BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1845

In the Matter of PACIFICORP, dba PACIFIC POWER, PacifiCorp's Application for Approval of 2017R Request for Proposals.	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S COMMENTS

I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these comments to Oregon Public Utility Commission (the "Commission") regarding PacifiCorp's 2017 renewable request for proposal ("2017 Renewable RFP"). NIPPC applauds PacifiCorp for proactively recognizing the significant potential cost savings and economic opportunities for ratepayers associated with the prompt acquisition of renewable resources. PacifiCorp will use these resources to meet its current energy needs and will eventually need them for compliance with the Oregon Renewable Portfolio Standard ("RPS"). As explained in PacifiCorp's integrated resource plan ("IRP"), now is the time to at least test the market because the costs of renewable resources are poised to increase in the near and medium term future, and the potential cost savings now outweigh the risks and cost increases associated with delaying action. The wind production tax credits ("PTC") are set to expire, which presents an opportunity too good to pass up (or at least too good to not perform a RFP to ascertain the benefits for customers).[1] Despite

[1] NIPPC raised major concerns and sought a short delay in PacifiCorp's 2016 Renewable RFP because the benefits associated with the expiring PTCs could be captured later in time and there was not a truly time-limited opportunity. Now,

historic trends, solar generation prices may also significantly increase in cost due to the eventual expiration of the investment tax credit, looming trade disputes that could significantly increase the costs of imported panels,[2] and a less friendly federal regulatory environment. Finally, NIPPC notes that approving an RFP does not necessarily mean that the Commission will acknowledge the resource short-list or PacifiCorp will finalize any contracts; however, it is impossible for PacifiCorp or the Commission to even know there are excellent economic opportunities, if PacifiCorp is not allowed to at least move forward with an RFP.

NIPPC appreciates that PacifiCorp is seeking Commission acknowledgement of its 2017 Renewable RFP, as PacifiCorp has not always demonstrated that the competitive bidding process should be respected. Although PacifiCorp could have informed parties of its plans sooner, PacifiCorp's overall approach is consistent with the competitive bidding guidelines, especially given the unique circumstances associated with the truly limited opportunity associated with the gradual phase out of the PTC. The 2017 Renewable RFP, as modified by the recommendations of the Oregon Independent Evaluator and NIPPC, is consistent with the competitive bidding guidelines and should be approved.

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however, is that time and there can be no further delays, if wind projects are going to be constructed and take advantage of the full value of the PTCs. This is a time-limited opportunity.

[2] Diane Cardwell, Solar Trade Case, With Trump as Arbiter, Could Upend Market, THE NEW YORK TIMES (June 30, 2017), available at https://www.nytimes.com/2017/06/30/business/energy-environment/solar-energy-trade-china-trump.html (explaining the Suniva trade case and its effect on the solar market).

The Commission, however, should make substantive changes to PacifiCorp's Renewable RFP to ensure that the 2017 Renewable RFP will fairly evaluate power purchase agreements ("PPA") versus utility ownership options. The inherent bias in the competitive bidding process is simply too large to overcome; however, NIPPC's hope is that important changes can be made to this RFP to ensure that at least some lower cost and risk PPAs will have a fair opportunity to compete.

NIPPC's key recommendations include:

- The 2017 Renewable RFP be open to more than just Wyoming wind so that ratepayers can take advantage of the best resources that can effectively deliver power to the Company's system regardless of location or renewable resource type;

- PacifiCorp's "repowered" projects be included in the 2017 Renewable RFP and their economics truly tested by the market;

- One-sided and biased PPA terms should be changed to ensure more comparable treatment between utility-owned and PPA options, including delay damages, termination rights, and availability guarantees that the RFP imposes only on IPPs submitting PPA bids;

- Bidders should not be required to have completed certain interconnection studies because only PacifiCorp knew that they would be needed and did not provide sufficient notice to bidders that it would be proceeding with an RFP;

- Bidders should be allowed to bid if they are in or have threatened litigation with PacifiCorp;

- PacifiCorp should be required to revise the term-normalization analysis in the RFP to use an annuity-based analysis called for in the existing guidelines while not unreasonably penalizing shorter-term bids for PPAs through use of generic fill costs from the IRP;

- For each utility owned resource on the short list, that the role of the Oregon IE be expanded to conduct a comprehensive due diligence review of the type utilized by reputable financing institutions for purposes of evaluating whether to provide project financing to construct and operate the proposed generation resource at the costs and bid prices submitted into the RFP; and

- The recommendations of the Oregon independent evaluator ("IE") should be adopted.

II. COMMENTS

A. The 2017 RFP Should Be Open to All Renewable Generation Types in Any Location that Can Deliver Power to PacifiCorp

NIPPC previously recommended in the Company's 2017 IRP that the Commission should not acknowledge an acquisition plan that relies only upon Wyoming wind, and PacifiCorp should acquire the best renewable resources, regardless of their location.[3] NIPPC directs the Commission to its recently submitted IRP comments, without repeating them in full here.

PacifiCorp failed to present persuasive arguments in the IRP for limited the RFP to Wyoming-based wind plants. It argued that it cannot produce a different type of resource in a different location and expect the same results, and that it already performed an Oregon Renewable RFP last year and it choose not to move forward with any acquisitions.[4] But PacifiCorp's concerns are insufficient to so severely limit an RFP designed to acquire over 1,200 MWs to only one type of resource in one location. If the all-in costs of renewable resources in other locations are less costly and risky than Wyoming wind plus associated transmission, then those acquisitions will be in the best interest of ratepayers. PacifiCorp may be correct that none of the bids into the 2016 Renewable RFP for Oregon-based resources would have beat the Wyoming Benchmark Resources and (potentially) other Wyoming wind bids, but we do not know what those

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[3] Re PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan, Docket No. LC 67, NIPPC IRP Comments at 6-11 (June 23, 2017).

[4] Re PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan, Docket No. LC 67, PacifiCorp IRP Comments at 35-36 (July 28, 2017).

bidders would propose in a new RFP in the market existing a year later, or what other options will be available today.

It appears that PacifiCorp believes that the restriction to Wyoming points of interconnection or points of delivery is necessitated by the 500-kV transmission line that is apparently part and parcel with the Benchmark Resources and apparently the RFP itself. Opening up the bidding to wind and solar resources in other locations may ensure that a resource can be acquired in today's market conditions even if, as Bates White discusses, PacifiCorp is ultimately unable to complete construction of the 500-kV transmission line as proposed.

Simply put, there is no harm in requiring PacifiCorp to prove through the RFP that there are no other better resources available than its Wyoming wind plants.

B. The Economics of PacifiCorp's Repowering of Its Own Wind Generation Resources Should Be Tested in the 2017 Renewable RFP

As explained by NIPPC in PacifiCorp's IRP, PacifiCorp should prove the cost effectiveness and reasonableness of its repowering proposal by including each resource proposed for repowering as a benchmark bid in this RFP.[5] NIPPC is not opposed to PacifiCorp moving forward with repowering, as long as the Company allows fair competition, which is a key component to demonstrate that the costs are reasonable.

PacifiCorp claims that its repowering is cost effective and refuses to test its repowering with market competition because it is not an "either/or" decision, and repowering does not preclude procurement of new, cost-effective wind enabled by new

5 NIPPC's complete arguments in favor of subjecting repowering to an RFP are not repeated here, but are included in the IRP. Re PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan, Docket No. LC 67, NIPPC IRP Comments at 10-13 (June 23, 2017).

transmission.[6] But PacifiCorp mischaracterized NIPPC's position. NIPPC is not opposed to PacifiCorp both repowering its own wind generation as well as acquiring new wind along with Gateway transmission. Instead, NIPPC's recommendation is simple: If repowering is truly an economic resource, then those economics should be subjected to and tested in a competitive RFP process. It may also be possible that, instead of repowering 900 MW of existing generation and acquiring 1,200 MW of new resources, acquisition of 2,000 MWs of new generation is the more economic and less risky decision to achieve the same increase in energy and renewable attributes.

C. The Terms of the RFP's Draft PPA Should Be Revised to Make It Less Biased

The 2017 Renewable RFP imposes more burdensome requirements on PPA bids than will exist for PacifiCorp's own Benchmark Resources or other utility-owned bids. Given the short period of time to review the RFP, it will be impossible to identify all potential concerns with the PPA terms and conditions; however, even slight changes in contract language can result in a significant barrier to fair treatment of PPA options. The Commission should require PacifiCorp to make the following revisions to the RFP Draft PPA to reduce the inherent bias in favor of PacifiCorp-owned generation.

Regardless of the cause, PPA bidders are subject to delay damages for each day the project misses its "Scheduled Commercial Operation Date",[7] and are subject to cancellation of the entire PPA if their facility does not achieve commercial operation by the "Guaranteed Commercial Operation Date".[8] Delay damages and cancellation are

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6 Re PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan, Docket No. LC 67, PacifiCorp IRP Comments at 24 (July 28, 2017).

7 Draft PPA, Section 2.4.

8 Id.

inherently reasonable, but only under certain circumstances. PacifiCorp's proposals should equally apply to PacifiCorp-owned resources to ensure comparable treatment. In addition, Wyoming wind projects will likely be unable to deliver power if PacifiCorp's proposed Gateway transmission project is not constructed in a timely manner. Neither ratepayers nor bidders that have otherwise fully performed their obligations should be subject to damages because PacifiCorp itself is unable to complete the Gateway transmission expansion on schedule. This can be accomplished by eliminating delay damages if the delay is because the expected transmission is not completed by the Schedule Commercial Operation Date or Guaranteed Commercial Operation Date, and PacifiCorp, not ratepayers, should be responsible for any increased costs that result in PacifiCorp needing to purchase more expensive replacement power due to its own failure to complete the expanded transmission line.

The Draft PPA imposes other unreasonable restrictions when an IPP developer does not fully install all aspects of the project as initially described in the PPA. For example, it is common in the industry to lose a turbine site or two during final micro-siting and environmental permitting processes that occur right up to commencement of construction. This is likely to occur for a successful utility-owned or IPP-owned bid, and the end result is construction of the best facility possible. Normally, a PPA would allow some flexibility to adjust the final precise nameplate capacity of the facility, and of course it would be difficult to imagine the Commission ever disallowing PacifiCorp's recovery of its wind facility due to a final change to the turbine number or layout.

However, under PacifiCorp's proposed PPA, if any turbines have not been fully completed at the time of final completion, there is no option for the PPA seller to cure the shortfall.[9] Even more egregious, the turbines cannot later be completed as part of the project, nor can the turbines be completed and the output sold to third parties. While damages may be appropriate for a significant delay or a significant reduction in nameplate capacity from that proposed in the initial bid, the developer should be able to cure the default, or (at a minimum) sell the generation to a third party that PacifiCorp will not buy.[10]

Another problem with the PPA is that PacifiCorp will not pay for any energy curtailed by the relevant transmission operator (which may be PacifiCorp) regardless of the reason for the curtailment (e.g., reliability, general curtailment, reduction, redispatch, Force Majeure, etc.).[11] This treatment of curtailments severely punishes the PPA bidder versus the utility-owned bid because only the PPA is limited to payment per energy delivered; the curtailment of production results in curtailment of payment to the IPP and must therefore be baked into the PPA bid price. In contrast, the utility-owned plant will recover all of its prudently incurred capital and operation costs in retail rates regardless of how much curtailment occurs or how much energy is delivered and can simply ignore curtailment in its RFP bid price. Therefore, this PPA provision could only be reasonable and fair if the RFP were limited to PPA bids. This requirement is particularly relevant because PacifiCorp has an aggressive target of 1,270 MW of new wind generation in an

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[9] Id.

[10] PacifiCorp has not been subject to this type of extreme remedy. For example, when PacifiCorp imprudently acquired the Rolling Hills facility, the Commission disallowed the project's costs in Oregon rates, but PacifiCorp was allowed to sell the generation to third parties. See Re PacifiCorp, dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202, Docket No. UE 200, Order No. 08-584 at 22-24 (Nov. 14, 2008).

[11] Draft PPA, Section 4.4.

area where the proposed additions to the transmission system may or may not fully relieve congestion and curtailments. The PPA should be revised to require payments to the seller for undelivered energy in the event of a PacifiCorp-ordered transmission curtailment to cure this deficiency and level the playing field.

The draft PPA requires that PPA bidders face expensive security requirements, project milestones, multiple types of liquidated damages, and other requirements, which PacifiCorp-owned resources cannot be fully subjected to. Again, these requirements can only be reasonable if they apply equally to both PPA and utility-owned resources. Therefore, PacifiCorp should be directed to modify the Benchmark Resource bid and all utility-ownership bids to include similar requirements and conditions.

For example, PPA bidders that fail to achieve the Guaranteed Availability must pay liquidated damages, will not be paid for energy not delivered, and must pay for the costs of replacement power. In an RFP with only PPA bids, these types of restrictions would be acceptable if they are commercially reasonable.[12] However, in this RFP that includes bids from PacifiCorp-owned plants, these PPA provisions should be revised to reduce the bias in favor of utility owned generation. The seller under a PPA should not be subject to liquidated damages (in addition to the cost of replacement power) for failure to meet the Guaranteed Availability, if the actual energy output of the plant exceeds the expected energy output in that year. In addition, to ensure comparable treatment, PacifiCorp should be required to annually file a report with its power cost rate cases demonstrating that it either met a comparable requirement at all of its Company-owned

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[12] NIPPC agrees with the IE that the right to terminate the PPA for failure to meet the Guaranteed Availability requirement is unreasonable and should be revised.

wind plants, or will reduce rates paid by its customers in the amount of liquidated damages it could impose on an IPP under the RFP's PPA.

Additionally, as with past RFPs, NIPPC remains concerned with the non-price scoring criteria in PacifiCorp's RFP. The non-price factors listed on pages 21 to 22 of the draft RFP amount to little more than point assignments for properly submitting a mature project proposal and completing the RFP application documents. These are a classic example of criteria that should exist to qualify as a bid that will be evaluated. Including these rather insignificant items as non-price scoring criteria provides PacifiCorp with the opportunity to arbitrarily make significant adverse scoring adjustments to PPA bids while giving the Benchmark a perfect score on these criteria. NIPPC recommends that the non-price scoring criteria be eliminated, changed as recommended by the IE, or at least significantly reduced in this scoring weight.

D. Bidders Should Not Be Required to Have Completed Interconnection System Impact Studies

PacifiCorp requires bidders to have provided a completed interconnection system impact study ("SIS") to be included on the short-list.[13] NIPPC recommends that bidders not be required to provide a completed SIS because this may be one of the most important ways in which PacifiCorp can bias the results of the RFP in favor of its Benchmark Resources. PacifiCorp decided sometime in 2016 that it would, or at least was likely to, propose an RFP for Wyoming wind and associated transmission, but did

[13] PacifiCorp's Utah RFP originally required a bidder to have an SIS to even bid into the RFP, and the revised draft RFP now has moved the SIS requirement to the short-list stage. However, both approaches have the same inherent flaw in that PacifiCorp used its informational advantage to impose an unreasonable restriction on its competitors.

not announce to the public its intentions until well into 2017. PacifiCorp's decision to keep this critical information to itself means that its own Benchmark Resources had a major advantage over its competitors because PacifiCorp's Benchmark Team had plenty of time to complete the necessary interconnection studies to support interconnection to a transmission line. Other potential bidders would have had no reason to request an interconnection to that new transmission line in time to complete the SIS and other studies by the time bids are due. Therefore, PacifiCorp is likely to have prevented potentially lower cost competitors from even participating in the RFP.

As NIPPC has repeatedly argued, it is a basic rule of fair solicitations that no party, particularly a utility or its affiliate, "should have an informational advantage in any part of the solicitation process. The RFP and all relevant information about it should be released to all potential bidders at the same time."[14] Thus, it is important to ensure that prospective bidders have all critical information about the RFP at the time the utility decides what it wants, which can occur years before the RFP. This is one reason why the Oregon process is designed so that an RFP is issued only after an IRP has been completed, and why the IRP should fully identify the specific resource needs and unique requirements. Given the unique timing circumstances of this case, NIPPC believes it is appropriate to issue the RFP before the IRP has been acknowledged, but that only heightens the need to ensure that PacifiCorp cannot use its informational advantages to harm its competitors and its captive customers.

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14 Allegheny Energy Supply Co., 108 FERC ¶ 61,082, P 23 (2004).

E. Bidders Should Not Be Barred from Bidding If They Are In or Have Threatened Litigation with PacifiCorp

It is inappropriate for PacifiCorp, as a dominant market participant that is regulated by the Commission to ensure that its actions are in the best interests of customers, to restrict the participation of bidders who have or have even threatened to litigate $100,000 or more in any type of controversy. In isolation, this restriction will harm customers by prohibiting otherwise lower cost and risk resources from even participating in the RFP.

Even more corrosive, this provision has far ranging impacts because it essentially provides warning to any of PacifiCorp's current and future business partners that, if they ever attempt to enforce their legal rights against PacifiCorp, then they will be prevented from bidding into its RFPs. PacifiCorp is an efficient and aggressive business entity, which often results in positive ratepayer savings. However, PacifiCorp should not be provided this new tool in their negotiations and dealing with independent power producers that will ensure that IPPs will need to choose between exercising their legal rights or being locked out of a key market.

If the Commission is inclined to approve this onerous provision, then PacifiCorp should be required to reveal which bidders will be barred (so that its actual impacts can be ascertained) and the $100,000 limitation should be increased to $125 million. One hundred thousand dollars is essentially nothing in this business. To illustrate the ridiculousness of PacifiCorp's proposal, imagine a developer that would be barred from bidding into the RFP because one of the Company's line trucks destroyed the developer's new Tesla car. NIPPC believes there should be no bar whatsoever for ongoing litigation because the goal of the RFP is to obtain the best deal for PacifiCorp's captive customers, not to protect PacifiCorp's shareholders from normal business risks and litigation. If any litigation bar applies, it should be at least more than $125 million because that is slightly more than the amount that a jury awarded against PacifiCorp to compensate a developer for PacifiCorp's theft of trade secrets associated with the Currant Creek gas plant.[15]

F. PacifiCorp's Benchmark Resources Should Be Subjected to a Due Diligence Review

For each resource that PacifiCorp may own that makes it on the short list, the Oregon IE should conduct a comprehensive due diligence review of the type utilized by reputable financing institutions to evaluating whether to provide project financing to construct and operate the proposed generation resource at the costs and bid prices submitted into the RFP. NIPPC has made a similar recommendation in the Commission's competitive bidding rulemaking and investigation; however, those rules will not be adopted prior to the issuance of this RFP.[16] There is no reason why the role of the current IE could not be expanded to ensure that this type of rigorous analysis, which is generally performed for IPP bids, should not occur now. PacifiCorp's acquisitions in this RFP may be the last major new resources for the next decade, which could essentially moot and make irrelevant the Commission's new competitive bidding rules, at least for PacifiCorp.

G. The Commission Should Direct PacifiCorp Not to Penalize IPP Bids Offering Shorter Term Commitments than PacifiCorp's 30-Year Rate-Base Bids

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15 USA Power, LLC v. PacifiCorp, 2016 UT 20 (Utah May 16, 2016).

16 NIPPC again will not repeat its previous arguments regarding a due diligence review, but refers to its comments in support of such an analysis in the competitive bidding rulemaking and investigation. Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources; Re Public Utility Commission of Oregon Investigation of Competitive Bidding Guidelines Related to Senate Bill 1547, Docket No. AR 600/UM 1776, NIPPC Comments at 12-13 (May 10, 2017).

PacifiCorp's RFP fails to demonstrate it will provide fair and unbiased treatment to bids of different term length. The Commission has confirmed that NIPPC's concern with proper treatment of term-normalization analysis is valid by ruling that the term-normalization issue should be addressed in permanent administrative rules developed in the ongoing AR 600 docket. Although those rules are not yet final, the existing RFP guidelines require that basic fairness and transparency should apply on this question, and the utilities' current approach has departed from the intent of the existing guidelines. Therefore, the Commission should require PacifiCorp to make its term-normalization analysis transparent in this RFP and should direct the Oregon IE to require PacifiCorp to conduct an analysis that focuses on the annuity-based analysis called for in the existing guidelines while not unreasonably penalizing shorter-term bids by IPPs through use of generic fill costs from the IRP.

1. The Term-Normalization Problem

The term-normalization issue is a problem inherent in a solicitation that attempts to equitably compare a longer-term obligation placed in rate base (typically 30-plus years) and the shorter-term PPA or other IPP structure (only 20 years in PacifiCorp's draft RFP). With all other factors being equal, the IPP option will be far less expensive to the ratepayer in the early years, and the utility-owned resource will be far more expensive in the early years due to front loading of rate-based costs and returns in normal rate-of-return ratemaking. To compare these different resources, there must be some form of term-normalization analysis to create comparable pricing scores. There has been no analysis or transparency of the term-normalization analysis in past RFPs, and the assumptions favoring longer-lived utility-owned resources are likely to have been a major contributing factor in the Oregon utilities' ability to "win" nearly all past RFPs with utility-owned bids.

In the ongoing AR 600 docket, the non-utility parties had to request a technical workshop on this topic to even understand how the utilities have implemented term-normalization analysis in past RFPs. The utilities explained[17] that they focus on the bid prices to develop the initial short list but that they use a "generic fill" for the costs of the shorter-lived resource after its term expires in the process of selecting the final short list from the initial short list. In other words, the IPP's actual bid price is substituted for a hypothetical assumed cost (the "generic fill") in the latter years simply because the bid has a shorter term than the longer-lived utility-owned bids. There is obviously a significant risk of intentional or unintentional errors in of the use of generic fill costs.

NIPPC is very concerned that the Oregon RFPs have been conducted to assume that the 30-plus-year bid for utility-owned projects is the norm, and errors have been introduced (through generic fill) to accommodate that type of bid. In AR 600, Staff suggested that this approach sends the wrong policy signal "because it is more likely that strategies which delay making long-term irreversible decisions, such as through shorter contracts or resource commitments, will provide greater value when resource technologies are changing quickly than when they are steady and known."[18]

These problems are compounded in the Oregon RFPs because, based on the utilities own account in the AR 600 workshop, the utility (which is an inherently

17 PacifiCorp actually provided no demonstration or example of how it has conducted term-normalization evaluation in its RFPs, and instead generally indicated its approach was consistent with Portland General Electric Company's presentation on the topic.

18 Order No. 17-173 at Appendix A at 14.

interested party) conducts the bulk of this analysis without meaningful oversight from the IE, and certainly without any meaningful participation from stakeholders or Commission Staff.

2. NIPPC's Proposed Solution for PacifiCorp's RFP

In this RFP, the Commission should ensure transparency on this issue by requiring complete disclosure as to the methods of conducting term-normalization analysis. This RFP presents the term-normalization issue because PacifiCorp proposes to limit bids for PPAs to a 20-year term (without providing any explanation for this limitation), but if a utility-ownership bid prevails it will be placed in rates for its depreciable life of at least 30 years.[19]

Fortunately, the IE retained for this RFP has previously prepared an excellent white paper on this issue that recommends use of an "annuity" analysis instead of the use of generic fill. NIPPC has attached the white paper prepared by Boston Pacific (Bates Whites' predecessor company) on the topic, which is also coincidentally available on PacifiCorp's website and thus familiar to PacifiCorp.[20]

As Boston Pacific persuasively explained (at p. 1):

> Our research indicates that, out of these five methods, the Equivalent Annual Annuity Method (the Annuity Method) should be among the methods required in an evaluation, if not the preferred method. The central appeal of the Annuity Method is that it essentially allows the bid to speak for itself, thereby minimizing the discretion of the bid evaluator. The other

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[19] In Order No. 13-347, the Commission approved a stipulation adopting PacifiCorp's proposal to use of a 30-year depreciable life for wind facilities. See UM 1647 PAC/300, Andrews/11-13, PAC/301, Andrews/1-2.

[20] http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/2012BLRFP/IE/RFP2012_BidEvalMethods_BP.pdf

methods add needless complexity and uncertainty to the bid evaluation process, and all give too much discretion to the bid evaluator.

NIPPC wholeheartedly agrees. Simply stated, an annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred, and the annuity analysis thus allows the bids to speak for themselves without any manipulation by the utility. It provides no advantage to any bid solely by virtue of its longer duration, as the use of generic fill is likely to do.

Although the Commission's existing Guidelines call for use of an annuity method,[21] the AR 600 workshop has demonstrated that the utilities are apparently conducting a method that is more analogous to the "Filler Method" described in the Boston Pacific white paper (at p. 5) to develop the final shortlist. According to Boston

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[21] Guideline 9(a) and 9(b) provide (emphasis added):

a. Selection of an initial shortlist of bids should be based on price and non-price factors and provide resource diversity (e.g., with respect to fuel type and resource duration). The utility should use the initial prices submitted by the bidders to determine each bid's price score. The price score should be calculated as the ratio of the bid's projected total cost per megawatt-hour to forward market prices *using real-levelized or annuity methods*. The non-price score should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan (e.g., dispatch flexibility, resource term, portfolio diversity, etc.) and conformance to the standard form contracts attached to the RFP.

b. Selection of the final shortlist of bids should be based, in part, on the results of modeling the effect of candidate resources on overall system costs *and risks*. The portfolio modeling and decision criteria used to select the final shortlist of bids must be consistent with the modeling and decision criteria used to develop the utility's acknowledged IRP Action Plan. The IE must have full access to the utility's production cost and *risk models*.

Pacific, under this filler method "the evaluator can significantly bias the" shorter term bids by assigning it filler costs after the end of its bid term (at p. 7).

In this RFP, PacifiCorp proposes use of the filler method to conduct a portfolio analysis.[22] In addition, PacifiCorp's draft RFP actually proposes to depart from a pure annuity-type analysis to develop the initial short list, instead including evaluation of subjective factors such as "terminal value benefits, as applicable" and use of differential revenue requirement analysis in production cost models.[23] It appears, therefore, that PacifiCorp may even be proposing to use generic fill costs for the 20-year PPA bids in development of the initial shortlist. That directly contradicts the methodology that the utilities represented they use at the AR 600 workshop. Another serious concern, properly called out by Bates White, is that PacifiCorp proposes to "force rank" the price scoring, which will only further move the bid rankings away from a pure comparison of the bids' pricing proposals.

NIPPC proposes that the Commission require that PacifiCorp implement the following term-normalization analysis in this RFP:

- No generic fill of bid prices or utility owned generation costs may be used to evaluate bids of unequal term lengths at any stage of the RFP.

- The price score should be calculated as the ratio of the bid's projected total cost per megawatt-hour to forward market prices using annuity methods, as follows, and consistent with the Boston Pacific white paper:

    - First, for each bid, the evaluator takes the present value of the total cost of the proposal to the utility's customers for the total term of the proposal;

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22 See PacifiCorp's Final Draft 2017R RFP at 3 (filed August 4, 2017) ("Final shortlist determined using economic analysis and production cost modeling to select the least cost/risk adjusted mix of bids in PacifiCorp's resource portfolio."); Draft RFP at 19-20.

23 Draft RFP at 20.

- Second, an annuity is calculated based on that present value. For purposes of this analysis, an annuity is the equal annual payment that yields the same present value as calculated in step one;

- Third, if the proposals are of different megawatt sizes then the evaluator could adjust the annuity by dividing the annuity by the contract capacity (Annuity/MW);

- Or PacifiCorp may use such other modifications to the annuity approach that Bates White deems appropriate and describes as the followed course of action in its final evaluation of the RFP.

This approach is consistent with the existing Guideline 9, which already requires use of an annuity method to develop the initial short list. Additionally, based on representations at the AR 600 workshop, the purpose behind using an IRP portfolio analysis in the Commission's RFP guideline 9(b) – to consider all of the "overall system costs *and risks*" in a manner "consistent with the modeling and decision criteria used to develop the utility's acknowledged IRP Action Plan" – is not being met in Oregon RFPs. In the AR 600 workshop, Portland General Electric Company represented that it does not use risk-based modeling in this analysis, and PacifiCorp generally concurred with that representation for its RFPs. Although PacifiCorp asserts in the draft RFP here that it will conduct some amount of risk modeling to develop the final short list, it is not possible to conduct such analysis "consistent with the modeling and decision criteria used to develop the utility's acknowledged IRP Action Plan," as Guideline 9(b) requires, because PacifiCorp's RFP is not based on any acknowledged IRP Action Plan. Additionally, given the fact that the RFP is limited to wind resource bids, the risk between different resource types under different carbon price and regulatory assumptions is much less relevant than in an all-source RFP.

In this case, the downsides of portfolio modeling (use of unspecified generic fill) far outweigh any possible benefits, and the Commission should prohibit use of generic fill and other discretionary evaluation techniques in favor of an annuity analysis.

H. The Oregon IE's Recommendations Should Be Accepted

Bates White, formerly Boston Pacific, conducted an expedited reviewed the 2017 Renewable RFP and has proposed a number of improvements to protect ratepayers to better ensure a fairer and more transparent RFP.[24] Bates While expressed concern regarding the short time it had to review the RFP,[25] and NIPPC hopes that it will make additional recommendations after it reviews the comments in this proceeding.[26]

The IE recommended the following changes to improve fairness and transparency: 1) not limiting the RFP to new projects, but allowing repowered and uncommitted resources; 2) more clearly defining credit requirements and accounting for step-in rights; 3) more clarity regarding other resources that would claim a share of the transmission capacity created by the Gateway transmission expansion; 4) clarification regarding the Success Fee; and 5) adjusting penalties in the PPA for failing to meet a project's Guaranteed Availability. NIPPC supports each of these recommendations

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[24] Boston Pacific's and past recommendations should be compared with Accion, which was the IE in PGE's last two RFPs. Accion's primary role was to defend PGE's actions, while Boston Pacific, in an extremely brief period of time, has identified important and significant concerns with PacifiCorp's 2017 RFP.

[25] Boston Pacific Report at 1-2 (Boston Pacific received the RFP on Friday 21, 2017 and was required to submit comments on Wednesday July 26, 2017).

[26] There are some of the stakeholders' concerns in which it will not be appropriate for the IE to address. For example, the IE's purpose to evaluate the process to ensure that it is fair, but it is not to opine on what PacifiCorp's actual resource need is or to address whether the RFP should or should not include non-Wyoming wind. See Boston Pacific Report at 2-4 (identifying a risk that the RFP will not be aligned with an acknowledged IRP, and taking as given that PacifiCorp's proposed resources are acknowledged).

because they identify areas in which PacifiCorp is biasing the results against PPAs (onerous provisions regarding credit and fees), or weeding out potential competition (e.g., barring repowered and existing resources).

The IE recommended the following changes to address uncertainty and assignment of risk: 1) PacifiCorp's resources should be held to their cost and performance assumptions; 2) bidders should not bear the risk of PacifiCorp failing to build Gateway transmission or constructing it slowly so that commercial operation dates are missed; 3) improvements to the price scoring; 4) the impact of cost overruns in the Gateway transmission should be assessed; and 5) change orders should not be paid for by ratepayers. The first and fifth of these recommendations are intended to address the inherent problem of attempting to compare IPP bids with known contract prices and terms to a cost-plus utility-ownership bid in an RFP. Without any mechanism to ensure PacifiCorp will be held to its bid costs and performance criteria, PacifiCorp will be able to use ratepayers as an insurance policy in case the utility's cost and performance assumptions regarding both transmission and generation assets prove to be overly optimistic. Absent these types of guarantees and protections (which come with all PPA bids) or appropriate cost adders on the utility resources to account for these unique risks of utility ownership, there is no way achieve a true level playing field between utility owned and non-owned resources.

III. CONCLUSION

NIPPC respectfully requests that the Commission approve PacifiCorp's 2017 Renewable RFP, with above changes, so that the Company can pursue this time limited opportunity to acquire new renewable energy before the costs of new generation significantly increase. The risks to ratepayers of taking no action now are too great not to allow an RFP to move forward.

Dated this 18th day of August 2017.

Respectfully submitted,

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Of Attorneys for Northwest and Intermountain Power Producers Coalition

Attachment A

Bid Evaluation Methods in Competitive Solicitations:
A White Paper on Techniques Used to
Evaluate Power Supply Proposals
with Unequal Lives

Bid Evaluation Methods in Competitive Solicitations:
A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives

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I. INTRODUCTION AND SUMMARY

For at least twenty years, utilities across the country have been issuing competitive solicitations to invite power sales proposals from affiliates and non-affiliates.[1] As the number of non-affiliated suppliers has increased, state and federal regulators have encouraged utilities to use such solicitations for an increasing portion of their capacity, energy and ancillary services needs. First and foremost, the goal of competitive solicitations is to evaluate a full range of resources in the wholesale marketplace to obtain the best possible deal for electric utility customers in terms of price, risk, reliability, and environmental performance.

In 2004, Boston Pacific prepared "Getting the Best Deal for Electric Utility Customers: *A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations*."[2] The Guidebook discussed (a) the importance of and role for competitive solicitations, (b) ways to ensure a credible process, (c) choosing solicitation formats and product types, and (d) how to conduct a fair and accurate bid evaluation. The purpose of this White Paper is to expand the discussion of one narrow, but important aspect of the bid evaluation process. Specifically, how should evaluators compare proposals of unequal lives? For example, how should evaluators accurately compare a proposal that has a 5-year term to another proposal that has a 10-year term?

This White Paper describes and quantifies five evaluation techniques for comparing proposals of unequal lives: (a) the Equivalent Annual Annuity Method, (b) Real Levelized Revenue Requirement Method, (c) Filler Method, (d) Deferred Replacement Cost Method, and (e) Option Method.[3] Our research indicates that, out of these five methods, the Equivalent Annual Annuity Method (the Annuity Method) should be among the methods required in an evaluation, if not the preferred method. The central appeal of the Annuity Method is that it essentially allows the bid to speak for itself, thereby minimizing the discretion of the bid evaluator. The other methods add needless complexity and uncertainty to the bid evaluation process, and all give too much discretion to the bid evaluator.

II. EQUIVALENT ANNUAL COST METHOD (ANNUITY METHOD)

According to standard financial theory, the Equivalent Annual Cost Method, or simply the Annuity Method, should be used to compare alternatives that have unequal lives.[4] If a business must choose between Alternative A, which lasts 10 years, and

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[1] One of the first such solicitations was used by Central Maine Power in 1984. More recent examples include competitive solicitations issued by utilities in Arizona, Colorado, Maryland, New Jersey, and Florida.

[2] Available at www.bostonpacific.com

[3] All assumptions and exhibits used in this White Paper are purely hypothetical and are only used to clarify the evaluation techniques.

[4] *See* Ross, Stephen A., Westerfield, Randolph W., and Jaffe, Jeffrey. Corporate Finance Fourth Edition Irwin. (1996) p. 185.

Alternative B, which lasts 20 years, the business should compare the annuity costs of the two alternatives. An annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred. The annuity of Alternative A would be calculated over ten years and that of Alternative B would be calculated over twenty years. The alternative with the lower annuity is the better choice.

Central to all methods of comparing alternatives of unequal lives is the assumption about what happens when the shorter-term choice expires. In the above example, what happens when Alternative A, the 10-year offer ends its initial term? With the Annuity Method, it is implicitly presumed that the initial offer is repeated. This means that the gap between the 10 and 20-year choices, in effect, would be filled in by assuming that the 10-year alternative would be offered again at the same price and non-price terms. The primary benefit of this technique is that it allows bids to speak for themselves and takes discretion out of the evaluator's hands.

There are three main steps involved in applying the Annuity Method to bid evaluation. First, for each bid, the evaluator takes the present value of the total cost of the proposal. Second, an annuity is calculated based on that present value. Again, an annuity is the equal annual payment that yields the same present value as calculated in step one. Third, if the proposals are of different megawatt sizes then the evaluator should adjust the annuity by dividing the annuity by the contract capacity (Annuity/MW). The evaluator can then compare a 10-year annuity to a 20-year annuity and choose the alternative with the lower annuity cost. Exhibit One provides a hypothetical quantitative example of the Annuity Method.

In Exhibit One, Proposal A, a 10-year offer, is compared to Proposal B, a 20-year offer, with the following contract assumptions for a combined cycle natural gas-fired generating facility:

TABLE ONE:
CONTRACT ASSUMPTIONS FOR EXHIBIT ONE

	Proposal A	**Proposal B**
Term Length	10 years	20 years
Heat Rate	6,500 Btu/kWh	7,200 Btu/kWh
Inflation	2.5%	2.5%
Capacity	500 MW	450 MW
After-Tax Cost of Capital	9.50%	9.50%
Fixed Price Fuel Contract	$3.50/MMBtu	$3.50/MMBtu
Capacity Factor	70%	70%
Variable O&M	$1.50/MWh	$1.75/MWh
Capacity Payment	$95/kW-yr	$75/kW-yr

The results of our analysis are shown in Table Two below and illustrate the need for a method to compare the proposals on an apples-to-apples basis. Simply comparing the present value for two proposals could convey misleading results. For example, only comparing the present values would lead one to choose Proposal A ($794.9 million) over Proposal B ($1 billion). Generally, the shorter-term contract would offer a lower present value because there are fewer years of costs; therefore the appropriate next step is to compare the annuities of the proposals. In this example, Proposal A's annuity is $126.6 million and Proposal B's annuity is $114.5 million. This would lead the evaluator to choose Proposal B, as it has the lower cost annuity. Unfortunately, this comparison is still inaccurate.

Comparing the annuities is insufficient because Proposal A is offering 50 more megawatts than Proposal B. The proper method to compare proposals with unequal lives and different capacity sizes is to compare them on an annuity per MW basis. In this illustration, Proposal A wins over Proposal B because its annuity per MW is cheaper ($253,200/MW compared to $254,400/MW).

TABLE TWO:
RESULTS OF EXHIBIT ONE

Results	**PV ($000)**	**Annuity ($000)**	**Annuity/MW ($000/MW)**
Proposal A	$794,899	$126,601	$253.20/MW
Proposal B	$1,008,845	$114,480	$254.40/MW

It should be noted that this example only tested one capacity factor. We recommend that the evaluator test a range of capacity factors and generate a screening curve to analyze how the contracts perform at different levels.[5]

As with any method, the Annuity Method has its possible faults. As previously mentioned, under the Annuity Method, it is presumed that beyond its initial term an offer is extended under the same terms and conditions as its initial term. If a solicitation takes place under severely depressed market conditions, but with the expectation that these conditions will improve in the long term, then the evaluation should request proposals of sufficient length to bridge the gap between the depressed and improved market conditions. Moreover, what if in Exhibit One, Proposal B (450 MW) was actually the lower-cost proposal? The Annuity Method does not have an easy answer regarding how the utility should solicit the remaining 50 MW. Presumably, the practical response is for the soliciting utility to conduct negotiations with Proposal A on those 50 MW.

[5] Using various capacity factors to generate a screening curve is vital to determining which proposal is the best alternative. However, in determining which supplier is the cheaper alternative, the evaluator must use the same capacity factor for each proposal.

III. REAL LEVELIZED REVENUE REQUIREMENTS METHOD

The Real Levelized Revenue Requirements Method is another method of comparing proposals of unequal lives. It is derived from quantitative methods used to evaluate the revenue needed to support the capital costs of building a new generation facility. That is, the cost of constructing and financing spread over the life of a new generation facility, which generally includes the return *of* investment (book depreciation), the return on investment (both equity and debt), and taxes.

There are five main steps involved in applying this approach. First, for each bid, the evaluator calculates the present value of the annual total cost using a nominal discount rate. Second, a real annuity is calculated based on the present value calculated in step one. That is, using a "real" discount rate (i.e., discount rate without inflation), the evaluator calculates the annuity payment (equal annual payment) that yields the same present value as calculated in step one. Third, inflation is factored back in by escalating the real annuity each year by the compounded rate of inflation. The present value of this "inflation-adjusted annuity" *using the nominal discount rate* will equal the present value of the proposal as calculated in step one. Fourth, the evaluator levelizes the MW in the same manner as the bid prices. Fifth, levelized annuity cost is divided by the levelized MW. Thus, to compare proposals of different contract lives and resource sizes, the evaluator would compare the levelized annuity per MW ($/MW) of one proposal to another.

Exhibit Two provides a hypothetical, quantitative example of the Real Levelized Revenue Requirement method. It compares Proposal A, a 10-year 750 MW offer to Proposal B, a 5-year 650 MW offer. The example assumes that the evaluator calculates the annual nominal cost of the capacity and energy prices, etc., listed in each bid ("Total Bid Price Costs" column). For Proposal A, it is assumed the bid prices result in a nominal cost of $95 million in year 1 and decrease by $6 million per year thereafter. For Proposal B, it is assumed the bid prices result in a nominal cost of $85.2 million in year 1 and decrease by $8 million per year thereafter. Table Three, below, describes some of the other assumptions used in the exhibit.[6]

TABLE THREE:
ASSUMPTIONS FOR EXHIBIT TWO

	Proposal A	**Proposal B**
Term Length	10 years	5 years
Discount Rate	10.0%	10.0%
Inflation Rate	2.0%	2.0%
Capacity	750 MW	650 MW
Real Discount Rate	7.84%	7.84%
Year 1 Nominal Costs	$95,000,000	$85,200,000

[6] The real discount rate is calculated by the following formula: real discount rate = [(1+discount rate)/(1+inflation rate)]-1. *See* Brealey, Richard A. and Myers, Stewart C. Principles of Corporate Finance Fourth Edition McGraw-Hill, Inc. (1991) p. 559.

Similar to the Annuity Method, a simple comparison of the present value of the annual nominal costs would produce misleading results. As shown in Exhibit Two, Proposal A has a present value of $446.4 million, while Proposal B results in a present value of $268 million. However, Proposal A has added value that is unaccounted for in this comparison (e.g., providing service in years 6 through 10 and 100 MW more of capacity). To account for these differences, the evaluator levelizes the costs and megawatts associated with each proposal. In year 1, using the real discount rate of 7.84%, the evaluator calculates the real annuity and the levelized megawatts ($66.1 million and 682 MW for Proposal A versus $66.9 million and 615 MW for Proposal B). Next, the evaluator adjusts the real annuity for inflation ("Inflation Adjusted Real Annuity" column). To ensure an apples-to-apples comparison, the same adjustment must be made to the megawatts ("Inflation Adj. Real Annuity MW"). Finally and most importantly, the evaluator divides the Inflation Adjusted Real Annuity by the Inflation Adjusted Real Annuity MW to get a $/MW comparison. Note that this $/MW is the same value in each year. The Table entitled "Proposal A Truncated at 5 Years" demonstrates that even if the evaluator truncates the 10 year bid at 5 years to compare it to Proposal B, the $/MW will remain the same at $96,860/MW.[7]

The concern with the Real Levelized Revenue Requirement Method is that (a) adds unnecessary complexity to the evaluation, which increases the possibility of error and (b) does not properly take into account inflation risk. One way that the evaluators might err is by failing to levelize the megawatts. Failing to adjust the megawatts across all years of the proposal will lead to inaccurate results.[8] In addition, similar to the Annuity Method, this method does not offer an easy solution to fulfilling the remaining megawatts if the lower capacity proposal is the winner. Again, the soliciting utility may choose to negotiate with other suppliers for the remaining balance of the megawatts.

IV. FILLER METHOD

A third technique used is called the Filler Method. In this method, the evaluator will "fill in" behind the shorter term contract with its estimate of future capacity and energy prices until the life of the shorter-term proposal matches the length of the longer-term proposal. To compare Proposal A, a 10-year Purchase Power Agreement (PPA), to Proposal B, a 5-year PPA, the evaluator would assert what capacity and energy prices the supplier in Proposal B would offer in years 6 through 10.

There are three main steps in applying the Filler Method. First, the evaluator determines which bid has the longest term. Second, for each of the shorter-term proposals, the evaluator must estimate the costs that might be incurred when "filling in"

[7] If performed correctly, the Real Levelized Revenue Requirement Method should produce results similar to the Annuity Method.
[8] It should be noted that if proposals offer staggering capacities throughout its term, (e.g., an increase in year 6 from 750 MW to 800 MW) then this method should accurately account for that increase.

with power purchases each year between the shorter-term and longer-term proposal. As already noted, typically this estimate is made as if the supplier was asked to bid a second time for extra years. Third, the evaluator must compare the present values of bids, which now include the filled-in costs.

This method gives the evaluating entity a significant amount of discretion, which can and often does raise concerns of affiliate abuse or inaccurate comparisons. In short, as compared to the Annuity Method, this Filler Method does not allow the bids to speak for themselves.

Moreover, when assessing future power supply offers, the evaluator must consider (a) improvements to fuel efficiency, (b) development of new technology, and (c) changes in capital costs. For example, ten years ago, a heat rate efficiency of a natural gas-fired generator was in the 8,500-12,000 Btu/kWh range while today new gas-fired generators have heat rates in the 6,000-7,000 Btu/kWh range. Yet, when evaluators utilize the Filler Method, rarely are these technological improvements taken into account, due in part to the difficulty of quantifying and predicting such improvements.

One common assumption made by evaluators during the "filler" years, is the escalation of the capacity price. For example, if the bidder in Proposal B offered a fixed capacity price of $96/kW-yr for each year of the 5-year bid, then the evaluator often assumes the bidder would want to compensate for inflation by increasing its capacity price; that is, the capacity price in year 6 would increase to $108.62/kW-yr ($96/kW-yr times the rate of inflation (2%) compounded over 5 years) and escalate each year by the rate of inflation until year 10. The evaluator is assuming that the bidder (a) did not already factor the rate of inflation into its bid, and (b) would not lower its capacity payment in future years. There are a number of reasons why a lower or equal capacity price could be offered, such as the ability of the supplier to refinance its debt or an excess of supply driving down the return of and on capital. Exhibit Three provides a hypothetical quantitative example of the Filler Method.

Exhibit Three demonstrates how an evaluator would generally extend the term of a shorter-term offer (Proposal A) to match a proposal that has a longer term. In this instance Proposal A has the following contract assumptions:

TABLE FOUR:
ASSUMPTIONS TO EXHIBIT THREE

	Proposal A
Term Length	5 years
Heat Rate	6,500 Btu/kWh
Inflation	2.5%
Capacity	500 MW
After-Tax Cost of Capital	9.50%
Fixed Price Fuel Contract	$5.00/MMBtu
Capacity Factor	70%
Fixed O&M	$4.50/kW-yr
Variable O&M	$1.50/MWh
Capacity Payment	$96/kW-yr

For the first five years of the contract the evaluator takes the bid as is. However after the first five years, the evaluator assumes that the capacity payment increases by 13% in year 6, from $96/kW-yr to $108.62/kW-yr. This is because the evaluator assumes that, in year 6, the effects of inflation (2.5%) compounded over five years have increased the capacity payment from $96/kW-yr to $108.62/kW-yr. Similarly, the evaluator also assumes that fixed operations and maintenance (O&M) costs increase from $4.50/kW-yr in year 5 to $5.09 kW-yr in year 6, but remains fixed for years 7 through 10. Further, with regard to variable costs, the evaluator assumed that the heat rate, variable O&M, and the fixed-price fuel contract remain constant for years 1 through 10.

The primary concern here is that by filling in costs for years 6 through 10 to match the term of a 10-year proposal, the evaluator can significantly bias the 5-year proposal. The filler method gives the evaluator too much discretion, creates uncertainty in the bid process, and thus could undermine the competitive market.

V. DEFERRED REPLACEMENT COST METHOD

A fourth method utilized is the Deferred Replacement Cost Method. This method has often been used to determine if it would be cheaper to self-build generation or to enter into a long-term contract. The presumption is that, for example, if a utility determines that it needs additional capacity and energy, it can either build a combined cycle power plant today with a useful life of 30 years or enter into a 10-year PPA today and build a new facility in year 11.

There are four steps involved in applying the Deferred Replacement Cost Method. First, the evaluator would calculate the present value of the revenue requirement needed to build and finance a new power plant today with an assumed useful life of 30 years. Second, for each bid, the evaluator would calculate the present value of the bid prices (capacity, energy, etc.) for each 10-year offer. Third, a revenue requirement model would calculate the revenue needed to cover the costs of building and financing a new plant in year 11 with a useful life of 30 years ("Year 11 New Plant"). Fourth, the evaluator must estimate the terminal value of the Year 11 New Plant, or the price of selling the Year 11 New Plant after having operated it for twenty years. Fifth, for each bid, the evaluator must compare (a) the present value of the 10-year proposal plus the present value of the revenue requirement of the Year 11 New Plant minus the present value of the terminal value to (b) the present value of building a new plant today.

This method is essentially a variation on the Filler Method and again, it gives the evaluator too much discretion in comparing proposals. The evaluator can err in estimating (a) the decrease or increase in cost of building a new facility in year 11, (b) the increase in fuel efficiency, and (c) the termination payment.

VI. OPTION METHOD

The Option Method is a market-based solution to the unequal lives concern, rather than an analytical method.

A call option is a contract giving the owner the right, but not the obligation to buy an asset at a fixed price on or before a given date. A properly structured RFP could embed a call option into the PPA, which would require the bidder to list the payment (option payment) needed to (a) extend the PPA to a specified date under the same terms and conditions, (b) extend the PPA to a specified date under different terms and conditions, or (c) acquire the generation facility.

For example, assume the RFP is soliciting capacity and energy products for a 10-year term, but wants to compare those 10-year offers to a 20-year offer. In this case, suppliers who are submitting proposals for 10 years should be asked to offer an option payment to extend the contract for another 10 years at the same capacity and energy prices. When evaluating the 10 and 20-year offers, all bids would then have the same term length (i.e., 20 years).

Embedding option payments into the RFP minimizes the evaluator's discretion, but is not without drawbacks. For example, not all suppliers might be willing to enter into the option agreement, especially if they own older facilities that have a useful life of less than 20 years.

VII. CONCLUSIONS

Getting the best deal for utility consumers in terms of price, risk, reliability, and environmental performance should always be the goal of competitive solicitations. To that end, a fair and accurate evaluation of proposals is essential.

Based upon our investigation into the five evaluation techniques (Equivalent Annual Annuity Method, Real Levelized Revenue Requirement Method, Filler Method, Deferred Replacement Cost Method, and Option Method), the Filler Method and the Deferred Replacement Cost Method give too much discretion to the evaluator while the Real Levelized Revenue Requirement Method requires unnecessary complexity. The Option Method is a potential solution to the problem, but raises additional concerns. Thus, it is recommended that at a minimum, the Annuity Method should be required as one way to compare proposals of unequal lives. Most importantly, this method allows the bids to speak for themselves because it minimizes the evaluators' discretion in making assumptions about costs once the initial term expires.

EXHIBIT ONE
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
20-YEAR PROPOSAL (PROPOSAL B) USING THE EQUIVALENT ANNUAL COST METHOD (ANNUITY METHOD)

PROPOSAL A

Assumptions

Heat Rate	6,500 Btu/kWh	After-tax CC	9.50%	Term Length	10 yrs		
Inflation	2.5%	Fuel Costs	$ 3.50 /MMBtu	Variable O&M	$ 1.50 /MWh	Annuity/MW	253.20
Capacity	500 MW	Capacity Factor	70%	Capacity Payment	$ 95 /kW-yr	($000/MW)	

Year	Equip Life	Capacity Payment ($/ kw-yr)	Capacity Costs ($000)	Energy Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)	Cumulative NPV ($000)	Annuity ($000)
2003		-	$ -	$ -	$ -	$ -	$ -	$ -	
2004	1	95.00	$ 47,500	$ 69,752	$ 4,599	$ 121,851	$ 111,279	$ 111,279	$ 126,601
2005	2	97.38	$ 48,688	$ 69,752	$ 4,599	$ 123,038	$ 102,615	$ 213,894	$ 126,601
2006	3	99.81	$ 49,905	$ 69,752	$ 4,599	$ 124,255	$ 94,639	$ 308,533	$ 126,601
2007	4	102.30	$ 51,152	$ 69,752	$ 4,599	$ 125,503	$ 87,297	$ 395,830	$ 126,601
2008	5	104.86	$ 52,431	$ 69,752	$ 4,599	$ 126,782	$ 80,535	$ 476,365	$ 126,601
2009	6	107.48	$ 53,742	$ 69,752	$ 4,599	$ 128,092	$ 74,309	$ 550,674	$ 126,601
2010	7	110.17	$ 55,085	$ 69,752	$ 4,599	$ 129,436	$ 68,573	$ 619,247	$ 126,601
2011	8	112.93	$ 56,463	$ 69,752	$ 4,599	$ 130,813	$ 63,290	$ 682,538	$ 126,601
2012	9	115.75	$ 57,874	$ 69,752	$ 4,599	$ 132,225	$ 58,423	$ 740,961	$ 126,601
2013	10	118.64	$ 59,321	$ 69,752	$ 4,599	$ 133,671	$ 53,938	$ 794,899	$ 126,601
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	14	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	15	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	16	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	17	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	18	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	19	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	20	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	21	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total			**$ 532,161**	**$ 697,515**	**$ 45,990**	**$ 1,275,666**	**$ 794,899**		

PROPOSAL B

Assumptions

Heat Rate	7,200 Btu/kWh	After-tax CC	9.50%	Term Length	20 yrs		
Inflation	2.5%	Fuel Costs	$ 3.50 /MMBtu	Variable O&M	$ 1.75 /MWh	Annuity/MW	254.40
Capacity	450 MW	Capacity Factor	70%	Capacity Payment	$ 75 /kW-yr	($000/MW)	

Year	Equip Life	Capacity Payment ($/ kw-yr)	Capacity Costs ($000)	Energy Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)	Cumulative NPV ($000)	Annuity ($000)
2003		-	$ -	$ -	$ -	$ -	$ -	$ -	
2004	1	75.00	$ 33,750	$ 69,537	$ 4,829	$ 108,116	$ 98,736	$ 98,736	$ 114,480
2005	2	76.88	$ 34,594	$ 69,537	$ 4,829	$ 108,960	$ 90,873	$ 189,609	$ 114,480
2006	3	78.80	$ 35,459	$ 69,537	$ 4,829	$ 109,824	$ 83,648	$ 273,258	$ 114,480
2007	4	80.77	$ 36,345	$ 69,537	$ 4,829	$ 110,711	$ 77,008	$ 350,265	$ 114,480
2008	5	82.79	$ 37,254	$ 69,537	$ 4,829	$ 111,620	$ 70,904	$ 421,169	$ 114,480
2009	6	84.86	$ 38,185	$ 69,537	$ 4,829	$ 112,551	$ 65,293	$ 486,462	$ 114,480
2010	7	86.98	$ 39,140	$ 69,537	$ 4,829	$ 113,505	$ 60,134	$ 546,595	$ 114,480
2011	8	89.15	$ 40,118	$ 69,537	$ 4,829	$ 114,484	$ 55,390	$ 601,985	$ 114,480
2012	9	91.38	$ 41,121	$ 69,537	$ 4,829	$ 115,487	$ 51,028	$ 653,013	$ 114,480
2013	10	93.66	$ 42,149	$ 69,537	$ 4,829	$ 116,515	$ 47,015	$ 700,029	$ 114,480
2014	11	96.01	$ 43,203	$ 69,537	$ 4,829	$ 117,569	$ 43,325	$ 743,353	$ 114,480
2015	12	98.41	$ 44,283	$ 69,537	$ 4,829	$ 118,649	$ 39,929	$ 783,283	$ 114,480
2016	13	100.87	$ 45,390	$ 69,537	$ 4,829	$ 119,756	$ 36,806	$ 820,088	$ 114,480
2017	14	103.39	$ 46,525	$ 69,537	$ 4,829	$ 120,891	$ 33,931	$ 854,019	$ 114,480
2018	15	105.97	$ 47,688	$ 69,537	$ 4,829	$ 122,054	$ 31,285	$ 885,304	$ 114,480
2019	16	108.62	$ 48,880	$ 69,537	$ 4,829	$ 123,246	$ 28,850	$ 914,154	$ 114,480
2020	17	111.34	$ 50,102	$ 69,537	$ 4,829	$ 124,468	$ 26,608	$ 940,763	$ 114,480
2021	18	114.12	$ 51,355	$ 69,537	$ 4,829	$ 125,720	$ 24,544	$ 965,307	$ 114,480
2022	19	116.97	$ 52,638	$ 69,537	$ 4,829	$ 127,004	$ 22,644	$ 987,951	$ 114,480
2023	20	119.90	$ 53,954	$ 69,537	$ 4,829	$ 128,320	$ 20,894	$ 1,008,845	$ 114,480
2024	21	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total			**$ 862,132**	**$ 1,390,738**	**$ 96,579**	**$ 2,349,449**	**$ 1,008,845**		

Results	PV ($000)	Annuity ($000)	Annuity/MW ($000/MW)	
Proposal A	$ 794,899	$ 126,601	$ 253.20 /MW	(Winner)
Proposal B	$ 1,008,845	$ 114,480	$ 254.40 /MW	

EXHIBIT TWO
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
5-YEAR PROPOSAL (PROPOSAL B)
USING THE REAL LEVELIZED REVENUE REQUIREMENT APPROACH

Assumptions

Discount Rate	10.00%	Inflation	2.00%	Proposal A	750 MW
Real Rate	7.84%			Proposal B	650 MW

PROPOSAL A

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity ($000) (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj. Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW ($000/MW)
1	$ 95,000	$ 66,055	102%	$ 67,376	750	682	696	96.86
2	$ 89,000	$ 66,055	104%	$ 68,723	750	682	709	96.86
3	$ 83,000	$ 66,055	106%	$ 70,098	750	682	724	96.86
4	$ 77,000	$ 66,055	108%	$ 71,500	750	682	738	96.86
5	$ 71,000	$ 66,055	110%	$ 72,930	750	682	753	96.86
6	$ 65,000	$ 66,055	113%	$ 74,388	750	682	768	96.86
7	$ 59,000	$ 66,055	115%	$ 75,876	750	682	783	96.86
8	$ 53,000	$ 66,055	117%	$ 77,394	750	682	799	96.86
9	$ 47,000	$ 66,055	120%	$ 78,942	750	682	815	96.86
10	$ 41,000	$ 66,055	122%	$ 80,520	750	682	831	96.86
PV	$ 446,386	$ 446,386		$ 446,386	4,608	4,608	4,608	96.86

PROPOSAL A - TRUNCATED AT 5 YEARS

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj, Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW ($000/MW)
1	$ 95,000	$ 66,055	102%	$ 67,376	750	682	696	96.86
2	$ 89,000	$ 66,055	104%	$ 68,723	750	682	709	96.86
3	$ 83,000	$ 66,055	106%	$ 70,098	750	682	724	96.86
4	$ 77,000	$ 66,055	108%	$ 71,500	750	682	738	96.86
5	$ 71,000	$ 66,055	110%	$ 72,930	750	682	753	96.86
6	$ 65,000	$ 66,055	113%					
7	$ 59,000	$ 66,055	115%					
8	$ 53,000	$ 66,055	117%					
9	$ 47,000	$ 66,055	120%					
10	$ 41,000	$ 66,055	122%					
PV	$ 446,386	$ 446,386		$ 264,831			2,734	96.86

EXHIBIT TWO
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
5-YEAR PROPOSAL (PROPOSAL B)
USING THE REAL LEVELIZED REVENUE REQUIREMENT APPROACH

PROPOSAL B

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity ($000) (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj. Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW
1	$ 85,200	$ 66,865	102%	$ 68,202	650	615	627	108.80
2	$ 77,200	$ 66,865	104%	$ 69,567	650	615	639	108.80
3	$ 69,200	$ 66,865	106%	$ 70,958	650	615	652	108.80
4	$ 61,200	$ 66,865	108%	$ 72,377	650	615	665	108.80
5	$ 53,200	$ 66,865	110%	$ 73,825	650	615	679	108.80
6								
7								
8								
9								
10								
PV	$ 268,081	$ 268,081		$ 268,081	2,464	2,464	2,464	108.80

Results ($000/MW):

Proposal A	$ 96.86 /MW	(Winner)
Proposal B	$ 108.80 /MW	

EXHIBIT THREE
HOW A 5-YEAR PROPOSAL IS EXTENDED TO A 10-YEAR PROPOSAL USING THE FILLER METHOD

5-YEAR PROPOSAL

Assumptions

Capacity	500 MW	After-tax CC	9.5%	Fixed O&M	$ 4.50 /kW-yr
Capacity Factor	70%	Inflation	2.5%	Variable O&M	$ 1.50 /MWh
Term Length	5 yrs	Capacity Payment	$ 96.00 /kW-yr	Fuel Costs	$ 5.00 /MMBtu
Heat Rate	6,500 Btu/kWh				

Year	Proposal Year	Capacity Payment ($/ kW-yr)	Capacity Costs ($000)	Energy Costs ($000)	Fixed O&M Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)
2003		-	-	-	-	-	-	-
2004	1	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 141,090
2005	2	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 128,850
2006	3	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 117,671
2007	4	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 107,462
2008	5	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 98,139
2009	6	-	$ -	$ -	$ -	$ -	$ -	$ -
2010	7	-	$ -	$ -	$ -	$ -	$ -	$ -
2011	8	-	$ -	$ -	$ -	$ -	$ -	$ -
2012	9	-	$ -	$ -	$ -	$ -	$ -	$ -
2013	10	-	$ -	$ -	$ -	$ -	$ -	$ -
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -
			$ 240,000	**$ 498,225**	**$ 11,250**	**$ 22,995**	**$ 772,470**	**$ 593,212**

5-YEAR PROPOSAL FILLED IN TO BE A 10-YEAR PROPOSAL

Assumptions

Capacity	500 MW	After-tax CC	9.5%	Fixed O&M	$ 4.50 /kW-yr
Capacity Factor	70%	Inflation	2.5%	Variable O&M	$ 1.50 /MWh
Term Length	10 yrs	Capacity Payment	$ 96.00 /kW-yr	Fuel Costs	$ 5.00 /MMBtu
Heat Rate	6,500 Btu/kWh				

Year	Proposal Year	Capacity Payment ($/ kW-yr)	Capacity Costs ($000)	Energy Costs ($000)	Fixed O&M Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)
2003		-	-	-	-	-	-	-
2004	1	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 141,090
2005	2	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 128,850
2006	3	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 117,671
2007	4	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 107,462
2008	5	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 98,139
2009	6	108.62	$ 54,308	$ 99,645	$ 2,546	$ 4,599	$ 161,097	$ 93,455
2010	7	111.33	$ 55,665	$ 99,645	$ 2,546	$ 4,599	$ 162,455	$ 86,066
2011	8	114.11	$ 57,057	$ 99,645	$ 2,546	$ 4,599	$ 163,847	$ 79,273
2012	9	116.97	$ 58,483	$ 99,645	$ 2,546	$ 4,599	$ 165,273	$ 73,026
2013	10	119.89	$ 59,945	$ 99,645	$ 2,546	$ 4,599	$ 166,735	$ 67,280
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -
2016	13	-	$ -	$ -	$ -	$ -	$ -	$ -
2017	14	-	$ -	$ -	$ -	$ -	$ -	$ -
2018	15	-	$ -	$ -	$ -	$ -	$ -	$ -
			$ 525,459	**$ 996,450**	**$ 23,978**	**$ 45,990**	**$ 1,591,877**	**$ 992,312**

Results:	Present Value
5-Year Proposal	$ 593,212 /MW
Filled In 10-Year Proposal	$ 992,312 /MW