August 2, 2017

Via Electronic Filing and FedEx

Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. UE 323– Rebuttal Testimony of Thomas Vitolo, PhD On Behalf of Sierra Club

Please find enclosed the original Confidential Rebuttal Testimony of Thomas Vitolo, PhD On Behalf of Sierra Club in Docket No. UE 323. The public version of this document was filed electronically and served upon all party representatives for this proceeding via e-mail. The confidential portion of this document was served pursuant to Protective Order No. 16-128 upon all eligible party representatives via FedEx or U.S. Mail.

Please do not hesitate to contact me if you have any questions or need other materials. Thank you.

Sincerely,

/s/ Alexa Zimbalist

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BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism	Docket UE-323

CERTIFICATE OF SERVICE

I hereby certify that on this 2nd day of August, 2017, I caused to be served the foregoing **Rebuttal Testimony and Exhibit of Thomas Vitolo, PhD On Behalf of Sierra Club** upon all party representatives on the official service list for this proceeding via electronic mail. The public version of this document was served upon parties via email, and the confidential portion of this document was served pursuant to Protective Order No. 16-128 upon all eligible party representatives via FedEx or U.S. Mail.

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Dated this 2nd day of August, 2017 at Oakland, CA.

/s/ Alexa Zimbalist

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BEFORE THE
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PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism	Docket UE-323

Rebuttal Testimony of Thomas Vitolo, PhD

On Behalf of
Sierra Club

REDACTED

August 2, 2017

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Exhibit List

Exhibit Sierra Club/201	PacifiCorp Responses to Sierra Club Data Requests 2.8 and 2.9

Q Are you the same Thomas Vitolo who previously submitted direct testimony in this proceeding on behalf of Sierra Club?

A Yes.

1. PURPOSE OF TESTIMONY

Q What is the purpose of your rebuttal testimony?

A My testimony responds to the rebuttal testimonies of Dana M. Ralston and Seth Schwartz. I address several issues related to PacifiCorp's coal contracts and the impacts that provisions in those contracts have on the optimal dispatch of PacifiCorp's coal units.

Q Please summarize your rebuttal testimony.

A First, I respond to Company Witness Ralston's incorrect assessment of my analysis and provide a revised assessment of the model I provided in direct testimony. Contrary to Mr. Ralston's assertion,[1] the model I relied on in my direct testimony does not use an average price for coal; rather it uses a "first-in, first-out" coal price inventory and accounting methodology to correctly capture the actual tier-1 and tier-2 payments made by PacifiCorp. In this rebuttal testimony, have updated the model by changing the first month of each calendar year to ensure accurate tier-1 and tier-2 payments

Second, I explain why decisions to sign minimum-take fuel contracts can result in actual dispatch dramatically inconsistent with optimal operations, that multiple-year minimum-take fuel contracts exacerbate that risk, and that a lack of appropriate accountability and a clearly defined, transparent process further exacerbates the risk of uneconomic overuse of coal-fired generators.

[1] PAC/600, Ralston/11

Q What do you recommend?

A My direct testimony included four recommendations to the Commission.[2] Three of those recommendations remain. However, I am withdrawing my second recommendation to reduce the coal fuel expense by $2.4 million. As discussed in more detail below, the revisions I made to the coal pricing model no longer support this adjustment because the difference in revenue between the "Actual" and "Minimum" dispatch scenarios for Naughton is negligible.

However, I stand by my other recommendations. PacifiCorp's long-term coal contracts with minimum take provisions are creating an impediment to optimal dispatch of those units. To address this issue, I continue to recommend the following actions:

- I recommend that the Commission direct PacifiCorp to refrain from entering into new multi-year coal supply and transportation agreements until the Commission has an opportunity to more carefully review how these contracts are affecting economic dispatch.

- I recommend that the Commission require PacifiCorp to demonstrate that any unit's dispatch in excess of its corresponding minimum-take quantities was in the best interest of rate payers in all future TAM proceedings.

- I recommend that the Commission require PacifiCorp to include all variable costs when making decisions regarding unit commitment and dispatch, including real-time, day-ahead, annual, and long-term planning horizons.

[2] Sierra Club/100, Vitolo/18-19

2. MODELING NAUGHTON

Q Please describe the modeling you performed of the Naughton plant.

A As I described in my direct testimony,[3] I used a spreadsheet dispatch model to simulate 15-minute dispatch at of each of the three Naughton units. The model inputs are the historical 15-minute locational marginal prices, the tons of coal to be burned in the year, the historical monthly Kemmerer coal purchase quantities and prices, and the capacity of the generating units.

I modeled each unit as an ideal two-state generator, capable of switching from "off" to "fully-on" instantly. Because the model operated each generator in a far more flexible fashion than the generators are actually capable, the modeled generators capture each of the high-priced intervals and turn off immediately before a low-priced interval begins. To meet the theoretical maximum revenue levels shown in the modeling results, unit operators would need to take immediate advantage of each high-priced interval, even if only 15 minutes in lengths optimal prices. In practice, the Naughton units can never generate quite as much revenue as the spreadsheet model calculates because they are physically incapable of reacting instantly to demand. Therefore, the model is always optimistic with respect to revenue projection.

Q How did you determine the fuel costs in your model?

A The coal costs in the spreadsheet dispatch model came directly from PacifiCorp's Monthly Fuel Reports.[4] This allowed me to use the actual costs PacifiCorp paid for the coal—costs which vary slightly from month to month.

[3] Sierra Club/100, Vitolo/11-13
[4] Sierra Club/102, Vitolo/10 (See Attach ICNU 0011-3 CONF, "2015 Jan-Dec Fuel Supply Cost Calculations CONF.xls" and "2016 Jan-Dec Fuel Supply Cost Calculations CONF.xls")

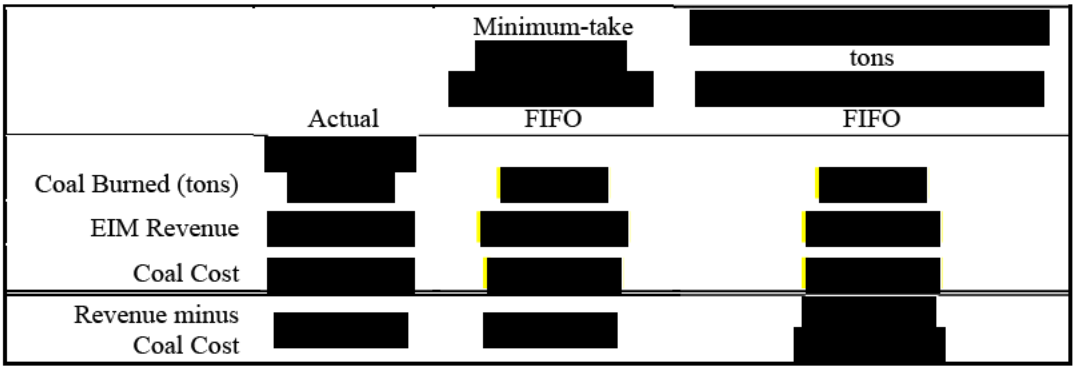
Q Company Witness Ralston asserts in his reply comments that your model used "average consumed cost of July 2015 to June 2016 instead of the *tier-1* price." (PAC/600, Ralston/11). Is his assertion correct?

A No. Recognizing that the contract to supply Naughton with coal includes both tier-1 and tier-2 prices, I used a first-in, first-out (FIFO) accounting technique. Under FIFO, the inventory items purchased or manufactured first are recorded as sold first. This approach allows for the cost of the first [redacted] million tons to reflect the higher priced tier-1 portion of the contract.

I relied on the Company's response to a data request to establish the first month in the contract year,[5] which was a necessary data input for applying FIFO accounting to a multiple tier pricing contract with annually resetting price-quantity pairs. Based on that response, the initial modeled contract year was from [redacted] to [redacted] the following year. This approach is corroborated by Mr. Ralston's reply testimony when he refers to the "July 2015 to June 2016 contract year."[6] However, upon inspection of the monthly average cost of coal delivered to the Naughton plant over the 2015–2016 study period, it became evident that [redacted] had significantly lower prices than all the other months. This suggested that the appropriate contract year for this analysis was [redacted] to the following [redacted], thereby ensuring that tier-1 prices are paid until the quantity of coal purchased reaches the tier-2 threshold. Rerunning the spreadsheet dispatch model with [redacted] as the first month in the coal contract, the results were somewhat different, as shown in Confidential Table 1 below.

[5] Sierra Club/102, Vitolo/7-8 (See "Attach Sierra Club 2.6 -1 CONF.xlsx", cells J30 and K30)
[6] PAC/600, Ralston/10 at line 20

Table 1: Naughton July 2015 – June 2016 Model Results



Q Please describe the [redacted] FIFO model results with respect to the actual coal burned versus the Minimum-take scenario.

A The results for the Actual model run were unchanged because 100 percent of the year's purchases were consumed regardless of which month is the first month in the contract year. For the Minimum-take scenario in which [redacted] million tons were consumed, the coal cost was [redacted] in the [redacted] FIFO model run. When compared to the results in my direct testimony, the [redacted] million tons model run still results in a slightly larger value for revenue minus coal cost more revenue than the Actual run, and still has a lower total variable operations and maintenance cost than the Actual model run. However, the revenue minus coal cost results of the Actual and 2.4 million-ton model runs are very similar. The difference is small enough that this model cannot be used to determine if one dispatch strategy was better or worse for ratepayers than the other.

Q Does the analysis using a [redacted] FIFO inventory scheme instead of a [redacted] FIFO inventory scheme as initially modeled change any of your recommendations?

A Yes. My original recommendation to reduce coal fired expense was based on the modeled difference between the Actual and Minimum-take scenarios. When the model uses a [redacted] FIFO scheme rather than a

[redacted] FIFO scheme, that difference is no longer $2.4 million. Although a difference remains, it is small enough that the spreadsheet dispatch model cannot be used to determine if one dispatch strategy was better or worse for ratepayers than the other. Therefore, I no longer recommend that the Commission reduce the coal-fuel expense increase in the 2018 TAM by $2.4 million.

Q Please describe the [redacted] FIFO model results with respect to the actual coal quantity burned versus the scenario where only [redacted] million tons of coal are burned.

A As discussed above, the results for the Actual model run were unchanged because 100 percent of the year's purchases were consumed regardless of which month was the first month in the contract year. For the scenario in which [redacted] million tons were consumed, the coal cost was [redacted] in the [redacted] FIFO model run against [redacted] in revenue. The difference, labeled the revenue minus coal cost, is [redacted]. As the Actual model run had a revenue minus coal cost of [redacted], the [redacted] million tons model run had a [redacted] million-dollar revenue minus coal cost advantage over the Actual model run. This was in addition to having a lower total variable operations and maintenance cost than the Actual model run, because total variable operations and maintenance costs increase with each ton of coal burned. Therefore, the conclusion remains the same as found in my direct testimony: Ratepayers would have been better off had PacifiCorp been able to burn only [redacted] million tons of coal in the year studied, rather than the [redacted] million tons actually burned.

Q Was it economically possible for the Kemmerer mine to sign a [redacted] million ton minimum-take coal contract to supply Naughton in 2015–2016?

A I believe so. It may be generally true that "customers must commit to substantial minimum purchase levels … in order to support the economic operations of the coal supplier."[7] However, the [redacted] of the Kemmerer coal contract describes just such a reduction in annual deliveries, from [redacted] million tons to [redacted] million tons, effective [redacted], at [redacted] and [redacted] prices.[8] Kemmerer Mine is clearly capable of operating with a contractual minimum-take of [redacted] million tons beginning in 2017 at similar prices, and is contractually obligated to do so. I have no reason to think the mine couldn't have also operated within that production range two years ago at similar prices.

Q Do you stand by your recommendations related to minimum take provisions in PacifiCorp's coal contracts?

A Yes. Even after adjusting to the [redacted] FIFO model, the results continue to show that the minimum-take provisions in the Naughton coal contract prohibited optimal dispatch. I continue to recommend that the Commission explicitly direct PacifiCorp to refrain from entering into any new contracts for coal fuel or transportation unless and until the Commission has had an opportunity to review whether and how these multi-year commitments in coal contracts are affecting economic dispatch. I also continue to recommend that the Commission require PacifiCorp to demonstrate that any unit's dispatch in excess of its corresponding minimum-take quantities was in the best interest of ratepayers in all future TAM proceedings. Finally, I continue to recommend that the Commission direct PacifiCorp in future TAM dockets and other resource

[7] PAC/700 Schwartz/4 line 17
[8] Sierra Club/102, Vitolo/7-8 (See "Attach Sierra Club 2.6 -1 CONF.xlsx", cells H34, H35, J30, and J31)

planning proceedings to include all variable costs when making decisions regarding unit commitment and dispatch, including real-time, day-ahead, annual, and long-term planning horizons.

3. MULTI-YEAR MINIMUM-TAKE COAL CONTRACTS LEAD TO SUBOPTIMAL DISPATCH

Q Do you agree with Mr. Schwartz' conclusion that PacifiCorp's general approach to negotiating long-term coal contracts is reasonable?[9]

A I agree with Mr. Schwartz' observation that multi-year coal supply contracts are common in the industry. However, I do not agree that PacifiCorp has provided sufficient information to conclude that its long-term coal contracts are prudent. Long-term coal contracts that include minimum-take or liquidated damages provisions create financial commitments for the Company's coal plants that can be in the hundreds of millions of dollars for a single plant. These financial commitments can match, or even exceed, the magnitude of costs necessary for major capital expenditures, yet the decision to enter into these commitments typically receives far less scrutiny.

Q Please explain why a contract with a minimum take provision is a commitment to a minimum capacity factor at a coal station.

A Coal fired power plants (or adjacent mine-mouth mines) typically have a coal stockpile, where a supply of coal is stored. Although the quantity varies, there is always a maximum quantity of coal that can be stored, both due to hard physical constraints and the escalating financial costs that come with excessive inventory. Additionally, as explained by Witness Schwartz, "few of PacifiCorp's coal-fired power plants have access to a liquid coal market."[10] For example, the Naughton plant has "no current coal supply options as the plant takes delivery by conveyor

[9] PAC/700 Schwartz/12
[10] PAC/700 Schwartz/12

from the Kemmerer mine and is located remote from any other mining operations."[11]

Because there is an upper limit on the amount of coal a power station can store on-site, and because it is typically physically impossible or extremely expensive to physically move coal from one PacifiCorp power station to another, for most PacifiCorp coal-fired power plants, a commitment to purchase coal is a commitment to burn the coal at that power station within the same contract year.

Q What is Naughton's minimum capacity factor for the 2015–2016 timeframe, given PacifiCorp's minimum-take contract?

A As discussed above, a reasonable estimate of a plant's minimum energy generation for a future year is simply the energy that would be generated should that year's minimum-take coal be burned. In the case of Naughton for the 2015—2016 contract year, their minimum-take quantity of [redacted] million tons corresponds with approximately [redacted] MWh. Naughton's combined capacity is 637 MW,[12] implying a minimum annual capacity factor of approximately [redacted] percent, subject to the Naughton units maintaining adequate availability over the year.

Q Does PacifiCorp dispute that customers would have been better off if Naughton could have dispatched at [redacted] million tons per year without incurring a take-or-pay penalty?

A No. As shown in Mr. Ralston's Confidential Table 2[13], the [redacted] million-ton dispatch scenario only becomes more expensive to ratepayers when the take-or-pay penalty is included. PacifiCorp's own analysis shows that when that penalty is removed, the [redacted]

[11] PAC/700 Schwartz/13
[12] PacifiCorp 2017 Integrated Resource Plan Volume 1 (April 4, 2017), Table 5.3, https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf
[13] PAC/600, Ralston/12

million-ton dispatch would have had [redacted] million more revenue minus coal cost than the actual dispatch model outcome, even larger than my estimate of [redacted] million.

Q What capacity factor corresponds with a [redacted] million-ton annual take for Naughton Units 1, 2, and 3?

A A [redacted] percent capacity factor corresponds with the three Naughton units consuming a total of [redacted] million tons of coal in a year.

Q What is Naughton's minimum capacity factor for the 2017–2018 contract year?

A As discussed earlier, the minimum-take quantity is reduced from [redacted] million tons to [redacted] million tons upon the retirement of Unit 3. Naughton 1 and 2 have a combined remaining capacity of 357 MW. The corresponding minimum annual capacity factor therefore increases to [redacted] percent.

Q In the light of the risk that a minimum-take contract may require operating the unit more often than would otherwise be optimal, should a utility never sign a minimum-take contract?

A As Mr. Schwartz discusses, a minimum-take provision may be a necessity for some coal contracts.[14] That the minimum-take provision imposes a financial risk on the utility ratepayers does not mean that minimum-take contracts must be avoided. On the other hand, it is incumbent on the utility to minimize contractual risk wherever possible, and that includes agreeing to a minimum-take (and maximum-take) that appropriately balances the financial consequences of not dispatching often enough and dispatching too often.

Multi-year minimum-take contracts are substantially riskier. To the extent that a minimum-take provision doesn't align with the appropriate dispatch, the loss

[14] PAC/700 Schwartz/8

multiplies with each additional year in the multi-year contract. Additionally, the electric industry periodically undergoes substantial structural changes that can be difficult or impossible to predict. National economic outlook, international relations, access to new fuel resources, and the changing capital costs of new generators can all result in substantial changes to dispatch at a given generator over the span of just two or three years. Multi-year contracts necessarily expose utilities ratepayer to these structural risks whereas single-year minimum-take contracts minimize this exposure.

Q How does PacifiCorp reduce the ratepayer risk associated with multi-year minimum-take coal contracts?

A I don't know. Sierra Club asked PacifiCorp to describe in detail the process it used to evaluate the negotiated position for coal and rail contract terms, including how the Company assesses and evaluates reasonable coal contract minimums, term of agreement, price(s), and liquidated damages.[15] PacifiCorp responded with a list of general considerations, and summarized that the process "takes into consideration the unique circumstances"[16] of each plant. The Company did not, however, indicate that it uses any structure, procedure, tools, or processes to decide whether to sign a multi-year minimum-take contract for coal or coal transport.

Q What is the total financial obligation associated with the multi-year minimum-take contracts?

A Each contract is unique in length, price, and minimum take quantity. The current Kemmerer Mine contract runs from [redacted] to [redacted], a length of [redacted] years.[17] It has a minimum-take of [redacted] million tons for the first contract year, and a minimum-take of

[15] Sierra Club/102, Vitolo/6 (Sierra Club DR 2.3); Sierra Club/201,Vitolo/1-3 (Sierra Club DR 2.8 and 2.9)
[16] Sierra Club/102, Vitolo/6 (Sierra Club DR 2.3(a)); Sierra Club/201, Vitolo/1-3 (Sierra Club DR 2.8(d) and 2.9(c))
[17] Sierra Club/102, Vitolo/7-8 (See "Attach Sierra Club 2.6 -1 CONF.xlsx", rows 23-38)

[redacted] million tons for subsequent years. If we assume no price escalation and just use the 2016 price of [redacted] per ton, the total value of the contract exceeds [redacted] million. A contractual commitment to spend hundreds of millions of dollars of ratepayer money on a single capital expenditure would be subject to considerable scrutiny and subject to a finding of imprudence. I believe that coal contracts of similar magnitude warrant similar scrutiny.

Q Does this conclude your rebuttal testimony?

A Yes.

UE 323 / PacifiCorp
May 25, 2017
Sierra Club Data Request 2.8

Sierra Club Data Request 2.8

Refer to the direct testimony of Dana Ralston, page 18 at 3-9 with respect to the Dave Johnston Powder River Basin RFP.

(a) Describe in detail the process used by the Company to determine the tonnage of coal expected to be consumed by Dave Johnston power plant in 2018. Provide work papers supporting this expectation.

(b) Provide the PRB RFP as issued, or in draft form if not yet issued.

(c) Would the Company accept new contracts with minimum tonnage requirements at Dave Johnston? If so, provide the analysis, or an example of such analysis, conducted by the Company to determine the reasonable minimum tonnage accepted under this or similar contracts.

(d) Describe in detail the process used by PacifiCorp to evaluate bids for coal, including how the Company assesses and evaluates the key terms, including but not limited to term, price or price indexing, fixed contract components, minimum tonnage, ability to redirect shipments, and termination fees or damages.

Response to Sierra Club Data Request 2.8

(a) The tonnage of coal consumed at the Dave Johnston plant in the 2018 Transition Adjustment Mechanism (TAM) is determined by the optimized dispatch of all the Company's generating resources using Generation and Regulation Initiative Decision Tool (GRID). The incremental coal cost for the Dave Johnston, which includes the minimum take-or-pay provisions specified within the supply contract, is input into GRID and the dispatch is based on multiple variables including but not limited to, system load, coal and gas operation limitations (heat rate, fuel prices, ramp rate, up/down times, outage, etc.), hydro and wind generation, contractual positions, market prices and firm transmission constraints. No adjustments to the incremental coal costs of Dave Johnston were needed to reflect the minimum coal volume requirement. Please refer to the confidential work papers supporting the Direct Testimony of Company witness, Dana M. Ralston; specifically the file entitled "Incremental Costs 2018 TAM" and to Confidential Attachment Sierra Club 2.8 -1.

(b) Please refer to Attachment Sierra Club 2.8 -2, which provides a copy of the Dave Johnston Powder River Basin (PRB) request for proposals (RFP).

(c) The PRB coal region is the largest coal producing region in the United States (U.S.). The Dave Johnston plant is within 200 miles of all of the Wyoming PRB mines (13

mines). Since October 1999, the Company has fueled the plant with PRB coal transported by rail.

For the Dave Johnston plant, the Company maintains a portfolio of contracts to provide the plant's coal requirement. The contracts in this portfolio are spot and short-term contracts. To secure coal, the Company regularly solicits proposals (bids) from all of the Wyoming PRB mines through a formal RFP process. Proposals (bids) received by the Company are then reviewed to determine which bids best meet the Company strategy for length of term, coal quality, heat rate, transportation and pricing. Contracts resulting from this process have fairly uniform terms, including take-or-pay contract requirements.

The RFP process, the resulting short-term contracts, and the use of the plant's inventory provide the Company with the ability to control the volume of coal purchased and ensure that purchases do not exceed the plant's coal requirement.

(d) The Company objects to this request on the basis that it is overly broad and not likely to lead to admissible evidence relevant to this proceeding. Notwithstanding the foregoing objection, the Company responds as follows:

The process used in evaluating bids for coal contracts reflects the unique circumstances of each plant, potential suppliers, coal quality and volume requirements, availability of transportation infrastructure, and the economics and risks associated with each transaction, including risks connected with minimum tonnage, the potential for liquidated damages and termination fees.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 323 / PacifiCorp
May 25, 2017
Sierra Club Data Request 2.9

Sierra Club Data Request 2.9

Refer to the direct testimony of Dana Ralston, page 19 at 1-5 with respect to Railway agreements.

(a) Provide a copy of the existing contract that expires in 2017.

(b) Provide the basis of the expected increase and what elements of the Company's experience inform that expectation.

(c) Describe a narrative of the process used by PacifiCorp to evaluate and negotiate a new rail contract, including how the Company assesses and evaluates the key terms, including but not limited to term, price or price indexing, fixed contract components, minimum tonnage, ability to redirect shipments, and termination fees or damages.

(d) Provide the analyses conducted by the Company to determine the reasonable term, price, fixed contract components, minimum tonnage, and termination fees or damages associated with the new BNSF Railway agreement.

Response to Sierra Club Data Request 2.9

(a) The Company requests special handling. Please contact Natasha Siores at (503) 813-6583 to make arrangements for review.

(b) The Dave Johnston plant is captive to BNSF for the rail delivery of Powder River Basin (PRB) coal. Trucking the coal is not feasible due to long haul distances and a lack of truck loading infrastructure at PRB mines. The current BNSF rail contract became effective January 1, 2014. On January 1, 2014, the average increase in historically utilized rates exceeded 15 percent compared to the rates in the prior agreement. Based on prior negotiations, the current economic climate and professional judgment, we are forecasting an increase of 8 percent.

(c) The processes used in evaluating rail contract proposals take into consideration the unique circumstances of each plant, potential transportation alternatives, coal quality and volume requirements, configuration and availability of unloading infrastructure, and the economics and risks associated with each transaction, including risks connected with minimum tonnage, the potential for liquidated damages and termination fees.

(d) The contract negotiation process is ongoing and has not been completed, and no analysis has been conducted.