEU/SWEEP, WPA, and IEA generally prefer a Commission-approved tariff or alternative standardized framework over LLESA's, while Staff agrees that LGS-3 and GS-3 permit the Companies to require a service agreement but recommends that the tariffs be amended if an LLESA requirement is adopted. These varying positions underscore the need for the Commission to adopt a uniform process, including an approved standard Form LLESA.

1 37. Q. DO THE EXISTING LGS-3 AND GS-3 SCHEDULES AUTHORIZE THE
2 COMPANIES TO REQUIRE A SERVICE AGREEMENT – IN THIS CASE,
3 AN LLESA – AS A CONDITION OF RECEIVING BUNDLED ELECTRIC
4 SERVICE?

5 A. Yes. The Companies’ existing LGS-3 and GS-3 schedules provide the authority,
6 without an amendment, to require a contract for service – an “electric” service
7 agreement – as a condition of receiving electric service. Schedule No. GS-3, Special
8 Condition 10, expressly permits Sierra to require a contract for service, and
9 Schedule LGS-3 likewise expressly permits Nevada Power to require a contract for
10 service. Those schedules govern bundled retail service; Rule 9 agreements – or line
11 extension agreements – govern the design, construction, and cost allocation of
12 transmission and distribution facilities for master planned community developers,
13 and distribution-only and bundled service customers and do not obligate the
14 Companies to procure generation capacity and energy for a projected load. The
15 LLESA supplies the generation- and energy-related commitments that the
16 underlying tariffs allow the Companies to require. The Companies therefore
17 disagree that tariff amendments are a prerequisite to requiring a contract for service
18 such as the LLESA. Shawn EliceGUI’s rebuttal testimony further describes the
19 Companies’ tariff authority, the distinction between Rule 9 facilities obligations
20 and generation supply, and why a contract for service such as the LLESA is
21 necessary.

1 **38. Q. HOW DO THE COMPANIES RESPOND TO EDGECORE’S POSITION**
2 **THAT LOAD ASSOCIATED WITH MECP 1 RENO 1, LLC MOUNT**
3 **ELBERT RENO (“MT. ELBERT”) SHOULD NOT BE SUBJECT TO AN**
4 **LLESA?**

5 A. The Companies’ primary position is that the Form LLESA applies to EdgeCore’s
6 requested load. Although EdgeCore’s load request is not new, it has been
7 withdrawn, reinstated, and accelerated over time, creating continued uncertainty
8 regarding whether and when the load will materialize. EdgeCore’s Rule 9 HVD
9 agreement addresses the design, construction, and cost allocation of transmission
10 and distribution facilities needed to interconnect the load associated with Mt.
11 Elbert; it does not address the supply of generation-capacity or energy, the
12 transmission associated with integrating the related generation-capacity and energy
13 projects into the bulk electric grid, fuel transportation contracts, and it does not
14 provide the customer commitment needed to protect existing customers if the
15 requested load does not materialize as forecast. EdgeCore’s own testimony and
16 communications reflect revisions to its ramp and continuing customer-development
17 uncertainty, including the need to refine commissioning and operating-load
18 assumptions. If, however, the Commission accepts EdgeCore’s project-specific
19 exemption request, the Companies would request a service agreement that contains,
20 at a minimum, the minimum demand and minimum energy billing requirements be
21 required, as permitted through Special Condition 10 in the GS-3 tariff, to provide
22 some protection to existing customers from continued shifts in costs for loads that
23 have not yet materialized. If the Commission approves load mitigation at 80 percent
24 of EdgeCore’s requested ramp based on Staff’s support, the Companies request that
25 approval of a service agreement includes implementation, at a minimum, of the
26 minimum billing provisions of the LLESA into the service agreement.

1 **39. Q. HOW DO THE COMPANIES RESPOND TO NOVVA’S POSITION THAT**
2 **THE FORM LLESA SHOULD NOT APPLY TO THE NOVVA HOLDINGS,**
3 **LLC PROJECT ASTRO (“ASTRO”) IN SIERRA’S SERVICE**
4 **TERRITORY?**

5 A. The Companies disagree. The Form LLESA applies to Novva’s requested load for
6 Astro because of the characteristics of that request, including its accelerated load-
7 ramp schedule. The line extension agreement associated with Astro does not
8 provide the customer commitments, minimum-billing, cost-recovery, security, and
9 termination protections necessary to address those incremental resource obligations
10 and protect existing customers if the requested load does not materialize as
11 represented. The Companies therefore recommend that the load associated with
12 Astro, be subject to the Commission-approved Form LLESA. If, however, the
13 Commission accepts Novva’s project-specific exemption request for Astro, the
14 Companies would request a service agreement that contains, at a minimum, the
15 minimum demand and minimum energy billing requirements be required, as
16 permitted through Special Condition 10 in the GS-3 tariff, to provide some
17 protection to existing customers from continued shifts in costs for loads that have
18 not yet materialized.

19
20 **40. Q. HOW DO THE COMPANIES RESPOND TO REDWOOD MATERIALS’**
21 **POSITION REGARDING APPLICATION OF THE LLESA AND**
22 **TREATMENT OF ITS LOAD?**

23 A. Redwood Phase 1 is not subject to the proposed Form LLESA because its load is
24 neither new nor accelerated, and the Companies do not recommend changing that
25 treatment. The Companies continue to support the mitigation proposed for
26 Redwood’s load because mitigation reflects the level reasonably expected to
27 materialize for resource-planning purposes while avoiding an unsupported full-

1 ramp assumption. As of August 2026, Redwood's existing load, non-coincident
2 peak was [REDACTED] far lower than the [REDACTED] requested load. If the
3 Commission accepts Redwood's position and Staff's support for a different
4 mitigation amount, the Companies would request a service agreement be required,
5 as permitted through Special Condition 10 in the GS-3 tariff, to provide some
6 protection to existing customers from continued shifts in costs for loads that have
7 not yet materialized. If the Commission approves load mitigation at 80 percent of
8 Redwood's requested ramp based on Staff's support, the Companies request
9 approval of a service agreement that implements, at a minimum, the minimum
10 billing provisions of the LLESA into the service agreement. That treatment would
11 link the forecasted amount to a customer commitment and protect existing
12 customers to a limited extent if the requested load does not develop as represented.
13 It would not predetermine treatment of Redwood Phase 2, its additional requested
14 capacity, or future projects, which should be evaluated under the approved
15 applicability standard and the facts presented when service is requested.

16
17 **41. Q. HOW DO THE COMPANIES RESPOND TO POWERHOUSE RENO'S**
18 **POSITION REGARDING APPLICATION OF AN LLESA TO ITS**
19 **REQUESTED LOAD?**

20 A. PowerHouse Reno asks the Commission to include its originally requested ramp in
21 the load forecast without requiring execution of an LLESA, contending that it has
22 demonstrated commitment through project investment and that the proposed
23 agreement should not determine queue position or forecast inclusion before
24 Commission approval. The Companies continue to support requiring a customer
25 commitment through the approved Form LLESA for PowerHouse Reno's
26 applicable load. PowerHouse Reno does not have an executed Rule 9 HVD
27 agreement. A corresponding commitment under PowerHouse Reno's Rule 9

arrangement is, therefore, also needed for the transmission and distribution facilities required to interconnect its project. The issue is not whether PowerHouse Reno intends to develop its project; it is whether the Companies and existing customers have sufficient assurance regarding the timing and magnitude of the requested ramp before the Companies incorporate that load into the forecast and undertake generation-capacity and energy-supply obligations necessary to serve it. Project expenditures and transmission or distribution studies, without the required Rule 9 and LLESA commitments, do not establish the facilities, minimum billing, security, cost-recovery, ramp, and termination commitments needed to protect existing customers if the requested load materializes later, at a lower level, or not at all. An approved LLESA would allow PowerHouse Reno to state the monthly ramp it expects to achieve and would allow the Companies to plan the generation-capacity and energy resources and the related transmission integration and fuel transportation resources attributable to that committed request, combined with others, on the same basis applied to other customers whose loads meet the applicability criteria, while the Rule 9 commitment would support the facilities required to interconnect the project. Accordingly, the Companies recommend that PowerHouse Reno's AREP SOF III TRIC, LLC, Project PowerHouse, be required to sign a contract for service – in this case, the LLESA.

42. Q. PLEASE SUMMARIZE THE COMPANIES' REQUEST FOR COMMISSION APPROVAL REGARDING APPLICABILITY OF THE FORM LLESA AND THE LOADS TO BE REFLECTED IN THE RESOURCE-PLANNING FORECASTS.

A. The Companies request that the Commission approve the applicability provisions of the Form LLESA and confirm that customers meeting those provisions must provide the commitments required by the approved form before their applicable

requested load ramps are included without mitigation for generation-capacity and energy planning.¹⁰ A clear applicability determination is necessary so the Companies can build upon the Base Minus Load Forecast and update the Base Load Forecast on a consistent basis, create expansion plans for each and compare those plans to identify the incremental resource needs attributable to confirmed large-load requests. For EdgeCore, the Companies' primary request is that the Commission find the Form LLESA applicable to its requested load. If the Commission instead adopts EdgeCore's position and Staff's general support for project-specific treatment, the Companies request approval for a service agreement that contains, at a minimum, the minimum billing provisions of the Form LLESA. For Redwood, the Companies request confirmation that Redwood Phase 1 is not subject to the Form LLESA and approval of the Companies' proposed mitigation; if the Commission adopts a different mitigation amount consistent with Redwood's position and Staff's support, the Companies request approval for a service agreement that contains, at a minimum, the minimum billing provisions of the Form LLESA. PowerHouse Reno is included only in the study-phase population in this case and has not executed a Rule 9 agreement. Its load, therefore, should not be treated as a committed load in the current Base Load Forecast and will need to be evaluated and updated in a future load forecast after the required Rule 9 and, if applicable, LLESA commitments are executed. These determinations will allow the Base Minus and Base cases in a future IRP filing to reflect the appropriate load and provide the comparison that is critical to identifying incremental resources, including those attributable to large customers.

¹⁰ If an applicable large load customer does not sign a Commission approved Form LLESA, neither mitigated or unmitigated load will be added to the Companies' load forecast.

1 **43. Q. WHAT OPTIONS ARE AVAILABLE TO THE COMMISSION TO**
2 **IMPLEMENT ITS APPLICABILITY DETERMINATIONS AND**
3 **IDENTIFY THE RESOURCES NEEDED TO SERVE THE APPROVED**
4 **LARGE-LOAD FORECAST?**

5 A. The Commission's options reflect its broad authority and include the ability to
6 approve the Companies' recommended applicability treatment, adopt one or more
7 of the project-specific alternatives described above, or specify another combination
8 of load commitments and mitigation. The Companies recommend a two-step
9 implementation process and are open to modifications from the Commission. First,
10 after a standard Form LLESA is approved, the Commission should direct a defined
11 confirmation period during which each customer with an executed LLESA
12 confirms that it wishes to proceed under the approved provisions and reaffirms or
13 updates its requested monthly load ramp if there is a desire to contract the monthly
14 ramp. This first step should also incorporate every Commission determination that
15 changes which loads, ramps, mitigation levels, or financial commitments are
16 included in the Base Minus Load Forecast or the Base Load Forecast, including the
17 specific treatment ordered for EdgeCore, Novva, and Redwood. Second, after those
18 confirmations and forecast adjustments are complete, the Companies would
19 compare the revised Base Minus and Base Load Forecasts, identify changes in the
20 incremental resource allocation, and confirm whether the resulting load needs
21 support all resources in the Preferred Plan. If the confirmed load creates generation-
22 capacity or energy needs beyond the Preferred Plan, those needs should be
23 addressed in a future IRP amendment. The Companies request authority to file an
24 amendment addressing those incremental generation-capacity and energy needs
25 without reopening or refiling the full 2026 Joint IRP or requiring filing a new Joint
26 IRP. If the available Preferred Plan resources are insufficient to serve the resulting

Base Load Forecast until additional resources can be approved, the Companies request that the Commission determine how available capacity should be allocated among the large customers incorporated into the Base Minus and Base Load Forecasts.

SECTION V. THE COMPANIES' OVERALL RESPONSE AND REQUEST FOR COMMISSION APPROVAL

44. Q. WHAT IS THE COMPANIES' OVERALL RESPONSE TO THE PARTIES' POSITIONS, AND WHAT SPECIFIC APPROVALS DO THE COMPANIES REQUEST FROM THE COMMISSION?

A. The Companies have considered the full record, including intervenor testimony, customer feedback, reserved positions, and extensive discovery. The parties generally agree that large loads should bear the incremental costs and risks they cause so that existing customers are protected, but they propose different mechanisms and modifications. No intervenor position demonstrates that the Companies should withdraw the Form LLESA or materially depart from its integrated protections. The Companies therefore continue to request approval of the Form LLESA, with the clarifications and implementation steps described in this rebuttal testimony. Specifically, the Companies respectfully request that the Commission:

1. **Approve the Form LLESA as the Commission-approved standard contract for service.** Approve the common form, including the Commission's resolution of the Customer-Reserved Positions identified in Exhibit G, and direct that applicable executed agreements be conformed to the approved provisions while preserving only appropriate customer-specific load, project, service, and security information, and the ability to modify the LLESA to incorporate sleeved resources.
2. **Confirm the Companies' authority under LGS-3 and GS-3.** Determine that the existing tariffs authorize the Companies, without tariff amendment, to

require an additional service agreement addressing generation-capacity, energy-supply, cost-recovery, and financial commitments, separate from Rule 9 facilities obligations.

3. **Approve the proposed applicability standard.** Confirm that the Form LLESA applies to bundled LGS-3 and GS-3 customers whose requested loads meet the proposed criteria and may require incremental generation, energy, or related commitments, and that applicable load ramps should not be included without mitigation unless supported by the required customer commitment.
4. **Approve the Companies' requested project-specific treatment.** Find the Form LLESA applicable to EdgeCore's requested load; alternatively, approve a service agreement with minimum billing charges from the Form LLESA. Find the Form LLESA applicable to Novva's Astro project requested load; alternatively, approve a service agreement with minimum billing charges from the Form LLESA. Confirm that Redwood Phase 1 is not subject to the Form LLESA and approve the Companies' proposed mitigation; alternatively, approve a service agreement with minimum billing charges from the Form LLESA. Recognize that PowerHouse Reno remains in the study-phase population and should be updated in a future load forecast after execution of the required Rule 9 and, if applicable, LLESA commitments.
5. **Approve the proposed Minimum Demand and Minimum Energy provisions.** Approve the 90 percent Minimum Demand and the 80 percent load factor applied to Minimum Demand, together with the customer-provided monthly Ramp Schedule and the established procedures for requesting changes to Ramp Demand, Maximum Demand, and load factor where associated costs can be avoided without shifting costs to existing customers.
6. **Approve the CSGC and its GRC reconciliation.** Approve the proposed demand-based CSGC methodology, including advance recovery for incremental generation and related interconnection-transmission revenue requirements and transparent recalculation and reconciliation in each applicable GRC.
7. **Approve the LTER with the clarified quarterly process.** Approve recovery of incremental long-term energy-supply costs assigned to the LLESA customer group, net of applicable BTER and DEAA contributions, with quarterly updates through BTER filings using actual applicable invoices and a separate deferred account for group-specific over- or under-collections and carrying charges.
8. **Approve the \$2/MWh administrative charge.** Authorize the proposed charge and require the associated revenues to be separately and transparently shown in each GRC for review against the incremental activities and costs of administering the LLESA portfolio.

9. **Approve the proposed security requirements.** Confirm that security is intended to secure payment and performance of all obligations under the LLESA, is distinct from the narrower Termination Payment calculation, and may be reviewed and adjusted to remain aligned with the exposure secured.
10. **Approve the termination and mitigation provisions.** Approve the remaining minimum-bill exposure calculation, the three-year mitigation process, continued efforts to identify qualifying replacement load after payment, and customer participation in identifying replacement load; decline to require a separate Short-Term Period termination charge on the current record.
11. **Approve the proposed contract-term framework.** Approve the ten-year minimum term and permit final agreement terms aligned with the duration of the generation, energy, and related obligations undertaken for each applicable customer, subject to Commission review.
12. **Direct customer confirmation following approval.** Establish a defined period for each customer with an executed LLESA to confirm that it will proceed under the approved provisions and to reaffirm or update its monthly requested load ramp and related customer-specific values. Establish process for providing applicable customers who did not execute an LLESA to commit to the approved Form LLESA and when to address the requested load ramps.
13. **Authorize the forecast and resource-planning updates.** Direct the Companies to incorporate the Commission's applicability, mitigation, ramp, and commitment determinations into the Base Minus Load Forecast and Base Load Forecast; compare the revised forecasts; identify changes in incremental resource allocation; and confirm whether the resulting load needs support all resources in the Preferred Plan.
14. **Authorize an IRP amendment for needs beyond the Preferred Plan.** Permit the Companies to file an amendment addressing incremental generation-capacity and energy needs beyond the Preferred Plan without reopening or refiling the full 2026 Joint IRP or requiring a new Joint IRP.
15. **Provide an interim load allocation method if required.** If approved Preferred Plan resources cannot support all confirmed ramps before additional resources are approved, determine the allocation among customers included in the Base Minus and Base Load Forecasts.
16. **Direct an Advice Letter filing if a tariff is desired.** If the Commission directs development of a tariff, authorize the Companies to begin with the approved Form LLESA and file an Advice Letter providing a public forum for focused stakeholder feedback and a defined path to an approved tariff, rather than first opening an investigatory docket that would ultimately require a subsequent advice letter filing.

These approvals will establish a uniform, transparent, and administrable framework for confirming large load requests, incorporating the appropriate committed load into the Companies' forecasts, identifying and obtaining approval of the resources needed to serve that load, and ensuring that the resulting incremental costs and non-performance risks are not shifted to existing customers.

SECTION VI. DEMAND SIDE MANAGEMENT PLAN AND DISTRIBUTED RESOURCES PLAN

45. Q. WHAT TESTIMONY SUPPORTS THE COMPANIES' POSITIONS REGARDING THE DEMAND SIDE MANAGEMENT PLAN AND DISTRIBUTED RESOURCES PLAN PORTIONS OF PHASE II?

A. The Companies' positions regarding the Demand Side Management Plan and Distributed Resources Plan portions of Phase II are supported by the prepared rebuttal testimony of Chris Belcher, Michael Brown, Adam Grant, Patricia Rodriguez, Chris Sarda, and Joseph Sinobio. That testimony responds to intervenor recommendations, explains the Companies' analyses and proposals, and provides the evidentiary support for the relief requested in those portions of Phase II. My testimony below addresses selected issues relevant to the Companies' overall resource-planning position; it should be read together with the more detailed testimony of the Companies' witnesses sponsoring the DSM and DRP rebuttal cases.

1 **46. Q. DID THE COMPANIES MODEL DEMAND RESPONSE SAVINGS “AS A**
2 **SUPPLY-SIDE RESOURCE, EVALUATED ON EQUAL FOOTING**
3 **AGAINST GAS GENERATION OPTIONS” IN THE 2024 IRP AS STATED**
4 **BY AEU-SWEEP WITNESS COURTNEY FIELDMAN IN HER Q&A 13?**

5 A. No. As stated in the Economic Analysis Section of the Supply Plan narrative in the
6 2024 IRP (Docket No. 24-05041, Vol. 8 at 228-29), “Certain DSM and DRP
7 programs are included in the Base Case and in all subsequent cases... These
8 programs... are the same in all modeled cases and plans. Due to timing of the DSM
9 and DRP program development, the programs proposed in this 2024 Joint IRP
10 differ from those modeled.” As stated, the specified DSM and DRP programs were
11 included in all plans; they did not compete for selection with supply-side projects.

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13 **47. Q. SHOULD THE COMPANIES BE DIRECTED TO “MODEL DEMAND**
14 **RESPONSE AND DEMAND-SIDE MANAGEMENT OPTIONS AS**
15 **DISPATCHABLE SUPPLY-SIDE CAPACITY RESOURCES THAT**
16 **ACTIVELY COMPETE AGAINST SUPPLY-SIDE GENERATION**
17 **OPTIONS” AS STATED BY AEU-SWEEP WITNESS COURTNEY**
18 **FIELDMAN IN ITEM 2 IN HER Q&A 27?**

19 A. No. The Companies will continue to assess the appropriate method of capturing
20 demand response and demand side management options, as they evolve, in each
21 IRP filing, factoring in the nature and characteristics of these demand side programs
22 and the appropriate modeling tools for each.

1 **48. Q. SHOULD THE COMPANIES BE DIRECTED TO USE AN AVOIDED**
2 **GENERATION CAPACITY COST BASED ON PROCURED BESS**
3 **PROJECTS RATHER THAN WOOD MACKENZIE’S FORECAST**
4 **CAPACITY PRICE, AS STATED BY MR. KEVIN LUCAS IN HIS Q&A 8**
5 **AND MR. TURNER IN HIS Q&A 66?**

6 A. No. As the Grid Service Tariff Riders (GSR) are broken down into two components,
7 energy (GSR-E) and capacity (GSR-C), a strictly capacity-only price is needed for
8 the GSR-C component. The method proposed by witnesses Lucas and Turner does
9 not isolate a capacity-only price. The Net Cost of New Entry is an industry standard
10 construct for a long-run avoided capacity-only price. As in prior filings, Wood
11 Mackenzie is the source of this forecast capacity price in the 2026 Joint IRP.

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13 **49. Q. IF THE COMPANIES WERE ORDERED, DESPITE THE STATEMENT IN**
14 **MY PRIOR Q&A, TO USE AN AVOIDED GENERATION CAPACITY**
15 **COST BASED ON PROCURED BESS PROJECTS, SHOULD THE COST**
16 **BE ADJUSTED FOR CAPACITY ACCREDITATION USING THE**
17 **EFFECTIVE LOAD CARRYING CAPABILITY (“ELCC”) FROM THE**
18 **COMPANIES’ 2026 ELCC UPDATE FOR SOLAR AND STORAGE**
19 **(TECHNICAL APPENDIX ECON-12) AS STATED BY MR. LUCAS IN HIS**
20 **Q&As 8 AND 35?**

21 A. No. Utility-scale supply-side resources and behind-the-meter resources are
22 completely different resource types, and the performance metrics (such as ELCC)
23 that describe one should not be used as a substitute for the other. This assertion is
24 seemingly reinforced by the following statement of Mr. Turner in his Q&A 68 in
25 reference to E3’s 2026 ELCC Update for Solar and Storage: “...this rigorous
26 modeling was applied only to supply-side solar and storage resources for resource
27

adequacy planning purposes, not to the demand-side or behind-the-meter battery resources subject to the GSR-C tariff. [footnote omitted]”

SECTION VII. OTHER ITEMS

50. Q. IN Q&A 40, VOTE SOLAR WITNESS CUSTODIO STATES: “AS NOTED, I’M NOT AN ATTORNEY. AND I UNDERSTAND VOTE SOLAR’S POSITION IS THAT THE PURPA ISSUES IN THIS PROCEEDING ARE APPROPRIATELY IN PHASE THREE OF THIS PROCEEDING AND WILL BE MORE FULLY DEVELOPED BY A DIFFERENT WITNESS FOR VOTE SOLAR IN THAT PHASE.” DO YOU HAVE ANY GENERAL COMMENTS REGARDING VOTE SOLAR’S APPLICATION OF PURPA?

A. Yes. Ms. Custodio represents that Vote Solar will present a more fully developed position through a different witness in Phase III. The Companies likewise will respond more fully to Vote Solar’s position in that phase through the appropriate witness or witnesses.

SECTION VIII. CONCLUSION AND APPRECIATION FOR THE PUBLIC PROCESS

51. Q. DO THE COMPANIES HAVE ANY FINAL OBSERVATIONS REGARDING THIS PUBLIC PROCESS?

A. Yes. The Companies acknowledge and appreciate the substantial investment of time and expertise by all parties in this public process, and specifically the Commission’s careful oversight and consideration of a complex and rapidly developing set of issues. The Companies value the robust public record developed through testimony, discovery, technical analysis, customer engagement, and the presentation of differing positions. The Companies look forward to working with the Commission, Staff, BCP, customers, and all other interested parties to implement a process that exemplifies transparency, provides meaningful protection for existing customers in

1 Nevada, and supports opportunities for responsible economic development. These
2 objectives are not mutually exclusive. With Commission oversight, clear customer
3 commitments, appropriate cost-causation protections, and continued participation
4 by all parties in a robust discussion supported by a complete record, the appropriate
5 balance is achievable.
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7 **52. Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?**

8 A. Yes.
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EXHIBIT WELLS-REBUTTAL-1

PUCN, provided that all other applicable rates will be assessed at the realized Project load levels.

“Event of Default” shall have the meaning set forth in Section 10.1.

“Excess Energy” means, solely with respect to a Generating Facility or Alternative Generating Facility where Customer is obligated to pay for one hundred percent (100%) of the energy generated by such Generating Facility or Alternative Generating Facility, energy generated by such Generating Facility or such Alternative Generating Facility minus the energy served to the Project from such Generating Facility or such Alternative Generating Facility.

“Execution Date” shall have the meaning set forth in the preamble to this Agreement.

“Generating Facility” means one or more energy generating facilities from which NV Energy will procure or generate electric capacity and energy for Customer that is approved by the PUCN to serve customers pursuant to the PUCN Resource Approval.

“Governmental Authority” shall mean any federal, state, or local government or political subdivision thereof, or any agency or instrumentality of such government or political subdivision, or any self-regulated organization or other non-governmental regulatory authority or quasi-governmental authority (to the extent that the rules, regulations or orders of such organization or authority have the force of law), or any arbitrator, court or tribunal of competent jurisdiction.

“GS-3 Tariff” shall mean [~~Schedule LGS-3 (Large General Service - 3) / Schedule GS-3 (Large General Service)~~>] of the Tariff Schedules.³

“HVD Agreement” shall have the meaning set forth in the Recitals.⁴

“Interim Period” has the meaning set forth in Section 2.3(d)(i).

“Load Factor” means the application of an eighty percent (80%) factor to convert Maximum Demand to Minimum Energy for billing purposes.

“Load Factor Reduction” has the meaning set forth in Section 4.6.

“Long-Term Energy” has the meaning set forth in Section 5.2(a).

“Long-Term Energy Rate” means ~~(a) a fixed rate of \$[insert price]/MWh for the hours and loads the applicable Generating Facility or Alternative Generating Facility is in production, plus (b) all BTER and DEAA rates for hours and loads during non-production hours, as described in Section 5.2(c), as it may be adjusted pursuant to Section 5.2(b); a rate (per MW/h) payable by Customer that reflects both (a) Customer’s pro rata share of all incremental costs incurred by NV Energy associated with (i) all power purchase~~

³ **Note to Draft:** To be conformed based on the Project location (i.e., the northern or southern NV Energy service territory).

⁴ **Note to Draft:** To be conformed to the applicable HVD Agreement.

agreements or similar agreements (including each Resource Procurement Agreement or Replacement Resource Procurement Agreement) and (ii) all natural gas infrastructure and natural gas transportation-related agreements, in each case, that are approved by the PUCN and required to serve the aggregate maximum demand of all applicable customers (including the Maximum Demand of Customer in accordance with this Agreement), and (b) the then-applicable BTER and DEAA rates (which rates are payable as part of the ESA Overall Rate). Customer's pro rata share of such incremental costs shall be based on the Maximum Demand of Customer relative to the aggregate maximum demand of all applicable customers (including Customer). For the avoidance of doubt, Customer's pro rata share of such incremental costs shall not be increased as a result of any changes to the maximum demand of any other applicable customer, and NV Energy shall provide Customer with any updates to Customer's pro rata share of such incremental costs as soon as reasonably practicable after NV Energy files (a) its Integrated Resource Plan with the PUCN in calendar year 2026, (b) any Report on the progress of the Action Plan filed pursuant to the Nevada Administrative Code § 704.9498. The Long-Term Energy Rate shall be determined by NV Energy on a quarterly basis pursuant to and in accordance with this Agreement.

"Long-Term Energy Supply Commencement Date" means the date that the applicable Generating Facility or Alternative Generating Facility has achieved commercial operation, as determined by NV Energy.

"Long-Term Energy Supply Period" shall have the meaning set forth in Section 5.2(a).

"Market-Based Energy Product" has the meaning set forth in Section 5.1(b).

"Market-Based Energy Rate" means a rate calculated by NV Energy for Short-Term Energy based on Platts Megawatt Daily Day-Ahead, Mead On-Peak and Off-Peak or other similar indices. The Market-Based Energy Rate will include (a) an energy charge comprised of (i) fixed prices and volumes (which may include fixed price MW blocks consisting of a 24 hour by 7 day defined MW block applicable to all months with a minimum term of twelve (12) rolling months or such other products as the Parties may mutually agree) and (ii) market-based day-ahead Platts Megawatt Daily Mead index rates for residual volumes (i.e., the difference between the metered volume and any fixed price MW blocks applicable to the delivery period), calculated as the sum of (x) Platts Megawatt Daily Day-Ahead Mead On-Peak price multiplied by the metered volume during the On-Peak period and (y) the Platts Megawatt Daily Day-Ahead Off-Peak price multiplied by the metered volume during the Off-Peak period for such residual volumes⁵; (b) a \$2/MWh administrative fee; (c) all BTGR rates based on the GS-3 Tariff; and (d) all BTER and DEAA rates for such Short-Term Energy, to the extent such BTER and DEAA rates are not included within clause (a) above.

"Maximum Demand" shall have the meaning set forth in Section 4.44.2.

⁵ On-Peak and Off-Peak are defined per the "NAESB Inadvertent Interchange On and Off Peak Period," as applicable to the Western Interconnection. See: www.naesb.org for more information on On and Off Peak Periods.

Ramp Demand, and (ii) following the Ramp Period, the Maximum Demand (“Long-Term Energy”), and Customer shall pay to NV Energy, as part of the ESA Overall Rate, the Long-Term Energy Rate (as it may be adjusted on a quarterly basis pursuant to Section 5.2(b) and in accordance with this Agreement) with respect to the Long-Term Energy. Invoices shall be provided to Customer on a monthly basis by the method or methods authorized by the Tariff Schedules and shall be paid by Customer in accordance with the payment terms set forth therein.

(b) Long-Term Energy Rate Adjustments. Notwithstanding anything to the contrary in this Agreement, the Parties agree that the Long-Term Energy Rate shall be ~~adjusted, subject to PUCN approval on a case-by-case basis, to reflect any increase in the cost to NV Energy of the applicable Generating Facility or Alternative Generating Facility (as applicable), which increase in cost will be reflected in the Long-Term Energy Rate beginning on the date of the next monthly invoice to be provided to Customer following such increase in cost and continuing for the remainder of the Term. NV Energy shall provide Customer with written notice of any such increase in cost, and the resulting change to the Long-Term Energy Rate, within ten (10) Business Days after any such increase in cost occurs~~ determined by NV Energy and adjusted, if required, on a quarterly basis, pursuant to and in accordance with this Agreement. NV Energy shall use commercially reasonable efforts to avoid or mitigate an increase in the ~~cost of the applicable Generating Facility or Alternative Generating Facility (as applicable) and the resulting Long-Term Energy Rate~~; provided, however, that the foregoing covenant shall not restrict NV Energy from entering into any amendment, modification or supplement to any Resource Procurement Agreement or Alternative Resource Procurement Agreement (as applicable) (including with respect to the cost of ~~the~~ any applicable Generating Facility or Alternative Generating Facility (as applicable)).

~~(c) Long-Term Energy Rate Calculation. Notwithstanding anything to the contrary in this Agreement, the Parties agree that the Long-Term Energy Rate reflects the fixed rate for the applicable Generating Facility or Alternative Generating Facility (as applicable) for the hours and loads the applicable Generating Facility or Alternative Generating Facility (as applicable) is in production, plus all BTER and DEAA rates for the hours and loads during non-production hours. NV Energy shall provide Customer with written notice of any increase in production hours cost, and the resulting change to the Long-Term Energy Rate, within ten (10) Business Days after any such increase in cost occurs. For illustrative purposes only, an example calculation of the Long-Term Energy Rate is provided in Exhibit A.~~

5.3 Forecast. Within thirty (30) days after the Effective Date, Customer shall provide NV Energy with a non-binding, forward-looking, five-year monthly forecast (the “Forecast”). Customer shall update the Forecast annually and deliver such updated Forecast to NV Energy no later than October 1 of the calendar year covered by the then-existing Forecast; provided that, in the event that Customer becomes aware of any material changes to the then-existing Forecast, Customer shall update such Forecast and deliver such updated Forecast to NV Energy as soon as is reasonably practicable. If Customer fails to deliver an updated Forecast to NV Energy as provided in this Section 5.3, Customer agrees that NV Energy shall use and be entitled to rely on the last Forecast received from Customer. For the avoidance of doubt, Customer’s obligation to

Facility or the Alternative Generating Facility (as applicable) is not delivering the expected energy and capacity, NV Energy shall use commercially reasonable efforts to enter into a Replacement Resource Procurement Agreement or identify a Replacement Generating Facility and to obtain the PUCN Replacement Resource Approval. If NV Energy enters into a Replacement Resource Procurement Agreement and the PUCN Replacement Resource Approval is obtained, the Parties agree that the Long-Term Energy Rate shall be adjusted to reflect any increase or decrease in the cost to NV Energy of the applicable Replacement Generating Facility as compared with the cost to NV Energy of the applicable Generating Facility or Alternative Generating Facility (as applicable) (as the Long-Term Energy Rate may have been adjusted pursuant to Section 5.2(b)). NV Energy shall use commercially reasonable efforts to avoid or mitigate a significant increase in the Long-Term Energy Rate in connection with the Replacement Generating Facility; provided, however, that the foregoing covenant shall not restrict NV Energy from entering into any Replacement Resource Procurement Agreement.

(b) In the event that NV Energy does not enter into a Replacement Resource Procurement Agreement, or if the PUCN Replacement Resource Approval is not obtained:

(i) if the Resource Procurement Agreement or the Alternative Resource Procurement Agreement (as applicable) was terminated during the Short-Term Energy Supply Period, each of the Parties shall have the right to terminate this Agreement upon written notice to the other Party, and Customer shall be liable for its payment obligations that arose prior to the date of termination, and

(ii) if after achieving commercial operation the Generating Facility or the Alternative Generating Facility (as applicable) was not delivering the expected energy and capacity (and, therefore, the Long-Term Energy Supply Period commenced), Customer shall have the right to terminate this Agreement pursuant to Section 3.2 and if Customer elects to terminate this Agreement, Customer shall be liable for both (A) its payment obligations that arose prior to the date of termination and (B) the payment of the Termination Payment pursuant to Section 3.3.

5.6 Excess Energy. NV Energy will purchase Excess Energy from Customer at a rate equivalent to its Short Term Avoided Cost. Alternatively, NV Energy may, at its election, purchase from Customer Excess Energy at a rate equivalent to the higher of (a) seventy-five percent (75%) of its weighted average of the per kWh levelized cost of energy for NV Energy's most recent PUCN-approved renewable energy facilities for comparable periods, or (b) its Short Term Avoided Cost. The settlement for such Excess Energy purchase will take place monthly as part of the next regularly scheduled invoice. The Short Term Avoided Cost used for monthly settlement will be equal to the annual average of the hourly Short Term Avoided Cost. During the first billing cycle of a calendar year, an adjustment payment will be calculated to true-up the Short Term Avoided Cost reflecting the hourly granularity for each instance when the purchase of Excess Energy occurred.

ARTICLE VI. CUSTOMER SECURITY

6.1 ESA Customer Security.

refer to calendar days, unless stated otherwise. If the final date for payment of any amount or performance of any act required by this Agreement falls on a day other than a Business Day, that payment is required to be made or act is required to be performed on the next Business Day.

13.15 No Construction Against Drafting Party. The language used in this Agreement is the product of both Parties' efforts and each Party hereby irrevocably waives the benefits of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific words in a contract.

13.16 Business Formation. Nothing in this Agreement creates a partnership, joint venture or other similar business construct between the Parties.

13.17 Counterparts. This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

13.18 Time of Essence. Time is of the essence with respect to all obligations of the Parties hereunder.

13.19 PUCN Jurisdiction. Customer acknowledges that certain services provided by NV Energy, including services provided under this Agreement, are subject to the terms and conditions of the Tariff Schedules on file and in effect with the PUCN and PUCN rules and regulations. **Without limiting the foregoing, Customer acknowledges that this Agreement shall at all times be subject to such changes or modifications by the PUCN as the PUCN may from time to time direct in the exercise of its jurisdiction, pursuant to Rule No. 10 of the Tariff Schedules.** Customer further acknowledges that, notwithstanding Section 13.10, the charges and rates under this Agreement will be revised by the PUCN from time to time in a NV Energy general rate case or similar ratemaking proceeding.

[Signature page follows.]

Summary report:	
Litera Compare for Word 11.16.0.74 Document comparison done on 10/5/2026 4:45:57 PM	
Style name: GT-1 - No headers and footers, no moves, no comments	
Intelligent Table Comparison: Active	
Original filename: NV Energy - Form of Electric Service Agreement (Schedule LGS-3 GS-3) (NVE Draft 4-23-26).docx	
Modified filename: NV Energy - Form of Electric Service Agreement (Schedule LGS-3 GS-3) (NVE Draft 10-5-26).docx	
Changes:	
Add	8
Delete	9
Move From	0
Move To	0
Table Insert	0
Table Delete	0
Table moves to	0
Table moves from	0
Embedded Graphics (Visio, ChemDraw, Images etc.)	0
Embedded Excel	0
Format changes	0
Total Changes:	17

EXHIBIT WELLS-REBUTTAL-2

Compilation of Data Request Responses Referenced in Wells Rebuttal Testimony
Including:

- BCP Data Request 6-25
- IEA Data Request 1-08
- Staff Data Request 03
- Staff Data Request 06
- Staff Data Request 143 Supplement
 - Staff Data Request 155
 - Staff Data Request 156
 - Staff Data Request 240

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	08-06-2026
REQUEST NO:	BCP 6-25	KEYWORD:	exhibit wells exhibit 2 LLESA CSGC LTER PPA RPS deficiencies
REQUESTER:		RESPONDER:	Pascal, Misha (NV Energy)

REQUEST:

Reference: (Reference Exhibit Wells – Exhibit

Question: The LLESA's CSGC is intended to capture thermal incremental generation cost attributed to large loads, and the LTER is intended to capture incremental PPA and gas pipeline fixed costs. The CSGC covers only "thermal builds and related transmission needed to interconnect the generation" load. However, the driven network transmission upgrades (deliverability, bulk system reinforcement) remain socialized through transmission rates. Reserves and ancillary services are not addressed. Utility-owned renewables and storage driven by the incremental load and incremental RPS compliance driven by the new load sit in neither charge. (A) Explain how the Companies will address these deficiencies so other rate payers are not subsidizing the cost causers?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The CSGC and LTER are only two of the ways cost-causation is addressed for LLESA customers, it is also addressed through the otherwise applicable rates, the LLESA minimum billing requirements and the General Rate Case process, in which the incremental revenue requirement attributable to large-load customers is isolated and will be reviewed by Staff, BCP, and interveners:

- Load-driven bulk transmission: To the extent the current bulk transmission costs are not captured in the CSGC, these costs are assigned to large-load customers via minimum billing where such customers are contributing to any socialized costs that cannot be isolated.
- Reserves/ancillary services: These costs are recovered through the otherwise-applicable base tariff rates an LLESA customer pays on its minimum billing determinants. A separate charge would be warranted only to the extent the load causes reserve/ancillary costs above what those existing rates already recover and can be isolated.
- Utility-owned renewables/storage driven by the load: If Utility-owned renewables/storage were to be determined by the load as required only to meet large load needs, it would be recovered on the same cost-causation basis as thermal, through the CSGC construct and reconciled in the GRC. In this case, all incremental renewable and storage resources need to meet the large load needs are PPAs with the incremental costs being appropriately collected through the LTER.
- Incremental RPS from the new load: RPS compliance cost is already recovered through the otherwise-applicable base tariff rates the customer pays on its minimum billing determinants, which reflect the embedded cost of the Companies' system RPS compliance. To the extent the load, including its thermal-served portion, increases the absolute RPS requirement, a separate charge would be warranted only for the compliance cost caused above and beyond what those existing rates already recover; assigning the full RPS cost again outside that framework would double-recover amounts the customer is already paying. Please see the response to BCP 6-06. Approximately 3 GW of renewable generation, 3.8 GW of battery storage and 1.2 GW of thermal generation are identified in the Preferred Plan as resources that the large-load customers will pay the incremental costs.

Critically, these items are further backstopped by the LLESA's minimum billing obligations, which are independent of the CSGC and LTER. Because an LLESA customer must pay full BTGR demand and energy charges on a minimum of 90% of Maximum Demand and 72% of maximum demand for energy related rate components, regardless of actual usage, the billing determinants alone require LLESA customers to contribute BTGR and BTER revenue that is not tied to the CSGC or LTER. That embedded contribution ensures costs are borne by the customers that cause them. The GRC process then reconciles actual costs and billing determinants each cycle, identifying and resolving any variance through the calculation of rates.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	06-23-2026
REQUEST NO:	IEA 1-08	KEYWORD:	elicegui QA18 wells QA39; determine generation storage resources removed preferr
REQUESTER:	Holman	RESPONDER:	Wells, Janet

REQUEST:

Reference: Volume 2, Direct Testimony of Shawn Elicegui, page 13 (Q&A 18) and Direct Testimony of Janet Wells, page 29 (Q&A 39).

Question: Volume 2, Direct Testimony of Shawn Elicegui, page 13 (Q&A 18) and Direct Testimony of Janet Wells, page 29 (Q&A 39). Mr. Elicegui states that the Companies will create an "LLESA Load Forecast" and run that scenario through PLEXOS LT to create an "LLESA Expansion Plan". Ms. Wells states that if a customer chooses not to execute an agreement, the Companies will "request the Commission provide direction to the Companies regarding removing the loads from the load forecast for final planning". Please explain in detail the specific methodology, framework, and/or criteria the Companies would prefer to use to determine which generation or storage resources (including currently executed Power Purchase Agreements) will be removed or canceled from the Preferred Plan if large load customers fail to execute the LLESAs and the load forecast is subsequently reduced.

If the Companies plan to rely solely on the new PLEXOS LT "LLESA Expansion Plan" to determine which competitively procured resources to cut, please explain whether any qualitative criteria, execution milestones, or development security payments already made by developers will be considered before voiding their executed PPAs.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The Companies plan to rely on the LLESA Scenario (LLESA load forecast and LLESA Expansion Plan) to confirm the resources identified in the Preferred Plan are supported through executed agreements. As provided in the response to WRA 1-05, in the event the LLESA load forecast no longer supports the Preferred Plan, NV Energy would identify the resources needed to align with confirmed LLESA agreements and determine next steps. That determination would rely on the Plexos LT LLESA Expansion Plan, including the criteria currently utilized such as the deliverability of the project, open position targets and Nevada's Renewable Portfolio Standards. At this time, the Companies have not identified specific additional qualitative criteria for consideration of the resources needed.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	05-19-2026
REQUEST NO:	Staff 03	KEYWORD:	elicegui QA 16; communicate add load forecast PLEXOS LT identify resources need
REQUESTER:	Venkat	RESPONDER:	Elicegui, Shawn (NV Energy)

REQUEST:

Reference: Elicegui Direct Q&A 16

Question: Mr. Elicegui states, "With the Base Minus Load Forecast prepared, the Companies can add load associated with large load service requests, either as directed by the Commission or when such addition is justified and documented by an agreement such as an LLESA. Then, the Companies can use PLEXOS LT to identify resources needed to serve the large service request." Please explain in detail:

A. How and when the Commission could direct NV Energy to add the load. For example, could such direction come in the instant docket or could it come in a separate proceeding?

B. How long would it take for NV Energy to use PLEXOS LT to identify resources needed to serve the large request. How would NV Energy communicate the identification of the resources needed to serve the large service request, e.g., would it be filed in the instant docket or a separate proceeding?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

A. NV Energy requested that the Commission make a decision within 135 days of the filing about the applicability of the proposed large load electric service agreement ("LLESA"), the terms and conditions that should be included in the LLESA, and whether certain entities that will not be end

users of electricity (such as horizontal developers) also need to enter into an agreement with similar terms and conditions.

NV Energy proposes that the Commission provide a 30-day window within which customers who have signed LLESAs, which were filed on May 27, 2026, and the Company confirm that they accept the final terms of the LLESA determined in this proceeding and the customer reaffirm the requested load. NV Energy also proposes that other customers who have not signed an LLESA should also have an opportunity within that window to decide if they will sign an LLESA at this time.

With that information, the Commission could then direct NV Energy to develop and file a revised load forecast with the Commission, as well as an expansion plan, within the IRP proceeding. The revised expansion plan would identify the resources within the Preferred Plan needed to serve the confirmed LLESA load. NV Energy proposes that these steps occur in this proceeding because the Companies believe that it is possible to evaluate the Preferred Plan on a parallel track with evaluating the terms and conditions of the LLESA. It currently is anticipated that the revised expansion would select all of the renewable and thermal projects proposed in the Preferred Plan, as well as add an additional 200 MW of project capacity in 2031 or 2032.

By proceeding in parallel to review the LLESA and the Preferred Plan, stakeholders can evaluate the resources included in the Preferred Plan with an understanding that the load represented by the signed LLESAs requires the addition of resources represented in the Preferred Plan. A decision on the three issues referenced in Elicegui Direct Q&A 19 and requiring the Companies and the customers who have signed LLESAs to confirm they will accept the terms of the approved LLESA and the customer reaffirm the requested load, should provide sufficient certainty to determine the required elements of the Preferred Plan.

B. After receiving direction regarding which customer loads to include in the load forecast, NV Energy can identify the resources needed to serve the large load request and make a filing identifying those resources within 15 business days in the instant docket.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	05-19-2026
REQUEST NO:	Staff 06	KEYWORD:	elicegui QA 18; LLESA load forecast PLEXOS LT expansion plan, file LLESA applica
REQUESTER:	Venkat	RESPONDER:	Elicequi, Shawn (NV Energy)

REQUEST:

Reference: Elicequi Direct Q&A 18

Question: Mr. Elicequi states, "After those applications are filed, the Companies will create a third load forecast scenario ("the LLESA Load Forecast") and will run that scenario through PLEXOS LT to create an expansion plan ("the LLESA Expansion Plan"). The Companies will supplement the 2026 Joint IRP with a copy of the results of the LLESA Expansion Plan." Please explain in detail:

- A. When the referenced LLESA applications will be filed.
- B. When NV Energy plans to run the scenario through PLEXOS LT.
- C. When NV Energy expects to supplement the 2026 Joint IRP with a copy of the results of the LLESA Expansion Plan.
- D. Why NV Energy chose to file the instant docket before creating the LLESA Load Forecast and before creating the LLESA Expansion Plan.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

- A. The applications were filed on May 27, 2026.

B. NV Energy started running the scenario through PLEXOS LT on May 8.

C. NV Energy expects to supplement the filing on June 3.

D. Please see the response to Staff 4, part E. Also note that, as this filing developed, the value of comparing the expansion plans for the base load forecast to the base minus scenario became clearer. As all LLESA load is relatively flat load, test scenarios that layer on varying amounts of LLESA load to the Base Minus load forecast result in relatively straightforward expansion plans that are essentially variations on a theme. These are load forecast scenarios that vary between the base and base minus only in the amount of relatively flat load included. During the development of the filing (and, in particular, in the last 8 weeks before the filing was made), the value of augmenting the base minus load forecast became more and more apparent. As explained in the testimony of Shawn EliceGUI, signed LLESAs provide more load forecast certainty. The base minus load forecast can be augmented with the load represented by signed agreements because the contracts provide more load forecast certainty. The Companies can then use PLEXOS LT to produce an action plan. The LLESA Expansion plan will require the addition of all the renewable and thermal projects included in the Preferred Plan, plus an additional 200 MW of project capacity in 2031 or 2032.

SUPPLEMENT NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	08-26-2026
REQUEST NO:	Staff 143 Supplement	KEYWORD:	CSGC LTER white paper july 9 2026 meeting materials; sponsoring witness irp
REQUESTER:	Venkat	RESPONDER:	Wells, Janet

REQUEST:

Reference: CSGC/LTER White Paper

Question: Please provide the CSGC and LTER white papers that were included as the meeting materials for the July 9, 2026, meeting with Staff and BCP. Please specify which NV Energy witness will be sponsoring the above white papers in the IRP.

ORIGINAL RESPONSE:

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): Yes

Note: The confidential attachment(s) will not be available on the Company's website

JUSTIFICATION FOR CLAIM OF CONFIDENTIALITY: Confidential attachment 2 contains customer-specific Information.

TOTAL NUMBER OF ATTACHMENTS: Two

RESPONSE:

Attached are the CSGC and LTER white papers that were included as the meeting materials for the July 9th, 2026 meeting. Misha Pascal will be the sponsoring witness for the white papers.

SUPPLEMENTAL RESPONSE:

SUPPLEMENT : 1

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

Staff 143 Supp Attach 01 provides the redacted/public version of the LTER Workpaper.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	07-31-2026
REQUEST NO:	Staff 155	KEYWORD:	form LLESA termination short-term energy period payment costs
REQUESTER:	Olesky	RESPONDER:	Wells, Janet

REQUEST:

Reference: Termination

Question: The Form LLESA "Elective Termination by Customer" states that Customer shall have no right to terminate this Agreement during the Short-Term Energy Supply Period pursuant to this Section 3.2.

1. Please confirm that the Customer does not have the right to terminate its LLESA during the Short-Term Energy period.
2. If a Customer is not allowed to terminate its LLESA during the Short-Term Energy period, please explain why such prohibition exists.
3. If the Form LLESA were to be modified to allow the Customer to terminate its LLESA during the Short Term Energy Period, please state if a termination payment, or any other type of termination cost would be assessed against the Customer.
4. If the above answer is yes, please describe the termination cost that would be assessed, and how it would be calculated.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

1. Confirmed.

2. The Form LLESA does not allow customer termination during the Short-Term Period because it would be challenging to calculate a payment before the resources required to meet the service request are under construction and not yet in service.
3. A termination payment would be necessary if termination was permitted during the short-term supply period.
4. The calculation of that termination payment would need to reflect all costs incurred to date and likely through the life of the long-term energy supply resources that were acquired or in the process of being acquired or built to meet the load needs of the Customer. The intent would be to ensure no costs were shifted to existing customers due to the termination. At this time, the Companies have not developed a proposed calculation for assessing an appropriate termination payment under these circumstances, or how it would best be reviewed to ensure that the payment does not omit any potential cost shifts.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	07-31-2026
REQUEST NO:	Staff 156	KEYWORD:	form LLESA mitigation; LCMPE CTT other applicable tariff large load customers te
REQUESTER:	Olesky	RESPONDER:	Wells, Janet

REQUEST:

Reference: Mitigation

Question: The Form LLESA "Mitigation and Refund of Termination Payment" states that Commencing on the date of delivery of the Termination Notice and continued for a period of thirty-six months after the Termination Date, NV Energy shall use commercially reasonable efforts to mitigate the amount of the Termination Payment, which efforts are expressly limited to NV Energy providing bundled retail electric service, up to the Minimum Demand, to one or more customers, if available, pursuant to electric service agreements with such customers and the GS-3 Tariff (or other tariffs applicable to large load customers).

Please explain if the reference to 'or other tariffs applicable to large load customers' means a customer without an LLESA but who signs a LCMPE or CTT could mitigate the amount of the terminated customer's termination payment.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The intent of the 'or other tariffs applicable to large load customers' was to represent any future tariffs that contain the same protections as the Form LLESA. Unless the LCMPE or CTT tariffs are employed as the underlying tariff for an executed LLESA, the mitigation of the termination payment would not be appropriate.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	REQUEST DATE:	08-18-2026
REQUEST NO:	Staff 240	KEYWORD:	wells QA34 LLESA; LTER CSGC minimum calculations recording variances accounting
REQUESTER:	Burakowski	RESPONDER:	Wells, Janet

REQUEST:

Reference: Wells Direct Q&A 34 - LLESA

Question: Ms. Wells states, "minimum billing requirements (Minimum Demand and Minimum Energy...) provide planning and revenue stability to support procurement and deliverability of energy. Minimum energy revenue that exceeds an LLESA customer's actual usage is credited to all customers through the Base Tariff Energy Rate and Deferred Energy Accounting Adjustment mechanism, consistent with existing regulatory accounting treatment."

Please provide a detailed explanation of how these differences will be tracked, recorded, and credited to customers through the BTER and DEAA mechanisms, as well as the "Minimums" relation to, collection of, or impact on the CSGC, LTER, BTGR, and public policy costs for the LLESA customers. The response should include, at a minimum, the following information regarding minimum demand and minimum energy:

- Indicate frequency the utility will perform the minimum calculations and recording of variances, such as daily, weekly, monthly, quarterly or as an annual true-up.
- Explain the process of tracking and recording/posting the variances, including any related accounting processes. Please indicate if and/or how the minimums will be used to collect/impact all rates, including the BTER, DEAA, BTGR (between GRCs), CSGC, LTER and any public policy costs. and provide detailed descriptions/walkthroughs of the processes.
- Clarify if the LTER costs and revenues related to the incremental PPAs will be included in the normal BTER related Fuel and Purchased accounts if so, how will the LTER revenue be recorded and tracked to ensure that the LTER recovers the costs of the incremental PPAs. If it is not going to be blended with the BTER Fuel and Purchased power accounts, how will it be tracked and how will the PPAs be

differentiated so that it is possible to audit that the costs are properly recorded. Will there be a balancing account for LTER(DEAA) for these incremental PPAs and the LTER revenue, if so, does this account earn carry and if so, how is it calculated and to whom does it accrue.

- Provide the specific general ledger accounts to be used, detailed descriptions/walkthroughs of the processes, including frequency, and samples journal entries for each scenario demonstrating how transactions would be recorded and impact each of the above listed rates.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy's proposal to consider for tracking, recording, and crediting through the reconciliation of the incremental costs intended to be recovered from LLESA customers and the revenue received to cover that incremental cost include:

1. CSGC – this rate is designed to collect sufficient revenue under the minimum billing proposal to ensure all incremental costs are paid through the CIAC collected prior to any investment being included in rate base. The reconciliation, including the revenue requirement and revenue received, will be shown for the specific group of customers within each GRC. The frequency will therefore follow the frequency of filed GRCs. Please see the responses and attachments to Staff 142 and Staff 143 that demonstrate the reconciliation of revenue requirement solving for a zero overall impact to existing customers and describe the process through the white papers. Please also see the responses to Staff 217 and 218 that discuss the mechanisms available to track and determine how revenue is allocated to existing customer classes.
2. LTER – this rate is designed to collect sufficient revenue under the minimum billing proposal to ensure all incremental costs are paid through the LTER rate. Please see the response to Staff 126 that is responsive to the questions related to LTER. The reconciliation of the actual incremental costs to the revenue received will be shown for the specific group of customers within each quarterly BTER filing and as provided in the response to Staff 126 can include a separate deferral account. In the response to Staff 126, the RBTER calculations completed today are provided as an example for a mechanism that can be employed. Carry is included in the calculations and that carry would accrue to the specific deferral account identified. Please see the responses and attachments to Staff 142 and Staff 143 that demonstrate the calculation of the rate to be applied to the minimum billing requirements to collect the forecast revenue to cover the incremental costs of the specific PPAs and gas transportation costs identified as required to provide for the load needs of the large-load customers.

NV Energy's proposal for the application of the minimum demand and energy requirements to the existing rates will be tracked and recorded as follows:

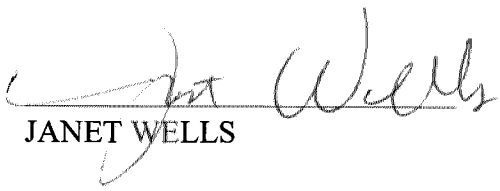
3. BTGR – BTGR revenue received from minimum billing requirements and including the administrative charge will be used to allocate revenue requirement to the specific group of customers and rate class and the revenue received will be recorded to that group of customers and rate class to offset those costs.
4. BTGR (between rate cases) – BTGR revenue received between rate cases based on minimum billing requirements and the administrative charge will contribute to earnings. Assuming the existing sharing mechanisms remains in place and is not altered, earnings in excess of 30 basis points above the rate of return used to set revenue requirement would be shared with customers in the subsequent rate case. The revenue will be tracked and recorded to the appropriate rate class to offset the allocation of costs.
5. BTER/DEAA – LLESA customers pay the existing BTER/DEAA rates as updated in each quarter to reflect costs other than those collected through the LTER. The revenue will be recorded to the base rates in the same way retail customer BTER/DEAA revenue is recorded for all other customers.
6. Public program rates will be paid based on actual usage and will be credited to the specific programs based on the revenue received.
7. Specific general ledger accounts and samples of journal entries are not specifically provided in the response. Please see the workbooks attached to Staff 142 for examples of the CSGC and the existing RBTER for examples of the LTER.

AFFIRMATION

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

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

Date: October 6, 2026


JANET WELLS