Noble Americas Exhibit 200
Witness: Kevin C. Higgins

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

In the Matter of PacifiCorp, dba	**)**	
Pacific Power	**)**	**Docket No. UE-307**
2017 Transition Adjustment	**)**	
Mechanism	**)**	

Rebuttal Testimony of Kevin C. Higgins

on behalf of

Noble Americas Energy Solutions LLC

August 12, 2016

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who pre-filed Opening Testimony in this proceeding on behalf of Noble Americas Energy Solutions ("Noble Solutions")?

A. Yes, I am.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony responds to the Reply Testimony of PacifiCorp witness Brian S. Dickman in which Mr. Dickman opposes my proposal to adjust the calculation of the Schedule 294, 295, and 296 transition adjustments to reflect the value of freed-up Renewable Energy Certificates ("RECs").

I also respond to Mr. Dickman's opposition to my position that in calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should <u>not</u> be escalated in Years 6 through 10, but rather should *decline* in each of those years to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization.

Q. What are the primary conclusions in your Rebuttal Testimony?

A. Mr. Dickman's objections are not reasonable grounds to reject my proposals. I continue to recommend that the Schedule 294, 295 and 296 transition adjustments should be adjusted to reflect the value of freed-up RECs. Otherwise, direct access customers will unreasonably pay for Renewable Portfolio Standard ("RPS")-related resources twice: once from their Electricity Service Supplier ("ESS") and a second time from PacifiCorp, which banks the RECs paid for by direct access customers for future use by cost-of-service customers. In the alternative, PacifiCorp could agree to transfer to the ESS the RECs for which these customers are paying the Company and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer.

Although in UE 296 the Commission did not accept my argument to adjust the transition adjustments to reflect the value of freed-up RECs, the recent passage of Senate Bill 1547 has significantly increased future Oregon RPS requirements. The increase in the RPS will exacerbate the inequities in requiring a double payment from direct access customers for RPS-related resources. This change in circumstances warrants a further consideration of this issue by the Commission in this case.

Further, in UE 296, I argued that in calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should <u>not</u> be escalated in Years 6 through 10 as proposed by PacifiCorp. Rather, Schedule 200 costs used in this calculation should *decline* each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. In my opinion, the effects of this decline in return should be passed through to the Consumer Opt-Out charge in the Schedule 296 transition adjustment.

The Commission did not accept this argument in UE 296. However, this matter is being appealed by Noble Solutions to the Oregon Court of Appeals. In the event that this issue is reconsidered by the Commission, the appropriate adjustments are presented in my testimony and exhibits in this docket.

Response to Mr. Dickman on Whether to Credit the Value of Freed-Up RECs in the Transition Adjustment for Direct Access Customers

Q. Briefly summarize the disagreement between you and the Company on the issue of whether to credit the value of freed-up RECs in the calculation of the transition adjustment for direct access customers.

A. The Oregon RPS is applicable to both cost-of-service and direct access service. When direct access customers purchase power from an ESS, the energy provided by the ESS must meet RPS requirements, which at present require that 15% of supply come from qualifying renewable electricity when serving in the PacifiCorp territory.[1] At the same time, direct access customers pay for the renewable energy that PacifiCorp has acquired to meet the RPS for its cost-of-service customers. The payments from direct access customers to PacifiCorp

[1] ORS 469A.052(1), 469A.065.

occur because the Company recovers its RPS-related costs both through Schedule 200, through which the fixed costs of utility-owned renewable generation are recovered, and Schedule 201, through which power purchases of RPS-eligible resources are recovered. Direct access customers are charged directly for Schedule 200 and also pay for the difference between Schedule 201 costs and the value of the freed-up power, as calculated through the transition adjustment calculation.

In paying both the ESS and PacifiCorp for RPS power, direct access customers are paying twice to meet RPS requirements. There is no dispute that such a double payment occurs; the dispute between Noble Solutions and PacifiCorp is whether something should be done about it. I believe the double payment extracted from direct access customers is an unintended consequence of the transition adjustment calculation. This result is both unreasonable and inequitable. To remedy this problem, I recommend that direct access customers be credited with the value of freed-up RECs in the calculation of the Schedule 294, 295, and 296 transition adjustments. I first made this proposal in UE 296, but the Commission declined to adopt it, citing to PacifiCorp's arguments in opposition.

However, circumstances have changed since the Commission ruled on this matter in UE 296. With the signing into law of Senate Bill 1547 in May 2016, the Oregon RPS will increase significantly. Under the new law, the proportion of resources that must be RPS-eligible is increased to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040. These and other significant changes in the RPS requirements warrant a further consideration by the Commission to address the problem caused by the inequity of requiring a double payment from direct access customers for RPS-related resources.

In his Reply Testimony, Mr. Dickman continues to oppose my proposal.

Q. What specific objections to your proposal does Mr. Dickman offer?

A. Mr. Dickman restates the reasons offered by the Commission in denying my proposal in UE 296. In its decision in that proceeding, the Commission accepted PacifiCorp's argument that my adjustment necessarily assumes that PacifiCorp will sell its RECs, when in fact PacifiCorp intends to bank the RECs that are freed up by direct access customers. The Commission also cited to PacifiCorp's representations that if the RECs are sold in the future, departing direct access customers will receive a share of the revenues from sales, noting that under such circumstances, the net present value of the value of any freed-up RECs would be *de minimis*.

Q. Is your recommended approach for valuing RECs freed up by direct access dependent on the assumption that PacifiCorp must sell the freed-up REC?

A. No. As I pointed out in my Opening Testimony, my argument recognizes at the outset that PacifiCorp banks freed-up RECs for the purpose of the Oregon RPS. The purpose of the valuation exercise is to establish a reasonable estimate of the value of the banked RECs that are attributable to direct access customers. While PacifiCorp may bank RECs for the purpose of the Oregon RPS, *the Company also regularly sells RECs*. The value of the Company's REC sales can be used to value the banked RECs for the purpose of incorporating the value of freed-up RECs in the transition adjustment.

Q. What about PacifiCorp's contention that if RECs are sold in the future, departing customers will receive a share of the revenues from the sales?

A. Under the scenario portrayed by the Company, if PacifiCorp elected to sell RECs that were freed up (and had been paid for) by direct access customers, the proceeds would be shared with *all* customers, with the direct access customers receiving only a tiny pro rata share. I agree that under such a system the credit to direct access customers would be *de minimis*. But this outcome is not a reason to fail to credit direct access customers with the value of the RECs they free up, it is a reason to reject the inequitable mechanism for allocating the benefits from RECs freed up by direct access customers as depicted by the Company.

Q. Can you provide a simple illustration of why the sharing of REC sale proceeds described by PacifiCorp is inequitable when the RECs in question are freed up by direct access customers?

A. Yes. First, it is important to recognize that we are talking about RECs that are freed up as a result of direct access. The RECs are freed up because PacifiCorp's RPS obligation is *reduced* pro rata for the direct access load. And at the same time, the ESS supplying the direct access customer is independently required to meet Oregon's RPS standards for its direct access load.

So let's consider an example of how the sharing arrangement described by Mr. Dickman would work. In 2015, PacifiCorp's total Oregon direct accesss load was about 208,000 MWh. With a 15% RPS requirement, this translates into an RPS requirement for the direct access load of about 31,200 MWh, meaning that the direct access customers must fund the acquisition of 31,200 RECs through their ESSs while PacifiCorp's RPS requirement is reduced by the same 31,200 RECs.

Let's assume, for illustrative purposes, a hypothetical value of $1 unbundled REC.[2] If PacifiCorp sold the 31,200 freed-up RECs at this value, it would produce revenues of $31,200. Under the mechanism described by Mr. Dickman, this $31,200 would be shared among all of PacifiCorp's Oregon customers, who, in 2015 consumed about 13 million MWh of power. Spreading $31,200 over 13 million MWh of retail load produces a credit of just over 2 tenths of a cent per MWh on all retail MWh, including direct access load.[3] For the direct access customers, the 2 tenths of a cent per MWh, given their RPS requirement of 15%, translates into a credit of about 1.6 cents per REC.[4]

So under the mechanism that Mr. Dickman portrays as reasonable, direct access customers would (1) free up RECs worth $1 a piece, (2) they would incur a cost of $1 per REC themselves for their direct access load, (3) and they would continue to fully pay for their pro rata share of PacifiCorp's RPS on half of cost-of-service customers. Yet they would get back a credit for the RECs *they freed up* of only 1.6 cents per REC. This is the result of the pro rata sharing that Mr. Dickman portrays as reasonable. In my opinion, this result is fundamentally unreasonable.

Q. How does this result compare to your recommendation?

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[2] This value is in the general range of REC values that are identified in public sources. See, for example, pricing information compiled by the US Department of Energy at http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.
[3] $31,200 / 13,000,000 MWh = $.0024 per MWh.
[4] $.0024/REC / .15 = $.016 /REC.

A. Under my recommended approach, in this example, the direct access customers would be paid the full $1 per REC for each REC they cause to be freed up. Then, if PacifiCorp were to sell the freed-up RECs, the revenue from the sale could be used to reimburse the Company for the payment to the direct access customers.

Q. Are there any alternatives to using the Company's REC sales to determine the value of RECs freed up by direct access customers?

A. Yes. PacifiCorp has issued a Request for Proposals ("RFP") to acquire new RECs to help the Company meet its RPS obligations. As an alternative to using PacifiCorp REC *sales* to value the RECs freed up by direct access customers, the value of RECs *acquired* by the Company through the RFP could be used to determine this value. If PacifiCorp will be paying third parties for additional RECs necessary to meet the RPS standard, then there is no valid reason for failing to recognize the value of RECs freed up by direct access customers, which are banked for later use for the benefit of the Company's cost-of-service customers. The RFP pricing should provide a convenient means for determining this value. Moreover, this alternative approach dispenses with the Company's contention that the Company's REC sales cannot be attributed directly to RECs freed up by direct access. Additionally, the Company's recent acquisition of RECs to meet the newly increased RPS standard is a materially different factual circumstance than that in existence when the Commission addressed this issue last year. The Company is no longer simply banking excess RECs but is also actively acquiring RECs for future use and has stated it will continue to hold additional REC RFPs to meet its new RPS requirements.

Q. Does Mr. Dickman offer additional reasons for opposing your proposal?

A. Yes. Mr. Dickman argues that valuing RECs would be administratively burdensome. In support of his argument, Mr. Dickman asserts that if a REC credit is provided to direct access customers, then remaining customers would have to be surcharged. Further, Mr. Dickman contends that RECs that are "hypothetically sold" would have to be separately tracked to ensure that if a direct access customer returns to cost-of-service rates, the customer would not receive any benefit from those RECs. Mr. Dickman raises the specter of having to create "multiple REC banks" just to keep track of all of this information.

Q. What is your response to Mr. Dickman's arguments concerning the administrative burden of adopting your proposal?

A. Mr. Dickman's arguments are without merit. First, the Company has already contended that the REC values that would be provided to direct access customers would be *de minimis*. No surcharge should be necessary to recover the costs of credits that PacifiCorp maintains are too trivial or minor to merit consideration. Further, to the extent that recovery is determined to be appropriate, it could be accomplished through the recently-created Schedule 203, the Renewable Resource Supply Deferral Adjustment, which recovers the costs deferred for renewable resources as approved by the Commission, and which apparently is not unduly burdensome for PacifiCorp to administer.

Second, it is difficult to take seriously Mr. Dickman's claim that crediting direct access customers with the value of the RECs they free up would require "multiple REC banks" to ensure that direct access customers who were credited with freeing up RECs in one period did not receive the benefit of the banked REC in a later period. In making this argument, Mr. Dickman fails to recognize that the issue he raises concerning RECs acquired in one period and banked for use in a later period really pertains to a much more general policy question of how to rationalize paying for a resource in one period and using it later when the composition of customers may have changed. Totally apart from direct access, future customers who are not yet on the PacifiCorp system do not pay for RECs that are acquired today and banked for later use. Yet Mr. Dickman shows no concern and offers no proposals to establish "multiple REC banks" to ensure that *new* cost-of-service customers, who join the system say in 2020, do not benefit from banked RECs created in 2016. Yet, this is exactly what he contends would be needed for direct access customers if they were credited with the RECs they freed up. In fact, in the scenario posited by Mr. Dickman, direct access customers are simply a specific case in the more general situation created when banking is pursued. Today's direct access customers are <u>not</u> PacifiCorp's cost-of-service customers, just as a cost-of-service customer who does not materialize until 2020 is not a PacifiCorp customer today. If a direct access customer returns to cost-of-service rates pursuant to the terms and conditions of the Company's tariff then that customer should be not be treated any differently than a brand new cost-of-service customer. And just as it would be considered ill-advised to establish "multiple REC banks" to ensure that future new customers did not receive the benefits of RECs that are banked today, any proposal to subject direct access customers to a proposal to require such tracking should be rejected as equally frivolous, as well as discriminatory.

Q. Are there any alternative approaches to accomplishing your objective?

A. Yes. In my Opening Testimony, I suggested an alternative in which PacifiCorp could agree to transfer to the ESS the RECs for which the ESS's direct access customers are paying PacifiCorp and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer. This solution would address all of PacifiCorp's objections, to the extent there is any merit to any of those objections, but PacifiCorp did not respond to this proposal in its Reply Testimony.

<u>Response to Mr. Dickman Concerning the Escalation of Schedule 200 in the Calculation of the Consumer Opt-Out Charge</u>

Q. Briefly summarize the disagreement between you and the Company regarding the escalation of Schedule 200 rates in the calculation of the Consumer Opt-Out Charge.

A. In UE 296, I recommended two refinements to the calculation of the Consumer Opt-Out Charge. PacifiCorp's calculation of the Consumer Opt-Out charge is based on projected Schedule 200 costs for Years 6 through 10. Under PacifiCorp's approach, these projected costs are simply current Schedule 200 rates escalated at an assumed rate of inflation. However, I argued that it is not reasonable for Schedule 200 costs to be escalated for Years 6 through 10 as part of this calculation, because the five-year opt-out customer will have already departed cost-of-service rates five years prior, and *incremental* fixed generation costs incurred during Years 6 through 10 should not be incurred on the departed customer's behalf. Rather, the opt-out charge for Years 6 through 10 should be limited to the generation investment that had been built for the departed customer's benefit. At the maximum, this would extend to the five-year planning horizon following the customer's departure (i.e., Years 1 through 5 of the opt-out period). Consistent with this position, I have not objected to assumed Schedule 200 cost escalation for Years 1 through 5. The allowance for escalation of costs in the first five years is very conservative from Noble Solutions' perspective because it assumes that PacifiCorp cannot unwind prior commitments for five full years after the date of the opt-out election.

My first refinement to the Consumer Opt-Out charge was that Schedule 200 costs should not be escalated in Years 6 through 10; since incremental generation expenditures are not incurred on departed customers' behalves, it is not reasonable to assume increased Schedule 200 costs for departing customers beyond the projected Year 5 Schedule 200 price.

The second refinement is an extension of this argument. Not only should Schedule 200 costs not be escalated for the purpose of determining the Consumer Opt-Out charge, these costs should in fact *decline* each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. That is, as I just discussed, the portfolio of generation resources acquired to meet the departed customer's load should not be increased after Year 5. Once the portfolio of assets is "frozen" for the purposes of this calculation, the revenue the Company earns from its return on these assets properly will decline each year as a portion of those assets is depreciated and amortized. This treatment is consistent with basic ratemaking principles, which provide that a utility's return is earned on its net plant, reflecting the removal of accumulated depreciation and amortization from rate base. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.

The Commission did not accept my recommendation in UE 296. However, Noble Solutions has appealed this decision in the Oregon Court of Appeals. In my Opening Testimony in this docket, I testified that if this issue is readdressed by the Commission, then the reduction in overall Schedule 200 revenue requirement of 2.36% per year that I calculated in UE 296 is still applicable. The appropriate adjustments are presented in my Opening Testimony and Exhibits in this docket.

In his Reply Testimony, Mr. Dickman objects to my proposal. Mr. Dickman maintains that the escalation of Schedule 200 costs in Years 6 through 10 is necessary to account for the time value of money, allowing the fixed generation costs to be reduced to a present value to calculate the Consumer Opt-Out Charge. Mr. Dickman asserts that if it is appropriate to include an inflation adjustment in Years 1 through 5, as Noble Solutions concedes, then it is equally appropriate to have the same adjustment in Years 6 through 10.

Q. Is it necessary to include an inflation adjustment if a discount rate is used?

A. No. When applying present value analysis using a nominal discount rate, the analyst should use projected future values that reflect the actual expected future values, including inflation, *but only to the extent that the variable in question is actually subject to inflation*. If, as is the case with the return on a discrete set of rate base items, the value is expected to *decline* due to accumulated depreciation, then it is <u>not</u> proper to mechanistically inflate these values simply because a discount rate is being used.

Q. In reality, have Schedule 200 rates been escalating as projected by PacifiCorp in the Consumer Opt-Out Charge calculation?

A. No. In Table KCH-1 below, I compare PacifiCorp's projections for Schedule 200 provided in UE 296 for calculating the Consumer Opt Out Charge for Schedules 47/48[5] to the same projections in this case.[6]

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[5] PacifiCorp's Schedule 200 projections for calculating the Consumer Opt Out Charge in UE 296 were presented in Exhibit Noble Solutions 102, Higgins/4 in that docket.

[6] PacifiCorp's Schedule 200 projections for calculating the Consumer Opt Out Charge in this docket are presented in Exhibit Noble Solutions 104, Higgins/3.

Table KCH-1

Comparison of PacifiCorp Schedule 200 Projections		
Year	UE-296 PacifiCorp Projected Avg Schedule 200 for Schedule 47/48 ($ per MWh)	UE-307 PacifiCorp Projected Avg Schedule 200 for Schedule 47/48 ($ per MWh)
2015	$26.98	
2016	$27.49	
2017	$28.01	$26.73
2018	$28.54	$27.31
2019	$29.08	$27.91
2020	$29.63	$28.55
2021	$30.19	$29.24
2022	$30.76	$29.94
2023	$31.34	$30.96
2024	$31.94	$31.43
2025		$32.15
2026		$32.86

As shown in Table KCH-1, the projected Schedule 200 rate for 2017 in UE 296 was $28.01 per MWh, which was calculated *by adding two years of projected inflation* onto the 2015 Schedule 200 rate of $26.98 per MWh.

However, in this docket, Table KCH-1 shows that the updated Schedule 200 rate for 2017 of $26.73 per MWh is actually even slightly less than the 2015 rate of $26.98. Thus, the two years of Schedule 200 inflation that were baked into the 2017 value in UE 296 did not materialize.

The point here is not to exclude inflation from the calculation in Years 1 through 5, but to dispel the notion that Schedule 200 inflation is somehow inexorable, or necessary to conduct a present value analysis, or that it even represents a conservative assumption from PacifiCorp's standpoint. It is none of those things. (It is a conservative assumption from *Noble Solutions'* standpoint in that Noble Solutions is not objecting to including the inflation assumption for Years 1 through 5.)

Q. How do you respond to Mr. Dickman's claim that if the inflation adjustment is appropriate for Years 1 through 5 then it must be equally applicable to Years 6 through 10?

A. That is simply not the case. One of Mr. Dickman's own statements demonstrates the flaw in the Company's argument. On page 93 of his Reply Testimony, Mr. Dickman states:

> In fact, the exact same inflation adjustment is made to the fixed costs in years one through five as in years six through 10 because costs from both periods must be reduced to a present value to calculate the charge. The only difference between the two periods is that years six through 10 do not include costs of new investments.

According to Mr. Dickman, Years 1 through 5 include the costs of new investments whereas Years 6 through 10 do not. However, the Company's workpapers indicate that *virtually identical inflation rates were applied to both periods*. On its face, five years of inflation *including* new investments and five years of inflation *excluding* new investments would not be governed by the same inflation assumptions.

Q. On pages 93 to 94 of his Reply Testimony, Mr. Dickman depicts the Company's inflation methodology as comparable to that used by Portland General Electric ("PGE") in its five-year opt-out program. Do you believe this is an apt comparison?

A. No, not at all. The dispute in this case regarding cost escalation pertains to the inflation assumptions used by PacifiCorp for Years 6 through 10 in the calculation of the Consumer Opt Out Charge. Unlike PacifiCorp, *PGE does not even have a consumer opt out charge*. PGE's five-year program assesses transition charges based on only five years of ongoing valuation calculations, whereas PacifiCorp assesses ten years of transition charges calculated through the ongoing valuation method. And consequently, PGE's calculations have no need for cost escalation assumptions for Years 6 through 10 because those years play no role whatsoever in determining PGE's transition adjustments for its five-year opt-out program.

Q. On page 94 of his Reply Testimony, Mr. Dickman lists a number of fixed generation costs that could increase for existing assets, which he claims you ignore. What is your response to this argument?

A. Each of the items listed by Mr. Dickman (overhauls, capital additions, maintenance, union labor contracts, etc.) is a cost incurred to provide *forward-going* service some six to ten years (or more) *after* the direct access customer has departed the Company's generation service. My adjustment provides for continued *full* recovery of the assets that the departed customer "left behind" after adjusting properly for accumulated depreciation. The purpose of the exercise of calculating "uneconomic utility investments" attributable to the five-year program participant and thus eligible for inclusion in the consumer opt-out charge is to estimate the above-market costs of the fixed generation investments that *were* incurred on that customer's behalf.[7] But it does not include new expenditures incurred to provide forward-going service to the Company's future cost-of-service customers – nor should it.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

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7 Oregon's direct access statute defines "uneconomic utility investments," in pertinent part, as:

> "all electric company investments, including plants and equipment and contractual or other legal obligations, properly dedicated to generation, conservation and workforce commitments, that *were prudent at the time the obligations were assumed* but the full costs of which are no longer recoverable as a direct result of ORS 757.600 to 757.667, absent transition charges."

ORS 757.600(35) (emph. added).