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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE SOUTH HILLS AND PEREGRINE POWER PLANTS AND FOR AN ASSOCIATED ACCOUNTING ORDER	)	**CASE NO. IPC-E-26-04** **REDACTED COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission ("Commission"), by and through its attorney of record, Kelsea E. Ross, Deputy Attorney General, submits the following comments.

I. BACKGROUND

On March 10, 2026, Idaho Power Company ("Company") applied ("Application") to the Commission requesting: (1) a Certificate of Public Convenience and Necessity ("CPCN") for the South Hills Power Plant ("South Hills"), a natural gas-fueled facility made up of twelve reciprocating internal combustion engines ("RICE") providing up to 222 megawatts ("MW") of nameplate generation to meet an identified capacity deficit in 2029; (2) a CPCN for the Peregrine Power Plant ("Peregrine"), a natural gas-fueled facility with a single simple-cycle combustion turbine ("SCCT") providing 430 MW of nameplate generation to meet an identified capacity deficit in 2030; and (3) an order confirming the Company's application of accrual of Allowance for Funds Used During Construction ("AFUDC") for South Hills and Peregrine to coincide with initial procurement activities for the natural gas-fueled facilities. Application at 1.

On April 6, 2026, the Commission issued a Notice of Application and Notice of Intervention Deadline, setting a deadline for interested parties to file a petition to intervene. Order No. 36994. The Commission granted intervention to Idaho Irrigation Pumpers Association, Inc. ("IIPA"), Micron Technology, Inc. ("Micron"), and Northwest Energy Coalition and Renewable Northwest in Order Nos. 36993 and 37026.

II. STAFF ANALYSIS

Staff believes that the Company's system faces significant capacity deficits in 2029 and 2030, and Staff believes that South Hills and Peregrine (collectively "Proposed Projects") are the least-cost least-risk ("LC-LR") solutions to resolve a large proportion of those deficits. Therefore, Staff recommends that Commission grant a CPCN for each project.

However, Staff has multiple concerns about how the Proposed Projects were selected and their cost-effectiveness. Staff believes that in selecting South Hills, the Company violated its own Request for Proposal ("RFP") process due to time constraints to get necessary resources online by June 2029. In selecting Peregrine, Staff believes the Company did not comply with any RFP requirements due to time constraints. Furthermore, Staff believes that the Proposed Projects would not be the least-cost resources if it were not for time constraints. Staff contends that the Company bears partial responsibility for the time constraints and should therefore bear some of the financial consequences. Therefore, Staff recommends that the Commission deny the accrual of early AFUDC and impose a hard cost cap on recoverable costs for South Hills and Peregrine. Staff also recommends that the Company delay enrollment of additional new large load ("NLL") customers until it can demonstrate a reasonable plan to recover from its serial capacity deficits while ensuring its other customers do not bear any of the costs needed to serve NLL customers.[1]

Lastly, Staff believes that the Proposed Projects are substantially more expensive than existing resources, that these resources are being driven into the system because of NLL customers, and therefore that the costs of the Proposed Projects should be associated with the NLL allocation mechanism being discussed in concurrent Case No. IPC-E-26-07.

[1]Staff's recommendation is based on its interpretation of *Idaho Code* §61-335, which states that a new large load is "responsible for funding its full cost of service, including its share of generation, transmission, substation, and distribution infrastructure investments that would not be placed in service or be required by the public utility but for the new large load."

Staff's comments are organized into the following four sections:

A. The System Need is Valid and the Proposed Projects Are Least-Cost Least-Risk;

B. Lack of Time has Caused Multiple Problems;

C. The Company Bears Partial Responsibility for the Lack of Time; and

D. Staff's Proposed Actions.

A. <u>The System Need Is Valid and the Proposed Projects Are Least-Cost Least-Risk</u>

Based on its review and analysis, Staff agrees that large and growing capacity deficits exist in the Company's system in 2029 and 2030 and therefore additional system resources are necessary. Staff believes that – given the time constraints of the capacity deficits – the Proposed Projects are part of the LC-LR *feasible* solution. As a result, Staff recommends the Commission approve a CPCN for (1) South Hills and (2) Peregrine.

i. The System Need Is Valid

Company Witness Ellsworth's testimony focused on the forecasted capacity deficit for the system and the need for new resources. He explained how the forecasted deficit for 2029 has grown from 142 MW in the 2023 Integrated Resource Plan ("IRP") to 192 MW in the 2025 IRP. Ellsworth Direct at 8. Company Witness Ellsworth also explained that "during the near-term resource decision-making phase, the annual capacity positions can be very fluid." *Id.* at 12. Accordingly, for this case, the Company updated its Aurora modeling inputs from the 2025 IRP baseline to reflect the latest information about the load and resources. *Id*. As a result, capacity deficits were 236 MW in 2029 and 352 MW in 2030. *Id.*

Staff reviewed the Company's updated load and resource ("L&R") assumptions and agrees that they are consistent with other recent new-resource cases and ongoing system trends. Staff believes that the L&R assumptions are reasonable. Since the L&R assumptions are what determine the results via the Company's complex modeling software, for Staff's review of the Application, Staff acknowledged the computational result put forth by the Company: a 236 MW deficit in 2029 and a 352 MW deficit in 2030. Based on that result, Staff believes that the Company must acquire additional system resources.

ii. The Company Faces Time Constraints

Company Witness Richins explained that "[d]espite considerable investment and expansion in generation resources in recent years, [the Company's] system today is fully utilized by current customers, and the Company continues to experience sustained customer growth." Richins Direct at 5. Additionally, "many of the resources selected through the extensive [acquisition] process are not able to come online as expected." *Id* at 6. Furthermore, "rising costs, supply chain constraints, permitting obstacles, and constrained system capacity [are] posing significant challenges for [the Company] and third-party developers in bringing resources online in time to meet identified capacity deficiencies." *Id*. Staff interprets Company Witness Richins' explanation to mean that in a time of sustained load growth, a variety of factors have contributed to the cancellation of planned resources and increased the difficulty of acquiring new ones, creating difficult-to-resolve time constraints for the Company.

iii. A Summary of the Current Acquisition Situation

This subsection summarizes Staff's understanding of the sequence of events related to the 2028 All-Source RFP process, the inadequacy of the 2028 RFP bids to satisfy the capacity deficiency, and the Company's resolution of that inadequacy.

In his testimony, Company Witness Hackett recounted the approval process for the 2028 RFP and the subsequent selection process. Specifically, how the solicitation was divided into two groups of competitive bids with Group One bids consisting of resources that could be online before the summer of 2028 ("Group One"), and Group Two bids consisting of resources that could subsequently be online ("Group Two"). Hackett Direct at 13. The Group One winning bid was discussed in an earlier case. *See* Case No. IPC-E-25-27. Thus, Company Witness Hackett's testimony focused on the Group Two bids. Group Two bids were further sub-divided into bids with a commercial operation date ("COD") no later than June 1, 2029 ("2029 Bids"), and bids with a COD *after* June 1, 2029. *Id* at 18. Staff believes that Hackett and the Company were focused on the 2029 Bid group because only that group could alleviate the 2029 capacity deficiency.

Company Witness Hackett explained that the top-ranked project in the 2029 Bids group was the Bennett Gas Expansion Project (a Company self-build project), which already had received a CPCN from the Commission in Order No. 36958, issued in Case No. IPC-E-25-29. *Id.* at 23. The second ranked project, a combined solar and Battery Energy Storage System ("BESS"), was in the midst of negotiations.[2] *Id.* at 24. The Company already assumed these two resources would be online when it calculated the 2029 capacity deficit of 236 MW. *Id.*

When the Company considered all the remaining resources on the 2029 Bid final shortlist ("FSL"), it realized that "the remaining BESS projects…would be necessary additions to help fill the 2029 capacity deficiency." *Id*. Accordingly, the Company asked the BESS-project bidders to provide "updated pricing or general project updates…." *Id*. All the bidders complied except for two. *Id*. The long-duration storage bidder withdrew, and the Company's Internal Bid Team chose to provide "a general project update indicating a transition from the planned BESS to a natural gas resource instead." *Id.* at 25. In other words, *after* the 2029 FSL was completed and approved, the Company's Internal Bid Team withdrew its 60 MW BESS proposal and substituted a 222 MW natural gas resource. *Id.* at 26. The Company called the newly-proposed gas resource "South Hills." *Id.* at 27.

Given the new South Hills resource, the Company performed additional economic analyses and represented that the net present value ("NPV") of "a portfolio inclusive of South Hills [was] [redacted] more cost-effective than the next best feasible alternative." *Id.* at 28. Staff believes that although the South Hills project greatly alleviated the 2029 capacity deficit, it was insufficient to satisfy the incremental 2030 capacity deficit. Specifically, "even with South Hills coming online in 2029, [the Company] anticipate[d] a remaining capacity deficiency of 145 MW in 2030." *Id.* at 31. Therefore, Staff concludes that the Company needed to acquire additional resources for 2030.

Staff believes, the Company considered the remaining bids from the 2028 RFP but decided that collectively they were inadequate and what was needed was another dispatchable gas resource. As stated by the Company:

> [B]ecause of the decrease in the ELCC of new solar projects and the limited ELCC of wind resources, only the remaining BESS projects would have the potential to fill the 2030 capacity deficiency. Due to concerns with the economics of the BESS projects and their ability to meet the identified capacity deficiency, as well as the then recently published 2025 IRP that identified continued increased peak load and the need for flexible generation resources, *Idaho Power began investigating an alternative gas resource solution* that could more economically meet the Company's resource needs.

[2] The negotiated contracts have recently been filed as Case No. IPC-E-26-20.

Id. at 32–33 (emphasis added). The Company considered issuing a new 2030 RFP but represented that the long timeline prescribed by the Oregon Public Utility Commission ("OPUC") made that option infeasible. *Id.* at 33. Consequently, the Company proposed to self-build Peregrine, with a target COD of 2030. *Id.* at 34. The Company performed economic analysis with Peregrine as a possible resource and calculated that "the net present value of the portfolio that includes Peregrine [was] [redacted] more cost-effective than the best feasible alternative." *Id.* at 36.

In summary, Staff concludes that the Company contracted with several bidders from the 2028 RFP but decided that the remaining project bids were inadequate to satisfy the capacity deficit in 2029 and 2030. In addition, because of the time constraints to solicit for new resources and bring them online, the Company changed one of its self-bids from a BESS to a gas resource, awarded that self-bid, and then awarded itself a second self-built gas resource.

iv. Given the Time Constraints, the Proposed Projects Are Least-Cost Least-Risk

Staff carefully reviewed the Company's economic analyses and believes that the Proposed Projects are more cost-effective than the best feasible alternative. The most important part of this review was an assessment of feasible alternatives. The Company asserted that the only feasible alternatives were the residual bids from the 2028 RFP (a mix of solar, wind, and BESS resources) and the two gas projects injected by the Company. *Id*. at 32. Staff agrees with Company Witness Hackett's assertion that the Company had insufficient time to solicit new bids for additional resources. *Id* at 33.

Although the Company does not state the situation clearly, Staff deduced that the residual bids from the 2028 RFP were *not capable of serving* the new load without the *assistance* of at least one *new* gas resource. Company Witness Hackett eludes to this when he states that the "2025 IRP…identified…the need for flexible generation resources…." *Id.* at 32. Staff notes that flexible generation is another way of saying dispatchable generation, which includes gas-powered generation. Company Witness Ellsworth supports this argument when he describes the feasible scenarios of his economic analyses. *Id.* at 18–19. Staff believes that its observation was confirmed when the Company was asked in discovery to produce its modeling assumptions. The modeling assumptions used for each of the three scenarios included South Hills, Peregrine, or both.

Response to IIPA Request No. 1-4(a) – Confidential Attachment. Staff deduces that a scenario *without* a new gas resource could not meet system reliability standards.

Staff believes the Company had concluded that the only feasible solutions to meet load growth in 2029 and 2030 required at least one new gas resource. The only question was which combination of gas resources and resources in the remaining 2028 RFP bids would be the most cost-effective. The Company's analysis showed that the most cost-effective solution included the Proposed Projects.

Staff believes that the Company properly performed an economic analysis of these options and that the analysis was based on reasonable assumptions. Staff reviewed the assumed resources, the estimated cost of each new resource, and the calculation of the NPV for each portfolio. Staff scrutinized the adjustments the Company made to account for new gas pipeline costs, the repeal of wind and solar tax credits, and the imposition of tariffs. The Company provided a detailed breakdown of its calculations in Confidential Response to Staff Production Request No. 38, which Staff believes was reasonable.

In summary, if one accepts the Company's premise that the new resources were needed by June 1, 2029, and June 1, 2030, Staff agrees that the only feasible solution involved South Hills or Peregrine, and the most economical solution included both. Given the Company's time constraints, Staff agrees that the Proposed Projects would be part of the LC-LR solution.

v. The Proposed Projects Meet CPCN Criteria

Under *Idaho Code* §§ 61-526 and 61-528, the Company must show the financial ability, good faith, and necessity of additional service in the community to receive a CPCN. Additionally, to obtain a CPCN, the Company must follow Commission Rule of Procedure 112. IDAPA 31.01.01.112. Through discovery and review of the Company's Application and supporting documentation, Staff believes that the Company has met the necessary regulatory requirements for a CPCN for the Proposed Projects. Therefore, Staff recommends the Commission approve a CPCN for (1) South Hills and (2) Peregrine.

B. The Lack of Time has Caused Multiple Problems

Although Staff recommends approving the CPCNs for the Proposed Projects, Staff has serious misgivings about the Company misusing and bypassing RFP processes and the cost-effectiveness of the Proposed Projects. Specifically, Staff believes that the Company:

1) Misused its own RFP process to award South Hills;
2) Did not comply with *any* RFP process to award Peregrine;
3) Dismissed a lower cost solution due to time constraints; and
4) Paid a premium for the Proposed Projects due to time constraints.

Each of these problems is directly connected to the lack of time the Company gave itself to bring new resources online by June 2029 and June 2030 and is discussed in more detail below.

i. The Company Misused Its Own RFP Process to Award South Hills

As outlined in Section A(iii) above, Staff believes that the Company allowed its Internal Bid Team to categorically replace one of its bids (a 60 MW BESS project) with a completely different project (a 222 MW natural gas generator (i.e., South Hills)). According to Company Witness Hackett, "the Internal Bid Team provided a general project update indicating a transition from the planned BESS to natural gas resource instead." Hackett Direct at 25. What the Company does not state is that this complete bid replacement occurred *after* the bid deadline had passed;[3] after the bid projects had been scored and ranked by the Company and the independent evaluator;[4] and after the FSL had been approved by the OPUC.[5] In other words, by substituting a completely different project long after the selection process was complete, the Company effectively bypassed the entire RFP selection process.

Staff understands that there are extenuating circumstances but does not agree with the Company's choice to characterize the situation as a mere bid change. Staff believes that if the practice of wholesale project substitution at any point in the RFP process is accepted, all future RFP selection processes would become meaningless. Staff believes that South Hills should have

[3] The bid deadline was August 23, 2024, for Benchmark Bids and September 16, 2024, for third-party bids. Hackett Direct Exhibit No. 1 at 12.
[4] The Company filed its final shortlist on July 22, 2025. Hackett Direct at 23.
[5] The OPUC approved the final shortlist on August 30, 2025, and the Bid Evaluation Team asked bidders to update their bids in October 2025. *Id*. at 23–24

been characterized as an outside-the-RFP selection, which – although still objectionable – would have been a more accurate characterization.

ii. The Company Did Not Comply with Any RFP Process to Award Peregrine

For many years, Commission has directed the Company to acquire new resources only through a carefully monitored RFP process. Specifically, prior to January 2, 2026, the Commission directed the Company "to comply with RFP guidelines applicable in its Oregon service area, should the Company commence an RFP process for a new supply-side resource prior to the development of Idaho-specific RFP guidelines." Order No. 32745 at 2. As of January 2, 2026, the Commission directed the Company to comply with a new Idaho-specific process via Order No. 36898.

Staff interpret Order Nos. 32745 and 36898 to be premised on similar objectives: (1) ensuring a competitive process; and (2) constraining the Company's ability to award projects to itself. In the event a waiver to the normal RFP process was needed, Order No. 36898 established a waiver process, including the requirement that "[t]he Company's [waiver] application should justify the need and/or the economic value of the opportunity, and why the normal RFP process should not apply." Order No. 36898 Attachment 1.

Regarding the selection of Peregrine, Staff believes that the Company did not comply with any ordered RFP process and did not request a waiver or otherwise provide justification as to why the RFP process should not apply. Staff believes that the Company stated this indirectly when it explained that:

> [D]ue to the 18-month timeline for processing an RFP and determining a final shortlist under the OPUC competitive bidding rules that the Company was required to follow at the time, coupled with the significant lead time for major equipment, issuance of an entirely new RFP soliciting additional 2030 resources would not allow for sufficient time to procure a resource that was able to meet a June 1, 2030, commercial operation date. *As a result, the Company was required to take immediate action to evaluate the procurement of alternative resources* to fill the identified capacity deficiencies.

Hackett Direct at 33 (emphasis added). The "alternative resource" the Company selected was Peregrine. *Id.* As additional evidence, Staff notes that the 2028 RFP process documentation omits any mention of Peregrine or a gas-resource of comparable capacity. *See* Hackett Direct and Exhibit Nos. 2 and 3.

Staff also notes that the Company decided to self-build Peregrine in the second quarter of 2025, *before* the OPUC had even approved the 2028 RFP FSL. Staff's argument is derived from the fact that the Company's request to begin AFUDC accrual was in April 2025, and the Company made its large downpayment for the Peregrine turbine in June 2025. *See* Response to Staff Production Request No. 9; Waites Direct at 6–7. The Company filed its FSL with OPUC on July 22, 2025, which the OPUC approved on August 30, 2025. *See* Hackett Direct at 23.

In summary, Staff believes the Company awarded itself the self-build Peregrine project outside of any RFP process, in direct contravention of the Commission's orders.

iii. The Company Dismissed a Lower-Cost Solution

Staff also believes the Company dismissed a reasonable lower-cost resource, a combined-cycle combustion turbine ("CCCT"), from consideration due to time constraints. Because a CCCT could not be operational by June 1, 2030, the Company dismissed that resource and instead opted for Peregrine, a SCCT. Given the long-term potential cost savings of the CCCT, Staff believes the Company should have given more consideration to procuring a CCCT, while delaying the load growth or bridging the time gap with market purchases.

When a system requires additional baseload dispatchable power, a CCCT is more cost-effective than a SCCT.[6] This is because even though a CCCT costs more than an SCCT to build, a CCCT extracts approximately 50 percent more energy from each unit of gas,[7] thereby costing less to operate in the long run if significant energy is needed. The Company stated that the new load driving the need for these resources would require electricity to be generated around the clock. Ellsworth Direct at 9. Therefore, because of the superior efficiency of a CCCT, Staff believes a CCCT would be the most cost-effective option.

Staff also points to the 2025 IRP as evidence of this potential cost savings. For the 2025 IRP, in all 13 of the main cases, the Aurora system selected a 300 MW or a 400 MW CCCT in 2030, instead of a SCCT, as the most economic option. 2025 IRP (Appendix C) at 43–55. The Company further tested the validity of this result by running a "Forced SCCT 2030" scenario. 2025 IRP at 108. The result showed that "[f]orcing the replacement of the CCCT with a smaller

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[6] Northwest Power and Conservation Council – Natural Gas https://www.nwcouncil.org/2021powerplan_natural-gas_generating-resource-reference-plants/ (last visited July 17, 2026).

[7] 2025 IRP (Case No. IPC-E-25-23, Response to Staff Request No. 1 – Confidential Attachment) - the assumed heat rate for a CCCT compared to the assumed heat rate for a SCCT.

SCCT increased costs, as expected." 2025 IRP at 108. Table 10.4 in the 2025 IRP shows that the Preferred Portfolio had a NPV of $10.97 billion, and the Forced SCCT 2030 scenario had a NPV of $11.04 billion, an increase of $70 million. 2025 IRP at 114.

Even though a CCCT should be the least-cost resource, the Company said that a CCCT was not a viable option because of the time constraints. Specifically, Company Witness Hackett stated:

> A CCCT resource would require the same turbine necessary for the SCCT resource but also requires the addition of a steam component, and due to the lead time for procurement of the turbine alone, a CCCT resource would not be feasible for commercial operation by June 1, 2030.

Hackett Direct at 34. When Staff asked for specific details, the Company represented that the earliest the CCCT turbine was available in the [redacted], and that "[redacted] Confidential Response to Staff Production Request No. 43. This means that a CCCT could have been brought online in 2030, but after the summer peak, when the capacity deficit risk would be the highest. Staff believes this risk still exists for the SCCT option because of the potential for project delays. Therefore, due to the lack of time, Staff believes the Company traded the certainty of a long-term more cost-effective resource for the *possibility* of having a more expensive resource online one summer earlier.

iv. The Proposed Projects are Relatively Expensive

Lastly, Staff notes that the Proposed Projects are relatively expensive compared to existing resources. Staff believes that the relatively higher expense of these new resources is an important fact when considering the allocation of costs to ratepayers.

Staff presents two ways of showing the premium cost: (1) a comparison of the normalized capital costs assumed in the 2025 IRP to the updated capital costs for the resources in this case; and (2) a comparison of the portfolio NPV in the 2025 IRP to the NPV of a comparable portfolio in this case.

The total capital costs assumed in the 2025 IRP were based on a synthesis of industry data available in late 2024 or early 2025.[8] The total capital costs for the Proposed Projects are informed by negotiated prices for the RICE units and the SCCT turbine in mid-2025 and supplemented by estimates for the balance of the engineering and construction costs. Hackett Direct at 30, 39. In both cases, the values are normalized to the cost per kilowatt ("$/kW"). Staff provides a summary of the normalized capital costs in the Table No.1 below.

Table No. 1: Comparison of Capital Costs ($/kW)

Resource	2025 IRP	IPC-E-26-04	Percent Change
RICE	$2,587	[redacted]	[redacted]
SCCT	$1,391		

Staff believes the increased costs are primarily due to increased industry demand for dispatchable resources, [9] and companies are desperate for dispatchable power and willing to pay a premium to obtain it.

A second way to discern the high cost of the new resources is to compare the NPV calculated in this case with the NPV calculated approximately one year ago in the 2025 IRP. In order to meaningfully compare the two, the underlying assumptions needed to be matched as closely as possible. The Company stated that when it performed its economic analyses in this case, "[t]he modeling assumptions utilized in Aurora were consistent with those utilized in the 2025 IRP." Ellsworth Direct at 18. However, Staff noted the following significant differences:

1) South Hills and Peregrine were prescribed instead of generic SCCT and CCCT resources;[10]
2) The normalized costs of future resources were updated;[11]
3) The Southwest Intertie Project – North COD shifted from November 2028 to May 2029;[12]
4) The Environmental Protection Agency Rule 111(d) was assumed to be repealed; and[13]

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[8] 2025 IRP, Appendix C, p.22; and Case No. IPC-E-25-23, Response to Staff Request No.1 – Confidential Attachment 1.

[9] Penn State "Why gas turbines are in short supply – just as the grid needs them most" https://iee.psu.edu/news/blog/why-gas-turbines-are-short-supply-just-grid-needs-them-most (last visited July 23, 2026).

[10] Response to IIPA Production Request No.1-4(a) – Confidential Attachment.

[11] Response to Staff Production Request No.40.

[12] Ellsworth Direct at 13.

[13] Response to Staff Production Request No. 39(a).

5) The Qualified Facility resource forecast used the "No PURPA Replacement Contract" scenario.[14]

Staff believes the 2025 IRP scenario that most closely matches the assumptions listed above is the "Without 111(d) Bridger 3&4 NG" scenario, which had a NPV of $10,782 million. 2025 IRP at 112 (Table 10.2). Table No. 2 below compares this NPV to the current case's confidential NPV. Response to IIPA Production Request No. 1-4(a) – Confidential Attachment.

Table No. 2: Comparison of 20-year portfolio NPVs ($ million)

	2025 IRP	IPC-E-26-04	Percent Change
20-year NPV	$10,782	$[redacted]	[redacted]

Staff notes this unusually large increase in the forecasted NPV occurred in approximately one year's time. Staff believes that the primary drivers of this increase were the high capital costs for the Proposed Projects and higher operational costs caused by substituting SCCT technology for the CCCT.

In summary, Staff believes the lack of time to bring new resources online in June 2029 and June 2030 has forced the Company to acquire relatively expensive resources with respect to both the initial cost and over the long run.

C. The Company Bears Partial Responsibility for the Lack of Time

Staff believes that the fundamental issue underlying all the problems described in the previous section is the lack of time to bring new resources online. The Company needed more time to issue a new RFP to obtain adequate resource bids, and it needed more time for those new resources to be constructed. While many of the circumstances leading to this lack of time have been outside the Company's control, Staff believes this situation was foreseeable and avoidable. Therefore, Staff believes the Company bears partial responsibility for each of the problems described above.

Staff believes this current lack of time was foreseeable and avoidable based on the following three premises:

1) The Company has been in a time-constrained situation since 2021;

[14] *Id.*

2) The amount of load and load profile of the Micron memory manufacturing fabrication complex ("Micron FAB") is a singular cause of the capacity requirements from 2026 to 2030; and
3) In 2024, despite unresolved capacity deficits, the Company committed to serve the Micron FAB load, thereby compounding future capacity deficits and the time problem.

Staff addresses each of these premises in more detail below.

i. The Company Has Been Time-Constrained Since 2021

Staff believes the Company's time shortage began during development of the 2021 IRP. Staff noted in its comments in Case No. IPC-E-21-43 regarding the 2021 IRP that the Company belatedly recognized that its system was already in deficit, but to acquire new resources within acquisition lead-time, it established a 2023 capacity deficit date. Case No. IPC-E-21-43 Staff Comments at 4. Because the time to acquire resources can range widely – from two to more than five years – addressing a capacity deficit only two years away forced the Company to pursue solutions that could be implemented within the lead-time available. Continuous baseline growth in the Company's service area has created additional capacity needs each subsequent year, perpetuating the problem of only being able to solicit resources that can be quickly placed in service. The Company has filed "consecutive requests to acquire resources to be online in 2023, 2024, 2025, 2026, 2027, and 2028." Ellsworth Direct at 12 (citing to Case Nos. IPC-E-22-06, IPC-E-22-13, IPC-E-22-29, IPC-E-23-05, IPC-E-23-20, IPC-E-24-12, IPC-E-24-16, IPC-E-24-42, IPC-E-24-45, IPC-E-24-46, IPC-E-25-10, IPC-E-25-27, and IPC-E-25-29). In short, Staff believes the Company has been chasing the capacity deficit continuously since 2021.

ii. The Micron FAB Load Is the Main Cause of the 2026-2030 Capacity Deficits

Staff believes the Micron FAB load is the main cause of the 2027-2030 capacity deficits. To verify this, Staff asked the Company to perform a reliability assessment *without* the Micron FAB load, but the Company declined. Response to Staff Production Request No. 25. Therefore, Staff provides evidence from the 2025 IRP and from discovery requests in relevant cases to support its belief that the Micron FAB load is the main reason for the 2027-2030 capacity deficits.

The 2025 IRP Technical Report (Appendix C) includes monthly and annual load forecasts for each customer class. Included in these is a line item for the Additional Firm Load ("AFL") class, which consists of "Idaho Power's largest customers…including…Meta…Idaho National Laboratory (INL); Lamb Weston; Micron Idaho Semiconductor Manufacturing; Micron Technology, Inc.; Simplot Caldwell; Simplot Pocatello Don Plant…." 2025 IRP Appendix A at 23. The annual load forecast shows that the AFL class average load will grow from 258 average megawatts ("aMW") in 2026 to 875 aMW in 2030, an increase of 617 aMW. 2025 IRP Technical Report (Appendix C) at 17. Over the same time period, the total system load will grow from 2,102 aMW to 2,807 aMW, an increase of 705 aMW. *Id*. Therefore, the AFL class is contributing 88 percent of the load growth between 2026 and 2030 (617 aMW divided by 705 aMW). Accordingly, Staff believes that the AFL class is the primary cause of the capacity deficits in those years.

Among the customers in the AFL class, Micron FAB is contributing most of the growth. Exhibit No. 3 of Attachment 1 in Case No. IPC-E-24-44 (Micron FAB Special Contract) lists the minimum monthly billing demand for the Micron FAB. The demand grows from 20 MW at the service effective date (pre-2026) to 495 MW on June 1, 2030. Furthermore, this load is characterized as "flat both seasonally and diurnally." Ellsworth at 9. From this, Staff deduces that the Micron FAB by itself is adding approximately 445 aMW of load between 2026 and 2030 (495 MW times an assumed 90 percent load factor). This means that the Micron FAB's 445 aMW load growth is 72 percent of the AFL class's 617 aMW load growth between 2026 and 2030. Therefore, Staff believes that Micron FAB is the primary cause of the capacity deficits in those years because it is contributing the most growth in the AFL class.

iii. The Company Compounded the Time Problem by Agreeing to Serve the Micron FAB

Staff's final premise is that the Company compounded its inability to get resources online in time by agreeing to serve the Micron FAB in too short of a time frame. Staff acknowledges that the Company has an obligation to provide service on a nondiscriminatory basis. However, Staff notes that the Company also has an obligation to provide prudent, cost-effective resources, and therefore must allow sufficient time to obtain those resources through prudent, cost-effective processes.

The Company began communicating with Micron about a new special contract for the Micron FAB in late 2022 and ultimately signed the contract in November 2024. Response to Staff

Production Request No. 45. This was long after the Company first recognized that it was in a capacity deficit in 2021. Specifically, the Company pointed out that between 2022 and November 2024, the Company had submitted eight cases for new resources and more cases were in the approval pipeline. Ellsworth Direct at 12 (citing to Case Nos. IPC-E-22-06, IPC-E-22-13, IPC-E-22-29, IPC-E-23-05, IPC-E-23-20, IPC-E-24-12, IPC-E-24-16, IPC-E-24-42, IPC-E-24-45, IPC-E-24-46, IPC-E-25-10, IPC-E-25-27, and IPC-E-25-29). All of these cases were to acquire resources for capacity deficits stemming from baseline growth across all classes. Staff believes the difficulty of climbing out of the existing capacity deficit should have been apparent in between 2022 and November 2024. By accepting the additional Micron FAB load during that time, which must be served in only two more years, the Company significantly compounded its time problem. *See* Response to Staff Production Request No. 45.

Staff understands that several significant changes outside of the Company's control occurred over the next year, including a change of Presidential administration, reversal of green energy policies, and the imposition of tariffs. But Staff contends that the Company willingly embraced a timeline that had zero margin for error; Thus, Staff believes the Company bears some responsibility for the time crisis that has resulted.

D. **Staff's Proposed Actions**

In light of these circumstances, Staff believes that the Company ought to bear some of the financial consequences of its choices. As filed, the Company's proposals would – outside of established processes – award itself with two self-build projects for which it will potentially earn a return. Also, self-build projects lack the cost accountability that comes with a third-party contract; thus, the final cost of the Proposed Projects could be higher.

Therefore, Staff proposes the following:

1) Reject early AFUDC accrual;
2) Impose a hard cap on the Proposed Projects;
3) Delay timelines for additional NLL until the capacity deficit is remedied; and
4) Ensure the Proposed Project costs are associated with the NLL allocation case.

Each of these is discussed below.

i. Reject Early AFUDC Accrual

AFUDC is a monthly interest accrual that recognizes the opportunity cost the Company incurs while financing capital assets needed to improve or expand the system during construction. When a project is placed into service, the AFUDC accrual is incorporated into the overall cost of the asset and becomes part of rate base. In a future rate case, the Company may seek recovery on the total prudent cost of the project, including AFUDC, less accumulated depreciation.

The Company requested authority to accrue AFUDC beginning in December 2025 for South Hills and in April 2025 for Peregrine, corresponding to when the initial procurement activities occurred. Response to Staff Production Request No. 9. The initial procurement activities as of the date of application totals $[redacted] with $[redacted] relating to Peregrine and $[redacted] relating to South Hills. Response to Staff Production Request No. 8 – Confidential Attachment. Typically, the Company does not begin accruing AFUDC on generating resources until a project has been identified as the LC-LR resource. According to the Company, it made a down payment for the Peregrine turbine in April 2025 to secure necessary components to ensure the Proposed Projects could be completed in time to meet projected capacity needs. Waites Direct at 6–7. The Company also states that the requested AFUDC accrual would apply to costs associated with purchased services, materials, labor, equipment, and other costs incurred beginning in December 2025. Response to IIPA Production Request No. 1-9. Staff believes that the Company selected the only vendor with a lead time that aligned with the required in-service date. Response to Staff Production Request No. 8d. Staff also reviewed the down payment amount by reviewing the associated invoice. Response to Staff Production Request No. 8b. Staff does not dispute the Company's procurement activities or the timing of those activities. Rather, Staff's analysis focuses on whether the Company's request satisfies the Commission's prior guidance regarding authorization of early AFUDC accrual.

In Order No. 36958 issued in Case No. IPC-E-25-29, the Commission authorized the Company to accrue AFUDC for the Bennett Gas Expansion Project beginning with the initial procurement activities. In doing so, however, the Commission emphasized that early AFUDC accrual was appropriate under the specific facts of that case and declined to authorize AFUDC for prospective resource procurements solely because the Company considered a project to be a viable resource. *Id.*

As outlined in Sections B and C above, Staff believes the circumstances supporting the Commission's decision in Order No. 36958 are not present in this case. In the Bennett Gas Expansion Project, the Commission found that the Company completed the RFP process and identified the project as the LC-LR resource, consistent with Order No. 36898. Order No. 36958. By contrast and in this case, Staff believes that the Company neither completed the RFP process nor sought a waiver under the framework established in Order No. 36898. Therefore, Staff believes the Commission's decision in Order No. 36958 does not support the Company's request in this case. Accordingly, Staff recommends the Commission deny the Company's request to accrue AFUDC beginning with the initial procurement activities. Instead, Staff recommends that accrual should begin with the issuance of an order granting a CPCN for each facility.

ii. Impose Hard Caps on the Proposed Projects

Staff recommends the Commission to set hard caps on recovery for each of the Proposed Projects. A hard cap on each project will limit the total amount that ratepayers may need to pay when the Company seeks recovery of its investments. Staff believes there are multiple reasons for establishing a cost cap on the South Hills and Peregrine projects.

First, a hard cap would incentivize the Company to construct each proposed natural gas plant within the cost estimate provided in this case. As described above, Staff believes the Company is unfairly favoring its own self-build projects by bypassing the RFP process. Additionally, the Company has a profit incentive to earn a rate of return on its capital investments. As such, the Company has incentive to invest as much capital as possible. In this case, the Proposed Projects are self-build projects, in which the Company may earn a rate of return. Without a hard cap, Staff believes the Proposed Projects lack adequate cost accountability that would neutralize any incentives from capital returns.

Second, because self-build projects do not have the typical contractual cost overrun protections that occur in third-party contracts, there are no contractual cost overrun protections. Staff believes the hard cap would act as a protection for all ratepayers. The only contractual protection that Staff has discovered would come from engineering-procurement-construction agreements, but those only address a portion of the overall project value. *See* Response to Staff Production Request No. 7. The proposed South Hills and Peregrine Power Plants have an estimated cost of [redacted] million and [redacted] million, respectively, as of July 16, 2026. Confidential

Response to Staff Production Request No. 46. If the Company's final construction costs exceeds its most recent cost estimate, Staff believes the Company may seek recovery of the additional costs from ratepayers in a future proceeding.

Lastly, Staff believes there should be a hard cap because the Company is partially responsible for the timing issue that has effectively forced these two projects to become the only feasible options. Staff believes that the Company should not be able to shift the cost of its questionable decision making onto ratepayers.

In view of these concerns, Staff believes that ratepayers should not have to absorb the financial consequences if the Company exceeds the current cost estimates. Therefore, Staff recommends that the Commission establish a hard cap on recovery for each Proposed Project, set at the Company's most recent cost estimate for each, as shown in Confidential Attachment A to these comments.

iii. Delay Signing Additional NLL

As the Company works to address its identified capacity deficits, Staff recommends that the Company delay signing additional NLL Energy Service Agreements until the Company's system recovers sufficient capacity headroom and the Company has adequate time to properly solicit and build new resources. NERC provides similar guidance in its recent Large Loads Working Group Reliability Guideline:[15]

> Demand may outstrip generation supply as large loads are added faster than the addition of generation resources. Many large loads are expected to require firm service, limiting their ability to be considered flexible or providing limited demand-response capabilities. This directly impacts [bulk power system] reliability through the reduction of [Balancing Authority] Operating Reserves. To address this, [Resource Planners] should model scenarios in their evaluation of resource adequacy, *such as delayed generation additions*, before incorporating large load additions.

Large Loads Working Group Reliability Guideline at 12 (emphasis added).

In this current era of rapid utility growth, Staff believes the time it takes to solicit, contract, and build new resources ranges from three to five years for variable energy resources and five to

[15] NERC "Risk Mitigation for Emerging Large Loads" Large Loads Working Group Reliability Guideline May 2026 https://www.nerc.com/globalassets/our-work/guidelines/reliability/RG_Risk-Mitigation-For-Emerging-Large-Loads.pdf (last visited July 16, 2026).

ten years for baseload and transmission resources. Therefore, Staff believes it is essential for the Company to allow for a longer procurement horizon**,** reflective of such development lead times. New firm commitments to serve NLLs should match the realistic availability schedules of planned infrastructure. Staff argues this alignment avoids circumventing RFP processes or resorting to inefficient, costly resources.

If the Company decides to commit to a NLL before fully resolving the system capacity deficit, Staff recommends the Company (1) require the NLL to be interruptible before other customers during capacity shortfall events; or (2) require the NLL to fully fund the needed resources and being allocated their full cost. Staff recommends that the Commission direct the Company to provide a detailed plan to resolve any system capacity deficit, whenever the Company proposes to enroll additional NLL.

iv. Associate the Project Costs with the NLL Allocation Method

Staff acknowledges that this case is not the appropriate venue for determining class cost of service, rate design, or cost allocation results for these projects. However, Staff requests that the Commission direct the Company to ensure all costs associated with the Proposed Projects, inclusive of adding natural gas pipeline capacity, transportation, storage, fuel delivery infrastructure, interconnection upgrades, and any other related or enabling investments, are fully captured, clearly documented, and distinctly tagged in the Company's records so they can be readily isolated, retrieved, and reported in future proceedings. Staff believes it is important that these costs be recorded in a manner that preserves their visibility and traceability for future proceedings, rather than being consolidated, blended, or embedded in ways that make them difficult or impossible to isolate later. Staff notes that this level of cost clarity is essential so that the full set of project-specific costs can be accurately used in future proceedings according to the methods and requirements to be forthcoming in the Company's parallel docket to evaluate its cost-of-service methodology, Case No. IPC-E-26-07.

III. PUBLIC INPUT

As of July 31, 2026, the Commission received 152 written customer comments regarding the Company's Application. All customer comments expressed opposition to the Company's proposal to construct two natural gas-fired generating facilities. Many of the comments contained substantially similar form language, while several customers supplemented the form language with individualized statements expressing additional concerns or recommendations.

The comments expressed concerns regarding the potential impact of the proposed facilities on customer rates, including the anticipated construction costs and future natural gas fuel costs. Many customers raised concerns regarding air quality, greenhouse gas emissions, and other environmental impacts associated with natural gas generation. Several customers questioned the Company's projected load growth and whether the proposed facilities are necessary to meet future energy needs. Other comments addressed the availability of interstate natural gas pipeline capacity needed to serve the proposed generating units.

Numerous customers encouraged the Company to pursue alternative resources, including battery energy storage, solar generation, and other renewable energy resources, as alternatives to the proposed natural gas facilities. Customers also expressed concern that increased demand associated with large commercial customers, including data centers, should not result in additional costs being borne by existing residential customers. Additional comments referenced the Company's long-term clean energy objectives, the Company's IRP process, rooftop solar policies, public health considerations, and potential impacts of the proposed facilities on Idaho's environment and natural resources.

Several customers submitted individualized comments in addition to the form comments. These comments provided more specific concerns and recommendations regarding the Company's proposal, including requests that the Commission carefully evaluate the need for the proposed facilities, consider available alternatives, examine potential impacts to customers, and ensure future energy needs are addressed while balancing reliability, affordability, and environmental considerations. Although the specific concerns varied among customers, the individualized comments generally reflected a desire for additional review of the Company's need determination, projected load growth assumptions, and potential impacts of the proposed facilities on customers and Idaho communities.

Overall, the comments reflected Customer concerns regarding the affordability of electric service, the Company's long-term resource planning, the environmental impacts of the proposed generating facilities, and the allocation of costs associated with serving future load growth. Customer comments received by the Commission have been included in the record for the Commission's consideration.

IV. STAFF RECOMMENDATIONS

Staff recommends the Commission:

1) Approve CPCNs for South Hills and Peregrine;
2) Deny the Company's request to accrue AFUDC beginning with the initial procurement activities. Instead, accrual should begin with the issuance of a final order granting the CPCN for each facility;
3) Establish separate hard caps of recovery for South Hills and Peregrine, set at the Company's most recent cost estimate for each, as shown in Confidential Attachment A;
4) Direct the Company to provide a detailed plan to resolve any system capacity deficit, whenever the Company proposes to enroll additional NLL; and
5) Direct the Company to ensure all costs associated with South Hills and Peregrine, inclusive of additional natural gas capacity and infrastructure, interconnection upgrades, and any other related or enabling investments, are fully captured, clearly documented, and distinctly tagged in the Company's records.

Respectfully submitted this 31st day of July 2026.

Kelsea Ross

Kelsea E. Ross
Deputy Attorney General

Technical Staff: Matt Suess, Kimberly Loskot, Steven Verdieck, and Karla Ducharme

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CONFIDENTIAL ATTACHMENT A

[redacted]

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 31st DAY OF JULY 2026, SERVED THE FOREGOING **REDACTED COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-26-04, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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