Report on Contract Negotiations
2026 All Source Request for Proposals for Peak Capacity and Energy Resources

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List of Acronyms

AFUDC	Allowance for funds used during construction
AP	Asset purchase
AS	All Source
B2H	Boardman to Hemingway transmission line
BESS	Battery energy storage system
BLM	US Bureau of Land Management
BSA	Battery storage agreement
BTA	Build transfer agreement
COD	Commercial online date
CUP	Conditional Use Permit
EIA	Energy Information Administration
EPC	Engineering, procurement, and construction
FERC	US Federal Energy Regulatory Commission
G2H	Gas-fired system convertible to hydrogen
GIA	Generator Interconnection Agreement
IE	Independent Evaluator
IPC	Idaho Power Company
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
LBNL	Lawrence Berkeley National Laboratory
LDES	Long duration energy storage
LEI	London Economics International LLC
LTCE	Long-term capacity expansion
LTSA	Long term service agreement
NPV	Net present value
O&M	Operations and maintenance
OATT	Open Access Transmission Tariff
OPUC	Oregon Public Utilities Commission
PPA	Power purchase agreement
PTC	Production tax credit
RFP	Request for proposals
RFQ	Request for quotes
ROFO	Right of First Offer

1 Executive Summary

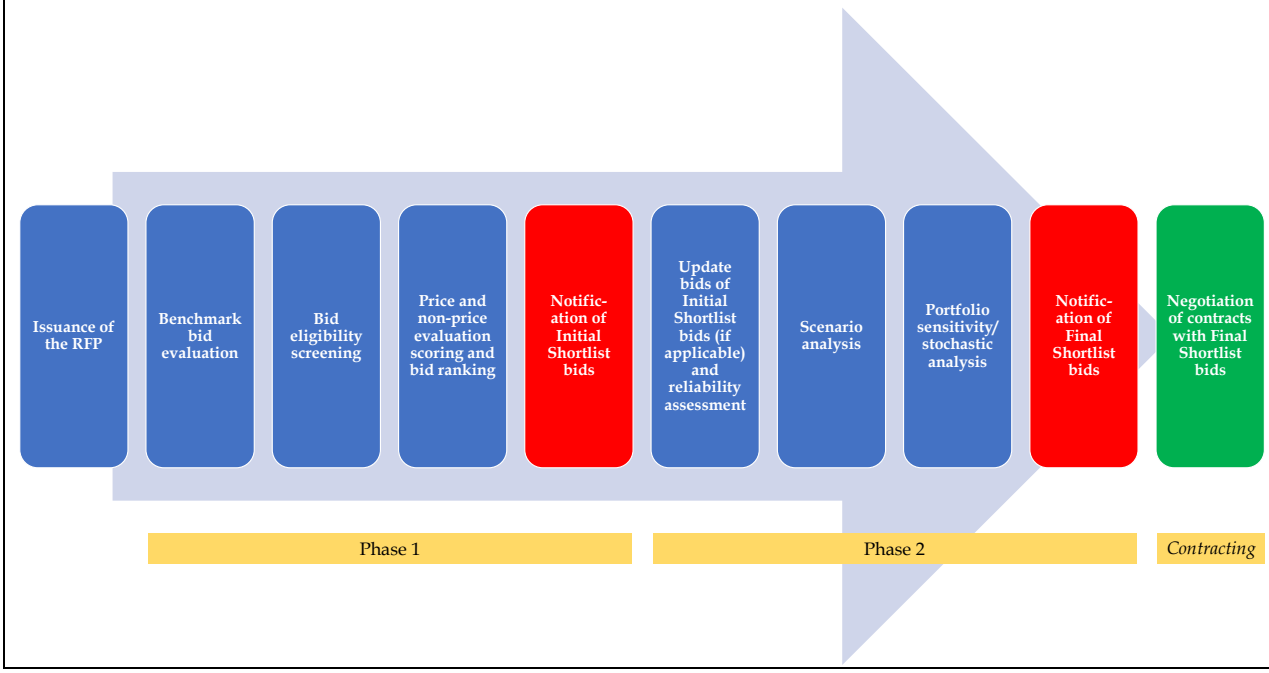
In this Independent Evaluator ("IE") report, London Economics International LLC ("LEI") provides an overview and assessment of the contract negotiations process associated with the 2026 All Source ("AS") Request for Proposals ("RFP") for Peak Capacity and Energy Resources (together, "2026 AS RFP" or "AS RFP") issued by Idaho Power Company ("IPC" or "Company"). The report covers the contract negotiations between IPC and the following projects and entities, which made it through the final shortlist stage of the RFP process:

- Boise Bench (a benchmark bid submitted by IPC);
- Crimson Orchard Solar LLC (bid by [redacted]);
- Jackalope Wind, LLC (a benchmark bid by IPC in partnership with [redacted] a wholly owned subsidiary of [redacted] ("[redacted]")); and
- Powerex Corp. (for market-based resources).

The overview and assessment specifically cover the final contract price, key commercial terms, ownership structure, and an overview of potential risks associated with each project.

The diagram below (Figure 1) provides a summary illustration of the RFP process to date. The content of this report covers the negotiation of contracts with Final Shortlist bids (the green marker of the timeline below)—or the contracting phase of the RFP process.

Figure 1. Summary of the RFP process



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Through the 2026 AS RFP, IPC seeks to procure energy to meet system needs identified for years 2026/2027. A total of 192 proposals were submitted for consideration by 32 companies. Among these, 188 proposals were resource bids, encompassing a collective proposed capacity exceeding 64,000 MW. The submissions covered a wide spectrum of technologies, ranging from solar, wind, and geothermal, to long-duration energy storage ("LDES"), gas-fired systems convertible to hydrogen, and battery energy storage systems ("BESS"). Furthermore, the resource capacity bids varied in structure, featuring power purchase agreements ("PPAs"), battery storage agreements ("BSAs"), and asset purchases ("AP").

Following a comprehensive eligibility screening process, 144 proposals were determined to meet the minimum requirements outlined in the RFP and as such proceeded to the initial shortlist bid evaluation (Phase 1).[1] Following a meticulous scoring exercise based on price and non-price scoring criteria for resource bids and a price ranking exercise for market-based bids, 63 bids from the eligibility pool were identified as part of the Initial Shortlist.[2] This selection encompassed 58 resource-based products and all four market purchase bids. The Initial Shortlist reflected a diverse range of technologies, ensuring that all technologies offered during the RFP process were duly considered. This concluded Phase 1 of the RFP process.

In Phase 2 of the RFP process, bidders on the Initial Shortlist were invited to submit updates to their bids, incorporating pertinent price or schedule modifications, interconnection study results, or any other significant changes that could influence the integrated resource plan ("IRP") production cost model or RFP minimum requirements. These updates were assessed through the Company's cost models, long-term capacity expansion ("LTCE") model AURORA, and IRP models. The Initial Shortlist bids were also tested under a range of potential environmental and policy-price scenarios (scenario analysis). A total of 11 bids were selected for the Preliminary Final Shortlist based on their performance and costs under each of the scenarios; five projects were eliminated mainly due to concerns over uncertainty of upgrades and interconnection costs.[3]

To supplement the scenario analysis, IPC conducted a portfolio stochastic (sensitivity) analysis on the Preliminary Final Shortlist to assess the performance of bids under dynamic market conditions and comprehend the range of net present value ("NPV") portfolio costs under a broad spectrum of stochastic shocks. The stochastic risk analysis employed aligns with the methodology used in IPC's 2023 IRP development process and conforms with discussions held during public meetings with the 2023 IRP Advisory Council. IPC then ranked the bid resources that were most consistently selected across the sensitivity runs. Based on this analysis, 10 out of 11 bids were

[1] For more, please see: London Economics International LLC. *Review of eligibility and initial shortlist; 2026 All Source Request for Proposals for Peak Capacity and Energy Resources*. August 2, 2023.

[2] Ibid.

[3] For more, please see: London Economics International LLC. *Closing Report; 2026 All Source Request for Proposals for Peak Capacity and Energy Resources*. Errata December 27, 2023.

identified for the Final Shortlist for contract negotiations.[4] These Final Shortlist bids are listed in Figure 2.

Figure 2. Ranking of Final Shortlist Bids

Delivery Year	Project	Project sponsor	Technology and capacity	Bid type
2026	Resource Adequacy Market Contract – 5 Years	Powerex	Up to 300 MW	Market purchase product
2026	Powers Butte	Savion	200 MW Solar + 100 MW BESS	Resource-based product
2026	Powers Butte	Savion	200 MW Solar	Resource-based product
2026	Boise Bench	Idaho Power	150 MW BESS	Resource-based product
2026	Crimson Orchard	[redacted]	100 MW Solar + 100 MW BESS	Resource-based product
2026	Moon Crater	[redacted]	200 MW Solar + 50 MW BESS	Resource-based product
2027	Jackalope	[redacted] / Idaho Power	600 MW Wind	Resource-based product
2027	Taurus	[redacted]	350 MW Wind + 250 MW Solar	Resource-based product
2027	Taurus	[redacted]	350 MW Wind	Resource-based product
2027	Blue Springs	[redacted]	330 MW Solar	Resource-based product

In response to Condition 2 of the February 1, 2024 Final Shortlist Acknowledgement Report ("Acknowledgement Report") prepared by Oregon Public Utility Commission ("OPUC" or "Commission") staff, LEI's engagement in this RFP process was extended via a contract extension approved by the OPUC to cover contract negotiations between IPC and Final Shortlist bidders.[5] In this Acknowledgement Report, among other items, the OPUC expressed concern over the following:

- the potential for cost over-runs by utility-owned bids;[6]
- the structure of bids could be modified over the course of contract negotiations and would no longer reflect the bid structure presented in the Final Shortlist;[7]
- negotiated commercial terms may shape the Final Shortlist and impact bid price;[8]
- contracts could be finalized prior to acknowledgement of the Final Shortlist;[9]

[4] Ibid.

[5] Public Utility Commission of Oregon. Report dated February 1, 2024. Docket No. UM 2255. p. 16-17.

[6] Ibid. p. 16.

[7] Ibid.

[8] Ibid.

[9] Ibid. p. 6.

- unique risks and advantages can come in several forms, such as "construction cost over-runs, reasonableness of forced outage rates, end effect values, reasonableness of O&M costs, performance assumptions and construction schedules or delay risks";[10]
- the contract negotiations process may be used by the utility to provide more lenient terms for utility-owned bids or less attractive terms for third-party bids. This would lead to uncompetitive outcomes, as well as increased costs and risks to ratepayers;[11]
- contract long term service agreement ("LTSA") terms may be misaligned with the life of the relevant asset.[12]

As part of this phase of work and to address the concerns raised by OPUC staff, LEI was tasked with monitoring contract redlines and shared correspondences between IPC and Final Shortlist bidders, as well as attending meetings between IPC and bidders. As per Condition 2, LEI paid attention to changes in price, commercial terms, ownership structure, and other terms impacting the risk for cost over-runs or the risk that utility-owned bids may outbid third party-owned bids.

As of December 2024, and since the filing of the Acknowledgement Report, out of the 10 projects on the Final Shortlist, six bids were withdrawn from contract negotiations (discussed in Section 3), one project continues to negotiate its agreements with IPC (discussed in Section 2.1.3), and three contracts have been executed (discussed in Sections 2.1.1, 2.1.2, and 2.2.1). Figure 3 shows the number of bids that were selected in each key stage of the RFP process.

A table summarizing the status of each project is provided in Figure 4. As of end of December 2024, IPC contracted 800 MW of resource bids and 200 MW of market-based energy. Of this total, 400 MW is scheduled to come online in 2026 and 600 MW in 2027. An additional 300 MW may still be procured under this RFP (100 MW of which would be delivered in 2026 and 200 MW in 2027)—as indicated in the column labeled "contracting status" in Figure 4.[13]

[10] Ibid. p. 14.

[11] Ibid. p. 15.

[12] Ibid. p. 13.

[13] This additional 300 MW would consist of (1) 100 MW of additional capacity from Boise Bench and (2) 200 MW of capacity through the [redacted] project. While there is also potential for the Powerex contract to increase from 200 MW to 300 MW, at the time of writing this report, LEI was not aware of any agreed upon increases.

Figure 3. Summary of total number of bids in each key RFP stage

Procurement stage	Total number of bids	Total combined capacity of bids (MW)	Total number of project sponsors
Bids submitted	192	64,000 MW	32
Eligible bids	144	40,000 MW	29
Initial Shortlist	63	18,800 MW	16
Preliminary Final Shortlist	11	3,610 MW	7
Final Shortlist	10	3,430 MW	7
Resources contracted to date	3	1,000 MW	3

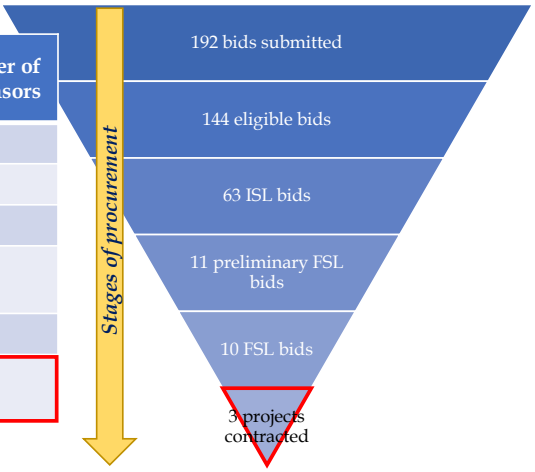


Figure 4. Contracting status of Final Shortlist bids

Delivery year	Project	Project owner	Technology and capacity initially bid	Bid type	Ownership structure/ contract type	Contracting status
2026	Resource Adequacy Market Contract – 5 Years	Powerex	up to 300 MW	Market purchase product	PPA	Contract executed for 200 MW, with potential to increase to 300 MW
2026	Powers Butte	Savion	200 MW Solar + 100 MW BESS	Resource-based product	BSA/PPA	Withdrawn
2026	Powers Butte	Savion	200 MW Solar	Resource-based product	PPA	Withdrawn
2026	Boise Bench	Idaho Power	150 MW BESS	Resource-based product	Utility build	Contract executed, later amended to include an additional 50 MW of capacity; an additional 100 MW of capacity may still be procured
2026	Crimson Orchard	[redacted]	100 MW Solar + 100 MW BESS	Resource-based product	Solar: PPA BESS: BSA	Negotiations underway; delivery year modified to 2027
2026	Moon Crater	[redacted]	200 MW Solar + 50 MW BESS	Resource-based product	Solar: PPA BESS: BSA	Withdrawn
2027	Jackalope	[redacted]/ Idaho Power	600 MW Wind	Resource-based product	Utility build/PPA	Contracts executed
2027	Taurus	[redacted]	350 MW Wind + 250 MW Solar	Resource-based product	PPA	Withdrawn
2027	Taurus	[redacted]	350 MW Wind	Resource-based product	PPA	Withdrawn
2027	Blue Springs	[redacted]	330 MW Solar	Resource-based product	PPA	Withdrawn

As required, LEI monitored the negotiations process from inception to completion—from February to November 2024. As of end December 2024, LEI attended nearly all meetings (virtually, via Microsoft Teams or Webex), received nearly all email communications and contract redlines shared between IPC and each bidder, and reported (in writing or orally) to the OPUC on a monthly basis.[14] LEI conducted these activities for projects bid by four sponsors: Powerex (for market-based resources), [redacted] (for Jackalope Wind), [redacted] (which bid the Crimson Orchard solar plus storage project), and Savion (which bid one solar project and one solar plus storage project, both named Powers Butte). In total, LEI's monitoring activities spanned 10 months and over 50 virtual meetings lasting between one to eight hours each. LEI is not aware of any meeting or substantial contract redlines associated with other Final Shortlist projects. LEI's effort in the contract negotiations phase of work is summarized in Figure 5.

Figure 5. Summary of LEI's effort in the contract negotiations phase of work

Project	Project sponsor	Technology and capacity	Ownership structure/ contract type	Contracting status	Number of meetings attended by LEI	Timeframe of monitoring
Resource Adequacy Market Contract – 5 Years	Powerex	200 MW	PPA	Contract executed	3	February – March 2024
Powers Butte	Savion	200 MW Solar + 100 MW BESS	BSA/PPA	Withdrawn	2	February – April 2024
Powers Butte	Savion	200 MW Solar	PPA	Withdrawn		
Boise Bench	Idaho Power	200 MW BESS	Utility build	Contract executed	N/A	Contract and amended contract received in September 2024
Crimson Orchard	[redacted]	100 MW Solar + 100 MW BESS	Solar: PPA BESS: BSA	Negotiations underway	2	March – November 2024, reinitiated in January 2025
Moon Crater	[redacted]	200 MW Solar + 50 MW BESS	Solar: PPA BESS: BSA	Withdrawn	N/A	N/A
Jackalope	[redacted]/ Idaho Power	600 MW Wind	Utility build/PPA	Contracts executed	44	February – October 2024
Taurus	[redacted]	350 MW Wind + 250 MW Solar	PPA	Withdrawn	N/A	N/A
Taurus	[redacted]	350 MW Wind	PPA	Withdrawn	N/A	N/A
Blue Springs	[redacted]	330 MW Solar	PPA	Withdrawn	N/A	N/A

Of the four negotiation processes monitored, at the time of preparing this report, IPC signed agreements with two bidders: Powerex and [redacted]. Through the Powerex contract, a PPA, IPC will receive 200 MW (and potentially up to 300 MW) of firm, market-based resources. The Powerex deal is discussed in greater detail in Section 2.2.1. Through the [redacted] contract, IPC will receive ownership—once constructed—of a 300 MW wind facility, with an additional 300 MW of energy procured through a PPA. Both elements (i.e., utility-owned and third-party-owned elements) of the project were bid into this RFP as a benchmark bid. To finalize this agreement, IPC and [redacted] had to negotiate several contract types: (1) a PPA; (2) a build transfer agreement

[14] As of January 14, 2025, LEI also attended one contract negotiations call between IPC and [redacted], held in early January.

("BTA") and accompanying exhibits; (3) an "interconnection side letter" where parties agreed to consolidate the PPA and BTA interconnections into a single transmission line; (4) an operations and maintenance ("O&M") agreement; and (5) an engineering, procurement, and construction ("EPC") agreement. The Jackalope project is discussed in Section 2.1.2.

Of the remaining two negotiations monitored by LEI, one remains underway (with [redacted]) while the other (with Savion) was terminated relatively early in the negotiations process following the project's withdrawal. With respect to the former, it is LEI's understanding that negotiations were partially delayed due to the time-intensive nature of the Jackalope negotiations. As of preparing this report, IPC and [redacted] are still negotiating a PPA and energy storage system tolling agreement ("tolling agreement")—this is discussed briefly in Section 2.1.3. With respect to the latter, Savion was forced to withdraw its PPA and BSA after it failed to receive critical siting permits. Savion stated its intent to rebid its project in the next RFP, the 2028 AS RFP for Peak Capacity and Energy Resources.[15] Additional detail is provided in Section 3.1.1.

Another project for which contracts were signed is the Boise Bench project—submitted into this RFP by IPC as a benchmark bid. LEI was not involved in the process through which IPC negotiated its battery energy storage system supply agreement with supplier [redacted] ("[redacted]"), since this was not part of the IE's extended scope of work. These contracts were provided to LEI once executed; LEI reviewed these executed contracts. This is discussed in Section 2.1.1.

To LEI's knowledge, the remaining Final Shortlist projects pulled out of the negotiations process for reasons including inability to: meet the specified commercial online date ("COD"), make progress on generation interconnection, or keep to the bid price (i.e., the project was deemed no longer financially viable). This is discussed in greater detail in Section 3.

As IE, LEI attests to the reasonableness of the results of the contract negotiations process. The process was conducted with fairness and impartiality, upholding the integrity of the selection process. During the negotiations process, IPC was sensitive to the structure of commercial and legal terms, which have implications on future power delivery obligations by each project and the risk of incurring unforeseen costs. The Company made efforts to mitigate these risks, and did not provide more "lenient" terms to one project over any other. It took over half a year for parties to have ironed-out agreements with which they felt sufficiently comfortable to execute. Parties that withdrew from the negotiations process did so not due to the nature of commercial terms but rather due to circumstances outside the scope of contract negotiations. LEI addresses the concerns listed in Acknowledgement Report Condition 2 in Figure 6.

In terms of monitoring activities, LEI found IPC to be forthcoming in its status updates with LEI and the OPUC and diligent in ensuring the IE's access to relevant materials and meeting invitations. LEI estimates that it missed two calls—due to miscommunication and scheduling issues—and potentially a series of additional meetings that took place over the course of one weekend prior to the execution of the Jackalope contracts. Despite missing these meetings, LEI

[15] Savion has rebid over a dozen iterations of the project in the 2028 RFP process.

later received email communications, relevant attachments, and/or meeting summaries from IPC that disclosed the purpose and content of the discussions. LEI makes note of these missed meetings to highlight the challenge of getting all parties organized and in alignment, a tall order when the number and the pace of simultaneous negotiations increase. These situations also occur when non-core IPC, external counsel, or bidder staff set up these meetings, not knowing that IE attendance is also required. If LEI missed any additional meetings, it is not aware of them.

Figure 6. LEI's responses to Acknowledgement Report Condition 2

Acknowledgement Report Condition 2 concerns	LEI's feedback
Condition 2.1: Risk of cost over-runs by utility-ownership projects that outbid third-party projects	The IE finds IPC to have mitigated this risk to the best of its ability; IPC gave careful attention to terms related to price and cost, recognizing that over-runs detrimentally impact ratepayers and as such are at risk of disallowance by the regulator
Condition 2.2: Risk of projects changing ownership structure (specifically into utility-owned projects)	The project ownership structure did not change for any of the projects for which contracts were executed
Condition 2.3: Commercial terms shaped the Final Shortlist and impacted bid prices	Commercial terms were important levers of negotiation for each party; there was significant "give and take" in the negotiation of commercial terms to arrive at agreements with which each party was comfortable moving forward. The execution of contracts indicates that each party had sufficient confidence in the risk allocation implied in the commercial terms of the agreements to move forward with execution

2 Findings from the contract negotiations workstream

The contract negotiations process was monitored for four projects: Jackalope wind, Powerex, [redacted], and Savion. Of these projects, agreements for Jackalope and Powerex have been executed, negotiations for [redacted] remain underway, while the Savion project self-withdrew from consideration. In addition to these four projects, LEI also reviewed the executed agreements associated with the Boise Bench project, but did not attend any meetings or receive email communications between IPC and vendors. In its monitoring role, LEI focused on the items of interest specified in the OPUC's February 1, 2024 Acknowledgement Report and concludes that the process was fair. Key takeaways are provided in Figure 7. The IE believes that IPC took all reasonable precautions available to mitigate the risk to ratepayers.

Figure 7. LEI's assessment of the contract negotiations process

Potential concerns in the contract negotiations	LEI's assessment
Cost over-runs for utility-owned bids	IPC has mitigated this risk to the best of its ability. Project costs are generally lower than what was proposed in the initial bid structure; neither IPC nor the project developers have control over future circumstances that may impact real-time construction cost over-runs
Changes of ownership structure from third-party-owned to utility-owned project	No project structure was modified to become a utility-owned bid from a third-party-owned bid. IPC does have the right of first offer for PPA projects, but this remains unchanged from bid submittal
Commercial terms impacted the Final Shortlist and price terms	Signed agreements consist of commercial terms to which both seller and buyer have agreed; terms were not negotiated in isolation but in synergy with one another. Executed price terms are generally more attractive than what was submitted into the RFP process, and CODs remain unchanged. Projects that withdrew from contract negotiations did so not because commercial terms were unattractive but as a result of external pressures
Contracts could be finalized prior to acknowledgement of the Final Shortlist	No contracts were finalized prior to the start of the contract negotiations phase of work
Utility-owned bids have unique risks and advantages	As explained in the Acknowledgement Report (pages 12-13), unique project risks were assessed earlier in the RFP process; the IE's position remains unchanged following the contract negotiations phase of work, though some clarification may be required of IPC
Utility-owned bids may receive more lenient terms than third-party owned bids	No project received more lenient terms than any other project
The LTSA may not align with the life of the asset	For full transparency, some clarification may be required on a project-by-project basis

2.1 Negotiations of resource bids

Nine out of ten projects on the Final Shortlist were resource bids; of these nine projects, two contracts have been executed while negotiations remain ongoing for one. The contracts executed to date are those associated with the Boise Bench utility-owned project and the Jackalope wind project, which consists of a hybrid of third-party and utility-owned elements. One additional project—Crimson Orchard by [redacted]—may eventually result in a PPA and battery tolling agreement.[16] These three projects are discussed in further detail below. Key price, commercial terms, and risks are discussed on a project-by-project basis. LEI finds that the negotiations of these contracts were conducted in a fair and transparent manner, and each party made an effort to minimize the risks associated with the development of these projects.

2.1.1 Boise Bench by IPC

The Boise Bench battery storage project is an IPC benchmark bid and "pure" BTA. There were no contract negotiations meetings that LEI attended for this project and no email conversations were monitored given the structure of the bid. Instead, IPC shared with LEI the final negotiated battery energy supply agreements signed with the selected battery supplier [redacted]. It is worth noting the increase in storage unit capacity since the initial bid into the 2026 RFP—from 150 MW to 200 MW, or an additional 50 MW. LEI understands that IPC may further procure an additional 100 MW of capacity on top of the executed 200 MW, for a total of 150 MW above the bid amount.[17]

The original battery energy storage supply agreement for a 150 MW battery storage project was signed on July 2, 2024. The amended and restated agreement for a 200 MW battery storage project was signed on July 31, 2024. LEI does not foresee any issues with the capacity increase from the original 150 MW to 200 MW. The finalized price terms appear more favorable than those proposed during the bid phase. Additionally, with the withdrawal of other bids, the increased capacity will help IPC achieve the procurement target set for this RFP. The COD for the expanded project also remains unchanged from the initial bid. As with any project, there is potential for cost over-runs due to inflation and economic factors beyond the utility's control. Nevertheless, several cost items remain unknown, increasing uncertainty around the potential for cost over-runs. Moreover, the warranty term is shorter than originally bid (shortened from five to three years), and performance specifications for the lifetime of the asset following expiration of the warranty remain unclear. Provision of an update by IPC addressing some of these areas of concern may be beneficial. The IE is of the view that the risks associated with this utility-owned project are not outside the range of normalcy.

2.1.1.1 Price terms

The price submitted by the IPC Internal Bid team was informed by a request for quotes ("RFQ") issued by the Company from BESS equipment suppliers. Suppliers were shortlisted based on

[16] June 2025 update: LEI notes for the record that the PPA and tolling agreement were executed by IPC and [redacted].

[17] This understanding is based on email exchanges between LEI and IPC.

competitiveness and value, and were provided the opportunity to update their pricing when the Boise Bench project was advanced into the Final Shortlist. The price included in the bid documentation was based on a supplier quote dated April 26, 2023, which was valid for a period of 30 days. The total cost proposed was $[redacted], which consisted of:

- BESS system equipment costs of $[redacted];
- Idaho sales tax of $[redacted];
- balance of system costs of $[redacted];
- interconnection/shared facilities costs of $[redacted], which includes (1) estimated Generator Interconnection Agreement ("GIA") costs, (2) costs for a step-up transformer, and (3) a $[redacted] generation tie line from the site to the Boise Bench substation; and
- Allowance for funds used during construction ("AFUDC") of $[redacted].

This price assumed a standard five-year warranty extendable to 20 years. In terms of interconnection, while there are no network upgrade costs, the bid proposal assumed direct assigned interconnection costs of $[redacted].

On top of this total cost, the bid also included optional cost estimates for extended warranties, preventative maintenance, and capacity guarantees provided by [redacted], an O&M service provider for utility-scale batteries.

In the final supply agreement with [redacted] the total cost of the 150 MW 4-hour BESS came out to $[redacted],[18] consisting of:

- BESS system equipment costs of $[redacted];
- Idaho sales tax of $[redacted];
- balance of system costs of $[redacted] (unchanged);
- interconnection/shared facilities costs of [redacted] (unchanged); and
- AFUDC of $[redacted].

In response to questions from the IE, IPC clarified why the executed contract price is 27.1% lower than the price bid into the RFP. Namely, the bid price reflected historic costs and generic market information seeing as no technology supplier had been selected at that point in time. The contract price reflects the most economic price offered by a supplier. IPC explains that the largest contributor to this fall in price is the drop in lithium prices since 2023.[19]

[18] This discussion is revised as of June 2025.

[19] Email communications between LEI and IPC in April 2025.

The increase to a 200 MW 4-hour system resulted in a price of $[redacted] for the BESS system equipment. This price (of $[redacted]) includes all costs associated with manufacturing, handling, and packaging, and costs associated with the transportation and delivery of the equipment to the delivery point. Compared to the BESS system equipment costs of $[redacted] from the original bid, which the IE assumes are the two relevant figures to compare for price comparison purposes (i.e., LEI assumes that "system equipment costs" in the original bid consists of the same costs associated with the contract price in the executed contract), this amount is 10.7% lower. It should be noted that this amount does not include the Idaho sales tax, shared facilities costs, and AFUDC, and the optional costs for extended warranties, preventative maintenance, and capacity guarantees. Note that, because the contract with [redacted] is a contract for the BESS system only, there are also no cost estimates pertaining to items such as interconnection, permitting, or BESS assembly. Moreover, the contract price covers a three-year warranty period, which is less than the warranty period assumed in the original bid.

2.1.1.2 Key contract terms

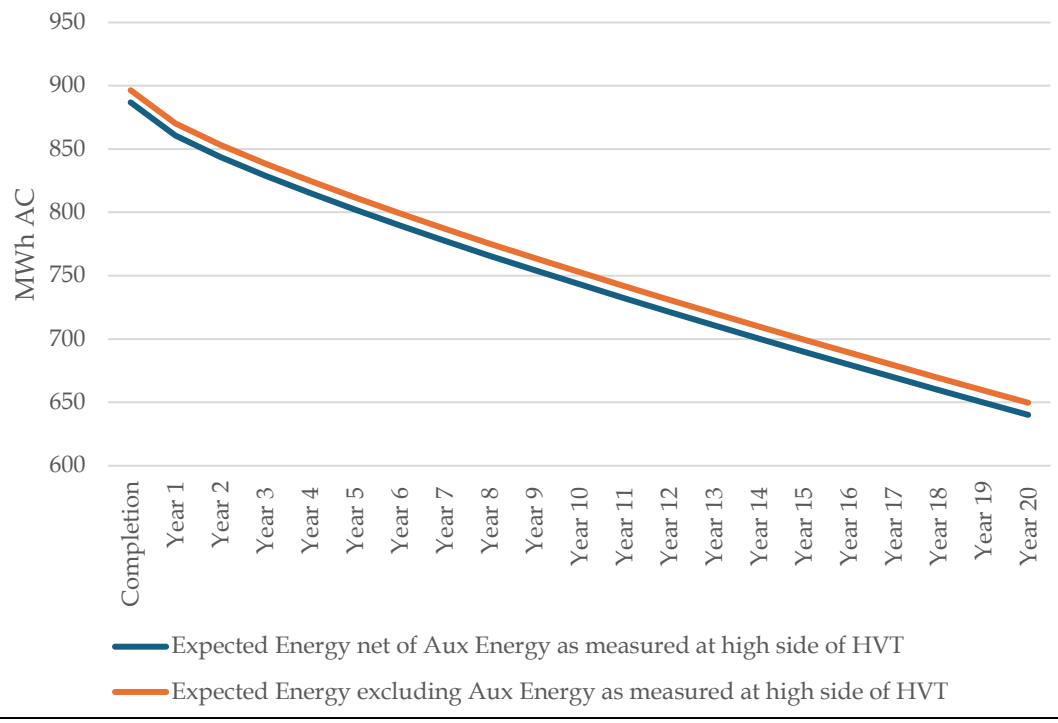
LEI reviewed the supply agreement and notes several key commercial terms.[20] Since LEI was not tasked with attending any negotiation meetings with potential suppliers of the BESS equipment for Boise Bench, LEI's overview reflects its understanding of the contracts ultimately executed with [redacted].

- **Energy Capacity Guarantee During the Warranty Term:** The energy capacity guarantee for the three-year warranty term of the project is the full 200 MW AC (800 MWh of "guaranteed AC usable energy"). If the BESS fails to meet the energy capacity guarantee for the three-year warranty term, rather than paying liquidated damages, the seller ([redacted]) must do whatever is necessary to get the equipment to achieve the energy capacity guarantee.

- **Expected Energy:** The supply agreement provides expected energy on a yearly basis for 20 years. This level of expected energy is "measured at the high side of the HVT," where LEI assumes HVT to refer to high voltage transformers. This expected energy is provided in graphical form below. Based on LEI's calculations, the expected energy decreases by about 27.8% (net of auxiliary energy) (or 27.5% excluding auxiliary energy) between commissioning completion and year 20. The contract notes that this estimate may change if commissioning completion is delayed due to delays caused by IPC; the factor (percentage) used to "scale down" the expected energy increases the more time passes from the originally agreed upon completion commissioning date, and also varies based on the average temperature expected for the new month of delivery. Essentially, this implies that the battery's performance may be negatively impacted by any IPC-caused delays in achieving commissioning completion.

[20] Note that LEI is not a legal expert and as such its review of key terms is commercial, rather than legal, in nature.

Figure 8. Expected energy, commissioning completion to year 20



- **Key Dates:** The supplier is to deliver the equipment by the guaranteed delivery date, which is October 20, 2025. Installation is to be completed by December 15, 2025, with commissioning commencing on December 17, 2025. The commissioning completion date is scheduled for May 1, 2026 while final completion is set to occur on June 1, 2026. This schedule remains unchanged in the amended supply contract, meaning that an increase in the capacity of the project did not impact project timing. The COD remains unchanged from the initial bid documentation. Failing to meet COD within a certain window of time can result in penalties to be paid by the supplier or even termination of the agreement.

- **Minimum Performance Threshold for Commissioning Completion:** [redacted]

- **Roundtrip Efficiency Performance During the Warranty Term:** The roundtrip efficiency performance guarantee [redacted] This is slightly [redacted] than the 86% roundtrip efficiency adopted

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by the National Renewable Energy Laboratory, it falls within the range of 83-87% identified through testing.[21]

Based on LEI's interpretation, the [redacted] agreement also includes other important commercial terms, including the items listed below:

- **Buyer Obligations:** Among other items, IPC will be responsible for securing the required permits and interconnection as well as BESS assembly and equipment installation. The supplier inspects the unit to confirm that installation has been successfully completed.

- **Supplier Obligations:** The supplier is in charge of designing the BESS, transporting it to the project site, testing and commissioning the project, reviewing the project's point of interconnection design, conducting quality assurance and quality control, and assisting in compliance with local authorities or the grid operator, as necessary. It will also design, procure, and deliver the equipment that will house the control system and other communications equipment, as well as integrate the project with IPC's remote control and monitoring system.

- **Warranty:** For all BESS equipment except the skidded inverters and electrically integrated medium voltage transformers ("PCS"), the warranty starts on the day the unit is transported to the project site and expires the earlier of (1) [redacted] months after commissioning completion or (2) [redacted] months after delivery. For PCS equipment, the warranty starts on the delivery day and expires the earlier of (1) [redacted] months after the commissioning completion or (2) [redacted] months after delivery.

2.1.1.3 Key risks

LEI makes the following conclusions based on its review of the original and amended battery supply agreements:

- **areas at risk for cost over-runs:** While executed price terms seem more attractive than the terms submitted into this RFP process, LEI notes several risks for cost over-runs associated with the Boise Bench project.

  First, the [redacted] agreement covers the supply and delivery of the BESS facility, only. It does not seem to include costs that would presumably be incurred by IPC, such as balance of system costs; interconnection/shared facilities costs; AFUDC; taxes; extended warranties, preventative maintenance, and capacity guarantees; permitting expenses; or BESS assembly. With respect to permitting, LEI notes that the Boise Bench project is to be located in Ada county, Idaho. As explained in Section 3.1.1, another developer was unable to obtain the necessary project permits in Ada—this can pose a potential construction schedule/delay risk as well as potential risk for additional costs for the Boise Bench

[21] "Annual Technology Baseline." National Renewable Energy Laboratory. Accessed January 2, 2025. <https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage>

project. The status of permitting for the Boise Bench project is not known to LEI. As LEI understands it, another notable cost item that seems to be missing is the O&M costs associated with operating the project over its lifetime.

Second, LEI notes the shortened warranty period, from [redacted] to [redacted] years. This implies a cost risk for any defects that may be observed in years [redacted] and [redacted] of the project's life.

Third, there are risks beyond the utility's control that may also influence the final price outcome, such as, for example, labor costs (for construction and installation) and interest rate changes (or higher financing costs).

This being said, LEI understands that some of these costs may not be reasonably known at this time, and so the provision of these costs would be estimates.

- **changes to the ownership structure of any of the negotiated projects:** The ownership structure remains unchanged. Notable, and relevant, is the increase in project capacity from 150 MW to 200 MW, increasing the capacity owned by IPC over what was proposed in the original bid. Though the capacity procured for this project is larger than what was initially proposed, the IE finds IPC's explanation for this decision to be rationale: inability to move forward with a significant portion of the Final Shortlist projects, as well as more advantageous price terms than initially assumed, proved this to be a feasible path forward.
- **how commercial terms impacted the Final Shortlist and bid prices:** As LEI was not involved in the negotiations with suppliers, it is unable to report on this item.
- **timing of contract finalization:** All contracts were executed following acknowledgement of the Final Shortlist.
- **unique risks and advantages (construction cost over-runs, reasonableness of forced outage rates, end effect values, reasonableness of O&M costs, performance assumptions and construction schedules or delay risks):** The risk of cost over-runs is not insignificant, as explained in the first bullet point of this section. O&M costs are also unclear, and as such no conclusion can be made as to their reasonableness.

  In terms of project performance, as noted above, the supplier is required to pay penalties for failing to meet certain performance levels or to remedy any deviations from the project's expected performance—both are beneficial to customers. However, this obligation seems to only apply for the life of the warranty, or [redacted] years. It is unclear how performance will be maintained over the remaining life of the asset. LEI is not aware of the performance thresholds and availability guarantees for the period following the end of the warranty.

  The construction schedule seems reasonable; the risk of delay is outside the utility's control.
- **alignment of LTSA terms with the life of the asset:** IPC will be the operator of the BESS unit. It is unclear how long [redacted] will provide service support, if requested by IPC, following the conclusion of the warranty period. If the warranty is not extended with [redacted], then, according to the contract, it seems that the warranty obligation will fall on IPC.

The risks described above are not negligible. The provision by IPC of supplemental information addressing some of these risks may help to clarify these areas of uncertainty.

2.1.2 Jackalope Wind by IPC and [redacted]

The Jackalope wind benchmark bid consists of (1) third party-owned (PPA, at 298.92 MW capacity) and (2) utility-owned (BTA, at 301.74 MW capacity) elements. With respect to the former, [redacted] will develop a portion of the Jackalope project from which IPC will purchase the net output, capacity rights, and green tags. With respect to the latter, [redacted] will develop a separate portion of the Jackalope project that will be handed over to IPC once construction is complete. Upon project completion, [redacted] will act as the O&M provider, while the turbine warranty—provided by [redacted], the turbine manufacturer—will be handed over to IPC along with the wind facility itself.

Seeing as the project consists of different ownership structures, as well as both construction and operations phases for the asset that will ultimately become utility-owned, IPC and [redacted] negotiated multiple contracts:

- a PPA for the third party-owned sales of electricity;
- a BTA for the asset that will become utility owned;
- an EPC agreement covering the terms of construction for the utility-owned element of the project;
- an O&M agreement that provides the terms for [redacted] engagement as O&M provider during the lifetime of the utility-owned asset; and
- a turbine warranty with turbine manufacturer GE.

In addition to these main agreements, IPC and [redacted] negotiated specific issues like the project's production tax credit ("PTC") structure and cybersecurity protocols, among others, as well as a side agreement modifying the originally envisioned interconnection arrangement. It took about nine months for IPC and [redacted] to come to an agreement on all contracts and their exhibits and appendices. Several meetings were even conducted in-person in Boise, Idaho, during which time parties negotiated terms and conditions over two-to-three-day sprints lasting several hours each. The contracts were finalized at the end of October 2024.

The main commercial terms of the executed contracts generally align with the terms proposed during bid submission into this RFP process, including COD. Because multiple interconnected agreements were negotiated simultaneously, parties needed to make sure that they felt comfortable enough with the resulting risk allocation implied by the agreements before signing. Price terms do not seem to deviate significantly from the bid prices submitted. The BTA portion of the project does run the risk of cost over-runs given that (1) some construction costs, like reimbursable costs, may be higher than anticipated (though will not be incurred without sign off by IPC) and (2) the consortium's proposed interconnection plan modifications are yet to be approved by the US Federal Energy Regulatory Commission ("FERC"). However, these risks do not seem to be outside the range of reasonableness. Though, for consistency, agreed-upon

commercial terms were applied across all agreements, and as such LEI generally concludes that [redacted], which LEI finds to be reasonable. Nevertheless, it does potentially put the PPA at risk if parties are unable to come to mutual agreement in the relevant circumstances.

2.1.2.1 Price terms[22]

PPA price terms

The initially proposed PPA price of $[redacted]/MWh covered the as-generated product for a term of 35 years, and excluded GIA network upgrade costs or ancillary services from the Jim Bridger Station (which were assumed recoverable by [redacted] through transmission network credits as defined in IPC's Open Access Transmission Tariff ("OATT")). In the final shortlist, the PPA price was updated to $[redacted]/MWh.

The executed PPA price is $[redacted]/MWh, which is 2.5% lower than the initially proposed PPA price. This contract price includes Green Tags and capacity rights. The price will apply for the same period as in the initially proposed PPA, a 35-year term. This PPA price reflects the project's updated interconnection point design, as approved through a FERC waiver—see the "interconnection side letter" discussion in Section 2.1.2.2. The PPA price does not include any costs associated with this new interconnection arrangement.

BTA price terms

The initially proposed "all-in" BTA price was $[redacted]/kW, consisting of the cost components provided below. According to LEI's calculations, a price of $[redacted]/kW produces an "all-in" (total) BTA price of approximately $[redacted].[23, 24] The "all-in" price included:

- a "base" BTA price of $[redacted]/kW (or, based on LEI's calculations, about $[redacted]);

[22] This section of the report was updated in June 2025 to reflect information provided by IPC in response to clarification questions posed by LEI and OPUC Staff. The information provided by IPC did not change LEI's conclusions with respect to the results of this RFP process.

[23] This calculation is based on an assumed capacity of 301.74, as provided in the executed BTA. The original bid documents provide an assumed capacity of 301.7 MW, which results in an "all-in" price of $[redacted], a slight variation from the dollar value associated with 301.74 MW. For price comparability (between the original bid and the executed contract), LEI uses the 301.74 MW value for this rough calculation.

[24] Note that, as part of the quantitative assessment conducted to determine the Final Shortlist, the Company included PPA network upgrade in the total capital investment associated with the Jackalope projects. This means that the Company assumed a total capital investment of $[redacted] (BTA total price + $[redacted] in PPA-related network upgrades) rather than $[redacted] (BTA total price, only).

- "other" costs totaling $[redacted], consisting of:
    - a gen-tie price of $293/kW (unless [redacted] retains ownership of the tie-line, in which case IPC would pay a monthly charge of $[redacted]/kW-month in place of the $[redacted]/kW fee);
    - an environmental fee of $[redacted]/kW;
    - an eagle mitigation cost of $[redacted]/kW; and
    - interconnection costs and network upgrades of $[redacted]/kW (which is 37.5% of the total interconnection and network upgrade costs anticipated for the project).

The original bid documents also caution that one of the permits required by the project—Wyoming's Industrial Siting Council—requires financial assurance to insure decommissioning and reclamation activities. This financial obligation will be transferred to IPC once project ownership transfers to the Company. This would entail an additional project cost, estimated at $[redacted] of annual financial assurance for $[redacted] of decommissioning/reclamation activities at end-of-life.

The executed BTA "all-in" (total price) BTA price is just under $[redacted]. Compared to the initial "all-in" BTA price submitted during the RFP bid process ($[redacted]), the executed price is 9.8% higher. The total price includes the following:

- a "base purchase price" of $[redacted]/kW, or approximately $[redacted]. According to LEI's calculations, this is a 5.9% increase as compared to the "base purchase price" in the bid submission ($[redacted]);
- "other" components of the bid price that amount to $[redacted]/kW, or $[redacted]. According to LEI's calculations, this is 30.3% higher compared to the initial "other" component of the price ($130.4 million). This portion of the price consists of the following:
    - approximately $[redacted] for a network upgrades transmission line;
    - approximately $[redacted] in network upgrades.

    Note that there are no longer any gen-tie costs associated with the project, which reflects the project's new point of interconnection as permitted through a FERC waiver—see the "interconnection side letter" discussion in Section 2.1.2.2.

For additional context, IPC prepared a cost analysis from the perspective of the levelized cost of energy ("LCOE") to show cost changes from the Final Shortlist to contract execution as well as overall economic benefit. Cost changes reflect modifications to the project's physical design (network upgrades will replace the need for new gen-tie construction), which in turn impact financial structure (network upgrade costs are "separate" from the BTA price). The analysis also shows the benefits of the FERC waiver. This analysis looks at the impact of the BTA and PPA together, seeing as both were submitted and evaluated as a single bid. As seen in Figure 9, while the final LCOE for the combined Jackalope project is higher than what was initially bid into the 2026 AS RFP, it is lower than what it would have been had FERC not approved the waiver.

Figure 9. IPC's LCOE analysis of total project costs

Final shortlist LCOE	BTA	PPA
600 MW Wind	$[redacted]	$[redacted]/MWh
Transmission Generator Tie Line	-	-
Network Upgrades Transmission Line	-	-
Network Upgrades	$0	$[redacted]
LCOE of Combination	**$[redacted]**	

Executed contract LCOE with FERC waiver	BTA	PPA
600 MW Wind	$[redacted]	$[redacted]/MWh
Transmission Generator Tie Line	$0	$0
Network Upgrades Transmission Line	$[redacted]	$0
Network Upgrades	$[redacted]	$0
LCOE of Combination	**$[redacted]**	

Contract price LCOE without FERC waiver	BTA	PPA
600 MW Wind	$[redacted]	$[redacted]/MWh
Transmission Generator Tie Line	$[redacted]	$0
Network Upgrades Transmission Line	$0	$0
Network Upgrades	$[redacted]	$[redacted]
LCOE of Combination	**$[redacted]**	

Source: IPC.

O&M price terms

[redacted] as operator will receive O&M fees for its services. The initially proposed 10-year average total O&M fee was $[redacted]0/kW, consisting of (1) [redacted] and (2) [redacted].

As per the executed agreements, the pre-COD fee is estimated at $[redacted]; however, this is only an estimate, and actual costs will be charged by [redacted] to IPC on a time and materials basis. Once the project is operational, the annual fee will be based on the nameplate capacity of the project. The fee structure below for the initial contract term of 10 years was calculated based on an assumed nameplate capacity of 300 MW, but may change subject to the ultimate MWac of installed capacity. LEI understands that the estimated annual fees in the executed agreement align with the $[redacted]/MW yearly fixed fee; the reimbursable budget is subject to annual limits

for the O&M. proposed in the original bid. The fees in the executed agreement seem lower than those estimated by the US Energy Information Administration ("EIA").[25]

Figure 10. Executed O&M price for Jackalope Wind

Operating Year	Annual Fee
1	$[redacted]9 ($[redacted]/MW)
2	$[redacted] ($[redacted]/MW)
3	$[redacted] ($[redacted]/MW)
4	$[redacted] ($[redacted]/MW)
5	$[redacted] ($[redacted]/MW)
6	$[redacted] ($[redacted]/MW)
7	$[redacted] ($[redacted]/MW)
8	$[redacted] ($[redacted]/MW)
9	$[redacted] ($[redacted]/MW)
10	$[redacted] ($[redacted]/MW)

2.1.2.2 Key contract terms

Key commercial terms in the Jackalope agreements include the following:

- **Availability Guarantee:** Parties discussed the appropriate amount of time (expressed as a percent) to assign for project availability, as well as method for determining availability (i.e., an energy-based measure (reflecting actual production losses) or time-based measure (hours-based mechanism that considers only hours where the turbines may be spinning, excluding outages)). The "guaranteed availability" in the executed PPA is [redacted]; the "target mechanical availability" is [redacted] in the executed O&M agreement. The initial bid documents suggested an availability guarantee of [redacted]; making the final executed terms better than the initial bid.
- **COD:** Parties agreed to a "scheduled commercial operation date" in the PPA/ "guaranteed substantial completion date" of the BTA of June 1, 2027. Some flexibility is built into the date to account for any delays in meeting COD, which could result in an actual COD beyond the June 2027 date. The contract attempts to mitigate delays through penalty provisions, which helps to provide adherence to the overall project timeline. In its original bid, [redacted] proposed a COD of June 1, 2027.

[25] London Economics International LLC. *Review of the Idaho Power Company's benchmark bids, submitted in response to the 2026 All Source Request for Proposals for Peak Capacity and Energy Resources*. June 23, 2023.

- **Construction Milestones and Milestone Payments for the BTA component of the project:** From IPC's perspective, establishing construction milestones and associated payments will allow the Company to keep project construction on track. [redacted].

  Based on LEI's understanding, the executed contract differs from the bid documentation in that it does not ultimately assign firm deadlines to individual project milestones. Instead, the project is only required to meet the COD. This seems reasonable, as it obligates [redacted] to meet COD while providing some flexibility in the work schedule.

  The following table shows a comparison of the milestone structure as provided in the initial bid documentation versus in the executed contract. Notably, in the executed contract, [redacted].

Figure 11. Construction milestone structure, bid proposal vs. executed contract, Jackalope Wind

Bid milestone	Payment percentage	Executed milestone	Payment percentage
Firm date	[redacted]%	Notice to proceed payment	[redacted]%
Mobilization	[redacted]%	Construction mobilization	[redacted]%
Foundation completion	[redacted]%	100% foundation completion	[redacted]%
Mechanical completion	[redacted]%	100% mechanical completion	[redacted]%
Substantial completion	[redacted]%	Post-closing payment	[redacted]%

- **Outages:** The PPA agreement consists of three outage categories:
  - **Forced Outage:** A forced outage is one that results in more than [redacted]% of the facility's nameplate capacity being unavailable. This remains unchanged from the submission of the bid documentation. Based on LEI's research, a typical wind forced outage rate is below 5%;[26]

[26] London Economics International LLC. *Review of the Idaho Power Company's benchmark bids, submitted in response to the 2026 All Source Request for Proposals for Peak Capacity and Energy Resources*. June 23, 2023.

- **Maintenance Outage:** This refers to any outage involving [redacted]% of the facility's net output that is not a forced outage or a planned outage. The definition aligns with NERC Event Type MO. This remains unchanged from the submission of the bid documentation.
- **Planned Outage:** An outage, excluding forced or maintenance outages, as per NERC Event Type PO. Planned outages are not allowed in the months of [redacted]. The months during which planned outages are prohibited are reasonable, [redacted].

- **PPA Term:** The original PPA bid contemplated a 35-year term, which reflects the life of the proposed asset. The term remains unchanged in the executed PPA.

The contract negotiations were time consuming and at times challenging because a considerable number of commercial terms were found to be contentious during the negotiations process. It took time for both parties to discuss and come to an agreement on these terms. Some of these terms included:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted].

At a high level, from LEI's view, disagreement between parties reflected the negotiation of risk allocation between IPC and [redacted] at different phases of the Jackalope project's development (i.e., during construction versus during project operations). For example, IPC—which will only own the developments rights to the BTA portion of the Jackalope assets during construction—sought protections/recourse in the event that the project does not materialize. IPC wanted to ensure a guaranteed fixed price and project schedule to prevent [redacted] from walking away from the contract before delivering the completed project. [redacted], on the other hand, wanted to

ensure that it would not be liable for any situation impacting the project that is outside of its control, and was not willing to take on contract risk that it believed falls on the asset owner (IPC) and not the O&M provider ([redacted]). Both perspectives are rational.

In addition to the commercial terms above, other key concerns relevant to the utility-owned aspect of the agreement included the following:

- **Warranties (general):** [redacted];
- [redacted] **Warranties and Guarantees:** [redacted].

Finally, in an interconnection "side letter," parties mutually agreed to adjust Jackalope's existing LGIAs, specifically modifying (1) the number of transmission lines associated with the project and (2) the point of interconnection, as well as introducing (3) updated upgrade scope and costs if the requested LGIA amendments are rejected by FERC. LEI understands that these modifications to the LGIA beneficially impacted the project's pricing. Initially, separate LGIAs (i.e., separate transmission lines connecting to the Jim Bridger substation, jointly owned and operated by IPC and PacifiCorp) were envisioned for the PPA and BTA portions of the Jackalope project.[27] Following discussion between IPC and [redacted], it was agreed that, subject to receipt of a waiver from FERC, the separate transmission lines for the PPA and BTA portions of the project will be consolidated into a single transmission line. This single line would connect to a new (to be developed) Jackalope switching station that then connects to Jim Bridger at a single point of connection. The following was discussed during negotiations:

- If approved, [redacted].
- If FERC approval is not received, [redacted]

[27] There is also a third LGIA for a 200 MW wind plant (called Jackalope III) that will be developed by a [redacted] affiliate. LEI understands that Jackalope Wind III is not being developed by [redacted] for IPC.

[redacted]

The FERC waiver was granted on December 18, 2024. As a result of the waiver, the project's point of interconnection was moved from the existing Jim Bridger substation to a new (yet to be built) Jackalope switching station. Duplicative gen-tie lines are consolidated and network upgrades replace the need for expansion works at Jim Bridger.[28] As a result, per IPC, the LCOE of the combined BTA and PPA is more favorable compared to the no FERC waiver scenario (please refer to Figure 9).

2.1.2.3 Key risks

Both IPC and [redacted] put in a great deal of effort to finalize the Jackalope agreements, and LEI finds the negotiations to have been conducted in a fair manner. LEI addresses each of OPUC's concerns below:

- **areas at risk for cost over-runs:** Costs associated with the BTA may deviate from baseline projections based on actual construction costs known only after closing. [redacted] is obligated to provide detailed documentation to explain any such deviation in costs (which may be subject to dispute). The annual O&M budget may also deviate based on actual reimbursable costs incurred, which may vary based on actual inflation rates and final project design. LEI finds that the contracts are reasonable and attempt to mitigate the risks of such over-runs, which cannot be reasonably foreseen or accounted for ahead of time.

  In addition to the above, LEI understands that both the BTA and PPA contract prices may require amendment if FERC rejects the proposed modification to the project's LGIA. While this risk is not insignificant, IPC and [redacted] have no ability to influence FERC's decision in this matter. LEI also understands that the parties agreed to the LGIA amendments to make the price terms of the agreements more competitive, which—if successful—will benefit ratepayers.[29]

  Finally, LEI understands that the project has not yet received several federal, state, and local permits required for construction and operations. According to the original bid documents, the project is largely located on US Bureau of Land Management ("BLM")-managed land; while this helps to alleviate some risk, any permitting delays could potentially impact the project's timeline and price terms.

- **changes to the ownership structure of any of the negotiated projects:** The ownership structure remains unchanged. If FERC does not approve the LGIA amendments, then the ownership of the Jackalope switching station and a 35-mile 345 kV line leading into Jim

[28] Information shared via email and phone by IPC with LEI in June 2025.

[29] As explained in the previous section, the FERC waiver has been granted.

Bridger will be a shared facility, and [redacted] will provide O&M services under these circumstances.

In addition, the executed PPA contains a Right of First Offer ("ROFO") clause that gives IPC the opportunity to receive from [redacted]

One clause may suggest less lenient terms for the PPA than the BTA—[redacted]

- **how commercial terms impacted the Final Shortlist and bid prices:** All items were part of the larger negotiations; parties used commercial terms as levers to get comfortable with the risk allocation resulting from the finalized contracts individually and together (as a portfolio of agreements). COD and price were generally not adversely affected.
- **timing of contract finalization:** All contracts were executed following acknowledgement of the Final Shortlist.
- **unique risks and advantages (construction cost over-runs, reasonableness of forced outage rates, end effect values, reasonableness of O&M costs, performance assumptions and construction schedules or delay risks):** It does not appear to be the case that the utility-owned element received more lenient terms than the third-party owned element. On the whole, commercial terms also seem reasonable to LEI. The construction schedule seems reasonable; the risk of delay is outside the utility's control. Only the forced outage rate in the PPA seems slightly higher than what seems to be industry standard.
- **alignment of LTSA terms with the life of the asset:** The O&M agreement between [redacted] and IPC [redacted] LEI understands that, in general, O&M agreements can vary based on the provider's risk appetite, the risk profile of the project, and other parameters.

Overall, while there are risks associated with these contracts, overall they do not appear to be unexpected or unreasonable.

2.1.3 Crimson Orchard by [redacted]

The Crimson Orchard 100 MW solar plus 100 MW battery storage project consists of PPA and battery storage agreement components.[30] LEI understands that—given the relatively few resources that made it into the contract negotiations phase of the RFP process, and the gap in meeting resource needs identified for 2026/2027—executing the [redacted] contract is a current priority for IPC. The negotiations of this contract remain underway. To date, it is known that [redacted] will no longer be able to meet its original 2026 COD; rather, it is now targeting 2027. At this point in time, negotiations have been conducted in a fair and transparent manner.

2.1.3.1 Price terms

As of preparing this report, PPA and tolling price terms appear higher than what was initially proposed in the original bid submission. Note that the prices below are not final, as the contracts have not yet been executed;[31] they only indicate how pricing terms have changed thus far in the contract negotiations process:

- the PPA price increased from $[redacted]/MWh to $[redacted]/MWh,[32] or by [redacted]%;
- the tolling component increased from $[redacted]/kW-month to $[redacted]/kW-month,[33] or by [redacted]%.

The original bid proposed a term of 20 years. While the latest tolling agreement[34] reviewed by LEI notes this 20-year term, the PPA does not.

The economic feasibility of the [redacted] project depends on the availability of federal incentives such as through the Inflation Reduction Act ("IRA"). Repeal of the IRA may result in project cancelation, which is a general risk to this RFP process. Tariff changes, such as import or economy-wide tariffs, also have the potential to adversely impact project viability.

2.1.3.2 Key contract terms

For the PPA, discussions have so far covered items such as [redacted] proposal to allow termination if the Conditional Use Permit ("CUP") is not obtained from Elmore county by a specific deadline. IPC aims to integrate the project into its resource planning by 2027 and proposes timelines for relief or termination if CUP approval is delayed. Both parties are looking for

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[30] While the Jackalope project by [redacted] also has a PPA component to it, Jackalope is discussed as a hybrid bid in Section 2.1.2.

[31] June 2025 update: The contract has been executed; the prices included in this section reflect the executed prices.

[32] June 2025 update: The PPA price assessed as part of the final shortlist was $[redacted]/MWh.

[33] June 2025 update: The tolling price assessed as part of the final shortlist was $[redacted]/kW-month (derived from $[redacted]/kW-year).

[34] The most recent contract redlines were shared on January 8, 2025.

appropriate language for mutual termination rights and have discussed the implications of security postings, with [redacted] seeking to mitigate risks due to significant prior investment. Other items of discussion include curtailment and tax issues.

With respect to the battery storage agreement, parties have discussed language around terms including liquidated damages clauses (to prevent "double stacking" of claims), availability commitments, security provisions, liability associated with tax credits, approved suppliers and associated technology performance, sharing event cap (related to operations in the Western Resource Adequacy Program), ROFO, and force majeure.

2.1.3.3 Key risks

As a third-party-owned project, an assessment of utility-owned project risks is not applicable.

Major project development risks include (1) impact to economic feasibility due to the potential repeal of federal tax incentives or the imposition of more stringent tariffs and (2) ability to secure the necessary permitting.

2.2 Negotiations of market-based bids

Of the Final Shortlist bids, only one was a market-based bid. The agreement with Powerex was fully executed on March 12, 2024, the first one to be executed among the Final Shortlist bids. LEI has not identified any concerning commercial terms related to cost over-runs, ownership modification, or how commercial terms shaped the price.

2.2.1 Powerex

LEI attended three meetings between IPC and Powerex in March 2024. These meetings primarily focused on refining the language in the original agreement. No substantial alterations were implemented regarding COD, capacity, or pricing terms.

2.2.1.1 Price terms

The price terms remain unchanged between the original bid and the executed contract:

- **Fixed Capacity Price:** $[redacted]/kW-month, [redacted];
- **Energy Price:** [redacted] Seeing as this is a market-based resource, LEI does not anticipate any risk for cost over-runs.

2.2.1.2 Key contract terms

The final agreement was executed expeditiously; as such, LEI concludes that commercial terms were not contentious. Important terms include the following:

- **Delivery Term:** The delivery term will be five years from the energization of the Boardman to Hemingway ("B2H") transmission project. The contract maintains the option to renew the contract for five additional years. This is similar to the original bid, in

which Powerex proposed a delivery term of June 1, 2026, contingent on B2H, for five or ten years;

- **Delivery Months:** The delivery months will be June to September;
- **Capacity Quantity:** The executed capacity quantity is 200 MW, with the potential to increase to 300 MW by mutual agreement before June 1, 2026. In its original submission, Powerex proposed a capacity of up to 300 MW.

2.2.1.3 Key risks

LEI has not identified any areas of concern. It is important to highlight a contingency related to B2H, whereby delivery may be affected if there are delays in the line's construction.

2.3 Concluding remarks on key outcomes and risks of the contract negotiations process

LEI finds the results of the contract negotiations process to be reasonable, especially in light of the circumstances of this RFP, where the majority of bidders withdrew their projects from further consideration. The process was conducted in a fair and transparent manner, and IPC took reasonable measures to mitigate price and commercial risks, which ultimately fall on ratepayers. From the perspective of the IE, there are several risks with respect to the Boise Bench project (discussed in Section 2.1.1) and the Jackalope project (discussed in Section 2.1.2), as well as Powerex (discussed in Section 2.2.1) that the OPUC may wish to clarify with the input of IPC.

Additionally, some prices may have deviated from the original bid prices over the course of the negotiations process. These adjusted prices were not reflected in the simulation (modeling) exercises undertaken by the utility in the earlier phases of work associated with this RFP. It may be helpful to understand whether these projects would have maintained their respective positions in the initial and final shortlists had they submitted these updated prices as part of the original bid submission. Such exercise should, however, be considered in the context of project withdrawals following acknowledgement of the Final Shortlist.

Finally, LEI notes that the contract negotiations phase of work was a rather long and tedious one. Initially, IPC intended on entering negotiations simultaneously with all project owners (and not in rank order according to the Final Shortlist). In practice, given the intensity of the work, discussions could not be held concurrently. The ability of IPC to successfully finalize contracts, and for the IE to be able to effectively monitor this process, would have been reduced had a greater number of bidders been engaged in negotiations. The complexity of items discussed necessitated the engagement of many staff across all participating parties—IPC, bidders, their respective legal and tax councils, the IE, and some other parties as well, such as [redacted] in the case of the Jackalope project. They required staff to dedicate a substantial amount of time to iron out risk allocation between parties, because commercial terms were not negotiated in isolation from one another but as a package. At the same time, LEI understands that time is an important factor; the longer it takes IPC to engage a bidder, the more likely it becomes that bid parameters—especially price—submitted into the RFP process will become outdated or adversely impacted by increasingly challenging macroeconomic conditions. There is no perfect approach to this predicament, but it is still worth acknowledging for the record.

3 Final Shortlist bids that withdrew from contract negotiations

After acknowledgement of the Final Shortlist, several Final Shortlist bids—Blue Springs by [redacted] (solar PPA), Taurus by [redacted] (two PPAs, one solar and one solar plus wind), Moon Crater by [redacted] (solar plus storage PPA and battery storage agreement), and Powers Butte by Savion (one solar PPA and one solar plus storage PPA and battery storage agreement)—withdrew from the contract negotiations process. Changing circumstances resulted in these withdrawals, including specifically the inability to obtain the necessary permits, failure to make any progress with respect to the cluster study or generation interconnection process, inability to meet the required COD, or loss of project financial viability. The withdrawal of these projects from the 2026 RFP process was not related to the contract negotiations process, but rather to obstacles identified to project development. The utility is limited in how it can go about remedying these outcomes, potentially impacting its ability to meet the needs underpinning its RFP. Section 3.1 provides additional context for the withdrawals; Section 3.2 provides a discussion on the implications of this result of the 2026 AS RFP.

3.1 Reasons for withdrawals

The number of projects to have withdrawn from contract negotiations is not insignificant, representing over 70% of the capacity of the Final Shortlist. These would also have been third-party owned projects. However, the conditions resulting in withdrawal from the 2026 RFP process may be difficult to control for. The reasons for project withdrawals can be categorized into three main buckets: (i) inability to meet the required COD, (ii) lack of progress in the interconnection process, and (iii) loss of economic viability. These three categories of reasons could impact the ability of the utility to meet the energy and capacity needs identified for 2026 and 2027.

3.1.1 Failure to receive permitting approval in time to meet COD

Negotiations with **Savion** for the Powers Butte projects were cut short due to the inability to secure the required CUPs from Ada and Canyon counties in a timely manner. At the time negotiations began, Savion had begun the permitting process in Ada county; Savion's participation in public hearings in Ada confirmed organized pushback from local stakeholders, which put into question the project's ability to meet 2026 COD. At the same time, the first public hearing session for Canyon county had been delayed; this timing put 2026 COD at risk, seeing as the status of the CUP would not be known for several months after the public meeting. Negotiations continued in good faith until it became clear that the projects would be unable to receive the CUPs in time to make the required COD.

The [redacted] projects, too, informed IPC that it would be unable to meet the 2027 COD. LEI is not aware of the reason beyond this determination by the [redacted] team.

Both parties expressed their interest in participating in future RFPs, including the ongoing 2028 RFP.

From the 2026 RFP process, it has become clear that permitting is a key risk to project development, and one that is outside the control of either party. A 2023 survey of utility-scale wind and solar developers by Lawrence Berkeley National Laboratory ("LBNL") found that:

- about 60% of solar and over 45% of wind siting applications by participating developers were delayed by six months or more. Community opposition as well as local ordinances or zoning were two of the leading causes of project delays;
- community opposition on average leads to a delay of 11 months for solar projects and 14 months for wind projects;
- close to half of respondents' projects were delayed during the permitting stage of work;
- 49% of solar respondents and 55% of wind respondents strongly agreed with the statement that community opposition is expected to be more of an issue in the future. Developers find themselves spending more to address or mitigate opposition than they had five years prior;
- public opposition can be hard to predict, especially if a project has not yet been made public.[35]

Survey participants were also encouraged to share additional feedback. One participant commented that, "These answers are hard to capture because every community is unique and thus the strategy we deploy"; another wrote that, "Community acceptance and local permitting is one of, if not THE, biggest challenge to widespread decarbonization. We need all the attention we can get across government to support us on the ground."[36]

3.1.2 Lack of progress on the interconnection process

To LEI's knowledge, the [redacted] project withdrew because it was not in the cluster study and failed to make any progress in the interconnection process. Like Savion and [redacted] expressed its interest in resubmitting in a future RFP.

The generation interconnection process has also become a more challenging process to overcome. Data compiled by LBNL suggests that interconnection costs have grown substantially over the past few years, are generally higher for renewable and storage resources than natural gas units, and are higher for resources still in the queue than for those that have completed all required

[35] Nilson, Robi, Ben Hoen, and Joe Rand. *Survey of Utility-Scale Wind and Solar Developers Report*. Lawrence Berkeley National Laboratory. January 2024. <https://eta-publications.lbl.gov/sites/default/files/w3s_developer_survey_report_-011824_version.pdf>; Nilson, Robi, Ben Hoen, and Joe Rand. *Summary: Survey of Utility-Scale Wind and Solar Developers Report*. Lawrence Berkeley National Laboratory. January 2024. <https://eta-publications.lbl.gov/sites/default/files/w3s_developer_survey_summary_-_011724.pdf>

[36] Nilson, Robi, Ben Hoen, and Joe Rand. *Survey of Utility-Scale Wind and Solar Developers Report*. Lawrence Berkeley National Laboratory. January 2024. <https://eta-publications.lbl.gov/sites/default/files/w3s_developer_survey_report_-011824_version.pdf>

interconnection studies. LBNL also concludes that many projects facing high interconnection costs tend to withdraw from the queue.[37] Even FERC took up this matter in 2023, recognizing the need for reform as the increasing length of queues across the country have resulted in severe delays and backlogs.[38] The LBNL survey discussed in Section 3.1.1 listed interconnection as one of the top three leading causes of project delays and cancelations.[39]

3.1.3 Loss of economic viability

While initial redlines between IPC and [redacted] were shared for the **Moon Crater** project, the developer ultimately decided that the project is not as economic as initially considered. LEI is not aware of the circumstances that led the developer to come to this determination.[40]

Unfortunately, the cancelation of renewable resource projects procured through large-scale procurement efforts is not unique to this RFP. Recent macroeconomic conditions have, for example, led to the cancelation and rebidding of large-scale offshore wind projects in the New England region, New York, and New Jersey, to name several examples; reasons for the cancelations included supply chain disruptions/delays, higher interest rates, failure to obtain the required project tax rates, and the increased cost of capital.[41] The LBNL survey also found that supply chain issues is a leading cause of delays for solar projects in particular.[42] These types of macroeconomic conditions are outside the control of the developers, and result in the delayed procurement of resources.

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[37] "Generator Interconnection Costs to the Transmission System." Berkeley Lab Energy Markets & Policy. Accessed December 18, 2024. <https://emp.lbl.gov/interconnection_costs>; "Generator Interconnection Costs to the Transmission System – Summary Briefing." Berkeley Lab Energy Markets & Policy. June 2023. <https://emp.lbl.gov/publications/generator-interconnection-costs>

[38] "Explainer on the Interconnection Final Rule." US Federal Energy Regulatory Commission. Updated December 12, 2024. <https://www.ferc.gov/explainer-interconnection-final-rule#_ftnref8>

[39] Nilson, Robi, Ben Hoen, and Joe Rand. *Survey of Utility-Scale Wind and Solar Developers Report*. Lawrence Berkeley National Laboratory. January 2024. <https://eta-publications.lbl.gov/sites/default/files/w3s_developer_survey_report_-011824_version.pdf>

[40] June 2025 update: IPC explained that, because Moon Crater was the lowest ranked project from an economic perspective, the Company elected to not pursue a contract.

[41] See, for example: "Offshore wind project cancellations jeopardize Biden's clean energy goals." PBS News. November 4, 2023. <https://www.pbs.org/newshour/nation/offshore-wind-project-cancellations-jeopardize-bidens-clean-energy-goals>; "Cancellations reduce expected U.S. capacity of offshore wind facilities." US Energy Information Administration. July 9, 2024. <https://www.eia.gov/todayinenergy/detail.php?id=62445>

[42] Nilson, Robi, Ben Hoen, and Joe Rand. *Summary: Survey of Utility-Scale Wind and Solar Developers Report*. Lawrence Berkeley National Laboratory. January 2024. <https://eta-publications.lbl.gov/sites/default/files/w3s_developer_survey_summary_-_011724.pdf>

3.2 Implications for large-scale utility procurements

In this RFP, project withdrawals have put into question IPC's ability to meet identified system needs, especially in year 2026. LEI understands that IPC began considering contingency options as it became increasingly clear that multiple bidders would be withdrawing from contract negotiations. The options considered—all of which would have required approval by the OPUC—included:

- revisiting the Initial Shortlist and determining (by reaching out to bidders) whether those projects would be able to deliver their proposed projects by 2026 COD. IPC found that these projects face the same challenges—such as lack of progress on interconnection—as those that withdrew from contract negotiations;
- asking whether projects with which IPC already has signed contracts that are already in the generation interconnection queue can come online earlier;
- procuring short-term transmission (import) solutions, either firm or non-firm; and
- turning to supplemental storage.

Other fallback options may be revisited in the event that negotiations with [redacted] (see Section 2.1.3) do not materialize in an executed contract. It should also be noted that IPC secured more capacity in the final shortlist stage than initially authorized, as it anticipated that some projects in the Final Shortlist may not move forward.

In short, a Final Shortlist does not guarantee contract execution. Some strategies may help to mitigate the risk of project withdrawals, though realistically none presents a true buffer against permitting, interconnection, and macroeconomic risk. They include:

- developing a "wait list" consisting of projects in the Initial Shortlist that did not make it into the Final Shortlist. This would give bidders advance notice of the possibility that they may be called upon if the utility is unable to procure sufficient resources through the Final Shortlist;
- in the eligibility stage, awarding a greater number of points to projects that are more advanced in the development process; and
- creating a "buffer" or "cushion" amount of capacity (as a percent) over the targeted procurement amount, which bakes in some margin of error.

LEI—together with IPC and the OPUC—will also monitor the ability of the 2028 RFP to mitigate these results with its design as a two-track solicitation, one for 2028 COD and the other for COD in years 2029 and beyond.