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April 4, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301

RE: UM 2274 Portland General Electric Corrected Benchmark Scoring Compliance Filing

Dear Filing Center:

On March 29, PGE noted a modeling error that impacted the scoring of RFP offers, including those received from the benchmark team. Upon discovery, PGE worked with the Independent Evaluator (IE) and with Commission Staff to update scoring, and we are providing corrected workpapers, corrected IE report, and we are re-sealing the Benchmark offers before accessing the next tranche of bids. This approach is consistent with Oregon Administrative Rule 860-089-0350(1)-(3).

The corrected version of PGE's scoring model is included in Appendix A, and contains highly protected information under Modified Protective Order 24-083, and will be uploaded to Huddle.

In Attachment B is independent evaluator Bates White's corrected final report, Analysis of the Portland General Electric Benchmark Bids. This file contains highly protected information under Modified Protective Order 24-083, the highly confidential version will be uploaded to Huddle.

Please direct any questions regarding this filing to Jacob Goodspeed at (360) 936-7527. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Managing Corporate Counsel

EEA:lad

Confidential

Analysis of the Portland General Electric Benchmark Bids

April 4, 2024

Prepared by Bates White, LLC

Table of Contents

1. INTRODUCTION AND SUMMARY

1.1. Introduction

As the Oregon Public Utility Commission ("Commission")'s Independent Evaluator, Bates White has been tasked with reviewing and validating the assumptions and calculations of Portland General Electric (PGE)'s self-build (or "Benchmark") offers. The purpose of this memo is to document our findings with respect to our review of the Benchmarks for the 2023 All Source Request for Proposals ("2023 RFP" or "RFP").

PGE is offering a total of eight projects as Benchmarks in this RFP. The base offers for each project are as follows:

Table 1: Project Summary Data – Base Offers Only

[Begin Highly Confidential] [Begin Highly Confidential]

Project	Partner	Technology	Renewable Capacity	BESS Capacity	Transaction Type
[redacted]		Solar+BESS	[redacted]		BTA
		Solar+BESS			BTA
					BTA
		BESS			PPA
		Wind			PPA
		Wind			BTA
		Solar			PPA
		Storage			BTA
		BESS			BTA
					BTA
		BESS			PPA
					BTA
		Solar+BESS			PPA
					PPA
		Solar			BTA

[End Highly Confidential] [End Highly Confidential]

Each offer contains several variants which adjust variables such as capacity, transaction type, COD and more. A full listing of bid options is provided later in this report. As in past RFPs PGE's Benchmark team has partnered with developers to sponsor these projects. The offers cover a range of technologies including hybrid solar and battery energy storage system (BESS) projects, standalone BESS systems, standalone solar projects and other hybrid offers. There are also a mix of transaction types offered, both straight Power Purchase Agreements (PPAs) and Build Transfer Agreements (BTAs) and some hybrid transactions.

Generally speaking, the greatest risk in cost-based utility offers is that the utility has either failed to include all costs for the project or underestimated the cost of building the project. Here that risk has been mitigated to a great degree because the projects will all be built (and in the case of PPA bids, operated) under performance-based contracts just as any offers from a third-party bidder would be. Therefore, construction cost overruns will be absorbed by the developer and protections such as delay damages, warranties and credit support will be provided. For the PPAs, developers will also be responsible for operating cost overruns and subject to performance guarantees and responsible for securing and utilizing tax credits. In addition, the BTA bids contain quotes for O&M service agreements that would help mitigate operating cost and performance risk.

Because most costs will be contractually contained, we focus here on evaluating the offers as proscribed in the RFP. This involves a two-step process. First, bids are screened for meeting the minimum requirements. Second, the costs and benefits of each bid are evaluated. We independently reviewed the bids to see if they met the minimum qualifications in the RFP and evaluated the levelized cost of each bid in PGE's models as well as an in-house levelized cost model. We also reviewed the benefits of each bid as calculated by PGE to ensure they were reasonable and created in line with RFP rules. Finally, we examined some key risks of the transactions and conducted scoring sensitivities to examine the potential impact of these risks on the costs of the bid.

1.2. Summary of Conclusions

Our ultimate conclusion is that the benchmark offers are acceptable. We base this conclusion on several considerations.

- PGE's evaluation scoring was done per RFP requirements. We reviewed the PGE scoring model and associated cost/benefit calculations. While we noted some issues, corrections were made, the inputs matched what was presented in the bids and the models appeared to correctly calculate the levelized costs of the bids.

- From what we could observe, and based on our questions to PGE evaluators, the benefits of each bid appeared to be calculated in accordance with the RFP rules. Energy values were fairly consistent across bids and flexibility values matched those in the RFP rules. Capacity values were more difficult to verify as they depend on the output of a more complex modelling process, but they, too, appeared to be within reason based on a comparison of bid capacity contributions to similar resources in PGE's 2023 Integrated Resource Plan (IRP) and when considering some key differences between the IRP and current analysis.

- Some offers were eliminated for not meeting the minimum requirements in the RFP. We agreed with these eliminations. While we note some areas of concern for select remaining offers we believe it was appropriate to continue with evaluating the offers.

- Our examination of key risks for company-owner options shows that risks surrounding the use or monetization of the ITC have the most negative affect on bids, though a combination of factors such as low performance or O&M cost overruns can also negatively affect utility-ownership models.

2. BATES WHITE'S ACTIONS TO REVIEW AND VALIDATE THE BENCHMARKS

This report is intended to fulfill our duties under Oregon Administrative Rules (OARs). Most notably section 860-089-0450.(7). This reads

> "The IE must review the reasonableness of any score submitted by the electric company for a benchmark resource. Once the electric company and the IE have both scored and evaluated the competing bids and any benchmark resource, the IE and the electric company must file their scores with the Commission. The IE and electric company must compare results and attempt to reconcile and resolve any scoring differences. If the electric company and IE are unable to resolve scoring differences, the IE must explain the differences in its closing report to the Commission."

Bates White relied on a multi-part investigation in order to review and validate the Benchmark submissions. First, we reviewed the full contents of the submissions. Second, we assessed each bid and bid variant against the minimum qualification requirements in the RFP. Third, we reviewed eliminations proposed by PGE's evaluation team to ensure we agreed on their actions. Fourth, we reviewed PGE's cost/benefit scoring to ensure that all inputs were correct, models functioned properly, and that all analysis was done in line with the RFP rules.

Finally, we examined the impact of changes in key inputs upon bid scores. This was meant to fulfill, in part, our obligations under OAR 860-089-0450.(6)., which charges the IE with evaluating the "unique risks and advantages associated with any company owned-resources." As noted earlier, each offer here is done under a PPA or BTA with an established developer. Therefore the projects are either entirely pay for performance (in the case of the PPAs) or have protection from capital cost overruns (in the case of the BTA). Despite this, are still some risks to the utility-owned options related to items such as tax credit utilization and operating cost control which we evaluate herein.

3. ASSESSMENT OF THE BENCHMARKS

3.1. Bid Variants

While the benchmark team submitted eight total projects, each project contained a number of different variants. Most projects provided a suite of size options, either in the main generating unit or in the paired BESS unit. Others varied the Commercial Operation Date (COD). A total of 37 variants were provided. The table on the following page shows all bid variants received.

Table 2: Project Summary Data – All Offers

[Begin Highly Confidential] [Begin Highly Confidential] [Begin Highly Confidential]

Variant	Project	Partner	Technology	Renewable Capacity	BESS Capacity	ESS Duratio	Transaction Type	COD
Base	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
1	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
1	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
3	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
Base	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
1	[redacted]		Solar	[redacted]			BTA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			BTA	[redacted]
Base	[redacted]		BESS	[redacted]			PPA	[redacted]
	[redacted]			[redacted]			BTA	[redacted]
1	[redacted]		BESS	[redacted]			PPA	[redacted]
	[redacted]			[redacted]			BTA	[redacted]
2	[redacted]		BESS	[redacted]			PPA	[redacted]
	[redacted]		Wind	[redacted]			PPA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
Base	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
1	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
2	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			PPA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
3	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
4	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			PPA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
Base	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
1	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]		Wind	[redacted]			BTA	[redacted]
	[redacted]		Solar	[redacted]			PPA	[redacted]
2	[redacted]		Storage	[redacted]			BTA	[redacted]
Base	[redacted]		Storage	[redacted]			BTA	[redacted]
1	[redacted]		Storage	[redacted]			BTA	[redacted]
2	[redacted]		Storage	[redacted]			BTA	[redacted]
3	[redacted]		Storage	[redacted]			BTA	[redacted]
4	[redacted]		Storage	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			BTA	[redacted]
Base	[redacted]		BESS	[redacted]			PPA	[redacted]
	[redacted]			[redacted]			BTA	[redacted]
1	[redacted]		BESS	[redacted]			PPA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
Base	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
1	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
Base	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
1	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
Base	[redacted]		Solar	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
1	[redacted]		Solar	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
2	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]
	[redacted]			[redacted]			PPA	[redacted]
3	[redacted]		Solar+BESS	[redacted]			BTA	[redacted]

[End Hi [redacted]

One initial review showed that some of these projects utilize PGE utility assets. Specifically, the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** will use existing transmission capacity from the **[Begin Highly Confidential]** [redacted] **End Highly Confidential]** uses PGE-owned land near the Carty generating station (but no transmission from that project). These assets were disclosed in Appendix P of the RFP as required.

PGE disclosed in the same Appendix that they would offer eight projects in the RFP, consistent with what was offered here. The disclosure in the Appendix is generally accurate (though there area some variations between the capacity reported there and what was offered).

3.2. RFP Evaluation Process

The process for evaluating RFP offers is laid out in Appendix N of the RFP. Bids are first put through a minimum requirements screen, then evaluated for initial scoring. Top performing bids are then selected to an initial shortlist and allowed to make a best and final offer. A second round of eligibility screening is then conducted and remaining bids are evaluated in portfolio analysis. From this a final shortlist is selected and contracts are negotiated. The process is laid out in the diagram below. The process covered in this memo covers through the initial scoring.

Figure 1: 2023 All-Source RFP Analysis Process

3.3. Minimum Requirements Screen

The minimum requirements to participate in the RFP are laid out in Appendix N. Below we roughly summarize the key requirements by category. Note that there are additional requirements for bidders that make the initial and final shortlists.

- Interconnection – Bids had to have a completed System Impact Study by the relevant transmission provider. Bids that did not have such a study could provide a narrative as to how the project would obtain interconnection studies in time to support the project COD.

- Transmission – Bids had to provide an achievable plan to supply transmission service. The key requirement for bids was to provide for eligible firm transmission service for at least 75% of the resource interconnection limit.[1] Eligible products include long-term firm, conditional firm bridge number of hours and conditional firm reassessment. Conditional Firm Bridge system conditions products were also deemed conforming in this solicitation.
- COD – Projects had to be online by December 31, 2027. An exception was made for “long lead time” projects, which had to be online by the end of 2029.
- Labor- bids must use union labor.
- Equipment – bid that contemplate PGE ownership must use PGE preferred vendors.
- Financing – Bidders must provide an acceptable plan to obtain project financing.
- Technology – Proposed technology must be commercially proven and deployed at a large scale.
- Entity – Must be authorized to sell power under applicable laws.
- Offtake – PGE must be the offtaker for all output from the resource and the resource must include all RECs.
- Size – Solar resources must be larger than 3 MW and other facilities must be larger than 10 MW.
- Site Control – Bidders must demonstrate site control for the resource location and gen-tie path.
- Permitting – Bids must meet the permitting requirements in the RFP. Bidders were allowed to provide an explanation explaining why a given permit was not applicable to their project or could be obtained at a later date than specified in the permitting requirements.
- Delivery – Bids must deliver to appropriate PGE delivery points.
- Term – PPA bids needed to be a minimum of 15 years and a minimum of 30 years.
- Service Agreements - Bids that involved utility ownership had to include quoted vendor costs for a long term service agreement (LTSA) for a minimum of five years,

We evaluated each project according to these requirements. The table below shows the results of our rankings. We coded the cells in green for areas where the bids passed the test and yellow for

[1] Bids for dispatchable resources had to have long-term firm rights for 100% of the resource interconnection limit.

potentially questionable issues. Areas shaded in red reflect issues that we believe would cause bid disqualification.

Table 3: Minimum Requirements Screen

[Begin Highly Confidential]

Category	
Interconnection	[redacted]
Transmission	
COD	
Labor	
Equipment	
Financing	
Technology	
Entity	
Offtake	
Size	
Site Control	
Permitting	
Delivery	
Term	
Service Agreements	

[End Highly Confidential]

Our review revealed that most projects passed this screen, though some bid variants were rejected. Below we discuss our findings in each category.

For the entity and financing plan requirements, **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Project size and term requirements were all acceptable. All bids were of the appropriate scale and PPA terms in line with the RFP requirements.

All bidders had effective site control of their project. Most bids had 100% site control. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

In general, most bidders did not have concrete equipment purchase plans at his point. In our experience this was to be expected – at this stage it is rare to see a bidder making a concrete commitment without a similar commitment from the purchasing entity. Some identified specific equipment they were likely to purchase while others noted they were working with multiple vendors. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** PGE will permit these offers but will continue to review the selection.[2] Given that no firm choice has been made and this is early in the development cycle this is acceptable, but the choice does bear monitoring should the bid be shortlisted. Moreover, similar treatment should be extended to third-party bidders. In our experience this is typically not an issue that results in bid elimination.

Most bidders provided limited detail on labor strategy, but did state they would meet all requirements in the Inflation Reduction Act to earn the appropriate tax credits. With the exception of **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** all projects will be located in Oregon and, therefore, must be built to state law.

Most bids provided quotes and term sheets for LTSA agreements. Quotes were very high-level but, again, this would expected at this point as final project approval and details had not been agreed to.

Most bids had completed System Impact Studies, as required by the RFP. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Most offers had an acceptable permitting process in place, providing explanations of the process in order to support the COD. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Several bidders proposed on-system resources and therefore did not need transmission to PGE's service territory. **[Begin Highly Confidential]** [redacted]

[redacted]

[2] PGE stated that the preferred vendors list is something that is "constantly updated" and that they would take a closer look once tech spec redlines are received from bidders.

[redacted] **[End Highly Confidential]**

One issue which showed some clear failures was in the COD category. **[Begin Highly Confidential]** [redacted]

[redacted] **[End Highly Confidential]**

3.4. Price Score

3.4.1. Price Scores - Cost

All bids which passed the minimum requirements screen were then scored. Unlike in past RFPs this RFP does not feature a non-price score. Bids are scored entirely based upon their associated costs and benefits and bids are ranked based upon their cost/benefit ratio. Bids were evaluated in two separate categories, renewable (which included hybrid offers) and dispatchable.

To evaluate PGE's price scores we took two steps. First, we reviewed the full price score model as provided by PGE. The model calculates a cost-benefit ratio for each offer, with the costs being the real levelized dollar per MWh cost of the bids – this includes contract prices (the PPA or APA cost), transmission and integration costs, operating costs (for BTA bids) and the value of tax incentives (again for BTA bids). Output for renewable resources came from the bids while BESS output came from the energy value model, which optimized margins given energy prices and operating constraints.

Second, to validate the model outputs we independently modeled each offer in a simplified levelized cost model. This provided an independent check on PGE's levelized cost calculation. We were able to identify some errors in data input and highlighted these to PGE evaluators, who provided corrections. We were also able to verify the general preference ranking of offers.

The chart below shows the final levelized costs for the base offers on a nominal $/MWh basis.

Table 4: Levelized ($/MWh) Prices Renewable category

[Begin Highly Confidential]

Bid Number	Project	Cost PGE
10.1.Base	[redacted]	
27.1.Alt3		
10.1.Alt1		
27.1.Alt2		
27.1.Alt1		
27.1.Base		
150.1.Base		
150.1.Alt3		
105.1.Alt1		
105.1.Alt4		
150.1.Alt1		
105.1.Base		
55.1.Alt1		
150.1.Alt2		
105.1.Alt2		
105.1.Alt3		
150.1.Alt4		
55.1.Base		
150.1.Alt5		
105.1.Alt5		
55.1.Alt2		

[End Highly Confidential]

[Begin Highly Confidential] [redacted] **[End Highly Confidential]**

The next table shows the same information for the Dispatchable category.

Table 5: Levelized ($/MWh) Prices Dispatchable Category

[Begin Highly Confidential]

Bid Number	Project	Cost PGE
74.2.Base	[redacted]	
74.1.Base		
74.2.Alt1		
74.1.Alt2		
74.1.Alt1		
92.1.Alt4		
92.1.Alt3		
92.1.Alt2		

[End Highly Confidential]

[Begin Highly Confidential] [redacted] **[End Highly Confidential]** Again, we were able to verify bid inputs and the general ranking of the offers.

3.4.2. Price Scores - Benefits

Per the RFP there are three categories of benefit.

- Energy value – This reflects the value of the energy generated by the project. PGE used the reference case energy market prices developed by Wood Mackenzie in February 2024, which were used in regulatory dockets UMs 1728 and 1893, to calculate energy values for each offer.
- Capacity value – Per the RFP PGE calculated capacity contributions for each offer using the Sequoia model. PGE valued capacity at the net cost of a 4-hour BESS unit as displayed in their 2023 CEP/IRP.
- Flexibility Value – Per the RFP the flexibility values were imported from the 2023 CEP/IRP and came from the Gridpath model. These were applied to BESS units only and varied depending on storage duration.

The following table shows the real levelized $/MWh benefit for each category for the Dispatchable resources.

Table 6: Real Levelized ($/MWh) Benefits – Dispatchable Category

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

The prime value of these bids is in the capacity contribution, as we would expect. Energy values are essentially the same and fairly small. This reflects both the low value of energy and the fact that the BESS units must utilize energy to charge. The cost of charging energy is included in this calculation, bringing the overall value down a bit.

Flexibility values are also somewhat similar, though there is some variation. This is more due to the assumed output of each offer. The actual value of flexibility is fairly small, $9.77/kW-year, so a 100 MW BESS unit would only generate $977,000 of flexibility value in a year so small changes in the capacity factor of the unit will move the $/MWh value to a larger degree.

[Begin Highly Confidential] [redacted] **[End Highly Confidential]**

We next looked at the benefits for each bid in the renewable category. The table below shows those benefits.

Table 7: Real Levelized ($/MWh) Benefits – Renewable Category

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

Since these resources are a little more varied in their generation technologies and their use of storage we would expect a bit more variation in values.

On the energy side values are more similar as all units except **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

More important for the overall assessment is the fact that the energy values are very low. As stated above, these values come from a Wood Mackenzie reference case forecast developed in February 2024. Prices, particularly for the spring/summer months and daylight hours, are very low. As a quick example, the table below shows the average price in 2035 for a given hour across each month.

Table 8: Average Nominal Hourly Energy Value ($/MWh) for 2035

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

[Begin Highly Confidential] [redacted] **[End Highly Confidential]**

These low energy values have a couple of key impacts. First, it makes the bids less likely to be a positive on a cost/benefit scale (as we shall see later). Second, it means that bids which provide more capacity value should score much better and that this contribution of capacity value will be an important determination in what bids are likely selected.

Flexibility values are a relatively small contributor to bid value, as expected. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Capacity values are more varied. These are affected by bid output (all else equal a lower output will have a higher $/MWh capacity value) as well as overall capacity contribution. The latter is a function of output profile and transmission. Regarding transmission, offers which had full firm transmission were not restricted in the Sequoia model. However, per RFP rules, bids with conditional firm service either were assumed to be curtailed in some hours of highest need (if they had conditional firm – number of hours service), or curtailed entirely (in the case of conditional firm-system-conditions products). These conditions were applied to bids until their BPA-designated projects to supply full firm service were due to be completed.

[Begin Highly Confidential] [redacted] **[End Highly Confidential]** To dig into this more the table below shows the total average capacity assigned to each bid by PGE.

Table 9: Average Annual Capacity Contribution (MW) – Renewable Projects

[Begin Highly Confidential]

Bid	[redacted]
10.1.Base	[redacted]
10.1.Alt1	[redacted]
27.1.Base	[redacted]
27.1.Alt1	[redacted]
27.1.Alt2	[redacted]
27.1.Alt3	[redacted]
55.1.Base	[redacted]
55.1.Alt1	[redacted]
55.1.Alt2	[redacted]
105.1.Base	[redacted]
105.1.Alt1	[redacted]
105.1.Alt2	[redacted]
105.1.Alt3	[redacted]
105.1.Alt4	[redacted]
105.1.Alt5	[redacted]
150.1.Base	[redacted]
150.1.Alt1	[redacted]
150.1.Alt2	[redacted]
150.1.Alt3	[redacted]
150.1.Alt4	[redacted]
150.1.Alt5	[redacted]

[End Highly Confidential]

Here we see a few things. **[Begin Highly Confidential]** [redacted]

[3] See Ch 10, table 50, CEP IRP.

[redacted] **End Highly Confidential]** PGE evaluators noted that the IRP estimates of solar capacity contribution assumed a larger amount of solar coming from the 2021 All Source RFP. Since the actual amount from that RFP was lower, solar here would be expected to have a better contribution as there is less saturation. This helps explain in part the relatively high year-round value attributed to solar here versus in the IRP.

Another factor noted by PGE evaluators driving the generally higher contributions was the addition in this analysis of hydro generation contracts recently signed by PGE. These were not included in the IRP analysis. The key aspect of this is that the hydro generation is flexible. The contribution of a resource is dictated by running Sequoia with and without the resource. Adding resources such as the RFP bids allows the hydro contracts to conserve their generation in off-peak hours and utilize that supply in higher-need hours. This means that the RFP resources are making a relatively higher contribution to system reliability in this scenario than in one without such flexible generation.

[Begin Highly Confidential] [redacted]

[redacted]

[redacted] **[End Highly Confidential]**

While we are not in the position to re-run the Sequoia model it does appear that the capacity contributions of these resources are generally reasonable given the numbers from the IRP and given the differences noted by PGE evaluators.

3.4.3. Price Scores - Total

Putting together the costs and benefits gives the final bid score. The rankings for the Renewable Category are shown below.

Table 10: Total Nominal Levelized Costs and Benefits – Renewable Offers

[Begin Highly Confidential]

Bid	Name	Cost	Benefit	Ratio
150.1.Alt1	[redacted]			
150.1.Alt2				
150.1.Alt4				
150.1.Alt5				
150.1.Base				
150.1.Alt3				
27.1.Alt3				
27.1.Alt2				
27.1.Alt1				
27.1.Base				
55.1.Base				
55.1.Alt2				
10.1.Alt1				
10.1.Base				
105.1.Alt1				
105.1.Alt4				
55.1.Alt1				
105.1.Base				
105.1.Alt2				
105.1.Alt3				
105.1.Alt5				

[End Highly Confidential]

[Begin Highly Confidential] [redacted] **[End Highly Confidential]**

The next table shows this information for the dispatchable offers.

Table 11: Total Costs and Benefits – Dispatchable Offers

[Begin Highly Confidential]

Bid	Name	Cost	Benefit	Ratio
74.2.Alt1	[redacted]			
74.1.Alt2				
74.1.Base				
74.2.Base				
74.1.Alt1				
92.1.Alt4				
92.1.Alt3				
92.1.Alt2				

[End Highly Confidential]

[Begin Highly Confidential] [redacted] **[End Highly Confidential]**

4. RISKS

As part of the OARs we are obligated to "assess the unique risks and benefits" of the benchmark offers. In this section we look at these values.

Generally speaking, the greatest risk in cost-based utility offers is that the utility has either failed to include all costs for the project or underestimated the cost of building the project. Here that risk has been mitigated to a great degree because the projects will all be built (and in the case of PPA bids, operated) under performance-based contracts just as any offers from a third-party bidder would be.

Despite this, there are some risks that are still worth examining here. In particular we see four key risks; (a) overvaluation of ITC credits, (b) ITC normalization, (c) operating and capital expenditure risk and (d) underperformance risk.

The first two risks related to the treatment of the Investment Tax Credit generated by the projects. PGE plans to sell the tax credits to a third party. PGE recognizes that such sale will involve some sort of a discount from the credit value (otherwise the purchasing party would receive no net value on the transaction). For this RFP, per Commission direction, PGE is to use the transfer discount rate approved in docket UP 424, Order No. 23-459 for the purpose of price scoring.[4] **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

The second risk relates also to the ITC. In this case the risk is, if the credits are not sold off, that the company has to utilize the ITC itself. This can reduce the value of the credit because utilities generally must normalize, or spread the value of the tax credit out over its lifetime. This can also be a risk if the utility has no room in a given year to utilize tax credits.

The third risk is more basic and inherent to the utility ownership model. That is, O&M and ongoing capital spend could be higher than estimated. Again, there are protections in the form of using LTSA quotes from vendors and ultimately regulatory review, but still, this is a greater risk than a PPA, where this risk is borne by the supplier.

The final risk is also inherent in the ownership model for utilities. If a renewable resource outputs less power than predicted the cost/MWh increases since the total dollar cost of the asset does not change. For a PPA, which pays per-MWh, this is not a risk.

To test these resources we asked PGE to re-run their models under four cases 1) increasing the ITC discount from **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** to 15%, 2) assuming the utility uses the ITC but must normalize the cost, 3) O&M and ongoing capital costs increase 10% from estimates and 4) average annual output decreases 10% annually.

The results are in the table below.

[4] Order 24-011 p2.

Table 12: Total Costs and Benefits – All Offers

[Begin Highly Confidential]

Bid	[redacted]
10.1.Base	
10.1.Alt1	
27.1.Base	
27.1.Alt1	
27.1.Alt2	
27.1.Alt3	
55.1.Base	
55.1.Alt1	
55.1.Alt2	
74.1.Base	
74.1.Alt1	
74.1.Alt2	
74.2.Base	
74.2.Alt1	
92.1.Alt2	
92.1.Alt3	
92.1.Alt4	
105.1.Base	
105.1.Alt1	
105.1.Alt2	
105.1.Alt3	
105.1.Alt4	
105.1.Alt5	
150.1.Base	
150.1.Alt1	
150.1.Alt2	
150.1.Alt3	
150.1.Alt4	
150.1.Alt5	

[End Highly Confidential]

The biggest individual risk for solar bids appears to be the ITC normalization, which adds **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** In this RFP PGE has proposed the use of an affiliate transaction to secure the benefits of avoiding ITC normalization. This exercise helps demonstrate the value of avoiding normalization.

The ITC discount increasing adds **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** We also note that a combination of factors (here this is low output, increased O&M costs and a higher ITC discount) can change the bid score rapidly.

It's also reasonable to note that some of these risks are symmetric, if the plant overperforms or has lower than expected costs the benefit goes to the customer. This is less likely regarding cost overruns, but units can beat their P(50) output expectation.

To be clear, this is just to demonstrate key risks. At this point PGE's scoring is acceptable. It is reasonable to use a P(50) output and cost estimates for O&M and the Commission has determined an appropriate discount rate for ITC sales.

This analysis of key risks for company-owner options shows that risks surrounding the use or monetization of the ITC have the most negative affect on bids, though a combination of factors such as low performance or O&M cost overruns can also negatively affect utility-ownership models.