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

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List of acronyms

AEO	Annual Energy Outlook
AFUDC	Allowance for Funds Used During Construction
AS	All Source
BSA	Battery storage agreement
BTA	Build-transfer agreement
COD	Commercial operations date
EIA	Energy Information Administration
ERIS	Energy Resource Interconnection Service
Gas-H2	Hydrogen Combustion Turbine
GI	Generation Interconnection
GWW	Gateway West
IE	Independent Evaluator
IPC	Idaho Power Company
IRP	Integrated Resource Plan
ITC	Investment tax credit
LCOC	Levelized cost of capital
LEI	London Economics International LLC
LTCE	Long-Term Capacity Expansion
LTSA	Long-Term Service Agreement
MW	Megawatts
MWh	Megawatt hour
NIPPC	The Northwest & Intermountain Power Producers Coalition
NREL	National Renewable Energy Laboratory
NRIS	Network Resource Interconnection Service
OAR	Oregon Administrative Rules
OPUC	Oregon Public Utilities Commission
PGE	Portland General Electric Company
PPA	Power purchase agreement
PTC	Production tax credit
PVRR	Present value revenue requirement
Recip	Reciprocating gas engine

RFP	Request for Proposals
RNW	Renewable Northwest
SMR	Small modular reactor
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" or "Idaho Power") 2028 All Source ("AS") Request for Proposals ("RFP") for Peak Capacity and Energy Resources ("2028 AS RFP"). This report is the second deliverable of this engagement, in which LEI provides its observations on, and recommendations to the updated draft 2028 AS RFP ("updated draft RFP") filed by IPC with the Oregon Public Utilities Commission ("OPUC" or "the Commission") in Docket UM 2255 on July 16, 2024.

Through both its Reply Comments[1] and the July 16, 2024 updated draft RFP, the Company addressed most of LEI's comments and recommendations from the first IE Assessment Report[2] ("first IE Report"). Nonetheless, following a review of stakeholders' comments, discussions with Staff, and review of the revisions made to the RFP, LEI would like to provide additional recommendations that we believe would provide additional clarity to the RFP documents and enhance the procurement process. The proposed recommendations are enumerated in Figure 1 and discussed in detail in Section 3.

Figure 1. List of LEI's outstanding recommendations to the updated draft RFP

1) Bid evaluation process	LEI is satisfied with the design of Exhibit R and does not have any further recommendations
2) Sensitivities	LEI recommends that the Company carry out a series of additional sensitivity analyses
3) ERIS vs NRIS	LEI considers the existing 5% "penalty" for ERIS projects to be reasonable
4) Existing facilities	LEI recommends that the Company allow existing resources to participate in the RFP so long as they provide incremental capacity, and only bid such incremental capacity
5) Utility ownership risk	LEI recommends that the Company request benchmark bids and third-party bidders to include O&M agreements supporting projects over their respective lives
6) Draft RFP form contracts	LEI believes that the contract negotiations stage is the appropriate forum through which to resolve most of the comments on the Draft RFP form

[1] Filed on June 10, 2024.

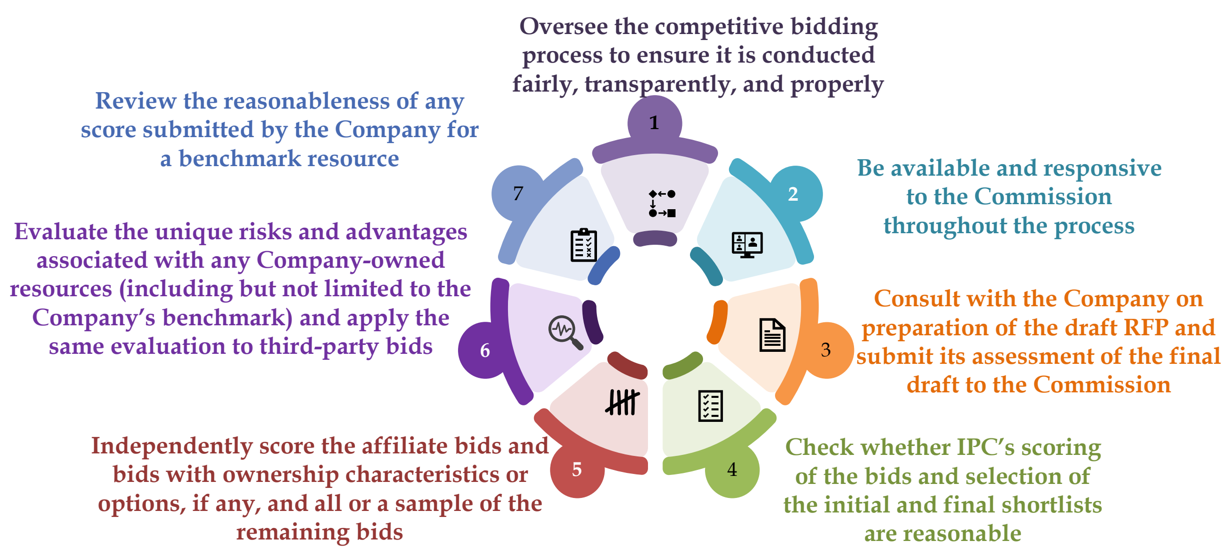
[2] The first Independent Evaluator Assessment Report was filed on May 28, 2024.

2 Introduction

IPC issued its updated draft RFP on July 16, 2024, through which it seeks to procure up to 138 megawatts ("MW") of peak capacity resources and 555 MW of energy resources in 2028. This RFP is a response to the resource needs identified in IPC's 2023 Integrated Resource Plan[3] ("IRP") as well as its 2028 and 2029 incremental needs, as provided in its application in Docket UM 2317.

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.[4] Resources can be existing or new; new resources must have a target commercial operations date ("COD") on or before the summer of 2028, or beyond. In addition to the bids expected to be submitted by developers, the Company will also submit four benchmark bids, which will be evaluated using the same bid scoring criteria that apply to third-party bids.

Figure 2. Duties of the IE



Source: OAR 860-089-0450

This RFP process will be overseen by the IE to ensure that it is conducted in a fair and reasonable manner. LEI,[5] through a competitive bidding process, was selected to serve as the IE for this RFP

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

[4] *Ibid*.

[5] "IE" and "LEI" are used interchangeably throughout this report.

process. Per Oregon Administrative Rules ("OAR") 860-089-0450, the IE's duties include the items enumerated in Figure 2 above.

This report is the second IE report and one of several reports that the IE will be filing with the OPUC as part of its responsibilities. This report focuses on LEI's observations and recommendations on the latest updated draft RFP that was posted on the Company's RFP website[6] on July 16, 2024.[7]

3 LEI's observations on the updated draft RFP and recommendations

The IE conducted a comprehensive review of the updated draft RFP for Idaho Power's Draft 2028 All-Source RFP, dated July 16, 2024, which was published on the IPC RFP 2028 website[8] (a web page on the Company's website dedicated to this RFP) and on an RFP portal (the Company's solicitation platform called Zycus).[9] Since the first IE report was submitted,[10] stakeholders (including Staff) filed Opening Comments,[11] the Company filed Reply Comments (including an updated version of the Draft RFP) on June 10, 2024 followed by a revised version of the Draft RFP on July 16, 2024. Throughout this process, the Company, the IE, and Staff discussed additional feedback and resolved outstanding issues. Drawing from this consultation process and our review of the July 16, 2024 Draft RFP, we discuss in this report how key suggestions from the first IE report were addressed by the Company and provide our final recommendations on the Draft RFP.

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6 *See*: https://docs.idahopower.com/pdfs/AboutUs/businessToBusiness/2028_IPC_AllSource_RFP.pdf

7 *See*:
https://dewdrops.zycus.com/isource/supplier/3158602/response/6362445/confirmParticipation?supplierContactId=3158602&tenantId=9031d9a8-2780-424f-b667-2c84a98a43e8

8 *See*: https://docs.idahopower.com/pdfs/AboutUs/businessToBusiness/2028_IPC_AllSource_RFP.pdf

9 *See*:
https://dewdrops.zycus.com/isource/supplier/3158602/response/6362445/confirmParticipation?supplierContactId=3158602&tenantId=9031d9a8-2780-424f-b667-2c84a98a43e8

10 May 28, 2024.

11 NIPPC & RNW: June 3, 2024. Key Capture Energy: June 17, 2024.

3.1 IE's recommended adjustments to the final RFP

Figure 3. Summary of the IE's recommendations

	Recommendations from IE reports	IPC's response
1st IE report	**Bid evaluation process**: provide clarification on the strategy to review each category of project without undue preference based on the commissioning year	Introduced Exhibit R
1st IE report	**GWW sensitivity**: clarify whether any sensitivity analysis will be carried out on the commercialization year of the GWW project	No project coming online in 2028 will be affected by the GWW project
2nd IE report	**Sensitivity on 2028 needs**: add a sensitivity analysis around 2028 needs	N/A – new IE recommendation
2nd IE report	**ERIS vs NRIS**: IE agrees with IPC's response	The 5% "penalty" for ERIS projects is necessary to capture the reliability risk of ERIS projects
2nd IE report	**Existing facilities' participation**: allow existing resources to participate in the RFP so long as they provide incremental capacity, and only bid such incremental capacity	N/A – new IE recommendation
2nd IE report	**Utilities' ownership risk**: request that benchmark bids and third-party bidders include O&M agreements supporting projects over their respective lives	N/A – new IE recommendation
2nd IE report	**Draft contract forms**: while LEI believes that the negotiation stage is an appropriate forum to address all draft form-related comments, LEI recommends that PPAs be revised to provide an annual output guarantee	N/A – new IE recommendation

3.1.1 Bid evaluation process

In the first RFP report drafted by the IE, we raised some concerns over the lack of clarity around the approach and methodology used by IPC to compare bids with a 2028 in-service year versus bids coming online in 2029 and beyond. The IE recommended that IPC better articulate the evaluation process for these two categories of projects, and how the evaluation will be conducted in a fair and non-discriminatory manner. LEI specifically requested clarification on the Company's strategy for reviewing each category of project in a manner that would ensure no undue preference based on the year of commissioning in the selection of the least cost, least risk projects. In the June 10, 2024 revision of the RFP, IPC introduced Exhibit R, which was designed to address similar concerns expressed by the OPUC and stakeholders. For instance, in its Opening Comments filing,[12] the Northwest & Intermountain Power Producers Coalition ("NIPPC") commented that "Idaho Power should expressly clarify in the Draft RFP document that it will allow bids with a later COD than April 1, 2028, and clarify the treatment of such bids as expressed at the workshop."[13] Exhibit R identifies two general categories of bids: (i) proposals already part

[12] June 3, 2024.

[13] May 14, 2024.

of an interconnection process[14] with commercial operation dates on or after April 1st 2028 (Pool 1), and (ii) proposals that are currently not part of any interconnection process, with CODs of later years than 2028 (Pool 2). While Exhibit R provides more clarity on how the Company would consider bids with CODs later than 2028, it also breaks up the original procurement process into two separate and sequential processes to address concerns related to the limited number of bidders that would be eligible for this RFP were no adjustments made to the interconnection requirement. While the procurement processes for Pool 1 and Pool 2 bids will be run in sequence, the two processes are slated to slightly overlap in the year 2025 (the final selection of Pool 1 bids would overlap with the submission of Pool 2 bids). Such overlapping would allow the Company to include Pool 2 bids in the Pool 1 final shortlist process, thus allowing for a consideration of tradeoffs associated with projects boasting later commercialization dates. The IE is satisfied with the design of Exhibit R and does not have further recommendations on this matter.

3.1.2 Sensitivities

Gateway West transmission line

In our first IE report, we recommended that IPC clarify whether any sensitivity analysis would be carried out on the commercialization year of the Gateway West ("GWW") transmission project. In its response, the Company noted that none of the projects coming online in 2028 will be affected by the transmission line due to the timing of transmission line development. In other words, the GWW transmission line is not considered an enabling infrastructure for 2028 projects. While the IE is satisfied with that answer, we remain concerned by the potential impact of the online date of the transmission line on generation projects with COD in 2029 and beyond. In this respect, we maintain our recommendation to carry out a sensitivity analysis on the project commissioning year, especially for Pool 2 projects.

Identified needs in 2028

The capacity and energy needs for the year 2028 are based on the 2023 IRP. However, we understand that these needs are not yet final and could further evolve based on, among others, load forecast updates, existing resource availability, progress of coal to gas conversion, and capacity associated with the Western Resource Adequacy Program ("WRAP"). The potential variability in needs generates a risk of over-procuring and over-building, where the associated costs would be borne by ratepayers. We recommend that IPC consider reflecting this uncertainty in its modeling exercise by adding a sensitivity analysis around 2028 needs.

3.1.3 ERIS vs. NRIS

Under FERC's Generation Interconnection ("GI") rules for Large Generation Interconnections, developers have the flexibility to request interconnection service under an Energy Resource Interconnection Service ("ERIS") or a Network Resource Interconnection Service ("NRIS"). ERIS refers to an interconnection service that allows the interconnection customer to connect its generating facility to the transmission system and be eligible to deliver

[14] Idaho Power Generator Interconnection Serial Study Process or the Transitional Cluster Study Process.

electric output using the existing firm or non-firm capacity of the transmission system on an as-available basis.[15] NRIS refers to an interconnection service that allows the interconnection customer to integrate its generating facility with the transmission system in a manner comparable to that in which the transmission owner integrates its generating facilities to serve native load.[16]

In the RFP, the Company reflects its preference for NRIS over ERIS by providing a non-price scoring advantage of 5%. In its Opening Comments,[17] Renewable Northwest ("RNW") suggested the Company reduce its proposed 5% "penalty" for ERIS projects. However, during the May 14, 2024 workshop, in its reply comments, and later on in discussions with the IE and Staff, IPC defended the non-price scoring advantage for NRIS, affirming that "interconnecting with ERIS increases the risk that additional, and potentially significant, network upgrade costs will be identified when IPC submits a transmission service request,"[18] and in any case, "the "penalty" equates to 1.25 points of the possible 100 points that a bid can earn in the scoring and modeling methodology." The Company expressed the desire to still acknowledge the incremental risk inherent to ERIS bids. In fact, while resources studied for NRIS will generally identify upfront (i.e., before the Company issues a transmission service request) the network upgrades needed to support the resources' load deliverability and integrate into Idaho Power's system. Load deliverability for ERIS resources is not fully studied at the time of filing but only when the utility submits a network transmission service request; it is only at that time that requested network upgrades would be known, thus generating potential additional costs and delays. Furthermore, the non-firm nature of ERIS resources creates the risk that ERIS resources will not be deliverable when needed by the system, such as at critical times. If firm transmission is not available to designate resources as network resources, the Company would have to either use firm point-to-point transmission at an additional cost or use non-firm transmission with a higher likelihood of curtailment. The IE found the arguments of the Company to be reasonable and thus does not have further comments on the matter.

3.1.4 Existing facilities

In its Opening Comments, NIPPC recommended that the RFP provide the opportunity for existing resources to "bid to repower, add storage, or reprice the remaining years on an existing Power purchase agreement ("PPA") to facilitate a reasonable contract renewal."[19] In its Reply Comments, the Company stated that the requirement prohibiting resources under contract with the Company to participate in the RFP "is intended to ensure that a resource provides incremental capacity in 2028." Moreover, "If Idaho Power were to accept bids from projects that are already contracted with IPC for deliveries beyond April 2028, those projects would not provide incremental capacity in 2028, it would simply be a renegotiation of existing contract terms and

[15] *Ibid*

[16] Southwest Power Pool, Energy-Only Resource Planning Update, Strategic Planning Committee Meeting, January 18, 2027.

[17] RNW's Opening Comments, June 3, 2024.

[18] Idaho Power Company's Reply Comments, June 10, 2024.

[19] NIPPC's Opening Comments, June 3, 2024.

conditions."[20] While we agree with the Company's statement, we also believe that it would be reasonable to allow existing resources to participate in the RFP so long that these resources provide incremental capacity. Furthermore, to prevent fully depreciated assets from benefiting from a cost advantage in the RFP, existing resources shall only be allowed to bid incremental capacity in the RFP.

3.1.5 Utility ownership risk

Stakeholders such as NIPPC have expressed concerns over how O&M costs that are not reflective of Long Term Service Agreements ("LTSAs") and O&M agreements for the life of utility-ownership bids could lead to utility-owned bids (including benchmark bids) being shortlisted ahead of third-party bids that capture these LTSA and O&M lifetime costs upfront (in their submitted bids). In addition, NIPPC recommended that "contingency risk adders be developed and applied for utility-owned resource costs in this RFP consistent with the process adopted in Portland General Electric Company's ("PGE") ongoing RFP."[21] Although LTSAs are very much project specific and driven by multiple factors including project risk and return profile, appetite for performance risk, operations and maintenance strategy, and so forth are drivers that contribute to the uncertainty surrounding the nature of cost agreements. The IE, however, believes that IPC could draw from its current experience with the 2026 RFP contract negotiations as well as from reasonable assumptions on maintenance agreements. We recommend that IPC request from benchmark bids and third-party bidders O&M assumptions covering (or reflective of) the full life of each project. This would in particular include costs associated with capacity maintenance programs or augmentation programs.

3.1.6 Draft RFP form contracts

In its June 3, 2024 Opening Comments, NIPPC provided feedback on several contract terms.[22] IPC replied to these opening comments in its June 10, 2024 filing. IPC believes that most of the contract terms mentioned in NIPPC's Opening Comments should be discussed and negotiated between the parties (i.e., IPC and winning bidders) during the contract negotiations phase of the procurement process. While the IE agrees with IPC, for the reader's convenience, where applicable, LEI notes where its feedback aligns with that of NIPPC. Where necessary, LEI provides additional observations. LEI is not a legal expert, therefore the comments in the subsections that follow should not be taken as legal advice.

3.1.6.1 Pre-COD damages payment

LEI agrees with NIPPC that damages owed by the Seller for termination prior to COD should be limited to the amount of the Project Development Security so that the Seller is credited for the

[20] Idaho Power Company's Reply Comments, June 10, 2024.

[21] NIPPC's Opening Comments, June 3, 2024.

[22] Oregon Public Utilities Commission. *Northwest & Intermountain Power Producers Coalition's Comments on Draft Request for Proposals*. Docket No. UM 2317. June 3, 2024.

damages paid during the delay. However, LEI believes that these provisions would be better discussed and negotiated during the contract negotiations process.

3.1.6.2 Performance guarantee

LEI agrees with NIPPC's recommendation that the PPA be revised to provide for an annual output guarantee. Output guarantees are usually considered on an annual basis for new project developments. LEI recommends that this provision should be addressed during the negotiations period.

3.1.6.3 Deficit damages

NIPPC recommends that the PPA's deficit damages for each MW placed in service less than the expected nameplate capacity should be reduced from $150,000/MW to $100,000/MW. Deficit damages terms vary across contracts and are often, based on our experience, expressed as a percentage-based penalty; we suggest this item to be addressed during the negotiations period.

3.1.6.4 Future environmental attributes

In its Opening Comments, NIPPC recommends that "PPA/battery storage agreement ("BSA") be revised to ensure that the Seller is not responsible for the open-ended and uncapped costs to register and supply future environmental attributes that do not exist today."[23] While we agree with NIPPC's comments, it is challenging to form an opinion on a "fair" allocation of these costs between IPC and developers. In this respect, we believe the contract negotiations serve as an adequate forum in which to discuss such provisions.

[23] NIPPC's Opening Comments, June 3, 2024.

4 Comments on AURORA assumptions and modeling

In response to an IE information request, on July 18, 2024, IPC provided key assumptions to its AURORA model that will be used to select final shortlisted bids. These include load forecast, supply (new entry and retirements), fuel prices, and planned key scenarios. In addition, IPC also provided the IE with the draft financial model that it will use to evaluate bids. The comments in this section of the report pertain to assumptions to be used in the AURORA model and the updated financial model provided to the IE; LEI expect that an updated financial model will be provided by IPC before the actual evaluation of bids, which will require additional review by the IE.

4.1 Assumptions used in the AURORA model

4.1.1 Load forecast

As stated by IPC, the load forecast used to evaluate bids submitted in response to the 2028 AS RFP will be derived from the load forecast underlying the 2023 IRP. As LEI understands it, as of preparing this report, the 2023 IRP has not yet been acknowledged by OPUC. The load forecast is developed internally at IPC; IPC plans to use an updated version of the forecast that will be available in September 2024. While LEI acknowledges the importance of incorporating an up-to-date load forecast, potential issues arise from the fact that the load forecast could change from what was demonstrated in the 2023 IRP. LEI recommends that IPC transparently communicate with bidders any potential issues or uncertainties related to the updated September 2024 load forecast utilized in the 2028 AS RFP process, and provide regular updates on any changes or revisions to the forecast as they become available.

4.1.2 Supply

According to IPC, power generating facilities that are currently operational and included in the AURORA model align with the portfolio of resources provided in the 2023 IRP. The AURORA model accounts for existing and contracted system resources, as well as resources that align with announced and/or assumed clean energy goals of IPC's customers. Any other new entry additions are determined through so-called Long-Term Capacity Expansion ("LTCE") modeling. Similarly, retirements are modeled in accordance with the 2023 IRP: retirement decisions are based on either a plant's economic feasibility or end-of-life date. LEI finds IPC's approach to modeling new entries and retirements to be in line with established industry practice and therefore deems it to be an appropriate and consistent approach.

4.1.3 Fuel prices

Fuel costs are a key driver in the selection and optimization of resources by the AURORA model. Most fuel forecasts utilized by IPC are from well-known third-party vendors. Below is a list of sources associated with each of IPC's fuel assumptions to be applied in the bid evaluation modeling exercises:

- ***natural gas (base case):*** Platt's long-term Henry Hub gas price forecast as of September 2024 (once it is available);

- ***natural gas (low case):*** Henry Hub gas price from the US Energy Information Administration's ("EIA's") 2023 Annual Energy Outlook ("AEO") High Oil & Gas Supply forecast;
- ***natural gas (high case):*** Henry Hub gas price from the EIA's 2023 AEO Low Oil & Gas Supply forecast;
- ***clean gas (hydrogen):*** National Renewable Energy Laboratory ("NREL");[24]
- ***biomass:*** NREL 2022 Annual Technology Baseline;
- ***coal:*** IPC's internally developed forecast, as per its 2023 IRP;
- ***uranium (small modular reactor, "SMR"):*** NREL's 2022 Annual Technology Baseline;
- ***carbon price (base case):*** based on California Energy Commission data,[25] and assumes a price range of approximately $28/ton to $83/ton throughout the IRP planning horizon;
- ***carbon price (low case):*** assumes zero price on carbon emissions; and
- ***carbon price (high case):*** based on a federal interagency working group Technical Support Document under Executive Order 13990,[26] and assumes a price range of $65/ton to $132/ton throughout the IRP planning horizon.

LEI understands that the fuel forecasts used in this RFP process align with the 2023 IRP and use the same methodology applied in the 2026 AS RFP process. IPC will also provide LEI with an update to all fuel forecast assumptions (for example, the September 2024 natural gas base case forecast) once they are available and prior to running AURORA.

4.1.4 Scenarios

We understand that IPC envisions running the following sensitivity scenarios as summarized in Figure 4. In addition, IPC will conduct a stochastic analysis to evaluate the impact on portfolio costs when certain variables deviate from their established planning-case levels. As outlined in the RFP, the stochastic analysis will consider variations in hydrologic conditions, load/demand, natural gas prices, and carbon prices, all of which will be based on the 2023 IRP. According to IPC, the expected range of values for the fuel variable in the stochastic analysis are as follows:

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[24] Denholm, Paul et al. *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. National Renewable Energy Laboratory. 2022. <https://www.nrel.gov/docs/fy22osti/81644.pdf>

[25] California Energy Commission. *2020 Integrated Energy Policy Report.* Preliminary Green House Gas Allowance Price Projections, Low-price Scenario. <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update>

[26] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Interagency Working Group and Social Cost of Greenhouse Gases, United States Government. February 2021. <whitehouse.gov/wp-content/uploads/2021/02/Technical SupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf>

- ***natural gas***: the stochastic spread is derived from the gas price forecast, which will be available in September 2024. IPC anticipates the spread will be similar to the range of $1.35/MMBtu to $20.48/MMBtu applied in the 2026 AS RFP process; [27] and
- ***carbon price:*** price adder will be the same adder applied in the 2026 AS RFP, ranging between $0/ton and $412/ton.

Figure 4. IPC's proposed sensitivities

1) Base Case	Gas: Platts Henry Hub natural gas price forecast as of September 2024
	Includes a carbon price forecast and total emissions constraints on some coal units as well as state-level carbon policies and RPS standards
2) High gas and high carbon	Gas: Based on EIA's 2023 Annual Energy Outlook Low Oil and Gas Supply forecast
	Carbon: 2023 IRP high carbon price forecast
3) Low gas and zero carbon	Gas: Based on EIA's 2023 Annual Energy Outlook High Oil and Gas Supply forecast
	Carbon: Assumes no federal or state legislation that would require a tax or fee on carbon emissions and therefore zero carbon costs
4) Large load – 100 MW	The load forecast is increased above the base load forecast
	Load breakdown (peak load ramp): • 2026: 65 MW • 2027 – 2029: 100 MW per year
4) Large load – 200 MW	The load forecast is increased above the base load forecast
	Load breakdown (peak load ramp): • 2026: 65 MW • 2027: 143 MW • 2028 – 2029: 200 MW per year

Source: Idaho Power's responses to LEI's comments dated July 18, 2024.

The hydrology and electricity demand variables for the stochastic analysis are based on the 2023 IRP. The modeled stochastic hydrologic conditions will range from 4,714,020 MWh to 11,669,165 MWh, as described in the 2023 IRP. The electricity demand stochastic spread is also based on the methodology described in the 2023 IRP, but will be updated with the upcoming September 2024 load forecast. In addition to the sensitivities proposed by IPC, LEI recommends incorporating a sensitivity analysis on 2028 needs, and the GWW project commissioning year.

[27] Idaho Power's responses to LEI's comments dated July 18, 2024.

4.2 Draft financial model

In the 2028 AS RFP process, IPC will use the same proprietary Excel-based model used in the 2026 AS RFP to conduct its financial analysis and subsequently prioritize bids to form the initial shortlist. This model serves as an initial screening tool that calculates the levelized cost of capacity ("LCOC") of each bid, whether for a single or bundled project (e.g., solar plus storage). It computes the cost of a bid's resources over the project's lifetime in terms of present value revenue requirement ("PVRR") per megawatt hour ("MWh"). The LCOC is the monthly cost per kilowatt that customers would incur for each project selected by IPC (Figure 5).

Figure 5. LCOC formula

$$LCOC = \frac{{}^{PVRR}/_{plant\ size} \times 1{,}000}{12\ months}$$

The LCOC calculation uses project-specific information provided in "EXHIBIT B – Bid Entry Form" as well as underlying internal assumptions developed by IPC.

IPC's operational and financial input assumptions are the same across different technology types. Assumptions are based on the latest information available in the 2023 IRP and are similar to the assumptions used in the 2026 AS RFP (see Figure 6 below). LEI will review these assumptions again during the initial shortlist process to check for any changes.

Figure 6. IPC's key financial assumptions

Table 9.1 Financial Assumptions	2028 RFP (2024)	2023 IRP		Δ
Plant operating (book) life	Expected Life of Asset			
Discount Rate weighted average cost of capital	6.62%	7.12%		-0.504%
Composite tax rate	25.74%	25.74%		0.000%
Deferred rate	21.30%	21.30%		0.000%
General O&M escalation Rate	2.60%	2.60%		0.000%
Annual property tax rate (% of Investment)	0.44%	0.44%		0.000%
Property tax escalation rate	3.00%	3.00%		0.000%
Annual insurance premiums (% of Investment)	0.046%	0.046%		0.000%
Insurance escalation rate	5.00%	5.00%		0.000%
AFUDC Rate (annual)	7.20%	7.20%		0.000%
Are we selling tax credits in this RFP?	Yes			
Tax value to IPC after sellng credits	95%			
Current Year PTC Credit	$ (27.50)	-27.5		
PTC Term	10.00	10		
ITC Credit	30.00%	0.3		
PTC Adder				
Discount Delay	0.50	0.5		
Financing:				
Composition				aft-tax
Debt	50.00%	4.895%	2.45%	1.82%
Preferred	0.00%	0.000%		
Common	50.00%	9.600%	4.80%	4.80%
Cost				
Debt	4.89%		7.2474%	6.62%
Preferred	0.00%			
Common	9.60%			
Incremental Borrowing Rate	5.00%	last debt issuance for a 20 year bond		

Source: "2028 RFP Financial Models Template.xlsx" sent to the IE on July 11, 2024.

Comparing 2028 model assumptions with the 2023 IRP and the assumptions used in the 2026 AS RFP, the following financial assumptions were updated:

- the discount rate weighted average cost of capital was adjusted as a result of Rate Case No. IPC-E-23-11 (2023 GRC), decreasing from 7.12% to 6.62%;
- the Allowance for Funds Used During Construction ("AFUDC") annual rate decreased slightly from 7.50% to 7.20%;
- financing debt/common composition ratio changed slightly from a 50.1/49.9 to 50/50;
- financing cost of debt and common equity decreased from 5.73% to 4.89% and from 10% to 9.60%, respectively;
- the incremental borrowing rate decreased from 5.50% to 5.00%; and
- the investment/production tax credits ("ITC"/"PTC") sale assumption was added.

The added transferability assumption of selling ITCs/PTCs on the secondary market was added to the model to reflect the tax credits transferability provisions included in the Inflation Reduction Ac[28]t. The expectation is that the secondary market will pay for the tax credits at a discount, and IPC will need to apply a discount rate in modeling the value of these tax credits when evaluating bids. In the July 11, 2024 version of the model, IPC had a preliminary discount rate assumption of 95% for selling credits in the secondary market. This preliminary discount rate is merely a placeholder while IPC is investigating the proper rate based on market information. The IE will reevaluate this assumption once it is finalized.

In addition to the key financial assumptions listed above, IPC has tax and economic (book) project life assumptions for each technology type (see Figure 7 below), which are used to calculate production tax credit amounts. Project life assumptions are also based on the 2023 IRP.

Figure 7. IPC's project life assumptions

Project Lives	Tax	Book
Solar	5	35
Wind	5	30
BESS	5	20
SMR	15	60
Biomass	5	30
Geothermal	5	30
Clean Gas	5	35
Gas-H2	20	30
Recip	20	40
SCCT	20	35
CCCT	20	30

Source: "2028 RFP Financial Models Template.xlsx" sent to the IE on July 11, 2024.

[28] DEPARTMENT OF THE TREASURY, Internal Revenue Service, 26 CFR Part 1, April 30, 2024.

Compared to the 2026 AS RFP, project life assumptions remain similar, with the exception of:

- nuclear SMR tax life reduction from 20 years to 15 years;
- biomass and clean gas tax life reduction from 20 years to 5 years; and
- addition of two (2) new peaking gas technologies: hydrogen combustion turbine ("Gas-H2"), and reciprocating as engine ("Recip").

LEI analyzed the methodology employed by IPC to determine the LCOC for each bid using the Excel-based financial model entitled "2028 RFP Financial Models Template.xlsx" submitted via email on July 11, 2024. The model differentiates between LCOC calculations for ownership offers, such as BTA offers, and those for third-party-owned assets, such as PPA or BSA offers.

LEI considers the LCOC computation in IPC's draft financial model to be a sound and justifiable approach for ranking bid proposals.