PSCo 2022 All-Source | FAQ

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December 21st, 2022 Update

1. Q: Will the Company accept bids from existing generation with incremental capacity via an amendment to an existing PPA?

   A: In order to be found bid eligible, a project has to meet a portion of the targeted capacity resource need during the Resource Acquisition Period (i.e., the period ending 2028); incremental generation to an existing project would meet this requirement. Amendments to the existing PPA would need to include terms and conditions consistent with those in the applicable Model PPA included in the 2022 Solicitation.

2. Q: We would like to understand any boundaries for PSCO in considering a blended price bid for wind & solar in the RFP or do they need to be kept disaggregated to compare our wind bids against other wind bids, and our solar bid against other solar bids?

   A: A single $/MWh payment rate for generation from a blended wind and solar project would be bid eligible. Comparisons to other wind and solar bids would be conducted as part of computer-based modeling to the extent a bid was advanced to that stage of evaluation.

3. Q: We would like to understand whether surplus solar bids utilizing existing interconnection capacity at wind facilities will be evaluated differently from other solar bids.

   A: In its response, the Company assumes that a “surplus solar bid” or “solar under wind” is one in which the existing interconnection capacity and maximum wind generation size in MW are the same. In this case, “surplus-type” solar bids would be evaluated differently from stand-alone solar bids with their own interconnection based, in part, on the projected impact of interconnection capability limits. Evaluation differences would, in such instances, be dependent upon the relative MW of solar proposed relative to the existing interconnect and wind generation capacity; higher levels of combined solar and wind MW to interconnection capacity would tend to increase such differences with stand-alone solar bids.

4. Q: How would the evaluation of a “solar under wind” hybrid bid differ from the evaluation of stand-alone solar bids?

   A: The relative benefits of a combined solar and wind project subject to interconnection capacity limits compared to standalone solar bids would be evaluated in the computer-based modeling conducted during Phase II, assuming the project(s) passes the initial eligibility and economic screening as described in the draft RFP documents. Solar/wind hybrid proposal hourly generation patterns are limited to the maximum allowable interconnection limits in the computer model. Whether any specific wind/solar hybrid would be selected in a portfolio of resources is dependent upon the interactions of the proposed project with the Company's existing resource portfolio and, for example, the size, type, performance, location, and pricing of all other proposals advanced to computer-based modeling.

5. Q: Please confirm that the BVEM/apprenticeship information required for bid eligibility is for the construction only of the facilities being bid.

   A: For the 2022 All-Source Solicitation, the BVEM information is required for the construction of a project and is not required for the ongoing operation and maintenance of a facility after it achieves commercial operation.

6. Q: We had a few questions about the information that we've seen on your website, specifically related to "Segment 4" of "Colorado's Power Pathway". We see that there may be a new substation siting area between the Tundra and May Valley Substations. Could you please confirm if these new substations are indeed in Xcel's plans? Is there any additional information that you can provide (estimated in-service dates, the likelihood of construction, etc.)?

   A: The alternative substation siting locations shown for Segment 4 between Tundra and May Valley substations were included in the planning/permitting information provided as part of our routing outreach activities. No decision as to whether additional interconnection points along the Tundra – May Valley segment will be constructed has been made.

   Incremental generation tie line interconnects into the existing Tundra substation are limited given multiple physical constraints in that area. Whether or not an additional substation would be built between Tundra and May Valley will be dependent upon the attractiveness of the bids for new generation received in the 2022 All-Source Solicitation proposing to interconnect along that line at or near the Tundra substation. A new substation would require a new CPCN.

7. Q: Are bidders able to propose changes to the included nondisclosure agreement (NDA)?

   A: As the Public Utilities Commission (PUC) has already approved the form of the NDA for use in the 2022 Solicitation, the Company will not entertain any edits to the NDA.

8. Q: Please confirm that the Second Bid Fee described in Section 4.8 of the RFP documents for a hybrid plant is the sum of the component MW.

   A: The amount of the Second Bid Fee is based on the sum of the component MW for a hybrid facility; for example, for a 200 MW solar farm with a 100 MW battery the Second Bid Fee would be based on 300 MW.

9. Q: Please clarify how potential refund of the Second Bid Fee would be treated if the Public Utilities Commission did not approve the PPA or a BOT purchase and sale agreement (PSA).

   A: In the RFP the Company states that if a PPA or PSA is executed, the Second Bid Fee will, at the option of the bidder, be refunded to the bidder or applied to fulfill the bidder's Security obligations under the PPA or PSA. The question asks what would happen to the Second Bid Fee if a PPA or PSA is executed but is later terminated because the Commission fails to approve the PPA or the PSA.

   The model PPA and the model PSA require the bidder to post security shortly after the agreement is executed. As a result, in the scenario posed the Second Bid Fee would likely have already been either refunded to the bidder or applied to fulfill the bidder's Security obligations well before the Commission rules on approval or rejection of the agreement.

   If the bidder opted to have the Second Bid Fee refunded, there is no issue.

   If the bidder applied the Second Bid Fee to fulfill its Security obligations under the agreement and the Commission did not approve the agreement, the Second Bid Fee would be refunded as part of the Security refunded to the bidder.

10. Q: For the second bid fee, is the nameplate capacity for the hybrid facility based on AC MW? If we have a facility with DC coupled BESS, would that change the calculation?

    A: For a DC-coupled solar PV + battery energy storage system (BESS) project, Xcel would consider the AC nameplate to be (PV MW_dc + BESS MW_dc) * DC/AC Inverter Efficiency.

11. Q: Does Xcel plan to support mid-span interconnections of projects to the CPP segments? If so, does Xcel have any interconnection standards developed for these interconnections to the 345KV transmission lines?

    A: Projects that propose to bisect a CPP segment would be found bid eligible. However, as described in the RFP such new interconnections will significantly delay a project vis-à-vis connection directly to one of the CPP substations. There is not a standard particular to the CPP lines; PSCo expects to apply the current standards for connecting to 345 kV that are evident in interconnection study reports.

12. Q: Will Xcel Energy allow developers to build gen-ties underneath the Colorado Power Pathway (CPP) circuits, or on the same easement, to reach the new switching stations?

    A: No, Xcel Energy's easement cannot be shared. A developer would have to acquire their own and meet any safety requirements.

13. Q: Is the Craig substation and switchyard considered a point on the Xcel transmission system, and is it an eligible point of injection for the All-Source RFP? If it is an acceptable point of injection, will transmission costs apply to the energy generated by the project?

    A: Craig is an acceptable point of interconnection. PSCo has approximately 42 MW in each of Craig units 1 and 2 (84 MW total). A generator replacement up to that amount would have no transmission costs if delivered to the PSCo network load. Amounts above 84 MW may have some transmission delivery costs.

14. Q: Is there a particular ISO or RTO that you are looking for projects to be connected to?

    A: Projects must connect to the PSCo Balancing Authority (BA) Area, per Appendix C of the RFPs, section C.1 Power Delivery Requirements:

    Proposals must specify delivery of capacity and energy to the Public Service system at a point of delivery within or at the boundary of the Public Service Balancing Authority Area and at a Public Service-owned transmission facility.

15. Q: Are proponents expected to provide BVEM for EPC labor during the construction period, even if this is managed entirely by the EPC firm?

    A: Yes.

16. Q: Can the Company provide the latitude and longitude for the approved CPP substations and the existing Tundra substation?

    A: Canal Crossing Substation (new): 40.142989°, -103.713095°

    Goose Creek Substation (new) 38.995099°, -102.499945°

    May Valley Substation (new) 38.352437°, -102.401917° *(updated January 13th, 2023)*

    Tundra Substation (existing) 38.342°, -104.413°

17. Q: Attachment 9 (PV Solar Equipment Suppliers) of the BOT PV specs document lists various PV module providers. Regarding the approved module vendor list, is there an opportunity to supply products from companies that have Chinese headquarters, but have been found under the preliminary Auxin determination to have not been circumventing duties? An example, Jinko Solar, is not currently on the approved vendor list.

    A: Jinko would be acceptable in addition to the approved vendor list. Any others not listed would need the same confirmation from Xcel and any response from Xcel could be updated with a final Auxin determination.

18. Q: Has the Company expressed a preference for a certain generation type for a BOT or asset sale proposal?

    A: The only BOT or asset sale proposal that would not be bid-eligible would involve coal-fired generation. Otherwise, the Company has not expressed a preference.

January 6th, 2023 Update

19. Q: Is Xcel interested in discussions with developers regarding joint venture opportunities on new renewable projects?

    A: The Company is not entertaining any joint venture or partnering opportunities.

20. Q: For solar plus storage projects, can we submit another project under the same bid fee that is solar only?

    A: Two bid fees will be required for a solar + storage project and solar only project.

21. Q: In the RFP, under Commission Required Communications - Bid Information Disclosure, it states:

    > *Public Service notifies bidders that, upon completion of the competitive acquisition process begun with this RFP, Public Service will post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost; generation technology type; size of project; contract duration or expected useful life of facility for utility proposals; and whether the proposed purchased power agreement includes an option for the utility to purchase the bid facility during or at the end of the contract term.*

    Upon completion of the competitive acquisition process can bid price and utility cost; generation technology type; size of project; contract duration be redacted when posted to the website or will this information be posted for public viewing?

    A: The referenced text is directly from Commission rule 3613(k) and as a regulated utility in Colorado, Xcel Energy is required to comply with this rule. The information listed in the first paragraph will not be redacted.

22. Q: Appendix A - Form H Emission Rates—should this form be filled in for renewable generation resources?

A: Form H should be completed for all generation types. If your chosen generator type has no associated emissions, the input would be “0”.

23. Q: Appendix D - Model Asset Purchase Term Sheets and Generators Technical Specifications—should bidders fill out the PPA for bid submission?

    A: Yes, bidders should provide the necessary information in the Model PPAs and provide them as part of the bid package; see the Exceptions to Model PPA Bid Narrative topic for further instructions as to what information the Company expects.

24. Q: Appendix F - Commission Confidentiality Order—should bidders fill out the nondisclosure agreement prior to bid submission?

    A: No; please provide at the time of bid submission as part of the overall package.

25. Q: What is the definition of a Pre-Construction Development Assets (PCDA) and what RFP/s does it apply for?

    A: Bidders have the option to designate their new, natural gas-fired generation project as a Pre-Construction Development Asset (PCDA) in either the Dispatchable or Ownership RFP only; it is a bidder option and not a requirement. A PCDA is a contingency generation proposal that would progress through development (e.g., site and air permitting) but would not begin construction until/unless approved in a proceeding outside and following the Company’s current ERP. The developer’s pre-construction costs as proposed during the current Solicitation would be paid by the Company’s ratepayers. Bidder’s may propose a PCDA as a Company-owned asset following construction through a PSA or as an IPP-owned asset with cost recovery through a PPA. Renewable and storage resources cannot be PCDAs.

26. Q: For Proposal Content Requirements, section 4.3 of the RFPs, 3. Form attachments (as necessary to elaborate on form information)"— in Appendix A Forms there are no references to the required attachments.

    A: Several of the Bid Narrative Topics request additional information which would be provided as an attachment; see, for example, the Real Property Acquisition topic. Some Bid Forms also request that additional information be provided in addition to the Excel worksheets; see, for example, Form D1C_Taxes.

27. Q: Should the certificate of "Wind turbine cold weather package", section 4.2 of both the Renewable and Ownership RFP, be sent in the bid or shall we have it just for PPA negotiation purpose?

A: Per Section 4.2 of the RFP documents, confirmation that wind turbines can operate down to -30° Celsius is required at bid receipt. Projects not providing such documentation will not be accepted for evaluation.

28. Q: The capacity need, section 1.2 of the RFPs, what happens if the bidded capacity is higher than the yearly capacity need? Will PSCo ask to propose a different COD or shall the bidder bid with different CODs?

    A: Table 2, Resource Capacity Need by Year (Cumulative), of the RFP documents shows the Company's targeted need for generation capacity credit to meet forecasted peak loads plus planning reserve margin requirements. For thermal generation resources (e.g., combustion turbines), the Company assumes summer nameplate capacity at 100% for generation capacity credit purposes; energy-limited resources (e.g., wind, solar, storage) receive less than nameplate capacity based on the results of ELCC studies. Bidders may propose projects that have higher nameplate capacity that would result in more targeted generation capacity credit than as shown in Table 2. The relative economic merits of acquiring generation capacity credit early would be evaluated in computer-based modeling of generation portfolios. The Company will not ask bidders to change their proposed COD, but will evaluate proposed CODs as part of its due diligence for feasibility.

29. Q: When is the last date when the bidders can send questions to PSCo?

    A: While the Company will accept questions up to the day of bid submission, it cannot guarantee that bidders would receive information in time to be helpful. Depending upon the nature of the question and which subject matter experts might need to be involved, the Company targets a five-day turnaround in answering questions.

30. Q: What is the process should the planned COD be delayed?

    A: The Model PPAs contain language as to consequences to the Seller should they not achieve the COD Milestone.

31. Q: What is the process should technological improvements occur on the project?

    A: The Company expects bidders to design, construct, and operate projects that match the technologies, sizes, and operational characteristics of the projects they proposed in the Solicitation.

32. Q: Can you please define "commercial arrangement" further and give examples of what would create a new/unique bid (and added bid fee) and what wouldn't?

A: Commercial arrangement refers to one of three types of ownership/cost recovery: 1) IPP-owned with cost recovery via a PPA; 2) Company-owned through a project designed, permitted, and constructed by the Company (self-build), and 3) Company-owned through a project designed, permitted, and constructed by a developer and sold to the Company on a turn-key basis (BOT).

Generally, a single bid is represented by a single physical project as to generation type, COD, MW size, and interconnection location; there are exceptions to interconnection location and PPA/BOT proposals as described in the RFP documents.

33. Q: How will the RFP evaluate out-of-state projects? Will a project located in New Mexico be at a disadvantage compared to Colorado based projects?

    A: No specific prioritization is given to Colorado located projects. However, all proposals are required to deliver energy to the Company's Balance Area (BA) transmission network on a firm transmission basis. The Company's BA transmission network does not extend outside of Colorado; thus bidders proposing generation or storage projects outside of Colorado will be required to obtain transmission (purchase or build) to the Company's system and include those costs in their bid prices. Also, the Company has conducted ELCC studies for renewable energy resource zones only in Colorado; to the extent, a potentially cost-effective proposal for an out-of-state renewable generator is received the Company might need to conduct an ad hoc ELCC study.

34. Q: Can you share details on the bid evaluation criteria and weightings of the criteria?

    A: The bid evaluation process is provided in Section 5 of the RFP documents. The Solicitation does not use a weighted criteria methodology to advance bids to computer-based modeling of generation portfolios.

35. Q: How does the Company Self-Build commercial structure and process (BOT) commercial structure?

    A: In the BOT process, the Seller is responsible for all design, permitting, and construction of the project and then sells the project to the Company on a turn-key basis at COD. In the self-build process, the Company is responsible for all design, permitting, and construction activities. Both processes require the Company to obtain a certificate of public convenience and necessity from the Colorado PUC.

36. Q: Please confirm that the meaning of Table 2, Resource Capacity Need by Year (Cumulative), in section 1.2 of the RFPs, is such that between 2023 & 2024 PSCo is targeting an addition of 205 MW (388 MW less 183 MW)?

    A: Table 2 of the RFP documents provides the generation capacity needs by summer peak season; in order to assign generation capacity credit for a particular year, the generator must have a COD no later than 6/1 of that particular year. In general, the Table 2 values are the minimum generation capacity needs by year. Generation capacity acquired in advance of a particular year's need serve to reduce the needs of subsequent years. Thus, the math in the question is correct on a nominal basis. Whether or not it is cost-effective to obtain generation capacity credit early will be determined within computer-based modeling and based upon the bids received and the particular modeling assumptions for each portfolio required to be presented in the 120-Day Report.

37. Q: In PSCO's 2021 Clean Energy Plan, PSCo indicates a desire for the below resource additions (2,400 MW of wind, 1,600 MW of large-scale solar, 400 MW of battery storage, 1,300 MW of dispatchable resources; 1,200 MW of distributed solar resources). The total capacity of these resources differs from that in the RFPs Section 1.2, Table 2 Resource Capacity Need by Year. Which resource addition plan is PSCo targeting? If PSCo is targeting the amount in Table 2, can PSCO please share a breakdown of MW need by resource type?

    A: The Company disagrees with your assertion that the Phase I portfolios "indicate a desire" for a targeted level of generation by type. All generation portfolios filed in the ERP proceeding during Phase I were created from load forecasts, generic resource pricing, and operational characteristics assumed at the time; the Company referred to such modeling results as "indicative" in the proceeding. These indicative modeling results are not binding in Phase II in which real projects with firm pricing and locations will be utilized to create cost-effective resource portfolios that meet the generation capacity needs shown in Table 2 and the energy and emission reductions targeted.

38. Q: When during the solicitation timeline is the final bid portfolio published?

    A: The Company's 120-Day Report will contain the Company's preferred portfolio of resources along with portfolios for several other scenarios required by the Commission to be presented. The Commission has 90 days after the filing of the 120-Day Report to make its decision as to the final, approved portfolio for acquisition.

39. Q: Could you please confirm whether the Resource Solicitation Cluster (RSC) will treat prior-queued projects on an equal basis with the RSC?

    A: The Company will follow its Tariff with respect to entering in one or more RSC for selected bids coming from the RFP. An RSC follows the same timelines as a typical DISIS process though an RSC can be started at any time. Projects that are already in the PSCo queue may also be studied in parallel as part of a Resource Solicitation Cluster under Section 4.2.2 of Attachment N. If a prior queued project is selected by the Resource Planning Entity and is also part of a Resource Solicitation Cluster, that project must withdraw one of its requests prior to the initiation of a Facilities Study following the conclusion of the Resource Solicitation Process; if the prior queued project is already in the Facilities Study phase, it may remain there.

40. Q: On Narrative Topics (Equipment Description), can you define the “Weighted Short Circuit Ratio” and the methodology that should be used to calculate it?

    A: See Chapter 2 of NERC’s 2018 white paper titled “Short-Circuit Modeling and System Strength” available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Short_Circuit_whitepaper_Final_1_26_18.pdf.

41. Q: On Narrative Topics (Real Property Acquisition Description and Plan), what is meant by “USGS-based map?” Should we begin with a USGS topo layer and overlay the project layout on top of that?

    A: That approach is acceptable.

42. Q: On Narrative Topics (Permitting Plan), we are asked to “list” permits and describe status – are we expected to provide documentation or simply discuss them? Relatedly, should we provide copies of every lease/affidavit of site control, or would a form lease with description of site control suffice?

    A: You are expected to provide documentation. As an alternative to providing copies of all land leases at time of bid submittal, you may provide a list of all registered memorandums of land contracts secured to date and then be ready to provide a copy of all land leases in the event of follow-up due diligence.

43. Q: In the Renewable bid forms, can you explain the distinction between forms D1A and D1B – Pricing and Quantity? Should we fill in both, or only one as applicable?

    A: Forms D1A_Pricing and D1B_Pricing allow for projects like solar with storage hybrid proposals to provide payment rates for the storage component in an energy payment rate (D1A) or demand payment rate (D1B) in the Renewable bid forms. For proposals like solar with storage hybrids bidders may provide either or both forms as applicable.

44. Q: Can you confirm that form D1C – Property Taxes, should this only be completed for projects sited in Morgan, Routt, or Pueblo counties?

    A: Form D1C_Taxes need only be completed for projects which propose to locate generation, storage, and/or transmission equipment (including radial generation tie lines) in those counties.

45. Q: On the bid form F8 – Energy Production Profile - Annual and Monthly, what is meant by "Monthly Maximum Expected Hourly Generation"? Would this just be the MW of the project, assuming there is at least one hour each month where it is at 100% generation?

    A: For many renewable generation types the Monthly Maximum Expected Hourly Generation could be expected to be the facility nameplate, but this is not true of all renewable generators.

46. Q: On the bid form D2 – Electrical Interconnection Cost Estimates, what is the project LGIP identifier (or source of estimate if no LGIP)?

    A: If the proposed project has been entered into a prior PSCo transmission study queue, it will have an LGIP identifier.

47. Q: Does the 18-year limit for PPA terms on hybrid projects apply to the entire contract or just the storage component? Could the solar component extend to 25 years still?

    A: The 18-year maximum PPA term for storage applies only to the storage component of a proposal like a solar with storage hybrid project in which the bidder proposes a capacity payment rate for the storage component. In that case, the solar component can have a maximum PPA term of 25 years.

48. Q: Does PSCO have any guidance of how COD, initial security fund, and test energy apply for a Wind Farm Repower site, where the Existing wind farm will continue to operate during the execution of the repower project?

    A: Each bidder should include in their bid sufficient details to adequately evaluate the conditions and circumstances of each proposal. Without additional details here, the Company can only offer conditional guidance. However, using an example where a previously existing and operating facility submits a bid that includes a proposal to repower (replace or refurbish) an existing facility and the repower is a condition precedent of the continued effectiveness of the contract. Then, in this example, a Repower COD would be subject to the same or similar conditions as the COD requirements of a newly developed facility. In addition, without further information, a Bidder would be expected to fund the Initial Security Fund no later than thirty days following execution of the PPA. Similarly, Test Energy means and is limited to Renewable Energy generated by the Facility prior to a Repower COD, and only as required to satisfy the COD

Conditions of the Repower COD. Any further guidance on the treatment of Test Energy would depend on several factors, including but not limited to, whether the company is or is not the buyer of the Renewable Energy prior to commencing or during the repower construction, the timeline or schedule of construction, and commissioning, and the status of real-time and SCADA communications during testing. Each bidder should consider the possibility that any excess energy generated during the testing period that is not required to satisfy the Repower COD Conditions may not be purchased by the Company under a proposed PPA and adjust their bid accordingly.

49. Q: If there are differences between federal and state Environmental Justice screening criteria, which do we default to for the Community and State Reaction Assessment Narrative Topic?

    A: The Community and State Reaction Assessment bid narrative topic does not require a definition of "Environmental Justice" screening criteria. As stated in the Topic "Each respondent must present a current assessment of, and a plan for continuing to monitor, local community, disproportionately impacted community, and state reaction to the project, and a plan to work with the local community and disproportionately impacted communities on project issues." That is, every bidder is required to reach out to the local community and disproportionately impacted community and understand their concerns with the proposed project and develop a plan to address those concerns. As stated in the Topic, the term disproportionately impacted community is defined in Colorado statute.

50. Q: Example Resource Types for the Various RFPs, Table 1 from the RFPs, does not include Reciprocating Internal Combustion Engines (RICE) as an example resource type. Please confirm RICE proposals are acceptable for RFP evaluation.

    A: RICE proposals are bid eligible generation technologies.

51. Q: In the initial economic screening, bids are to be ranked by technology. For thermal resources, please clarify whether "technology" is meant to refer to simple cycle vs. combined cycle resources, or specific technology types. For example, would bids for simple cycle aeroderivative turbines only be ranked against other aeroderivative turbine bids, or would they also be ranked against bids for other simple cycle combustion technologies, such as frame turbines.

    A: As it applies to thermal generation resources, the Company will rank Frame-type CTs, aeroderivative CTs, and recips separately in its initial economic screening.

52. Q: How will PSCo consider proposals for open-cycle thermal resources that can act efficiently as both "peaking resources" and "intermediate resources"? In other words, will any incremental benefits related to resource flexibility be factored into the evaluation process?

A: Proposals are represented in computer-based modeling with the performance characteristics and limitations and pricing bid, subject to changes made during due diligence. During computer-based modeling, thermal generation proposals available to the model are dispatched with respect to the other generation resources (both bid and existing) in that particular case. Thus economic benefits to operation flexibility are captured within the computer modeling. Operational characteristics of specific proposals can also be evaluated on a non-quantitative/non-price basis; see Section 5.1 of the RFP documents.

53. Q: Flexible resources capable of quickly and efficiently starting, stopping, and ramping without incurring minimum run time constraints can mitigate price volatility arising from real-time supply and demand imbalances. However, such value is not accurately captured in hourly production cost models and is best quantified by applying a real-time (5-minute) modeling granularity. How will PSCo quantify these benefits in its evaluation process?

    A: Sub-hourly valuation was discussed in Phase I of the Company's ERP filing; the Commission approved the use of the Encompass hourly model for Phase II evaluations.

54. Q: PSCo will be required to join an Organized Wholesale Market by 2030. How will PSCo incorporate market dispatch of proposed resources into its evaluation?

    A: Per Commission Decision, the Company will not simulate a broader Western energy market for the 2022 All-Source Solicitation.

55. Q: What is the anticipated timeline, based on PSCO's resource study cluster/queue process, for projects planning to interconnect via line taps of the approved CPP segments to receive interconnection agreements?

    A: PSCo will follow its Tariff with respect to entering in one or more RSC for attractive bids coming from the RFP. An RSC follows the same timelines as a typical DISIS process though an RSC can be started at any time. The time to negotiate an IA following the completion of required studies can vary significantly among different counterparties.

56. Q: Would different project configurations be viewed as separate bids or rather as options under a single bid (e.g., wind only and wind + storage)? If a project has the potential to increase in size, can that be considered one bid? For example, a 50 MW, 100 MW, and 150 MW project.

    A: Generally, a single bid is represented by a single physical project as to generation type, COD, MW size, and interconnection location; there are exceptions to interconnection location as described in the RFP documents. Thus, a wind-only and a wind/storage hybrid project are two separate projects and two separate bids. Also, 50 MW, 100 MW, and 150 MW projects are three separate bids.

57. Q: The RFP indicates PSCO is interested in Solar/wind with storage. Would PSCO be interested in projects that have combined solar, wind, and storage?

    A: The Company has not expressed any particular interest in any specific technology as part of the Solicitation other than encouraging hydrogen-capable dispatchable bids. A wind/solar/storage hybrid project would be bid eligible based on generation technology.

58. Q: The CODs requested are several years out. If accepted, how much flexibility is there for respondents to introduce any change to the proposed projects (size, layout, technologies) if the development process necessitates it after bid acceptance?

    A: The Company is required to file portfolios of discrete generation/storage bids that have been found to meet the various scenarios documented in the Commission's Phase I Decision. As such, the Company is not open to entertaining changes to proposed projects (including generation type, scale, or price) included in any portfolio filed in the 120-Day Report to the Commission.

59. Q: What are PSCO's preferred BESS use cases? Are some – for instance, peak shaving or frequency regulation – more desired than others, like time shifting or back-up power?

    A: The Company has not expressed a preferred use case for storage. Per the terms of the Model storage PPAs (Stand-Alone and Solar with Storage), the Company expects to retain full dispatch rights to storage devices. Please see Articles 7.2, 7.3 and Exhibit I of the Stand-Alone and Solar with Storage Model PPAs.

60. Q: Does PSCO have a preferred battery duration?

    A: The Company has not stated any duration preference for energy storage projects.

61. Q: If a 398 MW project with a 2025 commercial operation date (COD) were submitted but not selected by PSCo as another project was more competitive and filled the 398 MW identified need, will PSCo consider this project to fill the capacity need in the following year (e.g. 2026 / 433 MW)?

    A: Table 2 in the RFP documents show the minimum firm capacity need by year to meet reliability criteria and the values are on a cumulative basis. Bids in excess of the stated capacity need in a given year may be selected for other reasons besides reliability, including economics, reducing emissions, meeting environmental goals, etc. Bids will be evaluated for inclusion in portfolios based on the commercial operation dates (COD), however, if bidders are interested in bidding a project with multiple different COD options, they are welcome to do so and these will be considered separate mutually-exclusive options. A separate bid fee is required for alternate COD alternatives, with the exception of the specific circumstances stated in the RFP documents.

62. Q: For existing sellers bidding incremental power generation, will the evaluation model be different from the other bidders? Will the existing PPA price and generation be used as an input in the model?

    A: The way in which the existing PPA and an incremental bid are evaluated depends on how the bidder proposes the contractual arrangements to occur between Xcel and the counterparty. Possible non-comprehensive options could include terminating the PPA and beginning a new PPA with pricing and terms encompassing the fully expanded project; the existing PPA remains and a new PPA is entered into for the incremental production, etc. which would be evaluated as alternatives to the base case assumption where the existing PPA continues unchanged. The bid and existing PPA would be modeled in accordance with the proposal given.

63. Q: The market price input listed on the Assumption document table 2.14-2, is that one data point you used for pricing forecast? How is it modeled with the mentioned "resources that exist within Colorado"?

    A: The Company's generating resources, both owned and contracted energy and capacity resources within the Colorado service territory, are modeled and dispatched along with a market resource (which is a proxy for the spot market) that utilizes the price forecast provided in Table 2.14-2.

64. Q: If a project needs a new substation to connect to the system, who pays for that PSCo or the bidder? Who owns the substation, PSCo or the bidder?

    A: Please see Section C6 of Appendix C "Funding of Network Upgrades for Interconnection" of the RFP documents for information as to how funding for substation construction could occur. The Company will own any new substations.

65. Q: Will Xcel allow line taps of the CPP transmission line for interconnection, or can interconnection only occur at the new/existing substations along the CPP route?

    A: Projects that propose to bisect a CPP segment would be found bid eligible. However, as described in the RFP such new interconnections will significantly delay a project vis-à-vis connection directly to one of the CPP substations.

    For line tap proposals, the Company would also encourage an additional proposal with a project structure that does connect to one of the CPP substations, and bidders can submit both of those options under a single bid fee.

66. Q: As we understand from the RFP, having an Interconnection queue or agreement is not required at the time of bid proposal submission, and the Public Service will study the same to determine the costs and requirements for electric interconnection and delivery. In the pre-bid meeting, Resource Solicitation Cluster process for filing of IX queue was discussed. It would be really helpful if you could let us know the process of filing IX queue request in the resource solicitation cluster process along with the timelines and cost.

    A: The Company, and not any particular bidder, will file a particular Resource Solicitation Cluster study request. Timelines and costs for an RSC study are consistent with those of the DISIS and are outlined in the Company's OATT. Bids submitted in a Resource Solicitation Cluster have the advantage that they will meet the Milestones (M1, M2, etc.) set forth in the OATT.

January 13th, 2023 Update

67. Q: For simple cycle gas units (both gas turbines and reciprocating engines) and combined cycle units, what capacity factor, number of starts per year, and operating hours would you like us to assume to fill in bid form D1B Expenses?

    A: Regarding assumptions for both CC and Simple Cycle CT starts, capacity factor, and operating hours, we are not providing those assumptions to bidders at this time. Please use box 4 on Form D1B to provide what assumptions were used to generate the cost estimates provided in Sections 1-3.

68. Q: Is there available information on how long the Interconnection process (from LGIA submittal to GIA) is expected to take?

    A: It is a complicated question. Assuming a clean DISIS process with no delays and no restudies, including restudies of prior DISIS clusters that can delay the results of a later queued DISIS, the answer is about 585 days. Once a restudy is required, either of a prior queue or the queue in question, delays of indeterminate length can be imposed. That is the situation PSCo finds itself in today with significant delays in some DISIS clusters. https://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/PSCo_DISIS_Restudies_Notice_11-16-22.pdf

69. Q: Please confirm the refundability of Interconnection Study Deposit and Security in event of terminating PPA negotiations or disapproval by the PUC of a project PPA.
    A: If the project was entered into a Resource Solicitation Cluster AND PSCo's queue reform filing in FERC Docket No. ER23-629 is approved, and the customer would recover its security. The portion of the study deposit not spent on the RSC study would also be refunded.

70. Q: For each bid profile, what inputs/categories can include optionality without issuing a new bid? For example, would providing a storage project with different annual cycle caps count as one bid or require a different bid for each cycle cap?

    A: A storage project with different annual cycle caps would count as two bids if the price changes with the limitations. Please send a new bid form for each change in operational restrictions, and for any other changes that might equal a new bid, bidders should ask the project manager.

71. Q: Section 4.5 in the Dispatchable RFP Document says that a NOIR must be submitted for each bid, however, Section 4.5 in the Renewable RFP Document doesn't say for each bid, leaving the impression that only 1 NOIR is required regardless of how many bids are submitted. Could you clarify if 1 NOIR is required or if 1 NOIR per bid is required?

    A: The Renewable RFP is the correct version. Only 1 NOIR is required per bidder, even with multiple bids.

72. Q: On Narrative Topics (Transmission Plan), does the Colorado Power Pathway count as "New Transmission" for the purposes of this RFP?

    A: Components of the CPP as currently planned and approved do not count as "New Transmission" for this Solicitation. However, required additional components to the planned CPP such as a new switching station would count as "New Transmission".

73. Q: After PSCo and shortlisted respondents have negotiated and agreed upon a PPA, how many days will the respondent have to execute the PPA?

    A: The Company expects each parties' internal approval process to be completed within a week or so following final negotiations.

74. Q: For the 3rd party report for wind bids, are there specific 3rd party wind consultants PSCo is looking for to provide this report, or can it be any wind consultant that EDPR chooses?

    A: A bidder is allowed to use their choice of a 3rd party consultant, but the consultant must have prior experience calculating and modeling long-term wind speed data for large-scale wind facilities including the incorporation of waking and blocking inputs and considerations. The evaluation team may contract with a specific 3rd party consultant to validate a bidder's information.

75. Q: Is C.4 "Application of the Xcel Energy OATT" of the RFP Documents saying projects are required to be a NRIS project or is it preferred?

A: No. The use of the term "network" in Appendix C.4 is referring to network integration transmission service (NITS), not network resource interconnection service (NRIS). As seen in Section 4.5 of the model PPAs, PSCo requires counterparties to have ERIS at a minimum.

76. Q: Section 3.1, paragraph 5 in the Company Ownership RFP states "Projects may submit proposals to interconnect to both the Colorado's Power Pathway ("CPP") May Valley Longhorn Extension and elsewhere on the transmission system, with different pricing options, under a single bid fee." Will a CPP line tap and a CPP substation gen-tie bid for the same project with two pricing options incur one or two bid fees?

    A: This would incur a single bid fee.

    As described in the "Transmission Plan" narrative topics section of the RFP documents:

    > *For proposals intending to interconnect to the approved CPP project, the Company encourages bidders to interconnect at one of the planned CPP substations, which can potentially be accommodated coincident with their expected in-service dates (ISDs). Proposals that plan to interconnect at new, unplanned switching stations on the CPP system should not expect new switching stations to be available until at least 24-36 months after execution of an LGIA or an E&P agreement. The Company also notes that no switching stations other than the approved substations in the CPP project plan are currently under development.*

    The Company is clarifying that bidders proposing to interconnect at new, unplanned switching stations on the CPP may also submit a bid that interconnects at a planned CPP substation interconnection and will only be charged a single bid fee for this option. These two options are also allowed to have different COD dates due to the construction timing differences. This waiver of additional bid fees is additive to the list provided in section 4.8 of the RFPs.

February 3rd, 2023 Update

77. Q: Is it required that respondents provide pricing that is consistent and compliant with PSCo Technical Specifications only, or are bidders allowed to provide pricing that only includes their proposed changes to PSCo Technical Specifications?

    A: See Company Ownership RFP Section 4.3: Exceptions to Technical Specifications. A bidder is required to meet the Technical Specifications in their base bid, including pricing to meet all requirements. If a bidder is requesting an exception to the technical specifications, they must clearly state in an exceptions log in the bid narrative what the exception is, reason for such exception and any adjustment or impact to the base bid (e.g. project cost, schedule, annual energy production, operations, etc.).

78. Q: Is there a maximum project size for this RFP? Sometimes in relation to a Most Severe Contingency within the system.

    A: This Solicitation does not have a maximum project size for bid eligibility purposes. However, the Company has a strong preference that the PSCo BA Most Severe Single Contingency not exceed a value of 750 MW (as set by Comanche Unit 3) based on incremental generation resources acquired in the 2022 Solicitation. A project's operational characteristics are a listed Non-Price Factor that will be assessed and a proposed project sized around 750 MW will be compared to similar, smaller generation options in determining which bids are advanced to computer-based modeling.

79. Q: Does the 18-year term only apply to the energy + capacity payment scheme, meaning that the energy only payment scheme does not need to have an 18-year term limit on the storage?

    A: An energy payment only structure does not need to abide by the 18-year limitation and may bid the full 25-year term allowed for PPAs.

80. Q: For the solar+storage, do you expect the energy capacity to be maintained throughout the lifetime of the asset (i.e., include augmentations), or to be sized beginning of life with a guaranteed degradation curve?

    A: The Model Solar + Storage PPAs contemplate a single Guaranteed Storage Capacity in MWh to be maintained over the life of the proposed PPA Term. If a bidder intends to propose a project with a projected Guaranteed Storage Capacity degradation curve over the proposed PPA Term as an exception to a static MWh Guaranteed Storage Capacity, the bidder should provide all necessary incremental information for the Company to understand what is proposed. In addition to the proposed degradation curve this would include a comprehensive red-line version of the applicable Model PPA in a Microsoft Word format along with a summary of its proposed PPA language changes as described in the "Exceptions to Model PPA" Bid Narrative topic in the RFP documents. Bidders should note that the Model PPAs have a coherent structure as to ensuring system performance including obligations to system performance, test procedures to verify performance, and impacts to payment rates and terms of default that assume a constant Guaranteed Storage Capacity through the PPA Term. Any Model PPA red lines provided at the time of bid submission for a project that proposes a declining Guaranteed Storage Capacity over time should ensure that proposed changes to all impacted terms of the Model PPA are provided at the time of bid submission. Bidders are expected to provide the associated price reduction associated with the proposed exceptions as indicated in the Bid Narrative.

81. Q: Is PSCo anticipating documentation that demonstrates compliance with the Dynamic Reactive Power Capability and Grid Disturbance Ride Through Capability requirement or is a Proponents statement within the Proposal submission confirming compliance sufficient to meet the proposal criteria?

A: A statement in the Bid Narrative section of the proposal confirming that the project would meet the standards is sufficient at the time of bid submission. As indicated in Section 4.9 of the RFP documents, the Company may seek clarification and/or additional information during its evaluation of any bid. Such additional information could include documentation that the project meets the standards.

82. Q: In the Xcel website, only the Solar + storage PPA model is available. Should Wind+storage bid consider the same PPA model?

    A: Yes, bidders use the corresponding solar + storage model PPA for other renewable + storage projects and mark them up as needed to accommodate other technologies.

83. Q: When does Xcel plan to start negotiating PPAs for the awarded projects and when does Xcel plan to have those PPAs executed?

    A: PPA negotiations commence after the Commission issues a Phase II decision, see Section 4.1 of the RFP documents for the indicative schedule. The Company typically schedules 90 days from the start of negotiations to reaching an executed contract. However, the amount of time required following the Commission’s decision will vary depending on the number of projects selected in the RFP. Currently, the Company anticipates reaching executed contracts for all projects-within approximately 120 to 180 days.

84. Q: Would the Resource Solicitation Cluster (RSC) process need to be completed before negotiating and/or executing the PPAs so awarded project developers have their final interconnection cost estimates?

    A: No, the RSC process does not need to be completed before the PPA can be negotiated/executed. Interconnection costs are determined in the generator interconnection process which results in an LGIA that is a separate contract. See model PPA section 1.2 Interpretation with Other Agreements. In the LGIA, the generator is required to fund the Transmission Provider Interconnection Facilities and provide financial security for the Network Upgrades. In PSCo’s current application of its Tariff, it releases that security when the project reaches COD.

85. Q: Is there a preference toward a build transfer as opposed to a PPA?

    A: The Company has not expressed a preference between PPAs and Build-Own-Transfer bids. However, as discussed during the Bidder's Conference, pursuant to the Colorado PUCs Phase I Decision the Company will target a 50% ownership of all energy and capacity acquired during the 2022 All-Source RFP. Company ownership could be met through Company self-build projects, BOT proposals, and sale of existing assets. Bidders who submit proposals for projects greater than 2 MW may submit the project as both a PPA and as a BOT/asset sale under a single bid fee; see Section 4.8 of the RFP documents.

86. Q: Can any renewable (wind, solar, etc.) + storage bid a hybrid project with energy payments and capacity payments for the storage?

    A: Yes, but the storage component with capacity payments has an 18-year limit for the PPA. The renewable component can have a maximum PPA term of 25 years.

87. Q: If Colorado Power Pathway (CPP)/Resource Sonication Cluster (RSC) study timeline(s) incur delays from publicly announced in-service dates, will Xcel's evaluation account for that project's flexibility to come online at a later COD?

    A: Bidders are generally not afforded a chance to change their bid after the bid receipt date except in response to the Company's due diligence efforts, the COD and Substantial Completion dates are assumed to be firm. The Model PPAs contain language as to consequences to the Seller should they not achieve the COD Milestone. With that being said if the CPP or RSC does incur delays the Company will work with the winning projects to arrive at mutually satisfactory outcomes.

88. Q: Does Xcel have a base assumption for PPA approval timelines that bidders can incorporate into their schedule in the case that PUC refiling is required (i.e. as defined in section 6.1 of the Renewable PPA Form)?

    A: Once a portfolio of resources is approved by the Commission's Phase II Decision, Commission Rule 3613(i) provides that the Company must complete the competitive acquisition process by executing contracts for potential resources within 18 months after the utility's receipt of bids in its competitive acquisition process (i.e., by early September 2024 based on the bid receipt date for this RFP), assuming an extension is not granted for good cause under the provisions of Rule 3613(i)).

    In the event it is determined that further PUC approval is required under the terms of section 6.1, the statutory provisions of §40-6-109.5 C.R.S provide that the Commission shall issue its decision on an application no later than 120 days after the application is deemed complete and may extend the time to issue a decision for an additional 130 days. While the Commission may consider expedited treatment of a proceeding under certain circumstances, this 250-day timeline is often utilized.

89. Q: For solar generation co-located with 'tolled' storage at a common Point of Interconnection (POI), does Xcel have any preference for a surplus interconnection arrangement that would limit the POI injection based on the solar facility? Or where transmission capacity may be available,

does Xcel prefer storage to not be limited allowing for the full output of both the solar facility and 'tolled' storage which would be connecting at the same POI?

A: The Company has not stated a preference for surplus interconnection or not. The Company will evaluate the bid based on what the developer proposes.

90. Q: What are the expectations of filing Attachment N in Form I from PSCO at the time of bid? At the time of bid, do we need to provide a complete interconnection package as we do for a new interconnection package in DISIS?

    A: Filing Attachment N is for the Company's due diligence work on the bid and for the Resource Solicitation Cluster (RSC) if selected through this RFP. The bidder needs to provide what's required in the RFP and the Company expects bidders to be well along in the process of developing a complete interconnection request. The Company expects to enter a Resource Solicitation Cluster around the time of the 120-day report and the projects that are included in the RSC must have completed interconnection applications to enter the study, which include all the requirements in Attachment N.

91. Q: On the 20th of December Bidder's Conference, it was mentioned that bidders do not need to include the network upgrade cost required in the bid pricing. Can you please confirm in case if there are network upgrades required for the deliverability of the projects Xcel Energy will do those. And, is the above true for any of the proposals connecting to Xcel Energy's transmission system?

    A: As indicated in Section 2.3 of the RFP documents "The Company will pay any costs required to upgrade or reinforce the Public Service electric transmission system beyond the Point of Delivery as a consequence of adding a respondent's project to the Public Service system. Respondents, however, will be responsible for procuring transmission service and any associated third-party transmission costs needed to deliver power from the project to the Point of Delivery on the Public Service transmission system. All pricing in respondents' proposals should reflect those costs (to the extent applicable) at the time of submittal." For clarity purposes, the phrase "reflect those costs" in the last sentence refers to the costs described in the second sentence and not to those costs referred to in the first sentence.

    Also, as indicated in Section 2.3, any proposal "must include the cost of any dedicated radial transmission line(s) from the generation facility to the proposed point of interconnection. See Form D2.

92. Q: We would be interested in submitting a proposal to aggregate distributed energy resources into a turnkey virtual power plant that can provide dispatchable capacity to Xcel. This can be contracted as a PPA or Capacity Agreement and will have similar availability and dispatch characteristics as other resource types, but with several unique advantages over centralized power plants. Would such a proposal be acceptable and competitively evaluated for the All-Source RFP? Or perhaps for another upcoming RFP?

A: Section 4.2 of the Dispatchable RFP document details the minimum requirements in order for a proposal to be found bid eligible. A proposal's ability to adequately address Section 4.2 requirements would, in part, determine whether a virtual power plant proposal would be accepted and then evaluated with and against other proposals. Included in Section 4.2 is a requirement to fully address all Narrative Topics in Section 4.3.

In addition to the Section 4.2 requirements, a proposal must also provide the capacity to meet all or part of the Company's forecasted needs through 2028 as shown in Table 2 of the RFP documents. Table 2 demand forecasts are shown net of the impacts of current and forecasted incremental levels of: 1) behind-the-meter generation connected to the Company's distribution system (e.g., residential and commercial net-metered solar), and 2) current and forecasted incremental levels of demand side management programs (including dispatchable demand response programs). In order for a VPP proposal to document that it is adding incremental capacity resources and not just cannibalizing existing and/or forecasted incremental behind-the-meter and demand response resources, a VPP bid must include specific DER assets that make up its proposed capacity resources at the time of bid submittal. Such a specific list should document what feeders these resources are located and a list of customers agreeing to participate so the Company can determine that these are truly incremental capacity resources.

A proposal that simply indicates a forecasted level of capacity for sale to the Company without providing certainty to the Company that it is actually proposing incremental capacity (above and beyond current and incremental levels already assumed) would be found bid ineligible.

93. Q: Is it possible to submit a bid for a project with a COD that phases over multiple years? For example, can we bid a 500 MW project where the first 250 MW achieves COD 12/31/26 and the second 250 MW achieves COD 12/31/27?

A: A proposal for a single, phased in-service project would not automatically be found to be bid ineligible; however, a project with two in-service dates on the order of 12 months apart for considerable portions of the planned MW is neither typical nor contemplated. The Model PPAs and the terms and conditions therein are consistent with a single Commercial Operations Date. As such, a bidder contemplating bringing on a significant portion of the project capacity a year or so in advance of the PPA's COD should fully evaluate the financial impacts of issues such as test energy, security deposits, damages, and risk of default.

If a bidder were to propose two separate CODs for a single project under a single PPA, they must provide as part of their bid package a red-lined version to the appropriate Model PPA of changes consistent with the proposed pricing; review the Exceptions to Model PPA Bid Narrative topic for additional information. A review of the bidder's proposed Model PPA changes and a determination of whether such changes might be acceptable is conducted during the Company's due diligence efforts to determine which bids are moved forward to computer-based modeling.

Alternatively, bidders could separate a large project with two proposed CODs into two separate bids consistent with the Model PPA conventions. To the extent proposed pricing in two separate PPAs for two co-located projects is impacted by economies of scale, bidders should clearly indicate that the acceptance of either bid is contingent on accepting both bids. Two separate but contingent bids would require two separate bid fees.

94. Q: If a line tap is proposed, will additional value or consideration be given to project clusters that would use the same switchyard infrastructure?

    A: Bids that propose to interconnect to the PSCo transmission system at a new, unplanned substation will not be assigned estimated costs of that new substation during Initial Economic Evaluation as described in Section 5.1 of the RFP documents; however, during computer-based modeling, any portfolio that contains a bid(s) that require a new, unplanned substation will include the full cost of that substation during portfolio creation.

95. Q: Will we have to submit to the next Definitive Interconnection System Impact Study (DISIS) cluster to participate in the RFP process?

    A: No. In fact, PSCo would prefer that bidders do not enter the queue but rather will be entered into one or more Resource Solicitation Clusters in the event your project, along with other projects, have been selected for interconnection review through the RFP review process. Speculative projects in the queue have resulted in many delays in generator interconnection processing which is why PSCo has made a queue reform filing in FERC Docket No. ER23-629. See Appendix C of the Phase I RFP document for detailed transmission information. To the specific question, PSCo points out that the next DISIS window will open on March 15, 2023 and remain open until May 1, 2023.

96. Q: For some understanding of the request for proposal (RFP) process and how that interacts with projects that have been through the traditional Definitive Interconnection System Impact Study (DISIS) process and the Resource Solicitation Cluster (RSC) process. It is my understanding that if a project has gone through the traditional DISIS process and responds to an RFP, that project isn't placed into the RSC process. Is this correct? Would it matter if the project has a signed Large Generator Interconnection Agreement (LGIA) or not?

    A: Projects that are already in the PSCo queue may also be studied in parallel as part of a Resource Solicitation Cluster under Section 4.2.2 of Attachment N. The purpose of a Resource Solicitation Cluster is twofold: 1) to determine the transmission interconnection feasibility of connecting a group of generators specifically determined to be feasible by the Resource Planning Entity in the course of RFP evaluation, and 2) to complete the interconnection process for each generator in the cluster, resulting in LGIAs.

    If the prior queued project is selected by the Resource Planning Entity and is also part of a Resource Solicitation Cluster, that project must withdraw one of its requests prior to the initiation of a Facilities Study following the conclusion of the Resource Solicitation Process; if the prior queued project is already in the Facilities Study phase, it may remain there.

A project with an existing LGIA does not need to be studied in a Resource Solicitation Cluster.

97. Q: In regard to a project with a Large Generator Interconnection Agreement (LGIA), how will the project be represented in the base case of the Resource Solicitation Cluster (RSC) process, i.e., dispatched or not? For instance, if the project was studied as Energy Resource Interconnection Service (ERIS), would it be turned off or considered as existing generation?

    A: Such procedures are documented in the business practice manual (BPM) posted on OASIS. We would direct your attention to Section 3.4. https://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/External_BPM_-_Large_Generator_Interconnection_Procedures.pdf

98. Q: How is a project assessed within a combination of other projects within the Resource Solicitation Cluster (RSC) study? Or is the project solely evaluated based on the already assigned network upgrades as to whether it may be selected?

    A: The projects within a Resource Solicitation Cluster are studied in various portfolios that meet the Company's needs and the network upgrade costs are assigned to each portfolio.

99. Q: I wanted to ask about the Resource Solicitation Cluster (RSC) that is associated with RFP submissions, will the RSC process take the same amount of time as a typical DISIS process? Is there an opportunity for projects/proposals that PSCo deems attractive to be fast-tracked in these transmission studies?

    A: PSCo will follow its Tariff with respect to entering in one or more RSC for selected bids coming from the RFP. An RSC follows the same timelines as a typical DISIS process though an RSC can be started at any time. We have not determined, and will not until bid review, how many Resource Solicitation Clusters will be pursued.

100. Q: For the Resource Solicitation Cluster, can you please confirm that bidders will not be required to submit any other documentation beyond a completed Form I3 (LGIP) to be considered through this RFP process to be entered into the Spring 2023 Resource Solicitation Cluster?

    A: The Company uses the LGIP Interconnection Form (Form I3) in order to obtain interconnection relevant information from all bidders in a consistent format. Providing Form I as part of the 2022 All-Source Solicitation is not a formal request to interconnect nor is it a request to enter the 2023 DISIS. If a proposed project is advanced to computer-based modeling and selected in a portfolio of resources, the Company may include that project in a follow-on Resource Solicitation Cluster study. If a project is selected for study in a Resource Solicitation Cluster the Company will reach out at that time to obtain all required information from the bidder.

101. Q: Does Xcel want developers to apply for interconnection studies prior to the RFP publication utilizing the provisional interconnection process?

    A: No. PSCo does not recommend entering a project as a provisional request at this time as a provisional study would likely not be completed by the time bids will be due. Additionally, provisional requests are intended for projects that are ready to build so any such request would be premature. During bid evaluation, the bid evaluation team will be confirming/supplying interconnection cost and timing estimates for all bids regardless of whether the bid has a queue position or not. Also, we expect to enter in one or more Resource Solicitation Clusters with preferred portfolios sometime in mid-2023.

102. Q: Is Xcel accepting any Interconnection applications for CPP segments or switching stations currently?

    A: No, not until the next DISIS window opens on March 15, 2023.

103. Q: Is it Xcel's preference that Developers of projects wait to file interconnection applications until after they have been notified of their shortlist status?

    A: Yes. PSCo expects to submit one or more Resource Solicitation Clusters consisting of short-listed projects. The developer will be responsible for preparing a complete interconnection application which will then be submitted by the Transmission Access group following the provisions of Section 4.2.2 of Attachment N to the PSCo OATT.

104. Q: Will developers of projects selected under the upcoming RFP be responsible for paying for all interconnection costs and system upgrades (e.g., new interconnection substations) associated with their project?

    A: Developers will be responsible for payment of Transmission Provider Interconnection Facilities. The developer will also be required to provide security for the cost of the network upgrades, which security will be released once the network upgrades reach COD. See Appendix C of the RFP documents for more information.

February 10th, 2023 Update

105. Q: Does PSCo have a preference for a 2-hour vs. 4-hour energy storage duration?

    A: For a Company owned battery a longer duration is preferred. The Company has not expressed a preference for storage duration for a PPA battery. *Note: This is a clarification that gives a* *preference for Company-owned batteries, whereas it was previously stated in Question 60 that there was not a preference between 2 or 4-hour storage duration.*

106. Q: Does PSCo have a preference for sizing the collocated energy storage component in relation to the generating resource?

     A: The Company has not expressed a preferred ratio of renewable to storage capacity for renewable hybrid projects.

107. Q: Does PSCo have a preference for battery applications/use cases?

     A: Company ownership preference for the primary use is energy arbitrage and load shifting.

108. Q: Please confirm if the Battery Energy Storage Systems (BESS) auxiliary loads should be included or excluded in the BESS sizing (i.e., net delivered power at the point of interconnection (POI) 100 MW, excluding aux loads, or 103 MW delivered so 100 MW is useable at the POI).

     A: Auxiliary loads should be included.

109. Q: Does PSCo have a preference for battery duty cycles?

     A: For Company owned batteries the preference is 365 cycles and a 4-hour duration.

110. Q: Does PSCo have a preferred overbuild percentage or year for a BESS system? Or is designing and sizing the system to meet the required energy at Year 0 acceptable?

     A: For Company owned batteries, the preferred overbuild percentage should account for no augmentations until at least the 2nd operational year of the BESS site. For example, the Company preference is that no augmentation should take place until a minimum of one (1) year after the initial COD. Additionally, the Company has a preference for a 20-year system design life for Ownership batteries and would want a schedule and cost for augmentations to maintain the POI design capacity of the BESS site throughout the design life.

111. Q: Can hybrid (solar + storage) projects with executed LGIAs have a grid charging study performed via the Resource Solicitation Cluster if grid charging was not contemplated in the existing LGIA?

     A: Yes, grid charging can be studied in the DISIS/RSC process. It can also be studied by submitting a load request.
     https://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-Trns_Ld_Intrcnnct_Form_int.pdf

112. Q: Can you please clarify if the Community /State Reaction Assessment is applicable to operating facilities or if this is intended for new proposed resources only?

A: The Community/State Reaction Assessment is intended for both existing facilities and new proposed resources. Community benefits and impacts for an existing facility has can be discussed in this section, including if the existing site is located in or benefits disproportionately impacted communities.

113. Q: Does the Company anticipate identifying any back-up bids at the time of the 120-Day Report filing?

A: Yes. Consistent with the Commission's Phase I Decision, the Company will identify a pool of back-up bids in its 120-Day Report for each of the following generation types: natural gas, wind, solar, storage/battery, solar with storage. In the event contract negotiations fail on a project included in the approved portfolio, negotiations would begin with a similar project from the back-up pool of bids.

114. Q: The RFP provides for an alternative pricing structure with a "fixed price for the first contract year ("Base Year") that would be adjusted after the Base Year according to one or more known, published and widely recognized indices that are closely related to costs of operation in the proposed technology's industry" – could this indexation be adjusted in year two and later years for the ultimate cost of solar modules, other final EPC costs for a solar or storage project, etc.?

A: No, the Company expects bidders to assume construction cost risk and include that as part of developing their bid pricing.

115. Q: If not, what is the nature of acceptable variables?

A: The index-based pricing structure is generally expected to be a fixed first year price with a continuous escalation/tracking throughout the contract from the first year price using an industry standard index, preferably GDP. The Company prefers fixed price or fixed escalation contracts, but indexed pricing as described would not be deemed ineligible.

116. Q: Must there be a floor and cap on a price range for this index structure or can it be uncapped?

A: A contract meeting the conditions explained above is not required to have a floor and/or cap. Including a floor/cap in the pricing proposal is allowed if the bidder so desires.

117. Q: Does your group publish expected peak load hours/days/months that would be relevant and where could we find such information?

A: The Company does not provide this information specifically related to this RFP. Some estimation of the peak periods on the Company's system could reasonably be inferred from the Company's Tariff Books, specifically time of day pricing, demand response program structures, etc.

118. The Q&A indicates both DC and AC coupled storage are acceptable – would PSCo see more value in one versus the other?

A: The Company has no opinion on DC vs. AC coupling.

119. Q: RFP Q&A refers to targeted emissions reductions. What are these goals and where can we find more detailed background?

A: The Company intends to achieve an 80% carbon reduction on its system, as compared to 2005 levels, by 2030. In addition, the State of Colorado has a goal of 100% carbon-free electric generation by 2040 and the Company has a corporate goal of 100% carbon-free energy by 2050.

120. Q: Is there any guidance on project location preferences or valuation advantages for renewables/storage within Colorado?

A: The Company is not aware of and cannot provide guidance in this area.

121. Q: We work with a variety of banks and surety companies to provide seller security for a PPA or BOT situation, though have not yet selected a specific provider for projects we would bid for this RFP. We understand that we can satisfy section 4.2 on security requirements for our bid submission by explaining our overall strategy and experience on this point, without regard to the specific final solution provider, correct?

A: Bidders do not need to decide on the provider now but do need to review the terms of the model PPA with the understanding that any provider will need to meet those requirements if they get selected.

February 17th, 2023 Update

122. Q: The RFP provides for an alternative pricing structure with a "fixed price for the first contract year ("Base Year") that would be adjusted after the Base Year according to one or more known, published, and widely recognized indices that are closely related to costs of operation in the proposed technology's industry".

Could this indexation be adjusted in year two and later years for the ultimate cost of solar modules, other final EPC costs for a solar or storage project, etc.? If not, what is the nature of acceptable variables? Must there be a floor and cap on a price range for this index structure or can it be uncapped?

A: No, the Company expects bidders to assume construction cost risk and include that as part of developing their bid pricing. The index-based pricing structure is generally expected to be a fixed first year price with a continuous escalation/tracking throughout the contract from the first year price using an industry standard index, preferably GDP. The Company prefers fixed price or fixed escalation contracts, but indexed pricing as described would not be deemed ineligible. A contract meeting the conditions explained above is not required to have a floor and/or cap. Including a floor/cap in the pricing proposal is allowed if the bidder so desires.

123. Q: Does your group publish expected peak load hours/days/months that would be relevant and where could we find such information?

A: The Company does not provide this information specifically related to this RFP. Some estimation of the peak periods on the Company's system could reasonably be inferred from the Company's Tariff Books, specifically time of day pricing, demand response program structures, etc.

124. Q: The Q&A indicates both DC and AC coupled storage are acceptable – would PSCo see more value in one versus the other?

A: The Company has no opinion on DC versus AC coupling.

125. Q: Is there any guidance on project location preferences or valuation advantages for renewables/storage within Colorado?

A: The Company is not aware of and cannot provide guidance in this area.

126. Q: What is the PSCo definition of a Community Based Project?

A: Bidders can ignore this input field in the bid forms; the Company will not use the responses for bid eligibility or due diligence purposes.

127. Q: Where can I find the PSCo approved supplier list to verify if suppliers are in the approved manufacturer/vendor list, and who should we speak to in terms of adding them to the list?

A: For projects that will bid into the Company Ownership RFP the approved supplier/vendor lists are within the technical specifications (tech specs) by generation technology posted on the All-Source website (https://www.xcelenergy.com/PSCo2022AllSource).

If bidding into the Ownership RFP, please cross reference the tech specs and any suppliers not listed would need approval from Xcel via email with the RFP project manager of wanted additions to the supplier list and a description of why the supplier should be approved. If approval is not provided due to time list any unapproved suppliers in the Exceptions section along with a description of why the supplier should be approved.

February 24th, 2023 Update

128. Q: Information gathered from studies and surveys conducted during project development indicates that there is a high probability that the U.S. Fish and Wildlife Service (USFWS) may require or recommend mitigation due to the Projects' potential impacts to protected species (protected by the Endangered Species Act or the Bald and Golden Eagle Protection Act). Mitigation costs are project and location specific but could range from $2M to $40M and include, but are not limited to, incidental take permits, pole retrofits for eagle mitigation, turbine curtailment (IdentiFlight), habitat impact mitigation, etc. Final mitigation costs are unlikely to be known until one (1) to two (2) years after 2021 ERP projects are selected. Determination of final mitigation costs and systems requires further discussions with USFWS. What is the preferred method for identifying the potential costs?

1) Include the potential mitigation costs in bids with a narrative identifying the cost estimate and describing the uncertainty of the bid line item.

Or

2) Not include the potential mitigation costs in the bids with a narrative identifying the estimate and describing the uncertainty of the potential bid line item.

A: Bidders are encouraged to submit bids that reflect reasonably expected costs, including environmental mitigation, permitting, etc. If there are significant upside or downside risks to these projections that result in meaningful cost impacts to the project, bidders are encouraged to ensure the narrative section of the bid clearly identifies the risks and probabilities of occurrence. For bids submitted in the Company ownership RFP, the relative impacts to initial and ongoing costs should be described as well.

129. Q: Is a project with multiple PPA tenors allowed under a single bid fee; e.g. 15 / 18 / 20 / 25 year terms, with the same COD?

A: No, different PPA tenors would qualify as unique bids and a bid fee for each unique term would be required.

130. Q: Are there any specific naming conventions that respondents should title the files to submit?

A: No specific naming conventions have been requested. It is advisable though to name the bid narrative and bid forms to distinguish one bid from one another. For example, include the project name, which RFP the bid is for, and include MWs, CODs, and PPA tenors if your bids have multiple variations to help us distinguish your bids from one another. Note each bid needs a separate bid form, narrative, and any other included information as a bid package in its own zip file.

131. Q: If selected for the Resource Solicitation Cluster, will the Bidder be able to select ERIS vs. NRIS or will this be dictated by PSCo?

A: PSCo expects it will request the RSC be studied as ERIS.

132. Q: Regarding 20.1 Operating Modes - PSCo describes the operation mode based on MESA. Does this mean that PSCo wants bidders to use the site controller based on MESA? Or is it acceptable to use a site controller that supports an operating mode similar to the MESA function?

A: The Company is not willing to entertain any storage proposals for ultimate Company ownership through a BOT bid with different storage controllers than as specified in the Storage Tech Specs provided to potential bidders. For storage bids subject to PPAs, bidders may specify the type of controllers they deem appropriate as long as the storage system communicates with and responds to the Company's AGC and SCADA signals as described in the Model Storage PPAs; see Articles 7.2 and 7.3 and the referenced Exhibits therein for additional information.

133. Q: In the Renewable D1A and D1B (Pricing) forms, is the "Annual Free Curtailment" column related to the model PPA 8.4.2.(viii) ("non-compensable curtailment")?

A: The Annual Free Curtailment applies to the Article 8 section related to "Curtailment" in the Model PPAs as either 8.3.B.2.viii or 8.4.B.2.viii, as applicable.

134. Q: In "Curtailment Gross-Up PTC Cost Paid" and "Curtailment Energy Cost Paid" drop-down selection boxes, a "Yes" means that the Seller needs the respective compensation from the Company?

A: Yes.

135. Q: Regarding the location of the meter point in the Solar with Storage Model PPAs, can the Company provide any guidance as to what % of the total Discharging Energy will be Solar Discharging Energy or Grid Discharging Energy?

A: The terms of the Company's Model Storage PPAs as to the location of the meter point for Renewable Energy are unchanged from the terms of the Model Storage PPAs presented in our

Phase I ERP proceeding; please note that these Model agreements were filed publicly on March 31, 2021 and the Phase I proceeding was fully litigated and settled subsequently. With their Phase I decision, the Commission has approved the Model PPA terms regarding the metering point of Renewable Energy and its impact on round trip storage losses. As to "what % of the total Discharging Energy will be Solar Discharging Energy or Grid Discharging Energy" the respondent should expect, the Company will generally and naturally use the lowest cost energy to charge the BESS. As such, the periods where the lowest cost energy is available to charge the BESS vary widely based on many commonly understood system operating factors. If these lowest cost periods occur when there is solar generation available, then the Company would generally charge the battery using solar generation from the plant, and alternatively, if there is not solar generation available, the Company would generally charge the battery using energy from the grid. The respondent could conservatively assume the Company will attempt to maximize the economic benefit of the BESS. The Company cannot advise on forecasted market energy costs, nor is the Company intimately familiar with each specific project's variable projected solar availability, maintenance schedules etc. Each respondent is expected to perform their own analysis independently for their respective project and location and assess their own risk tolerance and submit bids accordingly. Any associated variance and risk are to be borne by the bidder.

136. Q: Since hybrid projects are required to submit Form D1A and D1B, are they also asked to submit Exceptions to Model PPA, if any, for both Energy Only and Energy & Capacity payment?

A: RFP Bidders are not to submit both Form D1A and D1B for a single Bid. Bidders must choose one pricing option per bid, and would complete either Form D1A or D1B, depending on the option chosen for that Bid. Bidders may submit both pricing options, but they would be identified as two separate Bids, each requiring a bid fee, with separate bid forms provided using the appropriate Form for each bid. Exceptions to the model PPA can be provided for any bid.

137. Q: Pursuant to the requirements of Exceptions to Model PPA, the bidders are guided to identify the associated price reduction according to their proposed changes in Model PPA. Would it be allowed to remark such price reduction as "To be discussed" at this stage and detail them on being shortlisted or in a further stage?

A: No.

138. Q: Would it be acceptable for an alternative pricing schedule to have variations based on adjustments in the Construction/Operation cost items?

A: No, this is a risk that is expected to be borne by the bidders and priced into their proposal.

139. Q: According to Step 2, bidders are able to submit final bid pricing based on the results of PSCo's verification of interconnection cost estimates. Would the opportunity to update the pricing also be given to the bidders whose cost estimates are not significantly different from the ones

provided by PSCo as acceptable as of now? Or are only informed/selected/applicable bidders eligible to do so?

A: Any bidder whose estimates of interconnection costs are modified by PSCo are given the opportunity to modify their pricing to account for the change in interconnection costs, and those costs only. It is expected that any change in pricing would be reasonably comparable to the changed interconnection costs.

140. Q: Form I is not required to submit if bidders have an interconnection queue in the PSCo DISIS Cluster study. As a substitute for Form I, should bidders submit such applications in the bid package?

A: The full application is not required to be submitted as part of the bid package. Please enter the queue generation interconnection number in cell C5 of Form D2.

141. Q: On Model PPA, Article 19 – Assignment: What would be critical factors preventing PSCo from giving prior consent to a Change of Control (COC) of Seller following the PPA? (e.g., timing of COC, development condition, etc.)

A: Section 19.1 of the model PPA lists requirements for a satisfactory change of control. Failure to satisfy any of these provisions would be a critical factor that would prevent consent.

142. Q: Would it be okay to submit more than two different bid packages under the same ID and remark that ID into each bid fee remittance? The bid packages will be in respective zip files, and so will the bid fees.

A: The Company prefers that you do a single wire transfer that covers the bid fees for all of your projects (bids) in a single transaction. A duplicate copy of the single transaction would be put into each bid zip file. There does not need to be a separate wire transfer/transaction for each bid, in fact we discourage it.

143. Q: On Form F3, since neither PPA nor RFP provides the definition of the term "Compliance Period", we would like to ask for your clarification about what are the criteria bidders consider in order to answer Yes/No in this Section.

A: Bidders can ignore this field, it is an inadvertent carry over from a previous version.

144. Q: Could we understand that the second bid fee will be refunded in the following cases: either the bidder determines to withdraw the proposal due to the inevitable circumstance during the evaluation process or the PPA negotiation would not achieve the execution?

A: The language in Section 4.8 of the RFP documents is clear “if the bidder and the Company fail to execute a Power Purchase Agreement due to, in whole or in part, bidder’s actions that do not reflect bidder's representations or commitments during the RFP bidding process, the Company shall have the right to retain the Second Bid Fee." Submitting a bid into the RFP indicates the Bidder is willing and able to enter into a contract under the terms specified in the bid. If the bidder later decides to withdraw a bid after negotiations have commenced due to an unwillingness or inability to fulfil the terms they specified in their bid, that would most likely result in forfeiture of the second bid fee.

145. Q: Would you confirm that if contracts related to employment are not yet completed, the bidder is asked to submit the applicable standards only and explanations of why not to submit and that such submission wouldn't cause any disadvantages in evaluation?

     A: Correct.

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Addendum to Ownership Tech Spec Equipment Suppliers

PV Solar Equipment Suppliers

- Jinko

BESS Integrators

- Powin
- Borrego
- WEG
- Gotion
- Mitsubishi
- LG

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Bidder's Conference Q&A

Q&A Session 1 – Logistics and general Questions

1. Q: Will bidders receive a confirmation email back when they submit an email to the All-Source RFP Email? If not, what should they do if they do not receive a response?

   A: Bidders do not get an automatic response, but we do respond to every email. Emails sent to the RFP Project Manager email are logged and replied to ASAP. Some questions require consultation with internal subject matter experts and therefore take more time to answer. If a bidder has not heard back from the RFP Project Manager in a reasonable time frame, they can send a follow-up email to confirm receipt.

2. Q: How will the RFP evaluate out-of-state projects? Will a project located in New Mexico be at a disadvantage compared to Colorado based projects?

   A: The one requirement is that the project must be able to provide documented firm transmission to the PSCo system. No prioritization is given to in state projects.

3. Q: Upon completion of the competitive acquisition process, can bid price and utility cost, generation technology type, size of the project, and contract duration be redacted when posted to the website or will this information be posted for public viewing?

   A: Yes, that information would be posted for public viewing.

4. Q: What Commercial Operation Date ("COD") is PSCo targeting within the Resource Acquisition Period ("RAP") of 2023-2028?

   A: There is no specific target. If the project's COD falls within the RAP, it is eligible.

5. Q: When does a project have to be online to meet the need in a given year? For example, to meet the 2027 need, would a project need to be online by January 1, 2027?

A: If the project is online before June 1st, it will be counted towards the reliability need (summer reliability) in that year.

6. Q: What percentage of capacity added is targeted to be company ownership from this RFP?

   A: This RFP will be approximately 50% company ownership of energy and capacity from the solicitation. That is part of the legislative statute.

7. Q: Is the Disadvantaged Community Portion of RFP only applicable if the project is in a Disadvantaged Community, or is there an expectation that we would look for Disadvantaged Community benefits in non-Disadvantaged Community areas?

   A: If it is “affecting” a disadvantaged area (there is a link to the state’s mapping of DI communities) then yes you can submit that information. Realizing that the term “affecting” is very generic, and that your project can impact DI communities without being in a DI community, it is better to be as inclusive of information as possible and share plans for impact.

8. Q: For solar plus storage projects can we submit another project that is solar only under the same bid fee or will it be a separate bid fee?

   A: That would be another bid fee.

Q&A Session 2 – CPP and Transmission Interconnection

9. Q: When is the RSC going to be filed compared to what is happening in Phase II? Is that after the 120-day report but before the Commission’s decision?

   A: At the 120-day decision.

10. Q: Are there more detailed maps for the CO Public Pathway publicly available?

    A: There are no detailed maps, but we have provided GPS coordinates for the 3 new substations. Longhorn has not been permitted yet.

11. Q: You showed a map delineating between bidder Transmission costs and Xcel Energy costs, and earlier, you mentioned that in a bid you could indicate if the bidder was to own the project, or if

Xcel would ultimately own the project. Can you break up the ownership of the transmission interconnect upgrades and designate that in your bid? Example: Bidder owns the generation, but Xcel owns the Generator Interconnection Facilities.

A: For Build-Own-Transfer bids, the Company ultimately owns the entire facility (generation and transmission) as indicated in the Ownership RFP document which includes reference to technical specifications applied to any developer-constructed transmission that must be followed for ultimate Company ownership. The question proposes a scenario in which a developer would own the Generation components while the Company would ultimately own the Transmission components including any radial gen-tie. While the Company would not necessarily find any project proposing such a structure as bid ineligible, the Company has not typically owned such "transmission serving generation" assets; such a construct raises significant regulatory, cost recovery complexity, and scheduling issues. Cost recovery would occur outside the Company's ATRR (atypical of transmission assets) and would also require the Company to file a CPCN with the Colorado PUC for transmission ownership. The time to prepare, file, and adjudicate a transmission CPCN in front of the PUC could add significant delays in the project schedule which should be allotted for in any proposal. Company ownership of the transmission asset would also assume that the Company ultimately received a CPCN with no objectionable language. In addition, at a minimum, the same transmission technical specifications that would apply to a BOT bid would apply to a bid for split project ownership. Bidders would also need to provide the total proposed purchase cost of all transmission assets proposed for Company ownership.

12. Q: For those projects that are already part of the Large Generator Interconnection process, is there anything you want to add about whether they will still go through the LGIP process?

    A: If you are not in the queue right now, we would discourage you from entering, as we will not have anything timely to report back. If you are already in the que, depending on which cluster you are in, the restudies could result in quite a delay, which is why our que reform includes a transition, similar to what we did in 2019. Those generator interconnection requests that can show readiness, to a high degree, would be eligible to continue through the que reform transition. Therefore, you would not need to withdraw from the queue. At some point, you will only have one project in the process.

13. Q: You mentioned that being in the RSC would satisfy the M1 readiness demonstration under the new tariff, but would it also satisfy M2, M3, and M4?

    A: Yes

14. Q: Can you talk about how you are evaluating projects in light of the potential queue reform if it does not go through at FERC, or if it is delayed or changed? Is the base case assumption that the reform is going to be adopted, and how are you adjusting your evaluation if that doesn't happen?

    A: If FERC says no to any portion of the items on queue reform proposal, then the queue would continue to unfold and would take a couple years to get through the current clusters. So, we have a separate provisional LGIA opportunity that also could meet the milestones. That process is designed so that a generator who is ready, but out of cycle and unable to go into the DISIS because they can't afford to wait for the DISIS to unfold, to get online. So, it would be essentially another quasi-Resource Solicitation Cluster, but for those generators that are really trying to get online and get to an LGIA within an appropriate time (about a year). We hope not to have to do that, but as much as needed, we will use that provisional process in the Tariff to get generators online.

15. Q: Will Xcel allow line taps of the CPP Transmission Line for interconnection, or can interconnection only occur at the new/existing substations along the CPP Route?

    A: The Tariff would support any valid point of interconnection to our existing or planned transmission system. The short answer, from a Tariff perspective we could accept that.

    From a bid evaluation perspective, that is one of the special exceptions for a single bid fee. If you are proposing a tap, we'd also like you to propose a project structure that does connect to one of the CPP substations, and you can submit both of those options under a single bid fee.

    One of the reasons is timing. We expect that a new switching station that splits one of the Pathway lines could add an additional couple of years to your timeline to get the project online and get your generator interconnected.

16. Q: Will PSCo accept interconnection requests for the May Valley to Longhorn segment?

    A: Yes, we will. Again, that was a special exception that if you can connect elsewhere, for a single bid fee you can propose an alternative. Whether we build it would be determined by whether there are cost-effective bids that we want to accept or need to accept on that line.

Q&A Session 3 – BVEM

17. Q: Is the Rubric scoring (BVEM) just for the construction part of the project, or for the total project? So, if we have 20% for engineering and procurement, is that relevant, or is this only for the labor portion of the project? This scoring rubric is only for your construction?

A: We are looking for the construction portion of your project. We are not looking for you to go down the supply chain.

18. Q: Are proponents expected to provide BVEM for EPC labor during the construction period, even if this is managed entirely by the EPC firm?

    A: The answer is yes. From our standpoint (BVEM evaluation team), we are just reviewing whatever the Xcel team sends to us. We are not in the early stage of filtering out the proposals.

19. Q: Could you talk a little bit more about the individual grades or points? It looks like maybe I can get one full point for each of the four pillars; is four my best score? Can you talk about how I might get a 0.7 vs a 0.8?

    A: We are still calibrating it to see if these will add up to a 1 or a 5, so it's a little irrelevant at this point. There isn't an ideal score that we're going for yet. It's not a scale out of 100 yet or a scale of 10. At the end of the day, we want these buckets to be equally weighted, so once we finish calibrating, it might be out of 1 or it might be out of 5. But as long as you complete the requirements of the RFP you can be awarded full points. Within the BVEM within the RFP, they're very specific about in state versus out of state labor, or industry average wages. That's exactly what we are scoring to.

    Follow up Q: Let's say I'm Company A, if I put that my wages are 100% of the national average but a competitor puts that their wages are 110% of the national average. We both completed it, but how are different scores like a 0.7, 0.8, or a 1.9 like you show here awarded? How can one know what their score will be? I feel like we are shooting for a target where we can't really see what we're aiming for.

    When reading the BVEM statute, it says "paying industry average wages", and then the RFP asks you for the prevailing wage, and it asks for your salaries and it also asks for salaries and fringe, so that's what we'll be scoring to. Tell us what your wages are; tell us what the prevailing wage is for that job. To get the max points, you would be paying that industry average wage or above. For that example, you're either below or you're at the statute level.

20. Q: My question speaks to projected COD rates. For a project that is going to be COD end of 2023, it will have a contractor and very good contract information whereas a contract going COD 2028 may not. So how are you looking at projects on a yearly basis where you have more certainty as you're closer to the COD date, and is that being factored into your scoring rubric?

What this will do is provide a much higher score for earlier stage projects than later stage projects. So, when you're looking on a time basis and your resource on a yearly basis, that is something I would suggest you try to consider because there is greater certainty near term. When you're looking at a 2025 resource versus a 2028 resource, the 2028 resource is going to look much worse.

A: This question brought up good feedback for the Labor Economist. The impact of near term vs. long term CODs on BVEM metrics will be considered when scoring is implemented and as the Company prepares its presentation of the results.

21. Q: If a company submits a PLA instead of a BVEM narrative, how will that be graded in terms of the rubric?

    A: In accordance with the RFP and our agreements, a PLA project gets 100%.

22. Q: It looks like there are many factors in PSCo's non-price factor analysis, BVEM metrics being one of them. Can you talk about what weight this will have on the overall score?

    A: There is no set rubric as to which part of the non-price scoring matters more or less. It is just an overall qualitative assessment.

23. Q: This question is on enforcement. We are aware of the statute, and we could paint a very optimistic picture with these responses, but could you speak to how it is actually enforced?

    A: It's kind of a two-step process. The CU folks are responsible for scoring the bids that the PSCo team gives them. As part of the two-step process, my team serves as a gatekeeper role. Are you or are you not compliant with providing the information that was requested? There is not exactly a set line that we can point to, but we can say that bids that the Xcel team deems non-compliant will have a chance to cure any issues before being disqualified for these matters. Before we disqualify anybody based on this information, we will reach out to you, we will give you an opportunity to cure, and before you are ultimately disqualified for not being compliant, the independent evaluator will confer with us, and we will make sure we are in agreement on that decision. We will give you every opportunity, as we are definitely in the business of trying to make your bid move forward, not in the business of trying to reject your bid.

    Follow up – In BVEM, if you are selected and your metrics are acceptable, how are you going to enforce that down the road as the project's being constructed? How do we get to the other side of that, ensuring that what we've said we're going to do in order to get this award is actually going to happen?

A: We do not have a procedure in place right now, and it's not defined by the PUC, and a lot of that might depend on what they say. Like most things, we expect people to be ethical, and if you say you're going to do something, we expect that you're going to do that.

24. Q: Quick process question. It feels like there might be a need to have more BVEM follow-up conversations. Do you expect that to happen in January or February as the rubric is finalized and more questions come in from EPCs, or is today our chance?

    A: This is the only in person event we are planning with the CU folks, but if you do have questions, you can submit them to the RFP inbox, and we will post them to the FAQ for the benefit of everyone else.

Q&A Session 4 – General Questions

25. Q: How would the company view a non-stationary storage solution like vehicle to the grid? Is that something you've given any thought to?

    A: We'll accept it as a bid. It's eligible, and we will evaluate it based on what we see in the bid.

26. Q: Have the latitude and longitudes of the CPP substations been released as part of the RFP?

    A: The three substations that have already been specifically located will be posted on the FAQ. As new substations become specifically defined, we will post that up there as well.

27. Q: Is the second $/kW fee refundable, is that posted at or around the 45 days, or is there a negotiations period later than that?

    A: It is later than that. Typically, we will begin negotiations after we define the final portfolio. The second bid fee would be due when we've actually selected you, the commission has approved you and we start PPA negotiations. That money is refundable to the bidder either in the form of a refund or it can be used to handle some of the security obligations under the PPA agreement; it's the bidder's choice. As long as we move to a successful conclusion of the negotiations. Really, it's meant to make sure everyone has some stake in the game in the negotiation process.

28. Q: If there is an area with a lot of developers, and we like to work with the same point of interconnection, can we work with other bidders to reach that same point of interconnection?

    A: You can. We will evaluate the interconnection bids, and if there are three projects proposing the same interconnection, and we want all three projects, we will look at the synergies of taking all three at once and really only one interconnection location. So, we are not going to triple the amount of the interconnection costs for selecting all three of those bids. We will do that on the back end with our Subject Matter Experts (SME) when we look at the bids, and their proposed interconnection locations, and decide whether there are some synergies to be recognized there or not.

    Q: Even if it's a new point of interconnection?

    A: Yes

29. Q: Does Xcel have any specific targets by technology (e.g., how many MWs of wind versus solar)?

    A: No, we do not. All sources, all technologies, and no specific amounts or types.

30. Q: Expand on the process by which you go from the initial economic screen to the computer-based modeling, and what is the cutoff to get into the computer-based modeling?

    A: It's described in our RFP documents to a certain extent. We'll use manual spreadsheet ranking criteria to sort the bids based on the Levelized Cost of Energy and Levelized Cost of Capacity by technology type. We will make buckets of different types of technologies, and we will sort them. We'll decide where the cut line is going to be, in consultation with the IE, and I will assure you, of any step in the process, this is probably one of the ones the IE is most actively involved with. Normally, we will try to be as inclusive as possible, because once we make that decision at the 45-day mark, it's a little more complicated procedurally for us to go back and add extra people in. If we start running the portfolios, and we're picking every single one of a certain technology type that we selected, we've got a conundrum: did we pick enough? So, we are going to be overly inclusive rather than exclusive in developing those cut lines to make sure that we have a big enough pool to create the portfolios that most satisfy our objectives.

31. Q: Going back to the Resource Solicitation Cluster, you talked about that process starting Q2 2023, around the 120-day report with an accelerated timeline, but what is your expectation on completing it or getting the first round of study results out?

A: It will follow a similar timeline to the DISIS – 90 days for the first phase of the process. It doesn't get sped up after the studies start; we still need the same amount of time for each phase in the process.

32. Q: Regarding property taxes in Pueblo County and other related counties, can you speak a little more about exactly what type of detail you're looking for us to opine? A number, back up, etc?

    A: What we need to be able to apply the credit to your project is the annual property taxes expected to be paid over time, as well as some sort of justification for it. We don't want you to submit a number with zero backup; we want to have some certainty that you are not "making up a number out of thin air".

    Follow up: Is this real property tax, personal property tax, or both? Is it incremental or base?

    A: All incremental property tax paid to Pueblo County, real or personal.

33. Q: In the minimum requirement list, it says the team needs to have experience with developing, construction, and commissioning a project. If we are planning on submitting the project as a joint venture, do both parties need to have that experience?

    A: If there's a lead project developer with experience, that would be satisfactory.

34. Q: Will the company consider resources connected to the distribution grid?

    A: Yes.

35. Q: How would the resource solicitation cluster timing be affected by any restudies of prior DISIS studies? I.e., what happens if FERC says no?

    A: It would be pushed to the end. It's a queued cluster based on the timing of its submittal. Whether it would be put in after the 2023 DISIS window or wherever it lands based on the FERC decision, it would be queued after the 2022 Spring at the very least. If FERC says no to the transition, then we will unfold, and it will be studied as a DISIS cluster way later – two years down the road plus. That's why I brought up the provisional option where we would try and bring the generators all online and study them for interim operation without final costs on the upgrades as needed.

36. Q: Can the resource capacity model acquire capacity early? That is, will the model only fill an individual year's need or can the model "go long" capacity in any year?

    A: Yes, the model can go long in capacity. I want to go back to the firm capacity need slide; that is the cumulative amount, so it is not that much in every year. We are looking at a total cumulative firm capacity amount of 1,500 MW by 2028. There is no specific timing required other than meeting the amount threshold in that given year. Early is perfectly fine.

    Q: To clarify what you mean by firm capacity, I'm seeing in 2026 that you need 35 MW of firm capacity. So, a 100 MW wind farm with a 35% capacity factor would meet the requirement?

    A: Not capacity factor, but Accredited Capacities. So, it's the ELCC "Electric Load Carrying Capability" of the resource. Again, I don't want people to get too hung up on that firm capacity need, because quite frankly, a lot of the need from this Solicitation is going to be driven by carbon compliance, not necessarily the firm capacity.

37. Q: On the topic of ELCC calculations, how is the project location defined? Is it based on project infrastructure or point of interconnect? I'm specifically curious about projects that are close to a boundary line of those ELCC regions and might interconnect in an adjacent one.

    A: The ELCC will correspond to where the physical renewable resource is located regardless of where the interconnect location is.