Observations on Idaho Power Company's Draft 2028 All-Source Request for Proposals for Peak Capacity and Energy Resources: Independent Evaluator Assessment Report

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May 28, 2024

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List of acronyms

AS	All-Source
B2H	Boardman to Hemingway
BEF	Bid Entry Form
BSA	Battery Storage Agreement
BTA	Build-Transfer Agreement
COD	Commercial Online Date
DR	Data Request
ERIS	Energy Resource Interconnection Service
FSL	Final Shortlist
GIA	Generation Interconnection Agreement
IE	Independent Evaluator
IPC	Idaho Power Company
IRP	Integrated Resource Plan
ISL	Initial Shortlist
LEI	London Economics International LLC
LGIA	Large Generator Interconnection Agreement
LTSA	Long-Term Service Agreement
NIPPC	Northwest & Intermountain Power Producers Coalition
NRIS	Network Resource Interconnection Service
OAR	Oregon Administrative Rules
OPUC	Oregon Public Utility Commission
PPA	Power Purchase Agreement
Q&A	Question and Answer
RFP	Request for Proposals
S&P	Standard & Poor's
SGIA	Small Generator Interconnection Agreement
SMM	Scoring and Modeling Methodology
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

1 Executive Summary

London Economics International LLC ("LEI") was retained to serve as the independent evaluator ("IE") of Idaho Power Company's ("IPC" or "the Company") 2028 All-Source ("AS") Request for Proposals ("RFP") for Peak Capacity and Energy Resources ("2028 AS RFP"). This report is the first deliverable of this engagement, in which LEI provides its observations and recommendations with respect to the draft 2028 AS RFP ("Draft RFP") originally filed by IPC on February 29, 2024,[1] later updated on April 24, 2024[2] and May 17, 2024.[3] This report also includes a summary of stakeholders' comments discussed during the Introductory Stakeholder Workshop ("Workshop") hosted by IPC on May 14, 2024.

On April 30, 2024, the Public Utility Commission of Oregon ("OPUC," or "Commission") granted Idaho Power Company a partial waiver of OAR 860-089-0200 (1), subject to the conditions recommended by the Commission Staff ("Staff"), thus approving LEI (the IE of 2026 All-Source RFP) as the IE for the IPC's 2028 AS RFP. IPC was also granted a partial waiver of OAR 860-089-0250 (2), allowing the Commission to consider IPC's proposed scoring and modeling methodology concurrent with its review of the 2028 Draft RFP. The waivers were originally filed by IPC "in order to further expedite review of the 2028 All-Source RFP,"[4] thus allowing sufficient time for the resources selected to be built and commercialized to meet the energy and capacity needs identified for the summer of 2028.

IPC first filed the Draft RFP with the OPUC on February 29, 2024. Under the accelerated schedule agreed upon between IPC and the OPUC, the IE is slated to release an Independent Evaluator Assessment Report ("IE Report") by May 28, 2024. In this IE Report, in compliance with the Commission's April order,[5] LEI included a summary of lessons learned drawn from its monitoring of the 2026 All-Source RFP ("2026 AS RFP") (see Section 3). In Section 4, LEI highlights key comments and recommendations drawn from its review of the Draft RFP and participation in the Workshop (see Figure 1 for a summary of the IE's recommendations). Finally in Section 5, LEI summarizes stakeholders' comments on the Draft RFP.

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[1] In the Matter of Idaho Power Company, Application for Approval of 2028 All-Source Request for Proposals to Meet 2028 Capacity Resource Need, February 9, 2024.

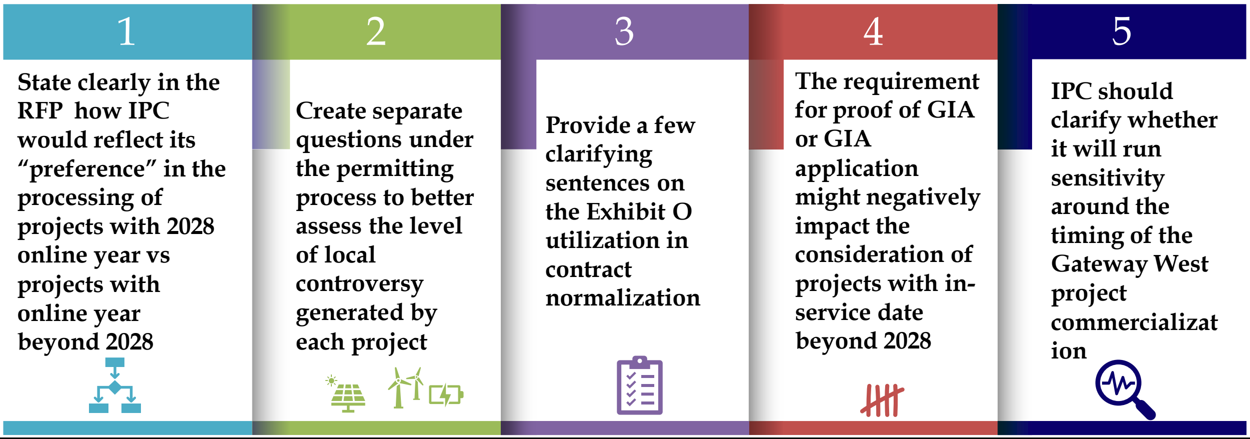
[2] Idaho Power's Revised 2028 All-Source RFP, April 24, 2024.

[3] Idaho Power's 2028 All-Source Request for Proposals Final Draft, May 17, 2024.

[4] Idaho Power Company's application and request for partial waiver of competitive bidding rules, February 29, 2024.

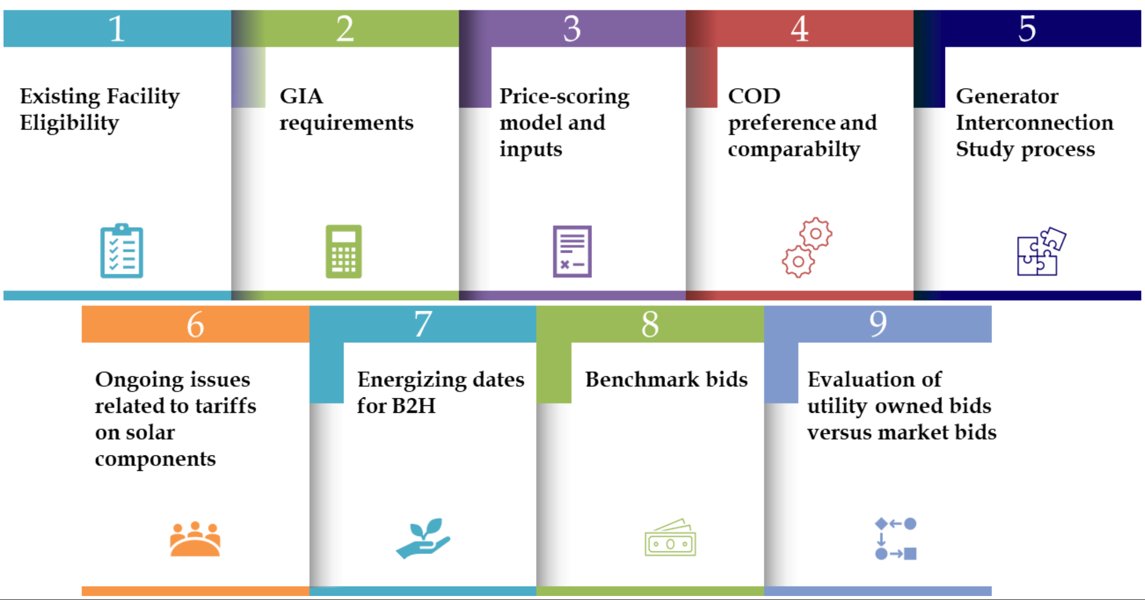
[5] Public Utility Commission of Oregon Staff Report Public Meeting April 30, 2024, Docket No. UM 2317, May 2, 2024.

Figure 1. List of LEI's recommendations with respect to the Draft RFP



Stakeholders present at the Workshop also had several comments on the first draft RFP documents.[6] These main comments are listed in Figure 2 below and discussed in detail in Section 5.

Figure 2. List of stakeholder comments on the Draft RFP



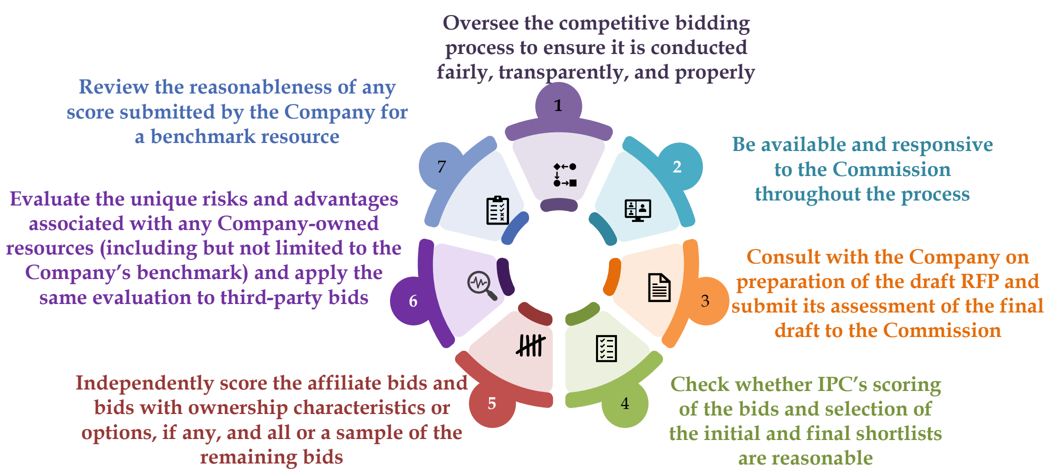
[6] The Draft RFP was attached to IPC's Application and Request for Partial Waiver of Competitive Bidding Rules filed with the OPUC on February 29, 2024.

2 Introduction

IPC is in the process of issuing an RFP through which it seeks to procure up to 138 MW of peak capacity resources and 555 MW of energy resources. This RFP is a response to the resource needs identified in IPC's 2023 Integrated Resource Plan ("IRP").[7] The Company, through this RFP, is soliciting bids for two types of products, namely (i) unit-contingent energy and capacity delivered from electric resources that support the energy and capacity needs identified through the 2023 IRP and (ii) Market Purchase Proposals, or firm energy (preference for the Western Systems Power Pool ("WSPP") Schedule C or equivalent) that meet the eligibility requirements of the Western Resource Adequacy Program ("WRAP") in terms of resource or system specificity, transmission, and other requirements.[8] Resources can be existing[9] or new; new resources must have a pending or executed Large Generator Interconnection Agreement ("LGIA")/Small Generator Interconnection Agreement ("SGIA"), and a target commercial operation date ("COD") on or before the summer of 2028, or beyond. In addition to the bids expected to be submitted, the Company will also submit three affiliate (benchmark) bids,[10] which will be evaluated using the same bid scoring criteria as third-party bids. This RFP process will be monitored by the IE, to ensure that the RFP process is conducted in a fair and reasonable manner. Per Oregon Administrative Rules ("OAR") 860-089-0450, the IE's duties include the items enumerated in Figure 3. The IE Report is one of several deliverables the IE will be filing with the OPUC as part of its responsibilities.

This IE Report summarizes LEI's comments and recommendations with respect to the Draft RFP filed on February 29, 2024, updated on April 24, 2024, and finalized on May 17, 2024.

Figure 3. Duties of the IE



[7] The 2023 IRP was filed on September 29, 2023; it is currently under review by the Commission.

[8] *Ibid*.

[9] Not contracted to deliver to IPC as of or after April 1, 2028.

[10] See Exhibit P of Draft RFP.

3 Lessons learned from the 2026 All-Source RFP

The partial waiver of OAR 860-089-0200 (1) and (2) granted by the Commission to IPC was subject to conditions recommended by Staff, including a request that the IE "include in its initial report an analysis of lessons learned and opportunities for improvement from the previous RFP."[11] In this section, LEI summarizes key takeaways from its monitoring of the 2026 All-Source RFP process, and discusses how it relates to current and future RFP processes.

3.1 Clear instructions and a well-defined RFP schedule are crucial elements for ensuring a seamless RFP process

In the 2026 AS RFP, LEI highlighted the clarification and additional precision needed in the RFP itself to enhance the bidders' understanding of the process; most of these recommendations were reflected in the final version of the RFP filed with the Commission. Mitigating bidders' confusion upfront has allowed the consultation (including questions and answers ("Q&A")) with the stakeholders to be focused less on procedural matters and more on important overarching issues (such as the exclusion of the imputed debt, contract normalization, and scenario analysis). Similarly, the bid submission process, completeness of the bids, and communication with bidders were carried out without major incidents, mainly because there seems to have been alignment between IPC's and bidders' expectations on the process. The 2028 AS RFP was designed to reflect the final version of the 2026 AS RFP; carrying past recommendations over into new processes generates efficiencies, saves time, and reduces uncertainty for stakeholders.

3.2 Inputs of the IE in the scheduling process

The IE has a very important mission to monitor the procurement process; ensuring it is conducted fairly, transparently and properly; and that it complies with the state's Competitive Bidding Rules. The IE performs its independent review activities throughout the procurement process and reports on key milestones of the process. While we understand that utilities develop procurement schedules in line with internal objectives and timelines, it is imperative that the IE be allocated sufficient time to carry out its tasks. At times in the 2026 AS RFP process, the IE felt pressured to expedite its analysis within timelines that were not commensurate with the scope of work. To allow for efficiency going forward, we recommend the participation of the IE in the finalization of the RFP schedule to be explicitly one of the first milestones of the Draft RFP process.

Per this recommendation, the IE was provided the opportunity to share its inputs for the final schedule of the Draft RFP; in this respect, we have no major concern with the IE's deliverables timeline for the 2028 AS RFP.

3.3 Project management

The availability of the utility's key team members is instrumental to successful communication. Conducting weekly or bi-weekly calls aids in keeping the entire team (OPUC, IPC, and the IE) informed about the progress of the RFP process and offers an opportunity for all parties to ask

[11] Public Utility Commission of Oregon Staff Report Public Meeting April 30, 2024, Docket No. UM 2317, May 2, 2024.

questions. These scheduled meetings should be incremental to any ad-hoc meeting required for any outstanding issues that warrant a discussion. While weekly calls with the utility might not be necessary, it is still best practice for the IE to hold regular (weekly) meetings with the OPUC; not only does it allow for a constant flow of information between the parties, but it also enables both parties to have meaningful conversation on important matters.

We recommend weekly calls between the IE and OPUC Staff and, at a minimum, bi-weekly calls between the IE, Staff, and the utility.

3.4 Alignment with IRP

It would be ideal for RFPs to align with Commission-approved IRPs. The 2026 AS RFP was subject to constant adjustments following changes in IRP data. While we do not expect similar issues in the 2028 AS RFP, as the needs identified for 2028 stem from the final 2023 IRP which is already under the Commission's review, going forward, we recommend that utilities give more consideration to this issue.

3.5 Non-price scoring and final project selection

There might be a need to revisit the non-price scoring to provide meaningful weight to a project's status. It is important to factor into the analysis COD contingency regarding transmission infrastructure under development, such as the Boardman to Hemingway ("B2H") and the Gateway West transmission projects; the timeliness of the development of this infrastructure has a direct impact on the ability of prospective generators to meet in-service dates. Ideally, IPC should also consider selecting bids in the Final Shortlist ("FSL") with no contingency to proposed/under-construction transmission lines.

3.6 Contract negotiations monitoring

The IE should be included in the contract negotiations to uphold fairness throughout the RFP process. Contract monitoring was not part of the original scope of the IE's work in the 2026 AS RFP; however, as we progressed through the procurement process, the need for the IE to monitor contract negotiations became increasingly apparent in the face of emerging concerns over alternative contract arrangements IPC was planning to consider and the ability of IPC and bidders to agree on key contracting terms. Going forward, we recommend that the IE's scope of work explicitly includes monitoring of contract negotiations. Included in this requirement is for the utility to ensure that the IE is invited to all meetings and copied on all email exchanges between the utility and the bidder.

3.7 Contract execution

In the 2026 AS RFP, the number of projects (and associated volume of energy and capacity) selected in IPC's Final Shortlist exceeded the needs identified for 2026 and 2027. As the IE understands it, it is not IPC's intent to sign contracts with all projects in the FSL but rather to ensure that the Company will be able to sign contracts that meet the needs mentioned in the RFP. As of preparing this report, only one contract (a market-based bid) has been executed; all remaining projects are still under negotiation. LEI will continue to monitor and report on these negotiations; as such, key takeaways will be shared, when available.

4 LEI's observations with respect to the Draft RFP

The IE reviewed the Draft RFP filed on February 29, 2024 in Docket UM 2255, later updated on April 24, 2024 and made available to the IE on May 1, 2024. The relatively accelerated review time allocated to the IE (from May 1, 2024 to the submission of the IE report on May 28, 2024) was balanced by the design of the RFP documents that emulated the final version of the approved 2026 AS RFP; as such, it included recommendations made by both the IE and Staff. Nonetheless, the IE has identified a series of recommendations that would add more clarity to the RFP. We also comment on several issues that warrant further consideration.

4.1 IE's recommended adjustments to the Draft RFP

LEI, as the IE, recommends that IPC incorporate in the final RFP the improvements listed in Figure 4. In the following subsections, LEI describes in greater detail areas of concern and proposed improvements that should be reflected in the final RFP.

Figure 4. Summary of recommendations to be incorporated in the final RFP

1) Resource preference	State clearly in the RFP how IPC would reflect its "preference" in the processing of projects coming online in 2028 vs projects with in-service date beyond 2028
2) Permitting	Create separate questions under the permitting process to better assess the level of local controversy generated by each project; this could include assessment of consultation with the community
3) Contract normalization	Provide a few clarifying sentences on the utilization of Exhibit O in contract normalization
4) Requirement for securing GIA	The requirement for proof of GIA or GIA application might negatively impact the consideration of projects with in-service date beyond 2028
5) Sensitivity	Include sensitivity analysis around the commercialization timing of the Gateway West transmission project

4.1.1 Resource preference

In the RFP, IPC states "While IPC is focused on meeting needs in 2028, IPC is interested in receiving proposals beyond 2028 as well and will review over the course of the evaluation process based on the most up-to-date information."[12] In this respect, we understand that IPC, during scoring, will not discriminate against projects coming online post-2028. Nonetheless, it is not clear in the Draft RFP how IPC will consider the two categories of projects in its evaluation. During the May 14, 2024 Workshop, IPC justified the expansion of eligibility to projects with a commissioning year beyond 2028 by its foundational goal of selecting the most cost-effective

[12] Draft 2028 All-Source Request for proposals for peak capacity and energy resources, May 17, 2024.

projects (and thus not filtering out cost-effective projects solely based on their in-service date). IPC nonetheless stated that although they would consider all projects, they would have a preference for the projects coming online in 2028. We recommend that IPC better articulate the evaluation process for these two categories of projects in a fair and non-discriminatory manner. For instance, because the 2028 needs stem from the 2023 IRP, IPC could first solve for the 2028 energy and capacity needs (considering only projects with a 2028 in-service date), and then evaluate separately all other projects coming online beyond 2028. However, the efficiency of this approach could be limited when we factor in the cost-effectiveness of the prospective projects. For example, the difference in risk and cost profile between a 2028 project and a 2029 project could be so overwhelming in favor of, for example, a 2029 project, that it would force IPC to reconsider prioritizing the 2028 project over the 2029 project, solely based on in-service date. We recommend IPC provide a description of its methodology to address this issue.

4.1.2 Permitting

In the Bid Entry Form ("BEF"), question 8 combines a number of requirements that relate to the ability of a developer to obtain site control, permitting, notification to proceed, and so forth. The question of site control and permitting greatly impacts a project's ability to be built on time. Permitting issues tend to be localized and, in some cases, dependent on the support (or lack thereof) of the communities within which the proposed project is sited. We recommend that IPC add explicit language/questions to the non-price scoring to assess the level of community engagement and risk of controversy. The higher the risk of controversy, the higher the risk of project delay or cancellation. It could be an additional question requesting proof of initial (or completion of) consultation with the community, town hall meetings, memorandum of understanding with the community, or others.

4.1.3 Contract normalization

Exhibit O appears to be a useful tool for IPC to compare various terms on equal footing bids. However, there is little context provided on Exhibit O. We recommend that IPC indicate that Exhibit O is a template for informational purposes only, and add general commentary on how Exhibit O will be used.

4.1.4 Proof of GIA application, a concern for large generators

In Section 4.2 of the RFP, IPC indicates its preference for "bids from resources with proof of generator interconnection status and ability to deliver, such as a pending or executed Generation Interconnection Agreement (LGIA or SGIA), progress or status of the interconnection study, and/or understanding of contingent queue projects that may hinder deliverability."[13] In the non-price scoring, resource-based bids earn points based on progress made on the GIA. Bidders who lack documentation on the submittal of a GIA receive "0" points. Although we understand the need for IPC to hedge some of the project risks (related to in-service dates), the scoring on this question negatively impacts projects with commercialization dates beyond 2028. Large projects with in-service dates in 2030, for instance, are unlikely to be registered in the transitional cluster

[13] Draft 2028 All-Source Request for proposals for peak capacity and energy resources, May 17, 2024.

study, and as such the earliest cluster study window available to these projects would be after March 2025[14] (with results known by 2026 or 2027). It is unlikely that projects coming online post-2028 would secure a GIA; in this case, the projects' answer would be "red." Consistent with Section 4.1.1, if IPC plans to evaluate all 2028 and post-2028 projects separately, we recommend that—for post-2028 bids—IPC use a modified form that does not include the GIA criteria.

4.1.5 Sensitivity

We would like IPC to clarify whether any sensitivity analysis will be carried out on the commercialization year of the Gateway West transmission project. We recommend that such analysis be reflected in IPC's sensitivity modeling exercise.

4.2 Summary of improvements made by IPC in the May 17, 2024, RFP update

The Final Draft RFP filed by IPC on May 17, 2024, is reflective of the following comments:

- **Clarifying bid fee requirement:**
  A correction was made to the eligibility criteria (Criteria #5) of Appendix D. The language was modified to reflect that market-based bids also need to provide a bid fee, similar to resource-based proposals.

- **Non-Price Scoring Matrix (Exhibit D)**
  IPC added a weight to each question of the "Market Purchase Non Pricing" tab (similar to what was already provided in the "Resource-based Non Pricing" tab). Both NIPPC and the staff in the workshop made this request.

- **Updating the RFP schedule:**
  The schedule in Section 2.8 was updated to reflect the latest changes agreed upon between IPC, Staff, and the IE.

- **Clarifying requirements for bid packages:**
  The paragraph "Exceptions to the Draft Form Agreements" was moved from Section 6.12 (under Section 6 "Requirements for All Bid Packages") to Section 4.7 (under Section 4 "Resource Based Proposals: Additional Specifications and Instructions"), as Exhibit F on the draft form agreement only applies to resource-based bids.

  Table 6.1 was renamed from "non price factor" to "Bid Package Requirements" and further rows were added to be consistent with the text in Section 6.4.

- **Changes in Section: 7.3 Phase 2 – Final Shortlist**
  The reference to B2H was removed. During the Workshop, IPC noted that B2H would not impact the bid evaluation given that the project would be commercialized before 2028.

[14] After March 1, 2025, all projects greater than 20 MW would be subject to the cluster study.

5 Stakeholders' comments on the Draft RFP

On May 14, 2024, IPC hosted the "Draft RFP and Scoring and Modeling Methodology Workshop" virtually via Microsoft Teams to introduce its 2028 All-Source RFP (UM 2317) to interested stakeholders. IPC presented the Company's procurement needs, ownership types (asset purchase or power purchase agreement ("PPA")/battery storage agreement ("BSA")), delivery point, transmission arrangements, and commencement of commercial operations, among other eligibility criteria. IPC also provided an overview of the RFP submission process and changes from the 2026 AS RFP. Based on Microsoft Teams' list of virtual meeting participants, over 30 stakeholders joined this Workshop. These stakeholders represented various organizations, including the Company, the Commission, consultants, and generators.

5.1 Existing facility eligibility

Stakeholders expressed their interest in having the RFP include some flexibility for existing projects to repower. During the Workshop, IPC confirmed that projects near the end of their PPA terms can bid into the RFP and will be considered a new resource. Priority will be given to projects repowering from summer 2028 and any time thereafter.

NIPPC issued a discovery request for clarification on this issue (DR#1).

5.2 Generation Interconnection Agreement requirement

Stakeholders expressed concern with the RFP process starting in advance of 2023 IRP acknowledgment, and how this short notice could limit the number of projects that could meet the RFP's GIA requirements. Exhibit C (Bid Eligibility) of the RFP states that an eligible bid, among other eligibility requirements, must provide "Evidence that the Bidder's proposal has a Generator Interconnection Agreement OR Generator Interconnection application in either the IPC Serial Study Process or the Transitional Cluster Study Process[15]." During the Workshop, IPC explained that potential interconnection and upgrade costs and schedule will unlikely be available before mid-2026, but the Company requires confirmation that the GIA process started as an added assurance that the project commercial operational is viable.

NIPPC issued a discovery request for clarification on this issue (DR#3).

5.3 Availability of the price-scoring model and inputs to the public

Stakeholders expressed interest in having access to the price-scoring model and its inputs. During the Workshop, IPC explained that the model (with formulas intact) will be shared with the IE and Commission Staff; what is ultimately made available to the public is a report of these inputs being viable and accurate. Model assumptions will be aligned with the 2023 IRP, with some specific updates based on new information available (for example, changes in discount rate or production tax credit rates).

[15] Draft 2028 All-Source Request for proposals for peak capacity and energy resources, May 17, 2024.

NIPPC issued a discovery request on this issue. It requested the price scoring model and all assumptions used for the value of tax benefits of utility-ownership bids, including carrying costs, transferability assumptions, and any other assumptions (DR#4).

5.4 Commercial operation dates and their scoring/comparability

Stakeholders are of the view that IPC is likely to prefer a summer 2028 COD. The RFP states that "IPC will be accepting bids for energy or capacity incremental to its system beginning in the summer 2028 timeframe and beyond from Resource-Based Proposals and Market Purchase Proposals. While IPC is focused on meeting needs in 2028, IPC is interested in receiving proposals beyond 2028 as well and will review them over the course of the evaluation process based on the most up-to-date information." During the Workshop, IPC confirmed that priority will be given to 2028 COD to fulfill the needs identified in the 2023 IRP; however, 2029 COD and beyond will also be considered based on economic opportunity and anticipated needs for the following years.

Scoring for the different CODs will be calculated in separate annual "buckets." Projects meeting the 2028 COD will be evaluated/scored in the 2028 COD bucket.

5.5 Generator Interconnection Study process (ERIS versus NRIS)

Stakeholders were satisfied with the RFP allowing for bids with Energy Resource Interconnection Service ("ERIS") interconnection, but wanted to understand the non-price scoring for bids with ERIS versus Network Resource Interconnection Service ("NRIS"). During the Workshop, IPC confirmed that having an NRIS study provides a non-price scoring advantage of 5% (equivalent to 1.25 points out of the 25 total points for the non-pricing score), and further explained that the NRIS is a more fulsome study that explicitly evaluates transmission service available, providing more confidence that the transmission service request would not be constrained.

5.6 Ongoing issues related to tariffs on solar components

Stakeholders expressed concern about solar resource bid cost increases due to potential changes to tariff exemptions and other ongoing anti-dumping complaints and issues in the solar industry, as well as how IPC would handle such circumstantial changes during the RFP process. During the Workshop, IPC acknowledged this concern and the volatility this brings to the solar and battery markets over the next couple of years. In the RFP process, bidders will have the opportunity to update their bids after the Initial Shortlist ("ISL"), and during contract negotiations. However, if the bids experience material changes that either affect the ability to deliver on the proposed COD or make the project uneconomical, IPC will need to reevaluate whether the bids remain the best projects for the results of the RFP.

5.7 Energizing dates for B2H

Stakeholders expressed concern over recent news regarding energizing dates for the B2H transmission line and the impact on the 2028 AS RFP. During the Workshop, IPC explained that B2H is assumed to be online prior to the 2028 COD.

5.8 Benchmark bids

One stakeholder asked if IPC anticipates including additional benchmark bids beyond what was disclosed in the RFP's Exhibit P (Proposed 2028 AS RFP Benchmark Bids). Specifically, the stakeholder referred to changes at the at the federal level around normalization of tax credits that has opened up some opportunities for utilities to submit solar-owned solar projects. During the Workshop, IPC stated that it does not anticipate anything different than what is already in the RFP as far as benchmark bids.

5.9 Risk evaluation of utility-owned bids versus market bids

In the 2026 AS RFP, stakeholders expressed concerns over the evaluation of the unique risks and advantages of utility-owned bids versus market-based bids; the application of a contingency cost adder to utility-ownership bids under certain circumstances was suggested[16] as a method to address this concern.

In June 2023, as part of its work as IE for the 2026 AS RFP, LEI investigated the potential of including a cost adder to get Build Transfer Agreement ("BTA") and PPA bids "on equal footing." LEI's investigation revealed a lack of readily available evidence to easily quantify the risks associated with BTAs relative to PPAs. Notably, we identified a past cost adder proposal put forth by NIPPC in 2012 (in Docket UM 1182), which the Commission ultimately rejected in Order 13-204 due to its reliance on a limited dataset and concerns about precision, as it would apply bid adders uniformly to all benchmark resources irrespective of individual bid circumstances. The Commission also acknowledged that the application of generic cost adders to every utility-owned resource could distort the comparative analysis done by the IE.

LEI agrees with the Commission's determination in UM 1182 that there is no fair, sure way to quantify/determine cost adders. Instead, LEI believes that any cost overruns could be better reviewed and addressed in the context of rate case proceedings. While there may be other examples of these sorts of discussions taking place in other jurisdictions, LEI has come across one such example.

In a recent RFP proceeding in Colorado, stakeholders expressed concern that the lack of a mechanism to hold utility-owned bids to their cost, stated performance, and construction schedules could increase costs to customers and "impact the justification of the need determinations made" in the utility's electric resource plan.[17] As such, the regulator determined that utility-owned bid prices should not be allowed to change significantly.

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16 Northwest & Intermountain Power Producers Coalition's Comments On Draft Request For Proposals, UM 2255, March 17, 2023.

17 This concern was informed by past instances of cost overruns or lackluster asset performance, which some stakeholders argued was a burden on ratepayers. Hence, stakeholders wanted to shift some of this risk from ratepayers onto the utility.

- The solution in Colorado was to put in place (two) symmetrical performance incentive mechanisms ("PIMs") that would apply to each project (not to the utility's portfolio of projects) with a narrow deadband (5%) around which any cost overruns or savings would be shared between the utility and customers.[18] However, this scheme does not appear to be an ideal solution for costs and performance accountability. Some stakeholders in Colorado have argued that PPAs aren't eligible for a similar risk-sharing arrangement (where they could potentially earn any amount other than their bid price) while the PIMs mechanism does not address the fact that the utility-owned bid was awarded a contract under the RFP process over a third-party bid. Although not perfect, this is one option that is worth noting in the context of this discussion.[19]

- In addition to the PIMs concept, other ideas discussed included Colorado Commission Staff's recommendation to allow cost recovery on a $/MWh-basis, similar to how PPAs recover their costs, and to tie recovery to the utility's revenue requirement and modeling projections provided in its electric resource plan.[20] Commission Staff argued that the benefits of this approach include greater alignment of customer and utility incentives, similar treatment of utility-owned assets to the treatment received by PPAs, and assurance of reasonable costs, among others. It does not seem that this recommendation was approved by the Commission. The discussion in Colorado attests to the complexity of the question being posed.[21]

- Also important to note is that Colorado statute only allows the utility to own up to 50% of the energy and capacity (and the associated infrastructure) developed or acquired to meet the resource need "if the Commission finds the cost of utility or affiliate ownership of the

[18] The sharing is set up in a tiered structure around the deadband.

[19] Colorado Public Utilities Commission, Interim Commission Decision Setting Deadline for Initial Comments on Risk-Sharing Mechanism and Other Performance Incentive Mechanisms, Proceeding No. C23-0672-I, Adopted October 4, 2023. Comments on Risk-Sharing Mechanism and Other Performance Incentive Mechanisms, Proceeding No. C23-0672-I, Adopted October 4, 2023; Colorado Public Utilities Commission, Phase II Decision: (1) Addressing Resource Selection and Thereby Modifying Public Service's Clean Energy Plan; (2) Addressing the Additional Transmission Investments Identified in Phase II; (3) Establishing Performance Incentive Mechanisms for Utility-Owned Generation; (4) Addressing the 2024 Just Transition Solicitation; and (5) Addressing Related Matters, Proceeding No. 21A-0141E, Adopted December 6, 13, 20, 2023; Public Service Company of Colorado, Public Service Company of Colorado Response to Decision No. C23-0672-I Regarding a Risk Sharing Mechanism for Company-Owned projects in the Preferred Plan, Proceeding No. 21A-0141E, October 20, 2023.

[20] There was also a calculation proposed, so the methodology is slightly more complex than what has been presented. LEI has introduced these concepts at a high level.

[21] Trial Staff's Comments on Risk-Sharing Joined by UCA and CEC Pursuant to Decision No. C23-0672-I in Public Service Company of Colorado's Electric Resource plan, Proceeding No. 21A-0141E, October 20, 2023; Colorado Public Utilities Commission, Phase II Decision: (1) Addressing Resource Selection and Thereby Modifying Public Service's Clean Energy Plan; (2) Addressing the Additional Transmission Investments Identified in Phase II; (3) Establishing Performance Incentive Mechanisms for Utility-Owned Generation; (4) Addressing the 2024 Just Transition Solicitation; and (5) Addressing Related Matters, Proceeding No. 21A-0141E, Adopted December 6, 13, 20, 2023.

generation assets comes at a reasonable cost and rate impact."[22] These sorts of constraints around procurement could also potentially be considered for future RFP proceedings in Oregon.

While the issue at hand is a difficult one to address, we believe nonetheless that a conversation is warranted. We also recommend the conversation to take place within the context of rate case proceedings where a variety of rate design tools and mechanisms might be available to hold utilities accountable for their costs.

[22] Senate Bill 19-236.