26-05007

Public Utilities Commission of Nevada
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PUBLIC UTILITIES COMMISSION OF NEVADA
Docket No. 26-05007
Phase II: DSM, DRP, TEP, LLESA

Prepared Supplemental Direct Testimony of
Adam E. Danise, P.E., on behalf of the
Regulatory Operations Staff

1. Q. Please state your name, occupation, and business address.

A. My name is Adam E. Danise. I am a Regulatory Engineer for the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission"). My business address is 9075 West Diablo Drive, Suite 250, Las Vegas, Nevada 89148.

2. Q. Did you previously file testimony in this docket?

A. Yes, I filed prepared direct testimony in Phase II of this docket on September 22, 2026. My background is described in Question and Answer ("Q&A") 2 of that testimony and my statement of qualifications was attached as Attachment AED-1.

3. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's Supplemental Direct Testimony responding to the Commission's Procedural Order No. 4 issued on September 24, 2026, in the Joint Application of 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, "NV Energy") for approval of their joint 2027-2046 triennial integrated resource plan ("IRP") for the three-year Action Plan period 2027-2029, and the Energy Supply Plan ("ESP") period of 2027-2029 (referred to here as the "2026 Joint IRP Application"). Specifically, I address how large load customers that proceed under some form of approved Large Load Electric Service Agreement ("LLESA") could affect NV Energy's resource requirements and service priority and the determinations necessary to implement an approved LLESA.

4. Q. Are you changing any of your recommendations contained in your Direct Testimony?

A. No. Under PO No. 4, the Commission directed Staff to file Supplemental Prepared Direct Testimony containing specific recommendations should the Commission wish to proceed with approval of some form of the LLESA. As such, Staff submits the instant Supplemental Direct Testimony pursuant to PO No. 4; nothing contained herein shall be construed as changing Staff's recommendations. Staff's recommendations are that the Commission should deny NV Energy's proposed form LLESA and open an investigation to establish a ratepayer protection mechanism ("RPM").

5. Q. How would approval of some form of LLESA affect NV Energy's resource planning?

A. Approval of some form of LLESA would establish the terms and conditions under which NV Energy provides, and large load customers receive bundled retail electric service, but the approval of the form LLESA itself should be a separate and distinct Commission action. Approval of a form LLESA should not be used as a basis for approval of any particular generating or transmission resource. An executed LLESA establishing the associated load ramp, customer cost responsibility, and customer protections should be required before granting prudency approval of any incremental high-cost conventional resource additions needed to serve that large load customer. For demonstrating NV Energy's capability to fulfill its obligations under an executed LLESA, NV Energy should include the full amount and timing of the enforceable large load customer load ramp without a discretionary load-realization reduction. However, an executed LLESA does not necessarily lead to the construction, procurement, or acquisition of the incremental thermal generating and/or transmission capacity necessary for NV Energy to meet its obligation because NV Energy's ability to obtain such capacity is constrained by market dynamics outside of its control. As such, any form LLESA that may be approved by the Commission does not, by itself,

solve the resource adequacy concerns related to serving large load customers as described in Q&As 48-51 of my Direct Testimony and further discussed below.

6. Q. Does NV Energy's LLESA implementation comport with its Preferred Plan?

A. Not without reconciliation by NV Energy. As discussed in Q&As 48-51 of my Direct Testimony, the filed Base Load Forecast and the LLESA Scenario do not contain the same set of load assumptions and, therefore, the supporting expansion plan for each forecast differs. Thus, the customer commitments used to implement an approved LLESA may differ from the combined load and resource assumptions supporting NV Energy's Preferred Plan. The Commission should expressly determine which customer load treatment and resource plan governs the LLESA implementation.

NV Energy's June 4, 2026, Supplemental Filing adds the identified LLESA loads associated with the executed LLESAs filed in Docket Nos. 26-05026, 26-05027, 26-05028, 26-05029, and 26-05030 (referred to as the "filed LLESAs") to the Base Minus Load Forecast and excludes every other data center load assumed in the Base Load Forecast. NV Energy's Preferred Plan includes placeholder combustion turbines ("CTs") starting in 2034, while the first subsequent placeholder CT in the LLESA Expansion Plan is in 2037. NV Energy attributes that difference to the treatment of later data center load growth.[1] Accordingly, approval of a form LLESA must be followed by an explicit reconciliation of the large load customers that proceed under the approved form LLESA, the treatment of other large load customers that have executed a Rule 9 Agreement with NV Energy, and normal load growth. Approval by the Commission of a form LLESA in this docket should not mean that every other large load customer with an executed Rule 9 Agreement who does not sign the LLESA is excluded from resource planning until NV Energy can procure additional generating resources in a future IRP filing.

[1] *See* NV Energy's Supplemental Filing at 2 and 8.

7. Q. Does the LLESA Scenario in NV Energy's Supplemental Filing require the same resources as the Preferred Plan?

A. Not entirely. NV Energy's Supplemental Filing describes approximately 3,400 MW of high-load factor demand by 2032 associated with the filed LLESAs.[2] The LLESA Expansion Plan retains the Preferred Plan's thermal, renewable, and storage projects, but requires an additional 200 MW thermal generating project in 2031 and a five-year extension to the Stillwater project instead of a three-year extension. NV Energy states that this result indicates a need for additional capacity and that it continues to evaluate the timing and nature of that addition.[3] However, NV Energy provides minimal if any discussion regarding its ability to place that additional 200 MW thermal generating project into service in 2031 or the cost to do so.[4]

NV Energy's placeholder resources also differ. The Preferred Plan includes 591 MW of four-hour battery energy storage system ("BESS") capacity and 720 MW of ten-hour BESS capacity as placeholders in 2031. The LLESA Expansion Plan instead includes 1,430 MW of ten-hour BESS capacity placeholders in that same year.[5] Again, NV Energy does not provide any discussion regarding the availability or cost of ten-hour BESS capacity in the market or its ability to procure the large amount of ten-hour BESS capacity it needs to meet the LLESA forecasted loads in 2031. Furthermore, NV Energy has not provided any discussion regarding its ability to close the large open capacity positions of 1,269 MW in 2029 and 1,077 MW in 2030, which exceeds NV Energy's stated targets in 2029 and 2030.[6]

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2 *Id.*

3 *Id.* at 1.

4 *Id.* at 3. To preserve its ability to place 401 MW, 401 MW, and 421 MW of thermal generation capacity in service in 2030, 2031, and 2032, NV Energy had to make financial commitments with suppliers prior to obtaining Commission approval of those resources. *See* Supplemental Direct Attachment AED-1, NV Energy's Supplemental Response to Staff data request ("DR") 91 and a redacted version of the attachment to Staff DR 91 Staff can provide the Commission NV Energy's Confidential Response to Staff DR 91 upon request. It is unlikely that NV Energy will be able to place an additional 200 MW of thermal generating capacity into service in 2031 without making additional financial commitments prior to obtaining Commission approval and be subjected to significant costs to accelerate procurement and construction of the aeroderivative CTs and associated balance of plant facilities.

5 *See* NV Energy's Supplemental Filing at 8.

6 *Id.*

NV Energy's proposed LLESA implementation is untenable and, if the Commission wishes to approve some form of LLESA, the Commission should divorce its approval of an LLESA from NV Energy's proposed LLESA implementation and deny the filed LLESAs, as discussed in the Supplemental Direct Testimony of Staff witness Anne-Marie Preisach

8. Q. Is it important for the Commission to consider electric service priority and the total amount of large load customers' load that could be served if it wishes to approve some form of LLESA?

A. Yes. NV Energy's Preferred Plan adds approximately 11,000 MW of nameplate generating capacity by 2033, which corresponds to approximately 4,237 MW of planning capacity (a reduction of approximately 61 percent).[7] Approval of some form of LLESA does not shorten resource development lead times and NV Energy's ability to procure additional thermal and renewable generation above the levels requested in its Preferred Plan is constrained, which limits the amount and timing of electric service that can be provided to large load customers.[8] Load mitigation in a planning forecast does not itself change a large load customer's executed Rule 9 Agreement or any load obligations in a future LLESA. If NV Energy cannot procure and deliver sufficient generating resources in the amounts and timeframes needed to accommodate all large load customer load ramps, the next increment of constrained electric service capability must be sequenced amongst the affected requests. Thus, the Commission should distinguish approval of any LLESA form from the determination of service priority and develop a large load customer queue to determine the order in which large load customers would receive bundled retail electric service from NV Energy. Staff witness Anne-Marie Preisach provides further discussion regarding the criteria that should be applied to that queue.

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[7] *See* Supply Side Narrative, Volume 9, at 344 and 428.

[8] *See* Supplemental Direct Attachment AED-2, NV Energy's Supplemental Response to Staff DR 22 and Supplemental Attachment 01 to Staff DR 22.

9. Q. If the Commission approves some form of LLESA, does Staff still recommend that MECP 1 Reno 1, LLC's (EdgeCore Digital Infrastructure ("EdgeCore")) Phase 1 and Phase 2 projects and Redwood Materials, Inc.'s ("Redwood") Phase 1 project be included in NV Energy's Base Minus Load Forecast, served under Sierra's General Service ("GS")-3 tariff, and not be subjected to the new tariff or schedule recommended by Staff Witness Anne-Marie Preisach?

A. Yes. As detailed in Recommendation No. 2 of my Direct Testimony, EdgeCore's Phase 1 and 2 projects and Redwood's Phase 1 projects are distinct legacy projects that should be included in NV Energy's Base Minus Load Forecast, receive the proposed exemption from full incremental cost treatment, and not be subjected to the new tariff or schedule recommended by Staff Witness Anne-Marie Preisach.[9] If the filed LLESA load ramps receive first priority without incorporating EdgeCore's and Redwood's legacy phased projects, those phases could face later service dates or additional resource requirements. Therefore, I recommend that the Commission expressly determine EdgeCore's and Redwood's executed 120 kilovolt HVD agreements status, rather than allowing that priority to arise indirectly from the sequence in which the existing LLESAs were negotiated.

10. Q. If the Commission adopts Staff's recommendation to include EdgeCore's Phase 1 and Phase 2 and Redwood's Phase 1 projects in NV Energy's Base Minus Load Forecast while permitting the filed LLESAs to proceed, what would be the resulting generating resource build-out?

A. Staff propounded Staff DR 133 on NV Energy requesting NV Energy to model a generic load increase to the Base Minus and Base Load Forecasts of 399 MW in the 2027/2028 timeframe and 500 MW in the 2034 timeframe (as hypothetical case that includes EdgeCore's and Redwood's legacy phased projects) and asked if NV Energy

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[9] *See* my Direct Testimony at 27.

would need to make resource additions to serve this additional load.[10] In its response to Staff DR 133, NV Energy states that the increased load in the Base Minus Load Forecast alters the mix of resources in the Base Minus Expansion Plan and the incremental resources required to meet the Base Load Forecast, and would change the estimated Customer Specific Generation Charge ("CSGC") and Long-Term Energy Rate ("LTER").[11] The resulting change is consequential to the amount large-load customers pay, not merely to the selection of resources. In testimony filed on September 22, Staff witness Swetha Venkat explains that the CSGC calculation depends on the identified incremental resource costs and the estimated contribution required to avoid increasing existing customer rates.[12] Accordingly, a Commission decision modifying the planning baseline or participating loads must be reflected in the corresponding resource assumptions and CSGC/LTER calculations. NV Energy's response to Staff DR 133 confirms that the CSGC/LTER estimates would change but does not establish the direction or magnitude of those changes.[13]

11. Q. Can you quantify the resource changes resulting from the modified Base Minus Load Forecast evaluated in Staff DR 133?

A. Yes. NV Energy's redacted Attachment 01 to Staff DR 133, provided in Attachment AED-3, identifies Lux Solar Center, Southern Bighorn 1 & 2, and the six-hour configuration of Castor Storage as additional selections relative to the original Base Minus case. Those projects represent 525 MW of nameplate solar photovoltaic capacity and 835 MW of nameplate BESS capacity. However, the adjusted case no longer selects Winston Solar's 400 MW of photovoltaic capacity and 400 MW of battery output capacity or the 47 MW Stillwater extension. Accordingly, the net change in the selected-project inventory is an increase of 125 MW of nameplate solar

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[10] *See* Supplemental Direct Attachment AED-3, NV Energy's Response to Staff DR 133 and a redacted version of Attachment 01 to Staff DR 133. Staff can provide the Commission NV Energy's Confidential Response to Staff DR 133 upon request.

[11] *Id.* NV Energy's response to Staff 133 does not address placeholder resources.

[12] Direct Testimony of Swetha Venkat at 4-5 and 16-19.

[13] *See* Attachment AED-3.

PV capacity and 435 MW of nameplate BESS capacity, offset by the removal of 47 MW of nameplate geothermal capacity.[14]

12. Q. Does that establish how much capacity must be added to the original LLESA Scenario?

A. No. It quantifies a material change in the resources selected for the modified Base Minus Load Forecast but does not establish a one-for-one replacement obligation for LLESA customers. The comparison includes project substitutions, different in-service timing, and different storage durations, and it does not include placeholder resources. NV Energy states that, all else equal, the revised LLESA Scenario would likely require a larger resource addition than the 200 MW in 2031 but had not completed the resource-selection or production-cost analyses for that combined case when it provided the response.[15] NV Energy adds that any additional generating capacity beyond the Preferred Plan would need to be requested in a future IRP filing.[16]

NV Energy's original LLESA Scenario already identifies additional resource requirements beyond those requested in its Preferred Plan. Furthermore, NV Energy's response to Staff DR 133 indicates that the assumed Base Minus Load Forecast treatment of EdgeCore's and Redwood's legacy phased projects would likely increase the required addition. Consequently, the Commission should not approve implementation of both sets of service commitments (EdgeCore's and Redwood's legacy phased projects and the filed LLESAs) on the assumption that the unchanged Preferred Plan supplies all required capabilities. If the Commission wishes to approve some form of LLESA, the Commission also needs to address the LLESA framework under which the form LLESA would be implemented, including, but not limited to: whether the previously filed LLESAs have any priority over other large load

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[14] *Id.* The redacted version of Attachement 01 to Staff DR 133, provided in Attachment AED-3, explains that Southern Bighorn substitutes for a similarly sized Winston Project with an in-service date nearly one year later and that the selected six-hour Castor BESS configuration also differs from the eight-hour Castor BESS configuration in the Preferred Plan, notwithstanding its equal 310 MW nameplate capacity.

[15] *Id.*

[16] *Id.*

customers, how electric service priority should be established in a queueing process, generating and transmission resource requirements, amount of large load customers' load that can be served by NV Energy's Preferred Plan, and large load customers' cost responsibility in the instant Docket. Additionally, it is imperative that if the Commission wishes to approve a form LLESA agreement, the form LLESA Agreement should be implemented uniformly across similarly situated large load customers, rather than a specialized LLESA agreement that is adjudicated in multiple separate filings that are unrelated to each other, which could possibly result in materially different LLESAs being applied to similarly situated customers.

13. Q. Does this conclude your testimony?

A. Yes, it does.

SUPPLEMENT
NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	**REQUEST DATE:**	08-17-2026
REQUEST NO:	Staff 91 Supplement	**KEYWORD:**	ft churchill thermal unit scheduling ; financial commitments equipment suppliers
REQUESTER:	Cameron	**RESPONDER:**	Atala, Fady (NV Energy)

REQUEST:

Reference: Ft. Churchill thermal unit scheduling

Question: Given that the Commission's Procedural Order No. 1 (dated June 18, 2026) did not grant the Companies' Prayer for Relief No. 2.a, which asked the Commission to approve the form LLESA on an expedited basis (deemed approved by September 18, 2026), please provide Staff with a list of the financial and/or other commitments the Companies will need to make to equipment suppliers, EPC contractors, Great Basin Gas Transmission Company, Tallgrass Energy, and any other counterparties, before knowing whether the form LLESA is approved, in order to maintain the ability to meet the June 2030, June 2031, and June 2032 in-service dates for the proposed Fort Churchill thermal generation additions. For each such commitment, also identify (a) the amount; (b) whether and to what extent it is refundable or otherwise recoverable if the project does not proceed; and (c) the latest date by which the commitment must be made to preserve the corresponding in-service date.

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: The attachment contains competitively sensitive pricing information. Public disclosure could negatively impact the Companies' ability to obtain competitive offers in future procurements. In addition, confidentiality safeguards project cost data and payment terms that are often derived from ongoing negotiations and subject to

third-party restrictions; releasing this information could reveal negotiating positions and increase future contract costs.

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

Please see attached confidential document "26-05007 Staff 91 Conf Attach 01.xlsx" which includes the preliminary list of financial and other commitments that may need to be made before a Commission decision on approval of the Form LLESA to preserve the ability to meet the proposed June 2030, June 2031, and June 2032 in-service dates for the Fort Churchill thermal generation additions. The information below is based on currently available project procurement, engineering, permitting, and interconnection support information and remains subject to refinement as vendor negotiations, contracting, permitting, and project schedule development progress. The commitments to Great Basin Gas Transmission Company, Tallgrass Energy, and any other counterparties are outlined in the Companies' response to Staff 67.

SUPPLEMENTAL RESPONSE:
SUPPLEMENT : 1

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

The supplement is providing the redacted version of 26-05007 Staff 91 Conf Attach 01.

Redacted

Phase	Item	Quantity / Deposit Basis	Commitment Amount	Commitment Date	Refundability / Recoverability	Reason for Commitment
Phase I	GE LM6000 combustion turbines	Quantity: 8;		April 10, 2026 (December 2026 (		Availability/critical path
Phase I	BEST generator step-up transformers	Quantity: 2;		February 15, 2026		Availability/critical path
Phase I	Hitachi Energy 345 kV circuit breakers	Quantity: 5		March 20, 2026; PO issued		Availability/critical path
Phase I	Owner's Engineer	Engineering support		August to December 2026		Engineering support needed to review technical specifications and designs from GE.
Phase I	WSP – LGIA support	Covers Phases II & III		March to July 2026		Engineering support needed for the interconnection application
Phase I	Trinity – air permit application support	Covers Phases II & III		June 4, 2026		Due to the approximately 18-month processing timeline, Trinity was engaged to support timely air permit application development.
Phase I	Sargent & Lundy – geotechnical specification support	Geotechnical specification support		May 5, 2026		Engineering support needed to write detailed technical specifications for the geotechnical survey, which will be used to determine optimal foundation and stack locations for air permitting.
Phase I	OE / site plot plan engineering	Covers Phases II & III		End of August 2026		Engineering support needed to identify foundation and stack locations.
Phase I	Geotechnical support services	Geotechnical support		September 1, 2026		Geotechnical support needed to locate foundations and stacks.
Phase II	Aeroderivative combustion turbines			Estimated September 10, 2026 (December 2026 (		High demand for turbines.
Phase III – 2 Units	F-Class combustion turbines	Quantity: 2;		Estimated October 1, 2026		High demand for turbines.
Phase III – 3 Units	F-Class combustion turbines	Quantity: 3;		Estimated October 1, 2026		High demand for turbines.

SUPPLEMENT
NV Energy
RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	**REQUEST DATE:**	09-17-2026
REQUEST NO:	Staff 22 Supplement	**KEYWORD:**	renewable resources; specific resource each forecasts
REQUESTER:	Olesky	**RESPONDER:**	Williams, Kimberly

REQUEST:

Reference: Renewable Resources

Question: Please list by name all renewable and thermal resources NV Energy would need to serve its existing customer loads through the following forecasts:
1. Base Minus load forecast
2. Base load forecast
3. Base Plus load forecast
4. Test load forecast
5. Second Test load forecast
6. Base Minus with all five LLESAs approved.
7. Base with all five LLESAs approved.

Please do not point to the filing in your response, but instead provide lists of specific resources for each of the forecasts as it is unclear which resources are needed for which forecast.

Please include in your response if there are any resources that will be shared between LLESA customers and all other customers, and if so, what portion would be assigned to LLESA customers and what portion would be assigned to all other customers.

ORIGINAL RESPONSE:
RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

After discussion with Ms. Olesky on June 11, 2026, it is understood that the initial question is intended to seek a list of all proposed renewable, storage, and thermal projects to serve the full forecasted load in each scenario. Note that Item 6 corresponds to the LLESA scenario in the June 4, 2026, supplemental filing.

Item 7 describes a scenario that the Companies have not studied. The requested load forecast has not been developed and, therefore, no expansion plan has been created for such a load forecast. An estimated impact of the requested scenario would be a peak load forecast that exceeds the Base Load Forecast by approximately 1,440 MW in 2032.

Please see the attached file for the requested resource lists excluding item 7. The expansion plans are presented in order of the lowest forecasted load to highest. The data request item numbers are provided to orient the reader. Only potential projects are listed; no placeholder resources are included.

As mentioned in the Economic Analysis Section of the IRP narrative and in the June 4, 2026, supplemental filing, insufficient renewable projects are available to meet all renewable energy needs in near-term years in many scenarios. The year in which sufficient renewable energy is projected for each scenario is as follows, in order of lowest load forecast to highest:

Base Minus Informational Case	2028
Test Scenario	2031
Second Test Scenario	2033
Preferred Plan (Base Load Forecast)	2033
Base Minus with LLESAs Scenario	2033
Base Plus Informational Case	2033

The supplemental filing indicates the following regarding constraints and inputs in PLEXOS LT for the creation of the Test, Second Test, and LLESA Scenario expansion plans:

"The same constraints and inputs that were used in the analysis for the IRP cases and plans in the Joint Application were applied in PLEXOS LT for the three scenarios – including the same fuel and purchase power price forecasts, planning reserve margin requirement, open position targets, candidate resources, and resource build limits. An additional build limit for aeroderivative combustion turbines ("CTs") in 2030 was applied to limit the build in that year to the project capacity in the Preferred Plan (Obsidian) as it is deemed unlikely that additional units could be obtained and put in service in that time frame."

In addition, for these three scenarios, Frame CTs were precluded in 2031 – the same constraint applied in creation of the Preferred Plan (Obsidian), consistent with the current expected availability described for such units in the Generation Section of the Supply Plan Narrative.

In the Companies' planning, the full portfolio of resources serves the combined bundled retail load. The output of a given resource is never reserved for a particular customer. The LLESA agreements address resource costs proposed to be borne by certain large customers, but not how the resources will be utilized by the Companies to serve the load.

SUPPLEMENTAL RESPONSE:
SUPPLEMENT : 1

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

As mentioned to Staff on 9/16/2026, the Companies discovered typos in cells D6 and D7 of the original attachment to this DR response. The year 2031 was misstated as 2030. The correct year was evident in the project code names in cells B6 and B7. A replacement file is attached with revised cells noted in bold font.

Projects by Scenario									
Project Name	**Code Name Used in Economic Analysis**	**Nameplate Capacity (MW)**	**COD**	**Base Minus Informational Case**	**Test Scenario**	**Second Test Scenario**	**Preferred Plan**	**LLESA Scenario**	**Base Plus Informational Case**
				DR Staff 22 Item 1	*DR Staff 22 Item 4*	*DR Staff 22 Item 5*	*DR Staff 22 Item 2*	*DR Staff 22 Item 6*	*DR Staff 22 Item 3*
1803 MW - CT-Aero	2029 - CT-Aero	1803	Jun 2029						•
401 MW - CT-Aero	2030 - CT-Aero	401	Jun 2030				•	•	•
200 MW - CT-Aero	2030 - CT-Aero	200	Jun 2030						•
401 MW - CT-Aero	2031 - CT-Aero	401	**Jun 2031**				•	•	
200 MW - CT-Aero	2031 - CT-Aero	200	**Jun 2031**					•	
842 MW - CT-Frame	2031 - CT-Frame	841	Jun 2031						•
421 MW - CT-Frame	2032 - CT-Frame	421	Jun 2032						•
421 MW - CT-Frame	2032 - CT-Frame	421	Jun 2032			•	•	•	•
Commerce Station Energy Storage	*EG_BESS_655	100	May 2028		•	•	•	•	•
White Pine Solar	*CI_BESS_803_Paired / *CI_PV_803_Paired	350/350	Dec 2028	•	•	•	•	•	•
Southern Bighorn 1 & 2	*VT_BESS_624_Paired / *VT_PV_624_Paired	400/400	Jul 2028		•	•	•	•	•
Trego Grid	*AH_BESS_492	200	Jun 2028		•	•	•	•	•
NGP Blue Mountain Third Amendment	*GN_Geo_395	30	Mar 2027	•	•	•	•	•	•
Winston Solar	*HS_BESS_805_Paired / *HS_PV_805_Paired	400/400	Oct 2029	•	•	•	•	•	•
Coyote Energy 1	*OW_BESS_900_Paired / *OW_PV_900_Paired	600/600	Dec 2030				•	•	•
Amargosa Energy Center	*VO_BESS_999_Paired / *VO_PV_999_Paired	1200/1200	Dec 2030		•	•	•	•	•
Boulder Solar III	*SY_BESS_111_Paired / *SY_PV_111_Paired	128/128	Jun 2028	•	•	•	•	•	•

Project Name	Code Name Used in Economic Analysis	Nameplate Capacity (MW)	COD	Base Minus Informational Case	Test Scenario	Second Test Scenario	Preferred Plan	LLESA Scenario	Base Plus Informational Case
				DR Staff 22 Item 1	*DR Staff 22 Item 4*	*DR Staff 22 Item 5*	*DR Staff 22 Item 2*	*DR Staff 22 Item 6*	*DR Staff 22 Item 3*
Dry Lake East Energy Storage II	*UL_BESS_558	150	Dec 2027		●	●	●	●	●
Fish Springs Ranch Energy Storage	*XY_BESS_001	75	Dec 2027				●	●	●
Jersey Valley Solar and Storage	*FT_BESS_277_Paired / *FT_PV_277_Paired	67/67	Nov 2027	●	●	●	●	●	●
Lux Solar Center	*AY_BESS_590_Paired / *AY_PV_590_Paired	125/125	Jul 2028		●	●	●	●	●
Sleepy Orange	*MZ_BESS_693_Paired / *MZ_PV_693_Paired	500/500	May 2030	●	●	●	●	●	●
Castor Storage (BESS-6)	*WX_BESS_666	310	May 2029		●	●			
Castor Storage (BESS-8)	*WX_BESS_777	310	May 2029				●	●	●
Stillwater (3 year extension)	*GW_Geo_021	47	Jan 2030				●		
Stillwater (4 year extension)	*GW_Geo_301	47	Jan 2030			●			
Stillwater (5 year extension)	*GW_Geo_122	47	Jan 2030	●	●			●	●
Nevada Geothermal Portfolio	*GG_Geo_007	50	Dec 2030	●	●	●	●	●	●
North Nevada Geothermal Portfolio	*RT_Geo_404	100	Dec 2030		●	●	●	●	●
Iron Point Energy Center	*JA_BESS_896_Paired / *JA_PV_896_Paired	250/250	Dec 2029		●	●	●	●	●
Hot Pot Energy Center	*KB_BESS_134_Paired / *KB_PV_134_Paired	350/350	Oct 2029		●	●	●	●	●

Note: The Stillwater extension is available in three versions, 3-year, 4-year, or 5-year, each with its own row in this table. The Castor Storage project is available in two versions, 6-hour or 8-hour duration, each with its own row in this table.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	**REQUEST DATE:**	07-27-2026
REQUEST NO:	Staff 133	**KEYWORD:**	pollard exhibit direct 2; resource additions LLESA additional bundled load tahoe
REQUESTER:	Maguire	**RESPONDER:**	Pollard, Tim

REQUEST:

Reference: Pollard Exhibit-Direct-2

Question: If the Commission were to find and order that the loads of certain customers with signed legacy Rule 9 agreements must be included in the Base Minus and Base forecasts at unmitigated amounts, resulting in the Base Minus forecast increasing by 399 MW in the 2027/2028 time period and 500 MW in the 2034 time period, what changes would NV Energy need to make to resource additions and the LLESA agreements included in the filing to factor in this additional bundled load serving requirement? For the sake of this DR assume these additional loads are in the Tahoe Reno Industrial Park area.

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: The confidential attachment contains customer-specific information.

TOTAL NUMBER OF ATTACHMENTS: Two

RESPONSE:

Please see the attached file for the requested information. As shown in the attachment, the expansion plan changes the mix of resources and, as a result, the incremental resources required to meet the Base Load Forecast change. Because the CSGC and LTER are estimated to capture

incremental costs, at a minimum, those estimates would change. As provided in the supplemental filing on June 4, 2026, the LLESA Scenario required an additional 200 MW of generation resources above the Preferred Plan to meet the executed LLESA load requests. If the Base Minus Scenario is updated to reflect the additional loads in the proposed approach in this question, all else equal, the LLESA Scenario will likely require a larger addition to meet the executed LLESA load needs. Any additional generation resources beyond the Preferred Plan will need to be requested in a future Amendment or IRP. The Companies have not created an LLESA scenario, in which the load ramps associated with the LLESA scenario represented in the June 4, 2026 supplemental filing, are added to the revised Base Minus scenario. Nor have the Companies revised the Base Load Forecast. Accordingly, the Companies have not used Plexos LT to complete resource selection analyses for these revised scenarios. In addition, production cost modeling for those two scenarios have not been completed using Plexos ST. The Companies will be completing such analyses.

Actual LLESA customer load needs will be dependent upon whether LLESA customers move forward after the Commission's decision on the form agreement.

Staff 133 attachment

The Companies modified the Base Minus forecast to consider the [redacted] projects at unmitigated Rule 9 HVD agreement ramp load levels in order to respond to this request.
The Companies interpret that Staff 133 is asking about projects, not placeholder resources.
The first table below presents the incremental projects selected in the Staff-133 prescribed expansion relative to the Base Minus informational case.
The second table presents the projects in the Base Minus informational case that were not selected in the Staff-133 prescribed expansion.
The third table presents the projects in the Preferred Plan that were not selected in the Staff-133 prescribed expansion.
Approximate open positions and anticipated RPS achievement are described to the right.

Additional Projects selected in Staff-133 compared to Base Minus load forecast

Type	Name (code-name)	MW
PV/BESS	Lux Solar Center (2028 - *AY_PV/BESS_590_Paired - North)	125/125
PV/BESS	Southern Bighorn 1 & 2 (2028 - *VT_PV/BESS_624_Paired - South)[1]	400/400
BESS	Castor Storage 6-hour (2029 - *WX_BESS_686 - South)	310

Projects not selected in Staff-133 compared to Base Minus load forecast

Type	Name (code-name)	MW
PV/BESS	Winston Solar (2029 - *HS_PV/BESS_805_Paired - North) [1]	400/400
GEO	Stillwater (2030 - *GW_Geo_122 - North)	47

[1] Southern Bighorn 1 & 2 has an in-service date nearly one year earlier than Winston Solar, but they are of similar size and technology in that they are both 400 MW paired PV/BESS facilities. The expansion in Staff 133 basically chose an earlier PV/BESS of the same size relative to that selected in the Base Minus expansion plan.

Projects not selected in Staff-133 compared to Base load forecast

Type	Name (code-name)	MW
CT	2030 Combustion Turbines - 8 Aeroderivative	401
CT	2031 Combustion Turbines - 8 Aeroderivative	401
CT	2032 Combustion Turbines - 2 Large Frame	421
PV/BESS	Winston Solar (2029 - *HS_PV/BESS_805_Paired - North)	400/400
PV/BESS	Iron Point Energy Center (2029 - *JA_PV/BESS_896_Paired - North)[2]	250/250
PV/BESS	Hot Pot Energy Center (2029 - *KB_PV/BESS_134_Paired - North) [2]	350/350
GEO	North Nevada Geothermal Portfolio (2030 - *RT_Geo_404 - North) [2]	100
GEO	Stillwater (2030 - *GW_Geo_021 - North)	47
PV/BESS	Coyote Energy 1 (2030 - *OW_PV/BESS_900_Paired - South)	600/800
PV/BESS	Amargosa Energy Center (2030 - *VO_PV/BESS_999_Paired - South)	1200/1200
BESS	Dry Lake East Energy Storage II (2027 - *UL_BESS_558 - South)	150
BESS	Fish Springs Ranch Energy Storage (2027 - *XY_BESS_001 - North)	75
BESS	Trego Grid (2028 - *AH_BESS_492 - North)	200
BESS	Commerce Station Energy Storage (2028 - *EG_BESS_655 - South)	100
BESS	Castor Storage 8-hour (2029 - *WX_BESS_777 - South) [3]	310

[2] Sleeved projects in the Preferred Plan that were not available for selection for Staff-133 or Base Minus informational case
[3] The Castor Storage project is selected in the Staff-133 prescribed expansion, but is selected at the 6-hour duration instead of the 8-hour duration

Approximate open positions (MW)

	2027	2028	2029	2030	2031	2032	2033	2034	2035
Staff-133*	1070	0	0	0	0	0	0	0	127
Base Minus*	852	0	0	0	0	0	0	0	23
Preferred Plan	1809	567	982	720	490	500	392	500	500

*Zeros indicate a long capacity open position

RPS Achievement

For the Staff-133 prescribed expansion, similar to the Base Minus informational case, RPS compliance is not anticipated in 2027. The credit commitment associated with Coeur Rochester was removed from the RPS target in this scenario following the Commission's recent denial of the Coeur Rochester ESA application in Docket No. 24-08011.

AFFIRMATION

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

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

Date: 10/01/2026

/s/ Adam E. Danise
ADAM E. DANISE